BestPractices Steam End User Training Guide

Alternate Text Narratives and Graphic Descriptions

September 13, 2010

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Steam End User Training
Welcome Module

Slide 1 – Steam End User Training

Welcome to the Department of Energy's Industrial Technologies Program BestPractices Steam End User Training. The Department of Energy does not endorse products, thus the visuals in this training will be vendor-neutral.

[Slide Visual – Steam End User Course Welcome]

Banner:
US Department of Energy
Energy Efficiency and Renewable Energy

US Department of Energy's
Industrial Technologies Program

BestPractices
Steam End User Training

Slide 2 – Course Contents

There are seven different sections in this training. The navigational tutorial will provide you with a brief demonstration on how to navigate through the training. The Introduction will provide you a history of the course development, and then focus on the general aspects of steam system management and investigation. In this section we will introduce the first of the steam system software tools, the Steam System Scoping Tool, or SSST, which provides support in identifying areas of potential improvement. This will prepare you for more in-depth discussions in the forthcoming sections of the training, including utilizing additional software tools from the BestPractices Steam System Tool Suite such as the Steam System Assessment Tools, SSAT, and the 3E-Plus Insulation Tool. The Steam Generation Efficiency module focuses on boiler efficiency. In this section the definition of boiler efficiency will be discussed and the various avenues of boiler losses will be explored. Resource Utilization Effectiveness will discuss fuel selection, steam demands, and cogeneration. The Steam Distribution System Losses module will cover steam leaks, steam traps, insulation issues, and condensate loss. Everything will be wrapped up with the Conclusion. Lastly, there will be an End of Course Quiz, which will evaluate your knowledge and understanding of the training.

[Slide Visual – Steam End User Course Contents]

- Navigational Tutorial
- Introduction - (SSST)
- Steam Generation Efficiency - (SSAT)
  - Boiler efficiency definition
  - Shell, Blowdown, and Stack Losses
- Resource Utilization Analysis – (SSAT)
  - Fuel selection
  - Steam demands
  - Cogeneration
- Steam Distribution System Losses - (3E-Plus)
  - Steam leaks
  - Steam traps
  - Insulation issues
  - Condensate loss
- Conclusion
- Quiz

Slide 3 – Steam Assessments

This course is structured like a typical steam system assessment. The assessment is designed to investigate the performance characteristics of the system, point out best practices, identify opportunities to improve performance, and evaluate the economic impact of potential improvements.
This training will provide an overview of typical steam systems, their components, operating principles, management techniques, and potential improvement opportunities.

Steam system modifications often affect the entire system requiring complicated calculations to accurately evaluate mass, energy, and economic impacts. This course will point out the various tools we have available to us in the investigation process. Many of the tools are the fundamental principles of physics that allow us to identify the "before" and "after" conditions associated with a specific modification. Additionally, the U.S.DOE has developed a sophisticated set of tools that enhance our ability to accurately and effectively evaluate steam system modifications. We will discuss these free tools that complete complicated calculations and help you identify, analyze, quantify, and prioritize energy savings within your plant's steam system.

Slide 4 - Steam System Schematics

We will use an example steam system to serve as the focus of our in-class steam system assessment. The example steam system represents a heavy industry site with typical components and common operating conditions. The evaluations and findings noted in this training represent opportunities

commonly identified in industrial steam system investigations. This steam system is not extraordinary in any manner including fuel cost, steam production, and operating conditions.

As you will see, the example system operates with three boilers—each boiler consumes a different fuel (natural gas, number 6 fuel oil, and green wood). The total fuel expenditure for the site is nominally 19 Million Dollars per Year. Typical steam production is 260,000 pounds per hour of 400 psig, 700 degree Fahrenheit superheated steam.

The three boilers deliver high pressure steam to the distribution system header. High pressure steam serves steam loads, as well as several cogeneration components. The backpressure turbines are connected to electrical generators, thus serving to reduce steam pressure and to generate electricity. Pressure reducing stations also assist in managing the flow of steam through the system.
As in all steam systems there are many auxiliary components such as condensate recovery tanks, makeup water treatment equipment, deaerator, feedwater pumps, and many more components not shown in the schematic.

[Slide Visual – Steam System Schematic]

This schematic represents a three-header steam system incorporating three boilers and many system components. The steam distribution system includes three back pressure turbines and two pressure-reducing valves. The turbines and pressure-reducing valves operate between the various steam pressures of the system. Each steam header includes end-use steam loads which discharge condensate through steam traps to their respective condensate collection tanks. Condensate is ultimately collected in the main condensate receiver, then pumped to a deaerator. The deaerator also receives makeup water and steam to preheat the collected condensate and makeup water. The deaerator outflow becomes the feedwater for the boilers.

Slide 5 – Results

The example system, which is based on a real-world steam system, was subjected to a steam system assessment using fundamental investigation techniques and the U.S.DOE Steam Tools. The assessment identified several projects that will result in significant energy savings that present economically attractive projects. The assessment identified more than $1,300,000 per year of energy savings, which represents more than 7 percent of the fuel input cost to the site.

This Steam End User Training will walk you through this real-world example of a steam system to help illustrate how you can identify areas with potential for saving energy and for reducing costs.

Now, let's get started so you can learn how to identify energy efficiency improvements at your site!

Steam End User Training
Navigational Tutorial Module

Slide 1 – Introduction

Hello, and welcome to the Steam End User Training. I would like to take a few minutes to show you how to navigate through the training.

Slide 2 - Table of Contents 1

As you can see in the table of contents, it is separated into 4 different sections, each one demonstrating a different major topic in the Steam End User Training: Introduction, Steam Generation Efficiency, Resource Utilization Effectiveness, and Steam Distribution System Losses. At the end of the course, you can take an interactive quiz to test your understanding of steam system concepts and improvement opportunities.

Click on a module or individual slide to navigate to it.

[Slide Visual – Navigational Tools]

The left side of screen shows the Slide Title Bar (Side Bar) that helps navigate the modules and supporting slides.

The Side Bar will show a list of the seven sections of the course.

Circle	Slide Title	Duration	Status
○	welcome.swf	04:43	
○	navigationaltutorial.swf	04:07	
○	introduction.swf	15:57	
○	boilerefficiencydefinition.swf	17:38	
○	shellloss.swf	03:57	
○	blowdownloss.swf	18:19	
○	stackloss.swf	35:40	
○	resourceutilizationeffectiveness.swf	44:17	
○	steamdistributionsystemloss.swf	43:37	
○	conclusion.swf	02:38	
Find	02:34 / 190:39 Minutes	Clear	

If you click the arrow or the module topic, a list of supporting slide titles will appear with a button to the right of each slide title that can be used as a bookmark. Click the arrow or title again to retract the supporting slide titles, showing on the module title.

To the right of each module and slide title will be the length of the module or slide, respectively, in minutes.

Once a slide is reviewed in its entirety, a check mark will appear to the right of the module/slice duration, under the Status Column of the left hand Side Bar.

At the bottom of the Side Bar is the Find button, time elapsed and total time in minutes, and a clear button.

The main screen shows the Welcome Module's Course Content.

The bottom of the screen shows the Control Bar with the Rewind button, Pause/Play button, Back, Forward, Fast-Forward, Slider Bar with slide number, Audio on/off, Closed Captioning on/off, Close, and Information button.

Each of these features will be covered in details below.

Slide 3 - Status

If you click on a module, the Side Bar will display its individual slides, as well as their titles and duration. You can click on any slide in order to navigate to it.

Under "Status," you will see a checkmark next to each module or slide that you have completed. At the bottom, you will see the total time of the training, as well as how much of that time you have completed. Click on "Clear" to get rid of all of the check-marks. You can also utilize the "Bookmark" feature. Select the small button on the left side of the slide title to bookmark a slide…..

[Slide Visual – Side Bar]

The left side of screen shows the Side Bar that helps navigate the modules and supporting slides.

Circle	Slide Title	Duration	Status
○	welcome.swf	04:43	
○	1 Steam End User	00:14	
○	2 Course Contents	01:08	
○	3 Steam Assessment	01:11	Check
○	4 Steam System	01:22	
○	5 Results	00:47	
○	navigationaltutorial.swf	04:07	
○	introduction.swf	15:57	
○	boilerefficiencydefinition.swf	17:38	
○	shellloss.swf	03:57	
○	blowdownloss.swf	18:19	

○	stackloss.swf	35:40
○	resourceutilizationeffectiveness.swf	44:17
○	steamdistributionsystemloss.swf	43:37
○	conclusion.swf	02:38

Find 02:34 / 190:39 Minutes Clear

Slide 4 - Bookmark

to return to it later to complete the training session, or for reference or questions. You can click the button again to cancel the bookmark.

[Slide Visual – Bookmark]

The left side of screen shows the Side Bar. A small button to the right of the slide title can be toggled on/off as a bookmark.

Circle	Slide Title	Duration	Status
○	welcome.swf	04:43	

Slide 5 – Play/Pause

At any time you have navigated the course with the Side Bar or bottom Control Bar, and the audio does not begin, double-click on the highlighted Side Bar slide title. The highlight identifies where you are, and the audio should restart.

Notice the toolbar below the main screen. "Rewind" will take you to the beginning of the module that you are viewing.

Click "Play" to continue……

[Slide Visual – Play/Pause]

Side Bar slide title is highlighted on the left.

"Rewind" button is highlighted at the bottom the screen, most left button.

The "Pause" button is highlighted at the bottom of the screen. It toggles as the "Play" button.

__Slide 6 - Rewind/Play__

- Slide in Action -

[Slide Visual – Play/Pause]

Note the "Play" button is highlighted as it toggled from "Pause". It is to the right of "Rewind".

__Slide 7 - Back/Forward__

"Back" and "Forward" will move back and forward between slides.

If you want to go twice as fast, you can click on "2-times Fast Forward Speed."

[Slide Visual – Back/Forward and Fast Forward]

To the right of "Play/Pause" button, the "Back" and "Forward" buttons are highlighted.

To the right of "Forward" button, the "Fast Forward" button is highlighted. One click results in "2-times Fast Forward".

__Slide 8 - Fast Forward__

If you want to go twice as fast, you can click on "2-times Fast Forward Speed."

Click on it again to get "4-times Fast Forward Speed".

You must return to "Normal Speed" to hear the audio, as the audio is off during "2-times and 4-times Fast Forward".

[Slide Visual –Fast Forward]

To the right of "Forward" button, the "Fast Forward" button is highlighted. A second click results in "4-times Fast Forward".

Slide 9 - Normal Speed

Click on it one more time to go back to the "Normal Speed".

[Slide Visual –Normal Speed]

To the right of "Forward" button, the "Fast Forward" button is highlighted. A third click results in "Normal Speed".

Slide 10 - Slider Number

You can also navigate to a particular section of the training by dragging the slider back and forward. Click it and hold down the mouse button.

[Slide Visual –Slider Bar]

To the right of "Fast Forward" button, the slider bar button is highlighted.

Slide 11 –Starting a Slide

It will display which slide you are on, out of the total number of slides in the module. As you reposition the slider cursor, you will notice the Side Bar will highlight the slide corresponding to the cursor position.

[Slide Visual –Slide Number on Bar]

Just above the cursor on the slider bar, the slide number of the total number of slides of the respective module is shown.

The respective slide title on the Side Bar is highlighted.

Slide 12 –Slide Number

To restart the training, you may click on the corresponding slide (which is highlighted), or just hit the "Play" button, as the "Pause" button was automatically engaged when using the slider.

[Slide Visual – Play/Pause]

Note the "Play" button is highlighted as it toggled from "Pause".

<u>Slide 13 - Sound On/Off</u>

Also, you can choose to have the "Sound" on or off.

> ***[Slide Visual –Sound]***
>
> **To the right of Slider Bar, the 'speaker' button is highlighted and can be toggled on/off.**

<u>Slide 14 – Closed Captioning</u>

"CC" allows the user to turn the closed-captioning on or off. Clicking the "X" will exit the program. Clicking "I" will display information about the program, including the author and the author's e-mail address.

> ***[Slide Visual –Closed Captioning]***
>
> **To the right of "Audio/Sound" button, the "Closed Captioning" button, denoted as "CC" is highlighted and can be toggled on/off. "On" will open a box at the bottom of the screen with the respective slide narrative displayed.**
>
> **To the right of "CC", is the "X" and "I" buttons.**

<u>Slide 15 – Minimize/Maximize Screen</u>

At the top left of the screen, you can click the middle button to minimize the window.
Click on the right button to maximize it, so that you can see it better.
Click on the left button order to close the training.

Now let's get started!

> ***[Slide Visual –Screen Display]***
>
> **To the upper right of the screen are three buttons.**
> **The left button will close the course display on the screen.**
> **The middle button will minimize the course display on the screen.**
> **The right button will maximize the course display on the screen.**

Steam End User Training
Introduction Module

Slide 1 - Introduction Title Page

Hello, and welcome to the Steam System End User training. In this training, we will investigate how to assess, evaluate, and manage steam systems. We will cover the entire steam system, from one end to the other.

Let's get started discussing the origin of the course, the need for the course, and then the overall course objectives.

[Slide Visual – Introduction Module]

Banner:
DOE's BestPractices
Steam End User Training

Introduction
Course Development
The Need for the Course
Course Objectives
Start the Investigation

Slide 2 - Original Course

This web-based training tool has been developed from its original, instructor-led classroom setting.

The original course was designed primarily with the industrial sector in-mind and with an industrial experience basis. The primary principles are applicable to all steam systems and even thermal-water systems; but, the foundation principles are based in heavy industry.

The course is designed for plant personnel, such as energy managers, steam system supervisors, engineers, equipment operators, and others with steam system responsibilities in industrial applications.

Now as a web-based training tool, participants can access the training any time and return to revisit topics of interest to help improve the efficiency and performance of their steam systems.

[Slide Visual - Instructor-led Classroom Course]

Header contains:

Industrial Technologies Program

Title includes:

A BestPractices Training Presentation
US Department of Energy
System Systems Assessment Training
Including Use of the Steam Systems Tool Suite

Three photographs of steam systems.

- **Photo 1: A large vertical exhaust pipe on a building exterior exhausting a steam plume from the top of the stack.**
- **Photo 2: Aseries of small steam pipes with a steam pressure gauge.**
- **Photo 3: Five horizontal runs of steam distribution piping from a common header. Steam distribution piping is insulated with an aluminum jacketing. A person is standing near the header.**

Bottom footer contains:

US Department of Energy Seal
US Department of Energy

Energy Efficiency and Renewable Energy
Bring you a prosperous future where energy is clean, abundant, reliable, and affordable.

Slide 3 - Course Developer

This course was developed by Greg Harrell and is intended to present a real-world view of how steam systems operate, practical evaluation techniques, and common improvement opportunities. This course has developed over many years of observing and investigating steam systems. It represents the compilation of Best Practices observed as sustainable steam system management measures.

[Slide Visual - Greg Harrell's Credentials]

Course Developer – Greg Harrell, Ph.D., P.E.

- **Ph.D. Mechanical Engineering-Thermodynamics, Virginia Tech (VPI&SU) - 1997**

- **1987 to 1993 - Design Engineer, Utilities Process Engineer, BASF Corp.**
  - **Oversight for engineering, technical activities of entire utilities department (steam production, electric power generation, compressed air systems, industrial refrigeration facilities, industrial HVAC systems, water filtration facilities and wastewater treatment plant**

- At Virginia Tech – Mechanical Engineering Professor, Energy Management Institute (EMI)
  - From 1997 to 2001 - Director of Technical Assistance for EMI
  - Undergraduate and graduate level thermodynamics professor
  - Directly involved in important aspects of energy management for industries located worldwide
  - Has conducted numerous energy surveys for industrial clients throughout the world - on 6 continents, in 22 countries, and in 36 of the United States
  - Developed U.S. DOE BestPractices Steam End User Training and U.S. DOE Steam Specialist Qualification Training
  - Played major role in development of the USDOE BestPractices Steam Tools and authored Steam System Survey Guide, which has become a text for university mechanical engineering courses
  - A Certified Instructor, Compressed Air Challenge®
- Currently – Consultant for Energy Management Services
  - Primary roles continue to include industrial systems energy analysis and individual process analyses, industrial training courses, university instruction, energy system modeling, and software development
  - A primary instructor in the North Carolina State University Energy Management Diploma Program
  - Major system focus areas - boilers, steam systems, combined heat and power systems (cogeneration), gas turbines, and compressed air systems

Slide 4 - Qualified Presenters

The course has been presented to thousands of participants representing all types of industry. The course instructors all have many years of practical steam system experience—their careers filled with conducting steam system assessment throughout the world in all types of settings. This combination of technical expertise, real-world experience, and direct feedback from industrial participants has resulted in the practical, useful, and straightforward course you see today.

[Slide Visual - Qualified Presenters and Their Contact Information]

- Greg Harrell, Ph.D., P.E.
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Slide 5 - Industrial Energy

Just for a moment let's examine the importance of effective management of steam systems. To start this discussion, consider the amount of energy required to operate our industries. It is interesting to note that in the United States energy is used in three broad categories of consumers. These consumers are segregated into transportation (automobiles, trucks, and airplanes), residential-commercial (homes and buildings), and industry. It is interesting to note that each of these three sectors consume approximately one-third of the energy used in the U.S. The transportation sector consumes almost one third of the energy, while residential and commercial together use somewhat more than one third of the energy. Remarkably, industry alone uses a third of the country's energy.

These three sectors use energy in very different ways. The transportation sector uses primarily liquid fuels as the energy resource. Residential and commercial locations use a large amount of electricity along with natural gas and fuel oils. Industry uses a broad mix of energy resources incorporating

electricity, many fuel types, and other energy resources. Management and support for these sectors require very different approaches. One thing is very apparent—managing the energy utilization of industry is critical to the competitiveness of the U.S. on the world stage.

[Slide Visual - 2004 Energy Use Pie Chart]

Title: <u>2004 Energy Use*</u>

Industry 34.0% (orange slice)
Transportation 28.0% (blue slice)
Commercial 17.0% (green slice)
Residential 21.0% (yellow slice)

Footnotes:
***Includes electricity losses**
Source: DOE/EIA Monthly Energy Review 2004 (preliminary)

<u>Slide 6 - Energy Consumption</u>

Our focus here is the industrial sector. It will be interesting to us to characterize the types of energy use in the industrial sector. U.S.DOE is serving as an energy manager for industrial sites in the United States. From the perspective of the U.S.DOE helping U.S. industry manage energy resources is a daunting challenge—there are a quarter of a million industrial sites in the United States. How can DOE help a quarter of a million diverse users? Like any good energy manager DOE investigated the measurements that indicate how energy is used in industry throughout the country. What DOE found is that half of the energy used in industrial sites is used by "large industrial sites". This is very interesting because large industrial sites comprise only 3 percent of the industrial population.

If we can influence the energy consumption of this small fraction of the total industrial population, then we can influence a significant portion of U.S. energy! Also, the techniques used to aid the large industrial sites can be replicated to the remaining industrial sites.

[Slide Visual - U.S. Manufacturing Plants: By Size Bar Chart]

Title: <u>U.S. Manufacturing Plants: By Size</u>

Horizontal Axis: Plant size and Annual Energy Costs
Small Plants <$100K
Mid-Size Plants $100K-$2M
Large Plant >$2M
All U.S. Plants (no cost provided)

Vertical Axis: Number of U.S. Plants
Range 0 to 250,000 by 50,000 increments

Chart reads:
Small Plants <$100K has 104,299 plants (yellow bar)
Mid-Size Plants $100K-$2M has 115,636 plants (yellow bar)
Large Plant >$2M has 6,802 plants (orange bar)
All U.S. Plants (no cost provided) has 226,737 plants (green bar)

[Slide Visual -Percent of Total Industrial Energy Pie Chart]

Title: Percent of Total Industrial Energy

Small and Medium 47% (yellow slice)
Large 53% (orange slice)

Source: 1998 EIA MECS

Slide 7 - Energy Requirements

As a result, let's take a look at how energy is used in a typical industrial site. As you can see from the chart, most of the energy is going into process heating and steam systems. Both process heating and steam systems consume more than one third of total industrial energy. It is also excellent to note that even though process heating and steam systems have their distinct differences, the investigation techniques and opportunities we have in process heating are very similar to those for steam. If we can better manage our process heating and steam systems, we can have a significant impact on our energy consumption and competitiveness in the world market. This is the primary driving force for this course; in other words, steam systems are a major factor in the energy consumption of the United States—and much of the world; therefore, we need to manage them effectively.

[Slide Visual - Typical Energy Requirements Pie Chart]

Title: Manufacturing Energy Use by Type of System (%)

Steam 35% (blue slice)
Process Heating 38% (bright yellow slice)
Motor Systems 12% (peach slice)
Process Cooling 1% (white slice)
Electro-Chemical 2% (yellow slice)
Other 4% (blue slice)
Facilities 8% (green slice)

Footnotes:

Note: Does not include off-site losses

Source: DOE/EIA Monthly Energy Review 2004 (preliminary)

Slide 8 - Course Divisions

This course is arranged in a similar manner to a typical steam system assessment. We will investigate all areas of the steam system. We will start with the boiler operations in the *Steam Generation Efficiency* section of the course. In this section we will examine the energy conversion efficiency of the boiler. Various boiler efficiency investigation methods will be identified. Boiler efficiency improvement avenues will be explored along with control strategies.

In the *Resource Utilization Effectiveness* section of the course we will target steam end-use components, fuel selection, steam system balancing, as well as combined heat and power activities. These are major concerns for most facilities and can present significant opportunities for economic improvement.

The *Distribution System* can provide tremendous waste in the form of steam leaks, steam trap failures, insulation related losses, and lost condensate. These areas will serve as investigation targets for our discussions.

Slide 9 - U.S. DOE Tools

Investigating and analyzing steam systems requires a significant amount of complex calculations to identify the impact potentials. Throughout this training, we will demonstrate the fundamental calculations and investigation techniques required to evaluate each area and each improvement opportunity.

The Steam System Survey Guide is a companion document to the Steam End User Training, to discuss major areas of potential improvements for steam systems and how to quantify those opportunities and is available for free download from the BestPractices Training Area.

Additional technical publications are provided for free download from the BestPractices Resources. You can reference these documents as you investigate improvements for your steam system's efficiency and performance.

The Steam System Tools Suite is a set of software tools constructed to aid in the evaluation of steam system projects. These software tools are available for free download from the U.S.DOE website. The Tools Suite includes the *Steam System Scoping Tool*, which is designed to guide the user to potential improvement opportunities. Also, included is the *Steam System Assessment Tool*, which allows the user to complete a comprehensive mass, energy, and economic balance on the steam system. This tool is designed to evaluate the system-wide impacts of changes in the steam system. Finally, the Tools Suite contains the *3E Plus Insulation Evaluation Tool*. This tool can be used to evaluate any insulation related project.

Slide 10 - Course Objectives 1

We are going to focus our attention on the fundamental and practical aspects of steam system operation, maintenance, and management. What we would like to accomplish is to help you identify opportunities you may have to improve your steam system, understand how to evaluate the true impacts, and to set a path to implement the improvements. The focus will be on the fundamentals of steam systems—if the fundamentals are mastered the steam system will be well managed.

Effective steam system management requires an excellent toolbox filled with evaluation tools and techniques that will enable the skilled assessor to identify and quantify improvement opportunities. We will focus on the essential measurements that characterize operations. We will focus some attention on the boiler and understand how boiler efficiency can be impacted and improved.

[Slide Visual - Course Objectives 1]

- **Become familiar with U.S.DOE Tools Suite to assess steam systems**
- **Identify the measurements required to manage steam systems**
- **Measure boiler efficiency**
- **Estimate the magnitude of specific boiler losses**
- **Identify and prioritize areas of boiler efficiency improvement**
- **Recognize the impacts of fuel selection**

Slide 11 - Course Objectives 2

We will introduce the topic of cogeneration and identify the common aspects of turbine operation. Attention will be given to the end-use equipment and potential opportunities to reduce steam demand. Steam trap management, insulation opportunities, and condensate recovery are all vital components in steam systems. These areas will be investigated.

There is a lot of information to discuss; so, let's get started.

[Slide Visual - Course Objectives 2]

- **Characterize the impact of backpressure and condensing steam turbines**
- **Quantify the importance of managing steam consumption**
- **Identify the requirements of a steam trap management program**
- **Evaluate the effectiveness of thermal insulation**
- **Evaluate the impact of condensate recovery**
- **Recognize the economic impacts of steam system operations**

<u>Slide 12 - Steam System</u>

One of the first steps in completing a steam system assessment is to identify the primary components of the steam system.

Steam systems can be large and complex with many components and arrangements but many of the primary components will be common from system to system.

Boilers and their auxiliary components, heat exchangers and other end-use equipment, water treatment systems, condensate recovery components, distribution piping, and many other components.

These components may be arranged in a simple system, with a single boiler, maybe one backup boiler—or it can be much more complicated.

[Slide Visual - Steam System Impact Schematic]

This schematic represents a two-header steam system with two boilers and all of the system components. Feedwater is preheated by steam injection from the low-pressure steam distribution header, as well as preheated make-up water utilizing boiler blowdown heat recovery.

The top of the schematic shows the Boiler Feedwater entering the two boilers. The two boilers are connected to the high-pressure steam distribution header.

The steam exits two boilers and enters the high-pressure steam system distribution header, indicated by a line below the boilers.

At the far right of the high pressure steam distribution system, the high-pressure end-user component loads are identified through a rectangular graphic and arrows entering and leaving the rectangle, indicating heat exchange with the components. The end-use components discharge condensate through a steam trap, represented by a rectangular graphic. Schematically, condensate passes through the bottom of the trap and recovered in a condensing tank.

The condensate tank uses a pump, which is denoted by a circle/square combination, to deliver the condensate to the main condensate receiver.

The main condensate receiver then pumps (denoted by a circle/square combination) the condensate to the deaerator tank as denoted by two red rectangles, with the smaller one on the top. The top rectangle also shows two triangles, each pointed away from each other, longest ends nearly touching. The bottom triangle is connected to a control valve represented by a hour-glass figure with a dome on the side, which provides steam to the deaerator from steam distribution system to preheat the collected condensate and make-up water. Make-up water also schematically enters at the top of the deaerator with the collected condensate.

The boiler feedwater schematically exits the deaerator from the bottom and is pumped (denoted as a circle/square combination) to the feedwater inlets of each boiler, near the top the schematic.

Slide 13 - Steam System 2 Pressures

The system may include multiple boilers, several steam pressures, different types of fuel, steam turbines, and many process end-users.

[Slide Visual - Steam System Impact Schematic]

This schematic represents a two-pressure header steam system with multiple boilers and all of the system components. Feedwater is preheated by steam injection from the low-pressure steam distribution header, as well as preheated make-up water utilizing boiler blowdown heat recovery.

The top of the schematic shows the Boiler Feedwater entering the two boilers. The two boilers are connected to the high-pressure steam distribution header.

The steam exits two boilers and enters the high-pressure steam system distribution header, indicated by a line below the boilers.

Under the high-pressure steam distribution line, you will see three cone-shaped graphics, that represent the steam turbines. The one nearest to the left is a high-pressure to condensing turbine. This turbine discharges to the condenser represented by the blue circle below the turbine. The rectangular graphic to the right of the cone-shaped graphic indicates the electrical generation component of the steam turbine. The turbine in the middle receives high-pressure steam and exhausts low-pressure steam to the low-pressure steam distribution system, as well as generates electricity. This turbine is denoted as red cone and rectangle combination. The steam turbine to the most right receives high pressure steam, drives a pump (denoted as a circle/square combination) and is also called a steam turbine-driven pump, then discharges to the low-pressure steam distribution system header.

Between the condensing turbine and the high-to-low pressure turbine, a light-blue triangular graphic that represents a pressure-reducing valve, which discharges to the low pressure steam distribution header, identified by a red line below the turbines.

At the far right of the high pressure steam distribution system, the high-pressure end-user component loads are identified through a rectangular graphic and arrows entering and leaving the rectangle, indicating heat exchange with the components. The end-use components discharge condensate through a steam trap, represented by a rectangular graphic. Schematically, condensate passes through the bottom of the trap and recovered in a condensing tank which is also connected to the low-pressure steam distribution system.

Under the low-pressure steam distribution line, you will see the low-pressure end-user component loads identified as a rectangular graphic and arrows entering and leaving the rectangle, indicating heat exchange with the components. The end-use components discharge condensate through a steam trap, represented by another rectangular graphic. Schematically, condensate passes through the bottom of the trap and recovered in a condensate tank, in which steam is vented represented by a vertical arrow leaving the top of the tank.

The low-pressure end-user condensate tank uses a pump, which is denoted by a circle/square combination, to deliver the condensate to the main condensate receiver, which is a large rectangle with three inputs denoted by three arrows at the top of the rectangle. The condensate

enters this main condensate receiver tank, after it passes through a control valve, denoted as an hour-glass shape with a dome on top. The third condensate input comes from the condensate from the heat exchanger that utilizes the high-pressure steam turbine. The condensate leaves this heat exchanger and is delivered via a pump (denoted as a circle/square combination) to the main condensate receiver.

The main condensate receiver then pumps (denoted by a circle/square combination) the high-pressure condensate, low-pressure condensate, and the condensing steam turbine condensate to the deaerator tank as denoted by two red rectangles, with the smaller one on the top. The top rectangle also shows two triangles, each pointed away from each other, longest ends nearly touching. The bottom triangle is connected to a control valve represented by a red hour-glass figure with a dome on the side, which provides low-pressure steam to the deaerator from the low-pressure steam distribution system to preheat the collected condensate and make-up water. Pre-heated make-up water also schematically enters at the top of the deaerator with the collected condensate.

The make-up water is preheated from the boiler blowdown and low pressure steam. Boiler blowdown from each boiler is noted as red dashed lines leading to a blowdown receiver tank denoted as a red rectangle on the right of the screen. Flash-steam is diverted from the blowdown flash-vessel to the low-pressure steam distribution line, also denoted in red dashed lines. Liquid from the blowdown flash-tank then schematically enters the top of a heat exchanger (represented as a white and green striped rectangle). Makeup water is shown entering the heat exchanger from the right, after it passes through the water treatment equipment, denoted as two red rectangles further on the right. The liquid exiting the heat exchanger is sent to the deaerator.

The heated boiler feedwater schematically exits the deaerator from the bottom and is pumped (denoted as a circle/square combination) to the feedwater inlets of each boiler, near the top the schematic.

Slide 14 - Steam System 3 Pressures

Some systems are even more complicated than that including many steam pressures and incorporating steam turbines driving process components as well as electrical generators!

[Slide Visual - Steam System Impact Schematic]

This schematic represents a three-pressure header steam system with multiple boilers and all of the system components. Feedwater is preheated by steam injection from the low-pressure steam distribution header, as well as preheated make-up water utilizing boiler blowdown heat recovery.

The top of the schematic shows the Boiler Feedwater entering the two boilers. The two boilers are connected to the high-pressure steam distribution header.

The steam exits two boilers and enters the high-pressure steam system distribution header, indicated by a line below the boilers.

Under the high-pressure steam distribution line, you will see three cone-shaped graphics, that represent the steam turbines. The one nearest to the left is a high-pressure to condensing turbine. This turbine discharges to the condenser represented by the blue circle below the turbine. The rectangular graphic to the right of the cone-shaped graphic indicates the electrical generation component of the steam turbine. The turbine in the middle receives high-pressure steam and exhausts low-pressure steam to the low-pressure steam distribution system, as well as generates electricity. This turbine is denoted as red cone and rectangle combination. The steam turbine to the most right receives high pressure steam, drives a pump (denoted as a circle/square combination) and is also called a steam turbine-driven pump, then discharges to the low-pressure steam distribution system header.

Between the condensing turbine and the high-to-low pressure turbine, a light-blue triangular graphic that represents a pressure-reducing valve, which discharges to the low pressure steam distribution header, identified by a red line below the turbines.

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Under the low-pressure steam distribution line, you will see the low-pressure end-user component loads identified as a rectangular graphic and arrows entering and leaving the rectangle, indicating heat exchange with the components. The end-use components discharge condensate through a steam trap, represented by another rectangular graphic. Schematically, condensate passes through the bottom of the trap and recovered in a condensate tank, in which steam is vented represented by a vertical arrow leaving the top of the tank.

The low-pressure end-user condensate tank uses a pump, which is denoted by a circle/square combination, to deliver the condensate to the main condensate receiver, which is a large rectangle with three inputs denoted by three arrows at the top of the rectangle. The condensate enters this main condensate receiver tank, after it passes through a control valve, denoted as an hour-glass shape with a dome on top. The third condensate input comes from the condensate from the heat exchanger that utilizes the high-pressure steam turbine. The condensate leaves this heat exchanger and is delivered via a pump (denoted as a circle/square combination) to the main condensate receiver.

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exchanger from the right, after it passes through the water treatment equipment, denoted as two red rectangles further on the right. The liquid exiting the heat exchanger is sent to the deaerator.

Slide 15 - Steam System Complex

The steam system may include condensing steam turbines and other major components. However, no matter how complex or simple the steam systems are, the management and investigation activities are basically the same—we need the same tools and fundamental knowledge.

[Slide Visual - Steam System Impact Schematic]

This schematic represents a three-pressure header steam system with multiple boilers and all of the system components. Feedwater is preheated by steam injection from the low-pressure steam distribution header, as well as preheated make-up water utilizing boiler blowdown heat recovery.

The top of the schematic shows the Boiler Feedwater entering the two boilers. The two boilers are connected to the high-pressure steam distribution header.

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Under the low-pressure steam distribution line, you will see the low-pressure end-user component loads identified as a rectangular graphic and arrows entering and leaving the rectangle, indicating heat exchange with the components. The end-use components discharge condensate

through a steam trap, represented by another rectangular graphic. Schematically, condensate passes through the bottom of the trap and recovered in a condensate tank, in which steam is vented represented by a vertical arrow leaving the top of the tank.

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The make-up water is preheated from the boiler blowdown and low pressure steam. Boiler blowdown from each boiler is noted as red dashed lines leading to a blowdown receiver tank denoted as a red rectangle on the right of the screen. Flash-steam is diverted from the blowdown flash-vessel to the low-pressure steam distribution line, also denoted in red dashed lines. Liquid from the blowdown flash-tank then schematically enters the top of a heat exchanger (represented as a white and green striped rectangle). Makeup water is shown entering the heat exchanger from the right, after it passes through the water treatment equipment, denoted as two red rectangles further on the right. The liquid exiting the heat exchanger is sent to the deaerator.

The heated boiler feedwater schematically exits the deaerator from the bottom and is pumped (denoted as a circle/square combination) to the feedwater inlets of each boiler, near the top the schematic.

<u>Slide 16 - Focus Areas</u>

When assessing our steam system, we must evaluate the system as a whole; but, we will be required to analyze many components individually then determine their impact on the system. There are many different components and sub-systems associated with the steam system.

We ask questions like, how can we improve boiler efficiency? How can we reduce steam consumption? What energy resources are available to us? How can we lose less energy throughout the system?

[Slide Visual - Steam System Focus Areas]

Steam System Focus Areas

- **Steam Generation Efficiency**
- **Resource Utilization Effectiveness**
- **Distribution System losses**

Slide 17 - Steam Generation Efficiency

For example, we will focus our attention on the boiler and ask questions like:
- **What are the performance characteristics of our boiler?**
- **What are the critical measurements required to manage boiler performance?**
- **How can we impact boiler efficiency?**

[Slide Visual - Steam Generation Efficiency]

Steam Generation Efficiency

- **Boiler efficiency is a major factor determining the operating costs of a steam system**
- **Several major factors impact boiler performance**
- **What are the efficiency control parameters?**
- **Are they maintained at appropriate levels?**

Slide 18 - Resource Utilization

We focus our attention on the end-use equipment and the energy resources we employ in our systems. We investigate opportunities to recover energy from process units. We target opportunities to reduce steam use. Significant focus is placed on improving the performance of our end-use systems. Cogeneration investigations identify potentials to convert steam energy into power. We investigate opportunities use alternative energy sources.

[Slide Visual - Resource Utilization Effectiveness]

Resource Utilization Effectiveness

- **Steam is generated for many purposes**
- **Steam can often be generated from different primary energy sources**
- **Multiple energy exports can be developed from one energy resource**
- **Are resources being properly utilized?**

➢ **Is the steam end-use *appropriate* or *inappropriate*?**

Slide 19 - Steam Distribution System Losses

Steam systems are often very large, extending into many process areas. We examine how energy can be lost from the distribution system? We try to identify opportunities to reduce the losses? We focus attention on recovering energy from the distribution system.

[Slide Visual - Steam Distribution System Losses]

Steam Distribution System Losses

- **The distribution system can experience significant losses**
- **What are the main avenues of loss?**
- **What methods are available to reduce the losses?**

Slide 20 - Driving Force Question

In most steam systems there are opportunities that will allow energy consumption to be reduced. If at your facility ideas are developed to reduce energy consumption, what will be the primary reason that the initiative will be implemented?

[Slide Visual - Driving Force]

What is the main driving force for change??

Slide 21 - Driving Force Economics

Economic impact is the primary driving force for change. One of our primary focal points in this course is to identify how to accurately connect a real-world steam system change to the true economic impact it will provide.

[Slide Visual - Driving Force]

What is the main driving force for change??

Answer: $

<u>Slide 22 - Driving Force More</u>

Energy savings, often fuel savings, are dominant points of focus resulting in economic impact. However, we do not want to lose sight of other economic factors; such as, maintenance impacts, reliability factors, site productivity, product quality, environmental impact, and potentially avoiding costly system modifications. All of these issues have economic connections—sometimes it is difficult to establish the true economic impact of these items. Some of these impacts may result in increased cost. We must attempt to accurately and realistically identify the true economic impacts and implementation costs associated with an opportunity.

[Slide Visual - Driving Force]

What is the main driving force for change??

Answer: $

- **Energy**
- **Reliability**
- **Maintenance**
- **Productivity**
- **Quality**
- **Cost avoidance**
- **Emissions reductions**

<u>Slide 23 - Measure</u>

Management of any resource requires measurements. Throughout this course we will identify the critical measurements that allow us to understand how our systems are performing and how much improvement has been or can be accomplished.

[Slide Visual - Measure]

You are not managing what you do not measure.

<u>Slide 24 - Start the Investigation</u>

Evaluating steam systems requires a broad range of knowledge and significant skills set. It can be very difficult to determine where best to start investigating. Often obtaining a broad overview of the system and the operating practices will lead to important investigation strategies.

Slide 25 - SSST 1

Investigating steam systems often begins with taking a broad view of the system and identifying areas to investigate that may yield fruitful results. The Steam System Scoping Tool (known as SSST) is designed to help you identify these potentially fruitful areas.

[Slide Visual - Steam System Scoping Tool]

Steam System Scoping Tool – (SSST)

Orange Banner with industrial plant graphic in background

Office of Industrial Technologies
BestPractices
Energy Smart Technology for Today
Steam System Scoping Tool
Version 2.0.0
December 2002
United States Department of Energy
Click anywhere on this frame to begin the assessment.

Slide 26 - Scoping Tool 2

The Steam System Scoping Tool is available free as an Excel based software tool.

SSST is not a calculation tool or a solution evaluation tool; rather, it is a tool used to help the user to become more aware of areas of the steam system that can be improved.

The tool is basically a questionnaire that asks general questions about the management practices of the steam system.

Questions are provided for each area of the steam system. The results of applying this tool are relative scores for the perceived performance of each area of the system.

These scores prompt the user to investigate certain areas of the steam system further.

Slide 27 - SSST Profiling

For example the Scoping Tool asks questions about the intensity of fuel and steam measurements. Based on the users input a score is developed for each category. The scores shown here are average scores for a sector of U.S. industry.

[Slide Visual of SSST Scorecard – System Profiling]

SUMMARY RESULTS		
	POSSIBLE SCORE	TYPICAL SCORE
SCOPING TOOL QUESTIONS		
1. STEAM SYSTEM PROFILING		
STEAM COSTS		
SC1: Measure Fuel Cost To Generate Steam	10	7.5
SC2: Trend Fuel Cost To Generate Steam	10	6.9
STEAM/PRODUCT BENCHMARKS		
BM1: Measure Steam/Product Benchmarks	10	5.6
BM2: Trend Steam/Product Benchmarks	10	5.7
STEAM SYSTEM MEASUREMENTS		
MS1: Measure/Record Steam System Critical Energy Parameters	30	22.5
MS2: Intensity Of Measuring Steam Flows	20	8.5
STEAM SYSTEM PROFILING SCORE	90	56.7
STEAM SYSTEM PROFILING SCORE	100%	63%

Slide 28 - SSST System Operations

Questions targeting steam trap management and insulation condition prompt the user to investigate these vital areas of steam system management. Again, the scores noted here are reflective of average scores for a sector of U.S. industry.

[Slide Visual - SSST Scorecard – System Operations]

	POSSIBLE SCORE	TYPICAL SCORE
SCOPING TOOL QUESTIONS		
2. STEAM SYSTEM OPERATING PRACTICES		
STEAM TRAP MAINTENANCE		
ST1: Steam Trap Maintenance Practices	40	23.9
WATER TREATMENT PROGRAM		
WT1: Water Treatment - Ensuring Function	10	8.6
WT2: Cleaning Boiler Fireside/Waterside Deposits	10	7.1
WT3: Measuring Boiler TDS, Top/Bottom Blowdown Rates	10	7.7
SYSTEM INSULATION		
IN1: Insulation - Boiler Plant	10	8.6
IN2: Insulation - Distribution/End Use/Recovery	20	14.0
STEAM LEAKS		

Slide 29 - SSST Boiler Operations

Boiler efficiency and control components are primary points of focus in the Scoping Tool. Boiler blowdown issues are also of concern.

[Slide Visual - SSST Scorecard – Boiler Operations]

	POSSIBLE SCORE	TYPICAL SCORE
SCOPING TOOL QUESTIONS		
3. BOILER PLANT OPERATING PRACTICES		
BOILER EFFICIENCY		
BE1: Measuring Boiler Efficiency - How Often	10	6.3
BE2: Flue Gas Temperature, O2, CO Measurement	15	9.4
BE3: Controlling Boiler Excess Air	10	7.1
HEAT RECOVERY EQUIPMENT		
HR1: Boiler Heat Recovery Equipment	15	8.5
GENERATING DRY STEAM		
DS1: Checking Boiler Steam Quality	10	4.2
GENERAL BOILER OPERATION		
GB1: Automatic Boiler Blowdown Control	5	2.6
GB2: Frequency Of Boiler High/Low Level Alarms	10	8.6
GB3: Frequency Of Boiler Steam Pressure Fluctuations	5	3.9
BOILER PLANT OPERATING PRACTICES SCORE	80	50.6
BOILER PLANT OPERATING PRACTICES SCORE	100%	63%

Slide 30 - SSST End-Use

Of course condensate recovery practices are a major point of concern. The tool focuses some attention to the potential of using backpressure steam turbines.

[Slide Visual - SSST Scorecard – End-Use]

	POSSIBLE SCORE	TYPICAL SCORE
SCOPING TOOL QUESTIONS		
4. STEAM DISTRIBUTION, END USE, RECOVERY OPERATING PRACTICES		
MINIMIZE STEAM FLOW THROUGH PRVs		
PR1: Options For Reducing Steam Pressure	10	7.4
RECOVER AND UTILIZE AVAILABLE CONDENSATE		
CR1: Recovering And Utilizing Available Condensate	10	6.4
USE HIGH-PRESSURE CONDENSATE TO MAKE LOW-PRESSURE STEAM		
FS1: Recovering And Utilizing Available Flash Steam	10	3.7
DISTRIBUTION, END USE, RECOVERY OP. PRACTICES SCORE	30	17.5
DISTRIBUTION, END USE, RECOVERY OP. PRACTICES SCORE	100%	58%

Slide 31 - SSST Results

The output of the tool is an overall score and individual area scores. Solutions are not offered—simply a low score prompts the user to investigate further and potentially identify improvement opportunities. In most steam systems there are interesting investigation opportunities in several areas. Typical overall scores for industrial plants are in the 60 percent and 70 percent ranges.

[Slide Visual - SSST Scorecard – Results]

SUMMARY OF RESULTS	POSSIBLE SCORE	TYPICAL SCORE
SCOPING TOOL AREAS		
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%

Slide 32 - SSST Next Steps

The tool provides guidance into where to find additional information for a particular area. The Scoping Tool will point the user to additional U.S.DOE resources.

[Slide Visual - Next Steps Directed by SSST]

- **Focus on areas requiring attention**
- **Investigate resources**
  - **Consult the U.S.DOE BestPractices website**
    - **www1.eere.energy.gov/industry/bestpractices**
  - **Steam System Survey Guide**
  - ***U.S.DOE Steam Tip Sheets***
  - **Improving Steam System Performance: A Sourcebook for Industry**
- **Use the Steam System Assessment Tool (SSAT)**
- **Use Insulation Tool (3E-Plus)**

Slide 33 - General Tools

Many tools are required to evaluate steam systems. The Steam System Scoping Tool is one of many tools that can be employed to investigate steam systems. The other tools in the U.S.DOE Steam Tools Suite will be introduced in this course as well as the fundamental techniques used to investigate and manage steam systems. The most important tools are the fundamental principles of physics and the real system measurements required to employ them. The U.S.DOE Steam Tools are extensions of these vital components.

Slide 34 - Information

Additional technical resources are available from the Department of Energy.

[Slide Visual - Additional Technical Resources]

Information

- **Programs**
  - **Industrial Technologies Program (ITP)**
  - **BestPractices Steam Program**
    - **http://www1.eere.energy.gov/industry/bestpractices/steam.html**
- **Software tools**
  - **(877) 337-3463**
  - **http://www1.eere.energy.gov/industry/bestpractices/software.html**
- **Steam Publications**
  - **http://www1.eere.energy.gov/industry/bestpractices/techpubs_steam.html**
- **Training**
  - **http://www1.eere.energy.gov/industry/bestpractices/training.html**
- **Technical Assistance**
  - **http://www1.eere.energy.gov/industry/bestpractices/info_center.html**

Slide 35 - Introduction Summary

Steam systems are complex arrangements of interconnected components that require tremendous amounts of energy and economic expenditure. Proper management of a steam system is vital to effectively utilize energy resources. Tools are available to help in this investigation and management process.

[Slide Visual- Summary]

- **Steam systems represent one of the largest energy consumers in the United States**
- **Steam system must be investigated to identify opportunities for improvements**
- **Resources and Tools to help identify and quantify the impact of efficiency improvements are available**

Steam End-User Training
Steam Generation Efficiency Module
Efficiency Definition Section

Slide 1 - Steam Generation Efficiency Module

This module will discuss steam generation efficiency and the primary factors that affect it. . The general concepts of boiler efficiency will be discussed.

[Slide Visual – Contents of Module Sections]

Banner:
DOE's BestPractices
Steam End User Training

Steam Generation Efficiency
Efficiency Definition
Radiation and Convection Losses –
Shell Losses
Blowdown Losses
Stack Losses

Slide 2 - Boiler Types

There are many types of boilers, but the primary boiler designations are *fire-tube boilers* and *water-tube boilers*. A fire-tube boiler is one in which the combustion gases are inside the tubes. This schematic depicts a 3-pass fire-tube boiler, in which we have a combustion zone, and smaller tubes that allow more heat transfer from the exhaust gases. Fire-tube boilers served as our first industrial steam generators. The large diameter pressure vessel holds all of the stress of the high-pressure steam. As industrial requirements necessitated higher pressure steam and greater steam flow rates, the vessel had to become larger and the wall of the vessel had to get thicker to accommodate the stress of greater pressures. These factors made boiler manufacturing difficult and expensive. As a result, water-tube boilers were developed. These boilers contain hundreds of tubes that hold the high-pressure steam and water. These relatively small diameter tubes can accommodate the stress of much higher pressures than the large diameter vessel.

Water-tube boilers allow the combustion gases to provide heat transfer to the water (and steam) that is contained in the tubes of the boiler. A common water-tube boiler arrangement will incorporate an upper steam-drum that allows the liquid water and steam to separate. A lower drum, often called a mud-drum, will serve as the lower collection header for the tubes. Hundreds of relatively small diameter tubes will connect the mud-drum to the steam-drum. As the water heats and boiling occurs the fluid rises in the tubes to the steam drum.

[Slide Visual - Boiler Types (Fire-Tube and Water-Tube)]

This schematic depicts a 3-pass fire-tube boiler, in which we have a combustion zone (at the bottom), and smaller tubes that allow more heat transfer from the exhaust gases. The pressure vessel holds all of the stress of the high-pressure steam.

Water-tube boilers allow the combustion gases to provide heat transfer to the water (and steam) that is contained in the tubes of the boiler. A typical water-tube boiler arrangement will incorporate an upper steam-drum that allows the liquid water and steam to separate. A lower drum, often called a mud-drum, will serve as the lower collection header for the tubes. Hundreds of relatively small diameter tubes will connect the mud-drum to the steam-drum. As the water heats and boiling occurs the fluid rises in the tubes to the steam drum.

Slide 3 - Fire-Tube Boiler

Generally, fire-tube boilers are designed for lower pressure and less capacity than water-tube boilers—but their operating ranges overlap. A typical fire-tube boiler might have a steam production rate of 5,000 pounds per hour, while a typical water-tube boiler might have a steam production rate of 200,000 pounds per hour. Fire-tube boilers produce saturated steam in most all cases.

[Slide Visual - Fire-Tube Boiler]

This schematic depicts a 3-pass fire-tube boiler, in which we have a combustion zone (at the bottom), and smaller tubes that allow more heat transfer from the exhaust gases. The pressure vessel holds all of the stress of the high-pressure steam.

- **Steam pressure limited**
    - **Typical 300 psig maximum**
- **Steam flow rate limited**
    - **Typical 1,200 BHp maximum**
        - **40,000 lbm/hr**
- **Saturated steam output**
- **One inherent efficiency advantage over water tube type – shell loss is minimal**
- **Generally manufactured offsite**
- **Many different styles**

Slide 4 - Water-Tube Boiler

Water-tube boilers can produce saturated steam or they can be equipped with a superheater internal to the boiler. From the standpoints of management, investigation, and improvement, knowing the differences between the two boiler types is not essential—because they generally work the same. There are no significant efficiency related reasons to choose one type of boiler or the other. The reasons for choosing one or the other are usually related to the relative cost for the given pressure and steam production requirements.

[Slide Visual - Water-Tube Boiler]

Water-tube boilers allow the combustion gases to provide heat transfer to the water (and steam) that is contained in the tubes of the boiler. A typical water-tube boiler arrangement will incorporate an upper steam-drum that allows the liquid water and steam to separate. A lower drum, often called a mud-drum, will serve as the lower collection header for the tubes. Hundreds of relatively small diameter tubes will connect the mud-drum to the steam-drum. As the water heats and boiling occurs the fluid rises in the tubes to the steam drum.

- **Operating pressures range from atmospheric to in excess of 4,000 psig**
- **Steam production ranges from 5,000 lbm/hr to 10,000,000 lbm/hr**
- **Saturated or superheated steam output**
- **Constructed onsite or offsite**
- **Many different styles**

Slide 5 - Common Fuels

This table contains information concerning the most common fuels used in the United States—and throughout the word. Natural gas is widely distributed through a national pipeline system. This fuel is primarily methane gas. Number 2 fuel oil is also known as *heating oil* and *home heating oil*. Number 2 fuel oil is distributed as a liquid that is very similar in composition to diesel fuel. During the distillation process, number 6 fuel oil is the material remaining after gasoline, kerosene, diesel, and other lighter materials have been boiled from the crude oil mixture. Number 6 fuel oil is also known as *heavy fuel oil*, *bunker C fuel oil*, and *residual fuel oil*. Number 6 fuel oil most often contains sulfur and is designated as High Sulfur content or Low Sulfur content. This is noted as HS and LS respectively in the information provided in this course. Number 6 fuel oil generally will not flow as a liquid until it has been heated to well above room temperature.

Coal properties vary significantly from region to region and from mine to mine. The characteristics of coals are not at all standard; but, some general characteristics can be used as a basic guide to coal properties. In the united states, the most common coals are the Eastern Bituminous Coals and the Western Sub-Bituminous Coals. A characteristic difference in these coals is moisture content. Eastern coal typically has less intrinsic moisture than western coal.

Natural gas and number 2 fuel oil are generally considered very easy fuels to utilize. The heavier fuel oils, like number 6 fuel oil are very common; but, are more difficult to handle. Number 6 fuel oil is generally a solid at room temperature and is heated to more than 200 degrees Fahrenheit to be pumped to the boiler burner. Solid fuels like coal and green-wood are much more difficult to handle and store. Solid fuels generally contain a portion of noncombustible material called ash that must be disposed of after the combustion process.

Green-wood is a dominant fuel in the pulp-and-paper industry because they generate a significant amount of waste-wood materials. It should be noted that green-wood is typically bark and tree components that were recently a part of a live tree. This fact is important because live trees are essentially half liquid water—green-wood as a fuel is nominally 50 percent liquid water. Green-wood is commonly known as *hog fuel*, *wood chips*, and simply *wood*.

The unit costs identified in this table are reflective of the average U.S. fuel costs for 2005. This information is understandably not current; but, it is reflective of the common differences in fuel prices. It is common for the energy based cost of natural gas to be four times greater than the energy based cost of coal—or even more. Fuel oil prices can be even higher. This is a dominant reason why we use coal.

It should be noted that there is significant volatility in the fuel market.

[Slide Visual - Common Fuel Table]

Typical Fuel Properties				
	Sales	Example Price	HHV	Unit Price
Fuel	Unit	[$/sales unit]	[Btu/lbm]	[$/10-Btu]
Natural Gas	10^3std ft^3	7.00	23,311	7.00
Number 2 Fuel Oil	gallon	1.80	19,400	12.92
Number 6 Oil (LS)	gallon	1.20	18,742	7.82
Number 6 Oil (HS)	gallon	1.00	18,815	6.62
Eastern Coal	ton	45.00	13,710	1.64
Western Coal	ton	30.00	10,088	1.49
Green Wood	ton	11.00	5,250	1.05

Slide 6 - Boiler Example

Throughout this training we will use an example steam system that reflects a steam system with real-world characteristics. This example system will help us illustrate the importance and usefulness of tools and investigations presented in this training. Throughout this course we will discuss all the aspects of this steam system; but, we will start by looking at one of the boilers serving this example site.

For this example the boiler is producing 100,000 pounds per hour, of 400 PSIG, 700 degree Fahrenheit steam from the combustion of natural gas.

This boiler is equipped with a fuel flow meter and the cost of the fuel is taken as 10 dollars per million BTU.

[Slide Visual - Water-Tube Boiler]

Water-tube boilers allow the combustion gases to provide heat transfer to the water (and steam) that is contained in the tubes of the boiler. A typical water-tube boiler arrangement will incorporate an upper steam-drum that allows the liquid water and steam to separate. A lower drum, often called a mud-drum, will serve as the lower collection header for the tubes. Hundreds of relatively small diameter tubes will connect the mud-drum to the steam-drum. As the water heats and boiling occurs the fluid rises in the tubes to the steam drum.

- **Natural gas fired boiler ($10.0/106Btu)**
  - **Steam pressure is 400 psig**
  - **Steam temperature is 700°F (superheated)**
  - **Boiler capacity is 120,000 lbm/hr**
  - **Current operating load is 100,000 lbm/hr**
  - **Natural Gas Supply is 2,480 sft/m**

Slide 7 - Case Study

This data will provide enough information to calculate the fuel related operating cost of the boiler.

[Slide Visual – Operating Cost]

Boiler fired with natural gas which has a higher heating value of 23,311 Btu/lbm
HHV is 1,000 Btu/sft^3
Steam conditions: 400 psig, 700°F
Output: 100,000 lbm/hr (steady)
Rating: 120,000 lbm/hr (maximum continuous)
Feedwater: 600 psig, 242°F
Fuel supply: 149,000 sft^3/hr (2,480 sft^3/min)
Fuel cost: $10.00/10 Btu ($10.0/10^{3}sft^3)

Determine the operating cost of the boiler

Slide 8 - Boiler Operating Cost

The fuel related operating cost of this example boiler is $13,000,000 per year. It should be noted that this example boiler can be considered a typical industrial boiler. The fuel is natural gas, which is one of the simplest fuels to burn. It is interesting to note that the characteristics of this boiler are not extreme; in other words, the boiler is producing a moderate amount of steam under typical conditions. Additionally, while the fuel cost may not be exactly representative of the fuel costs at a given facility this example cost is not extraordinary. The characteristics of this boiler are easily scalable to most boilers. It should also be noted that the investigation and improvement techniques required to manage this example boiler are the same techniques available to all boilers. Along with this is the fact that this example boiler is a real boiler that appropriately represents the types of opportunities potentially available to many boilers. Boilers are extremely expensive components—this is the reason we are interested in them.

[Slide Visual –Boiler Operating Cost Calculation]

K_{boiler} = V-dot$_{fuel}$ x k-dot$_{fuel}$ x $t_{operation}$

Boiler operating costs equals the cost of fuel in units per hour ; multiplied by the cost of the fuel per unit; multiplied by the hours of operation

Where:
K_{boiler} = Boiler Operating Costs
V-dot$_{fuel}$ = Volume Flow of Fuel Units per Hour (fuel supply)
k-dot$_{fuel}$ = Cost of Fuel per Unit (fuel costs)
$t_{operation}$ = Operating Period

K_{boiler} =149,000 sft^3/hr x (10.0 \$/10^3-sft^3) x (8,760 hrs/yr).

Boiler operating costs equals 149,000 standard cubic feet per hour; multiplied by 10 dollars per standard cubic feet; multiplied by 8,760 hours per year.

K_{boiler} = 13,000,000 \$/yr

Boiler operating costs equals $13,000,000 per year.

Slide 9 - Operating Cost

The cost of fuel for a typical boiler is so large that even very small changes in efficiency can represent significant cost impact. A 1 percent improvement in efficiency for the example boiler represents approximately $130,000 per year of fuel savings.

[Slide Visual – Savings Calculation 1]

0.01 x $13,000,000/yr - $130,000 savings!

There are other cost factors associated with boiler operations—water treatment costs, auxiliary equipment costs, maintenance costs, and operations costs; however, these costs typically combine to be significantly less than the cost of fuel for the boiler. Each cost factor should be investigated; but, fuel cost typically dominates.

In this example boiler investigation we will identify real-world methods that will reduce the fuel consumption of this boiler more than 7 percent, which represents more than $1,000,000 per year.

Calculations are often thought of as academic exercises; however, in the case of managing boiler performance and cost, evaluating boiler efficiency is one of the most important and practical tools available to us. To illustrate the importance and usefulness of boiler efficiency, we will examine the efficiency of an example boiler. We will also explore the major factors that impact the efficiency and operating cost of a boiler.

[Slide Visual – Operating Cost]

Boiler fired with natural gas which has a higher heating value of 23,311 Btu/lbm
HHV is 1,000 Btu/sft^3
Steam conditions: 400 psig, 700°F
Output: 100,000 lbm/hr (steady)
Rating: 120,000 lbm/hr (maximum continuous)
Feedwater: 600 psig, 242°F
Fuel supply: 149,000 sft^3/hr (2,480 sft^3/min)
Fuel cost: $10.00/10 Btu ($10.0/10^{3}sft^3)
Operating cost: 13,000,000$/yr

- **A small change in boiler efficiency (even 1%) can represent a significant economic impact**

Other operating costs include:

- **Water treatment**
- **Boiler feed pumps**
- **Flue gas conditioning**
- **Maintenance (personnel, services, equipment)**
- **Typically these costs combine to be much less than fuel costs**

Slide 10 - Efficiency Definition

Calculations are often thought of as academic exercises; however, in the case of managing boiler performance and cost, evaluating boiler efficiency is one of the most important and practical tools available to us. To illustrate the importance and usefulness of boiler efficiency, we will examine the efficiency of an example boiler. We will also explore the major factors that impact the efficiency and operating cost of a boiler.

[Slide Visual – Efficiency Sub-Section: Efficiency Definition]

Banner:
DOE's BestPractices
Steam End User Training

Steam Generation Efficiency
Efficiency Definition
Radiation and Convection Losses –
Shell Losses
Blowdown Losses
Stack Losses

Slide 11 - Classic Boiler Efficiency

Boiler efficiency is a way to determine how much fuel energy a boiler converts into steam energy. Steam energy is the desired commodity and fuel energy is the purchased commodity. The equation shown here is a simplified description of the energy efficiency of a boiler—expressed in terms of fuel energy into the boiler and steam energy out of the boiler.

[Slide Visual – Classic Boiler (Direct) Efficiency Equation]

n_{boiler} = **energy desired /**
energy that costs

The boiler efficiency is equal to the energy desired; divided by the energy that costs.

The fuel energy supplied to the boiler is determined by multiplying the fuel flow rate by the fuel energy content. Fuel energy content is described in terms of the heating value of the fuel, which is an expression of the thermal energy that is released when the fuel is burned. The maximum thermal energy that can be released when a fuel is burned is identified as the fuel Higher Heating Value or HHV of the fuel. The fuel heating value is determined by laboratory analysis.

[Slide Visual – Classic Boiler (Direct) Efficiency Equation 2]

$$n_{boiler} = \frac{\text{m-dot}_{steam}\ (h_{steam} - h_{feedwater})}{\text{m-dot}_{fuel}\ \ HHV_{fuel}}$$

Boiler efficiency is equal to the mass flow rate of the steam; multiplied by the difference in the enthalpy of the steam and the enthalpy of the feedwater; divided by the mass flow of the fuel; multiplied by the higher heating value of the fuel.

Where:

n_{boiler}	= Efficiency of the boiler, also called combustion efficiency, overall efficiency (dimensionless)
m-dot_{steam}	= Mass flow rate of steam generated in the boiler
m-dot_{fuel}	= Mass flow rate of fuel burned
h_{steam}	= Enthalpy is energy content of steam
$h_{feedwater}$	= Enthalpy is energy content of feedwater
HHV_{fuel}	= Higher Heating Value of fuel

The energy desired is the energy added to the steam as it passes through the boiler. Steam energy is determined by multiplying the steam production (or mass flow rate) by the specific energy added to the steam as it passes through the boiler. We describe the energy content of the steam as the *enthalpy* of the steam (*h* in the equation)—*enthalpy* is the thermodynamic property describing the amount of energy residing in the material. The energy added to the steam in the boiler is the difference in enthalpy of the steam leaving the boiler versus the feedwater entering the boiler. Enthalpy values are obtained from thermo-physical property data sets and field measurements like steam temperature and pressure.

[Slide Visual – Enthalpy Definition]

Enthalpy –energy of a substance that can be converted into heat, work, and other forms of energy.

Fuel energy is determined by multiplying the fuel consumption rate by the fuel energy content, also known as the heating value.

An alternate expression for the energy content of the fuel is identified as the Lower Heating Value (LHV). Most common fuels are composed primarily of carbon and hydrogen. These elements react with oxygen in the combustion process and primarily form carbon dioxide and water. The water formed in the combustion process is initially vapor (steam). If this water-vapor is allowed to cool below its condensation temperature the vapor will condense liberating heat. This energy release from the water-vapor represents additional energy available from the combustion of the fuel. The difference between the Higher Heating Value and the Lower Heating Value is the Higher Heating Value accounts for this additional energy liberation when the water-vapor condenses. The Lower Heating Value measures the fuel energy release with all the combustion products remaining in the vapor phase.

[Slide Visual – Lower Heating Value]

LHV – fuel energy released with all the combustion products remaining in the vapor phase.

Slide 12 - Boiler Efficiency 1

It is interesting to identify typical boiler efficiency. This will allow us to compare our boiler to typical operation. If we can identify best-practice boiler efficiency then we can characterize the operation of our boiler—possibly identifying the improvement potential.

[Slide Visual – Typical Boiler Efficiencies]

A typical boiler will have an efficiency of ----?

Slide 13 - Boiler Efficiency 2

If we were to examine many boilers we would probably find that the typical boiler efficiency is in the mid-80 percent range. We would also see that many of the boilers would have higher efficiency than this and many would have lower efficiency than this. But, we would see very few boilers with efficiencies much greater than 90 percent and very few boilers with efficiencies much lower than 70 percent.

Green-wood is a common fuel in many industries most prominently in the pulp and paper industry. The term green-wood refers to wood products that have not been dried. Pulp and paper plants harvest trees to process them into pulp and paper products. Paper is not made from the bark and limbs of the trees. As the trees are harvested the limbs, bark, and poor quality materials are removed along with other parts of the tree that cannot be converted into paper. This "green-wood" is fresh from the forest and typically contains about 50 percent cellulose and 50 percent liquid water. Green-wood is used as a major fuel source because it is readily available and is low-cost. However, a fuel that is composed of 50 percent liquid water will burn inefficiently—the liquid water will boil and carry a large amount of energy out of the boiler. As a result, green-wood-fired boilers will operate with low efficiency.

It is interesting to note that a typical industrial coal-fired boiler will operate with relatively high efficiency. This results from the fact that hydro-carbon fuels are composed primarily of hydrogen and carbon. Carbon combusts and forms carbon dioxide. Hydrogen combusts and forms H_2O—water. Water is God's greatest chemical for absorbing and transporting energy. Most of our boilers burning hydrocarbon fuels release water-vapor (steam) as a product of combustion. As a result, a significant portion of the energy available in the fuel is carried out of the boiler in the water-vapor that is formed in the combustion process. Fuels containing less hydrogen exhaust less water-vapor in the flue gases and generally have higher efficiency. Coals generally contain some amount of liquid water, some amount of ash (rocks), but mostly carbon.

Fuel oils usually contain more hydrogen than coals but they typically contain very little ash and almost no liquid water. As a result, fuel oil-fired boilers will operate with relatively high efficiency.

Natural gas contains a relatively large amount of hydrogen. Therefore, natural gas-fired boilers will operate with efficiencies lower than comparable coal and oil-fired boilers.

There are many factors that impact boiler efficiency—fuel type is one of them, the way we control the combustion process is another, and energy recovery equipment installed on the boiler is one more major factor effecting efficiency.

[Slide Visual – Typical Boiler Efficiencies]

A typical boiler will have an efficiency of ----?

70% Green Wood
82% Natural Gas
90% Oil and Coal

Efficiency is primarily dependent on the type of fuel, the combustion control effectiveness, and the energy recovery equipment.

Slide 14 - Example Steam Properties

Let's return to our example boiler because we have enough information to evaluate boiler efficiency. In order to determine the energy added to the steam passing through the boiler, we must use steam property data often known as "steam tables". From the temperature and pressure measurements of the steam and feedwater we can identify their enthalpies—again, enthalpy is an indication of energy content. Here you can see for 700 degrees Fahrenheit and 400 pounds per square inch gage, the enthalpy of the steam is 1,362 BTU per pound of steam. The feedwater is at 242 degrees Fahrenheit and 600 pounds per square inch gage—the enthalpy of the feedwater is 210 BTU per pound as shown in the table.

[Slide Visual – Efficiency Example Steam Properties]

Properties							
Location	Temp	P	Specific Volume	Enthalpy	Entropy	Quality	P
	[°F]	[psia]	[ft³/lbm]	[Btu/lbm]	[Btu/lbm°R]	[%]	[psig]
Boiler outlet	700	414.7	1.58946	1,361.88	1.63527	****	400
Saturated vapor	448	414.7	1.12025	1,204.62	1.46906	100.0	400
Saturated liquid	448	414.7	0.01939	428.04	0.62561	0.0	400
Deaerator storage	239	24.7	0.01692	207.74	0.35233	0.0	10
Feed pump exit	242	614.7	0.01694	210.42	0.35615	0.0	600
Condensate	180	14.7	0.01650	147.91	0.26289	0.0	0
Makeup water	75	14.7	0.01605	43.04	0.08397	0.0	0

$$n_{boiler} = \frac{\text{m-dot}_{steam}\ (h_{steam} - h_{feedwater})}{\text{m-dot}_{fuel}\ \ HHV_{fuel}}$$

Boiler efficiency is equal to the mass flow rate of the steam; multiplied by the difference in the enthalpy of the steam and the enthalpy of the feedwater; divided by the mass flow of the fuel; multiplied by the higher heating value of the fuel.

Slide 15 - Direct Efficiency

The steam property data along with the fuel consumption data gives us enough information to calculate boiler efficiency. This boiler is operating with an efficiency of about 77 percent. We are expecting a typical natural gas fired boiler to operate with an efficiency in the low 80 percent range. This boiler is operating with an efficiency that is below the expected value—we anticipate that there may be opportunities to improve the performance of this boiler.

Direct Efficiency Calculation 1- Entering data into the direct efficiency equation, we get 77 percent boiler efficiency.

[Slide Visual - Direct (Classic) Efficiency Equations]

$$n_{boiler} = \frac{\text{m-dot}_{steam}\ (h_{steam} - h_{feedwater})\ /}{\text{m-dot}_{fuel} \times HHV_{fuel}} \quad \times (100)$$

Boiler efficiency is equal to the mass flow rate of the steam; multiplied by the difference in the enthalpy of the steam and the enthalpy of the feedwater; divided by the mass flow of the fuel; multiplied by the higher heating value of the fuel.

$$n_{boiler} = \frac{(100{,}000 \text{ lbm/hr}) \times (1{,}361.88 \text{ Btu/lbm} - 210.42 \text{ Btu/lbm}) \times (100)}{(149{,}000 \text{ sft}^3\text{/hr}) \times (1{,}000 \text{ Btu/sft}^3)}$$

The boiler efficiency is equal to 100,000 pounds per hour, multiplied by 1,361.88 BTU per pound; minus 210.42 Btu per pound; divided by the 149,000 standard cubic feet per hour; multiplied by 1,000 Btu per standard cubic feet.

based on volumetric flow rate (HHV units are Btu/sft^3)

Or using fuel mass flow data (p = 0.043 lbm/sft^3)

$$\text{m-dot}_{fuel} = (149{,}000 \text{ sft}^3\text{/hr}) \times (0.043 \text{ lbm/sft}^3) = 6{,}407 \text{ lbm/hr}$$

$$n_{boiler} = \frac{(100{,}000 \text{ lbm/hr}) \times (1{,}361.88 \text{ Btu/lbm} - 210.42 \text{ Btu/lbm}) \times (100)}{(6{,}407 \text{ lbm/hr}) \times (23{,}311 \text{ Btu/lbm})}$$

The boiler efficiency is equal to 100,000 pounds per hour; multiplied by 1,361.88 BTU per pound; minus 210.42 Btu per pound; divided by the 6,407 pounds per hour; multiplied by 23,311 Btu per pound.

based on mass flow rate (HHV units are Btu/lbm)

$n_{boiler} = 77.1\%$

The boiler efficiency is equal 77.1%.

Slide 16 - Efficiency Calculation

In order to identify the improvement opportunities associated with this boiler, we ask "why is the efficiency not 100 percent?" In other words, if boiler efficiency indicates that 77 percent of the fuel energy went into the steam, where did the other 23 percent of the fuel energy go? It went to supply the losses of the boiler.

[Slide Visual - Equations]

$$n_{boiler} = \frac{\text{m-dot}_{steam}\,(h_{steam} - h_{feedwater})}{\text{m-dot}_{fuel} \times HHV_{fuel}} \times (100)$$

Boiler efficiency is equal to the mass flow rate of the steam; multiplied by the difference in the enthalpy of the steam and the enthalpy of the feedwater; divided by the mass flow of the fuel; multiplied by the higher heating value of the fuel.

$$n_{boiler} = \frac{(100{,}000\ \text{lbm/hr}) \times (1{,}361.88\ \text{Btu/lbm} - 210.42\ \text{Btu/lbm}) \times (100)}{(6{,}407\ \text{lbm/hr}) \times (23{,}311\ \text{Btu/lbm})}$$

The boiler efficiency is equal to 100,000 pounds per hour; multiplied by 1,361.88 BTU per pound; minus 210.42 Btu per pound; divided by the 6,407 pounds per hour; multiplied by 23,311 Btu per pound.

$n_{boiler} = 77.1\%$

The boiler efficiency is equal 77.1%.

Why is the efficiency not 100%?

Slide 17 - Boiler Losses 1

What are the typical boiler losses? Where can fuel go other than into the steam?

[Slide Visual – Boiler Losses 1]

- **Identify the Boiler Losses**

This schematic depicts a water-tube boiler. Fuel and air enters at the lower left of the combustion zone, feedwater enters at the top into the steam drum which connects to the mud drum through many tubes. The mud drum is at the bottom of the boiler. Steam exits the boiler from the steam drum into the superheater section, which is shown at the top of the boiler. The combustion gases leaving the boiler through the ducting at the upper right.

Slide 18 - Boiler Losses 2

Even though boilers are insulated, their outer surfaces are hot, indicating they are not perfectly insulated and fuel energy is being lost. This is identified as the *shell loss* also known as *radiation and convection loss*.

Another loss associated with operating a boiler is identified as the *blowdown loss*. In order to maintain proper boiler water chemistry some of the boiler water must be removed. This is an energy loss because the water that is discharged has been heated with fuel energy.

The exhaust gases from the combustion process exit the boiler with fuel energy. This energy can be identified by the elevated temperature of the gases. But there also can be un-reacted fuel or extra air in the exhaust gases. These exhaust gas related losses are identified as the *stack loss*.

Many other losses can be identified for boilers; such as, the energy carried from the boiler with ash in a coal-fired boiler. However, the three losses identified—shell, blowdown, and stack—are present on all fired boilers and they represent the fundamental points of concern for managing boiler efficiency.

[Slide Visual – Boiler Losses 2]

- **Identify the Boiler Losses**

This schematic depicts a water-tube boiler. Fuel and air enters at the lower left of the combustion zone, feedwater enters at the top into the steam drum which connects to the mud drum through many tubes. The mud drum is at the bottom of the boiler. Steam exits the boiler from the steam drum into the superheater section, which is shown at the top of the boiler. The combustion gases leaving the boiler through the ducting at the upper right.

➢ **Arrows show losses leaving the boiler:**
- **Outer surface as Radiation and Convection (Shell Losses)**
- **Blowdown (Blowdown Losses)**
- **Exhaust Stack (as Gases) as Combustion and Temperature (Stack Losses)**
- **Fly Ash and Bottom Ash (Other Miscellaneous Losses)**

Slide 19 - Indirect Efficiency

Generally managing boiler performance focuses on identifying and managing the losses. In fact, one of our most important tools is to identify, quantify, and reduce the boiler losses. This is accomplished through an indirect efficiency evaluation technique, which is the tool most often used in the field. Boiler efficiency is determined in an indirect manner by assuming the boiler efficiency is 100 percent minus all of the losses. Each loss is identified and quantified in this analysis.

In the next sections of our training, we will focus on each of these losses. We will explore each loss in detail identifying how to evaluate each one for our boilers. Additionally we will identify the fuel impact associated with each loss and the real-world improvement opportunities that can be targeted in each area. The real benefit associated with evaluating boiler performance with the indirect efficiency tool is that as boiler efficiency is determined, the roadmap for improvement is established. Evaluating the individual losses not only characterizes each loss but it also affords us the opportunity to identify the improvement potential associated with each.

[Slide Visual – Boiler Loss Indirect Efficiency]

➢ **Boiler efficiency can also be determined in an indirect manner by determining the magnitude of the losses**
- **Primary losses are typically**
  - **Shell loss**
  - **Blowdown loss**
  - **Stack loss**

$n_{indirect} = 100 \text{ percent} - E_{Losses}$

Indirect Boiler Efficiency is equal to 100% minus the sum of all boiler losses.

$n_{indirect} = 100 \text{ percent} - Loss_{shell} - Loss_{blowdown} - Loss_{stack} - Loss_{misc}$

Indirect Boiler Efficiency is equal to 100% minus the shell losses, minus the blowdown losses, minus the stack losses, minus the miscellaneous losses.

Where:

$n_{indirect}$	**= Indirect efficiency**
E_{Losses}	**= Sum of all Losses**
$Loss_{shell}$	**= Shell Losses**
$Loss_{blowdown}$	**= Blowdown Losses**
$Loss_{stack}$	**= Stack Losses**
$Loss_{misc}$	**= Miscellaneous Losses**

Steam End-User Training
Steam Generation Efficiency Module
Shell Losses Section

Slide 1 - Shell Losses Module

Next, we will identify the methods used to investigate, quantify, and control these individual losses. We will start with shell losses.

[Slide Visual – Efficiency Sub-Section: Shell Losses]

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Stack Losses

Slide 2 - Shell Loss Magnitude

Shell loss is the fuel energy that leaves the boiler from its outer surface. In other words, the outer surface of the boiler is hot, which indicates it is losing heat. It is difficult to accurately measure the thermal energy loss from the outer shell of a boiler. As a result, shell loss is generally estimated from some limited field measurements. An excellent and relatively easy estimating technique is identified in the American Society of Mechanical Engineers Performance Test Code 4 (ASME-PTC-4).

In this technique, the temperature of each surface of the boiler is measured. Typically this measurement is obtained with an infrared surface thermometer. Surface temperatures typically range from 120 to 180 degrees Fahrenheit, but hot spots greater than this range can exist. Hot spots can develop from damaged insulation on the boiler or damaged refractory inside the boiler.

The shell loss estimating technique utilizes the characteristic temperature of a boiler surface or 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 boiler shell loss. This technique is simple; however, the results must be considered a general estimate.

The total shell loss estimate is compared to the total fuel energy input to determine the magnitude of the loss.

Slide 3 - Shell Loss

It is interesting to note that for most boilers the total energy lost from the shell remains essentially constant with respect to boiler load. In other words, the shell loss energy flow is basically constant. This is not to say that the fraction of fuel input energy lost from the boiler shell remains constant—rather the energy flow (Btu per hour) remains essentially constant with respect to boiler load. This being the case, the shell loss expressed as a fraction of fuel input energy would double as the boiler transitions from full-load to half-load.

For most well-maintained boilers, the full load shell loss will be between 0.1 percent to 2 percent of fuel input energy.

Usually, shell losses are minimal and the best way to manage shell loss is to monitor for hot-spots, damaged insulation, and other surface problems. Typically, shell loss issues do not translate into significant energy losses but signify insulation or refractory issues that need to be repaired to increase the longevity of the boiler.

Slide 4 - Example Boiler Savings

For our example boiler, an ASME type shell loss investigation indicates that approximately 0.5 percent of the fuel input energy is lost through the shell of the boiler. This represents approximately 65,000 dollars per year of fuel energy. This is a relatively small fraction of the fuel input energy and there is very little that can be done to significantly reduce it.

Our Example Boiler:

- **From an ASME type investigation the radiation and convection loss of the example boiler is approximately 0.5 percent of the total fuel energy input to the boiler.**
  - **This represents a loss of approximately $65,000 per year**
  - **Surface temperature measurements did not indicate any hot-spots on the example boiler. The insulation, cladding, and refractory are in good condition. As a result, we will just accept that this loss will occur and continue our investigation into other areas of boiler efficiency.**

[Slide Visual – Radiation and Convection Loss]

Radiation and Convection Loss = $13,000,000/hr x (0.5%/100) = $65,000/yr

Radiation and Convection Loss is equal to $13,000,000 per hour multiplied by 0.5 percent equals = $65,000 per year.

Slide 5 – Shell Loss Summary

In summary, shell loss is generally a minor contributor to the overall fuel energy loss. Direct measurements of boiler shell loss are difficult to complete; but, simplified estimating techniques provide excellent insight into the magnitude of boiler shell loss. Shell loss should not be ignored—hot spots in the boiler shell indicate problems that should be corrected.

Steam End-User Training
Steam Generation Efficiency Module
Blowdown Losses Section

Slide 1 - Blowdown Losses Module

This section will discuss blowdown loss and its affect on boiler efficiency.

[Slide Visual – Efficiency Sub-Section: Blowdown Losses]
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Slide 2 – Blowdown

The next type of loss investigated is blowdown loss. Boiler feedwater is very clean water. However, in feedwater there are some dissolved chemicals. Essentially pure steam exits the boiler—the majority of the chemicals entering the boiler with feedwater are not soluble in the steam and will not leave the boiler with the steam. As a result, the concentration of these chemicals increases in the boiler. Elevated concentrations of chemicals results in many serious boiler problems—including foaming resulting in liquid carryover, scaling on the water-side of the tubes, and loose sludge in the boiler water. Blowdown is the primary mechanism that allows us to control chemical concentrations in the boiler water. Blowdown allows us to maintain an acceptable concentration of dissolved and precipitated chemicals in the boiler.

There is an energy loss associated with blowdown, because the water has been heated to the boiling point from feedwater conditions.

Slide 3 - Boiler Blowdown

There are two general types of boiler blowdown. One is typically from the lower sections of the boiler called bottom blowdown. The other type of blowdown is typically from the upper sections of the boiler and is called surface blowdown.

Bottom blowdown is actuated because some solids will precipitate from the chemicals dissolved in the feedwater. These solids tend to be heavier than water, and therefore tend to congregate in lower sections of the boiler. Bottom blowdown is used to flush these solids out. Bottom blowdown is typically a significant flow of water for a very short period of time. The intent is to sweep away any solid precipitates formed in the water. Even though while it is occurring it is a large flow rate, it continues for a short period of time. As a result, the total flow of bottom blowdown is usually much less than the total flow surface blowdown.

Surface blowdown is typically a much smaller flow rate than bottom blowdown; however, it continues for a much longer period of time—often continuously. Surface blowdown is the primary mechanism used to control the dissolved chemical concentrations in the boiler. Surface blowdown ends up removing most of the blowdown water.

[Slide Visual - Boiler Blowdown]

This schematic depicts a water-tube boiler. Fuel and air enters at the lower left of the combustion zone, feedwater enters at the top into the steam drum which connects to the mud drum through many tubes. The mud drum is at the bottom of the boiler. Steam exits the boiler from the steam drum into the superheater section, which is shown at the top of the boiler. The combustion gases leaving the boiler through the ducting at the upper right. The bottom blowdown is shown from the bottom mud drum. The surface blowdown is shown at the top from the steam drum.

Slide 4 - Blowdown Control

Generally, surface 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.

[Slide Visual - Conductivity Sensor]

This schematic depicts a water-tube boiler. Fuel and air enters at the lower left of the combustion zone, feedwater enters at the top into the steam drum which connects to the mud drum through many tubes. The mud drum is at the bottom of the boiler. Steam exits the boiler from the steam drum into the superheater section, which is shown at the top of the boiler. The combustion gases leaving the boiler through the ducting at the upper right. The surface blowdown is shown at the top from the steam drum with a conductivity sensor controlling the blowdown valve position. The blowdown is discharged to the sewer.

Slide 5 - Blowdown Loss Estimate

From the view of the boiler, feedwater enters, steam and blowdown exit. The boiler adds fuel energy to the steam and blowdown that exit the boiler. Blowdown is an energy stream that is discharged from the boiler. Blowdown is typically expressed as a fraction of feedwater mass flow and can range from less than 1 percent to much greater than 10 percent depending on water chemistry, boiler operating pressure, and other factors. However, it should be noted that 10 percent blowdown rate does not mean 10 percent energy loss—blowdown discharged from the boiler is not high-energy steam, it is moderate-energy water. From the perspective of the boiler, the energy added to the blowdown stream is blowdown flow rate times the difference in

the enthalpy of the blowdown and the feedwater. Therefore, 10 percent blowdown rate can translate into 5 percent fuel energy input. It should be noted that the relationship between blowdown mass-fraction and blowdown energy-fraction is dependent on many factors including boiler operating pressure and feedwater temperature.

[Slide Visual - Boiler Blowdown Loss - Boiler Calculation]

$$L_{blowdown} = \frac{\text{m-dot}_{blowdown}\,(h_{blowdown} - h_{feedwater})}{\text{m-dot}_{fuel} \times HHV_{fuel}}$$

Blowdown Loss is equal to the mass flow rate of the blowdown; multiplied by the difference of the enthalpy of the blowdown minus the enthalpy of the feedwater; divided by the mass flow rate of the fuel; multiplied by the Higher Heating Value of the fuel.

Where:

$L_{blowdown}$	= Loss due to blowdown (%)
$\text{m-dot}_{blowdown}$	= Mass flow rate of blowdown
m-dot_{fuel}	= Mass flow rate of steam generated per pound of fuel burned
$h_{blowdown}$	= Enthalpy of blowdown
$h_{feedwater}$	= Enthalpy of feed water at 242 degrees Fahrenheit
HHV	= Higher Heating Value of fuel

Slide 6 - System Loss

Again, from the perspective of the boiler, the energy added to the blowdown stream is blowdown flow rate times the difference in the enthalpy of the blowdown and the feedwater. However, every pound of blowdown discharged from the system is made-up with cold makeup water—as a result; a portion of the steam generated in the boiler is used to heat the makeup water to feedwater conditions in the deaerator. Therefore, from a system perspective, the energy associated with the blowdown stream is even larger than that identified from the boiler perspective.

[Slide Visual - Steam System Impact Schematic]

This schematic represents a three-pressure header steam system with multiple boilers and all of the system components. Feedwater is preheated by steam injection from the low-pressure steam distribution header, as well as preheated make-up water utilizing boiler blowdown heat recovery.

The top of the schematic shows the Boiler Feedwater entering the two boilers. The two boilers are connected to the high-pressure steam distribution header.

The steam exits two boilers and enters the high-pressure steam system distribution header, indicated by a line below the boilers.

Under the high-pressure steam distribution line, you will see three cone-shaped graphics, that represent the steam turbines. The one nearest to the left is a high-pressure to condensing turbine. This turbine discharges to the condenser represented by the blue circle below the turbine. The rectangular graphic to the right of the cone-shaped graphic indicates the electrical generation component of the steam turbine. The turbine in the middle receives high-pressure steam and exhausts low-pressure steam to the low-pressure steam distribution system, as well as generates electricity. This turbine is denoted as red cone and rectangle combination. The steam turbine to the most right receives high pressure steam, drives a pump (denoted as a circle/square combination) and is also called a steam turbine-driven pump, then discharges to the low-pressure steam distribution system header.

Between the condensing turbine and the high-to-low pressure turbine, a light-blue triangular graphic that represents a pressure-reducing valve, which discharges to the low pressure steam distribution header , identified by a red line below the turbines.

At the far right of the high pressure steam distribution system, the high-pressure end-user component loads are identified through a rectangular graphic and arrows entering and leaving the rectangle, indicating heat exchange with the components. The end-use components discharge condensate through a steam trap, represented by a rectangular graphic. Schematically, condensate passes through the bottom of the trap and recovered in a condensing tank which is also connected to the low-pressure steam distribution system.

Under the low-pressure steam distribution line, you will see the low-pressure end-user component loads identified as a rectangular graphic and arrows entering and leaving the rectangle, indicating heat exchange with the components. The end-use components discharge condensate through a steam trap, represented by another rectangular graphic. Schematically, condensate passes through the bottom of the trap and recovered in a condensate tank, in which steam is vented represented by a vertical arrow leaving the top of the tank.

The low-pressure end-user condensate tank uses a pump, which is denoted by a circle/square combination, to deliver the condensate to the main condensate receiver, which is a large rectangle with three inputs denoted by three arrows at the top of the rectangle. The condensate enters this main condensate receiver tank, after it passes through a control valve, denoted as an hour-glass shape with a dome on top. The third condensate input comes from the condensate from the heat exchanger that utilizes the high-pressure steam turbine. The condensate leaves this heat exchanger and is delivered via a pump (denoted as a circle/square combination) to the main condensate receiver.

The main condensate receiver then pumps (denoted by a circle/square combination) the high-pressure condensate, low-pressure condensate, and the condensing steam turbine condensate to the deaerator tank as denoted by two red rectangles, with the smaller one on the top. The top rectangle also shows two triangles, each pointed away from each other, longest ends nearly touching. The bottom triangle is connected to a control valve represented by a red hour-glass figure with a dome on the side, which provides low-pressure steam to the deaerator from the low-pressure steam distribution system to preheat the collected condensate and make-up water. Pre-heated make-up water also schematically enters at the top of the deaerator with the collected condensate.

The make-up water is preheated from the boiler blowdown and low pressure steam. Boiler blowdown from each boiler is noted as red dashed lines leading to a blowdown receiver tank denoted as a red rectangle on the right of the screen. Flash-steam is diverted from the blowdown flash-vessel to the low-pressure steam distribution line, also denoted in red dashed lines. Liquid from the blowdown flash-tank then

schematically enters the top of a heat exchanger (represented as a white and green striped rectangle). Makeup water is shown entering the heat exchanger from the right, after it passes through the water treatment equipment, denoted as two red rectangles further on the right. The liquid exiting the heat exchanger is sent to the deaerator.

The heated boiler feedwater schematically exits the deaerator from the bottom and is pumped (denoted as a circle/square combination) to the feedwater inlets of each boiler, near the top the schematic.

Slide 7 - System Loss Estimate

The actual total system impact associated with blowdown can be more than twice the impact identified from the boiler perspective. An estimate of the total system-wide impact of blowdown being lost from the system can be determined by evaluating the energy added to the blowdown stream by heating makeup water to the blowdown conditions. The loss equation noted here estimates that impact.

[Slide Visual – Boiler Blowdown Loss - System Calculation]

$$L_{blowdown} = \frac{\text{m-dot}_{blowdown}\,(h_{blowdown} - h_{makeup})}{\text{m-dot}_{fuel} \times HHV_{fuel}}$$

Blowdown Loss is equal to the mass flow rate of the blowdown; multiplied by the difference of the enthalpy of the blowdown minus the enthalpy of the make-up water; divided by the mass flow rate of the fuel; multiplied by the Higher Heating Value of the fuel.

Where:

$L_{blowdown}$ = Loss due to blowdown (%)
$\text{m-dot}_{blowdown}$ = Mass flow rate of blowdown
m-dot_{fuel} = Mass flow rate of steam generated per pound of fuel burned
$h_{blowdown}$ = Enthalpy of blowdown
h_{makeup} = Enthalpy of make-up water at 75 degrees Fahrenheit
HHV = Higher Heating Value of fuel

Slide 8 - Blowdown Management

Blowdown loss is managed through two primary avenues. First, the amount of blowdown required can be reduced if the feedwater quality is improved. Second, thermal energy can be recovered from the blowdown stream. To a lesser degree, the blowdown control strategy can be improved to reduce the amount of blowdown.

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. Common improvements include changing from sodium-cycle softening to demineralization or to reverse osmosis conditioning.

Of course feedwater quality can be improved through increased condensate recovery.

Blowdown thermal energy recovery will be discussed in more detail in this section. But, it should be noted that thermal energy recovery has proven a very successful management activity.

In any event, the first step in managing blowdown is to measure the energy loss associated with it. We will use our example boiler to further examine the blowdown issues.

Slide 9 - Blowdown Estimate

Utilizing conventional flow meters for the blowdown stream is problematic because the blowdown is ready to boil. Most flow meters will impose a sufficient pressure drop to result in two-phase flow, which is very difficult to measure. Therefore, in order to measure blowdown rate, we usually measure chemical composition in the feedwater and in the boiler water. The chemical component measured in the analysis must be of sufficient concentration to allow accurate measurement with our instruments. We take the ratio of the chemical concentration in the feedwater to the chemical concentration in the boiler water to establish the blowdown rate.

Our example boiler is operating with a nominal blowdown rate of 6 percent.

[Slide Visual – Blowdown Rate Fraction Equation]

$$\%Blowdown = \frac{C_{feedwater}}{C_{blowdown}}(100)$$

Blowdown Percent is equal to the Concentration of the feedwater divided by the Concentration of the blowdown; all multiplied by 100.

$$\%Blowdown = \frac{15\ ppm}{250\ ppm}(100)$$

Blowdown Percent is equal to the 15 parts per million divided by 250 parts per million; all multiplied by 100.

$$\%Blowdown = 6.0\%_{mass} \text{ of feedwater flow}$$

Blowdown Percent is approximately equal to 6% mass of the feedwater flow.

Where:

$C_{feedwater}$ = Chemical concentration of feedwater (parts per million)
$C_{blowdowr}$ = Chemical concentration of blowdown (parts per million)

Slide 10 - Blowdown Flow Rate

These blowdown equations are based on a simple mass-balance on the boiler water and steam flows. It must be noted that steady flow and steady operating conditions are assumed in the analysis. Additional analysis is required for systems operating with intermittent blowdown. The blowdown flow rate for our example boiler is about 6,400 Pounds per hour.

[Slide Visual – Blowdown Flow Rate Calculation]

$$\text{m-dot}_{blowdown} = \left(\frac{B}{1 - B}\right) \text{m-dot}_{steam}$$

The mass flowrate of the blowdown is equal to the Blowdown Fraction; divided by 1 minus the Blowdown Fraction; all multiplied by the mass flow rate of the steam.

$$\text{m-dot}_{blowdown} = \left(\frac{0.06}{1 - 0.06}\right) 100{,}000 \text{ lbm/hr} = 6{,}400 \text{ lbm/hr}$$

The mass flowrate of the blowdown is equal to 0.06; divided by 1 minus 0.06; all multiplied by the 100,000 pounds per hour equals 6,400 pounds per hour.

Where:

$\text{m-dot}_{blowdown}$	= Mass flow rate of blowdown
m-dot_{steam}	= Mass flow rate of steam generated per pound of fuel burned
B	= Blowdown rate fraction (percent of feedwater)

Slide 11 - Boiler Loss Estimate

The example boiler operates with approximately 6 percent of the feedwater leaving the boiler as blowdown. This represents approximately 1 percent of the total fuel input energy.

[Slide Visual – Boiler Blowdown Loss - Boiler Calculation]

$L_{blowdown} = \dfrac{\underline{\text{m-dot}_{blowdown}\ (h_{blowdown} - h_{feedwater})}\ /}{\text{m-dot}_{fuel} \times HHV_{fuel}} \times (100)$

Blowdown loss is equal the mass flow rate of the blowdown; multiplied by the difference of the enthalpy of the blowdown minus the enthalpy of the feedwater; divided by the mass flow rate of the fuel multiplied by the High Heating Value of the fuel; all multiplied by 100.

The enthalpy of the feedwater, $h_{feedwater}$ at 242 degrees Fahrenheit is 210.42 Btu/lbm.

$L_{blowdown} = \dfrac{(6{,}400 \text{ lbm/hr}) \times (428.04 \text{ Btu/lbm} - 210.42 \text{ Btu/lbm})}{(6{,}407 \text{ lbm/hr}) \times (23{,}311 \text{ Btu/lbm})} \times (100)$

Blowdown loss is equal the 6,400 lbm/hr; multiplied by the difference of the 428.04 Btu/lbm {minus} 210.42 Btu/lbm; divided by the 6,407 lbm/hr; multiplied by 23,311 Btu/lbm; all multiplied by 100.

$L_{blowdown} = 0.9\%_{\ energy}$

The blowdown loss is equal to 0.9% energy.

Slide 12 - Blowdown Loss Estimate

However, as pointed out previously the impact on the steam system is even greater than this "boiler focus" blowdown energy analysis. This is because blowdown discharged from the system has to be replaced with cold makeup water. The system based blowdown energy impact is about 1.7 percent of the fuel input energy. This may be a relatively small fraction of fuel input energy; however, it translates into more than $200,000 per year of fuel cost. Additionally, and more importantly, there are cost effective measures we can employ to virtually eliminate this loss.

Two primary avenues are used to reduce the loss associated with blowdown. First, providing cleaner feedwater can dramatically reduce the required blowdown. The primary methods used to improve feedwater quality are to utilize technologies to provide cleaner makeup water—demineralization, dealkalization, reverse osmosis. Increasing condensate recovery is an excellent strategy to improve feedwater quality; because, condensate is typically the cleanest water available—and it contains valuable thermal energy.

Second, the thermal energy in the blowdown stream can be recovered. In fact, almost all of the thermal energy of the blowdown stream can be recovered with time-proven cost-effective measures.

[Slide Visual – Boiler Blowdown Loss – System Calculation]

$13,000,000 operating costs x ~1.7% yields $215,000 operating savings.

$$L_{blowdown} = \frac{\dot{m}_{blowdown}\,(h_{blowdown} - h_{makeup})}{\dot{m}_{fuel} \times HHV_{fuel}} \times (100)$$

Blowdown loss is equal the mass flow rate of the blowdown; multiplied by the difference of the enthalpy of the blowdown minus the enthalpy of the makeup water; divided by the mass flow rate of the fuel multiplied by the High Heating Value of the fuel; all multiplied by 100.

The enthalpy of the make-up water, h_{makeup} at 75 degrees Fahrenheit is 43.04 Btu/lbm.

$$L_{blowdown} = \frac{(6{,}400\ \text{lbm/hr}) \times (428.04\ \text{Btu/lbm} - 43.04\ \text{Btu/lbm})}{(6{,}407\ \text{lbm/hr}) \times (23{,}311\ \text{Btu/lbm})} \times (100)$$

The blowdown loss is equal the 6,400 lbm/hr; multiplied by the difference of the 428.04 Btu/lbm minus 43.04 Btu/lbm); divided by the 6,407 lbm/hr multiplied by 23,311 Btu/lbm; all multiplied by 100.

$$L_{blowdown} = 1.7\%_{\ energy}$$

The blowdown loss is equal to 1.7% energy.

Slide 13 - Boiler Blowdown

Blowdown thermal energy recovery typically focuses on surface blowdown, because it is the largest portion of the blowdown flow and can be a relatively constant stream. The most common (and successful) blowdown thermal energy recovery systems include two stages of recovery.

[Slide Visual - Blowdown Types]

This schematic depicts a water-tube boiler. Fuel and air enters at the lower left of the combustion zone, feedwater enters at the top into the steam drum which connects to the mud drum through many tubes. The mud drum is at the bottom of the boiler. Steam exits the boiler from

the steam drum into the superheater section, which is shown at the top of the boiler. The combustion gases leaving the boiler through the ducting at the upper right. The bottom blowdown (intermittent) is shown at the bottom mud drum of the boiler schematic. The surface blowdown (continuous) is shown at the top steam drum.

Slide 14 - Blowdown Energy Recovery

First, we bring the high-pressure blowdown stream into a pressure vessel (flash tank) operating at low-pressure. This allows the saturated high-pressure liquid to generate flash steam as it comes to equilibrium in the flash tank. Part of the blowdown liquid flashes to steam and the rest remains liquid. The flash-steam is clean, so we can direct it right into the low-pressure steam system. The liquid that remains in the flash-vessel is hot, so we can still use this water in a heat exchanger to preheat makeup water. The blowdown water will eventually be discharged from the system because it contains the boiler water contaminants. We can capture almost all of the blowdown thermal energy with the installation of a simple flash-tank and a heat exchanger. The blowdown loss can be virtually eliminated with very simple, robust equipment!

[Slide Visual - Blowdown Energy Recovery]

This schematic depicts a water-tube boiler. Fuel and air enters at the lower left of the combustion zone, feedwater enters at the top into the steam drum which connects to the mud drum through many tubes. The mud drum is at the bottom of the boiler. Steam exits the boiler from the steam drum into the superheater section, which is shown at the top of the boiler. The combustion gases leaving the boiler through the ducting at the upper right. The surface blowdown is shown leaving the top steam drum and passing through a conductivity sensor which operates a control valve. Blowdown is discharged through the control valve into the low-pressure flash vessel, or flash tank. The saturated high-pressure liquid generates flash steam in the flash tank. The flash tank now contains low-pressure flash steam and saturated liquid. The low-pressure flash steam can be connected to the low-pressure steam distribution system or often directly to the deaerator. The remaining hot liquid can be utilized in a heat exchanger to preheat makeup water, but is ultimately discharged from the system for water quality control.

Slide 15 - Boiler Blowdown Recovery

In the example steam system, a blowdown thermal energy recovery system was installed and the fuel consumption decreased by $215,000 per year. The equipment required for the example system cost less than 50,000 dollars!

However, you need to be careful when selecting a heat exchanger for this service. The heat exchanger applied in this service must be capable of being cleaned because the blowdown stream can fowl the heat exchange surface.

Temperature sensors in each of the streams entering and leaving the heat exchanger allow the heat exchanger effectiveness to be determined and the frequency of cleaning evaluated.

Two types of heat exchangers offer good results in this application. A shell-and-tube straight-tube heat exchanger can be specified with the blowdown stream on the tube-side. In this arrangement, the heat exchanger ends must be removable to allow the tube internals to be cleaned periodically. Alternately, a plate-and-frame heat exchanger can be used, which allows both the blowdown side and the makeup water side to be cleaned.

[Slide Visual - Blowdown Energy Recovery Equipment]

Boiler blowdown has exited the boiler at high-pressure, passed through the blowdown control valve, and enters flash vessel at 20 psig. Low Pressure flash-steam discharges from the top of the flash vessel to the low pressure steam system.

Liquid is discharged from the bottom of the flash vessel to a heat exchanger that exchanged energy with makeup water. The temperature of the blowdown liquid entering the heat exchanger is measured by a temperature sensor, T1; the leaving temperature by sensor T2. Makeup water enters the heat exchanger from the top and its temperature is measured by sensor T3. Makeup water temperature leaves the heat exchanger and is measured by sensor T4.

A liquid level control sensor is attached to the side of the flash vessel which controls the flow through the exit of the heat exchanger through a control valve.

Slide 16 - Steam System Impact

The installation of a blowdown thermal energy recovery system will have multiple impacts on a cogeneration system. Flash-steam will be directed to the low-pressure header, which will reduce the amount of steam that can pass through the backpressure turbines. Additionally, the makeup water will be higher temperature, which will reduce the deaerator steam demand—further reducing the turbine steam flow. Finally, because the flash-steam generated from the blowdown is directed back into the steam system, the amount of makeup water required diminishes. As a result, the analysis of blowdown energy recovery becomes much more complicated when cogeneration systems are considered. This is where the Steam System Assessment Tool comes in handy!

[Slide Visual - Steam System Impact Schematic]

This schematic represents a two-header steam system with two boilers and all of the system components. Feedwater is preheated by steam injection from the low-pressure steam distribution header, as well as preheated make-up water utilizing boiler blowdown heat recovery.

The top of the schematic shows the Boiler Feedwater entering the two boilers. The two boilers are connected to the high-pressure steam distribution header.

The steam exits two boilers and enters the high-pressure steam system distribution header, indicated by a line below the boilers.

Under the high-pressure steam distribution line, you will see three cone-shaped graphics, that represent the steam turbines. The one nearest to the left is a high-pressure to condensing turbine. This turbine discharges to the condenser represented by the blue circle below the turbine. The rectangular graphic to the right of the cone-shaped graphic indicates the electrical generation component of the steam turbine. The turbine in the middle receives high-pressure steam and exhausts low-pressure steam to the low-pressure steam distribution system, as well as generates electricity. This turbine is denoted as red cone and rectangle combination. The steam turbine to the most right receives high pressure steam,

drives a pump (denoted as a circle/square combination) and is also called a steam-driven pump, then discharges to the low-pressure steam distribution system header.

Between the condensing turbine and the high-to-low pressure turbine, a light-blue triangular graphic that represents a pressure-reducing station, which discharges to the low pressure steam distribution header , identified by a red line below the turbines.

At the far right of the high pressure steam distribution system, the high-pressure end-user component loads are identified through a rectangular graphic and arrows entering and leaving the rectangle, indicating heat exchange with the components. The end-use components discharge condensate through a steam trap, represented by a rectangular graphic. Schematically, condensate passes through the bottom of the trap and recovered in a condensing tank which is also connected to the low-pressure steam distribution system.

Under the low-pressure steam distribution line, you will see the low-pressure end-user component loads identified as a rectangular graphic and arrows entering and leaving the rectangle, indicating heat exchange with the components. The end-use components discharge condensate through a steam trap, represented by another rectangular graphic. Schematically, condensate passes through the bottom of the trap and recovered in a condensate tank, in which steam is vented represented by a vertical arrow leaving the top of the tank.

The low-pressure end-user condensate tank uses a pump, which is denoted by a circle/square combination, to deliver the condensate to the main condensate receiver, which is a large rectangle with three inputs denoted by three arrows at the top of the rectangle. The condensate enters this main condensate receiver tank, after it passes through a control valve, denoted as an hour-glass shape with a dome on top. The third condensate input comes from the condensate from the heat exchanger that utilizes the high-pressure steam turbine. The condensate leaves this heat exchanger and is delivered via a pump (denoted as a circle/square combination) to the main condensate receiver.

The main condensate receiver then pumps (denoted by a circle/square combination) the high-pressure condensate, low-pressure condensate, and the condensing steam turbine condensate to the deaerator tank as denoted by two red rectangles, with the smaller one on the top. The top rectangle also shows two triangles, each pointed away from each other, longest ends nearly touching. The bottom triangle is connected to a control valve represented by a red hour-glass figure with a dome on the side, which provides low-pressure steam to the deaerator from the low-pressure steam distribution system to preheat the collected condensate and make-up water. Pre-heated make-up water also schematically enters at the top of the deaerator with the collected condensate.

The make-up water is preheated from the boiler blowdown and low pressure steam. Boiler blowdown from each boiler is noted as red dashed lines leading to a blowdown receiver tank denoted as a red rectangle on the right of the screen. Flash-steam is diverted from the blowdown flash-vessel to the low-pressure steam distribution line, also denoted in red dashed lines. Liquid from the blowdown flash-tank then schematically enters the top of a heat exchanger (represented as a white and green striped rectangle). Makeup water is shown entering the heat exchanger from the right, after it passes through the water treatment equipment, denoted as two red rectangles further on the right. The liquid exiting the heat exchanger is sent to the deaerator.

The heated boiler feedwater schematically exits the deaerator from the bottom and is pumped (denoted as a circle/square combination) to the feedwater inlets of each boiler, near the top the schematic.

<u>Slide 17 - Steam System Assessment Tool</u>

The Steam System Assessment Tool, also known as SSAT, was developed by the United States Department of Energy to aid in evaluating the complex interactions of steam system modifications. SSAT is a software tool based in Excel. KBC Linnhoff March's Prosteam software serves as the foundation of the tool. This tool allows the user to build a model of their steam system. This model can be used to evaluate the impacts of system changes.

[Slide Visual - Steam System Assessment Tool (SSAT)]

The first screen of the SSAT is shown.

US Department of Energy
Energy Efficiency and Renewable Energy
Bringing you a prosperous future where energy is clean, abundant, reliable, and affordable

Industrial Technologies Program Tools Suite
Steam System Assessment Tool, v.3.0
Contact the EERE Information Center 1-877-EERE-INF (8770337-3463) <u>eereic@ee.doe.gov</u>.

A picture of a steam site in the background with two large towers, several buildings, and a conveyor system.

- **Developed for the U.S.DOE under contract with the Oak Ridge National Laboratory by:**
- **KBC Linnhoff March**
- **Spirax Sarco Inc.**
- **Greg Harrell, Ph.D., P.E.**

- **Steam System Assessment Tool (SSAT)**
- **Steam system modeling software**
- **Common energy recovery projects built into the model**
- **Allows "what if" evaluations**

<u>Slide 18 - SSAT Model</u>

The SSAT model contains the common steam system components including the boiler, steam turbines, end-use equipment, condensate recovery, feedwater conditioning components, and the interconnections of the system. This schematic demonstrates the general connectivity of the model. High-pressure steam is generated in the boiler. This steam can pass to end-use equipment, through steam turbines, or through pressure reducing valves. The medium and low-pressure steam systems are similarly arranged. Users have flexibility in arranging the model to reflect their steam systems.

[Slide Visual - Model Tab Schematic]

The top center will contain the descriptive title provided by the user, the initial template reads "SSAT Default 3 Header Model" or a similar title for whatever model you chose. Below it, you will see the Model Status, which should read "OK." The model status provides an indication of the calculation condition of the model.

To the left of the Model Status, you will see a chart in light blue, which indicates the emissions per year for carbon dioxide, sulfur oxide, and nitrogen oxide.

At the top right, it will say "Current Operation" if you are on the Model tab, or "Operation After Projects" if you are on the Projects Model tab.

The red graphic near the top left represents the boiler. From the left, there is a dotted line entering it, which represents the amount of feedwater entering the boiler from the deaerator.

Also to the left of the boiler, we see the following information highlighted in orange: the type of fuel being used in the boiler, the fuel input energy, the fuel flow rate, and the boiler efficiency.

To the right of the boiler, we see a dotted line pointing to the right and then down, with a number next to it, indicating the amount of boiler blowdown.

Below the boiler, we see the amount of steam that is entering the high-pressure header, the temperature of it, and the thermodynamic quality of the steam.

The steam exits the boiler and enters the high-pressure header, represented by a dark blue line. Under the line, to the far left, you will see a light-blue triangular graphic that represents a pressure-reducing station. The pressure reducing station is also equipped with a desuperheating station. The number at the top indicates the amount of steam entering the pressure reducing valve. The number at the center-left of the valve indicates the amount of desuperheating water entering the unit. The number below indicates the amount of desuperheated steam entering the medium-pressure header; as well as the temperature of the steam.

To the right of the pressure-reducing station, you will see light blue, cone-shaped graphics, that represent the steam turbines. The one nearest to the left is a high-pressure to condensing turbine. This turbine discharges to the condenser represented by the blue circle below the turbine. The turbine exhaust pressure is noted as the condenser pressure. The turbine in the middle receives high-pressure steam and exhausts low-pressure steam. The one to the right receives high-pressure steam and exhausts medium-pressure steam. Above each turbine is an indication of the amount of steam coming into the turbine from the header. To the right, in dark blue, you see the power generation of the turbine.

In the center of the medium-pressure and low-pressure headers, we see an arrow pointing downward, which indicates the amount of flash entering the header from the condensate collection flash vessels that are located at the far-right of the schematic.

Above the header, to the right, the amount of heat loss is expressed in orange. Below, there is a yellow box that indicates the pressure, temperature, and thermodynamic quality of the steam.

The arrow to the right of the header points to a dark blue circle with a line through it, indicating the steam end-use components. Below this symbol is an indication of the thermal energy supplied to the end-use components from the steam. The end-use components discharge condensate through a steam trap, represented by a blue circle with a "T" in it. Schematically, condensate passes to the right through the trap. Failed steam traps that are blowing steam to the atmosphere are represented with the red arrow exiting the top of the trap symbol. The condensate appropriately passing through traps, again represented as exiting to the right of the trap, can be recovered or lost. Lost condensate is represented as the unrecovered condensate discharging down from the traps and recovered condensate enters the condensate collection system further to the right.

The green figures to the far-right of the schematic represent condensate flash-vessels. The top flash-vessel receives condensate from the high-pressure end-users. Flash-steam is formed because the flash vessel operates at medium-pressure but it receives saturated liquid condensate at high-pressure. As equilibrium is reached flash-steam is formed. This flash-steam exits the vessel through the top and is directed to the medium-pressure steam header, which is shown in the center of the diagram. Condensate exits the flash vessel and enters the medium-pressure condensate collection system. The medium-pressure condensate system is equipped with similar equipment as the high-pressure system.

All of the collected condensate enters the main condensate receiver located in the lower-center of the schematic. Process condensate is mixed with turbine condensate and makeup water prior to entering the deaerator. The steam system deaerator is represented at the lower-left of the schematic. The deaerator receives low-pressure steam to preheat the collected condensate and makeup water represented as entering from the bottom of the vessel. Boiler feedwater discharges from the deaerator to the left and up to the boiler. The line pointing out from the top of the deaerator and leading to the right shows the amount of steam escaping from the vent.

Slide 19 - Basic Model Data

The power of SSAT is in the fact that it completes mass, energy, and economic balances on the steam system that is built by the user. The user can make modifications to the steam system and observe a side-by-side comparison of the system before and after the changes. This allows the impact to mass, energy, and economics to be identified.

In the model, economic impacts are only associated with fuel, electricity, and water purchases. Of course, the boiler consumes fuel in the generation of steam. The turbines can impact the amount of electricity purchased from the electrical supplier. And makeup water is supplied to the system as required.

The model is thermodynamically rigorous and allows the very complex interactions in steam systems to be accurately identified and evaluated.

The tool has great flexibility allowing various fuel types and cost to be coupled with electrical impact costs as well as steam conditions. This slide shows a small portion of the input data that can be arranged by the user.

[Slide Visual – Basic Model Data]

General Site Data	Input Data		Notes/Warnings
Site Power Import (+ for import, - for export)	15000	kW	Power import + site generated power = site electrical demand
Site Power Cost	0.0700	$/kWh	Typical 2003 value: $0.05/kWh
Operating hours per year	8760	hrs	
Site Make-Up Water Cost	0.0025	$/gallon	Typical 2003 value: $0.0025/gallon
Make-Up Water Temperature	70	F	
Note: Enter average values for the operating period being modeled			
Boiler fuel - Choose from this drop-down list			Natural Gas
Site Fuel Cost per 1000 s.cu.ft	10.00	$	Typical 2003 value: $5.78/(1,000 s cu.ft)
Steam Distribution	Input Data		
High Pressure (HP)	400	psig	
Medium Pressure (MP)	150	psig	
Low Pressure (LP)	20	psig	
HP Steam Use by Processes	5.00	klb/h	
MP Steam Use by Processes	15	klb/h	
LP Steam Use by Processes	63	klb/h	

Slide 20 - Boiler Characteristics

The characteristics of the boilers are modeled by the tool. This allows accurate system impacts to be identified.

[Slide Visual – Operating Characteristics]

Boiler			
Method for specifying boiler efficiency			**Option 2 - Enter User Defined Value**
Note: Model default efficiencies represent Best Practice values assuming good operation and the installation of an economizer			
Option 2 - Enter efficiency (%)	**78.73**	**%**	
Note: Boiler efficiency is defined as 100% - Stack Loss (%) - Shell Loss (%). The "Stack Loss" sheet gives more information on heat losses			
Note: Efficiency is based on Higher Heating Value. Economizers are included in the boiler efficiency. Boiler blowdown losses are excluded			
Blowdown Rate (% of feedwater flow)	**6.00**	**%**	
Do you have blowdown flash steam recovery to the LP system?			**No**
Please select how you wish to define your HP generation condition and then provide supplementary information below if required:			
Method for specifying HP generation condition			**Option 2- User-defined superheated Conditions**
Note: As a default, the model will use HP steam with 100 F of superheat. At HP pressure (400 psig), this corresponds to a temperature of 548 F			
Option 2 - Enter temperature	**700**	**F**	
Option 3 - Enter thermodynamic quality	**99**	**% dry**	

Slide 21 - Steam Turbines

The complexity of analyzing cogeneration systems is significant. The interaction between components can make evaluations tedious and time consuming. SSAT allows the characteristics of steam turbines to be incorporated in the model. The tool accurately evaluates the interactions between these complex components.

[Slide Visual – Operating Characteristics]

HP to LP Steam Turbine(s)	Input Data		Notes/Warnings
Isentropic efficiency	65	%	
Note: If multiple turbines are installed, the operation of the impact turbine (the turbine affected by changes to the system) should be modeled			
Note: A generator electrical efficiency of 100% is assumed by the model			
Select the appropriate turbine operating mode			Option 1 – Balances LP header (Model default option)
Note: If Option 1 is chosen, the model will preferentially use the HP to LP turbine to balance the LP demand			
Option 2 - How should the fixed turbine operation be defined?			Option 2 not selected
Option 2 - Fixed steam flow	100	klb/h	
Option 2 - Fixed power generation	2000	kW	

Option 3 - How do you wish to define the operating range?			Option 3 not selected
Option 3 - Minimum steam flow	50	klb/h	
Option 3 - Maximum steam flow	150	klb/h	
Option 3 - Minimum power generation	1500	kW	
Option 3 - Maximum power generation	2500	kW	

Slide 22 - SSAT Investigations

Built into SSAT are many projects (or system modifications) that are common to real-worlds steam systems. For example, the tool is set up to model the impact associated with reducing steam demand, changing the fuel supplied to the boiler, or improving boiler efficiency.

Again, the software provides a side-by-side comparison of the before and after operating characteristics. The tool identifies the change in fuel consumption, electrical consumption, and water consumption resulting from the change in system operation.

[Slide Visual – Projects 1, 2, and 3]

Project 1 - Steam Demand Savings (Changing the process steam requirements) **Current use - HP: 5 klb/h (4.66 MMBtu/h) MP: 8 klb/h (8.16 MMBtu/h) LP: 58.4 klb/h (65.99 MMBtu/h)**		
Do you wish to specify steam demand savings?		**Yes**
If yes, enter HP steam saving	**0 klb/h**	
If yes, enter MP steam saving	**1 klb/h**	
If yes, enter LP steam saving	**0 klb/h**	
Project 2 - Use an Alternative Fuel **Existing Boiler Fuel : Natural Gas Fuel Cost : $0.00578/s cu.ft**		
Do you wish to specify an alternative fuel?		**Yes**
If yes, choose a new fuel from this drop-down list		**Typical Green Wood**
Site Fuel Cost	**20.00 $/ton**	**Typical 2002 value: $21.00/ton**
Note: HHV for alternative fuel is 10,502,894 Btu per ton. (5,251 Btu/lb)		

Project 3 - Change Boiler Efficiency Existing Efficiency : 85%		
Do you wish to specify a new boiler efficiency?		Yes
Note: An example use of this project option is to model the effect of installing an economizer by increasing the efficiency		
If yes, enter new boiler efficiency (%)	85 %	

Slide 23 – Projects

There are many projects that are built into the tool. Projects are included that allow the user to modify blowdown characteristics or condensate recovery. Only a small sampling of projects is shown here.

[Slide Visual – Projects 4 and 13]

Project 4 - Change Boiler Blowdown Rate			
Existing Blowdown Rate : 6%			
Do you wish to specify a new boiler blowdown rate?			**Yes**
If yes, enter new rate (% of feedwater flow)	**1**	**%**	
Project 13 - Condensate Recovery			
Currently recover 50% of HP, 50% of MP and 50% of LP at 180 F			
Do you wish to specify new condensate recovery rates?			**Yes**
If yes, enter new HP condensate recovery	**50**	**%**	
If yes, enter new MP condensate recovery	**60**	**%**	
If yes, enter new LP condensate recovery	**50**	**%**	

Slide 24 - Steam Turbine Projects

Turbine operations can also be modified.

[Slide Visual – Project 7]

Project 7 - HP to LP Steam Turbine(s)			
Not Installed			
Do you wish to modify the HP to LP turbine operation?			**Yes, install a new turbine**
If yes, select the appropriate turbine operating mode			**Option 1 - Balances LP header**
Note: If Option 1 is chosen, the model will preferentially use the HP to LP turbine to balance the LP demand			
Specify a new isentropic efficiency (%)	**70**	**%**	
Note: A generator electrical efficiency of 100% is assumed by the model			
Option 2 - How do wish to define the fixed turbine operation?			**Option 2 not selected**
Option 2 - Fixed steam flow	**100**	**klb/h**	
Option 2 - Fixed power generation	**2000**	**kW**	
Option 3 - How do wish to define the operating range?			**Option 3 not selected**
Option 3 - Minimum steam flow	**50**	**klb/h**	
Option 3 - Maximum steam flow	**150**	**klb/h**	
Option 3 - Minimum power generation	**1500**	**kW**	
Option 3 - Maximum power generation	**2500**	**kW**	

Slide 25 - Blowdown Thermal Energy Recovery

As an introduction to the tool we will use SSAT to evaluate the boiler blowdown thermal energy recovery opportunity. We have developed a model that reflects the characteristics of the steam system we have been dealing with. Initially we will assume the steam system is not equipped with cogeneration components. In other words, there are no steam turbines in this system we initially investigate.

We will use the built-in projects associated with boiler blowdown thermal energy recovery to identify the economic impact associated with the real-world project.

[Slide Visual – Projects 5 and 12]

Project 5 - Blowdown Flash to LP	
Not currently installed	
Do you wish to modify the blowdown flash system?	**Option 1 - Install blowdown flash**
Project 12 - Feedwater Heat Recovery Exchanger using Boiler Blowdown	
Not currently installed	
Modify the boiler blowdown heat recovery system?	**Yes, install a new heat exchanger**

Slide 26 - Before and After Comparison

The results indicate that for a steam system that is generating approximately 100,000 pounds per hour of 400 psig steam, from 10 dollars per million BTU natural gas, implementing blowdown thermal energy recovery can reduce operating cost more than $260,000 per year.

The majority of the savings is developed from the reduction of fuel consumption in the boiler—approximately $262,000 per year. Minimal savings is developed from a reduction in makeup water consumption--$3,000 per year.

[Slide Visual – Results Summary]

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	9,198	9,198		0	0.0%
Fuel Cost	12,930	12,669		262	2.0%
Make-Up Water Cost	177	174		3	2.0%
Total Cost (in $ '000s/yr)	22,306	22,041		265	1.2%
On-Site Emissions	**Current Operation**	**After Projects**		**Reduction**	
CO2 Emissions	150272 t/yr	177233 t/yr		3039 t/yr	2.0%
SOx Emissions	0 t/yr	0 klb/yr		0 klb/yr	N/A
NOx Emissions	297 t/yr	291 t/yr		6 t/yr	2.0%
Power Station Emissions		**Reduction After Projects**		**Total Reduction**	
CO2 Emissions		0 t/yr		3039 tb/yr	-
Sox Emissions		0 t/yr		0 t/yr	-
Nox Emissions		0 t/yr		6 t/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	0 kW	kW	-	-
Power Import	15000 kW	15000 kW	642 kW	4.3%
Total Site Electrical Demand	15000 kW	15000 kW	-	-
Boiler Duty	148 kW	145 kW	3 kW	2.0%
Fuel Type	Natural Gas	Natural Gas	-	-
Fuel Consumption	147606.2 s cu.ft/h	144620.9 s cu.ft/h	2985.3 s cu.ft/h	2.0%
Boiler Steam Flow	99.5 klb/h	97.5 klb/h	2.0 klb/h	2.0%
Fuel Cost (in $/MMBtu)	10.00	10.00	-	-
Power Cost (as $/MMBtu)	20.51	20.51	--	
Make-Up Water Flow	8100 m3/h	7942 m3/h	158 m3/h	2.0%

Slide 27 - Project Implementation

It is interesting to note that implementing the project in this steam system would most probably require less than $100,000. As a result, the project is very attractive from an economic standpoint.

It is also interesting to note that the economic impact is even greater than the loss estimate identified previously. This is because the model accurately identifies the boiler efficiency impacts and other energy related interactions.

[Slide Visual – Project Implementation]

For the example boiler implementing blowdown energy recovery:

- **Reduces fuel consumption more than $260,000/yr**
  - **The savings is greater than the system loss estimate provided previously of $215,000/yr**
    - **The energy recovered to the makeup water is not subjected to the boiler inefficiency**
    - **Steam generation and makeup water requirements are reduced because of flash steam**
  - **The project implementation cost should be much less than $100,000**

Slide 28 - Blowdown Energy Recovery

Effective blowdown thermal energy recovery can allow water quality to be controlled to higher levels with minimal economic impact because the blowdown energy is being recovered.

Makeup water requirements are reduced primarily because the flash steam generated in the flash recovery vessel is returned to the steam system.

Often the blowdown stream must be cooled before it is introduced to the sewer system. This can result in a large amount of purchased cooling water to be lost to the sewer system. Effective boiler blowdown thermal energy recovery can result in low-temperature blowdown being discharged to the sewer with no cooling water requirements.

Slide 29 - Steam Turbine Influences

Now we will examine the system impacts when blowdown thermal energy recovery is added to a steam system that is equipped with cogeneration components. I have constructed a model that includes steam turbines that are connected to electrical power generators. At this point we will not discuss the turbine characteristics other than to indicate the turbines are typical of what would be found in an industrial complex.

> ***[Slide Visual - Model Tab Schematic]***
>
> **The top center will contain the descriptive title provided by the user, the initial template reads "SSAT Default 3 Header Model" or a similar title for whatever model you chose. Below it, you will see the Model Status, which should read "OK." The model status provides an indication of the calculation condition of the model.**
>
> **To the left of the Model Status, you will see a chart in light blue, which indicates the emissions per year for carbon dioxide, sulfur oxide, and nitrogen oxide.**
>
> **At the top right, it will say "Current Operation" if you are on the Model tab, or "Operation After Projects" if you are on the Projects Model tab.**
>
> **The red graphic near the top left represents the boiler. From the left, there is a dotted line entering it, which represents the amount of feedwater entering the boiler from the deaerator.**
>
> **Also to the left of the boiler, we see the following information highlighted in orange: the type of fuel being used in the boiler, the fuel input energy, the fuel flow rate, and the boiler efficiency.**
>
> **To the right of the boiler, we see a dotted line pointing to the right and then down, with a number next to it, indicating the amount of boiler blowdown.**
>
> **Below the boiler, we see the amount of steam that is entering the high-pressure header, the temperature of it, and the thermodynamic quality of the steam.**

The steam exits the boiler and enters the high-pressure header, represented by a dark blue line. Under the line, to the far left, you will see a light-blue triangular graphic that represents a pressure-reducing station. The pressure reducing station is also equipped with a desuperheating station. The number at the top indicates the amount of steam entering the pressure reducing valve. The number at the center-left of the valve indicates the amount of desuperheating water entering the unit. The number below indicates the amount of desuperheated steam entering the medium-pressure header; as well as the temperature of the steam.

To the right of the pressure-reducing station, you will see light blue, cone-shaped graphics, that represent the steam turbines. The one nearest to the left is a high-pressure to condensing turbine. This turbine discharges to the condenser represented by the blue circle below the turbine. The turbine exhaust pressure is noted as the condenser pressure. The turbine in the middle receives high-pressure steam and exhausts low-pressure steam. The one to the right receives high-pressure steam and exhausts medium-pressure steam. Above each turbine is an indication of the amount of steam coming into the turbine from the header. To the right, in dark blue, you see the power generation of the turbine.

In the center of the medium-pressure and low-pressure headers, we see an arrow pointing downward, which indicates the amount of flash entering the header from the condensate collection flash vessels that are located at the far-right of the schematic. There is a red circle around the medium and low-pressure headers.

Above the header, to the right, the amount of heat loss is expressed in orange. Below, there is a yellow box that indicates the pressure, temperature, and thermodynamic quality of the steam.

The arrow to the right of the header points to a dark blue circle with a line through it, indicating the steam end-use components. Below this symbol is an indication of the thermal energy supplied to the end-use components from the steam. The end-use components discharge condensate through a steam trap, represented by a blue circle with a "T" in it. Schematically, condensate passes to the right through the trap. Failed steam traps that are blowing steam to the atmosphere are represented with the red arrow exiting the top of the trap symbol. The condensate appropriately passing through traps, again represented as exiting to the right of the trap, can be recovered or lost. Lost condensate is represented as the unrecovered condensate discharging down from the traps and recovered condensate enters the condensate collection system further to the right.

The green figures to the far-right of the schematic represent condensate flash-vessels. The top flash-vessel receives condensate from the high-pressure end-users. Flash-steam is formed because the flash vessel operates at medium-pressure but it receives saturated liquid condensate at high-pressure. As equilibrium is reached flash-steam is formed. This flash-steam exits the vessel through the top and is directed to the medium-pressure steam header, which is shown in the center of the diagram. Condensate exits the flash vessel and enters the medium-pressure condensate collection system. The medium-pressure condensate system is equipped with similar equipment as the high-pressure system.

All of the collected condensate enters the main condensate receiver located in the lower-center of the schematic. Process condensate is mixed with turbine condensate and makeup water prior to entering the deaerator.

The steam system deaerator is represented at the lower-left of the schematic. The deaerator receives low-pressure steam to preheat the collected condensate and makeup water represented as entering from the bottom of the vessel. Boiler feedwater discharges from the deaerator

to the left and up to the boiler. The line pointing out from the top of the deaerator and leading to the right shows the amount of steam escaping from the vent.

Slide 30 - SSAT Evaluation

The results are not dramatically different that what was observed in the system without cogeneration components. The combined economic impact is $241,000 per year. Blowdown thermal energy recovery is not expected to dramatically impact steam turbine operation; but, the impacts on the turbines are accurately reflected in the model results. It is interesting that the fuel impact is significantly greater. The model indicates fuel consumption will reduce more than $300,000 per year. Electrical purchases will increase more than $70,000 per year. These are not insignificant impacts.

The point is that SSAT is a powerful and useful tool that can be relied upon to accurately reflect the system interactions of complex steam systems.

[Slide Visual – Results Summary]

Cost Summary ($ '000s/yr)	Current Operation	After Projects		Reduction	
Power Cost	9,198	9,268		-70	-0.8%
Fuel Cost	12,861	12,554		307	2.4%
Make-Up Water Cost	174	170		4	2.2%
Total Cost (in $ '000s/yr)	22,234	21,993		241	1.1%

Utility Balance	Current Operation	After Projects		Reduction	
Power Generation	3245 kW	3131 kW		-	-
Power Import	15000 kW	15115 kW		-115 kW	-0.8%
Total Site Electrical Demand	18245 kW	18245 kW		-	-
Boiler Duty	147 kW	143 kW		4 kW	2.4%
Fuel Type	Natural Gas	Natural Gas		-	-
Fuel Consumption	146820.3 s cu.ft/h	143313.3 s cu.ft/h		3507 s cu.ft/h	2.4%
Boiler Steam Flow	99.0 klb/h	96.6 klb/h		2.4 klb/h	2.4%
Fuel Cost (in $/MMBtu)	10.00	10.00		-	-
Power Cost (as $/MMBtu)	20.51	20.51		-	-
Make-Up Water Flow	7961 m3/h	7785 m3/h		176 m3/h	2.2%

Slide 31 - Blowdown Loss Reduction

In summary, with respect to boiler blowdown; we must measure boiler water chemistry and the blowdown rate to appropriately manage our resources in this area. We should work to improve our boiler feedwater quality. Incorporating thermal energy recovery components can almost eliminate the loss associated with blowdown.

[Slide Visual – Blowdown Loss Reduction - Summary]

- **Measure blowdown flow (chemical analysis)**
- **Control blowdown flow (conductivity and chemistry)**
- **Control water chemistry**
- **Improve feedwater quality**
- **Recover flash steam to low-pressure systems and preheat inlet streams**

Steam End-User Training
Steam Generation Efficiency Module
Stack Losses Section

Slide 1 - Stack Losses Module

While blowdown and shell losses are relatively small, stack loss is almost always the largest boiler loss.

[Slide Visual – Efficiency Sub-Section: Stack Losses]

Banner:
DOE's BestPractices
Steam End User Training

Steam Generation Efficiency
Efficiency Definition
Radiation and Convection Losses –
Shell Losses
Blowdown Losses
Stack Losses

Slide 2 - Stack Losses

Stack loss is generally characterized into two interrelated categories—temperature, and combustion (or excess air). Managing the stack loss is a critical factor in managing boiler performance. We will discuss both of these aspects of stack loss—we will start our discussions by focusing on flue gas temperature.

Slide 3 - Stack Losses – Temp. Component

[Slide Visual – Efficiency Sub-Section: Stack Losses –Temperature Component]

Banner:
DOE's BestPractices
Steam End User Training

Steam Generation Efficiency
Efficiency Definition
Radiation and Convection Losses –
Shell Losses
Blowdown Losses
Stack Losses – Temperature Component

Slide 4 - Flue Gas Loss

A significant amount of fuel energy resides in the boiler exhaust gas. The temperature of the exhaust gas is an indicator of the amount of energy lost from the boiler. Flue gas temperature is a measurement that is required to reflect boiler performance. Boiler flue gas temperature should be monitored with respect to ambient temperature.

Higher flue gas temperatures indicate greater loss. It is good to know what can typically cause flue gas temperature to increase.

Slide 5 - Boiler Design

Boiler design is a primary factor in establishing the flue gas temperature. A boiler with more heat transfer area will be able to extract more energy from the flue gas. For example, the one-pass fire-tube boiler has much less heat transfer area than the three-pass fire-tube boiler. If the boilers were operating under similar circumstances, the one-pass boiler will operate with a higher flue gas temperature than the three-pass boiler. Of course, higher temperature indicates lower efficiency.

[Slide Visual - Boiler Schematic]

Boiler schematics are shown for a one-pass and a three-pass boiler configurations.

The single-pass, or one-pass boiler is shown on the left. Fuel enters the combustion zone, represented by a rectangle, which is surrounded by boiler water. Steam is released through the top of the boiler. Exhaust gases are released from the boiler via the combustion chamber. A front view of the one-pass boiler is indicated by a small circle (representing the fire-tube or combustion zone) inside a larger circle representing the boiler.

The three-pass boiler or multiple-pass boiler is shown on the right. Fuel enters the combustion zone, represented by a rectangle, which is surrounded by boiler water, however there are several small rectangle of combustion zones in the large boiling water chamber, which represents the multiple tubes inside the boiler for heat exchange. Steam is released through the top of the boiler. Exhaust gases are released from the boiler via the multiple flue gas passes. A front view of the three-pass boiler is indicated by a small circle (representing the fire-tube or combustion zone), many smaller circles representing the multiple fire-tube passes inside the combustion chamber, all inside a larger circle representing the steam-liquid chamber.

Slide 6 - Energy Recovery Components

A feedwater economizer is a heat exchanger installed to transfer thermal energy from the flue gas into the boiler feedwater. This is a common energy recovery component installed on boilers. A similar device is a combustion air heater—these heat exchangers recover thermal energy from the flue gas by preheating combustion air prior to entering the combustion zone. A boiler equipped with one of these energy recovery devices will operate with lower flue gas temperature than a similar boiler not equipped with one.

[Slide Visual - Boiler Configurations]

Boiler schematics are shown for water-tube boiler configurations, one with a feedwater economizer heat recovery device on the exhaust gases, and the second, most right configuration, without.

Both schematics depict water-tube boilers. Fuel and air enter at the lower left of the combustion zone, feedwater enters at the top of the steam generation section at the steam drum which includes multiple tubes for water to move through the heat exchange area. The steam outlet is shown at the top of the boiler, as well as the exhaust gases leaving the boiler.

The most left schematic incorporates a heat exchanger on the exhaust gas outlet, which appears as a red serpentine line through-out the exhaust gas exit from the boiler—this is a feedwater economizer.

The most right schematic does not have a feedwater economizer shown.

Slide 7 - Flue Gas Temperature Limitations

Care must be taken to avoid reaching too low of an exhaust gas temperature, as this could cause corrosive condensate to form in the exhaust gases. If there is sulfur in the fuel, sulfuric acid could form. Even if the fuel does not contain sulfur (like typical natural gas), we continue to be concerned about corrosive condensate because the products of combustion are carbon dioxide and water, which tend to combine to form carbonic acid.

[Slide Visual - Flue Gas Temperature Limitations Graph]

A graphic depicts fuel sulfur content along the x-axis as a percent of mass, beginning with 0% and increasing to 5% in increments of 1. The vertical or y-axis depicts the Flue Gas Exit Temperature in degrees Fahrenheit, beginning at 100 and increasing to 450 degrees Fahrenheit in increments of 50 degrees.

The acid dew point line begins at 0% fuel sulfur content and 250 degrees Fahrenheit and increases linearly until 5% content, in which the trend Line increases a bit steeper with the result of 5% boiler load and 300 degrees Fahrenheit.

The minimum recommended feedwater temperature line begins at 0% fuel sulfur content and 225 degrees Fahrenheit and increases linearly until 5% content, in which the trend Line increases a bit steeper with the result of 5% boiler load and 250 degrees Fahrenheit.

Slide 8 - Condensing Economizers

It is interesting to point out here that the water vapor (steam) formed in the combustion process contains a significant amount of energy. If this water vapor is allowed to condense then corrosion issues result. However, heat recovery heat exchange equipment has been developed that can handle the corrosive issues and allow the water-vapor to condense and release its energy. These components are identified as condensing economizers.

Condensing economizers can improve boiler efficiency more than 10 percentage points—which is exceptional. Condensing economizers are applied in clean fuel applications (natural gas and possibly number 2 fuel oil). It is very important to note that the flue gas must be cooled to less than 120 degrees

Fahrenheit to condense the majority of the water-vapor and recover the energy. As a result, the stream that is heated by the flue gas must be relatively cold—less than 100 degrees Fahrenheit—and there must be a large amount of material to be heated. Applications like food processing plants are often the target locations for this technology. Food processing plants commonly have large amounts of process water that requires heating.

[Slide Visual – Condensing Economizers]

- **Condensing economizers can improve boiler efficiency more than 10% in comparison to conventional boilers**
  - **Final flue gas temperature can approach 75°F**
  - **Indirect units can heat streams to 200°F**
  - **Direct units can heat streams to 140°F**
  - **A significant amount of relatively low-temperature energy is recovered**
  - **Equipment is limited to clean fuels**

Slide 9 - Boiler Load

Another factor that impacts flue gas exhaust temperature is boiler load. Typically, flue gas temperature increases as boiler load increases. This is simply a result of passing more material through a heat exchanger (the boiler). The graph of flue gas temperature versus boiler load is for a specific boiler and is intended to indicate a typical trend—the values on this graph are reflective of a specific boiler; the values will be different for your boiler; but, the trend will be similar.

[Slide Visual -Boiler Load Graph]

A graphic depicts boiler load along the x-axis as a percent of boiler full load, beginning with 50% and increasing to 110% in increments of 10. The vertical or y-axis depicts the Flue Gas Exit Temperature in degrees Fahrenheit, beginning at 400 and increasing to 600 degrees Fahrenheit in increments of 50 degrees.

The trend line begins at 50% boiler load and 425 degrees Fahrenheit and increases linearly until 100% load, in which the trend Line increases a bit stepper with the result of 110% boiler load and 560 degrees Fahrenheit.

Slide 10 - Failed Flue Gas Component

In almost all boilers, the combustion gases are forced to take a specific path through the heat exchange sections. Baffles or special ducting is in-place to ensure the gases travel through the boiler properly. If a baffle fails, then the gas can bypass heat transfer sections of the boiler. The flue gas temperature will increase as a result. This can be remedied by repairing the baffle.

[Slide Visual - Boiler Baffle Operation and Failure]

Boiler schematics are shown for two boiler configurations, one with baffles operating properly and the second with a failed baffle.

The first configuration (on the left) depicts baffles operating properly. The schematic depicts a water-tube boiler, in which two baffles are shown as red vertical lines inside the boiler's combustion zone. The combustion gas path is depicted by green arrows, beginning where the fuel and air enters at the lower left of the combustion zone, through the baffles which in a zig-zag path through the combustion zone, then out the combustion zone top to the boiler exhaust. Feedwater enters at the top of the steam generation section at the steam drum. The steam outlet is shown at the top of the boiler, as well as the exhaust gases leaving the boiler.

The second configuration (on the right) depicts a boiler with a failed baffle. The schematic depicts the same water-tube boiler, in which two baffles are shown as red vertical lines inside the boiler's combustion zone. However, the second baffle has a section missing at the top, thus allowing the hot gas (depicted by red arrows) to pass straight to the boiler exhaust stack, bypassing most of the combustion zone. Feedwater enters at the top of the steam generation section at the steam drum. The steam outlet is shown at the top of the boiler, as well as the exhaust gases leaving the boiler.

Slide 11 – Fouling

If we have waterside scaling or fireside fouling of the heat transfer surfaces, the surfaces become "insulated", and more energy remains in the exhaust gas. So, we want to make sure we maintain water quality to make sure solids do not precipitate on the heat transfer surfaces. Also, we want to keep the fireside of the tubes as clean as possible. Fire-side fouling is usually a problem with solid fuels and heavy fuel oils. On-line soot-blowing is the method used for chronic fouling conditions. Sootblowing is the act of inserting a lance into the combustion-side of the boiler to allow a high-velocity jet of steam or compressed air to pass across the fouled surfaces to dislodge the fouling material.

Water-side fouling is prevented through boiler water chemistry control. However, when fouling is significant, treatment measures may include chemicals to descale the boiler heat exchange surfaces, or hydro-blasting, both of which require a boiler outage. Often, water-side fouling results in tube failures.

[Slide Visual - Boiler Fouling]

The boiler configuration indicates fuel and air enter on the left side of the boiler's combustion zone. Internal baffles are depicted in white. The steam flow is depicted as a red loop inside the combustion zone, between the baffles. Feedwater enters at the top of the steam generation section at the steam drum. The steam outlet is shown at the top of the boiler, as well as the exhaust gases leaving the boiler.

- ➢ **Water-side fouling (scale) is typically managed through water treatment efforts**

- ➢ **Fire-side fouling is managed through sootblowing and periodic off-line cleaning**

Potential Energy Loss Resulting from Scale Deposits			
	Fraction of Total Fuel Input Energy Loss [%]		
	Scale Type		
Scale Thickness [Inches]	Normal	High Iron	Iron + Silica
1/64	1.0	1.6	3.5
1/32	2.0	3.1	7.0
3/64	3.0	4.7	--
1/16	3.9	6.2	--
National Institute of Standards and Technology, Handbook 115, Supplement 1			

<u>Slide 12 - Flue Gas Temperature Loss</u>

These are the common factors that impact flue gas exit temperature—there are many more.

One final note, excess air (extra air passing through the combustion zone) has the potential of impacting flue gas exhaust temperature. Typically, increasing the amount of excess air in the combustion zone will increase the final flue gas exhaust temperature. We will discuss the primary issues associated with excess air in the following section.

[Slide Visual – Factors Influencing Flue Gas Temperature]

- ➢ **The most common factors influencing flue gas temperature are:**
  - **Boiler design**
  - **Boiler load**
  - **Fire side fouling**
  - **Water side fouling**
  - **Failed flue gas path component**
  - **Excess air (possibly)**

Slide 13 - Temperature Loss Management

The first step in managing flue gas energy is to measure and monitor flue gas exit temperature. Along with this critical measurement ambient temperature should be noted, because, ambient temperature will have an impact on the final flue gas temperature of the boiler. Additionally, because flue gas temperature is a function of boiler load the steam production or firing rate should be noted along with these other measurements. These measurements will allow performance trends of your boiler to be noted.

[Slide Visual –Flue Gas Temperature Management]

- **Monitor and record flue gas temperature with respect to:**
  - **Boiler load**
  - **Ambient temperature**
  - **Flue gas oxygen content**
- **Compare flue gas temperature to previous, similar operating conditions**
- **Maintain appropriate fire-side cleaning**
- **Maintain appropriate water chemistry**
- **Evaluate heat recovery component savings potential**

Slide 14 - Combustion Component

Now, we will turn our attention to the combustion side of the stack loss. The combustion loss centers on unburned fuel, excess air, and other items of this nature.

[Slide Visual – Efficiency Sub-Section: Stack Losses –Combustion Component]

Banner:
DOE's BestPractices
Steam End User Training

Steam Generation Efficiency
Efficiency Definition
Radiation and Convection Losses –
Shell Losses
Blowdown Losses
Stack Losses – Combustion Component

Slide 15 - Perfect Combustion

As an example, we will examine the combustion of a simple fuel, methane. In a perfect world, methane will react with oxygen to release energy and form carbon dioxide and water. In this perfect arrangement, each molecule of fuel would find two molecules of oxygen in order to cause complete combustion.

[Slide Visual - Basic Combustion Equation]

Methane (CH_4) + 2 molecules of Oxygen (O_2) combusts and yields Carbon Dioxide (CO_2) and 2 molecules of Water (H_2O) + Energy Release

In this initial combustion discussion methane and oxygen are used as the only components for simplicity. Additionally, "inert" chemicals (nitrogen) are not considered at this time.

Slide 16 - Actual Combustion

In the real world, the combustion process does not proceed in a perfect manner. In fact, the combustion reaction may yield more chemicals than carbon dioxide and water—the common additional chemicals formed are carbon monoxide and hydrogen. Additionally, oxygen can pass through the combustion zone and not react with any fuel—exiting as oxygen molecules. Similarly, methane can pass through the combustion zone and not react with any oxygen—exiting as fuel.

As we look at these possible chemicals that can form and be released from the combustion zone some get our attention more than others. For example, carbon monoxide is a toxic gas that can cause definite health concerns. Carbon monoxide forms when fuel finds an insufficient amount of oxygen to completely react. The fuel will partially react and release only a portion of the fuel energy available. The carbon monoxide contains the remainder of the originally resident fuel energy. As a result, carbon monoxide represents more than safety and health issues, it also represents an economic issue because fuel energy was exhausted from the boiler. In fact, hydrogen and methane present exactly the same issues—none of them are good to breath, all are combustible and explosive, and all represent economic expenditure in the form of purchased fuel. Therefore, from a combustion management standpoint, it is essential for all the fuel to react.

Conversely, if oxygen passes through the combustion zone, it is not hazardous, it does not present a safety issue, and it requires very little economic investment to acquire.

[Slide Visual - Actual Combustion Equation]

- **In actual combustion processes fuel and oxygen do not react perfectly**

  Methane (CH_4) + 2 molecules of Oxygen (O_2) combusts and yields and energy release of alpha molecules Carbon Dioxide (CO_2) and beta molecules of Water (H_2O) + gamma molecules of Carbon Monoxide (CO) + delta molecules of Hydrogen (H_2), + epsilon molecules of Methane (CH_4) + zeta molecules of Oxygen (O_2)

Red circles encapsulate the gamma molecules of Carbon Monoxide (CO), the delta molecules of Hydrogen (H_2),and the epsilon molecules of Methane (CH_4)

A green circle encapsulates the zeta molecules of Oxygen (O_2)

- **Un-reacted CH4, CO, and H2 are *fuels* resulting from incomplete combustion**

Slide 17 - Combustion Management 1

The first principle of combustion management is based on the fact that adding extra oxygen to the combustion zone essentially ensures that all the fuel is combusted. In other words, in a perfect combustion situation, one molecule of fuel must encounter two molecules of oxygen to react completely. In the real-world, if more than enough oxygen is added to the combustion zone, then each molecule of fuel will find enough oxygen to react. The extra oxygen that passes through the combustion zone was acquired with minimal cost. In other words, if more than enough oxygen is passed through the combustion zone, it almost ensures that all the fuel burns up. This is the first rule of combustion control—add more oxygen to the combustion zone than is necessary to ensure all the fuel reacts completely.

[Slide Visual - Actual Combustion Equation]

Un-reacted CH4, CO, and H2 are *fuels* resulting from incomplete combustion

- **Wasting fuel**
- **Safety hazard**
- **Health and environmental hazards**

Methane (CH_4) + 2 molecules of Oxygen (O_2) combusts and yields and energy release of alpha molecules Carbon Dioxide (CO_2) and beta molecules of Water (H_2O) + gamma molecules of Carbon Monoxide (CO) + delta molecules of Hydrogen (H_2), + epsilon molecules of Methane (CH_4) + zeta molecules of Oxygen (O_2)

Red circles encapsulate the gamma molecules of Carbon Monoxide (CO), the delta molecules of Hydrogen (H_2),and the epsilon molecules of Methane (CH_4)

A green circle encapsulates the zeta molecules of Oxygen (O_2)

- **Combustion management strives to eliminate un-reacted fuel by adding extra *oxygen* to the combustion zone**
  - **Excess O2 provided to the combustion zone essentially eliminates un-reacted fuel**

Slide 18 - Combustion Management 2

However, the extra oxygen added to the combustion zone enters the boiler at ambient temperature and exits the boiler at flue gas temperature (450 degrees Fahrenheit for example). The extra oxygen gained this temperature by receiving fuel energy—fuel was purchased to heat the extra oxygen. The energy loss is actually much more than just heating the extra oxygen; because, ambient air contains almost 4 molecules of nitrogen for every 1 molecule of oxygen (3.76 for typical air). As a result, a large amount of nitrogen enters the combustion zone with any excess oxygen. This nitrogen enters at ambient temperature and receives fuel energy to exit the boiler at flue gas temperature. The majority of the combustion gas is nitrogen—a huge amount of nitrogen is heated by fuel energy. This brings us to Combustion Management Principle Number 2—do not put too much air into the combustion zone.

Stated differently, the two principles of combustion management are to first provide extra oxygen to the combustion zone to ensure all the fuel is consumed; and second, reduce the amount of extra air to limit the energy loss.

It should be noted that incomplete combustion can result even if excess air is provided to the boiler. This primarily results when a component in the burner has failed. The burner is attempting to accomplish many tasks; one primary task is to thoroughly mix the air and the fuel. A burner component can fail resulting in air rapidly channeling out of the combustion zone. This can result in the air and fuel not mixing even though significant amounts of extra air are passing through the boiler. Boilers that operate with the combustion zone at less than atmospheric pressure will experience some amount of air entering the boiler not through the flame zone. This tramp air will contribute to the excess air of the boiler but not influence the combustion process.

As a result, it is important to not only measure flue gas oxygen content but to also measure flue gas combustibles concentration.

[Slide Visual - Actual Combustion Equation]

- **The extra oxygen added to ensure complete reaction of the fuel is heated by fuel from ambient temperature to the temperature of the exhaust gas.**

  Methane (CH_4) + 2 molecules of Oxygen (O_2) plus 2 molecules of Nitrogen (N_2) (at 3.76 molecules each) combusts and yields and energy release of alpha molecules Carbon Dioxide (CO_2) and beta molecules of Water (H_2O) + gamma molecules of Carbon Monoxide (CO) + delta molecules of Hydrogen (H_2), + epsilon molecules of Methane (CH_4) + zeta molecules of Oxygen (O_2) plus 2 molecules of Nitrogen (N_2) (at 3.76 molecules each)

Red circles encapsulate the 2 molecules of Oxygen (O_2) plus 2 molecules of Nitrogen (N_2) (at 3.76 molecules each) on the input side of the equation and the zeta molecules of Oxygen (O_2) plus 2 molecules of Nitrogen (N_2) (at 3.76 molecules each) on the results side of the equation.

- **For most combustion processes *air* is used as the source of oxygen.**
  - **A large amount of N2 is heated from ambient temperature to exhaust gas temperature by fuel energy.**

Slide 19 - Minimum Oxygen Evaluation 1

The primary measurement required for combustion management is flue gas oxygen content. In order to determine if the amount of extra oxygen is appropriately low, a second measurement is required—the second measurement is combustibles concentration in the flue gas. Remember, combustion management desires to add enough oxygen to burn up all the fuel but not too much such that we experience a significant energy loss.

This is a graph of the combustibles concentration in the flue gas of the example boiler operating with natural gas. It should be noted that all burners are different and exhibit different characteristics. This example burner exhibits characteristics that have been observed in many natural gas fired boilers but it is not representative of all natural gas fired boilers. Most burners will operate with minimal combustibles concentration for a wide range of oxygen content. For a given fuel load, as flue gas oxygen content is reduced, a point is reached where combustibles concentration increases dramatically. This marks the minimum flue gas oxygen content for the burner fuel load. This indicates the condition where the burner performance is not sufficient to mix air with fuel. Combustion control then strives to operate the combustion process as near as practical to this lower oxygen limit. It is important to establish baseline combustibles concentration for each boiler over a wide range of fuel loading.

This brings up the point that combustion control should include at least periodic combustibles measurements. A baseline evaluation of combustibles should be determined for each boiler—this should be evaluated for the operating range of the boiler. Fuel type and burner configuration significantly influence baseline combustibles concentrations. The combustibles concentrations of solid fuel fired boilers will generally be much higher than a natural gas fired boiler. Boilers fired with heavy fuel oil will generally present higher combustibles concentrations than light fuel oil combustion but most commonly less than solid fuel combustion.

As a side note; the graph indicates combustibles concentration increases once the flue gas oxygen content has increased to relatively high values. This can be attributed to the fact that the additional air significantly cools the flame zone decreasing the reaction rates. Also, there is a maximum amount of air above which the fuel will not combust.

[Slide Visual -Minimum Oxygen Graph]

A graphic depicts Flue Gas Oxygen content along the x-axis as a percent of flue gas oxygen content, beginning at 0% and increasing to 9% in increments of 1%. The vertical or y-axis depicts the Combustibles in parts-per-million (ppm), beginning at 0 and increasing to over 160 ppm in increments of 20 ppm.

The general trend indicates combustibles concentration to be relatively low and constant over a broad range of flue gas oxygen content. The concentration increases dramatically as the flue gas oxygen content decreases below 2%. Combustibles concentration also increases as the flue gas oxygen content increases above 8%.

Slide 20 - Minimum Oxygen Evaluation 2

It must be mentioned that several factors impact the combustibles concentration in addition to the amount of excess oxygen in the combustion zone. In addition to extra oxygen in the combustion zone, the burner must also be in good condition. The purpose of the burner is to thoroughly mix and distribute the fuel and the air. In order for good combustion to take place, the air and fuel must remain in the combustion zone a sufficient amount of

time to allow combustion to take place, the combustion zone must be at the proper temperature, and the fuel and air must mix thoroughly. The condition of the burner impacts all of these factors. Babcock and Wilcox identify these primary factors as the "Three T's of Combustion". The Reaction TIME allows the combustion to be complete. The Reaction TEMPERATURE drives the chemical reaction to completion. The TURBULENCE (mixing) of the fuel and oxygen is needed to react completely. A deficiency in any one of these "T's" will result in un-reacted fuel.

Slide 21 - Oxygen Limits

Many factors impact combustion zone oxygen limits. The type of fuel significantly influences the allowable combustion zone oxygen limits. All fuels burn in the gas state; therefore, natural gas is more readily combustible than oil or coal. Oil must evaporate into the vapor state then burn. Coal must diffuse from the solid phase to the vapor stage before combustion can take place.

If the boiler is equipped with continuous-automatic combustion control oxygen control can be more precise and consistent than positioning control. Combustion control methodology also influences the combustion losses. As the oxygen content is maintained to the practical minimum and controlled more precisely the combustion loss decreases.

The type of burner and the condition of the burner also influence oxygen control parameters.

The location of the oxygen measurement can be a significant factor when operating boilers with flue gas pressures less than atmospheric pressure. In these situations any opening in the boiler will leak air into the flue gas resulting in elevated flue gas oxygen content measurements.

Generally, combustion parameters will be set such that excess oxygen increases as boiler load decreases. The primary reason for this is the diminished turbulence (mixing) as the flows through the burner decrease. Elevated burner loading results in excellent mixing, which allows reduced oxygen operation.

Slide 22 - Trim Control

Typically in boilers, fuel flow is controlled by measuring steam pressure and adjusting fuel flow to meet the pressure set point. 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 as steam pressure increases, fuel flow will be decreased to reduce steam production.

As the fuel flow into the boiler changes combustion, air flow must also change to maintain proper combustion parameters. Combustion control takes two primary forms. The first type we will discuss is identified as *continuous-automatic control* (also known as *trim control*). In this control method combustion airflow is controlled by continually monitoring flue gas oxygen content and adjusting the airflow to match a set point. This control can be very effective and efficient.

[Slide Visual - Automatic (Trim) Control]

The boiler configuration shows a feedwater supply from a deaerator depicted by a blue rectangle with a dome on top which utilizes a pump to send feedwater to the steam drum of the boiler. Feedwater enters the top of the boiler at the steam drum, passes through the boiler tubes, then exits as steam at the top of the boiler. A steam pressure indicator or gage is depicted as a small red circle in the steam outlet.

Just below the boiler feedwater supply, a combustion air fan provides air to the boiler's combustion zone. The air flow is controlled by a damper, depicted as a 'slash' in the rectangular ductwork leading to the boiler inlet. The damper is controlled by a 'combustion controller' device, a small blue rectangle, which communicates with a flue gas oxygen sensor, a small blue rectangle located in the boiler exhaust. The signals from the flue gas oxygen sensor and the steam pressure indicator are represented by a blue dotted line.

The combustion control is accomplished by adjusting airflow into the combustion zone to make the flue gas oxygen content match the set point.

Slide 23 - Positioning Control

The other common type of combustion control in boilers is simple and very common. This second type of control manages fuel flow the same way it is with continuous-automatic combustion control. If steam pressure decreases, fuel flow increases, and vice versa. Combustion air flow control is accomplished by mechanically linking the air-flow control device 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. It should be noted that this control does not incorporate any active oxygen or combustibles measurements. Oxygen and combustibles measurements are only taken to establish the position relationship between the fuel controller and the air controller. After the position relationship is established oxygen and combustibles measurements cease.

It should be noted that when positioning control is used the oxygen content cannot be minimized because of many factors. One factor influencing the airflow controller position is ambient temperature. Ambient temperature is a concern because the combustion air fan is basically a constant volume-flow device (for a given controller set point). If the position relationship is established for a relatively cool inlet-air temperature, the mass flow of air into the combustion zone could become dangerously low as the inlet air temperature increases. As a result, positioning control can only attain moderate efficiency.

***Tuning the boiler* is the act of reestablishing the position relationship between the air and fuel. This tuning activity is completed in the same manner the original air-fuel control point positions were established. The boiler is operated steadily at discrete fuel input positions and the airflow control device position is redefined. The boiler will be operated at discrete loads throughout the operating range of the unit. While the fuel-flow controller is 100-percent open, for example, the position of the air-flow controller is adjusted until an appropriate flue-gas oxygen content is attained. Combustibles concentrations should also be measured to ensure proper burner operation. The position relationship exercise is repeated over the operating range of the boiler (95-percent load, 90-percent load, down to minimum load). This retuning activity should be completed frequently to ensure safe and efficient boiler operation.**

Please note there are many forms of combustion control but the concepts presented in these two control techniques are the foundations of all combustion control methods.

[Slide Visual - Automatic (Trim) Control]

The boiler configuration shows a feedwater supply from a deaerator depicted by a blue rectangle with a dome on top which utilizes a pump to send feedwater to the steam drum of the boiler. Feedwater enters the top of the boiler at the steam drum, passes through the boiler tubes, then exits as steam at the top of the boiler. A steam pressure indicator or gage is depicted as a small red circle in the steam outlet.

Just below the boiler feedwater supply, a combustion air fan provides air to the boiler's combustion zone. The air flow is controlled by a damper, depicted as a 'slash' in the rectangular ductwork leading to the boiler inlet. The damper is controlled by the position of the fuel-flow device that communicates with the steam pressure sensor in the steam outlet. The signal from steam pressure indicator is represented by a blue dotted line. The flue gas oxygen sensor is only used for periodic measurements.

Slide 24 - Oxygen Content Control Parameters

This table is a good indicator of what you should expect from most boilers in terms of oxygen concentrations. It must be noted that many factors can influence the actual flue gas oxygen content—this table simply represents commonly observed operating conditions. The two types of control methodology discussed are identified in the table, automatic control and positioning control. Generally, the higher flue gas oxygen content values correspond with low burner load and the low flue gas oxygen contents correspond with high burner load. Less excess air is required at higher burner loads because high velocities in the burner enhances mixing and the combustion reactions.

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.

Again, many factors impact the flue gas oxygen concentrations that a specific boiler can operate with. Boilers that operate with a combustion zone pressure that is less than atmospheric pressure will experience air entering the flue gas path without passing through the combustion zone. In these situations the measured oxygen content can be significantly higher than the combustion zone oxygen content.

Oxygen control parameters must typically be modified when control components are placed on boilers to manage the amount of oxides of nitrogen that are emitted. Generally, reducing the combustion zone oxygen content will increase the formation of oxides of nitrogen. As a result, boilers controlling oxides of nitrogen will most commonly have higher flue gas oxygen content than boilers that are not managing oxides of nitrogen.

[Slide Visual - Typical Flue Gas Content Control Parameters Table]

Fuel	Automatic Control		Positioning Control		Automatic Control		Positioning Control	
	Flue Gas O_2 Content		Flue Gas O_2 Content		Excess Air		Excess Air	
	Min.	Max.	Min.	Max.	Min.	Max.	Min.	Max.
	[%]	[%]	[%]	[%]	[%]	[%]	[%]	[%]
Natural Gas	1.5	3.0	3.0	7.0	9	18	18	55
Number 2 Fuel Oil	2.0	3.0	3.0	7.0	11	18	18	55
Number 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

Higher oxygen limits are paired to low burner loads.

Lower oxygen limits are paired with higher burner loads.

Slide 25 - Stack Loss Evaluation

In summary, stack loss is the largest loss associated with most boilers. Managing stack loss is critical to controlling steam system operating costs. The measurements required to manage stack loss are flue gas exit temperature, flue gas oxygen content, ambient temperature, boiler load, and flue gas combustibles concentration. In order to quantify the stack loss, the critical measurements must be used in conjunction with combustion calculations. Combustion calculations can be arranged in many forms. One straightforward form is a stack loss table.

Slide 26 – Stack Loss – Natural Gas

The stack loss tables presented here are just one form of combustion data used to quantify stack loss. Other forms of stack loss information include computer models, calculations, graphs, and nomographs. All stack loss analyses use the same initial information—flue gas temperature, flue gas oxygen content, combustibles concentration, and fuel composition. Stack loss tables are a straightforward communication vehicle. Stack loss calculations are based on the difference in flue gas temperature and ambient temperature—this is known as the *net stack temperature*. Ambient temperature does have an impact on flue gas temperature because such a large amount of air passes through the boiler. When ambient air temperature decreases flue gas temperature will decrease.

The other primary input information required to use stack loss calculators is the amount of oxygen in the flue gas. A third measurement is also required to complete the stack loss analysis—combustibles concentration in the flue gas. Combustibles concentration is of course a measure of the unburned fuel exiting in the flue gas. Combustibles concentrations less than 100 PPM generally yield negligible impact on stack loss. The stack loss tables that follow are for various common fuels, the flue gas contains negligible combustibles, and water exits as a vapor (no condensate).

[Slide Visual – Stack Loss Table for Natural Gas

Flue Gas Oxygen Content Wet Basis [%]	Stack Loss [% of fuel higher heating value input] Net Stack Temperature [Δ°F] {Difference between flue gas exhaust temperature and ambient temperature}											
	155	180	205	230	255	280	305	330	355	380	405	430
1.0	13.1	13.6	14.1	14.7	15.2	15.8	16.3	16.9	17.4	18.0	18.5	19.1
2.0	13.2	13.8	14.3	14.9	15.5	16.1	16.6	17.2	17.8	18.4	18.9	19.5
3.0	13.4	14.0	14.6	15.2	15.8	16.4	17.0	17.6	18.2	18.8	19.4	20.0
4.0	13.6	14.2	14.8	15.5	16.1	16.7	17.4	18.0	18.7	19.3	20.0	20.6
5.0	13.8	14.5	15.1	15.8	16.5	17.2	17.8	18.5	19.2	19.9	20.5	21.2
6.0	14.1	14.8	15.5	16.2	16.9	17.6	18.3	19.1	19.8	20.5	21.2	22.0
7.0	14.4	15.1	15.9	16.6	17.4	18.1	18.9	19.7	20.5	21.2	22.0	22.8
8.0	14.7	15.5	16.3	17.1	17.9	18.8	19.6	20.4	21.2	22.1	22.9	23.7
9.0	15.1	16.0	16.8	17.7	18.6	19.5	20.4	21.2	22.1	23.0	23.9	24.8
10.0	15.5	16.5	17.4	18.4	19.4	20.3	21.3	22.2	23.2	24.2	25.2	26.1
Actual Exhaust T [°F]	225	250	275	300	325	350	375	400	425	450	475	500
Ambient T [°F]	70	70	70	70	70	70	70	70	70	70	70	70

Slide 27 - Number 2 Fuel Oil

This stack loss table is compiled for number 2 fuel oil. Number 2 fuel oil is common household heating fuel and is essentially diesel fuel.

[Slide Visual – Stack Loss Table for Number 2 Fuel Oil]

Flue Gas Oxygen Content Wet Basis [%]	Stack Loss [% of fuel higher heating value input] Net Stack Temperature [Δ°F] {Difference between flue gas exhaust temperature and ambient temperature}											
	180	205	230	255	280	305	330	355	380	405	430	455
1.0	9.5	10.0	10.5	11.0	11.5	12.1	12.6	13.1	13.7	14.2	14.7	15.3
2.0	9.6	10.2	10.7	11.3	11.8	12.4	12.9	13.5	14.1	14.6	15.2	15.7
3.0	9.8	10.4	11.0	11.6	12.1	12.7	13.3	13.9	14.5	15.1	15.7	16.3
4.0	10.1	10.7	11.3	11.9	12.5	13.1	13.7	14.3	15.0	15.6	16.2	16.8
5.0	10.3	10.9	11.6	12.2	12.9	13.5	14.2	14.8	15.5	16.2	16.8	17.5
6.0	10.6	11.3	12.0	12.6	13.3	14.0	14.7	15.4	16.1	16.8	17.5	18.2
7.0	10.9	11.6	12.4	13.1	13.8	14.6	15.3	16.1	16.8	17.5	18.3	19.0
8.0	11.3	12.1	12.8	13.6	14.4	15.2	16.0	16.8	17.6	18.4	19.2	20.0
9.0	11.7	12.6	13.4	14.3	15.1	16.0	16.8	17.7	18.5	19.4	20.3	21.1
10.0	12.2	13.1	14.1	15.0	15.9	16.8	17.8	18.7	19.6	20.6	21.5	22.5
Actual Exhaust T [°F]	250	275	300	325	350	375	400	425	450	475	500	525
Ambient T [°F]	70	70	70	70	70	70	70	70	70	70	70	70

Slide 28 - Number 6 Fuel Oil (Low Sulfur)

Number 6 fuel oil is heavy fuel oil—it is commonly solid at room temperature. Often number 6 fuel oil is classified into high-sulfur content and low-sulfur content.

[Slide Visual – Stack Loss Table for Number 6 Fuel Oil (Low-Sulfur)]

Flue Gas Oxygen Content Wet Basis [%]	Stack Loss [% of fuel higher heating value input]											
	Net Stack Temperature [Δ°F] {Difference between flue gas exhaust temperature and ambient temperature}											
	205	230	255	280	305	330	355	380	405	430	455	480
1.0	9.5	10.0	10.5	11.0	11.6	12.1	12.6	13.2	13.7	14.3	14.8	15.3
2.0	9.7	10.2	10.8	11.3	11.9	12.4	13.0	13.6	14.1	14.7	15.3	15.8
3.0	9.9	10.5	11.1	11.6	12.2	12.8	13.4	14.0	14.6	15.2	15.8	16.4
4.0	10.1	10.8	11.4	12.0	12.6	13.2	13.9	14.5	15.1	15.7	16.4	17.0
5.0	10.4	11.1	11.7	12.4	13.0	13.7	14.4	15.0	15.7	16.3	17.0	17.7
6.0	10.8	11.4	12.1	12.8	13.5	14.2	14.9	15.6	16.3	17.0	17.7	18.5
7.0	11.1	11.9	12.6	13.3	14.1	14.8	15.6	16.3	17.1	17.8	18.6	19.4
8.0	11.6	12.3	13.1	13.9	14.7	15.5	16.3	17.1	17.9	18.8	19.6	20.4
9.0	12.1	12.9	13.8	14.6	15.5	16.3	17.2	18.1	18.9	19.8	20.7	21.6
10.0	12.7	13.6	14.5	15.4	16.4	17.3	18.2	19.2	20.1	21.1	22.0	23.0
Actual Exhaust T [°F]	275	300	325	350	375	400	425	450	475	500	525	550
Ambient T [°F]	70	70	70	70	70	70	70	70	70	70	70	70

Slide 29 - Number 6 Fuel Oil (High Sulfur)

Often number 6 fuel oil is classified into high-sulfur content and low-sulfur content.

[Slide Visual – Stack Loss Table for Number 6 Fuel Oil (High-Sulfur)]

Flue Gas Oxygen Content Wet Basis [%]	Stack Loss [% of fuel higher heating value input] Net Stack Temperature [Δ°F] {Difference between flue gas exhaust temperature and ambient temperature}											
	205	230	255	280	305	330	355	380	405	430	455	480
1.0	9.7	10.2	10.8	11.3	11.8	12.3	12.9	13.4	14.0	14.5	15.0	15.6
2.0	9.9	10.5	11.0	11.6	12.1	12.7	13.2	13.8	14.4	14.9	15.5	16.1
3.0	10.1	10.7	11.3	11.9	12.5	13.1	13.6	14.2	14.8	15.4	16.0	16.6
4.0	10.4	11.0	11.6	12.2	12.8	13.5	14.1	14.7	15.3	16.0	16.6	17.2
5.0	10.7	11.3	12.0	12.6	13.3	13.9	14.6	15.3	15.9	16.6	17.2	17.9
6.0	11.0	11.7	12.4	13.1	13.8	14.5	15.2	15.9	16.6	17.3	18.0	18.7
7.0	11.4	12.1	12.8	13.6	14.3	15.1	15.8	16.6	17.3	18.1	18.8	19.6
8.0	11.8	12.6	13.4	14.2	15.0	15.8	16.6	17.4	18.2	19.0	19.8	20.6
9.0	12.3	13.2	14.0	14.9	15.7	16.6	17.4	18.3	19.2	20.1	20.9	21.8
10.0	12.9	13.8	14.7	15.7	16.6	17.5	18.5	19.4	20.4	21.3	22.3	23.2
Actual Exhaust T [°F]	9.7	10.2	10.8	11.3	11.8	12.3	12.9	13.4	14.0	14.5	15.0	15.6
Ambient T [°F]	70	70	70	70	70	70	70	70	70	70	70	70

Slide 30 - Typical Eastern Coal

All common fuels have a range in composition. The range in composition of commercially available natural gas is very small when compared to the variability of heavy fuel oil. However, when considering coals the range in variability is even greater.

[Slide Visual – Stack Loss Table for Typical Eastern Coal]

Flue Gas Oxygen Content Wet Basis [%]	Stack Loss [% of fuel higher heating value input] Net Stack Temperature [ΔºF] {Difference between flue gas exhaust temperature and ambient temperature}											
	230	255	280	305	330	355	380	405	430	455	480	505
1.0	8.5	9.0	9.6	10.1	10.7	11.2	11.8	12.3	12.8	13.4	14.0	14.5
2.0	8.7	9.3	9.9	10.4	11.0	11.6	12.1	12.7	13.3	13.9	14.4	15.0
3.0	9.0	9.6	10.2	10.8	11.4	12.0	12.6	13.2	13.8	14.4	15.0	15.6
4.0	9.3	9.9	10.5	11.2	11.8	12.4	13.1	13.7	14.3	15.0	15.6	16.3
5.0	9.6	10.3	10.9	11.6	12.3	12.9	13.6	14.3	14.9	15.6	16.3	17.0
6.0	10.0	10.7	11.4	12.1	12.8	13.5	14.2	14.9	15.6	16.4	17.1	17.8
7.0	10.4	11.1	11.9	12.6	13.4	14.2	14.9	15.7	16.4	17.2	18.0	18.7
8.0	10.9	11.7	12.5	13.3	14.1	14.9	15.7	16.5	17.4	18.2	19.0	19.8
9.0	11.4	12.3	13.2	14.0	14.9	15.8	16.7	17.6	18.4	19.3	20.2	21.1
10.0	12.1	13.0	14.0	14.9	15.9	16.8	17.8	18.7	19.7	20.7	21.6	22.6
Actual Exhaust T [°F]	300	325	350	375	400	425	450	475	500	525	550	575
Ambient T [°F]	70	70	70	70	70	70	70	70	70	70	70	70

Slide 31 - Typical Western Coal

These coal and wood stack loss tables should be considered estimates only.

[Slide Visual – Stack Loss Table for Typical Western Coal]

Flue Gas Oxygen Content Wet Basis [%]	Stack Loss [% of fuel higher heating value input] Net Stack Temperature [Δ°F] {Difference between flue gas exhaust temperature and ambient temperature}											
	230	255	280	305	330	355	380	405	430	455	480	505
1.0	10.1	10.7	11.2	11.7	12.3	12.8	13.4	13.9	14.5	15.0	15.6	16.1
2.0	10.4	10.9	11.5	12.0	12.6	13.2	13.7	14.3	14.9	15.5	16.0	16.6
3.0	10.6	11.2	11.8	12.4	13.0	13.6	14.2	14.8	15.4	16.0	16.6	17.2
4.0	10.9	11.5	12.1	12.8	13.4	14.0	14.6	15.3	15.9	16.5	17.2	17.8
5.0	11.2	11.9	12.5	13.2	13.8	14.5	15.2	15.8	16.5	17.2	17.9	18.5
6.0	11.6	12.3	13.0	13.7	14.4	15.1	15.8	16.5	17.2	17.9	18.6	19.4
7.0	12.0	12.7	13.5	14.2	15.0	15.7	16.5	17.2	18.0	18.7	19.5	20.3
8.0	12.5	13.3	14.1	14.9	15.7	16.5	17.3	18.1	18.9	19.7	20.5	21.3
9.0	13.0	13.9	14.7	15.6	16.5	17.3	18.2	19.1	20.0	20.8	21.7	22.6
10.0	13.7	14.6	15.5	16.5	17.4	18.4	19.3	20.2	21.2	22.2	23.1	24.1
Actual Exhaust T [°F]	10.1	10.7	11.2	11.7	12.3	12.8	13.4	13.9	14.5	15.0	15.6	16.1
Ambient T [°F]	70	70	70	70	70	70	70	70	70	70	70	70

Slide 32 - Typical Green Wood

Green-wood is a very common fuel in many industries. Green-wood refers primarily to the portions of trees that are not used in the papermaking and lumber making processes. Bark and other woodchips that have been removed from freshly cut trees are the primary sources of green-wood. It is interesting to note that green-wood is generally 50 percent liquid water. As a result, the stack loss associated with green-wood is very high.

[Slide Visual – Stack Loss Table for Typical Green Wood]

Flue Gas Oxygen Content Wet Basis [%]	Stack Loss [% of fuel higher heating value input] Net Stack Temperature [Δ°F] {Difference between flue gas exhaust temperature and ambient temperature}											
	230	255	280	305	330	355	380	405	430	455	480	505
1.0	35.7	36.7	37.1	38.1	38.4	39.6	39.8	41.0	41.2	42.5	42.6	44.0
2.0	36.0	37.1	37.4	38.6	38.9	40.1	40.3	41.6	41.8	43.1	43.2	44.7
3.0	36.3	37.5	37.8	39.0	39.3	40.6	40.8	42.2	42.4	43.9	43.9	45.5
4.0	36.7	37.9	38.2	39.6	39.8	41.3	41.4	42.9	43.0	44.7	44.7	46.4
5.0	37.1	38.4	38.7	40.2	40.4	42.0	42.1	43.8	43.8	45.6	45.5	47.4
6.0	37.5	39.0	39.3	40.9	41.1	42.8	42.9	44.7	44.7	46.6	46.5	48.6
7.0	38.0	39.6	39.9	41.7	41.8	43.7	43.7	45.8	45.6	47.8	47.6	49.9
8.0	38.6	40.4	40.7	42.6	42.7	44.8	44.7	47.0	46.8	49.2	48.9	51.5
9.0	39.3	41.3	41.5	43.7	43.7	46.1	45.9	48.5	48.1	50.9	50.3	53.3
10.0	40.2	42.4	42.5	45.0	44.9	47.6	47.3	50.2	49.7	52.9	52.1	55.5
Actual Exhaust T [°F]	300	325	350	375	400	425	450	475	500	525	550	575
Ambient T [°F]	70	70	70	70	70	70	70	70	70	70	70	70

Slide 33 - Combustion Management

In summary, proper combustion management requires adding enough oxygen to the combustion zone to burn all of the fuel but not adding too much air to make sure the thermal loss is minimized. Combustion management strategy initiates with measuring the condition of the combustion process, and utilizes the existing equipment to manage the combustion process to the best extent practical, and to examine the opportunities to modify operations and equipment to further improve combustion performance.

[Slide Visual – Combustion Management - Summary]

- **Combustion management principles:**
  - **Add enough oxygen to react all of the fuel.**
  - **Minimize the amount of extra air to limit the energy loss.**
  - **Monitor combustibles to identify problems.**

1. **Measure the oxygen content of boiler exhaust gas.**
   a) **Continuously.**
   b) **Periodically.**
2. **Control oxygen content within a minimum and maximum range.**
   a) **Continuous-automatic control.**
   b) **Positioning control.**
3. **Challenge the control range.**
   a) **Combustibles measurement.**
   b) **Burner repair.**
   c) **Control upgrade.**
   d) **Combustion tuning.**

Slide 34 - Stack Loss Example

Let's return to our example boiler, take some measurements, and estimate the boiler efficiency. For our example boiler we have measured the flue gas temperature to be 450 degrees Fahrenheit, ambient temperature to be 70 degrees Fahrenheit, and the flue gas oxygen content to be 7.0 percent. Combustibles concentration was measured to be less than 10 ppm, which is negligibly small.

[Slide Visual – Stack Loss Example]

Determine the Stack Loss (Natural Gas)

- **Combustion analyzer data:**
  - **Flue gas O2 content 7% by volume**
  - **Flue gas CO2 content 6% by volume**

- Flue gas CO content ~0 ppm
- Flue gas unburned fuel ~0%
- Flue gas temperature 450°F
- Intake air temperature 70°F
- Fuel temperature 70°F
- 380°F net flue gas temperature

Slide 35 - Stack Loss – Natural Gas 1

We take these measurements to the stack loss table for natural gas.

[Slide Visual – Stack Loss Table for Natural Gas]

Flue Gas Oxygen Content Wet Basis [%]	Stack Loss [% of fuel higher heating value input]											
	Net Stack Temperature [Δ°F] {Difference between flue gas exhaust temperature and ambient temperature}											
	155	180	205	230	255	280	305	330	355	380	405	430
1.0	13.1	13.6	14.1	14.7	15.2	15.8	16.3	16.9	17.4	18.0	18.5	19.1
2.0	13.2	13.8	14.3	14.9	15.5	16.1	16.6	17.2	17.8	18.4	18.9	19.5
3.0	13.4	14.0	14.6	15.2	15.8	16.4	17.0	17.6	18.2	18.8	19.4	20.0
4.0	13.6	14.2	14.8	15.5	16.1	16.7	17.4	18.0	18.7	19.3	20.0	20.6
5.0	13.8	14.5	15.1	15.8	16.5	17.2	17.8	18.5	19.2	19.9	20.5	21.2
6.0	14.1	14.8	15.5	16.2	16.9	17.6	18.3	19.1	19.8	20.5	21.2	22.0
7.0	14.4	15.1	15.9	16.6	17.4	18.1	18.9	19.7	20.5	21.2	22.0	22.8
8.0	14.7	15.5	16.3	17.1	17.9	18.8	19.6	20.4	21.2	22.1	22.9	23.7
9.0	15.1	16.0	16.8	17.7	18.6	19.5	20.4	21.2	22.1	23.0	23.9	24.8
10.0	15.5	16.5	17.4	18.4	19.4	20.3	21.3	22.2	23.2	24.2	25.2	26.1
Actual Exhaust T [°F]	225	250	275	300	325	350	375	400	425	450	475	500
Ambient T [°F]	70	70	70	70	70	70	70	70	70	70	70	70

Slide 36 - Stack Loss – Natural Gas 2

This data identifies the stack loss to be 21.2 percent.

[Slide Visual – Stack Loss Table for Natural Gas]

Flue Gas Oxygen Content Wet Basis [%]	Stack Loss [% of fuel higher heating value input]											
	Net Stack Temperature [ΔºF] {Difference between flue gas exhaust temperature and ambient temperature}											
	155	180	205	230	255	280	305	330	355	380	405	430
1.0	13.1	13.6	14.1	14.7	15.2	15.8	16.3	16.9	17.4	18.0	18.5	19.1
2.0	13.2	13.8	14.3	14.9	15.5	16.1	16.6	17.2	17.8	18.4	18.9	19.5
3.0	13.4	14.0	14.6	15.2	15.8	16.4	17.0	17.6	18.2	18.8	19.4	20.0
4.0	13.6	14.2	14.8	15.5	16.1	16.7	17.4	18.0	18.7	19.3	20.0	20.6
5.0	13.8	14.5	15.1	15.8	16.5	17.2	17.8	18.5	19.2	19.9	20.5	21.2
6.0	14.1	14.8	15.5	16.2	16.9	17.6	18.3	19.1	19.8	20.5	21.2	22.0
7.0	14.4	15.1	15.9	16.6	17.4	18.1	18.9	19.7	20.5	21.2	22.0	22.8
8.0	14.7	15.5	16.3	17.1	17.9	18.8	19.6	20.4	21.2	22.1	22.9	23.7
9.0	15.1	16.0	16.8	17.7	18.6	19.5	20.4	21.2	22.1	23.0	23.9	24.8
10.0	15.5	16.5	17.4	18.4	19.4	20.3	21.3	22.2	23.2	24.2	25.2	26.1
Actual Exhaust T [°F]	225	250	275	300	325	350	375	400	425	450	475	500
Ambient T [°F]	70	70	70	70	70	70	70	70	70	70	70	70

At 380 degrees Fahrenheit net stack temperature at 7% oxygen content, the stack loss is 21.2%

Slide 37 - Stack Loss Example

This information allows a gross estimate of boiler efficiency to be established as 78.8 percent, which is 100 percent minus the stack loss of 21.2 percent.

[Slide Visual – Stack Loss Example]

Determine the Stack Loss (Natural Gas)

- **Combustion analyzer data:**
  - **Flue gas O2 content 7% by volume**
  - **Flue gas CO2 content 6% by volume**
  - **Flue gas CO content ~0%**
  - **Flue gas unburned fuel ~0%**
  - **Flue gas temperature 450°F (380°F net)**
  - **Intake air temperature 70°F**
  - **Fuel temperature 70°F**
  - **Stack Loss 21.2%**
  - **Combustion efficiency 78.8%**

Slide 38 - Stack Loss Calculator

The Steam System Assessment Tool contains another form of stack loss calculator. This calculator allows flue gas temperature, ambient temperature, and flue gas oxygen content to be input with stack loss for various fuels as the output.

[Slide Visual – Stack Loss Calculator]

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 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)	450	°F	Stack Temperature - Ambient Temperature = 380°F
Ambient Temperature (°F)	70	°F	
Stack Gas Oxygen Content (%)	7	%	
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	21.3	%	
Number 2 Fuel Oil	16.8	%	
Number 6 Fuel Oil (Low Sulfur)	16.4	%	
Number 6 Fuel Oil (High Sulfur)	16.6	%	
Typical Eastern Coal (Bituminous)	15.0	%	
Typical Western Coal (Sub bituminous)	16.5	%	
Typical Green Wood	27.4	%	

Slide 39 - Indirect Efficiency Summary

Other investigations have yielded estimates of the shell loss and the blowdown loss. Other losses are considered negligible for this boiler. As a result, boiler efficiency can be determined in an indirect manner by subtracting these losses from a perfectly efficient boiler. This method estimates the boiler efficiency to be 77.4 percent.

Once again, we get indirect efficiency by subtracting the percentage of each loss from 100 percent.

[Slide Visual – Boiler Loss Indirect Efficiency Equations]

$n_{indirect}$ = 100 percent – E_{Losses}

Indirect Boiler Efficiency is equal to 100% minus the sum of all boiler losses.

$n_{indirect}$ = 100 percent – $Loss_{shell}$ – $Loss_{blowdown}$ – $Loss_{stack}$ – $Loss_{misc}$

Indirect Boiler Efficiency is equal to 100% minus the shell losses, minus the blowdown losses, minus the stack losses, minus the miscellaneous losses.

$n_{indirect}$ = 100 percent - 21.2 percent – 0.9 percent – 0.5 percent – 0 percent

$n_{indirect}$ = 77.4 percent

Where:

$n_{indirect}$	= Indirect efficiency
E_{Losses}	= Sum of all Losses
$Loss_{shell}$	= Shell Losses
$Loss_{blowdown}$	= Blowdown Losses
$Loss_{stack}$	= Stack Losses
$Loss_{misc}$	= Miscellaneous Losses

Slide 40 - Stack Losses – Example

Now, let's take a look at an example.

[Slide Visual – Efficiency Sub-Section: Stack Losses –Example]

Banner:
DOE's BestPractices
Steam End User Training

Steam Generation Efficiency
Efficiency Definition
Radiation and Convection Losses –
Shell Losses
Blowdown Losses
Stack Losses – Example

Slide 41 - Boiler Loss Example 1

Our example boiler is operating with an efficiency of about 77 percent. Typical natural gas fired boiler efficiency is 83 percent and higher efficiencies are attainable. As a result, we are expecting this boiler will have improvement opportunities.

[Slide Visual - Boiler Loss Example]

- **Natural gas fired boiler ($10.0/106Btu)**
  - **Steam pressure is 400 psig**
  - **Steam temperature is 700°F (superheated)**
  - **Ambient temperature is 70°F**
  - **Current combustion efficiency is 78.8%**

This schematic depicts a water-tube boiler. Fuel and air enter at the lower left of the combustion zone, feedwater enters at the top of the steam generation section at the steam drum which includes multiple passes for heat exchange with a mud drum at the bottom of the section. The steam outlet is shown at the top of the boiler as 700 degrees Fahrenheit. Exhaust gases are shown leaving the boiler at 450 degrees Fahrenheit. The flue gas oxygen content is identified at 7% near the flue gas outlet. The Fuel Cost for the boiler is reported at $13 million dollars per year. The current steam operating load is 100,000 pounds per hour with a capacity of 120,000 pounds per hour, or 83% load.

Slide 42 - Boiler Loss Example 2

Are there areas of interest? Are there measurements that indicate improvements may be possible?

> ***[Slide Visual - Boiler Loss Example]***
>
> **Are there any interesting areas of investigation?**
>
> **This schematic depicts a water-tube boiler. Fuel and air enter at the lower left of the combustion zone, feedwater enters at the top of the steam generation section at the steam drum which includes multiple passes for heat exchange with a mud drum at the bottom of the section. The steam outlet is shown at the top of the boiler as 700 degrees Fahrenheit. Exhaust gases are shown leaving the boiler at 450 degrees Fahrenheit. The flue gas oxygen content is identified at 7% near the flue gas outlet. The Fuel Cost for the boiler is reported at $13 million dollars per year.**

Slide 43 - Boiler Loss Example 3

The flue gas exhaust temperature is not extremely high; however, 450 degrees Fahrenheit is well above the practical limit of flue gas temperature for a natural gas fired boiler. It is common to design natural gas fired boilers to operate with flue gas temperatures less than 300 degrees Fahrenheit.

Additionally, the flue gas oxygen content appears to be elevated—7 percent flue gas oxygen content is the upper end of typical for natural gas boilers.

At this point we do not know if there are problems with the boiler, if the boiler has always operated with these conditions, or if recent changes have resulted in these conditions—but we do know that the primary boiler measurements indicate investigation should begin.

> ***[Slide Visual - Boiler Loss Example]***
>
> - **Are there any interesting areas of investigation?**
>   - **Flue gas oxygen content**
>   - **Flue gas exhaust temperature**
>
> **This schematic depicts a water-tube boiler. Fuel and air enter at the lower left of the combustion zone, feedwater enters at the top of the steam generation section at the steam drum which includes multiple passes for heat exchange with a mud drum at the bottom of the section. The steam outlet is shown at the top of the boiler as 700 degrees Fahrenheit. Exhaust gases are shown leaving the boiler at 450 degrees Fahrenheit. The flue gas oxygen content is identified at 7% near the flue gas outlet. The Fuel Cost for the boiler is reported at $13 million dollars per year.**

Slide 44 - Boiler Loss Example 4

Let's start our investigation by targeting the flue gas oxygen content—there may be adjustments we can make to the boiler operations immediately and begin saving fuel now.

[Slide Visual - Boiler Loss Example]

- **Are there any interesting areas of investigation?**
  - **Flue gas oxygen content**
  - **Flue gas exhaust temperature**

This schematic depicts a water-tube boiler. Fuel and air enter at the lower left of the combustion zone, feedwater enters at the top of the steam generation section at the steam drum which includes multiple passes for heat exchange with a mud drum at the bottom of the section. The steam outlet is shown at the top of the boiler as 700 degrees Fahrenheit. Exhaust gases are shown leaving the boiler at 450 degrees Fahrenheit. The flue gas oxygen content is identified at 7% near the flue gas outlet. The Fuel Cost for the boiler is reported at $13 million dollars per year.

Slide 45 - Boiler Loss Example 5

Our investigation of the boiler identifies that positioning control is used to manage the combustion operations.

[Slide Visual - Boiler Loss Example]

- **Are there any interesting areas of investigation?**
  - **Flue gas oxygen content**
    - **Positioning control is in place**
  - **Flue gas exhaust temperature**

This schematic depicts a water-tube boiler. Fuel and air enter at the lower left of the combustion zone, feedwater enters at the top of the steam generation section at the steam drum which includes multiple passes for heat exchange with a mud drum at the bottom of the section. The steam outlet is shown at the top of the boiler as 700 degrees Fahrenheit. Exhaust gases are shown leaving the boiler at 450 degrees Fahrenheit. The flue gas oxygen content is identified at 7% near the flue gas outlet. The Fuel Cost for the boiler is reported at $13 million dollars per year.

Slide 46 - Flue Gas Content Control Parameters 1

Recall, most natural gas fired boilers operating with positioning control will operate with flue gas oxygen content ranging from 3 percent to 7 percent. Our example boiler is operating at the upper end of this range; however, we also remember that the higher oxygen content is required for lower boiler loads. This boiler is operating at a fairly heavy load—greater than 80 percent.

[Slide Visual - Typical Flue Gas Content Control Parameters Table]

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
Number 2 Fuel Oil	2.0	3.0	3.0	7.0	11	18	18	55
Number 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

Positioning Control Flue Gas Oxygen Content 3% minimum, 7% maximum, for Natural Gas fuel.

Slide 47 - Flue Gas Content Control Parameters 2

As a result, we would expect this boiler to operate with flue gas oxygen content closer to 3 percent.

Now, before we spend a lot of time and energy attempting to reduce the combustion zone oxygen content, let's get an understanding of the savings potential. Remember the flue gas analysis data indicated there were negligible combustibles in the exhaust gas. This leads us to expect that the burner can operate with less excess air. At this point we are not sure what the minimum flue gas oxygen content is for this burner to operate with good performance. However, we fully expect this burner to be able to operate with less than 5 percent oxygen. Let's estimate the savings opportunity associated with reducing the flue gas oxygen content to 5 percent. This will help us understand how interested we should be in tuning the boiler.

[Slide Visual - Typical Flue Gas Content Control Parameters Table]

Fuel	Automatic Control		Positioning Control		Automatic Control		Positioning Control	
	Flue Gas O_2 Content		Flue Gas O_2 Content		Excess Air		Excess Air	
	Min.	Max.	Min.	Max.	Min.	Max.	Min.	Max.
	[%]	[%]	[%]	[%]	[%]	[%]	[%]	[%]
Natural Gas	1.5	3.0	3.0	7.0	9	18	18	55
Number 2 Fuel Oil	2.0	3.0	3.0	7.0	11	18	18	55
Number 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

Positioning Control Flue Gas Oxygen Content 3% minimum, 7% maximum, for Natural Gas fuel.

Slide 48 - Stack Loss – Natural Gas

The stack loss table is an excellent vehicle to help identify the tuning opportunity. We will take a conservative approach and assume we can tune the boiler to 5 percent oxygen—we are fairly confident we can use the existing combustion controls and achieve even lower oxygen content; but, right now we are interested to characterize the opportunity.

If the combustion zone oxygen content is reduced from 7 percent to 5 percent and the flue gas temperature remains constant, the stack loss will reduce from 21.2 percent to 19.9 percent. These values can be used to estimate overall boiler efficiency by subtracting them from 100 percent.

[Slide Visual – Stack Loss Table for Natural Gas]

- **To determine the order-of-magnitude importance of tuning a conservative evaluation will be made assuming 5% oxygen can be attained.**
  - **Efficiency could improve from 78.8% to 80.1%**

Flue Gas Oxygen Content Wet Basis [%]	Stack Loss [% of fuel higher heating value input]											
	Net Stack Temperature [Δ°F] {Difference between flue gas exhaust temperature and ambient temperature}											
	155	180	205	230	255	280	305	330	355	380	405	430
1.0	13.1	13.6	14.1	14.7	15.2	15.8	16.3	16.9	17.4	18.0	18.5	19.1
2.0	13.2	13.8	14.3	14.9	15.5	16.1	16.6	17.2	17.8	18.4	18.9	19.5
3.0	13.4	14.0	14.6	15.2	15.8	16.4	17.0	17.6	18.2	18.8	19.4	20.0
4.0	13.6	14.2	14.8	15.5	16.1	16.7	17.4	18.0	18.7	19.3	20.0	20.6
5.0	13.8	14.5	15.1	15.8	16.5	17.2	17.8	18.5	19.2	19.9	20.5	21.2
6.0	14.1	14.8	15.5	16.2	16.9	17.6	18.3	19.1	19.8	20.5	21.2	22.0
7.0	14.4	15.1	15.9	16.6	17.4	18.1	18.9	19.7	20.5	21.2	22.0	22.8
8.0	14.7	15.5	16.3	17.1	17.9	18.8	19.6	20.4	21.2	22.1	22.9	23.7
9.0	15.1	16.0	16.8	17.7	18.6	19.5	20.4	21.2	22.1	23.0	23.9	24.8
10.0	15.5	16.5	17.4	18.4	19.4	20.3	21.3	22.2	23.2	24.2	25.2	26.1
Actual Exhaust T [°F]	225	250	275	300	325	350	375	400	425	450	475	500
Ambient T [°F]	70	70	70	70	70	70	70	70	70	70	70	70

At 380 degrees Fahrenheit net stack temperature at 5% oxygen content, the stack loss is 19.9%

At 380 degrees Fahrenheit net stack temperature at 7% oxygen content, the stack loss is 21.2%

Slide 49 - Boiler Tuning Potential Analysis

These efficiency estimates can be used to estimate the fuel cost impact associated with tuning the boiler. The equation presented here is very simple; however, it is a rigorous representation of the economic impact of boiler efficiency changes.

This calculation indicates tuning the boiler has a potential of reducing fuel consumption more than 200,000 dollars a year. Tuning the positioning controls of a natural gas fired boiler will typically require a technician less than a day to complete. The tuning activity is relatively low-cost. In other words, we are very interested in tuning this boiler.

In fact, we did tune this boiler and we achieved nominally 5 percent oxygen in the combustion zone. The combustibles concentration remained negligible throughout the tuning activity. Actually during the tuning activity, the combustion zone oxygen content was reduced to less than 2 percent with minimal increase in combustibles concentration. An oxygen content less than 3 percent is considered outside the typical range for positioning control. Operators at the site were reluctant to tune the boiler to less than 5 percent oxygen because of historically operating at higher values.

Therefore, we want to examine the impact of transitioning from positioning control to continuous-automatic control.

[Slide Visual - Improved Efficiency Savings for 5% O_2 in Example]

$O_{savings} = \{1 - (n_{existing} / n_{adjusted})\}\ (\text{K-dot}_{boiler})$

The savings is equal to 1 minus the existing boiler efficiency divided by the adjusted boiler efficiency; multiplied by the Boiler Operating Costs.

$O_{savings} = \{1 - (78.8\% / 80.1\%)\}$ 13,000,000 dollars/year = 220,000 dollars/year

The savings is equal to 1 minus the 78.8% divided by 80.1%; multiplied by 13,000,000 dollars per year equals 220,000 dollars per year.

Where:

$O_{savings}$ = Estimated savings
$n_{existing}$ = Efficiency of the existing boiler
$n_{adjusted}$ = Efficiency of the boiler - adjusted
K-dot_{boiler} = Boiler Operating Costs

- **The savings potential is sufficient to warrant a field trial**

Slide 50 - Flue Gas Content Control Parameters

Continuous-automatic control is expected to be able to operate with combustion zone oxygen content ranging from 1.5 percent to 3.0 percent. Field trials indicate the burner performs well with reduced combustion zone oxygen content. We can complete another analysis to determine the impact of transitioning to continuous-automatic control.

[Slide Visual - Typical Flue Gas Content Control Parameters Table]

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
Number 2 Fuel Oil	2.0	3.0	3.0	7.0	11	18	18	55
Number 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

Positioning Control Flue Gas Oxygen Content 3% minimum, 7% maximum, for Natural Gas fuel.
Automatic Control Flue Gas Oxygen Content 1.5% minimum, 3% maximum, for Natural Gas fuel.

- **Additional improvement can be attained by upgrading to automatic combustion control (trim control)**

Slide 51 - Stack Loss – Natural Gas

The analysis proceeds exactly like the tuning calculations. The current stack loss is 19.9 percent and the conservative estimate of future operations is 18.8 percent.

[Slide Visual – Stack Loss Table for Natural Gas]

- **The installation of trim control has the potential to allow the combustion process to operate with less than 3% oxygen over a wide range of operating conditions.**
  - **Efficiency could improve from 80.1% to 81.2%**

Flue Gas Oxygen Content Wet Basis [%]	Stack Loss [% of fuel higher heating value input]											
	Net Stack Temperature [Δ°F] {Difference between flue gas exhaust temperature and ambient temperature}											
	155	180	205	230	255	280	305	330	355	380	405	430
1.0	13.1	13.6	14.1	14.7	15.2	15.8	16.3	16.9	17.4	18.0	18.5	19.1
2.0	13.2	13.8	14.3	14.9	15.5	16.1	16.6	17.2	17.8	18.4	18.9	19.5
3.0	13.4	14.0	14.6	15.2	15.8	16.4	17.0	17.6	18.2	18.8	19.4	20.0
4.0	13.6	14.2	14.8	15.5	16.1	16.7	17.4	18.0	18.7	19.3	20.0	20.6
5.0	13.8	14.5	15.1	15.8	16.5	17.2	17.8	18.5	19.2	19.9	20.5	21.2
6.0	14.1	14.8	15.5	16.2	16.9	17.6	18.3	19.1	19.8	20.5	21.2	22.0
7.0	14.4	15.1	15.9	16.6	17.4	18.1	18.9	19.7	20.5	21.2	22.0	22.8
8.0	14.7	15.5	16.3	17.1	17.9	18.8	19.6	20.4	21.2	22.1	22.9	23.7
9.0	15.1	16.0	16.8	17.7	18.6	19.5	20.4	21.2	22.1	23.0	23.9	24.8
10.0	15.5	16.5	17.4	18.4	19.4	20.3	21.3	22.2	23.2	24.2	25.2	26.1
Actual Exhaust T [°F]	225	250	275	300	325	350	375	400	425	450	475	500
Ambient T [°F]	70	70	70	70	70	70	70	70	70	70	70	70

At 380 degrees Fahrenheit net stack temperature at 3% oxygen content, the stack loss is 18.8%
At 380 degrees Fahrenheit net stack temperature at 5% oxygen content, the stack loss is 19.9%
At 380 degrees Fahrenheit net stack temperature at 7% oxygen content, the stack loss is 21.2%

Slide 52 - Automatic Combustion Control

Based on the operating cost of the tuned boiler, the savings estimate exceeds 150,000 dollars a year.

This simplified analysis indicates attractive savings opportunities associated with tuning the boiler and with installing a continuous-automatic combustion controller. At this time the cost of installing a combustion controller is not known, but it is expected to require less than $150,000—warranting further investigation.

[Slide Visual – Net Stack Temperature]

450°F – 70°F = 380°F Net Stack Temperature

Current Efficiency
At 7% O_2, n = 100% - 21.2% = 78.8%

Improved Efficiency
At 5% O_2, n = 100%-19.9% = 80.1%
At 3% O_2, n = 100%-18.8% = 81.2%

[Slide Visual - Additional Efficiency Savings for 3% O_2 in Example]

$O_{savings} = \{1 - (n_{existing} / n_{adjusted})\}\ (K\text{-}dot_{boiler})$

The savings is equal to 1 minus the existing boiler efficiency divided by the adjusted boiler efficiency; multiplied by the Boiler Operating Costs.

$O_{savings} = \{1 - (80.1\% / 81.2\%)\}$ **12,780,000 dollars/year = 166,000 dollars/year**

The savings is equal to 1 minus the 80.1% divided by 81.2%; multiplied by 12,780,000 dollars per year equals 166,000 dollars per year.

Slide 53 - Boiler Loss Example

We have set the strategy for combustion management for this boiler—tune the existing boiler combustion controls, explore installing continuous-automatic combustion control, and continually challenge the control parameters.

Now we are ready to examine the flue gas temperature impacts. The flue gas temperature is nominally 450 degrees Fahrenheit, which is not excessively high but it is much greater than the minimum allowable.

[Slide Visual - Boiler Loss Example]

- **Are there any interesting areas of investigation?**
  - **Flue gas exhaust temperature**
  - **Flue gas oxygen content**

This schematic depicts a water-tube boiler. Fuel and air enter at the lower left of the combustion zone, feedwater enters at the top of the steam generation section at the steam drum which includes multiple passes for heat exchange with a mud drum at the bottom of the section. The steam outlet is shown at the top of the boiler as 700 degrees Fahrenheit. Exhaust gases are shown leaving the boiler at 450 degrees Fahrenheit. The flue gas oxygen content is identified at 5% near the flue gas outlet. The Fuel Cost for the boiler is reported at $12.780,000 dollars per year.

Slide 54 - Elevated Flue Gas 1

As we examine the possible reasons for the current flue gas temperature, we find that the boiler water quality is maintained well within acceptable ranges, the fuel used has minimal potential for fouling, and the boiler is operating within design steam production limits. These issues do not identify any opportunities to allow the flue gas temperature to be corrected.

[Slide Visual - Water-tube Boiler]

- **Is the boiler operating at greater than design load?**
- **Will the boiler design allow reduced flue gas temperature operation?**
- **Are the boiler heat transfer surfaces fouled?**
  - **Waterside**
  - **Fireside**
- **Is a failed internal component allowing bypass of flue gas?**
- **Is excess air a factor?**

This schematic depicts a water-tube boiler. Fuel and air enter at the lower left of the combustion zone, feedwater enters at the top of the steam generation section at the steam drum which includes multiple passes for heat exchange with a mud drum at the bottom of the section. The steam outlet is shown at the top of the boiler as 700 degrees Fahrenheit. Exhaust gases are shown leaving the boiler at 450 degrees Fahrenheit. The flue gas oxygen content is identified at 5% near the flue gas outlet. The Fuel Cost for the boiler is reported at $12.780,000 dollars per year.

Slide 55 - Elevated Flue Gas 2

An examination of the original design information of the boiler reveals the boiler was originally designed with a feedwater economizer. In the past the feedwater economizer experienced some tube failures and was decommissioned.

[Slide Visual - Water-tube Boiler]

- **Is the boiler operating at greater than design load?**
- **Will the boiler design allow reduced flue gas temperature operation?**
- **Are the boiler heat transfer surfaces fouled?**
  - **Waterside**
  - **Fireside**
- **Is a failed internal component allowing bypass of flue gas?**
- **Is excess air a factor?**

The boiler was originally equipped with a feedwater economizer that was taken out of service

This schematic depicts a water-tube boiler. Fuel and air enter at the lower left of the combustion zone, feedwater enters at the top of the steam generation section at the steam drum which includes multiple passes for heat exchange with a mud drum at the bottom of the section. The steam outlet is shown at the top of the boiler as 700 degrees Fahrenheit. Exhaust gases are shown leaving the boiler at 450 degrees Fahrenheit. A feedwater economizer is shown in the exhaust duct and which is used to preheat the feedwater. The flue gas oxygen content is identified at 5% near the flue gas outlet. The Fuel Cost for the boiler is reported at $12.780,000 dollars per year.

Slide 56 - Feedwater Economizer Evaluation

Installing a new feedwater economizer will allow us to recover flue gas thermal energy by preheating boiler feedwater. A new feedwater economizer could be designed to reduce the flue gas temperature to 300 degrees Fahrenheit or even less. The stack loss table can be used to establish an estimate of the fuel savings potential.

[Slide Visual - Water-tube Boiler]

The feedwater economizer can be repaired or replaced

This schematic depicts a water-tube boiler. Fuel and air enter at the lower left of the combustion zone, feedwater enters at the top of the steam generation section at the steam drum which includes multiple passes for heat exchange with a mud drum at the bottom of the section. The steam outlet is shown at the top of the boiler as 700 degrees Fahrenheit. Exhaust gases are shown leaving the boiler at 300 degrees Fahrenheit. A feedwater economizer is shown in the exhaust duct and which is used to preheat the feedwater. The flue gas oxygen content is identified at 5% near the flue gas outlet. The Fuel Cost for the boiler is reported at $12,780,000 dollars per year.

Slide 57 - Stack Loss – Natural Gas

The current stack loss is 19.9 percent (we have only tuned the boiler. We have not installed continuous-automatic combustion control). The economizer will reduce the stack loss to 15.8 percent.

[Slide Visual – Stack Loss Table for Natural Gas]

- **A feedwater economizer could be designed to operate with a flue gas exit temperature less than 300°F.**
  - **Efficiency could improve from 80.1% to 84.2%**

Flue Gas Oxygen Content Wet Basis [%]	Stack Loss [% of fuel higher heating value input] Net Stack Temperature [Δ°F] {Difference between flue gas exhaust temperature and ambient temperature}											
	155	180	205	230	255	280	305	330	355	380	405	430
1.0	13.1	13.6	14.1	14.7	15.2	15.8	16.3	16.9	17.4	18.0	18.5	19.1
2.0	13.2	13.8	14.3	14.9	15.5	16.1	16.6	17.2	17.8	18.4	18.9	19.5
3.0	13.4	14.0	14.6	15.2	15.8	16.4	17.0	17.6	18.2	18.8	19.4	20.0
4.0	13.6	14.2	14.8	15.5	16.1	16.7	17.4	18.0	18.7	19.3	20.0	20.6
5.0	13.8	14.5	15.1	15.8	16.5	17.2	17.8	18.5	19.2	19.9	20.5	21.2
6.0	14.1	14.8	15.5	16.2	16.9	17.6	18.3	19.1	19.8	20.5	21.2	22.0
7.0	14.4	15.1	15.9	16.6	17.4	18.1	18.9	19.7	20.5	21.2	22.0	22.8
8.0	14.7	15.5	16.3	17.1	17.9	18.8	19.6	20.4	21.2	22.1	22.9	23.7
9.0	15.1	16.0	16.8	17.7	18.6	19.5	20.4	21.2	22.1	23.0	23.9	24.8
10.0	15.5	16.5	17.4	18.4	19.4	20.3	21.3	22.2	23.2	24.2	25.2	26.1
Actual Exhaust T [°F]	225	250	275	300	325	350	375	400	425	450	475	500
Ambient T [°F]	70	70	70	70	70	70	70	70	70	70	70	70

At 230 degrees Fahrenheit net stack temperature at 5% oxygen content, the stack loss is 15.8%
At 380 degrees Fahrenheit net stack temperature at 3% oxygen content, the stack loss is 18.8%
At 380 degrees Fahrenheit net stack temperature at 5% oxygen content, the stack loss is 19.9%

At 380 degrees Fahrenheit net stack temperature at 7% oxygen content, the stack loss is 21.2%

Improved Efficiency with 5% Boiler Tuning
At 5% O_2 and 380^oF, n = 100%-19.9% = 80.1%

Further Improved Efficiency by Adding Feedwater Economizer
300^oF-70^oF = 230^oF Net Stack Temperature
At 5% O_2 and 230^oF, n = 100%-15.8% = 84.2%

Slide 58 - Economizer Potential Analysis

The efficiency improvement calculation indicates the fuel savings is more than 600,000 dollars a year. A feedwater economizer is expected to require less than 400,000 dollars to purchase and install. As a result, this project is recommended to explore further.

[Slide Visual - Savings Calculation]

$O_{savings} = \{1 - (n_{existing} / n_{adjusted})\} (\text{K-dot}_{boiler})$

The savings is equal to 1 minus the existing boiler efficiency divided by the adjusted boiler efficiency; multiplied by the Boiler Operating Costs.

$O_{savings} = \{1 - (80.1\% / 84.2\%)\}$ 12,780,000 dollars/year = 615,000 dollars/year

The savings is equal to 1 minus the 80.1% divided by 84.2%; multiplied by 12,780,000 dollars per year equals 615,000 dollars per year.

Slide 59 - Stack Loss Reduction – Summary

Managing stack loss is a critical factor in improving boiler efficiency. Significant emphasis should be placed on measuring the critical parameters that identify boiler operating characteristics. Challenging flue gas temperature, oxygen values, and combustibles concentrations are all aspects of boiler management.

[Slide Visual - Stack Loss Reduction]

- **Measure, record, and compare**
  - **Flue gas exit temperature**
    - **And intermediate temperatures**
  - **Flue gas oxygen content**
  - **Boiler load**
  - **Ambient temperature**
  - **Flue gas combustibles**
- **Reduce flue gas exit temperature**
  - **Repair failed components**
  - **Clean fire side**
  - **Maintain water side**
  - **Install heat recovery components**
    - **Feedwater economizer**
    - **Combustion air preheater**
- **Reduce excess air**
  - **Tune boiler combustion process**
  - **Install automatic combustion control**
  - **Challenge control parameters**

Steam End-User Training
Resource Utilization Effectiveness Module

Slide 1 - Resource Utilization Module

In the resource utilization section of this course we examine the management activities associated with the various energy resources available to a site. These include fuel selection, steam end-use or demand management, and combined heat and power activities. In this broad section we will examine the main factors influencing fuel selection. We will identify the vital importance of investigating steam end-use components and reducing steam consumption or improving the energy resource utilization of the steam demands. We will introduce the concepts related to combined heat and power operations (also known as cogeneration).

[Slide Visual – Resource Utilization Effectiveness]

Banner:
DOE's BestPractices
Steam End User Training

Resource Utilization Effectiveness
Fuel Selection
Steam Demands
Combined Heat and Power

Slide 2 - Fuel Selection Intro

We will begin our discussions in the fuel selection arena.

[Slide Visual – Resource Utilization Effectiveness – Fuel Selection]

Banner:
DOE's BestPractices
Steam End User Training

Resource Utilization Effectiveness
Fuel Selection
Steam Demands
Combined Heat and Power

Slide 3 - Fuel Selection

Fuel purchases typically dominate the operating cost of a steam system. It has been pointed out that a wide variety of fuels are provided to industrial facilities throughout the world. Fuel selection ranges from natural gas through fuel oils to coal and wood and many more fuels. The primary driving factor associated with selecting a fuel is typically energy based cost. However, environmental costs, maintenance costs, and equipment costs also play major roles in fuel selection. Fuel selection is not a simple matter. It is our intent to introduce the topic and raise awareness—it is not our intent to explore all of the major aspects of fuel selection. It is very apparent that in most cases a particular facility cannot simply switch fuels—there will be major equipment, infrastructure, environmental, and material handling impacts.

One common aspect of fuel switching is the opportunity to attain favorable pricing of a primary fuel. For example, a facility may consume natural gas as the only fuel supplied to the site. In order to secure fuel supplies, the site may purchase natural gas at an elevated cost because interruption of service would be detrimental to site operations. If an alternate fuel could be stored onsite and could serve to provide backup service if natural gas were curtailed, then the natural gas could potentially be purchased at a reduced cost. This is commonly referred to as *firm versus interruptible pricing*.

We would expect that switching to coal from natural gas would dramatically increase the maintenance and operations requirements of the steam generation equipment. Additionally, environmental equipment will most probably be significantly more for coal combustion. Regulatory requirements can be insurmountable as well. However, if a facility already has multi-fuel capability; such as, natural gas and coal or oil and wood the opportunities for flexibility and effective management can be dramatic. Often in these cases—if the equipment is already in-place—the difference in operating and maintenance costs may be minimal with respect to the difference in fuel purchase cost.

Slide 4 - Fuel Selection 2

The steam system we have been investigating is an excellent example of the main issues associated with fuel selection. As you recall the boiler we have focused our attention on is a natural gas fired boiler. The site is equipped with two additional boilers—one that burns green-wood and another that burns heavy fuel oil. At this point in our investigation the example boiler has been equipped with a feedwater economizer (automatic combustion control has not been installed at this time). All three boilers are in operation to reliably satisfy the steam demands of the site. The fuel oil fired boiler and the green wood fired boiler operate as base-load components at approximately two-thirds load. Operations "likes" this condition because these fuels are more difficult to handle than natural gas. The natural gas fired boiler is easiest to operate; therefore, the site relies mostly on it for load control and it carries a larger portion of the steam load.

The fuels are purchased with significantly different costs—$10 per million BTU natural gas, $5 per million BTU number 6 fuel oil, and $2 per million BTU green-wood. The example is designed to demonstrate the economic incentive associated with shifting steam production from a high-cost producer to a lower-cost producer. An initial investigation is undertaken to identify the economic incentive associated with producing more steam from the fuel-oil boiler and less steam from the natural gas fired boiler. In this example we are not intending to eliminate all natural gas consumption. We are simply identifying the potential impact associated with improved management of fuel resources. As a result, we will examine the impact associated with shifting a small amount of steam production from the natural gas boiler to the oil boiler. This can easily be accomplished by simply increasing the fuel supply to the oil fired boiler. As an initial investigation of the "size of the opportunity," we will assume a very small amount of steam production will be shifted from the natural gas boiler to the oil boiler—1,000 pounds per hour.

[Slide Visual - Three Boilers]

Fuel: Green Wood
Fuel cost: $2.00/10^6 Btu
Boiler capacity: 120,000 lbm/hr
Steam production: 80,000 lbm/hr
Flue gas exit T: 400°F
Flue gas oxygen: 5.0%
Efficiency: ~71.3%

Fuel: Natural gas
Fuel cost: $10.0/10^6 Btu
Boiler capacity: 120,000 lbm/hr
Steam production: 100,000 lbm/hr
Flue gas exit T: 300°F
Flue gas oxygen: 5.0%
Efficiency: ~84.2%

Fuel: Number 6 oil *HS*
Fuel cost: $5.00/10^6 Btu
Boiler capacity: 120,000 lbm/hr
Steam production: 80,000 lbm/hr
Flue gas exit T: 350°F
Flue gas oxygen: 5.0%
Efficiency: ~87.4%

Slide 5 - Fuel Selection Calculation

The savings calculations are simple. The analysis determines the fuel cost associated with generating 1,000 pounds per hour of steam from the natural gas fired boiler and compares this to the cost of generating the same amount of steam from the oil fired boiler. The difference between these operating costs is the savings opportunity. In the analysis, 1,000 pounds per hour of steam is the target amount because this is an easily scale-able value. It should also be noted that the steam energy is the same for any of the boilers in this example (same feedwater, same blowdown rate, same steam discharge pressure, same steam discharge temperature). As a result, the savings calculation is relatively simple. The calculations indicate that for every 1,000 pounds per hour of steam production that can be transferred from the natural gas boiler to the oil boiler, savings of $62,000 per year will result. If 10,000 pounds per hour could be transferred, the savings would be 10 times the amount—and based on the operating conditions, it appears this amount of steam production could be shifted.

[Slide Visual – Fuel Selection Calculation]

Savings from fuel switching = O = Initial operating cost – Final operating cost

$O = (\text{K-dot}_1 - \text{K-dot}_2)\ T$

Savings from fuel switching is equal to the Initial operating cost minus Final operating cost; multiplied by the operating period.

$O = \{(\text{E-dot}_{steam}/n_1)(k_{fuel1})\} - \{(\text{E-dot}_{steam}/n_2)(k_{fuel2})\}T$

Savings from fuel switching is equal to the Fuel Energy of the steam divided by the boiler efficiency using fuel 1; multiplied by the cost of the fuel 1; minus the Fuel Energy of the steam divided by the boiler efficiency using fuel 2; multiplied by the cost of the fuel 2; all multiplied by the operating period.

$O = \text{E-dot}_{steam}\ \{(k_{fuel1} / n_1) - (k_{fuel2} / n_2)\}T$

Savings from fuel switching is equal to the Fuel Energy of the steam; multiplied by the cost of the fuel 1; divided by the boiler efficiency using fuel 1; minus the cost of the fuel 2; divided by the boiler efficiency using fuel 2; all multiplied by the operating period.

$O = \text{m-dot}_{steam}\,(h_{steam} - h_{feedwater})\,\{(k_{fuel1} / n_1) - (k_{fuel2} / n_2)\}T$

Savings from fuel switching is equal to the mass flow rate of the steam; multiplied by the difference of the enthalpy of the steam minus the enthalpy of the feedwater; multiplied by the cost of the fuel 1; divided by the boiler efficiency using fuel 1; minus the cost of the fuel 2; divided by the boiler efficiency using fuel 2; all multiplied by the operating period.

$O = 1{,}000\ \text{lbm/hr}(1{,}361.88\ \text{Btu/lbm} - 210.42\ \text{Btu/lbm})\{\{(10.0)(\$/10^6\ \text{Btu})\}/(0.842) - \{(5.00)(\$/10^6\ \text{Btu})\}/(0.874)\}\}(8{,}760\ \text{hrs/yr})$

Savings from fuel switching equals 1,000 lbm/hr multiplied by 1,361.88 Btu/lbm minus 210.42 Btu/lbm multiplied by \$10 per million BTU; all
$(10.0)(\$/10^6\ \text{Btu})\}/(0.842) - \{(5.00)(\$/10^6\ \text{Btu})\}/(0.874)\}\}(8{,}760\ \text{hrs/yr})$

O = 62,000 \$/yr
Savings from fuel switching equals \$62,000 per year.

Where:
O = Operating Cost Savings
K-dot$_{fuel}$ = Operating Costs of the Boiler
T = Operating period
E-dot$_{steam}$ = Fuel Energy of the steam
k-dot$_{fuel}$ = Fuel Costs
m-dot$_{steam}$ = Mass flow rate of steam generated in the boiler
h = Enthalpy is energy content of a substance
n = Efficiency

Slide 6 - Fuel Selection

Of course, the most economically attractive operating condition is to maximize steam production from the lowest cost producer and steam production from the highest cost producer should be minimized. Theoretically, the lowest cost operation would have the natural gas fired boiler operating as the variable load boiler and the other boilers at maximum load. However, every boiler (every burner) has a minimum stable load. Also, operating a boiler at full load can shorten the life of internal components. As a result, there are real-world limitations on the allowable operating conditions for the boilers.

Based on this, the most practical operating condition could be to have the natural gas boiler producing minimum steam production (40,000 pounds per hour for example), operate the green wood boiler at the maximum practical load (105,000 pounds per hour for example), and allow the oil boiler to respond to moderate changes in steam demand. The example continues with this concept (transferring steam production to the wood-fired boiler.

[Slide Visual - Three Boilers]

Fuel: Green Wood
Fuel cost: $2.00/10^{6}Btu
Steam production: 80,000 lbm/hr
Efficiency: ~71.3%
Practical Operating Condition: 105,000 lbm/hr

Fuel: Natural gas
Fuel cost: $10.00/10^{6}Btu
Steam production: 100,000 lbm/hr
Efficiency: ~84.2%
Practical Operating Condition: 40,000 lbm/hr

Fuel: Number 6 oil *HS*
Fuel cost: $5.00/10^{6}Btu
Steam production: 80,000 lbm/hr
Efficiency: ~87.4%

Modulate with changes in steam demand

Slide 7 - Fuel Selection Calculation

Increasing steam production from the wood-fired boiler may have some maintenance consequences that should be included in the analysis. Minimal changes in steam production are not expected to influence maintenance requirements.

If the green-wood boiler load is increased by 25,000 pounds per hour by reducing the steam production of the natural gas fired boiler the savings will be nominally $2,275,000 per year.

[Slide Visual – Fuel Selection Calculation]

Savings from fuel switching = O = Initial operating cost – Final operating cost

$O = (K\text{-dot}_1 - K\text{-dot}_2)\ T$

Savings from fuel switching is equal to the Initial operating cost minus Final operating cost; multiplied by the operating period.

$O = \{(E\text{-dot}_{steam}/n_1)(k_{fuel1})\} - \{(E\text{-dot}_{steam}/n_2)(k_{fuel2})\}T$

Savings from fuel switching is equal to the Fuel Energy of the steam divided by the boiler efficiency using fuel 1; multiplied by the cost of the fuel 1; minus the Fuel Energy of the steam divided by the boiler efficiency using fuel 2; multiplied by the cost of the fuel 2; all multiplied by the operating period.

$O = E\text{-dot}_{steam}\ \{(k_{fuel1} / n_1) - (k_{fuel2} / n_2)\}T$

Savings from fuel switching is equal to the Fuel Energy of the steam; multiplied by the cost of the fuel 1; divided by the boiler efficiency using fuel 1; minus the cost of the fuel 2; divided by the boiler efficiency using fuel 2; all multiplied by the operating period.

$O = m\text{-dot}_{steam}\,(h_{steam} - h_{feedwater})\ \{(k_{fuel1} / n_1) - (k_{fuel2} / n_2)\}T$

Savings from fuel switching is equal to the mass flow rate of the steam; multiplied by the difference of the enthalpy of the steam minus the enthalpy of the feedwater; multiplied by the cost of the fuel 1; divided by the boiler efficiency using fuel 1; minus the cost of the fuel 2; divided by the boiler efficiency using fuel 2; all multiplied by the operating period.

$O = 1{,}000$ lbm/hr (1,361.88 Btu/lbm – 210.42 Btu/lbm){{(10.0)($/$10^6$ Btu)}/(0.842) - {(2.00)($/$10^6$ Btu)}/(0.713)}}(8,760 hrs/yr)

Savings from fuel switching equals 1,000 lbm/hr multiplied by 1,361.88 Btu/lbm minus 210.42 Btu/lbm multiplied by $10 per million BTU divided by efficiency of 0.842 minus $2 per million BTU divided by efficiency of 0.713; all multiplied by 8,760 hrs/yr.

O = 91,000 $/yr

Savings from fuel switching equals $91,000 per year.

91,000 $/yr / 1,000 lbm/hr x 25,000 lbm/hr = 2,275,000 $/yr

$91,000 per year per 1,000 pounds per hour savings multiplied by 25,000 pounds per hour equals $2,275,000 per year savings.

Slide 8 - Fuel Selection

It should be noted that often when examining multi-fuel sites a combined fuel cost is developed based on the average or blended fuel cost. This is often a poor representation of the true economic impact to a site. Consider our example, the blended fuel cost would be near 5.5 dollars per million BTU. Often this fuel cost would be used to determine the economic impact associated with various steam system modifications. However, if typical steam demand changes were controlled by the output of the natural gas boiler then the actual impact fuel cost would be 10 dollars per million BTU—a far greater true impact. Alternately, if the natural gas boiler is routinely operated at minimum-fire and the oil boiler responds to changes in steam demand then the appropriate impact fuel cost would be 5 dollars per million BTU.

[Slide Visual – Fuel Switching Issues]

- Many issues limit fuel switching capabilities.
  - Environmental regulations.
  - Fuel storage and handling issues.
  - Boiler capabilities.
- How should multi-fuel sites be operated and modeled?
  - Impact fuel cost should be utilized.
    - The *impact fuel* is the fuel that will change consumption if steam demand changes.
    - Typically the highest cost fuel in use is desired to be the impact fuel.
    - “Blended costs” generally do not reflect actual system changes

Slide 9 - Steam Demands Intro

Now, let's discuss Steam Demands.

[Slide Visual – Resource Utilization Effectiveness – Steam Demands]

Banner:
DOE's BestPractices
Steam End User Training

Resource Utilization Effectiveness
Fuel Selection
Steam Demands
Combined Heat and Power

Slide 10 - Steam Demand

The types of steam consumers are very diverse and the methods applied to improve performance vary significantly. As a result, we will examine a simple and very common steam demand. We will target common avenues used to reduce steam consumption and demonstrate the methods used to identify the economic impact of the changes.

Slide 11 - Example Steam Demand 1

The steam end-use system selected for investigation is a simple air handling unit with a steam coil used to heat the air from 40 degrees Fahrenheit to 120 degrees Fahrenheit. The air is heated by low-pressure (20 psig) saturated steam. Outside, ambient temperature, air is drawn into the heat exchanger, is heated to 120 degrees Fahrenheit, and is then delivered into the process unit.

[Slide Visual – Steam Demand]

A fan represented by a circle/square combination supplies airflow at 10,000 standard cubic feet per min air at 40 degrees Fahrenheit (noted as T_i) and three green arrows leading from a cone-shaped duct transition to a length of horizontal rectangular duct. Inside the rectangular duct section, three vertical white lines with a circle at the top and bottom of each line represent a steam coil which is joined at a header at the top of the steam coil, outside the rectangular duct. A white arrow leads to the header indicating 20 psig saturated steam supply at the steam coil inlet. The bottom of the steam coil has a steam trap (represented as a rectangle with a "T" and circle inside) for each of the three coil passes.

The steam traps schematically deliver condensate from the bottom to a header leading away from the ductwork with a white arrow. It is noted that 20 psig saturated liquid condensate enters the steam traps.

The airflow that is heated from the steam coil is represented by three red horizontal arrows and is at 120 degrees Fahrenheit (noted as T_c).

Slide 12 - Example Steam Demand 2

Very often flow meters are not in-place to allow direct evaluation of the end-use components. In order to determine the amount of energy currently used by the air handling unit some field measurements are required. A steam flow meter could be installed to measure the steam demand. Alternately a condensate flow meter could be installed or the condensate could be collected in a known volume over a measured time-period to determine the point-in-time condensate flow. Often it is relatively easy to use a flow measuring device like a Pitot tube or insertion anemometer type of device to measure the airflow rate through the system. If the airflow is known along with the temperature rise of the air through the heat exchanger, then the first law of thermodynamics can be applied to the airflow to calculate the energy required to be supplied from the steam. In this case approximately 850,000 BTU per hour of thermal energy must be supplied from the steam to the air. This translates into more than 900 pounds per hour of steam demand, which is a relatively small steam demand; however, the impact cost of steam supplied to end-use equipment at this site is approximately $15 per thousand pounds. As a result, this steam demand requires almost $120,000 per year of fuel purchases.

[Slide Visual – Steam Demand]

A fan represented by a circle/square combination supplies airflow at 10,000 standard cubic feet per min air at 40 degrees Fahrenheit (noted as T_i) and three green arrows leading from a cone-shaped duct transition to a length of horizontal rectangular duct. Inside the rectangular duct section, three vertical white lines with a circle at the top and bottom of each line represent a steam coil which is joined at a header at the top of the steam coil, outside the rectangular duct. A white arrow leads to the header indicating 20 psig saturated steam supply at the steam coil inlet. The bottom of the steam coil has a steam trap (represented as a rectangle with a "T" and circle inside) for each of the three coil passes.

The steam traps schematically deliver condensate from the bottom to a header leading away from the ductwork with a white arrow. It is noted that 20 psig saturated liquid condensate enters the steam traps.

The airflow that is heated from the steam coil is represented by three red horizontal arrows and is at 120 degrees Fahrenheit (noted as T_c).

[Slide Visual – Boiler Equations]

$Q_{air} = \text{m-dot}_{air}\,(C_p)_{air}\,(T_e\ - T_i)_{air}$

Energy is equal the to the mass flow rate of the air; multiplied by the specific heat capacity of air, multiplied by the difference in the Temperature existing the heat exchanger minus the Temperature entering the heat exchanger.

$Q_{air} = 10{,}000(\text{std ft}^3/\text{min})\ (0.074(\text{lbm/std ft}^3)\ (0.24\ \text{Btu/lbm-R})\ (120°F – 40°F)\ (60\ \text{min/1 hour})$

Energy is equal the to the 100,000 standard cubic feet per minute ; multiplied by the0.074 pounds per standard cubic feet; multiplied by 0.24 BTU per pound-Rankine; multiplied by the difference 120 degrees Fahrenheit minus 40 degrees Fahrenheit; multiplied by 60 minutes per hour)

Q_{air} = 854,200 Btu/hr

Energy is equal to 854,200 Btu per hour.

Where:

Q_{air} = Quantity of energy flow of air
$m\text{-}dot_{air}$ = Mass flow of the substance
C_p = Specific heat capacity of the substance
T_i = Temperature of air entering heat exchanger
T_e = Temperature of air exiting heat exchanger

Slide 13 - Example Steam Demand 3

An investigation of the end-use system indicated that warm air from the process was being exhausted directly to the atmosphere at more than 65 degrees Fahrenheit. This air can be reintroduced to the fan rather than introducing ambient air at 40 degrees Fahrenheit. Supplying 65 degrees Fahrenheit air to the heat exchanger will reduce the steam demand by approximately 250 pounds per hour, which translates into more than $34,000 per year of fuel savings. This is a very simple example but it demonstrates the significant impact steam end-use management can present.

[Slide Visual – Steam Demand]

A fan represented by a circle/square combination supplies airflow at 10,000 standard cubic feet per min air at 65 degrees Fahrenheit (noted as T_i) and three green arrows leading from a cone-shaped duct transition to a length of horizontal rectangular duct. Inside the rectangular duct section, three vertical white lines with a circle at the top and bottom of each line represent a steam coil which is joined at a header at the top of the steam coil, outside the rectangular duct. A white arrow leads to the header indicating 20 psig saturated steam supply at the steam coil inlet. The bottom of the steam coil has a steam trap (represented as a rectangle with a "T" and circle inside) for each of the three coil passes.

The steam traps schematically deliver condensate from the bottom to a header leading away from the ductwork with a white arrow. It is noted that 20 psig saturated liquid condensate enters the steam traps.

The airflow that is heated from the steam coil is represented by three red horizontal arrows and is at 120 degrees Fahrenheit (noted as T_c).

[Slide Visual – Boiler Equations]

$Q_{air} = m\text{-}dot_{air}\,(C_p)_{air}\,(T_e - T_i)_{air}$

Energy is equal the to the mass flow rate of the air; multiplied by the specific heat capacity of air, multiplied by the difference in the Temperature existing the heat exchanger minus the Temperature entering the heat exchanger.

Q_{air} = (10,000 std ft^3/min)(0.074 lbm/std ft^3) (0.24 Btu/lbmR) (120°F – 65°F) (60 min/1 hour)

Energy is equal the to the100,000 standard cubic feet per minute ; multiplied by the0.074 pounds per standard cubic feet; multiplied by 0.24 BTU per pound-Rankine; multiplied by the difference 120 degrees Fahrenheit minus 65 degrees Fahrenheit; multiplied by 60 minutes per hour)

Q_{air} = 587,300 Btu/hr

Energy is equal the to 587,300 Btu per hour.

- Steam demand reduces to 70% of original value.
  - Steam saving is 250 lbm/hr.
    - $34,000/yr.

Slide 14 - Combined Heat and Power Intro

[Slide Visual – Resource Utilization Effectiveness –Combined Heat and Power]

Banner:
DOE's BestPractices
Steam End User Training

Resource Utilization Effectiveness
Fuel Selection
Steam Demands
Combined Heat and Power

Combined heat and power, or cogeneration, is an extremely common aspect of industrial facilities. There are a large number of cogeneration facilities in the country. The avenue of cogeneration that we will briefly investigate is the most common form of cogeneration in the industrial arena. Typically, in the industrial arena, cogeneration takes the form of converting fuel energy into steam in a boiler, then utilizing a steam turbine to convert steam energy into electrical power or simply shaft power.

Slide 15 – Cogeneration

This strategy places the industrial cogeneration complex in competition with utility companies (the electrical generators). So, it is useful to explore the methods utilities use to generate electrical power to identify any advantages or disadvantages that may exist.

It is interesting to note that many people associate *cogeneration* with *gas turbines*. While gas turbines can serve in cogeneration systems, they are only one potential cogeneration arrangement. In fact, the majority of cogeneration systems consist of conventional boilers and steam turbines.

Overwhelmingly, utilities produce electricity through the generation of steam. Almost 80 percent of the electricity generated in the U.S. is generated by steam. Almost 60 percent of the electrical power is produced by burning a conventional fuel in a boiler to generate steam that is passed through a steam turbine connected to an electrical generator.

[Slide Visual – Combined Heat and Power - Cogeneration]

A red arrow depicts the fuel input to the High-Pressure and High-Temperature Boiler. Steam produced from the boiler is delivered to a steam turbine/generator, with the steam section depicted as a cone-shape figure. Steam schematically leaves the steam section of the turbine at the bottom. A thick white line to the right of the steam turbine leading to the rectangle shape of the generator, is the shaft. A red arrow leaves the generator section, indicating Electrical Power Export.

The steam schematically leaving the bottom of the steam turbine enters a heat exchanger depicted as a circle with a red zigzag arrow through it. Condensate leaves the heat exchanger at the bottom and a pump, depicted as a circle/square combination, returns the condensate to the top of the boiler.

- **Combined heat and power (cogeneration) activities almost always include an aspect of power generation.**
- **It may be beneficial to explore the most common method of power generation**

Slide 16 - Simplified Utility Power Station 1

More than 50 percent of the electrical power is produced by coal-fired boilers generating steam that is passed through turbines. Therefore, let's examine a typical coal-fired power plant.

[Slide Visual – Combined Heat and Power - Cogeneration]

A red arrow depicts the fuel input to the High-Pressure and High-Temperature Boiler. Steam produced from the boiler is delivered to a steam turbine/generator, with the steam section depicted as a cone-shape figure. Steam schematically leaves the steam section of the turbine at the bottom. A thick white line to the right of the steam turbine leading to the rectangle shape of the generator, is the shaft. A red arrow leaves the generator section, indicating Electrical Power Export.

The steam schematically leaving the bottom of the steam turbine enters a heat exchanger depicted as a circle with a red zigzag arrow through it. Condensate leaves the heat exchanger at the bottom and a pump, depicted as a circle/square combination, returns the condensate to the top of the boiler.

- **Approximately 50% of the electrical power produced in the United States is produced from *standard power stations burning coal.***

Slide 17 - Simplified Utility Power Station 2

We have already identified the fact that coal will burn in a boiler with excellent efficiency—especially if the boiler is well equipped with energy recovery components. A typical coal-fired utility boiler will operate with an efficiency near and even greater than 90 percent. The steam turbine used to convert thermal energy in the steam into shaft power will convert more than 85 percent of the maximum theoretical value. In other words, the power plant

turbine will be 85 percent of perfect. The generator that converts shaft power to electrical power will only lose 1 percent in the conversion process—an efficiency of 99 percent.

[Slide Visual – Combined Heat and Power - Cogeneration]

What would be the individual component efficiencies?

A red arrow depicts the fuel input to the High-Pressure and High-Temperature Boiler. Steam produced from the boiler is delivered to a steam turbine/generator, with the steam section depicted as a cone-shape figure. Steam schematically leaves the steam section of the turbine at the bottom. A thick white line to the right of the steam turbine leading to the rectangle shape of the generator, is the shaft. A red arrow leaves the generator section, indicating Electrical Power Export.

The steam schematically leaving the bottom of the steam turbine enters a heat exchanger depicted as a circle with a red zigzag arrow through it. Condensate leaves the heat exchanger at the bottom and a pump, depicted as a circle/square combination, returns the condensate to the top of the boiler.

Slide 18 - Simplified Utility Power Station 3

The fundamental question to pose to a typical power generation station is "how much fuel energy is converted into electrical energy?"

[Slide Visual – Combined Heat and Power - Cogeneration]

What would be the overall fuel to power conversion efficiency?

A red arrow depicts the fuel input to the High-Pressure and High-Temperature Boiler. Steam produced from the boiler is delivered to a steam turbine/generator, with the steam section depicted as a cone-shape figure. Steam schematically leaves the steam section of the turbine at the bottom. A thick white line to the right of the steam turbine leading to the rectangle shape of the generator, is the shaft. A red arrow leaves the generator section, indicating Electrical Power Export.

The steam schematically leaving the bottom of the steam turbine enters a heat exchanger depicted as a circle with a red zigzag arrow through it. Condensate leaves the heat exchanger at the bottom and a pump, depicted as a circle/square combination, returns the condensate to the top of the boiler.

Boiler is 90% efficient.

Turbine is 85% isentropic.

Generator is 99% efficient.

Slide 19 - Simplified Utility Power Station 4

Even with all of these superb efficiencies, well-designed components, and inherent advantages, the fuel-to-power conversion efficiency is less than 40 percent. The primary reason for this poor performance is the fact that even though the turbine is nearly perfect in converting thermal energy into shaft energy, a large amount of thermal energy is left in the steam that exits the turbine.

[Slide Visual – Combined Heat and Power - Cogeneration]

What would be the overall fuel to desired energy conversion efficiency?

A red arrow depicts the fuel input to the High-Pressure and High-Temperature Boiler. Steam produced from the boiler is delivered to a steam turbine/generator, with the steam section depicted as a cone-shape figure. Steam schematically leaves the steam section of the turbine at the bottom. A thick white line to the right of the steam turbine leading to the rectangle shape of the generator, is the shaft. A red arrow leaves the generator section, indicating Electrical Power Export.

The steam schematically leaving the bottom of the steam turbine enters a heat exchanger depicted as a circle with a red zigzag arrow through it. Condensate leaves the heat exchanger at the bottom and a pump, depicted as a circle/square combination, returns the condensate to the top of the boiler.

Boiler is 90% efficient.

Turbine is 85% isentropic.

Generator is 99% efficient.

Overall Efficiency is 35%. Modified cycles can attain 42%.

$n = \text{W-dot}_{electrical} / \text{E-dot}_{fuel}$

Efficiency is equal to the Fuel Output Energy divided by the Fuel Rate

Where:
n = Efficiency
$\text{W-dot}_{electrical}$ = Fuel Output Energy
$\text{E-dot}_{fuel =}$ = Fuel Energy Rate

Slide 20 - Simplified Utility Power Station 5

Steam turbines can be thought of as removing a portion of the thermal energy from the steam and converting that thermal energy into shaft energy. For almost all real turbines nearly all of the thermal energy removed from the steam is converted into shaft energy—the losses are almost zero. The problem develops from the fact that the turbine is not able to remove all of the thermal energy in the steam for the conversion to shaft power.

Restating—essentially 100 percent of the thermal energy extracted from the steam is converted to shaft power; however, not all of the thermal energy in the steam is extracted. In fact, for all turbines the majority of the thermal energy in the inlet steam remains in the exhaust steam.

The steam leaving most utility steam turbines will have a temperature that is less than 100 Fahrenheit and a pressure that is near a perfect vacuum. Even though the steam temperature is very low there remains a tremendous amount of energy in the steam. The power plant does not have a need for this low temperature thermal energy. As a result, the thermal energy is rejected to the ambient, serving no useful purpose other than to condense the steam—the exhaust steam energy is rejected to the environment unused. As a result, a typical power plant may convert only 38 percent of the fuel energy into electrical power.

[Slide Visual – Combined Heat and Power - Cogeneration]

A red arrow depicts the fuel input to the High-Pressure and High-Temperature Boiler. Steam produced from the boiler is delivered to a steam turbine/generator, with the steam section depicted as a cone-shape figure. Steam schematically leaves the steam section of the turbine at the bottom. A thick white line to the right of the steam turbine leading to the rectangle shape of the generator, is the shaft. A red arrow leaves the generator section, indicating Electrical Power Export.

The steam schematically leaving the bottom of the steam turbine enters a heat exchanger depicted as a circle with a red zigzag arrow through it. Condensate leaves the heat exchanger at the bottom and a pump, depicted as a circle/square combination, returns the condensate to the top of the boiler.

Boiler is 90% efficient.

Turbine is 85% isentropic.

Generator is 99% efficient.

Overall Efficiency is 35%. Modified cycles can attain 42%.

$n = \text{W-dot}_{electrical} / \text{E-dot}_{fuel}$

Efficiency is equal to the Fuel Output Energy divided by the Fuel Rate

Why is the efficiency this low?

Slide 21 - Simplified Utility Power Station 6

The steam discharged from the turbine is relatively low temperature and very low pressure but it contains a huge amount of thermal energy—approximately 50 percent of the fuel input energy. We do not have any mechanism that can convert this low-grade thermal energy into shaft power; as a result, we condense the steam to allow condensate to be pumped to high-pressure as return water from the boiler. A typical utility power plant will discharge 50 percent of the fuel energy to the condenser. The boiler stack loss will be nominally 10 percent of the fuel energy, leaving 40 percent of the fuel energy to be converted into electricity.

The condenser is a large heat exchanger often cooled with river water, which is one of the primary reasons power plants are typically located on rivers. Our result is an overall efficiency of 35 percent.

[Slide Visual – Simple Utility Power Station]

A red arrow depicts the fuel input to the High-Pressure and High-Temperature Boiler. A note indicates the boiler is 90% efficient. Steam produced from the boiler is delivered to a steam turbine/generator, with the steam section depicted as a cone-shape figure. Steam schematically leaves the steam section of the turbine at the bottom. A thick white line to the right of the steam turbine leading to the rectangle shape of the generator, is the shaft. A red arrow leaves the generator section, indicating Electrical Power Export. Notes indicate the turbine is 85% efficient and the generator is 99% efficient.

The steam schematically leaving the bottom of the steam turbine enters a heat exchanger depicted as a circle with a red zigzag arrow through it. Condensate leaves the heat exchanger at the bottom and a pump, depicted as a circle/square combination, returns the condensate to the top of the boiler.

Boiler is 90% efficient.

Turbine is 85% isentropic.

Generator is 99% efficient.

10% of the Fuel Energy is shown as an arrow from the boiler.

50% of the Fuel Energy is show leaving the heat exchanger

Overall Efficiency is 35%. Modified cycles can attain 42%.

$n = \text{W-dot}_{electrical} / \text{E-dot}_{fuel}$

Efficiency is equal to the Fuel Output Energy divided by the Fuel Rate

<u>Slide 22 - Industrial Power Station 1</u>

In order for an industrial facility to participate in combined heat and power activities there must be some advantage that can be exploited. Are the performance characteristics of the individual power plant components dramatically better than a typical utilities power plant?

[Slide Visual – Combined Heat and Power - Cogeneration]

A red arrow depicts the fuel input to the High-Pressure and High-Temperature Boiler. Steam produced from the boiler is delivered to a steam turbine/generator, with the steam section depicted as a cone-shape figure. Steam schematically leaves the steam section of the turbine at the

bottom. A thick white line to the right of the steam turbine leading to the rectangle shape of the generator, is the shaft. A red arrow leaves the generator section, indicating Electrical Power Export.

The steam schematically leaving the bottom of the steam turbine enters a heat exchanger depicted as a circle with a red zigzag arrow through it. Condensate leaves the heat exchanger at the bottom and a pump, depicted as a circle/square combination, returns the condensate to the top of the boiler.

What would be the component efficiencies of a typical industrial facility?

Slide 23 - Industrial Power Station 2

Most industrial plants will not have equipment that is as efficient as the utility power stations. In many cases industrial boilers will not be equipped with some of the energy recovery and combustion management components the utilities boiler will be equipped with. Very often industrial sites will be burning fuels resulting in lower efficiency than coal—and usually the fuel cost is much higher than coal. The turbines and generators of the industrial site will generally not be as efficient as the power plant components. As a result, industrial plant cogeneration appears to be a poor proposition. However, the great advantage industrial facilities have over utility power stations is that the industrial plant has a need for thermal energy as well as shaft power. The industrial plant can make use of the thermal energy in the steam discharged from the turbine.

[Slide Visual – Combined Heat and Power - Cogeneration]

A red arrow depicts the fuel input to the High-Pressure and High-Temperature Boiler. Steam produced from the boiler is delivered to a steam turbine/generator, with the steam section depicted as a cone-shape figure. Steam schematically leaves the steam section of the turbine at the bottom. A thick white line to the right of the steam turbine leading to the rectangle shape of the generator, is the shaft. A red arrow leaves the generator section, indicating Electrical Power Export.

The steam schematically leaving the bottom of the steam turbine enters a heat exchanger depicted as a circle with a red zigzag arrow through it. Condensate leaves the heat exchanger at the bottom and a pump, depicted as a circle/square combination, returns the condensate to the top of the boiler.

Turbine is 70% isentropic.

Generator is 95% efficient.

Boiler is 85% efficient.

What would be the component efficiencies of a typical industrial facility?

What would be the overall "energy" conversion efficiency?

Slide 24 - Industrial Power Station 3

In fact, industrial plants will operate turbines with elevated discharge pressure that allows a significant amount of thermal energy to be exported to the process units. This provides industrial plants with a distinct advantage that allows cogeneration systems to be very competitive. Industrial plants can enjoy energy conversion efficiencies approaching 70 percent--which is a dramatic improvement over utility power stations operating at 40 percent efficiency.

[Slide Visual – Combined Heat and Power - Cogeneration]

A red arrow depicts the fuel input to the High-Pressure and High-Temperature Boiler. Steam produced from the boiler is delivered to a steam turbine/generator, with the steam section depicted as a cone-shape figure. Steam schematically leaves the steam section of the turbine at the bottom. A thick white line to the right of the steam turbine leading to the rectangle shape of the generator, is the shaft. A red arrow leaves the generator section, indicating Electrical Power Export.

The steam schematically leaving the bottom of the steam turbine enters a heat exchanger depicted as a circle with a red zigzag arrow through it. Condensate leaves the heat exchanger at the bottom and a pump, depicted as a circle/square combination, returns the condensate to the top of the boiler.

Turbine is 70% isentropic.

Generator is 95% efficient.

Boiler is 85% efficient.

Lower efficiency components can be utilized at industrial facilities and the "overall efficiency" can approach 70%, because industrial facilities have a need for thermal energy.

Slide 25 - District Heating Utility Power Station

It is good to note that utility power stations located within cities can take significant advantage of this same concept by exhausting steam from their power generation turbines to provide building heat. These are identified as *district heating systems*.

[Slide Visual – Combined Heat and Power - Cogeneration]

A red arrow depicts the fuel input to the High-Pressure and High-Temperature Boiler. Steam produced from the boiler is delivered to a steam turbine/generator, with the steam section depicted as a cone-shape figure. Steam schematically leaves the steam section of the turbine at the bottom. A thick white line to the right of the steam turbine leading to the rectangle shape of the generator, is the shaft. A red arrow leaves the generator section, indicating Electrical Power Export.

The steam schematically leaving the bottom of the steam turbine enters a heat exchanger depicted as a circle with a red zigzag arrow through it. Condensate leaves the heat exchanger at the bottom and a pump, depicted as a circle/square combination, returns the condensate to the top of the boiler.

Turbine is 80% efficient.

Generator is 98% efficient.

Boiler is 90% efficient.

- **Utility stations incorporating district heating uses of thermal energy operate with excellent efficiency.**
  - **Approaching 70%.**

Slide 26 - Steam Turbines 1

A general understanding of steam turbine operation is required to examine boiler-steam turbine cogeneration systems. Steam turbines take thermal energy from the steam and convert it into mechanical energy.

Typically, 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.

[Slide Visual – Steam Turbines]

The schematic shows a single stage backpressure steam turbine.

It receives high-pressure steam and exhausts low-pressure steam through the power of the shaft.

Slide 27 - Steam Turbines 2

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.

Steam turbines receive high-pressure steam and discharge low-pressure steam. The inlet steam is passed through a flow control valve and on to the stationary nozzles. The nozzles increase the velocity of the steam and channel it in the proper direction to strike the rotating turbine blades. The steam presents a force on the blade as the blade catches and turns the steam. Because the blade is mounted to a shaft that is free to rotate, the force results in the rotation of the shaft. Many blades are mounted on a single wheel that is in-turn mounted to the shaft. The nozzle, blade, and shaft arrangement is such that as a blade moves out of the jet of steam leaving a nozzle, another blade moves into the jet.

A turbine can be designed with a single wheel of blades or multiple wheels on the same shaft. A single nozzle can direct 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 will 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. This nozzle-blade, nozzle-blade arrangement continues until the steam exits the turbine casing.

[Slide Visual – Steam Turbines]

The schematic shows a single stage backpressure steam turbine.

It receives high-pressure steam and exhausts low-pressure steam through the power of the shaft.

Slide 28 - Steam Turbine Types

All steam turbines receive high-pressure steam and discharge low-pressure steam. Steam turbines use stationary nozzles and rotating blades to convert thermal energy into mechanical energy. There are several descriptors that identify some of the main characteristics of turbines.

[Slide Visual – Steam Turbine Types]

- **Topping turbine (backpressure)**
- **Extraction turbine**
- **Straight condensing turbine**
- **Extraction condensing turbine**
- **Multiple extraction**

Slide 29 - Backpressure Steam Turbines

A topping turbine exhausts steam with a pressure that is above atmospheric pressure. Topping turbines are also known as backpressure turbines and non-condensing turbines.

[Slide Visual – Backpressure Steam Turbines]

The schematic shows a single stage backpressure steam turbine and a multistage turbine.

The single stage has a stop valve, over-speed trip valve, and a hand valve. Steam enters through the stop valve, and the power of the shaft causes it to output steam through one stage.

The multistage has the same components, except the steam travels through several stages before it is output.

Slide 30 - Extraction Steam Turbines

An extraction turbine is simply a turbine with more than one outlet. Think of a multi-stage turbine with the low-pressure steam outlet after the last set of nozzles-and-blades. Then consider placing another outlet in the turbine casing that is between two sets of nozzles-and-blades. Recall, as steam passes

through a set of nozzles-and-blades pressure drops. As a result, this outlet that is between the nozzles-and-blades will be able to discharge steam with an intermediate pressure. Steam can be pulled-out (extracted) from the turbine before the final turbine outlet.

Extraction turbines can also be thought of as two turbines on the same shaft.

If a turbine has more than one intermediate outlet it is known as a multiple-extraction turbine.

[Slide Visual – Backpressure Steam Turbines]

The schematic shows a single stage backpressure steam turbine and a multistage turbine.

The single stage has a stop valve, over-speed trip valve, and a hand valve. Steam enters through the stop valve, and the power of the shaft causes it to output steam through one stage.

Slide 31 - Condensing Steam Turbines

A *condensing turbine* also exhausts steam, but it does so with a pressure below atmospheric pressure. Because the steam pressure is below atmospheric pressure, it must be condensed to be pumped out of the turbine. As you know, steam flows from high-pressure to low-pressure—when the steam pressure is below atmospheric pressure there is no motive force to cause the steam to flow out of the turbine. As a result, the steam is condensed and pumped. Very often the thermal energy in the steam exiting a condensing turbine is rejected to the environment and no useful benefit is gained. The thermodynamic quality of the steam exiting a condensing steam turbine is typically greater than 90 percent and is sometimes superheated. An extraction-condensing turbine is a turbine with one discharge at an intermediate steam pressure and another discharge below atmospheric pressure. This type of turbine is designed to balance steam demands with power demands.

[Slide Visual – Condensing Steam Turbines]

The schematic shows a steam turbine, condensing steam before it is exhausted out of the boiler.

Slide 32 - First Law of Thermodynamics

When the first law of thermodynamics is applied to steam turbines, a simple relationship develops—the thermal energy extracted from the steam is converted into shaft power. The development presented here is for steady state, steady flow conditions. The thermal energy extracted from the steam is identified as the change in enthalpy of the steam as it passes through the turbine.

Steam turbines are excellent at converting thermal energy into shaft energy. Most steam turbines only experience minor losses, which include steam leakage through the shaft seals, heat transfer loss from the turbine surface, and bearing friction. These losses typically amount to less than 5 percent of the thermal energy that is removed from the inlet steam—very often, this loss is less than 2 percent of the thermal energy.

[Slide Visual –First Law of Thermodynamics for Turbines]

W_{shaft} = m-dot$_{steam}$ $(h_i – h_e)_{steam}$

W_{shaft} equals Steam Output from the Shaft equals mass flow rate of the steam; multiplied by the difference of enthalpy of the steam at turbine inlet and the enthalpy of the steam at the turbine exit.

Where:
W_{shaft} = Shaft Energy Output
m-dot$_{steam}$ = Mass flow rate of the steam
h_i = Enthalpy of the steam at the inlet of the turbine
h_e = Enthalpy of the steam at the exit of the turbine

<u>Slide 33 - Turbine First Law Efficiency</u>

Recall, one of the most important investigation tools used in boiler investigations is boiler efficiency. Boiler efficiency investigations are based on an energy balance focused on the boiler. Typically, a significant amount of useful information is not obtained when an energy balance investigation is focused on a steam turbine. This is the result because steam turbine energy losses are most commonly minimal.

[Slide Visual – Turbine First Law Efficiency]

$n_{first\ law} = W_{shaft}$ /{m-dot$_{steam}$ $(h_i – h_e)$} ~ 100%

First Law Efficiency equals Steam Output from the Shaft; divided by the mass flow rate of the steam; multiplied by the difference of enthalpy of the steam at turbine inlet and the enthalpy of the steam at the turbine exit; approximately equal to 100%

Where:
$n_{fiirst\ law}$ = First Law Efficiency
W_{shaft} = Shaft Energy Output
m-dot$_{steam}$ = Mass flow rate of the steam
h_i = Enthalpy of the steam at the inlet of the turbine
h_e = Enthalpy of the steam at the exit of the turbine

Even though these losses are minor, a comparison of the performance characteristics of steam turbines indicates a wide range of conditions. For example, two turbines operating in the same steam system, between the same steam pressures, and with the same steam flow rate, can demonstrate that one unit will produce three times the power of the other unit. As a result, a different basis must be used to evaluate turbines.

<u>**Slide 34 - Perfect Turbine**</u>

For turbines, a more useful comparison is to compare the "real" turbine to a "perfect" turbine. As you know, the first and second laws of thermodynamics are the foundational principles of all physics. The first law of thermodynamics stated simply is "mass-and-energy is neither created nor destroyed—it can only change forms". The second law of thermodynamics is often thought to be more difficult to understand, but it can be thought of as an energy conversion limit. The second law of thermodynamics indicates that processes (real or theoretical) can convert power totally into heat; however, heat cannot be converted totally into power.

Consider a standard automobile. Power is generated in the engine and is converted into motion—the velocity of the car. The power of the engine is fully and totally converted into heat when the car stops at a stoplight as the brakes are applied and the brake rotors heat. However, no process, real or theoretical, could convert the heat in the brake rotors back into the same amount of power originally produced by the engine. But, the second law of thermodynamics can identify the maximum amount of power that can be produced from a heat source.

In other words, we can use the second law of thermodynamics to identify the theoretical maximum amount of power that could be produced by a perfect turbine from a known amount of steam energy. Our real turbine can then be compared to this theoretical perfect turbine.

When the first and second laws of thermodynamics are combined in the evaluation of a steam turbine, the concept of a perfect turbine is defined. The laws of physics dictate that a perfect turbine will convert the maximum amount of thermal energy into shaft energy. As a result, we can measure the power output of our real turbine and compare that measured amount to the theoretical maximum amount of output power possible. This evaluation technique will identify how close to perfect our real turbine is.

When the second law of thermodynamics is applied to a turbine, it identifies that the steam passing through a perfect turbine would experience no change in *entropy*. *Entropy* is a thermodynamic property of steam similar to enthalpy. Entropy and enthalpy properties are obtained from measurements and thermo-physical property data sets (like steam tables). Constant entropy is identified with the term *isentropic*. We use the concept of the perfect turbine and the fact that a perfect turbine would operate isentropically, to establish the efficiency evaluation methodology for a turbine. Turbine efficiency is also called isentropic efficiency.

[Slide Visual – Backpressure Steam Turbines]

The schematic shows a single stage backpressure steam turbine and a multistage turbine.

The single stage has a stop valve, over-speed trip valve, and a hand valve. Steam enters through the stop valve, and the power of the shaft causes it to output steam through one stage.

<u>**Slide 35 - Isentropic Efficiency**</u>

Isentropic efficiency is the actual power produced from a real turbine compared to the power that would be produced from a perfect turbine. The first law of thermodynamics indicates the power produced from a turbine is the steam flow rate multiplied by the change in enthalpy of the steam passing through the turbine.

For a large number of turbines, only four measurements are needed to establish isentropic efficiency: the pressure and temperature of the steam entering the real turbine, and the pressure and temperature of the steam exiting the real turbine. These four measurements are often easily obtained and the instrumentation is neither expensive nor elaborate. Steam property data is obtained based on the inlet and exit steam measurements.

[Slide Visual – Isentropic Efficiency]

$n_{isentropic}$ = Actual Work / Isentropic Work = $W_{actual} / W_{isentropic}$

The isentropic efficiency is equal to the Actual Work divided by the Isentropic Work of the Turbine.

$n_{isentropic} = \{\text{m-dot}_{steam}\,(h_{inlet} - h_{exit})\}_{actual} \,/\, \{\text{m-dot}_{steam}\,(h_{inlet} - h_{exit})\}_{isentropic} = (h_i - h_e)_{actual} / (h_i - h_e)_{isentropic}$

Isentropic Efficiency equals the mass flow rate of the steam; multiplied by the difference of enthalpy of the steam at turbine inlet and the enthalpy of the steam at the turbine exit under actual conditions; divided by the mass flow rate of the steam; multiplied by the difference of enthalpy of the steam at turbine inlet and the enthalpy of the steam at the turbine exit under isentropic conditions.

Slide 36 - Steam Turbine Efficiency

[Slide Visual – Backpressure Steam Turbines]

The schematic shows a single stage backpressure steam turbine and a multistage turbine.

The single stage has a stop valve, over-speed trip valve, and a hand valve. Steam enters through the stop valve, and the power of the shaft causes it to output steam through one stage.

It should be understood that a steam turbine with low efficiency is not the same as a boiler with low efficiency. A boiler with low efficiency indicates a large amount of fuel energy is lost (unrecoverable). A steam turbine with low isentropic efficiency merely indicates that most of the thermal energy originally in the steam has remained in the steam that is exhausted from the turbine. If the steam thermal energy is used then the fuel energy is not lost.

Slide 37 - Typical Steam Turbine Efficiency

The isentropic efficiency of a typical steam turbine can be lower than 15 percent and higher than 85 percent. This is a very broad range. The efficiency can be a result of the base design characteristics of the steam turbine, the control mechanism and loading, or failed components. Isentropic efficiency is a critical tool used to evaluate cogeneration steam systems.

[Slide Visual – Typical Steam Turbine Efficiency]

$n_{isentropic} = (h_{in} - h_{out})_{actual} / (h_{in} - h_{out})_{isentropic} = 15\%$ to 85%

Isentropic Efficiency equals the difference of enthalpy of the steam at turbine inlet and the enthalpy of the steam at the turbine exit under actual conditions; divided by the difference of enthalpy of the steam at turbine inlet and the enthalpy of the steam at the turbine exit under isentropic conditions; equal to 15% to 85%.

Slide 38 - Steam Turbines

Typically, a single-stage steam turbine will have lower efficiency than a comparable multi-stage turbine; however, there are exceptions to this. Generally, single-stage turbines are used for situations with lower power output—generally less than 1,000 kilowatts. Usually, their isentropic efficiency will not exceed 45 percent. Isentropic efficiency of multi-stage turbines can approach 90 percent.

[Slide Visual – Backpressure Steam Turbines]

The schematic shows a single stage backpressure steam turbine and a multistage turbine.

The single stage has a stop valve, over-speed trip valve, and a hand valve. Steam enters through the stop valve, and the power of the shaft causes it to output steam through one stage.

The multistage has the same components, except the steam travels through several stages before it is output.

Slide 39 - Backpressure Turbine Performance

Steam turbines operate with minimal losses. As a result, as long as the steam thermal energy exiting the backpressure turbine is being used for a good purpose, then shaft power is generated basically at the cost of fuel divided by boiler efficiency. This is a very important fact indicating the reason turbines are so widely used—turbines can be very cost effective.

The table indicates the general economic impact associated with operating a backpressure turbine with various fuel costs. For example, if fuel cost is 2 dollars per million BTU, a backpressure turbine will generate power with an impact cost of 8 dollars and 50 cents per megawatt-hour. If our purchased electricity is 50 dollars per megawatt-hour, then considerable savings is achieved by operating the turbine. As the table indicates, backpressure steam turbines can provide economically attractive operation over a wide range of site conditions.

[Slide Visual – Backpressure Turbine Performance]

Fuel Cost [$/$10^6$Btu]	Boiler Efficiency [%]	Backpressure Turbine Power Impact ($/MWH)
2.00	80.00	8.5
4.00	80.00	17.1
6.00	80.00	25.6
8.00	80.00	34.1
10.00	80.00	42.7
12.00	80.00	51.2
14.00	80.00	59.7
16.00	80.00	68.3
18.00	80.00	76.8

Slide 40 - Backpressure Turbine Economics

A classic question concerning steam turbines is, "What is the economic benefit of passing steam through a turbine to a low-pressure demand, as compared to passing steam through a pressure-reducing valve? "

We will briefly explore the primary points of the focus of this question.

[Slide Visual – Backpressure Turbine Economics]

A red arrow depicts the fuel input to the High-Pressure and High-Temperature Boiler. Steam produced from the boiler is delivered to a steam turbine/generator, with the steam section depicted as a cone-shape figure. Steam schematically leaves the steam section of the turbine at the bottom. A thick white line to the right of the steam turbine leading to the rectangle shape of the generator, is the shaft. A red arrow leaves the generator section, indicating Electrical Power Export.

The steam schematically leaving the bottom of the steam turbine enters a heat exchanger depicted as a circle with a red zigzag arrow through it. Condensate leaves the heat exchanger at the bottom and a pump, depicted as a circle/square combination, returns the condensate to the top of the boiler.

Slide 41 - Primary Factors

The 2 dominant parameters in deciding the answer to this question are impact electrical cost and impact fuel cost. Steam turbine isentropic efficiency, boiler efficiency, and steam demand are factors of concern—but energy costs are the dominant factors.

[Slide Visual – Primary Factors]

The primary factors impacting the analysis are:

- **Impact electrical cost**
- **Impact fuel cost**
- **Boiler efficiency**
- **Steam turbine efficiency**
- **Steam demand**

Slide 42 - Impact Costs

It is critical to properly establish the fuel and electrical impact costs because all other factors are secondary. We are using the term impact costs because in evaluating the operation of a steam turbine, it is generally not important to base the analysis on average fuel and electric costs. It is much more important to establish what fuel will be impacted and what costs will be incurred if fuel consumption increases or decreases. Similarly, a clear understanding of the electrical cost impacts must be developed.

For example, consider our example site. The average or blended fuel cost is approximately 5.5 dollars per million BTU. The table presented previously indicates a backpressure turbine operating with this fuel cost can compete with electricity purchased with a cost of about $25 per megawatt-hour. However, turning on the turbine will require additional fuel to be consumed in the boiler. Our system will probably increase steam production from the natural gas fired boiler. As a result, the backpressure turbine will only be competitive if the impact electrical cost is greater than 43 dollars per megawatt-hour.

[Slide Visual – Impact Costs]

$5.50/MMBtu is the average or blended rate of the three boiler fuels.
$10.00/MMBtu is the cost of natural gas and equivalent to $43/MWh.
Electrical Rate must be greater than $43/MWh for the turbine generation to be economical.

Slide 43 - Example Turbine-PRV Evaluation

We are going to explore the question of the economics associated with a backpressure steam turbine in our example system. We will assume we have a backpressure turbine installed on an electric generator and a pressure-reducing valve that operates in parallel with the turbine steam path. The turbine is a relatively small capacity single-stage unit with an isentropic efficiency of 32 percent. This isentropic efficiency is relatively low, but it is reflective of many steam turbines in operation.

Slide 44 - Turbine-PRV Economics

Our boiler is producing 400 PSIG superheated steam. Natural gas is the impact fuel with a cost of 10 dollars per million BTU. The steam load requires thermal energy from the 20 PSIG steam system. The electrical impact cost has been identified as $70 per megawatt-hour. An excellent way to investigate this question is to complete a side-by-side comparison of the two operating conditions. In other words, develop a representation of the operating characteristics of the system with the steam load supplied through the pressure-reducing valve and then develop a representation of the operating characteristics with the steam load supplied through the turbine. These two representations can then be compared and the change in fuel purchases and electrical purchases can be identified.

> ***[Slide Visual –Turbine-PRV Economics]***
>
> **A red arrow depicts the fuel input at $10 per million Btu to the boiler with an efficiency of 84%. Steam produced at 400 psig and 700 degrees Fahrenheit leaves the boiler and is delivered to a steam header.**
>
> **The steam header include a branch to a control valve, depicted as an hour-glass figure with a dome to the left with a control signal from the dome to the exit of the valve and to a steam turbine, as depicted by a cone-shape and rectangle combination.**
>
> **Steam passes through the steam valve and joins the discharge from the steam turbine.**
>
> **Steam leaves the boiler header and enters a steam turbine/generator, with the steam section depicted as a cone-shape figure. Steam schematically leaves the steam section of the turbine at the bottom. A thick white line to the right of the steam turbine leading to the rectangle shape of the generator, is the shaft. A red arrow leaves the generator section, indicating purchased electricity at $70 per megawatt-hour.**
>
> **Turbine isentropic efficiency is 32%.**
>
> **The steam schematically leaving the bottom of the steam turbine enters a heat exchanger depicted as a circle with a red zigzag arrow through it. The Thermal demand is nominally 30,000 lbm/hr of 20 psig steam (35.5 million Btu/hr) of load.**
>
> **Condensate schematically leaves the heat exchanger at the bottom and a pump, depicted as a circle/square combination, returns the condensate to the top of the boiler. Saturated liquid condensate is discharged from the load (heat exchanger) at 0 psig.**
>
> **The boiler's operating period is 8,760 hr/yr.**

Slide 45 - Side-by-Side Comparison 1

Initially, we will pass steam through the pressure-reducing valve to the steam demand that requires 35.5 million BTU per hour of thermal energy. This translates into 30,000 pounds per hour of steam load on the boiler. It is interesting to note that 400 PSIG steam enters the pressure-reducing valve with a temperature of 700 degrees Fahrenheit. This steam exits the pressure-reducing valve with a pressure of 20 PSIG and a temperature of 659 degrees Fahrenheit. This change in temperature results from the pressure change alone—no energy has been lost.

[Slide Visual –Side by Side comparison]

A red arrow depicts the fuel input to the High-Pressure and High-Temperature Boiler. Steam produced from the boiler at 400 psig and 700 degrees Fahrenheit is delivered to a pressure-reducing valve, and is discharged at 659 degrees Fahrenheit isenthalpic. Steam enters the heat exchanger/generator for Thermal demand nominally 30,000 lbm/hr of 20 psig steam (35.5 million Btu/hr). A red arrow leaves the generator section, indicating Electrical Power Export.

Condensate leaves the heat exchanger at the bottom and a pump, depicted as a circle/square combination, returns the condensate to the top of the boiler.

Fuel is $10.00 per million Btu

Slide 46 - Side-by-Side Comparison 2

Next, we turn on the turbine and allow the steam to pass through it to the steam load. The turbine takes some thermal energy out of the steam and converts it into shaft energy. As a result, the steam exits the turbine approximately 160 degrees colder than when it passed through the pressure reducing station. In order to satisfy the thermal demand, we must send a larger mass flow of steam to the end-user—the steam demand requires the same thermal energy no matter how the steam gets to it.

[Slide Visual –Side by Side comparison 2]

A red arrow depicts the fuel input to the High-Pressure and High-Temperature Boiler. Steam produced from the boiler at 400 psig and 700 degrees Fahrenheit is delivered to a steam turbine/generator, with the steam section depicted as a cone-shape figure. Steam schematically leaves the steam section of the turbine at the bottom. A thick white line to the right of the steam turbine leading to the rectangle shape of the generator, is the shaft. A red arrow leaves the generator section, indicating Electrical Power Export as Power Production. Turbine isentropic efficiency is 32%.

The steam schematically leaving the bottom of the steam turbine at 505 degrees Fahrenheit enters a heat exchanger depicted as a rectangle with a red zigzag arrow through it. Thermal demand is 20 psig. Condensate leaves the heat exchanger at the bottom and a pump, depicted as a circle/square combination, returns the condensate to the top of the boiler.

Fuel is $10 per million Btu.

Purchased Electricity is $70 per Megawatt-hour.

Slide 47 - SSAT Project Data

You can imagine that the calculations required to complete these investigations can be cumbersome and lengthy. SSAT, the steam system modeling software, is setup to complete exactly these calculations.

[Slide Visual –SSAT Project 7]

- **Modify the existing system to include a backpressure steam turbine.**
  - **The turbine will supply the original 30,000 lbm/hr thermal demand.**

Project 7 - HP to LP Steam Turbine(s)			
Not installed			
Do you wish to modify the HP to LP turbine operation?			**Yes, install a new turbine**
If yes, select the appropriate turbine operating mode			**Option 2 - Fixed operation**
Note: If Option 1 is chosen, the model will preferentially use the HP to LP turbine to balance the LP demand			
Specify a new isentropic efficiency (%)	**32**	**%**	
Note: A generator electrical efficiency of 100% is assumed by the model			
Option 2 – How do you wish to define the fixed turbine operation?			**Specify fixed steam flow**
Option 2 – Fixed Steam Flow	**32**	**klb/h**	
Option 2 – Fixed Power generation	**2000**	**kW**	
Option 3 – How do you wish to define the operating range?			**Option 3 – not selected**
Option 3 – Minimum steam flow	**50**	**klb/h**	
Option 3 – Maximum steam flow	**150**	**klb/h**	
Option 3 – Minimum power generation	**1500**	**kW**	

Option 3 – Maximum power generation	2599	kW	

Slide 48 - Initial Conditions (PRV Control)

SSAT is easily modified to incorporate the components of this example. SSAT allows us to build a model of a steam system that includes the high-pressure impact boiler, the low pressure steam demand, the pressure reducing valve, and the steam turbine.

SSAT completes a side-by-side comparison of the steam system operating with the pressure reducing valve in service, as is presented here, and with the steam turbine in operation….

[Slide Visual – Model Tab Schematic]

The top center will contain the descriptive title provided by the user, the initial template reads "SSAT Default 3 Header Model" or a similar title for whatever model you chose. Below it, you will see the Model Status, which should read "OK." The model status provides an indication of the calculation condition of the model.

To the left of the Model Status, you will see a chart in light blue, which indicates the emissions per year for carbon dioxide, sulfur oxide, and nitrogen oxide.

At the top right, it will say "Current Operation" if you are on the Model tab, or "Operation After Projects" if you are on the Projects Model tab.

The red graphic near the top left represents the boiler. From the left, there is a dotted line entering it, which represents the amount of feedwater entering the boiler from the deaerator.

Also to the left of the boiler, we see the following information highlighted in orange: the type of fuel being used in the boiler, the fuel input energy, the fuel flow rate, and the boiler efficiency.

To the right of the boiler, we see a dotted line pointing to the right and then down, with a number next to it, indicating the amount of boiler blowdown.

Below the boiler, we see the amount of steam that is entering the high-pressure header, the temperature of it, and the thermodynamic quality of the steam.

The steam exits the boiler and enters the high-pressure header, represented by a dark blue line. Under the line, to the far left, you will see a light-blue triangular graphic that represents a pressure-reducing station. The pressure reducing station is also equipped with a desuperheating station. The number at the top indicates the amount of steam entering the pressure reducing valve. The number at the center-left of the valve indicates the amount of desuperheating water entering the unit. The number below indicates the amount of desuperheated steam entering the medium-pressure header; as well as the temperature of the steam.

To the right of the pressure-reducing station, you will see light blue, cone-shaped graphics, that represent the steam turbines. The one nearest to the left is a high-pressure to condensing turbine. This turbine discharges to the condenser represented by the blue circle below the turbine. The turbine exhaust pressure is noted as the condenser pressure. The turbine in the middle receives high-pressure steam and exhausts low-pressure steam. The one to the right receives high-pressure steam and exhausts medium-pressure steam. Above each turbine is an indication of the amount of steam coming into the turbine from the header. To the right, in dark blue, you see the power generation of the turbine.

In the center of the medium-pressure and low-pressure headers, we see an arrow pointing downward, which indicates the amount of flash entering the header from the condensate collection flash vessels that are located at the far-right of the schematic.

Above the header, to the right, the amount of heat loss is expressed in orange. Below, there is a yellow box that indicates the pressure, temperature, and thermodynamic quality of the steam.

The arrow to the right of the header points to a dark blue circle with a line through it, indicating the steam end-use components. Below this symbol is an indication of the thermal energy supplied to the end-use components from the steam. The end-use components discharge condensate through a steam trap, represented by a blue circle with a "T" in it. Schematically, condensate passes to the right through the trap. Failed steam traps that are blowing steam to the atmosphere are represented with the red arrow exiting the top of the trap symbol. The condensate appropriately passing through traps, again represented as exiting to the right of the trap, can be recovered or lost. Lost condensate is represented as the unrecovered condensate discharging down from the traps and recovered condensate enters the condensate collection system further to the right.

The green figures to the far-right of the schematic represent condensate flash-vessels. The top flash-vessel receives condensate from the high-pressure end-users. Flash-steam is formed because the flash vessel operates at medium-pressure but it receives saturated liquid condensate at high-pressure. As equilibrium is reached flash-steam is formed. This flash-steam exits the vessel through the top and is directed to the medium-pressure steam header, which is shown in the center of the diagram. Condensate exits the flash vessel and enters the medium-pressure condensate collection system. The medium-pressure condensate system is equipped with similar equipment as the high-pressure system.

All of the collected condensate enters the main condensate receiver located in the lower-center of the schematic. Process condensate is mixed with turbine condensate and makeup water prior to entering the deaerator.

The steam system deaerator is represented at the lower-left of the schematic. The deaerator receives low-pressure steam to preheat the collected condensate and makeup water represented as entering from the bottom of the vessel. Boiler feedwater discharges from the deaerator to the left and up to the boiler. The line pointing out from the top of the deaerator and leading to the right shows the amount of steam escaping from the vent.

Slide 49 - Adjusted Conditions – Turbine Operation

—as is presented here.

[Slide Visual – Model Tab Schematic]

The top center will contain the descriptive title provided by the user, the initial template reads "SSAT Default 3 Header Model" or a similar title for whatever model you chose. Below it, you will see the Model Status, which should read "OK." The model status provides an indication of the calculation condition of the model.

To the left of the Model Status, you will see a chart in light blue, which indicates the emissions per year for carbon dioxide, sulfur oxide, and nitrogen oxide.

At the top right, it will say "Current Operation" if you are on the Model tab, or "Operation After Projects" if you are on the Projects Model tab.

The red graphic near the top left represents the boiler. From the left, there is a dotted line entering it, which represents the amount of feedwater entering the boiler from the deaerator.

Also to the left of the boiler, we see the following information highlighted in orange: the type of fuel being used in the boiler, the fuel input energy, the fuel flow rate, and the boiler efficiency.

To the right of the boiler, we see a dotted line pointing to the right and then down, with a number next to it, indicating the amount of boiler blowdown.

Below the boiler, we see the amount of steam that is entering the high-pressure header, the temperature of it, and the thermodynamic quality of the steam.

The steam exits the boiler and enters the high-pressure header, represented by a dark blue line. Under the line, to the far left, you will see a light-blue triangular graphic that represents a pressure-reducing station. The pressure reducing station is also equipped with a desuperheating station. The number at the top indicates the amount of steam entering the pressure reducing valve. The number at the center-left of the valve indicates the amount of desuperheating water entering the unit. The number below indicates the amount of desuperheated steam entering the medium-pressure header; as well as the temperature of the steam.

To the right of the pressure-reducing station, you will see light blue, cone-shaped graphics, that represent the steam turbines. The one nearest to the left is a high-pressure to condensing turbine. This turbine discharges to the condenser represented by the blue circle below the turbine. The turbine exhaust pressure is noted as the condenser pressure. The turbine in the middle receives high-pressure steam and exhausts low-pressure steam. The one to the right receives high-pressure steam and exhausts medium-pressure steam. Above each turbine is an indication of the amount of steam coming into the turbine from the header. To the right, in dark blue, you see the power generation of the turbine.

In the center of the medium-pressure and low-pressure headers, we see an arrow pointing downward, which indicates the amount of flash entering the header from the condensate collection flash vessels that are located at the far-right of the schematic.

Above the header, to the right, the amount of heat loss is expressed in orange. Below, there is a yellow box that indicates the pressure, temperature, and thermodynamic quality of the steam.

The arrow to the right of the header points to a dark blue circle with a line through it, indicating the steam end-use components. Below this symbol is an indication of the thermal energy supplied to the end-use components from the steam. The end-use components discharge condensate through a steam trap, represented by a blue circle with a "T" in it. Schematically, condensate passes to the right through the trap. Failed steam traps that are blowing steam to the atmosphere are represented with the red arrow exiting the top of the trap symbol. The condensate appropriately passing through traps, again represented as exiting to the right of the trap, can be recovered or lost. Lost condensate is represented as the unrecovered condensate discharging down from the traps and recovered condensate enters the condensate collection system further to the right.

The green figures to the far-right of the schematic represent condensate flash-vessels. The top flash-vessel receives condensate from the high-pressure end-users. Flash-steam is formed because the flash vessel operates at medium-pressure but it receives saturated liquid condensate at high-pressure. As equilibrium is reached flash-steam is formed. This flash-steam exits the vessel through the top and is directed to the medium-pressure steam header, which is shown in the center of the diagram. Condensate exits the flash vessel and enters the medium-pressure condensate collection system. The medium-pressure condensate system is equipped with similar equipment as the high-pressure system.

All of the collected condensate enters the main condensate receiver located in the lower-center of the schematic. Process condensate is mixed with turbine condensate and makeup water prior to entering the deaerator.

The steam system deaerator is represented at the lower-left of the schematic. The deaerator receives low-pressure steam to preheat the collected condensate and makeup water represented as entering from the bottom of the vessel. Boiler feedwater discharges from the deaerator to the left and up to the boiler. The line pointing out from the top of the deaerator and leading to the right shows the amount of steam escaping from the vent.

Slide 50 - System Impact

This is a summary of the two operating conditions with the pressure-reducing valve operation indicated as the current operation and the steam turbine operation indicated as after projects. The reduction column indicates the change in operating cost associated with turning on the turbine. For the impact components and costs that we have built into the model, the economic opportunity associated with operating the turbine rather than the pressure-reducing valve is 132,000 dollars a year. As you can see, the savings develops from the reduced electrical purchases. However, in order to satisfy the thermal demand, a significant amount of additional fuel is purchased. Even with a high fuel cost, there is an economics incentive to operate the turbines. They are an attractive investment, although it may not always be cost-effective to purchase and install a new one.

[Slide Visual – Cost Summary]

- **Operating the turbine will save the site $132,000/yr.**
  - **Electrical power purchases will decrease.**
  - **Fuel purchases will increase.**

Cost Summary ($ '000s/yr)	Current Operation	After Projects	Reduction	
Power Cost	9,198	8,805	393	4.3%
Fuel Cost	31,650	31,909	-258	-0.8%
Make-Up Water Cost	461	465	-3	-0.7%
Total Cost (in $ '000s/yr)	41,310	41,178	132	0.3%

Utility Balance	Current Operation	After Projects	Reduction	
Power Generation	7510 kW	8152 kW	-	-
Power Import	15000 kW	14358 kW	642 kW	4.3%
Total Site Electrical Demand	22510 kW	22510 kW	-	-
Boiler Duty	361 kW	364 kW	-3 kW	-0.8%
Fuel Type	Natural Gas	Natural Gas	-	-
Fuel Consumption	361306.6 s cu.ft/h	364257.3 s cu.ft/h	-2950.7 s cu.ft/h	-0.8%
Boiler Steam Flow	260.9 klb/h	263.0 klb/h	-2.1 klb/h	-0.8%
Fuel Cost (in $/MMBtu)	10.00	10.00	-	-
Power Cost (as $/MMBtu)	20.51	20.51	--	
Make-Up Water Flow	21065 gal/h	21214 gal/h	-149 gal/h	-0.7%

Slide 51 - Backpressure Turbine Economics

It should be noted that operating a steam turbine will almost always require additional fuel consumption. Steam turbines convert thermal energy into shaft energy. As a result the steam leaving the turbine will have less thermal energy than the entering steam. Almost all industrial steam demands require thermal energy, not necessarily steam mass flow.

Slide 52 - Improved Turbine Efficiency

Now that we have a detailed model of our steam system and it is set up to analyze the economic impact associated with operating a steam turbine rather than passing steam through a pressure-reducing valve, let's use the model to explore the influence of some key parameters. Recall that the original example incorporated fuel with an impact cost of 10 dollars per million BTU, an electric impact cost of 70 dollars per megawatt hour, and a turbine with an isentropic efficiency of 32 percent.

First, we will only change the turbine efficiency. In other words, the turbine we are turning on is not a low efficiency turbine but a more efficient turbine. We are now assuming the turbine is a multi-stage unit with good efficiency (70 percent).

[Slide Visual – Model Tab Schematic]

The same example is executed with a 70% isentropic efficient turbine.

The top center will contain the descriptive title provided by the user, the initial template reads "SSAT Default 3 Header Model" or a similar title for whatever model you chose. Below it, you will see the Model Status, which should read "OK." The model status provides an indication of the calculation condition of the model.

To the left of the Model Status, you will see a chart in light blue, which indicates the emissions per year for carbon dioxide, sulfur oxide, and nitrogen oxide.

At the top right, it will say "Current Operation" if you are on the Model tab, or "Operation After Projects" if you are on the Projects Model tab.

The red graphic near the top left represents the boiler. From the left, there is a dotted line entering it, which represents the amount of feedwater entering the boiler from the deaerator.

Also to the left of the boiler, we see the following information highlighted in orange: the type of fuel being used in the boiler, the fuel input energy, the fuel flow rate, and the boiler efficiency.

To the right of the boiler, we see a dotted line pointing to the right and then down, with a number next to it, indicating the amount of boiler blowdown.

Below the boiler, we see the amount of steam that is entering the high-pressure header, the temperature of it, and the thermodynamic quality of the steam.

The steam exits the boiler and enters the high-pressure header, represented by a dark blue line. Under the line, to the far left, you will see a light-blue triangular graphic that represents a pressure-reducing station. The pressure-reducing station is also equipped with a desuperheating station. The number at the top indicates the amount of steam entering the pressure-reducing valve. The number at the center-left of the valve indicates the amount of desuperheating water entering the unit. The number below indicates the amount of desuperheated steam entering the medium-pressure header; as well as the temperature of the steam.

To the right of the pressure-reducing station, you will see light blue, cone-shaped graphics, that represent the steam turbines. The one nearest to the left is a high-pressure to condensing turbine. This turbine discharges to the condenser represented by the blue circle below the turbine. The turbine exhaust pressure is noted as the condenser pressure. The turbine in the middle receives high-pressure steam and exhausts low-pressure steam. The one to the right receives high-pressure steam and exhausts medium-pressure steam. Above each turbine is an indication of the amount of steam coming into the turbine from the header. To the right, in dark blue, you see the power generation of the turbine.

In the center of the medium-pressure and low-pressure headers, we see an arrow pointing downward, which indicates the amount of flash entering the header from the condensate collection flash vessels that are located at the far-right of the schematic.

Above the header, to the right, the amount of heat loss is expressed in orange. Below, there is a yellow box that indicates the pressure, temperature, and thermodynamic quality of the steam.

The arrow to the right of the header points to a dark blue circle with a line through it, indicating the steam end-use components. Below this symbol is an indication of the thermal energy supplied to the end-use components from the steam. The end-use components discharge condensate through a steam trap, represented by a blue circle with a "T" in it. Schematically, condensate passes to the right through the trap. Failed steam traps that are blowing steam to the atmosphere are represented with the red arrow exiting the top of the trap symbol. The condensate appropriately passing through traps, again represented as exiting to the right of the trap, can be recovered or lost. Lost condensate is represented as the unrecovered condensate discharging down from the traps and recovered condensate enters the condensate collection system further to the right.

The green figures to the far-right of the schematic represent condensate flash-vessels. The top flash-vessel receives condensate from the high-pressure end-users. Flash-steam is formed because the flash vessel operates at medium-pressure but it receives saturated liquid condensate at high-pressure. As equilibrium is reached flash-steam is formed. This flash-steam exits the vessel through the top and is directed to the medium-pressure steam header, which is shown in the center of the diagram. Condensate exits the flash vessel and enters the medium-pressure condensate collection system. The medium-pressure condensate system is equipped with similar equipment as the high-pressure system.

All of the collected condensate enters the main condensate receiver located in the lower-center of the schematic. Process condensate is mixed with turbine condensate and makeup water prior to entering the deaerator.

The steam system deaerator is represented at the lower-left of the schematic. The deaerator receives low-pressure steam to preheat the collected condensate and makeup water represented as entering from the bottom of the vessel. Boiler feedwater discharges from the deaerator to the left and up to the boiler. The line pointing out from the top of the deaerator and leading to the right shows the amount of steam escaping from the vent.

$10/million Btu
$70/MWh
32% isentropic efficiency

Slide 53 - Improved Turbine Efficiency Impact

Notice the results are very different. The electrical power impact is more than twice what it was before—1,479 kilowatts versus 642 kilowatts. The economic benefit associated with operating this more efficient turbine is more than 300,000 dollars per year.

[Slide Visual – Results]

Improving turbine efficiency to 70% dramatically increases the impact.

Results for: **$10/million Btu**
$70/MWh

70% isentropic efficiency

Cost Summary ($ '000s/yr)	Current Operation	After Projects	Reduction	
Power Cost	9,198	8,291	907	9.9%
Fuel Cost	31,650	32,241	-591	-1.9%
Make-Up Water Cost	461	469	-8	-1.6%
Total Cost (in $ '000s/yr)	41,310	41,001	309	0.7%
On-Site Emissions	**Current Operation**	**After Projects**	**Reduction**	
CO2 Emissions	367831 t/yr	374698 t/yr	-6866 t/yr	-4.8%
SOx Emissions	0 t/yr	0 t/yr	0 klb/yr	N/A
NOx Emissions	728 t/yr	742 t/yr	-14 t/yr	-1.9%
Power Station Emissions		**Reduction After Projects**	**Total Reduction**	
CO2 Emissions		20348 t/yr	13481 t/yr	-
Sox Emissions		63 t/yr	63 t/yr	-
Nox Emissions		46 t/yr	32 t/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	7510 kW	8990 kW	-	-
Power Import	15000 kW	13521 kW	1479 kW	9.9%
Total Site Electrical Demand	22510 kW	22510 kW	-	-
Boiler Duty	361 kW	368 kW	-7 kW	-1.9%
Fuel Type	Natural Gas	Natural Gas	-	-
Fuel Consumption	361306.6 s cu.ft/h	368051 s cu.ft/h	-6744.4 s cu.ft/h	-1.9%
Boiler Steam Flow	260.9 klb/h	265.7 klb/h	-4.9 klb/h	-1.9%
Fuel Cost (in $/MMBtu)	10.00	10.00	-	-
Power Cost (as $/MMBtu)	20.51	20.51	--	
Make-Up Water Flow	21065 m3h	21409 m3/h	-344 m3/h	-1.6%

<u>Slide 54 - Fuel Price Impact</u>

Now let's return to the original turbine, where the turbine is a simple single-stage turbine with a low efficiency. Now, we will change only the fuel price. We will assume we have a spike in fuel pricing that drives the price to 15 dollars per million BTU. Notice on the results page, the economic benefit associated with operating the turbine is erased.

[Slide Visual – Results]

For the original example if fuel price is increased from $10/10^6Btu to $15/10^6Btu the economic improvement is erased.

Results for: **$15/million Btu**
$70/MWh
32% isentropic efficiency

Cost Summary ($ '000s/yr)	Current Operation	After Projects		Reduction	
Power Cost	9,198	8,805		393	4.3%
Fuel Cost	47,476	47,863		-388	-0.8%
Make-Up Water Cost	461	465		-3	-0.7%
Total Cost (in $ '000s/yr)	57,135	57,133		2	0.0%

On-Site Emissions	Current Operation	After Projects		Reduction	
CO2 Emissions	367831 t/yr	370835 t/yr		-3004 t/yr	-0.8%
SOx Emissions	0 t/yr	0 t/yr		0 t/yr	N/A
NOx Emissions	728 t/yr	734 t/yr		-6 t/yr	-0.8%

Power Station Emissions	Reduction After Projects		Total Reduction	
CO2 Emissions	8823 t/yr		5819 t/yr	-
Sox Emissions	27 t/yr		27 t/yr	-
Nox Emissions	20 t/yr		14 t/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	7510 kW	8152 kW		-	-
Power Import	15000 kW	14358 kW		642 kW	4.3%
Total Site Electrical Demand	22510 kW	22510 kW		-	-
Boiler Duty	361 kW	364 kW		-3 kW	-0.8%
Fuel Type	Natural Gas	Natural Gas		-	-
Fuel Consumption	361306.6 s cu.ft/h	364257.3 s cu.ft/h		-2950.7 s cu.ft/h	-0.8%
Boiler Steam Flow	260.9 klb/h	263.0 klb/h		-2.1 klb/h	-0.8%
Fuel Cost (in $/MMBtu)	15.00	15.00		-	-
Power Cost (as $/MMBtu)	20.51	20.51		--	
Make-Up Water Flow	21065 m3/h	21214 m3/h		-149 m3/h	-0.7%

Slide 55 - Electrical Price Impact 1

Once again we return to the original conditions of the example (fuel purchased at 10 dollars per million BTU), and change only the electrical impact cost from 70 dollars per megawatt hour to 100 dollars per megawatt hour. The economic benefit associated with operating the turbine increases significantly.

[Slide Visual – Results]

For the original example if electrical price is increased from $70/MWh to $100/MWh the economic impact is significantly increased.

Results for: **$10/million Btu**
$100/MWh
32% isentropic efficiency

Cost Summary ($ '000s/yr)	Current Operation	After Projects	Reduction	
Power Cost	13,140	12,578	562	4.3%
Fuel Cost	31,650	31,909	-258	-0.8%
Make-Up Water Cost	461	465	-3	-0.7%
Total Cost (in $ '000s/yr)	45,252	44,952	300	0.7%
On-Site Emissions	**Current Operation**	**After Projects**	**Reduction**	
CO2 Emissions	367831 t/yr	370835 t/yr	-3004 t/yr	-0.8%
SOx Emissions	0 t/yr	0 t/yr	0 t/yr	N/A
NOx Emissions	728 t/yr	734 t/yr	-6 t/yr	-0.8%
Power Station Emissions		**Reduction After Projects**	**Total Reduction**	
CO2 Emissions		8823 t/yr	5819 t/yr	-
Sox Emissions		27 t/yr	27 t/yr	-
Nox Emissions		20 t/yr	14 t/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	7510 kW	8152 kW	-	-
Power Import	15000 kW	14358 kW	642 kW	4.3%
Total Site Electrical Demand	22510 kW	22510 kW	-	-
Boiler Duty	361 kW	364 kW	-3 kW	-0.8%
Fuel Type	Natural Gas	Natural Gas	-	-
Fuel Consumption	361306.6 s cu.ft/h	364257.3 s cu.ft/h	-2950.7 s cu.ft/h	-0.8%
Boiler Steam Flow	260.9 klb/h	263.0 klb/h	-2.1 klb/h	-0.8%
Fuel Cost (in $/MMBtu)	10.00	10.00	-	-
Power Cost (as $/MMBtu)	29.31	29.31	--	
Make-Up Water Flow	21065 m3/h	21214 m3/h	-149 m3/h	-0.7%

Slide 56 - Electrical Price Impact 2

If the electricity impact cost drops to 40 dollars per megawatt hour, the economic impact becomes a loss.

[Slide Visual – Results]

For the original example if electrical price is decreased from $70/MWh to $40/MWh the economic impact is significantly decreased.

Results for: **$10/million Btu**
$40/MWh
32% isentropic efficiency

Cost Summary ($ '000s/yr)	Current Operation	After Projects	Reduction	
Power Cost	5,256	5,031	225	4.3%
Fuel Cost	31,650	31,909	-258	-0.8%
Make-Up Water Cost	461	465	-3	-0.7%
Total Cost (in $ '000s/yr)	37,368	37,405	-37	-0.1%

On-Site Emissions	Current Operation	After Projects	Reduction	
CO2 Emissions	367831 t/yr	370835 t/yr	-3004 t/yr	-0.8%
SOx Emissions	0 t/yr	0 t/yr	0 t/yr	N/A
NOx Emissions	728 t/yr	734 t/yr	-6 t/yr	-0.8%

Power Station Emissions	Reduction After Projects	Total Reduction	
CO2 Emissions	8823 t/yr	5819 t/yr	-
Sox Emissions	27 t/yr	27 t/yr	-
Nox Emissions	20 t/yr	14 t/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	7510 kW	8152 kW	-	-
Power Import	15000 kW	14358 kW	642 kW	4.3%
Total Site Electrical Demand	22510 kW	22510 kW	-	-
Boiler Duty	361 kW	364 kW	-3 kW	-0.8%
Fuel Type	Natural Gas	Natural Gas	-	-
Fuel Consumption	361306.6 s cu.ft/h	364257.3 s cu.ft/h	-2950.7 s cu.ft/h	-0.8%
Boiler Steam Flow	260.9 klb/h	263.0 klb/h	-2.1 klb/h	-0.8%
Fuel Cost (in $/MMBtu)	10.00	10.00	-	-
Power Cost (as $/MMBtu)	11.72	11.72	--	
Make-Up Water Flow	21065 m3/h	21214 m3/h	-149 m3/h	-0.7%

Slide 57 - Turbine-PRV Examples

This table is a summary of the turbine-PRV analyses. It is obvious from this information that impact fuel cost and impact electrical costs are critical parameters in establishing a representative result.

[Slide Visual – Turbine-PRV Examples Summary Information]

Electricity Cost	Fuel Cost	Turbine Isentropic Efficiency	Turbine Power Production	Turbine Operation Savings
$70/MWh	$10.00/10^{6}Btu	32%	642 kW	$132,000/yr
$70/MWh	$10.00/10^{6}Btu	70%	1,479 kW	$309,000/yr
$70/MWh	$15.00/10^{6}Btu	32%	642 kW	$2,000/yr
$100/MWh	$10.00/10^{6}Btu	32%	642 kW	$300,000/yr
$40/MWh	$10.00/10^{6}Btu	32%	642 kW	-$37,000/yr

Slide 58 - Condensing Steam Turbines 1

Condensing steam turbines are physically the same piece of equipment as backpressure turbines; however, the economic and energy impacts are dramatically different. Condensing steam turbines generally discharge steam with a pressure that is less than atmospheric pressure. The energy rejected in the condenser is not distributed to useful purposes.

[Slide Visual –Condensing Steam Turbine]

Condensing turbine discharge steam pressure is less than atmospheric pressure

- **The steam must be condensed to pump it back into the boiler**
- **Exiting steam quality is typically much greater than 90%**

[Slide Visual –Condensing Steam Turbine]

The single stage has a stop valve, over-speed trip valve, and a hand valve. Steam enters through the stop valve, and the power of the shaft causes it to output steam through one stage.

Slide 59 - Condensing Steam Turbines 2

Much like the turbine-PRV example, there is a short list of primary influencing factors.

[Slide Visual –Condensing Steam Turbine]

The single stage has a stop valve, over-speed trip valve, and a hand valve. Steam enters through the stop valve, and the power of the shaft causes it to output steam through one stage.

[Slide Visual –Condensing Steam Turbines]

- **The primary factors influencing condensing turbine operations are:**

Slide 60 – Condensing Steam Turbines 3

Impact power cost and impact fuel cost are the dominant factors, but turbine efficiency is also quite significant—much more significant than in the backpressure turbine examples. Boiler efficiency is also a factor but it is minimal in comparison to the other parameters. Turbine discharge pressure is another influencing factor that is a significant day-to-day performance management issue.

[Slide Visual –Condensing Steam Turbines]

- **The primary factors influencing condensing turbine operations are:**
  - **Purchased power cost**
  - **Purchased fuel cost**
  - **Turbine efficiency**
  - **Boiler efficiency**
  - **Turbine discharge pressure**

[Slide Visual –Condensing Steam Turbine]

The single stage has a stop valve, over-speed trip valve, and a hand valve. Steam enters through the stop valve, and the power of the shaft causes it to output steam through one stage.

Slide 61 - Condensing Steam Turbines 4

It is interesting to note the general energy flow through a typical condensing steam turbine. For every 100 Units of thermal energy supplied to the turbine approximately 120 units of fuel energy had to be input to the boiler. For the condensing turbine in this example, only 27 units of shaft energy are produced from the 100 units of steam thermal energy supplied to the turbine. Approximately 73 units of thermal energy are rejected into the condenser. Only about one fifth of the purchased fuel is turned into useful energy. The turbine in this example is representative of an excellent turbine with an isentropic efficiency of 80 percent. The turbine receives superheated steam at 400 PSIG and 700 degrees Fahrenheit and discharges to the condenser at a pressure of 1.4 PSIA. That is quite inefficient. So, with a condensing turbine, we must take great care to make sure everything operates at top performance and the correct impact parameters are considered.

[Slide Visual –Condensing Steam Turbine]

The single stage has a stop valve, over-speed trip valve, and a hand valve. Steam enters through the stop valve, and the power of the shaft causes it to output steam through one stage.

- **For this example:**
  - **The turbine receives superheated steam.**
    - **400 psig.**
    - **700°F.**
  - **Turbine isentropic efficiency is 80%.**
  - **The discharge pressure is 1.4 psia.**
  - **100 Units of Thermal Energy**
  - **27 Units of Shaft Energy**
  - **73 Units of Thermal Energy**

Slide 62 - Condensing Turbine Performance

This table identifies the economic impact associated with operating the example condensing steam turbine with various fuel costs. It should be noted that this analysis requires a much more specific set of information than the backpressure turbine information presented previously, because many additional factors influence the results. As a result, turbine inlet steam conditions and isentropic efficiency must be specified along with boiler efficiency. The table highlights the contrast in electrical power impact cost against fuel cost. As an example, a fuel cost of 10 dollars per million BTU, and an excellent turbine efficiency of 80 percent will result in an impact condensing power cost of about 150 dollars per megawatt hour. In other words, the example boiler burning 10 dollar per million BTU fuel with an efficiency of 84 percent can pass steam through a condensing turbine with an efficiency of 80 percent and produce electrical power that can compete with power purchased at a price of 150 dollars per megawatt-hour. 150 dollars per megawatt-hour electricity is generally very high-cost electricity.

[Slide Visual – Condensing Turbine Performance]

Condensing Turbine Impact Power Cost			
	Impact Condensing Power Cost [$/MWh]		
Fuel Cost	Turbine Isentropic Efficiency [%]		
[$/$10^6$Btu]			80
2.00			30
4.00			60
6.00			89
8.00			119
10.00			149
12.00			179
Steam inlet	400	psig	
Steam inlet	700	°F	
Steam exit	1.4	psia	
Boiler Efficiency	84	%	

Slide 63 - Condensing Steam Turbines 6

It is also interesting to note the dramatic impact turbine efficiency has on the economics of condensing turbine operations. This table contains the same basic information—the same boiler, the same steam properties, and the same fuel price range. Two additional sets of data have been added, each set is for a different turbine isentropic efficiency. The data indicates that as turbine efficiency decreases the cost of generating condensing power significantly

increases. For example, if our turbine experiences a decrease in isentropic efficiency from 80 percent to 60 percent, the cost of generating a megawatt-hour of condensing power at this will increase from 149 dollars per megawatt-hour to 194 dollars per megawatt-hour if the impact fuel cost is 10 dollars per million BTU. The condensing power cost increases to 278 dollars per megawatt-hour if the turbine efficiency drops to 40 percent.

A primary point of concern for general operations of condensing turbines must be maintaining turbine efficiency. There are several common factors that influence turbine isentropic efficiency.

[Slide Visual – Condensing Turbine Performance]

Condensing Turbine Impact Power Cost			
	Impact Condensing Power Cost [$/MWh]		
Fuel Cost	Turbine Isentropic Efficiency [%]		
[$/10^{6}Btu]	40	60	80
2.00	56	39	30
4.00	111	78	60
6.00	167	116	89
8.00	223	155	119
10.00	278	194	149
12.00	334	233	179
Steam inlet	400	psig	
Steam inlet	700	°F	
Steam exit	1.4	psia	
Boiler Efficiency	84	%	

Slide 64 - Condensing Steam Turbines 5

Turbine isentropic efficiency is impacted significantly by the steam flow through the turbine. This primarily results from the throttling effects of the steam flow control device. But there are several additional factors that influence turbine performance. The fluid-dynamic characteristics of the blades and nozzles are finely designed to produce the maximum performance characteristics. If the shape of the blades and nozzles are altered through erosion or deposits the performance of the turbine will diminish. Gaps must exist between the moving and stationary parts. Seals are designed into the turbine to minimize steam leaking through the gaps. If the seals fail or are worn significant amounts of steam can bypass through the gaps. Wet steam, steam with water droplets, can result in wear of turbine blades. But water droplets can also diminish performance because they can present a resultant force

opposite of the desired direction on the turbine blades. This occurs because the nozzles effectively accelerate the vapor but the inertia of the droplets keeps their velocity relatively low. As a result, the droplets often strike the back of the blades.

These blade, nozzle, and seal issues are typically repaired during major overhauls of the turbine.

[Slide Visual – Condensing Turbine Efficiency Factors]

- **Efficiency reductions can result from:**
  - **Blade deposits**
  - **Blade erosion**
  - **Seal wear**
  - **Wet steam**
- **Efficiency improvements can result from**
  - **Replaced blades**
  - **Improved seals**
  - **Turbine replacement**
  - **Increased load**

[Slide Visual –Condensing Steam Turbine]

The single stage has a stop valve, over-speed trip valve, and a hand valve. Steam enters through the stop valve, and the power of the shaft causes it to output steam through one stage.

Slide 65 - Condensing Steam Turbines 6

The day-to-day turbine management activity that is most common is managing discharge pressure. It is important to note that the energy extracted from the steam that is converted into shaft power, is proportional to the pressure ratio of the steam passing through the turbine. The pressure ratio is the inlet absolute pressure divided by the outlet absolute pressure. Because the pressure ratio is a relatively large number divided by a relatively small number; a slight change in the denominator (or discharge pressure) will have a significant impact on the pressure ratio and the power output of the turbine. For example, 500 divided by 1 is very different from 500 divided by 2. As a result, managing condensing turbine discharge pressure is a critical point. Therefore, the most common day-to-day operation management activities focus on maintaining the discharge pressure as low as possible. This is accomplished by ensuring the cooling medium is as cold as practical, maximizing the flow of the cooling medium, ensuring non-condensable gases are removed from the condenser, and by cleaning the heat transfer surfaces.

It should be noted that most condensing turbines have a minimum practical discharge pressure. This minimum pressure has an effect, so that further reductions in pressure will only minimally increase power output because of steam velocity and density effects.

[Slide Visual –Condensing Steam Turbine]

The single stage has a stop valve, over-speed trip valve, and a hand valve. Steam enters through the stop valve, and the power of the shaft causes it to output steam through one stage.

- **Condenser pressure can be reduced (improved) by**
  - **Removing non-condensable gases from condenser**
  - **Cleaning the condenser**
  - **Supplying the condenser with reduced temperature water**
  - **Supplying the condenser with additional cooling water**

Slide 66 - Conclusions

In summary, investigating and managing the energy resources that are encountered throughout the complex is a critical factor in managing operating costs. Primary energy resources should be evaluated to determine if there are any advantages that can be exploited to improve site operations. Every end-use component in the steam system should be evaluated to determine if there are opportunities to reduce steam consumption and to utilize the most appropriate energy resources. Combined heat and power activities can dramatically influence the economics of site operations. All of these areas should be central points of focus of site operations.

[Slide Visual – Summary]

- **Fuel selection can provide significant reductions in operating costs due to differences in energy costs.**
- **Reducing steam consumption can often result in the most significant energy reduction opportunities**
- **Combined heat and power, or cogeneration, is an extremely important aspect of industrial facilities.**

Steam End-User Training
Steam Distribution System Losses Module

__Slide 1 - Steam Distribution System Losses Module__

The steam distribution system typically consists of main steam headers, secondary or branch headers, condensate return piping, condensate collection equipment, as well as pipe and equipment condensate draining components. Often the distribution system is very large, extending to all areas of a facility. As a result, the distribution system can be a source of significant loss.

[Slide Visual – Steam Distribution Losses]

Banner:
DOE's BestPractices
Steam End User Training

__Steam Distribution Losses__
Steam Leaks
Heat Transfer Loss Through Insulation
Condensate Loss
Overall System

__Slide 2 - Pipe Failures__

We will start our investigation in managing the distribution system losses by first focusing on leaks.

[Slide Visual – Steam Distribution Losses – Steam Leaks]

Banner:
DOE's BestPractices
Steam End User Training

__Steam Distribution Losses__
Steam Leaks – Pipe Failures and Trap Failures
Heat Transfer Loss Through Insulation
Condensate Loss
Overall System

Slide 3 - Steam Leaks 1

This table indicates the maximum steam flow through an orifice or short section of pipe. It should be noted that the *discharge pressure* noted is the maximum backpressure at the orifice outlet for the calculation to be valid. Many (or most) leaks discharge to the atmosphere at 0 PSIG. However, this chart can be used for failed steam traps discharging to a closed condensate collection system that can be operating at an elevated pressure.

The table indicates a significant steam flow can pass through a relatively small opening. The amount of 100 PSIG steam that can pass through an orifice of one-sixteenth inch diameter is about 10 pounds an hour.

[Slide Visual – Steam Leak Rate (lbm/hr)]

This chart shows the Steam Leak Rate (pounds per hour) by Orifice Diameter

Steam Supply Pressure. The numbers on the left going up and down from one-sixteenth to one-half represent the Orifice Diameter in Inches. The numbers at the top going left to right from 20 to 500 indicate the Steam Supply Pressure in PSIG.

The Discharge Coefficient is 0.6 dimensionless.

Orifice Diameter (inch)	Leak Rate [lbm/hr] Steam Supply Pressure [psig]						
	20	50	100	150	300	400	500
1/16	3	6	11	16	30	39	49
1/8	13	25	43	62	119	157	195
3/16	30	55	98	140	268	353	439
1/4	53	98	174	249	477	628	780
5/16	82	153	271	390	745	981	1,218
3/8	118	221	391	561	1,073	1,413	1,754
7/16	161	300	532	764	1,460	1,924	2,388
1/2	210	392	695	998	1,907	2,513	3,118
	3	18	43	68	143	193	243
	Discharge Pressure [psig]						
Discharge coefficient	0.6	dimensionless					

At 100 psig steam supply and one-sixteenth inch orifice diameter, 11 pounds per hour of steam is lost due to leaks.

Slide 4 - Steam Leaks 2

If you consider that a steam cost of $10 per thousand pounds is a moderate cost—then even a small steam leak of 10 pounds per hour can result in a loss of more than $1,000 per year. The example steam system operates with a medium-pressure steam cost in the 15 dollars per thousand pounds range—as a result, this small steam leak would be more than 1,500 dollars per year. Steam leaks are very expensive and become enormous.

[Slide Visual – Steam Leak Rate (Cost per Year)]

This chart shows the Steam Leak Rate (in dollars per year) by Orifice Diameter.

Steam Supply Pressure. The numbers on the left going up and down from one-sixteenth to one-half represent the Orifice Diameter in Inches. The numbers at the top going left to right from 20 to 500 indicate the Steam Supply Pressure in PSIG.

The Discharge Coefficient is 0.6 dimensionless. The steam cost is 10 dollars per thousand pounds per hour.

Orifice Diameter (inch)	Leak Rate [$/yr] Steam Supply Pressure [psig]						
	20	50	100	150	300	400	500
1/16	300	500	1,000	2,600	3,400	4,300	1,400
1/8	1,200	2,100	3,800	10,400	13,800	17,100	5,500
3/16	2,600	4,800	8,600	23,500	31,000	38,400	12,300
1/4	4,600	8,600	15,200	41,800	55,000	68,300	21,900
5/16	7,200	13,400	23,800	65,200	86,000	106,700	34,100
3/8	10,400	19,300	34,200	94,000	123,800	153,700	49,200
7/16	14,100	26,300	46,600	127,900	168,500	209,200	66,900
1/2	18,400	34,300	60,900	167,000	220,100	273,200	87,400
	3	18	43	68	143	193	243
	Discharge Pressure [psig]						
Discharge coefficient	0.6	dimensionless					
Steam Cost	10.00	$ per 1,000 lbm					

At 100 psig steam supply and one-sixteenth inch orifice diameter, $1,000/yr of steam is lost due to leaks.

Slide 5 - Pipe Failures

Typically, even small steam leaks present significant savings opportunities. Often we are only interested in a general estimate of the cost of a steam leak in order to determine the repair strategy. Tables, like the ones shown here can be helpful in obtaining an order-of-magnitude opportunity associated with steam leaks. However, leaks can often be very difficult to estimate because of their irregular features. But, much of the time only a rough estimate of steam loss is necessary. Tables, like the ones presented here can aid in providing a gross estimate of steam loss.

Slide 6 - Steam Trap Management

Often the largest steam leaks in our industrial plants are difficult to detect. This is because most of the leaks result from failed steam traps and the steam traps discharge into closed condensate systems. Condensate collection systems are essential components in efficient steam systems but they can mask the steam loss from failed traps and make evaluating steam trap performance difficult.

A steam trap that is failed open can pass a large amount of steam because most steam traps have a restricting opening that is at least one-sixteenth inch diameter. Many steam traps have openings that are one-eighth inch diameter and even greater than one-half inch diameter. A one-eighth inch diameter orifice will pass four times more steam than a one-sixteenth inch diameter orifice. As we can see from the steam leak table the cost of a single failed steam trap can be enormous.

It is common for industrial facilities to have more than 10 percent and even greater than 30 percent of their steam traps failed. There are several failure modes and all of the failed traps will not be losing steam, but significant steam losses can occur when you consider that an industrial plant may have several thousand traps.

It is vital to properly manage the steam trap population by investigating the traps to determine if they are operating properly. It is necessary to inspect every steam trap in the facility and determine how it is performing. There are many different types of traps that function based on different principles. In order to investigate the steam traps it is vital to understand how each type works.

Slide 7 - Steam Traps

There are several common types of steam traps along with variations and combinations of types. We will now discuss the basic operating principles associated with the most common steam trap types.

[Slide Visual – Steam Traps]

Steam Traps

- **Thermostatic**
- **Closed Float**
- **Float and Thermostatic**
- **Open Float**
- **Thermodynamic**
- **Orifice**

Slide 8 - Thermostatic Steam Traps 1

A thermostatic steam trap operates based on temperature. Generally, the actuation results from an internal component expanding when temperature increases—and contracting when temperature decreases. When the trap internals are hot the trap valve is closed.

> ***[Slide Visual – Thermostatic Steam Trap Closed]***
>
> **Steam enters the steam trap from the bottom left. An internal component, a sealed bellows, represented by a 'spring-like" mechanism will expand with temperature increase, thus closing the trap with a plug at the bottom of the mechanism.**

Slide 9 - Thermostatic Steam Traps 2

When the trap internals are cold the trap valve is open.

> ***[Slide Visual – Thermostatic Steam Trap Open]***
>
> **Steam enters the steam trap from the bottom left. When the liquid is sub-cooled, the internal component, a sealed bellows, represented by a 'spring-like" mechanism will contract, raising the plug at the bottom of the mechanism, allowing condensate or condensate and flash steam to flow out the other side of the trap.**

Slide 10 - Thermostatic Steam Traps 3

When steam re-enters the valve the internals increase in temperature and the valve closes again.

Manufacturers use various methods to actuate the opening and closing activity with the common methods including bi-metallic strips or a fluid filled bellows.

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 exist in the trap with exactly the same temperature. The trap will only open after steam has cooled and condensed and the condensate has further cooled to a sufficiently low temperature.

> ***[Slide Visual – Thermostatic Steam Trap Closed]***
>
> **Steam enters the steam trap from the bottom left. An internal component, a sealed bellows, represented by a 'spring-like" mechanism will expand with temperature increase, thus closing the trap with a plug at the bottom of the mechanism.**

Slide 11 - Thermostatic Steam Traps 4

This trap will not discharge condensate immediately when it forms. The condensate must sub-cool before the trap opens—5 degrees Fahrenheit to 30 degrees Fahrenheit sub-cooling is typical. This type of trap is often considered the classic selection for heat tracing applications.

[Slide Visual – Thermostatic Steam Trap Open]

Steam enters the steam trap from the bottom left. When the liquid is sub-cooled, the internal component, a sealed bellows, represented by a 'spring-like" mechanism will contract, raising the plug at the bottom of the mechanism, allowing condensate or condensate and flash steam to flow out the other side of the trap.

Slide 12 - Closed-float Trap 1

The float type steam trap is arranged so that condensate enters a reservoir in the trap. The outlet valve is actuated by a float mechanism as the condensate level increases in the reservoir. The trap remains closed until the liquid level increases to the point that the float opens the outlet valve.

[Slide Visual – Closed Float Steam Trap]

Steam enters the trap and condensate collects in the reservoir. A float mechanism is used to control the condensate level in the trap. The condensate in the diagram is approximately half full in the reservoir and the plug closes the exit which will discharge the condensate.

Slide 13 - Closed-float Trap 2

As the condensate level increases the float inside the trap raises, which opens the outlet valve. Saturated liquid condensate passes through the outlet valve. As the saturated liquid condensate passes through the valve opening flash steam is formed.

[Slide Visual – Closed Float Steam Trap]

Steam enters the trap and condensate collects in the reservoir. A float mechanism is used to control the condensate level in the trap. The condensate in the diagram is nearly full in the reservoir. The float is raising and the plug opens the exit to discharge the steam and condensate.

Slide 14 - Closed-float Trap 3

The valve closes as the condensate level drops the float and valve arrangement.

[Slide Visual – Closed Float Steam Trap]

Steam enters the trap and condensate collects in the reservoir. A float mechanism is used to control the condensate level in the trap. The condensate in the diagram is approximately half full in the reservoir and the plug closes the exit which will discharge the condensate.

Slide 15 - Closed-float Trap 4

In the industrial arena a float type steam trap will always be coupled with another type of trap as a compound arrangement. Only liquid can exit the float type trap; therefore, the float type arrangement will not allow air or non-condensable gases to exit. This is why the float type trap is commonly coupled with a thermostatic type trap that provides air removal capabilities. This combined arrangement is identified as a *float-and-thermostatic trap*.

[Slide Visual – Closed Float Steam Trap]

Steam enters the trap and condensate collects in the reservoir. A float mechanism is used to control the condensate level in the trap. The condensate in the diagram is nearly full in the reservoir. The float is raising and the plug opens the exit to discharge the steam and condensate.

- **Rarely applied in this form in steam systems**
- **Opens to saturated condensate**
- **Will discharge condensate and flash steam**
- **Poor (no) air removal capability**

Slide 16 - Float and Thermostatic 1

Again, the float-and-thermostatic trap is a combination of two types of traps. When the trap fills with air, the air cools down triggering the thermostatic element to open.

[Slide Visual –Float and Thermostatic Steam Trap]

Steam enters the trap and condensate collects in the reservoir. A float mechanism is used to control the condensate level in the trap. A thermostatic element at the top of the reservoir allow air to enter, which when the air is cool, will cause the spring bellows to contract, opening the valve. The thermostatic element is closed in the diagram. The condensate in the diagram is nearly full in the reservoir. The float is raising and the plug opens the exit to discharge the steam and condensate.

Slide 17 - Float and Thermostatic 2

The thermostatic element can also open during startup conditions when the condensate load is heavy and subcooling has occurred.

[Slide Visual –Float and Thermostatic Steam Trap]

Steam enters the trap and condensate collects in the reservoir. A float mechanism is used to control the condensate level in the trap. A thermostatic element at the top of the reservoir allow air to enter, which when the air is cool, will cause the spring bellows to contract, opening the valve. The thermostatic element is open in the diagram and air can be seen leaving the thermostatic element. The condensate in the diagram is nearly full in the reservoir. The float is raising and the plug opens the exit to discharge the steam and condensate.

Slide 18 - Float and Thermostatic 3

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 backing up condensate should be avoided.

[Slide Visual –Float and Thermostatic Steam Trap]

Steam enters the trap and condensate collects in the reservoir. A float mechanism is used to control the condensate level in the trap. A thermostatic element at the top of the reservoir allow air to enter, which when the air is cool, will cause the spring bellows to contract, opening the valve. The thermostatic element is open in the diagram and air can be seen leaving the thermostatic element. The condensate in the diagram is nearly full in the reservoir. The float is raising and the plug opens the exit to discharge the steam and condensate.

- **Opens to saturated condensate**
- **Will discharge condensate and flash steam**
- **Significant air removal and startup capabilities**
- **Modulating type operation**

Slide 19 - Open-float Trap 1

An inverted bucket trap is another type of float activated trap. An upside-down bucket serves as the float.

When the trap body and bucket are filled with condensate the bucket sinks.

[Slide Visual – Open Float Steam Trap]

Steam enters the trap from the bottom and moves an up-side down bucket upward. A cantilever at the top of the trap and bucket is used to open and close the steam trap outlet located at the top of the trap. The bucket mechanism will float upward and close the outlet valve of the steam trap. This diagram shows the bucket in a low position and the cantilever is low and allows the outlet valve to be open, releasing steam and condensate.

Slide 20 - Open-float Trap 2

Steam enters the trap under the bucket, this causes the bucket to float, which closes the outlet valve.

[Slide Visual – Open Float Steam Trap]

Steam enters the trap from the bottom and moves an up-side down bucket upward. A cantilever at the top of the trap and bucket is used to open and close the steam trap outlet located at the top of the trap. The bucket mechanism will float upward and close the outlet valve of the steam trap. This diagram shows the bucket in a high position and the cantilever is close to the outlet valve to close the outlet of the trap.

Slide 21 - Open-float Trap 3

The steam that lifts the bucket to close the valve must condense before the valve will open allowing additional condensate to enter the trap.

> ***[Slide Visual – Open Float Steam Trap]***
>
> **Steam enters the trap from the bottom and moves an up-side down bucket upward. A cantilever at the top of the trap and bucket is used to open and close the steam trap outlet located at the top of the trap. The bucket mechanism will float upward and close the outlet valve of the steam trap. This diagram shows the bucket in a low position and the cantilever is low and allows the outlet valve to be open, releasing steam and condensate.**
>
> **Non-condensable gases exit through a vent-hole at the top of the bucket and out through the valve.**

Slide 22 - Open-float Trap 4

Non-condensable gases entering the bucket will pass through a vent-hole at the top of the bucket and then out through the valve as the bucket begins to sink.

This trap is very effective in many applications.

> ***[Slide Visual – Open Float Steam Trap]***
>
> **Steam enters the trap from the bottom and moves an up-side down bucket upward. A cantilever at the top of the trap and bucket is used to open and close the steam trap outlet located at the top of the trap. The bucket mechanism will float upward and close the outlet valve of the steam trap. This diagram shows the bucket in a high position and the cantilever is close to the outlet valve to close the outlet of the trap.**
>
> **Non-condensable gases exit through a weep-hole at the top of the bucket and out through the valve.**
>
> - **Opens to saturated condensate**
> - **Will discharge condensate and flash steam**
> - **Limited air removal capability**
> - **Application in superheated steam service should be questioned**
> - **Intermittent operation**

Slide 23 - Thermodynamic Traps 1

Thermodynamic steam traps are designed with a solid metal disk in a control chamber. Condensate enters the control chamber under the metal disk pushing the disk up and out of the way. Condensate passes through the gap made between the disk and the trap body to the outlet, which is an annular channel in the trap body.

[Slide Visual – Thermodynamic Steam Trap]

Condensate enters upward through the trap, pushing a solid metal desk (represented by a green rectangle) out of the way, allowing steam to fill the chamber by flowing around the disk. When the disk is raised, steam and condensate can leave the trap.

Slide 24 - Thermodynamic Traps 2

When steam comes in, the velocity through the gap is much greater than that of the condensate; this results in an area of low-pressure. The control chamber will fill with relatively low velocity steam, which results in a high-pressure area on the top of the metal disk. Therefore, there is a pressure difference acting on the disk—high-pressure on the upper surface of the disk and low-pressure on the lower surface at the gap. This results in the disk slamming the trap closed.

It remains closed until the steam in the control chamber turns into condensate reducing the pressure above the disk opening the trap.

[Slide Visual – Thermodynamic Steam Trap]

Condensate enters upward through the trap. The solid metal desk (represented by a green rectangle) is blocking the passage of steam and condensate from entering the chamber. There is existing steam and condensate in the chamber that cannot be released to the outlet of the trap due to the location of the disk.

Slide 25 - Thermodynamic Traps 3

The trap will remain open releasing condensate. If steam is present the trap will quickly close again.

[Slide Visual – Thermodynamic Steam Trap]

Condensate enters upward through the trap, pushing a solid metal desk (represented by a green rectangle) out of the way, allowing steam to fill the chamber by flowing around the disk. When the disk is raised, steam and condensate can leave the trap.

<u>**Slide 26 - Thermodynamic Traps 4**</u>

This trap is very effective in many applications.

[Slide Visual – Thermodynamic Steam Trap]

Condensate enters upward through the trap. The solid metal desk (represented by a green rectangle) is blocking the passage of steam and condensate from entering the chamber. There is existing steam and condensate in the chamber that cannot be released to the outlet of the trap due to the location of the disk.

- **Opens to saturated condensate**
- **Will discharge condensate and flash steam**
- **Intermittent operation**
- **Can be equipped with thermostatic element to improve air removal**

<u>**Slide 27 - Orifice Steam Traps 1**</u>

An orifice steam trap makes use of the drastically different properties of condensate and steam to regulate the throughput of the trapping device. Orifice traps do not have any moving parts but rely on a restricting orifice, small diameter short tube, or Venturi type nozzle as the primary working component. The density of condensate is anywhere from one order-of-magnitude to three orders-of-magnitude greater than the density of steam. This fact allows a significant amount of condensate to pass through a small opening and a minimal amount of steam to pass through the same opening.

[Slide Visual – Orifice Steam Trap]

Condensate passes through a restriction (represented by a narrow gap) and leaves as flash steam and condensate.

<u>**Slide 28 - Orifice Steam Traps 2**</u>

In fact, when condensate is present the restriction acts as a regulating mechanism. This occurs because as condensate passes through the restriction pressure drop will cause flash steam to form in the condensate flow. This flash steam formation will restrict the flow that can pass through the device.

[Slide Visual – Orifice Steam Trap]

Condensate passes through a restriction (represented by a narrow gap) and leaves as flash steam and condensate.

<u>**Slide 29 - Orifice Steam Traps 3**</u>

This type of trap has no moving parts, which serves as the main benefit of this device—maintenance requirements are low. It is critical to properly size this type of trap. If the trap is larger than necessary then significant amounts of live-steam will be lost to the condensate system. If the trap is smaller than necessary then condensate will backup into the system. Even though the main benefit of this trap is reduced maintenance requirements; proper sizing can lead to a small orifice diameter in the trap. This can become easily plugged with debris. .

[Slide Visual – Orifice Steam Trap]

Condensate passes through a restriction (represented by a narrow gap) and leaves as flash steam and condensate.

- **No moving parts**
- **Continuous operation**
- **Common applications are steady loads**
- **Limited air removal capability due to orifice limitations**

Slide 30 - Steam Trap Failures

In order to investigate steam traps, we must understand how they operate and how they fail. There can be many different failure modes for steam traps that can make managing the trap population difficult. However, it is good to note that two failure modes, in particular, typically provide the greatest impact to an industrial site. The first failure mode that impacts sites most significantly is when a trap fails closed. A failed closed steam trap typically does not waste energy; however, the economic impact can far exceed energy costs. This is because the device that is served by the failed steam trap will not be functioning properly. This can cause reduced production rates, poor quality, and water-hammer related failures.

The other failure mode that impacts sites most significantly is when a trap fails open, blowing a significant amount of steam. This failure mode obviously wastes steam and results in energy loss.

Again, there are other failure modes including leaking and intermittent operation, but these two failure modes impact site operations most significantly. This is actually good news, because these two types of failure are the easiest to identify. A steam trap failed open and blowing will exhibit high temperature and high noise. If the outlet of the trap can be seen the steam plume will be a direct indicator of the failure. Even if the trap discharges to a closed condensate collection system, the condensate receiver steam plume is an excellent indicator. Often this type of failure presents elevated pressure in the condensate return piping and can even result in presenting enough backpressure on other steam traps in the system, so they are not capable of functioning properly. Water-hammer in the condensate system is also a symptom of open and blowing steam traps.

On the other hand, steam traps that are failed closed will exhibit low temperature and no sounds of operation. It is not recommended to look only for open blowing steam traps and closed steam traps; however, the identification and repair of these types of failed traps has the potential of significantly improving steam system operations.

[Slide Visual – Steam Trap Failures]

- **Failure modes**
  - **Failed closed**
  - **Failed open**
  - **Failed partially leaking or partially closed**
- **Failed open and failed closed result in the greatest system impacts**
  - **These failure modes are the most readily recognized**
  - **These failures should be of first priority**

Slide 31 - Trap Investigation

The common tools used to investigate steam trap operation are temperature, sound, and sight.

[Slide Visual – Steam Trap Investigation]

Steam Trap Investigation

- **Visual**
- **Acoustic**
- **Thermal**
- **Combined methods**
- **In-line monitoring**

Slide 32 - Visual Trap Investigation

Steam traps that have visible outlets can often be easily identified as properly operating or failed. However, most of the steam traps in the industrial sector are connected to closed condensate systems because we want to recover the condensate and flash steam.

[Slide Visual – Visual Steam Trap Investigation]

- **Limited in applicability**
  - **Most condensate systems are closed**
  - **Safety and practicality limit use of this method**
- **Individual trap operation must be understood**

Slide 33 - Acoustic Trap Investigation

As a result, we must use listening devices and thermometers as our primary investigation tools. Ultrasonic instruments can provide excellent diagnostic capabilities.

[Slide Visual – Acoustic Steam Trap Investigation]

- Many instruments are available
- Individual trap operation must be understood
- Ultrasonic sensing is typically the most practical

Slide 34 - Thermal Trap Investigation

Contact thermometers and thermal imaging instruments can provide excellent support.

[Slide Visual – Acoustic Steam Trap Investigation]

- Many instruments are available
- Individual trap operation must be understood
- Data can be inconclusive

Slide 35 - Combined Trap Investigation

Combining investigation methods is the best analysis methodology.

In order to implement a world-class steam trap management program each trap must be investigated frequently—at least annually. The investigation must determine if the trap is functioning properly or if it is in a form of failure. If the trap is failed, the failure mode must be identified.

For traps that are failed open and blowing, an estimate of the steam loss should be developed. This will allow a repair priority to be established. Accurately evaluating steam loss through failed traps and leaks can be very difficult. However, keep in mind that we are really interested in the order-of-magnitude of the loss. As a result, a simple estimating technique can be useful. Steam traps are designed with a restrictive valve, opening, or channel—a limiting flow area.

Using this limiting orifice and the steam pressure in the trap the maximum steam loss possible can be calculated. There are many factors that can impact the actual flow through the trap; but, they should decrease the actual flow rather than increase it. A dominant factor is if some of the internal trap components partially block the opening. Alternately if a significant portion of the flow is condensate, the steam loss will be reduced; however, it takes a very large condensate flow to reduce the steam flow significantly. A simple orifice calculation or a table like the one presented previously in this training can provide a foundation for an order-of magnitude steam loss estimate.

Slide 36 - Trap Investigation

Additional investigation points should also be targeted when determining if each trap is functioning properly or not. Identifying if the trap is the correct type for the application is an important investigation. Evaluating if the trap is installed properly is very important.

Each trap will experience two-phase flow not only exiting the trap as flash steam forms but also entering the trap as steam pushes condensate through the trap. In fact, in many applications, the trap inlet piping will experience two-direction flow as the steam in the trap body is displaced by condensate

entering the trap. And do not forget that non-condensable gases will also be present in the steam system. As a result, we'd like to have the trap inlet pipes as short, as big, and as straight as possible. Gravity should be the primary force allowing condensate to flow into the trap and the pipe arrangement should allow steam to flow out.

Slide 37 - Trap Survey Investigation

Another good question to ask of each trap is if condensate is collected from the trap. It is important to investigate if the condensate is actually being collected or if some problem is preventing the condensate from being returned to the boiler with the highest practical temperature. Recall that there are many excellent reasons to recover condensate, but the primary worth of condensate resides in its temperature. Condensate needs to reach the boiler with the highest practical temperature.

Very often, effective condensate recovery is hampered from poor design of the return piping. Many times the return piping is tasked with transporting both liquid condensate and flash-steam. Often the mass flow of flash-steam is a relatively small portion of the total flow, but because the density of the flash-steam is very low, the volume flow of the flash steam can be a large portion of the total volume flow. This can result in water-hammer problems and backpressure issues. The problem can be exacerbated if a steam trap fails open discharging live steam into the condensate system. There can be a significant amount of energy in the flash-steam; but, if it is resulting in the loss of all the condensate, then it may be best to vent the flash steam from the system and pump the liquid condensate back to the boiler.

Slide 38 - Maintenance Program 1

A world-class steam trap management program will incorporate all of these aspects to ensure the steam traps and collection systems are operating at peak performance.

Every steam trap in the facility should be evaluated at least one time each year. The evaluations 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.

The assessment results should be compiled in a database that includes the analysis result for the trap—good, failed leaking, failed blowing, failed closed.

A loss estimation for each failed leaking trap should be established. This will be an estimate of the steam loss from the failed trap. An excellent method to establish the maximum steam loss through a failed trap is to obtain the diameter of the trap valve opening—this is the minimum opening restricting the steam flow. This information along with the operating pressure of the trap can be used to complete an orifice calculation to determine the maximum steam flow that can pass through the steam trap if the trap is failed in an unobstructed manner. This will serve as the maximum steam loss for a particular trap. Difficulty arises in identifying if a trap is failed with no internal obstructions or partially obstructed and if the trap is partially obstructed then what fraction of the maximum flow should be assigned to the trap. However, an order-of-magnitude loss estimate is generally sufficient to allow repair prioritization to occur.

Additionally, the trap discharge pressure should be considered because the trap backpressure can reduce the maximum steam flow that can pass through a restriction.

During the steam trap assessment, additional investigations should be targeted. For example, each installation should be evaluated to determine if the most appropriate trap type has been installed. Steam traps must be installed properly to function appropriately. This is true for the trap orientation and for the trap inlet and outlet piping. The trap piping will be required to carry two-phase flow, which significantly impacts the design. Commonly trap inlet piping will also require two-direction flow as condensate displaces steam in the trap and piping. Many additional installation factors should be considered.

The steam trap investigation is an excellent time to determine if condensate is recovered from the trap. If condensate is not recovered the recovery strategy should be investigated.

[Slide Visual – World Class Steam Trap Maintenance Program]

- **Training is essential.**
- **Investigate each trap at least one time each year (problem areas and high pressure should be more frequent)**
  - **Performance**
    - **Testing equipment is required**
    - **An order of magnitude leak rate should be determined for failed traps**
      - **Orifice calculations set the maximum steam flow**
  - **Trap type**
    - **Trap selection should match the application**
    - **Universal mounts can be a good option**
  - **Installation**
  - **Establish an investigation route**
  - **Condensate return**
  - **Outsourcing can be a good option**

Slide 39 - Maintenance Program 2

During the steam trap evaluation process, each trap in the facility is identified—this is a good time to develop a database that includes each trap in the facility. This allows a history of each application to be developed.

A single steam trap failed open can result in significant economic loss for the site; making steam trap management essential for most facilities. An excellent diagnostic tool that can be employed at many facilities is to visually observe the atmospheric vents of the condensate receivers. Most steam traps will appropriately form flash-steam that will pass through the condensate receiver vents; but, excessive vent steam flow indicates failed steam traps.

[Slide Visual – World Class Steam Trap Maintenance Program]

- **Maintain a steam trap database**
- **Prioritize repairs based on loss estimates**
- **Daily monitor receiver vents**
- **Training is essential**

Slide 40 - Trap Selection 1

This is an example of the importance of steam trap selection. In this example a steam coil is serving an air handling unit on a drum oven. A drum oven is basically a room that can be filled with 55 gallon drums. The room (or oven) is sealed and air is circulated from the oven, through a steam coil, and back to the oven to heat the contents of the drums. In this particular case, the drums contained various petroleum products that were being supplied to a production plant.

The facility was developing a project to replace the drum oven with one of larger capacity because the drum oven was the bottleneck of the process. The production rate of the entire plant was limited because the drums could not be heated fast enough. We were requested to investigate the oven and determine the capacity the new unit should have to allow production to be increased.

The desired supply air temperature in the drum oven was 310 degrees Fahrenheit. However, we measured a supply air temperature of approximately 280 degrees Fahrenheit. The steam coil was supplied with steam through a fully open control valve and the steam pressure in the steam coil was essentially the same as the main supply pressure of 135 PSIG. The saturation temperature of the steam supply was 358 degrees Fahrenheit.

During our investigation we observed that the steam coil was served with a thermostatic steam trap. This trap was opening when the condensate temperature was 285 degrees Fahrenheit—more than 30 degrees Fahrenheit of subcooling. As a result, the steam coil was mostly filled with condensate. This dramatically reduced the amount of energy transfer.

[Slide Visual - Steam Trap]

The schematic shows an oven, basically a closed room. Air is circulated from a mix of makeup air and from the oven to the room and across a steam coil, mostly filled with condensate. The saturation steam is supplied at 135 psig and 358 degrees Fahrenheit through a control valve. AThermostatic steam trap discharges condensate at 135 psig and 285 degrees Fahrenheit.

Slide 41 - Trap Selection 2

Rather than replacing the drum oven we replaced the thermostatic steam trap with a float-and-thermostatic steam trap. Immediately the supply air temperature increased to the point that the steam control valve regained control of the oven. The drum oven replacement project was canceled.

[Slide Visual - Steam Trap]

The schematic shows an oven, basically a closed room. Air is circulated from a mix of makeup air and from the oven to the room and across a steam coil. The saturation steam is supplied at 135 psig and 358 degrees Fahrenheit through a control valve. A Float and Thermostatic steam trap discharges condensate at 135 psig and 358 degrees Fahrenheit.

Slide 42 - Insulation

Insulation is a very important aspect of all steam systems. Most steam systems have a large amount of steam and condensate piping located throughout the plant. Huge energy losses can result if the distribution system is not properly insulated.

[Slide Visual – Steam Distribution Losses –Heat Loss Through Insulation]

Banner:
DOE's BestPractices
Steam End User Training

Steam Distribution Losses
Steam Leaks – Pipe Failures and Trap Failures
Heat Transfer Loss Through Insulation
Condensate Loss
Overall System

Slide 43- Insulation Issues

The fundamental aspect of insulation can be thought of as "is it there or not". We are not trying to make light of the very important factors; such as, insulation type, insulation thickness, and installation methods. However, a short length of un-insulated steam pipe can experience the same loss as a very long length of poorly selected insulation. In other words, we are not advocating ignoring insulated pipe but the largest losses and most important opportunities typically reside in repairing areas with missing insulation, badly damaged insulation, or water related issues. Opportunities related to missing or badly damaged insulation typically have simple paybacks in the fraction of a year range.

Slide 44 - Missing Insulation

In order to emphasize the primary points associated with insulation we will examine an example. During our investigation of the steam system we observed a section of the main steam distribution piping to be un-insulated. This steam header is insulated for most of its length; but as shown in the picture, as it transitions from one side of the pipe-bridge to the other it is un-insulated.

There is about 20 linear feet of un-insulated pipe. Most of this pipe is horizontal but two short sections are vertically oriented. The nominal diameter of the header is 10 inches. The pipe contains medium-pressure steam and an infrared thermometer indicates the pipe surface temperature is 550 degrees Fahrenheit.

The calculations required to estimate the heat transfer reduction from installing thermal insulation are lengthy and complicated. U.S. DOE offers a specialized software tool that simplifies the analysis tremendously—the software tool is 3E-Plus.

[Slide Visual – Missing Insulation Photo]

- **A 20 foot long section of 150 psig header is observed to be un-insulated**
  - **10 inch nominal diameter**
  - **Steam temperature is approximately 550°F**

A photograph of an industrial pipe bridge is shown. The piping is somewhat congested but fairly typical of an industrial plant. One of the pipes, prominently displayed in the picture, is a steam header that has a section with no insulation. The un-insulated section has horizontal and vertical runs. This run has four 90-degree elbows which allow the pipe to avoid an obstruction. The piping distribution runs from left to right, engages an elbow to allow the piping to be raised, then an elbow to allow the piping to run toward the viewer and over a structural member, engage another elbow to turn down to the original elevation, then another elbow to continue to advance to the right. The pipe at the left of the picture is observed to be insulated with a metal jacket covering the assembly. However, in a very short distance the insulation and covering are removed leaving the pipe un-insulated through the turns and straight sections. Insulation and jacketing are in-place on the pipe as it leaves the picture to the right.

<u>Slide 45 - 3E Plus Insulation Tool</u>

3EPlus is designed to complete analyses on all common insulation projects. The software is very user friendly and very powerful. Let's use this tool to determine the economic impact of insulating the steam header we saw with the missing insulation.

[Slide Visual – 3EPlus Software]

The first screen of the 3E Plus Insulation tool is shown. It says "3E Plus Insulation Thickness Computer Program.

Determining your insulation needs has never been easier.

3EPlus Insulation Thickness Computer Program
- **Calculates Thermal Performance of Piping and Equipment**
- **Translates BTU Losses into Actual Dollars**
- **Calculates Greenhouse Gas Emissions and Reductions.**

<u>Sections of the Program [buttons at top of page, descriptions on main screen]</u>
Energy
- **Insulation Thickness**
- **Energy Loss/Gain**
- **Cost of Energy**

Environment
- **CO2 Reduction with Insulation Thickness**

Economics
- **Calculations for New Insulation Projects**
- **Calculations from Previous Projects**

Brought to you by NAIMA North American Insulation Manufacturers Association

<u>Slide 46 - 3E Plus 1</u>

The software opens to a page that allows the user to input specific data concerning the insulation opportunity. In this example we assume all of the pipe is horizontal; even though we know there are vertical sections of the pipe as well. We have selected this for simplicity—we can attain a more detailed result if the analysis is broken into horizontal and vertical sections.

It is good to note at this point that the 3EPlus software is based in the principles of heat transfer and physics and it rigorously solves the governing equations for each scenario. However, it should be noted that the variability of the real world parameters governing the situations is significant. As a

result, the analysis must be considered an estimate. For example, we will input a wind speed into the analysis as 3 miles per hour. There is significant real-world variability in wind speed and wind speed has a major impact on the energy loss from the piping system.

The remaining input data is straightforward. We are working with typical piping; as a result, we will select ASTM C-585, which is the designation for common piping. If you are working with tubing another selection can be made.

There are many calculation types that can be selected from. In this example we will choose Heat Loss per Year. This will set the calculation results to an annual basis.

We have measured the pipe surface temperature to be 550 degrees Fahrenheit, which can be taken as the Process Temperature. Ambient Temperature is taken as 70 degrees Fahrenheit, which is conservatively high for the annual average ambient temperature.

The pipe is a 10 inch Nominal Pipe Size or NPS. The wind speed has been selected as 3 miles per hour.

The steam system serving this site is in operation 24 hours a day and 365 days a year; in other words, 8,760 hours per year.

All of this information in the upper portion of the page is basic to the analysis. Now in the lower section of the page we select the specific insulation properties.

The pipe material is steel. The insulation that is in-place on the remainder of the pipe is calcium silicate. Because we are addressing a short section of existing piping and insulation we will most probably install the same insulation and jacket material the rest of the system has. However, it is good to note that the software has the properties of the common insulation materials built in. The insulation on the remainder of the pipe is 3 inches thick and covered with an aluminum jacket. This jacket will be oxidized in service fairly quickly.

[Slide Visual -3EPlus Energy Tab – Insulation Thickness]

Insulation Thickness –
Surface Temperatures
Condensation Control
Personal Protection

Energy Tab
Insulation Thickness (Data Entry Screen)
Item Description: missing insulation
System Application: Pipe Horizontal
System Units: ASTM C585
Calculation Type: Heat Loss Per Year
Process Temperature :550.0 F
Ambient Temperature: 70.0 F
NPS Pipe Size: 10
Wind Speed: 3 mph

Annual Operation: 8760 hours per year

Insulation Layers
Add Button
Delete Button

#	Type	Name	Lock Thickness	Thickness, Inches
-	Base Metal	Steel		
1	Insulation	BLK+PIPE, Type I, C533-07	Fix	3
-	Jacket Material	0.1 Aluminum, oxidized, in service 07		

Slide 47 - Insulation Evaluation

When the Cost of Energy selection is made the user is allowed to input fuel cost which is used to evaluate the economic impact associated with installing the selected insulation.

Fuel type along with fuel higher heating value also become input parameters.

Another input parameter is Efficiency. This Efficiency is in reference to the fact that for every unit of thermal energy loss eliminated even more fuel energy consumption is eliminated. The main contributor to this additional loss is boiler efficiency. As a result, inputting boiler efficiency will more accurately identify the fuel cost impact associated with installing insulation.

[Slide Visual -3EPlus Energy Tab – Cost of Energy]

Cost of Energy –
Bare and Insulated Surfaces

Energy Tab
Insulation Thickness (Data Entry Screen)
Item Description: missing insulation
System Application: Pipe Horizontal
System Units: ASTM C585
Fuel Type: Natural Gas
Heat Content: 1000 BTU/cubic foot
Fuel Cost: 10.00 $/Mcf
Efficiency: 80 percent
Process Temperature :550.0 F

Ambient Temperature: 70.0 F
NPS Pipe Size: 10
Wind Speed: 3 mph
Annual Operation: 8760 hours per year

Insulation Layers
Add Button
Delete Button

#	Type	Name	Lock Thickness	Thickness, Inches
-	Base Metal	Steel		
1	Insulation	BLK+PIPE, Type I, C533-04	Fix	3
-	Jacket Material	0.1 Aluminum, oxidized, in service 07		

Slide 48 - Insulation Savings

The software calculates the energy loss from the uninsulated pipe and for the insulated pipe. The difference in these two energy losses is the savings opportunity associated with installing insulation. The boiler fuel impact is calculated as more than $600 per year for every foot of un-insulated pipe. In other words, insulating 20 feet of un-insulated pipe will reduce fuel purchases approximately $12,000 per year.

[Slide Visual – 3EPlus – Cost of Energy]

Cost of Energy –
Bare and Insulated Surfaces

Energy Tab
Item Description = Missing Insulation
System Units = ASTM C585
Geometry Description = Steel Pipe - Horizontal
Bare Surface Emittance = 0.8
Nominal Pipe Size = 10 in.
Process Temperature = 550 °F
Ave. Ambient Temperature = 70 °F
Ave. Wind Speed = 3 mph

Fuel Type: Natural Gas
Heat Content: 1000 BTU/cubic foot
Fuel Cost: 10.00 $/Mcf
Efficiency: 80 percent
Hours Per Year = 8760
Outer Jacket Material = Aluminum, oxidized, in service
Outer Surface Emittance = 0.1
Insulation Layer 1 = Calcium Silicate BLK+PIPE, Type I
Thickness: 3.08 in.

Append to Audit - Browse

Variable Insulation Thickness	Cost ($/ft/yr)	Heat Loss (Btu/ft/yr)	Savings ($/ft/yr)
Bare	636.90	50950000	
Layer 1	28.74	2300000	608.200

Savings = 608 $/ft-yr (20 ft) – 12,000 $/hr

<u>Slide 49 - 3E Plus 2</u>

3EPlus also incorporates an estimating tool that allows insulation purchase and installation costs to be evaluated. This tool incorporates standard costs for insulation materials and insulation jacked materials. These standard costs can be adjusted by the user to reflect local costs. Additionally, the tool estimates the time required for an insulating crew to install the materials. The user is allowed to input local labor rates along with construction difficulty rates. These items allow the purchase and installation costs to be estimated for the insulation project. This cost estimating tool is found in the Economics section of 3EPlus.

Using the project estimator in 3EPlus this project would require approximately 600 dollars to complete. In other words, this is a very attractive project.

[Slide Visual – 3EPlus – Project Costs]

($28.76 per Linear Foot) (20 Linear Feet) ~ $600 Project Costs

[Slide Visual – 3EPlus - Economics Tab]

Thickness Calculations
New Project

Economics Tab
Cost and Thickness Data
Surface number: 17

Pipe Size: 10

Single Layer

Thick	Cost
1	0.00
1.5	18.05
2	22.20
2.5	25.61
3	28.76
4	35.82

Double Layer

Thick	Cost
3	32.26
4	41.82
5	51.54
6	61.29
0	0.00
0	0.00

Triple Layer

Thick	Cost
6	69.17
7	81.04
8	92.83
9	99.73
10	115.57
0	0.00

Back, Next, and Calculate buttons at the bottom of the screen.

<u>**Slide 50 – Equivalent Steam Demand**</u>

When evaluating insulation projects in cogeneration systems significant care must be exercised because low-pressure steam will have a different worth than high-pressure steam. High-pressure steam is typically worth fuel cost divided by boiler efficiency. This is the method 3EPlus uses in the Cost of Energy calculation.

In cogeneration systems the impact cost of low-pressure steam can be less than one half the impact cost of high-pressure steam. We are referring to the true economic impact the site will experience by reducing the thermal loss at low-pressure.

In instances where the insulation project impacts steam that is not the same cost as high-pressure steam a slightly more complicated analysis is required. This analysis determines the impact the missing insulation has on the site steam demand. 3EPlus will be used in a similar manner to determine the energy savings from the insulation project. Then the energy impact will be converted into a steam system impact.

We will repeat our insulation example by considering that the steam header with the missing insulation is a medium-pressure steam header that is part of a plant that cogenerates. Because of the cogeneration aspects of the system reducing low-pressure or medium-pressure steam demand will not only impact fuel purchases but will also impact electrical purchases.

Consider that the steam supplied to this heat exchanger passes through the section of uninsulated pipe identified in the previous example. This uninsulated section of pipe becomes a part of the thermal load of the plant. In effect the thermal load of the heat exchanger has increased by the amount of heat transfer from the uninsulated pipe. This increase in thermal load has increased the amount of fuel required in the boiler. Additionally, this thermal load has impacted the amount of steam passing through the turbine supplying the medium-pressure system. As a result, the unit cost of medium-pressure steam should be used to determine the economic impact associated with insulating the header.

Therefore, we will use 3EPlus to determine the impact the uninsulated section of pipe has on thermal load. Then we will determine how much additional steam must be supplied to the heat exchanger because of the increased thermal load. The impact cost of steam will be used to identify the economic impact of installing the insulation.

[Slide Visual – Equivalent Steam Demand]

Heated material enters the left side of a heat exchange and exits the right side.

Steam supply enters the heat exchanger through a run of piping, mostly insulated, but there is a bare area approximately 20 feet long. An arrow indicates the bare pipe with the note 'Heat transfer loss from un-insulated pipe".

Condensate exits the heat exchanger at the bottom through a steam trap.

An insert photo of the bare piping is located in the upper right hand corner of the slide.
A photograph of an industrial pipe bridge is shown. The piping is somewhat congested but fairly typical of an industrial plant. One of the pipes, prominently displayed in the picture, is a steam header that has a section with no insulation. The un-insulated section has horizontal and

vertical runs. This run has four 90-degree elbows which allow the pipe to avoid an obstruction. The piping distribution runs from left to right, engages an elbow to allow the piping to be raised, then an elbow to allow the piping to run toward the viewer and over a structural member, engage another elbow to turn down to the original elevation, then another elbow to continue to advance to the right. The pipe at the left of the picture is observed to be insulated with a metal jacket covering the assembly. However, in a very short distance the insulation and covering are removed leaving the pipe un-insulated through the turns and straight sections. Insulation and jacketing are in-place on the pipe as it leaves the picture to the right.

Slide 51 – Insulation Savings

The previous 3EPlus evaluation identified the heat transfer from the uninsulated pipe and the heat transfer that will occur from the insulated pipe. The difference in these two values is the energy that will be saved if the pipe is insulated—this is the reduction in thermal load.

[Slide Visual – Equivalent Steam Demand – 3EPlus]

Cost of Energy –
Bare and Insulated Surfaces

Energy Tab
Item Description = Missing Insulation
System Units = ASTM C585
Geometry Description = Steel Pipe - Horizontal
Bare Surface Emittance = 0.8
Nominal Pipe Size = 10 in.
Process Temperature = 550 °F
Ave. Ambient Temperature = 70 °F
Ave. Wind Speed = 3 mph
Fuel Type: Natural Gas
Heat Content: 1000 BTU/cubic foot
Fuel Cost: 10.00 $/Mcf
Efficiency: 80 percent
Hours Per Year = 8760
Outer Jacket Material = Aluminum, oxidized, in service
Outer Surface Emittance = 0.1
Insulation Layer 1 = Calcium Silicate BLK+PIPE, Type I
Thickness: 3.08 in.

Append to Audit - Browse

Variable Insulation Thickness	Cost ($/ft/yr)	Heat Loss (Btu/ft/yr)	Savings ($/ft/yr)
Bare	636.90	50950000	
Layer 1	28.74	2300000	608.200

Slide 52 – Converted Steam Loss

A quick calculation indicates the uninsulated section of pipe increases the thermal demand by 111,000 BTU per hour.

[Slide Visual – Energy Loss Converted to Steam Loss Calculation 1]

$\text{Q-dot}_{total} = \text{q-dot}_{per\ length}\ L_{total}$

Heat Loss is the sum of the heat loss per length multiplied by the length of the item.

Q-dot_{total} = (50,950,000 Btu/yr-ft – 2,300,000 Btu/yr-ft) (20 feet) (1 year / 8,760 hrs)

Heat Loss equals 50,950,000 Btu/yr-ft minus 2,300,000 Btu/yr-ft; multiplied by 20 feet; multiplied by 1 year divided by 8,760 hrs.

Q-dot_{total} = 111,000 Btu/hr

Heat Loss equals 111,000 Btu per hour

Where:

Q-dot_{total} = Heat Loss

$q_{per\ length}$ = Heat Loss per unit length

L_{total} = Length

Slide 53 – Converted Steam Loss 2

The heat exchanger will require enough steam to satisfy this uninsulated section of pipe as well as the legitimate heat exchanger demand. This increase or impact in steam flow is determined through a first law of thermodynamics analysis of the un-insulated pipe and the heat exchanger. This is compared to the same heat exchanger load with the pipe insulated.

This additional steam demand will be eliminated when the pipe is insulated.

[Slide Visual – Energy Loss Converted to Steam Loss Calculation 2]

Location	Temp [°F]	P [psia]	Specific Volume [ft³/lbm]	Enthalpy [Btu/lbm]	Entropy [Btu/lbm°R]	Quality [%]	P [psig]
	Properties						
Medium Pressure	550	164.7	3.54075	1,298.86	1.67502	****	150
Saturated Vapor	366	164.7	2.75693	1,195.57	1.56726	100.0	150
Saturated Liquid	366	164.7	0.01818	338.36	0.52323	0.0	150

$$\text{m-dot}_{steam} = \frac{\text{Q-dot}_{total}}{(h_{steam} - h_{condensate})}$$

Mass flow rate of the steam is equal to the Total Heat Loss Converted to Steam divided by the difference in the enthalpy of the steam and the enthalpy of the condensate.

$$\text{m-dot}_{steam} = \frac{111{,}000 \text{ Btu/hr}}{(1{,}298.86 \text{ Btu/lbm} - 338.36 \text{ Btu/lbm})}$$

Mass flow rate of the steam is equal to 111,000 Btu/hr divided by the difference of 1,298.86 Btu/lbm minus 338.36 Btu/lbm.

m-dot_{steam} = 115 lbm/hr

Mass flow rate of the steam is equal to 115 pounds per hour.

Where:

m-dot_{steam} = Mass flow rate of steam generated in the boiler
h_{steam} = Enthalpy of the steam
$h_{condensate}$ = Enthalpy of the condensate
Q_{total} = Total Heat Loss

Slide 54 – Converted Steam Loss 3

The impact steam cost can be applied to this steam demand. Impact steam costs can be developed from steam system analyses like the ones completed with the SSAT software tool.

Again, this type of analysis is required for cogeneration systems—when the cost of steam is impacted by turbine operations. Often in cogeneration systems the impact cost of low-pressure steam is less than 50 percent of the cost of high-pressure steam.

[Slide Visual – Energy Loss Converted to Steam Loss Calculation]

K-dot$_{Steam}$ = m-dot$_{steam}$ k$_{steam}$

Impact Heat Loss is equal to the mass flow rate of the steam multiplied by the cost of the steam.

k$_{steam}$ is circled with a note "If the cost of steam is known."

K-dot$_{Steam}$ = (115 lbm/hr) (14.53 \$/10^3 lbm) = 1.68 \$/hr

Impact Heat Loss is equal to 115 pounds per hour multiplied by \$14.53 per 1,000 pounds of steam equal \$1.68 per hour.

K-dot$_{Steam}$ = 1.68 \$/hr (8760 hrs/1 yr) = 14,000 \$/yr

Impact Heat Loss is equal to \$1.68 per hour multiplied by 8,760 hours per year equals \$14,000 per year.

Where:
K-dot$_{Steam}$ = Impact Heat Loss Cost
m-dot$_{steam}$ = Mass flow rate of steam generated in the boiler
k$_{steam}$ = Cost per pound of steam (known)

Marginal Steam Costs (based on current operation)	
HP (\$/klb)	16.01
MP (\$/klb)	14.53
LP (\$/klb)	13.87

SSAT steam demand project can also be utilized

Slide 55 - Condensate Loss

Condensate recovery is a vital part of effective steam system management.

[Slide Visual – Steam Distribution Losses –Condensate Loss]

Banner:
DOE's BestPractices
Steam End User Training

Steam Distribution Losses
Steam Leaks – Pipe Failures and Trap Failures
Heat Transfer Loss Through Insulation
Condensate Loss
Overall System

Slide 56 - Condensate Recovery

Condensate is generally the cleanest water on the plant site—recovery of it can reduce boiler blowdown rates and reduce boiler chemical requirements. However, almost always the dominant worth of condensate is the thermal energy resident in it. Every pound of condensate that can be returned at 180 degrees Fahrenheit, for example, will eliminate the need to purchase a pound of makeup water at possibly 70 degrees Fahrenheit. The steam system would be required to heat the makeup water from 70 degrees Fahrenheit to 180 degrees Fahrenheit—the condensate would not require this energy expenditure.

[Slide Visual – Condensate Recovery]

- **Condensate typically has an energy value**
- **Make-up water typically has a value**
- **Condensate recovery costs generally center on the recovery system piping**
- **Increased condensate return reduces makeup water requirements, which generally improves feedwater quality**

Slide 57 - Return Example 1

We will explore a simple example that will identify the impacts associated with condensate recovery. In this example, a heat exchanger discharges 212 degrees Fahrenheit condensate straight to the sewer. We used a 5 gallon bucket and a stopwatch to measure the condensate flow to the drain. It took about 30 seconds for a 5 gallon bucket to fill up, which means the condensate flow is about 10 gallons per minute. This translates into about 5,000 pounds per hour of condensate that can be recovered. How beneficial is it to get this condensate back to the boiler and what would be required to recover the condensate?

[Slide Visual – Condensate Return Example]

The schematic depicts condensate return in a heat exchanger. Heated material and high pressure steam enter into the heat exchanger through several passes. Steam exits the heat exchanger through a steam trap and discharges to sewer.

- **Measured condensate temperature 212°F.**
- **Condensate flow measured by bucket and stopwatch (mass and energy balance is also a common method) to be 10 gallons/minute (5,000 lbm/hr)**

Slide 58 - Return Example 2

The classic condensate recovery method is to route the steam trap discharge to a vented condensate receiver. The receiver will be equipped with a pump and a level control device. The pump will transfer condensate from the receiver to the condensate return pipe and ultimately to the boiler. The condensate return piping and equipment should be insulated to ensure the thermal energy of the condensate is recovered.

[Slide Visual - Condensate Return Example 2]

The schematic depicts condensate return in a heat exchanger. Heated material and high pressure steam enter into the heat exchanger through several passes. Steam exits the heat exchanger through a steam trap and then routed to a vented condensate receiver. It is transferred to an insulated condensate return pipe and ultimately pumped to the boiler. A Level Controller senses the liquid level in the receiver.

- **The energy savings opportunity is based on the temperature of the condensate recovered into the boiler as compared to the temperature of makeup water**

Slide 59 - Return Example 3

It is assumed that the condensate will return to the boiler area with a temperature of 180 degrees Fahrenheit. We can use SSAT to quickly and accurately determine the system impact associated with returning this condensate; however, we will use the simple energy equations here as a first order estimate.

[Slide Visual - Condensate Return Example 3]

The schematic depicts condensate return in a heat exchanger. Heated material and high pressure steam enter into the heat exchanger through several passes. Steam exits the heat exchanger through a steam trap and then routed to a vented condensate receiver. The condensate temperature is 212 degrees Fahrenheit. It is transferred to an insulated condensate return pipe and ultimately pumped to the boiler. A Level Controller senses the liquid level in the receiver.

- **Condensate temperature entering boiler water system is 180°F**
- **Makeup water temperature is 70°F**

Slide 60 - Return Example 4

The calculation identifies the additional fuel the steam system will require to heat the makeup water from 70 degrees Fahrenheit to 180 degrees Fahrenheit—which is the temperature of the condensate as it returns to the boiler. The worth of the condensate from this one heat exchanger is 60,000 dollars per year of fuel purchases.

[Slide Visual - Condensate Cost Savings Equations]

$$o_{condensate} = \frac{\dot{m}_{condensate}\,(h_{condensate} - h_{makeup})\,T}{n_{boiler}}\,k_{fuel}$$

Condensate Cost Savings is equal to the mass flow rate of the condensate multiplied by the difference of the enthalpy of the condensate and the enthalpy of the makeup water; multiplied by the operating period; multiplied by the cost of fuel; all divided by the boiler efficiency.

$$o_{condensate} = 5{,}000\ \text{lbm/hr}(147.91\ \text{Btu/lbm} - 38.05\ \text{Btu/lbm})(8{,}760\ \text{hours/year})(10.0\ \$/10^6\text{Btu})(1/0.80)$$

Condensate Cost Savings is equal to 5,000 lbm/hr multiplied by 147.91 Btu/lbm minus 38.05 Btu/lbm; multiplied by 8,760 hours per year; multiplied by $10.00 per million Btu; all divided by 0.80.

$$o_{condensate} = 60{,}000\ \$/\text{year}$$

Condensate Value is equal t0 $60,000 per year.

Where:

$o_{condensate}$	= Condensate Cost Savings
m-dot$_{condensate}$	= Mass flow rate of condensate generated in the boiler
k_{fuel}	= Cost of the fuel
h_{makeup}	= Enthalpy is energy content of the makeup water
$h_{condensate}$	= Enthalpy is energy content of the condensate
n_{boiler}	= Boiler efficiency

Slide 61 - Condensate Recovery

Often condensate systems function poorly because they attempt to transport condensate and steam together. It must be understood that a significant amount of energy resides in the flash-steam collected in the condensate system. However, if there is no effective use of the flash-steam then it may be beneficial to simply vent the flash-steam through a local condensate receiver to allow effective recovery of the remaining condensate. This will allow us to pump water back into the boiler without the problems associated with transporting liquid and vapor together.

A common failure mode of condensate receivers is pump failure. Often the pump-receiver combination is improperly designed and the condensate actually boils as it enters the pump. This condition is identified as cavitation and is very detrimental to the life of the pump. Often condensate receiver-

pump arrangements are designed for less than 180 degrees Fahrenheit condensate. The cavitation problems develop from the fact that many steam traps discharge saturated liquid condensate, which will be 212 degrees Fahrenheit as it enters the receiver (assuming standard atmospheric pressure).

Most condensate recovery systems must be designed with an elevated receiver and the pumps well below the receiver to ensure sufficient static pressure to eliminate the possibility of boiling in the pump.

Slide 62 - Cascade Condensate Systems

If we have an opportunity to utilize the flash steam collected in the condensate system then this can greatly improve the energy efficiency of the steam system. Cascade condensate collection systems can make excellent use of the thermal energy resident in the flash steam. Additionally, cascade condensate collection systems minimize the impact of failed steam traps because live steam is directed to the lower pressure steam systems.

[Slide Visual – Cascade Condensate Systems]

The schematic depicts condensate return in a heat exchanger. Heated material and high pressure steam enter into the heat exchanger through several passes. Steam exits the heat exchanger through a steam trap. Condensate and steam from the steam trap, along with steam from additional steam traps, are collected in a condensate receiver tank with a level controller. Steam is then sent to the Low Pressure Steam System. Condensate is sent to the condensate system and may or may not be pumped.

Slide 63 - Overall System

At this point we want to draw our attention to an energy efficiency improvement strategy that is often recommended for steam system management.

[Slide Visual – Steam Distribution Losses –Overall System]

Banner:
DOE's BestPractices
Steam End User Training

Steam Distribution Losses
Steam Leaks – Pipe Failures and Trap Failures
Heat Transfer Loss Through Insulation
Condensate Loss
Overall System

Slide 64 - Pressure Reduction 1

It is commonly recommended to reduce the steam system operating pressure to reduce operating costs. This is only attractive in systems that do not cogenerate—reducing the steam generation pressure of cogenerating systems is almost always counter-productive. However, when considering steam systems that do not have cogeneration components, reducing the operating pressure can reduce energy requirements.

[Slide Visual – Steam Pressure Reduction]

- **When steam is produced for heating purposes only, what benefit would be gained if boiler pressure were reduced?**

Slide 65 - Pressure Reduction 2

Some of the primary energy reductions result in the distribution system and arise from reduced leaks and reduced heat transfer losses. For example, if steam is distributed throughout the system at 150 PSIG rather than 200 PSIG then any leak will pass 30 percent less steam. Similarly, a failed steam trap will discharge less steam.

As the steam pressure is reduced, the saturation temperature of the steam is reduced. Steam systems that distribute saturated steam throughout the system will experience less heat transfer loss because of this reduced distribution temperature. Even systems that distribute superheated steam can possibly experience reduced heat transfer loss. Distributing 150 psig saturated steam will result in 7percent less heat transfer losses than distributing 200 psig saturated steam.

Additionally, as condensate is formed and collected it is typically passed through a steam trap to a condensate collection system. As the condensate enters the low-pressure condensate collection system some flash steam forms. Often this flash steam is exhausted from the system. When steam pressure is reduced the amount of flash steam generated in the condensate system is reduced.

Most often the largest potential impact associated with reducing steam pressure is an improvement in boiler efficiency. Boiler efficiency improves because the boiling temperature of the water reduces as steam pressure is reduced. In other words, there is a larger temperature difference between the boiling water and the flue gases, which allows more heat transfer. This will result in a reduced flue gas exit temperature and improved boiler efficiency.

It is not known exactly how an individual boiler will respond to reducing steam generation pressure but an estimate of the maximum expected decrease in flue gas temperature is the decrease in boiling temperature of the water in the boiler. As an example, consider a steam generation pressure that is originally 200 PSIG. The boiling temperature of the boiler water is nominally 388 degrees Fahrenheit for this condition. The boiling temperature of the water operating at 150 PSIG is 366 degrees Fahrenheit. As a result, the maximum flue gas temperature reduction is estimated to be 22 degrees Fahrenheit. The maximum impact on boiler efficiency is 0.6 percent. Generally, the actual impact will be less than this value. Therefore, care must be exercised in using this estimate. The presence of flue gas energy recovery components will decrease the impact on boiler efficiency.

It should be noted that the steam end-use components will continue to require the same thermal energy when supplied high-pressure steam or low-pressure steam. As a result, the mass flow rate of steam supplied to the end-use equipment may change.

[Slide Visual – Steam Pressure Reduction]

- **When steam is produced for heating purposes only, what benefit would be gained if boiler pressure were reduced?**
  - **Boiler efficiency improvement**
  - **Heat transfer losses are reduced**
  - **Leak losses are reduced**
  - **Condensate system flash steam losses are reduced**
    - **If the steam loads receive reduced pressure steam**

Slide 66 - Pressure Reduction Study 1

Let's examine the impacts experienced on a real steam system. The steam system in question is already operating at relatively low-pressure but it is the design condition of the system. Measurements indicated the system pressure averaged 54 PSIG initially. The pressure was reduced to 30 PSIG. The saturation temperature of the steam decreased from 301 degrees Fahrenheit to 274 degrees Fahrenheit—a 27 degrees Fahrenheit reduction in steam temperature. The flue gas temperature decreased 25 degrees Fahrenheit. The boiler was burning number 2 fuel oil and the efficiency improved 1 percentage point.

Slide 67 - Pressure Reduction Study 2

The heat transfer loss from the piping system decreased 10 percent. All steam leaks decreased 30 percent.

Even though the boiler efficiency impact is only one percent in this example it is very significant. This is because all of the fuel energy is exposed to this one percent change; as a result, the total fuel cost will be impacted by this change. Typically the boiler efficiency impact is the most significant from an economic standpoint.

The savings potentials from leaks, insulation losses, and condensate flash steam loss sound significant—and they can be significant; however, several factors should be considered. First, leaks should be managed to a small fraction of the total steam supply. Leaks that do exist will decrease but leaks are typically a small portion of the system demands.

Second, heat transfer losses from the distribution system will decrease as the steam temperature decreases. However, the distribution system should be insulated resulting in minimal system heat transfer loss even in systems with miles of steam piping.

Third, the condensate flash steam loss reduction only occurs on unregulated steam loads. In other words, if a steam trap is serving a heat exchanger that is controlled with a steam control valve then the pressure of the condensate as it passes through the trap will not be influenced by the steam distribution pressure. Often it is only the traps serving the main distribution piping that reduce their flash-steam loading when steam pressure is decreased.

Slide 68 - Pressure Reduction 1

There are several points of concern when considering reducing steam pressure.

[Slide Visual – Steam Pressure Reduction]

- **What are the major problems associated with reducing system pressure?**

Slide 69 - Pressure Reduction 2

The savings potential can be significantly diminished if the lower boiler pressure results in liquid carryover from the boiler. As the boiler pressure is reduced the relative steam velocity in the boiler increases for a given boiler load. This increases the potential for liquid carryover, which can result in loss of boiler chemicals and can present a mass loss from the system as the liquid flashes through the condensate collection system. Carryover can also harm downstream components by causing water-hammer and component erosion.

[Slide Visual – Steam Pressure Reduction]

- **What are the major problems associated with reducing system pressure?**
  - **Boiler carryover potential increases**
    - **Water-hammer**
    - **Increased water treatment costs**
    - **Poor boiler water chemistry control**
    - **Equipment fouling**
      - **Equipment corrosion**
    - **Equipment erosion**
    - **Energy loss**

Slide 70 - Pressure Reduction 3

The reduced density of the lower pressure steam will result in increased velocities in the distribution system. This can decrease steam pressures throughout the system and limit steam supply to critical components.

Many steam trap and condensate collection systems rely on steam pressure to move the condensate through the collection components. The capacity of all steam traps is directly related to steam pressure. Reducing the steam supply pressure can result in a mal-functioning condensate collection system.

Additionally, most steam heat exchangers and many other components control steam flow by throttling the steam based on demand requirements. If these components operate with a reduced pressure then the flash steam savings noted will not occur.

Also, consideration should be given to the fact that heat transfer losses should not be a major load; in other words, the steam system should be well insulated. Steam leaks should be minimized as well.

These factors reduce the potential impact of reducing steam pressure.

[Slide Visual – Steam Pressure Reduction]

- **What are the major problems associated with reducing system pressure?**
- **Steam supply problems resulting from increased frictional loss**
  - **Pipe diameter may not be sufficient to supply the steam demand**
  - **Valve size**
- **Condensate recovery and return issues resulting from reduced driving pressure**
- **Heat exchanger temperature difference reduces limiting heat transfer**

Slide 71 - Pressure Reduction 4

There are many issues to consider when examining steam pressure reduction. There are many potential benefits and just as many potential pitfalls.

[Slide Visual – Steam Pressure Reduction]

- **Boiler carryover can become a very serious problem resulting from reducing system pressure**
  - **Equipment fouling**
  - **Equipment erosion**
  - **Energy loss**
  - **Water hammer**
  - **Water treatment costs**
- **Pressure reduction can be accomplished after the boiler**
  - **Boiler efficiency improvement will not be attained**
    - **Boiler efficiency improvement is typically the largest impact**

Slide 72 - Pressure Reduction Caution

As a result, the decision to reduce steam system operating pressure should be thoroughly investigated.

[Slide Visual – Steam Pressure Reduction]

- **Exercise caution when implementing this activity**
  - **There are many potential problems**
  - **System pressure reduction is a common recommendation**

This recommendation may not receive as much evaluation as necessary

Slide 73 – Steam Distribution Losses - Summary

In summary, there are several factors that can contribute to significant losses in the steam distribution system. Periodic evaluation and investigations can help identify areas of opportunities to help achieve an efficient steam generation and distribution system.

[Slide Visual – Steam Distribution Losses - Summary]

- **Repair/Replacement**
  - **Steam Leaks**
  - **Pipe Failures**
  - **Damaged/Missing Insulation**
- **Steam Trap Management Program**
- **Condensate Recovery**
- **Steam Pressure Reduction**

Steam End-User Training
Conclusion Module

Slide 1 - Conclusions

Let's briefly examine the major items we have covered in this training.

[Slide Visual – Conclusions]

Banner:
DOE's BestPractices
Steam End User Training

Conclusion

Slide 2 - Course Objectives

We had a long list of items to address in this training.

[Slide Visual – Steam End User Course Welcome]

- **Become familiar with U.S.DOE Tools Suite to assess steam systems**
- **Identify the measurements required to manage steam systems**
- **Measure boiler efficiency**
- **Estimate the magnitude of specific boiler losses**
- **Identify and prioritize areas of boiler efficiency improvement**
- **Recognize the impacts of fuel selection**
- **Characterize the impact of backpressure and condensing steam turbines**
- **Quantify the importance of managing steam consumption**
- **Identify the requirements of a steam trap management program**
- **Evaluate the effectiveness of thermal insulation**
- **Evaluate the impact of condensate recovery**
- **Recognize the economic impacts of steam system operations**

Slide 3 - Tools

You were introduced to the U.S.DOE Steam Tools, the Scoping Tool, the Assessment Tool, and the Insulation Tool.

[Slide Visual – Tools Visual Description]

- **In order to properly evaluate steam systems the physics of each process must be understood**
  - **Thermodynamics**
  - **Heat transfer**
  - **Fluid flow**
- **U.S.DOE Tools Suite**
  - **Steam System Survey Guide**
  - **Steam System Scoping Tool (SSST)**
  - **Steam System Assessment Tool (SSAT)**
  - **Insulation evaluation software – 3E-Plus**
- **Process measurements**

Slide 4 - Measure

We emphasized the importance of measurements and the management consequences developed from each measurement.

[Slide Visual – Measure]

You are not managing what you do not measure

Slide 5 – Primary Measurements

We pointed out many of the essential measurements required to manage the steam system.

[Slide Visual – Primary Measurements]

- **Boiler**
  - **Flue gas temperature**
  - **Flue gas oxygen content**
  - **Boiler fuel flow**
  - **Boiler steam flow**
  - **Water chemistry**

- Blowdown rate
- Boiler efficiency
- Combustibles
- System balancing
  - PRV steam flows
  - Turbine efficiencies
  - Electrical unit cost
- Steam consumers
  - Steam consumption
  - Control set points
- Condensate return
  - Makeup water flow
  - Condensate recovery
- Steam trap performance
- System
  - Fuel unit cost
  - Total fuel consumption
  - Steam production

Slide 6 - Boiler Efficiency

We explored the classic definition of boiler efficiency and the implications it holds.

[Slide Visual – Classic Boiler Efficiency]

$$n_{boiler} = \frac{\text{energy desired}}{\text{energy that costs}} (100) /$$

The boiler efficiency is equal to the energy desired; divided by the energy that costs; all multiplied by 100.

$$n_{boiler} = \frac{\text{m-dot}_{steam} (h_{steam} - h_{feedwater}) (100)}{\text{m-dot}_{fuel}\ \ HHV_{fuel}}$$

Boiler efficiency is equal to the mass flow rate of the steam; multiplied by the difference in the enthalpy of the steam and the enthalpy of the feedwater; divided by the mass flow of the fuel; multiplied by the higher heating value of the fuel; all multiplied by 100.

Where:

n_{boiler} = Efficiency of the boiler, also called combustion efficiency, overall efficiency (dimensionless)
$m\text{-}dot_{steam}$ = Mass flow rate of steam generated in the boiler
$m\text{-}dot_{fuel}$ = Mass flow rate of fuel burned
h_{steam} = Enthalpy is energy content of steam
$h_{feedwater}$ = Enthalpy is energy content of feedwater
HHV_{fuel} = Higher Heating Value of fuel

Slide 7 – Indirect Efficiency

We examined the indirect boiler efficiency method.

[Slide Visual – Boiler Loss Indirect Efficiency]

- Boiler efficiency can also be determined in an indirect manner by determining the magnitude of the losses
  - Primary losses are typically
    - Shell loss
    - Blowdown loss
    - Stack loss

$n_{indirect} = 100 \text{ percent} - E_{Losses}$

Indirect Boiler Efficiency is equal to 100% minus the sum of all boiler losses.

$n_{indirect} = 100 \text{ percent} - Loss_{shell} - Loss_{blowdown} - Loss_{stack} - Loss_{misc}$

Indirect Boiler Efficiency is equal to 100% minus the shell losses, minus the blowdown losses, minus the stack losses, minus the miscellaneous losses.

Where:

$n_{indirect}$ = Indirect efficiency
E_{Losses} = Sum of all Losses
$Loss_{shell}$ = Shell Losses
$Loss_{blowdown}$ = Blowdown Losses
$Loss_{stack}$ = Stack Losses
$Loss_{misc}$ = Miscellaneous Losses

Slide 8 – Stack Loss (Natural Gas)

We identified the techniques available to allow the individual boiler losses to be quantified.

[Slide Visual – Stack Loss Table for Natural Gas]

- **To determine the order-of-magnitude importance of tuning a conservative evaluation will be made assuming 5% oxygen can be attained.**
  - **Efficiency could improve from 78.8% to 80.1%**

Flue Gas Oxygen Content Wet Basis [%]	Stack Loss [% of fuel higher heating value input]											
	Net Stack Temperature [Δ°F] {Difference between flue gas exhaust temperature and ambient temperature}											
	155	180	205	230	255	280	305	330	355	380	405	430
1.0	13.1	13.6	14.1	14.7	15.2	15.8	16.3	16.9	17.4	18.0	18.5	19.1
2.0	13.2	13.8	14.3	14.9	15.5	16.1	16.6	17.2	17.8	18.4	18.9	19.5
3.0	13.4	14.0	14.6	15.2	15.8	16.4	17.0	17.6	18.2	18.8	19.4	20.0
4.0	13.6	14.2	14.8	15.5	16.1	16.7	17.4	18.0	18.7	19.3	20.0	20.6
5.0	13.8	14.5	15.1	15.8	16.5	17.2	17.8	18.5	19.2	19.9	20.5	21.2
6.0	14.1	14.8	15.5	16.2	16.9	17.6	18.3	19.1	19.8	20.5	21.2	22.0
7.0	14.4	15.1	15.9	16.6	17.4	18.1	18.9	19.7	20.5	21.2	22.0	22.8
8.0	14.7	15.5	16.3	17.1	17.9	18.8	19.6	20.4	21.2	22.1	22.9	23.7
9.0	15.1	16.0	16.8	17.7	18.6	19.5	20.4	21.2	22.1	23.0	23.9	24.8
10.0	15.5	16.5	17.4	18.4	19.4	20.3	21.3	22.2	23.2	24.2	25.2	26.1
Actual Exhaust T [°F]	225	250	275	300	325	350	375	400	425	450	475	500
Ambient T [°F]	70	70	70	70	70	70	70	70	70	70	70	70

At 380 degrees Fahrenheit net stack temperature at 5% oxygen content, the stack loss is 19.9%
At 380 degrees Fahrenheit net stack temperature at 7% oxygen content, the stack loss is 21.2%

Slide 9 - Fuel Selection

We addressed some of the main fuel selection issues.

[Slide Visual - Three Boilers]

Fuel: Green Wood
Fuel cost: $2.00/10^6Btu
Steam production: 80,000 lbm/hr
Efficiency: ~71.3%

Fuel: Natural gas
Fuel cost: $10.00/10^6Btu
Steam production: 100,000 lbm/hr
Efficiency: ~84.2%

Fuel: Number 6 oil *HS*
Fuel cost: $5.00/10^6Btu
Steam production: 80,000 lbm/hr
Efficiency: ~87.4%

Slide 10 – Backpressure

The fundamentals of backpressure steam turbines were presented.

[Slide Visual – Combined Heat and Power - Cogeneration]

A red arrow depicts the fuel input to the High-Pressure and High-Temperature Boiler. Steam produced from the boiler is delivered to a steam turbine/generator, with the steam section depicted as a cone-shape figure. Steam schematically leaves the steam section of the turbine at the bottom. A thick white line to the right of the steam turbine leading to the rectangle shape of the generator, is the shaft. A red arrow leaves the generator section, indicating Electrical Power Export.
The steam schematically leaving the bottom of the steam turbine enters a heat exchanger depicted as a circle with a red zigzag arrow through it.

Condensate leaves the heat exchanger at the bottom and a pump, depicted as a circle/square combination, returns the condensate to the top of the boiler.

Turbine is 70% isentropic.
Generator is 95% efficient.
Boiler is 85% efficient.

What would be the component efficiencies of a typical industrial facility?

What would be the overall "energy" conversion efficiency?

Slide 11 – Condensing Turbines

The operating characteristics of condensing steam turbines were identified.

[Slide Visual – Condensing Turbine Performance]

Condensing Turbine Impact Power Cost			
	Impact Condensing Power Cost [$/MWh]		
Fuel Cost	Turbine Isentropic Efficiency [%]		
[$/$10^6$Btu]	40	60	80
2.00	56	39	30
4.00	111	78	60
6.00	167	116	89
8.00	223	155	119
10.00	278	194	149
12.00	334	233	179
Steam inlet	400	psig	
Steam inlet	700	°F	
Steam exit	1.4	psia	
Boiler Efficiency	84	%	

Slide 12 – Steam Demand Costs

We discussed steam end-use components.

[Slide Visual – Steam Demand]

A fan represented by a circle/square combination supplies airflow at 10,000 standard cubic feet per min air at 65 degrees Fahrenheit (noted as T_i) and three green arrows leading from a cone-shaped duct transition to a length of horizontal rectangular duct. Inside the rectangular duct section, three vertical white lines with a circle at the top and bottom of each line represent a steam coil which is joined at a header at the top of the steam coil, outside the rectangular duct. A white arrow leads to the header indicating 20 psig saturated steam supply at the steam coil inlet. The bottom of the steam coil has a steam trap (represented as a rectangle with a "T" and circle inside) for each of the three coil passes.

The steam traps schematically deliver condensate from the bottom to a header leading away from the ductwork with a white arrow. It is noted that 20 psig saturated liquid condensate enters the steam traps.

The airflow that is heated from the steam coil is represented by three red horizontal arrows and is at 120 degrees Fahrenheit (noted as T_e).

[Slide Visual – Boiler Equations]

$Q_{air} = \text{m-dot}_{air}(C_p)_{air}(T_e - T_i)_{air}$

Energy is equal the to the mass flow rate of the air; multiplied by the specific heat capacity of air, multiplied by the difference in the Temperature existing the heat exchanger minus the Temperature entering the heat exchanger.

$Q_{air} = 10{,}000(\text{std ft}^3/\text{min})(0.074(\text{lbm/std ft}^3)(0.24(\text{Btu/lbmR})(120°F – 65°F)(60 \text{ min}/1 \text{ hour})$

Energy is equal the to the100,000 standard cubic feet per minute ; multiplied by the0.074 pounds per standard cubic feet; multiplied by 0.24 BTU per pound-Rankine; multiplied by the difference 120 degrees Fahrenheit minus 65 degrees Fahrenheit; multiplied by 60 minutes per hour)

$Q_{air} = 587{,}300$ **Btu/hr**

Energy is equal the to 587,300 Btu per hour.

- **Steam demand reduces to 70% of original value.**
    - **Steam saving is 250 lbm/hr.**
        - **$34,000/yr.**

Where:

Q_{air} = **Quantity of energy**
m-dot$_{air}$ = **Mass flow of the substance**
C_p = **Specific heat capacity of the substance**
T_i = **Temperature of air entering heat exchanger**
T_e = **Temperature of air exiting heat exchanger**

Slide 13 – Maintenance Program

The foundational components for a world-class steam trap management program were discussed.

[Slide Visual – Steam Demand]

- **Training is essential**
- **Investigate each trap at least one time each year (problem areas and high pressure should be more frequent)**
    - **Performance**
        - **Testing equipment is required**
        - **An order of magnitude leak rate should be determined for failed traps**
            - **Orifice calculations set the maximum steam flow**
    - **Trap type**
        - **Trap selection should match the application**
        - **Universal mounts can be a good option**
    - **Installation**
    - **Establish an investigation route**
    - **Condensate return**
    - **Outsourcing can be a good option**
- **Maintain a steam trap database**
- **Prioritize repairs based on loss estimates**
- **Daily monitor receiver vents**

Slide 14 - Insulation Savings

Insulation issues and evaluations were addressed.

[Slide Visual – 3EPlus – Cost of Energy]

Cost of Energy –
Bare and Insulated Surfaces

Energy Tab
Item Description = Missing Insulation
System Units = ASTM C585
Geometry Description = Steel Pipe - Horizontal
Bare Surface Emittance = 0.8
Nominal Pipe Size = 10 in.
Process Temperature = 550 °F
Ave. Ambient Temperature = 70 °F
Ave. Wind Speed = 3 mph

Fuel Type: Natural Gas
Heat Content: 1000 BTU/cubic foot
Fuel Cost: 10.00 $/Mcf
Efficiency: 80 percent
Hours Per Year = 8760
Outer Jacket Material = Aluminum, oxidized, in service
Outer Surface Emittance = 0.1
Insulation Layer 1 = Calcium Silicate BLK+PIPE, Type I
Thickness: 3.08 in.

Append to Audit - Browse

Variable Insulation Thickness	Cost ($/ft/yr)	Heat Loss (Btu/ft/yr)	Savings ($/ft/yr)
Bare	636.90	50950000	
Layer 1	28.74	2300000	608.200

Table reads: Layer 1 Savings are 608.200 $/ft/yr

Savings = 608 $/ft-yr (20 ft) – 12,000 $/hr

Slide 15 – Condensate Return Example

The important aspects of condensate recovery were identified.

[Slide Visual - Condensate Return Example]

The schematic depicts condensate return in a heat exchanger. Heated material and high pressure steam enter into the heat exchanger through several passes. Steam exits the heat exchanger through a steam trap and then routed to a vented condensate receiver. The condensate temperature is 212 degrees Fahrenheit. It is transferred to an insulated condensate return pipe and ultimately pumped to the boiler. A Level Controller senses the liquid level in the receiver.

- **Condensate temperature entering boiler water system is 180°F**
- **Makeup water temperature is 70°F**

Slide 16 – Driving Force

In all of these areas we connected the real-world equipment to the energy analysis and we translated our findings into the language of business—economics.

[Slide Visual – Driving Force]

What is the main driving force for change??

$

- **Energy**
- **Reliability**

- Maintenance
- Productivity
- Quality
- Cost avoidance
- Emissions reductions

Slide 17 – Contact Information

Here is some contact information for this training, including websites, e-mail addresses, and phone numbers.

[Slide Visual – Contact Information]

- BestPractices Steam
  - http://www1.eere.energy.gov/industry/bestpractices/
    - Tools
    - Books
    - Fact-sheets
    - Tip-sheets
- Save Energy Now Assessments
- Industrial Assessment Centers
- EERE Information Center
  - (800) 862-2086
  - eereic@ee.doe.gov

- Tony Wright
  - US DOE BestPractices Technical Manager
  - (865) 574-6878
  - wrightal@ornl.gov

- Bill Orthwein
  - US DOE BestPractices Program Manager
  - (202) 586-3807
  - william.orthwein@ee.doe.gov

Slide 18 – U.S. DOE Tip Sheets

The Department of Energy has developed reference materials to help identify steam system improvement opportunities. This is a list of tip sheets that can help you effectively manage your steam system. They can all be found at the web address at the bottom of the screen.

[Slide Visual – U.S. DOE Tip Sheets]

- **Benchmark the Fuel Cost of Steam Generation**
- **Clean Boiler Water-side Heat Transfer Surfaces**
- **Consider Installing a Condensing Economizer**
- **Consider Installing High-Pressure Boilers with Backpressure Turbine-Generators**
- **Consider Installing Turbulators on Two- and Three-Pass Firetube Boilers**
- **Consider Steam Turbine Drives for Rotating Equipment**
- **Considerations When Selecting a Condensing Economizer**
- **Cover Heated, Open Vessels**
- **Deaerators in Industrial Steam Systems**
- **Flash High-Pressure Condensate to Regenerate Low-Pressure Steam**
- **Inspect and Repair Steam Traps**
- **Install an Automatic Blowdown Control System**
- **Install Removable Insulation on Valves and Fittings**
- **Insulate Steam Distribution and Condensate Return Lines**
- **Improve Your Boiler's Combustion Efficiency**
- **Minimize Boiler Blowdown**
- **Minimize Boiler Short Cycling Losses**
- **Recover Heat from Boiler Blowdown**
- **Replace Pressure-Reducing Valves with Backpressure Turbogenerators**
- **Return Condensate to the Boiler**
- **Upgrade Boilers with Energy-Efficient Burners**
- **Use Feedwater Economizers for Waste Heat Recovery**
- **Use Low Grade Waste Steam to Power Absorption Chillers**
- **Use Steam Jet Ejectors or Thermocompressors to Reduce Venting of Low-Pressure Steam**
- **Use Vapor Recompression to Recover Low-Pressure Waste Steam**
- **Use a Vent Condenser to Recover Flash Steam Energy**

http://www1.eere.energy.gov/industry/bestpractices/tip_sheets_steam.htm

Slide 19 – U.S. DOE Technical Documents

For more detailed and in-depth information the Department of Energy has developed Technical Documents. Here is a list of technical documents that can help you effectively manage your steam system. They can all be found at the web address at the bottom of the screen.

[Slide Visual – U.S. DOE Technical Documents]

- **Improving Steam System Performance: A Sourcebook for Industry**
- **Achieve Steam System Excellence: Industrial Technologies Program BestPractices Steam Overview Fact Sheet**
- **BestPractices Steam Technical Brief: Steam Pressure Reduction-Opportunities and Issues**
- **BestPractices Steam Technical Brief: How to Calculate the True Cost of Steam**
- **BestPractices Steam Technical Brief: Industrial Heat Pumps for Steam and Fuel Savings**
- **BestPractices Steam Technical Brief: Industrial Steam System Heat-Transfer Solutions**
- **BestPractices Steam Technical Brief: Industrial Steam System Process-Control Schemes**
- **Guide to Combined Heat and Power Systems for Boiler Owners and Operators**
- **Guide to Low-Emission Boiler and Combustion Equipment Selection**
- **Review of Orifice Plate Steam Traps**
- **Save Energy Now in Your Steam Systems**
- **Steam Digest: Volume IV (2003)**
- **Steam Digest 2002**
- **Steam Digest 2001**
- **Steam Systems Energy Efficiency Handbook**
- **Steam Systems Survey Guide**

http://www1.eere.energy.gov/industry/bestpractices/techpubs_steam.html

Slide 20 - Homework

For your homework, take the Steam System Tool Suite Introduction web-based training, if you have not already. Then, try to apply it to your own steam system to identify at least one energy efficient improvement.

Slide 21 – Thank You!

You have completed the technical component of the Steam System End-User Training. In order to complete the training, test your knowledge with the End of Course Quiz. You can also re-visit the training course in its entirety or review a particular individual module of interest. Thank you for your time and effort!

[Slide Visual – Thank you!]

- **Technical component of the training is finished**
- **Test your knowledge with the End of Course Quiz**
  - **Your Steam End User Web-based Training will be Complete!**
- **You can revisit the training course anytime**
  - **Entire course**
  - **Individual Modules/Topics**
- **Visit ITP's Steam Resources for additional information**
- **Feedback is welcome!**