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Updating BASF boiler plant to today's technology

ESC Energy Solutions Center

on the cover

The photo shows two new watertube boilers and deaerator tank at the BASF facility in Durham, N.C. Photo courtesy: Inveno Engineering, LLC

ESC Energy Solutions Center

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UPDATING BASF BOILER PLANT TO TODAY'S TECHNOLOGY

Eventually, boiler replacement is inevitable

By Kelly Paffel, Inveno Engineering, LLC; and Jeff Coger, BASF Agriculture Solutions

REGARDLESS OF HOW ROBUST THE CONSTRUCTION, BOILERS DON'T LAST FOREVER. Advances in technology result in more efficient designs and simplicity of operation. The BASF facility in Durham, N.C. reached the point with its boiler plant where replacement was necessary.

Existing boiler plant operation

The two existing firetube boilers at the BASF facility in Durham, N.C. were manufactured by York Shipley Inc. in 1981 with a capacity of 300 boiler horsepower each. The boilers operated admirably during their 40 years of service (see Figure 1). However, with age, the boilers started to require increasing maintenance. With renovations and improvements downstream came a large reduction in steam output needs. The boilers, being limited on steam output turndown, began short cycling in the summer and winter. The on/off operation resulted in more stress on the boiler and burner equipment and a reduction in overall energy efficiency of the system.

The existing spray deaerator was not meeting ASME dissolved-oxygen requirements of 7 pbb. This resulted in an increase in non-condensable gases. With these elevated non-condensable gases in the system, higher corrosion rates of internal piping and infrastructure can occur. All other associated equipment such as blowdown tank, chemical feed system, makeup water meters and steam flow meters were deemed to be older technologies and needed to be updated to the latest technologies.

It was time to upgrade the boiler plant. The goals for upgrading the boiler plant system were to achieve the highest degree of safety, system optimization, high reliability and an energy efficiency with today's technologies. Along with these goals was to also create a work environment that is highly desirable to work in for plant operations and plant personnel. With the boiler upgrade, other aspects of the system were reviewed and upgraded such as the associated support equipment, which included the deaerator, blowdown and chemical systems.

FIGURE 1: BASF's original York Shipley boilers. Courtesy: Inveno Engineering, LLC

Engineering project scope

Inveno Engineering, LLC senior steam team field engineers and the Swagelok local support team were assigned engineering and design for the new boiler project. The project, which began January 2019, consisted of engineering, design, full AutoCAD prints, equipment specifications, request for proposals (RFPs) and procurement recommendations. The engineering scope was to encompass the boiler selection process, boiler plant layout, code validation, specifications, vendor interviews, installation, startup and validation testing. Inveno engineers implemented the steam system team concept, which included onsite engineers, onsite AutoCAD team, offsite technical personnel, offsite support engineering, technical writers and support staff. The Inveno team worked with the BASF team to ensure a successful project.

The steam system engineering team goals were to accomplish:

- Safety
- Reliability

Key project personnel involved in the project

The key project personnel involved in the BASF boiler upgrade project were:

- Jeff Coger; facilities engineer, BASF Agriculture Solutions, Seeds & Traits; Durham, N.C.
- Jordon Grigston, local technical support, Swagelok
- Kelly Paffel; technical manager/project team leader; Inveno Engineering, LLC; Naples, Fla.
- Graham Thorsteinson; senior field engineer; Inveno Engineering, LLC; Naples, Fla.

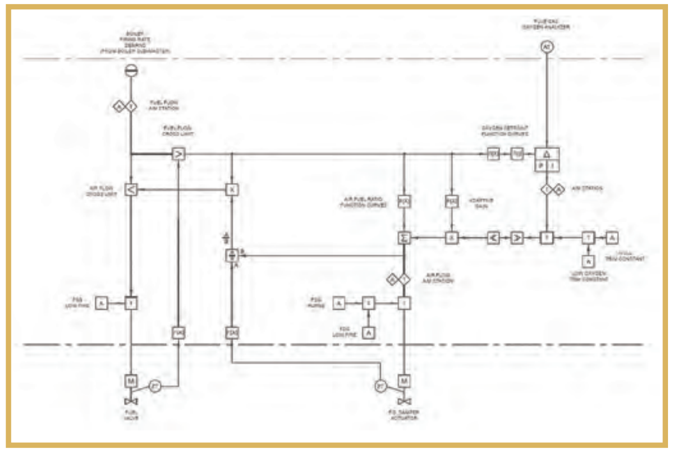


FIGURE 2: SAMA drawing for the combustion control system. Courtesy: Inveno Engineering, LLC

- Plant optimization
- Energy efficiency
- High turn down to meet plant steam requirements
- Latest technologies in boiler control and management
- Proper deaerator operation with newest control system
- Chemical treatment.

Another part of the project was to develop a detailed steam system balance, ensuring that the new boilers will meet and exceed the steam system requirements.

An essential part of the project is to ensure all codes are followed to ensure a safe operation for everyone involved. The following codes were adhered to during the entire project, Boiler ASME, B31.9, B31.1 ASME pressure vessels, B16.1, etc.

New boilers: Firetube versus watertube

One of the first steps in deciding on new boilers is to determine the operational design of the boiler. Firetube design and watertube design were the two boiler designs considered. All boilers have their positive and negative features. The Inveno Engineering steam team and BASF reviewed all aspects of operation including their loads and run conditions and decided to proceed with a watertube design boiler.

The firetube boiler design was eliminated due to several considerations. First is the installation consideration for a firetube boiler that requires additional space for boiler tube replacement if required after years of operation. The other negative consideration is the thermal losses off the exterior casing of the firetube boiler, specifically, the back wall area. The firetube boiler back wall would have high elevated temperatures of more than 300°F thus an energy loss in excess of $25,000 a year. Safety concerns for plant personnel with high surface temperatures and OSHA requirements for plant personnel protection for areas of greater than 140°F. Insulating the firetube back wall presented several operational issues such as having to remove the insulation for annual boiler inspections.

The watertube boiler presented a much smaller footprint and ease of accessing the boiler internals maintenance. Watertube boilers provide better compensation for expansion and contraction thus providing a longer operational life expectancy. The combination of the boiler and a burner design allowing for 10:1 turndown with the addition of the latest control technology provided the perfect combination for this specific application.

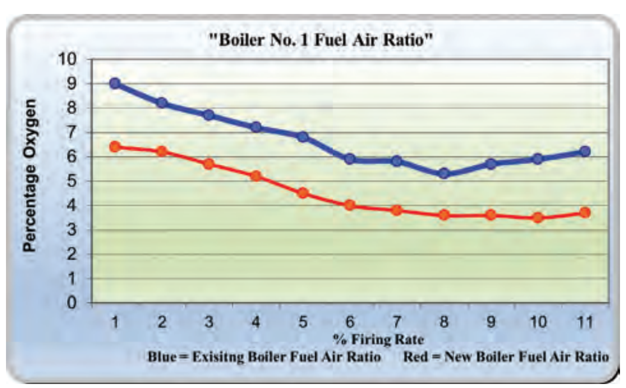


FIGURE 3: No. 1 boiler fuel/air ratio curves, older boiler versus new boiler.

Control systems

The boiler control system design was selected to be a parallel positioning control with oxygen trim because it was determined to be the best control scheme for the boilers. Parallel positioning systems offer key design benefits over the other control schemes for this size of boiler operation. One actuator positions the fuel control valves, while a second actuator positions the air control damper. Each combustion actuator is equipped with a position re-transmitter for cross limiting purposes to ensure proper fuel/air mixing. The parallel positing system allows proper tuning of the fuel/air ratio for each firing rate demand, typically at each 10% of the firing curve (see Figure 2).

Oxygen trim system adjusts for any factors that may affect the fuel/air ratio curve and adjusts accordingly to keep the combustion at peak performance.

Advantages for this control scheme includes:

- Allows electronic characterization of fuel/air ratio
- Boiler will have variable speed drives, which mates to this control scheme
- Provides large turndown
- Oxygen trim is easily accomplished.

The control system and the burner management system were to be accomplished by programmable logic controllers (PLCs), which also provide relevant data and operational parameters for the plant personnel. The boilers, DA tank and flowmeter data were set up to connect to the site's building automation system (BAS), notifying personnel of key alarms and allowing for energy tracking of consumed resources (e.g., natural gas, makeup water, steam output).

Fuel/air ratio: Combustion process

The combustion fuel/air ratio curves are derived from a combustion testing process and is important in the overall boiler efficiency. Lower oxygen levels are in direct relationship to the quantity of excess air required for the combustion process. To achieve complete combustion, a portion of combustion air must be available for the combustion process that exceeds the stoichiometric amount needed to complete the combustion process. The ratio of the excess combustion air to the theoretical amount of air required is called "excess air."

Due to the burner characteristics, the excess air levels are curved from low fire, which has higher excess air levels (oxygen levels) on a curve up to high fire that has lower excess air levels.

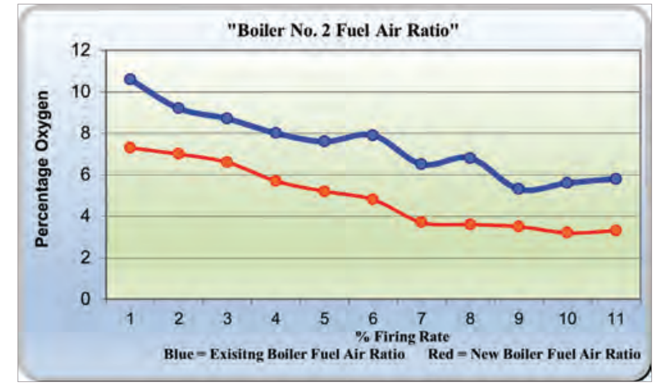
Unfortunately, if more excess air is added to the combustion process, it results in lower combustion efficiency. The combustion process/burner is taking ambient air for the oxygen needed in the combustion process, but it has to heat up all the other gases in the ambient air such as the large quantity of nitrogen. All combustion air will be increased to temperatures above 2,600°F and higher, which is the flame temperature.

The new burner technologies allow the burner to operate at lower or reduced excess air in the combustion process. Another benefit is the flue gas exit volume is reduced. Lower excess air levels reduce the flue gas temperature and gas velocities. The flue gas velocity reduction allows the gas to spend more time in the boiler where the heat energy can be absorbed. The fuel/air curves for each of the boilers is shown in Figures 3 and 4, which indicate the curves with the older boilers versus the new boilers.

The fuel/air curves for each boiler indicate the significant reduction in excess air levels thus improving boiler efficiency (see "Old versus new: Energy efficiency gains").

The economics are attractive for keeping a boiler operating at peak performance with respect to the optimum fuel-air ratio curve. BASF can monitor the fuel ratios and has Clever Brooks local technical support team check the operation on a periodic bases to ensure the optimal performance.

FIGURE 4: No. 2 boiler fuel/air ratio curves, old boiler versus new boiler. Courtesy: Inveno Engineering, LLC



Deaerator (spray versus tray design)

The new deaerator design was required to provide a feedwater dissolved oxygen content of no greater than seven ppb and operate at steam pressure of 8 psig with a 20-minute feedwater storage time for the boiler operation (see Figure 5). Reviewing the two deaerator design choices, the spray type and tray type design, both deaerator types can provide the performance standard dictated by the engineering RFPs. However, due to height considerations of the existing boiler plant, it was decided to proceed with a spray-type deaerator that had a lower height requirement and maintained the required net positive suction head (NPSH) for the boiler feed pumps. The control system for the deaerator was another area where the plant needed to have control of the steam pressure, feed pumps and monitor points the critical points in the system.

Insulation

Keeping with the proactive insulation management program was critical to overall boiler plant system to maintain a high steam system thermal cycle efficiency. Because boiler components (deaerator, blowdown tank, etc.) operate above 212°F (100°C) temperature can have negative effects on uninsulated control components and energy losses are unacceptable in today's industrial boiler operations.

What items in a boiler plant and system need to be insulated? The simple answer is everything. Insulating the steam lines is not sufficient in today's boiler plant operation. Therefore, the deaerator, steam line, condensate lines, blowdown tank and other boiler plant-related components were insulated. All insulation was metal jacketed to ensure the long-lasting energy and safety effects of the insulation.

Plant layout

The philosophy of BASF and the Inveno steam team is the boiler plant needs to be free of all components that are not related to the boiler operation. The boiler plant is not a storage area; it is an area where the combustion process is occurring with a very combustible fuel. The other factors are to have a clean, well-organized and well-lit environment for the boiler plant personnel that provides an excellent work environment and work habits (see Figure 6). With this type of environment, the boiler plant will stay in this condition for the life of the boiler and plant personnel will take pride in their plant.

Chemical systems

A key factor in a boiler chemical program for a steam boiler operation is to be able to conduct daily steam/boiler samples

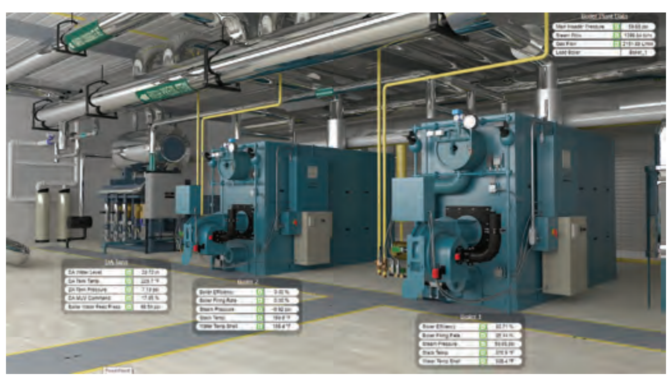
FIGURE 5: New deaerator at the BASF boiler plant. Courtesy: Inveno Engineering, LLC

FIGURE 6: It was important to BASF to have a clean, well-organized and well-lit environment for the boiler plant personnel that provides an excellent work environment and work habits. Courtesy: Inveno Engineering, LLC

for testing. The chemical program is a major factor to have a reliable and long operational life of the boiler and steam system. In any boiler plant sampling system, a central steam sampling location is a must for any boiler chemistry monitoring program. The next key factor for the steam sampling system was to ensure that all components are meeting the code requirements and designed for long reliable operation. Inveno steam team discovered that more than 37% of existing steam/boiler sampling systems had code violations.

Swagelok was able to provide a custom solution with a central sampling system that provides all aspects for code requirements and personnel safety. The central steam/boiler sampling system allows plant personnel to take the required samples with a safe and reliable operation. The new sample cooler used Swagelok tube fittings coming from the boilers and DA tank. The high-quality airtight fittings provided a robust test result of the dissolved oxygen testing for the deaerator. Testing the deaerator operation to 7 ppb or lower is a low dissolved oxygen level and the plant could not afford to question the testing results that could be influenced from air leakage from low quality tube fittings. The plant reduced the chemicals consumption from three different chemicals down to one chemical for the overall boiler operation. BASF implemented a new "Ultramine" program. This simplified the maintenance of the chemical program, which reduced chemical storage and handling as well as chemical pump failures.

FIGURE 7: The boiler room layout is improved for more efficient operation and maintenance. Courtesy: Inveno Engineering, LLC



Final manufacturer selection

One of the key factors in the final manufacturer final selection was the engineering support the manufacturer could bring to the project. Another key factor was the technical local service support for all the boiler plant components. Any boiler plant operation needs to have the required technical support and service to ensure an energy efficient and reliable operation.

Cleaver Brooks was selected to the be manufacturer for all the boiler plant equipment. The company's equipment met all of BASF's extensive requirements and it has a highly reputable local service team that can aid in the long-term upkeep of the new equipment.

Return on investment

Although the project was not undertaken with energy savings in mind, the return on investment (ROI) from energy savings alone is estimated to be around $30,000. Saving energy is a noble goal. However, there were other more pressing considerations. The existing equipment was at the end of its operational life. BASF wanted to acquire the newest technology in boiler operation, which it did. The deaerator was not performing. The boilers were at high cycle rates in summer operation. BASF now achieves a 10:1 boiler turndown ratio. The new boilers are not attended; the new system allows for remote monitoring. The boiler room layout is improved for more efficient operation and maintenance (see Figure 7). **GT**

Kelly Paffel is the technical manager at Inveno Engineering, LLC. He is a global expert on steam systems and boiler plant operations with more than 40 years of experience. Paffel is known for his online publication "Steam System Best Practices," a resource used by plants and engineers internationally to ensure proper operation of steam and condensate systems.

Jeff Coger is facilities engineer at BASF Agriculture Solutions. He received his undergraduate mechanical engineering degree from Kettering University. His background includes seven years in automotive manufacturing engineering and as many years as a facilities engineer. He has a passion for solving problems but solving them in a way that prioritizes quality, reliability and maintainability. Coger firmly believes in approaching projects with the mindset, as quoted by Benjamin Franklin, "The bitterness of poor quality remains long after the sweetness of low price is forgotten."

Capturing carbon, and selling it

Although CO_2 is a large part of greenhouse gas (GHG) emissions, processed CO_2 is a valuable product with an attractive revenue stream

Dr. Sudhir Brahmbhatt, Technology Services Inc.

THE CLEAN POWER PLAN, ANNOUNCED IN 2015 BY PRESIDENT OBAMA AND THE U.S. ENVIRONMENTAL PROTECTION AGENCY (EPA) WAS AN IMPORTANT STEP IN REDUCING EMISSIONS. The goal was to lower CO_2 emissions from existing coal-fired power plants 30% below 2005 levels by 2030. The plan includes strong standards for power plants and customized goals for states to cut carbon emissions.

The power generation industry has sought ways to minimize carbon emissions including operating modes, energy generation feedstock and adding better carbon capture technologies to decrease emissions. However, new processes and systems are costly. The power industry struggles to justify the economics of meeting new U.S. regulations calling for cleaner air. An approach to solving this dilemma is creating a revenue stream to help power companies optimize carbon capture investments.

FIGURE 1: Coal is the biggest air polluter in the U.S. Coal pollutes when it is mined, transported to the power plant, stored and burned Courtesy: Technology Services Inc.

Carbon capture

The average coal plant generates 3.5 million tons of CO_2 per year. In the U.S. alone, burning coal emitted 1.87 billion tons of CO_2 in 2011, according to the U.S. Energy Information Administration (EIA). Coal generates 44% of the Nation's electricity and is the biggest air polluter in the U.S. Coal pollutes when it is mined, transported to the power plant, stored and burned (see Figure 1).

Carbon dioxide capture and storage (CCS) is a set of technologies that can reduce CO_2 emissions from new and existing coal-and gas-fired power plants and other large industrial sources such as cement production and natural gas processing facilities. CCS could play an important role in reducing greenhouse gas (GHG) emissions, while enabling low-carbon electricity generation from power plants.

CCS is the process of capturing CO_2 before it enters the atmosphere, transporting it and storing it (carbon sequestration) for centuries or millennia. Usually, the CO_2 is captured from large point sources such as a chemical plant or coal-fired or biomass power plant, and then stored in an underground geological formation. The aim is to prevent the release of CO_2 from heavy industry with the intent of mitigating the effects of climate change. Although CO_2 has been injected into geological formations for several decades for various purposes including enhanced oil recovery (EOR), long-term CO_2 storage is a relatively new concept.

Carbon capture and utilization (CCU) and CCS are sometimes collectively discussed as carbon capture, utilization and sequestration (CCUS). This is because CCS is a relative expensive process that yields a product with an intrinsically low value (i.e., CO_2). Hence, carbon capture makes economically more sense when being combined with a utilization process where the cheap CO_2 can be used to produce high-value chemicals and other products to offset the high costs of capture operations.

FIGURE 2: Dry ice has many industrial applications. Courtesy: Technology Services Inc.

CO_2 can be captured directly from an industrial source such as a cement kiln, using a variety of technologies including absorption, adsorption, chemical looping, membrane gas separation or gas hydration. As of 2020, about one thousandth of global CO_2 emissions were captured by CCS. Most projects are industrial.

As estimated in the U.S. Inventory of Greenhouse Gas Emissions and Sinks, more than 40% of CO_2 emissions in the U.S. are from electric power generation and industry. CCS can reduce CO_2 emissions from power plants that burn fossil fuels by 80 to 90%. CCS Technologies applied to a 500 MW coal-fired power plant that emits around 3 million tons of CO_2 annually reduces GHG emissions (with a 90% reduction efficiency) equivalent to reducing annual electricity-related emissions from more than 300,000 homes.

EPA's Greenhouse Gas Reporting Program includes facilities that capture CO_2 to supply it to markets for injecting it underground. According to the program, carbon capture is being done at more than 120 facilities in the U.S., mainly from industrial processes. The CO_2 is used for EOR, food and beverage manufacturing, pulp and paper manufacturing and metal fabrication.

The costs to capture CO_2 from power plants, large industrial manufacturing facilities and other sources are significant. When there is no apparent return on investment (ROI) for producers and manufacturers to invest in these technologies, it is difficult for them to justify the investment. CCS potentially offers an opportunity for emitters to capture CO_2 to meet the clean power plan requirements and sell it to recover some of the cost of capturing and purifying it. Based on the current CO_2 demand, CCS can offer attractive investment returns on carbon capture technology.

Recovering CO_2 from power plants

In the industrial history of the U.S., some of the CO_2 sources (ethanol and ammonia plants) were owned and operated by those who operated CO_2 plants near the raw gas source. Many independent U.S. CO_2 producers still operate as direct sales suppliers to consumers. However, since the emergence of the major gas companies through industry consolidation, most of the raw CO_2 is sold to gas refiners.

There is a large margin difference between the price of raw gas from a producer and the price from a refiner/gas company. Raw gas prices direct from a source range from \$5 to \$25 per ton versus consumer market prices, which usually range from \$60 to \$100 per ton. In some high-priced markets with little regional competition or no local supply, CO_2 can range from \$150 to \$300 per ton.

For 2010, total U.S. merchant CO_2 production capacity was 40,000 tons per day (TPD). Most of the merchant CO_2 is now from ethanol plants. Ethanol plants continue to be the dominant source of CO_2 supply. Ammonia plants are expected to continue to lag as the number of plants shut down due to high natural gas prices from 2002 onward. This could change due to current low natural gas prices.

This same margin can apply to power producers who can efficiently capture CO_2 from their processes. It is necessary to evaluate CO_2 production costs, distribution and overhead from CCS schemes on a local basis, considering the regional nature of CO_2 supply and its largest markets in the U.S. When the markets are understood and the costs and requirements for producing CO_2 for the merchant trade are known, the risks for direct marketing can be properly evaluated.

CO_2 as a product of value

Processed CO_2 is a valuable product with an attractive revenue stream. It can be in short supply in many U.S markets. CO_2 has a complex supply chain. Crude CO_2 is typically produced as a byproduct, purified to a liquid state and delivered to points of distribution.

Applications include food processing, where it is used in freezing, chilling, packaging operations, beverage carbonization and decaffeination. Other CO_2 markets include EOR, urea fertilizer production, pharmaceuticals and medicine, horticulture, fire suppressants, welding and lasers, refrigeration, clean water applications, propellant for aerosols and as a fumigant to remove infestation.

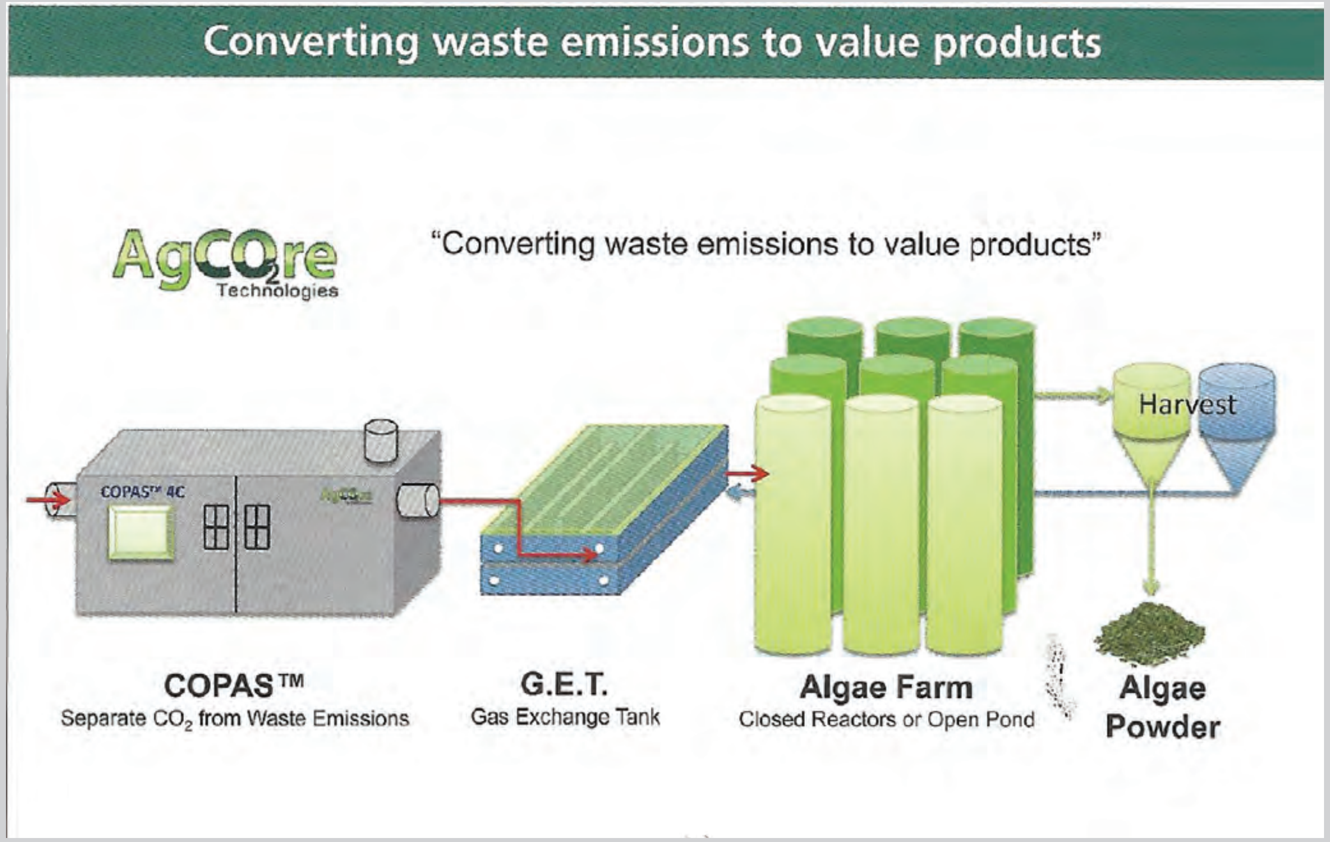


FIGURE 3: The flow diagram demonstrates how the process of capturing, separating and infusing CO_2 for use in algae farming operations takes place. Courtesy: Agcore Technologies

Another key application for CO_2 is dry ice (see Figure 2). In the food industry it is used for meat processing, short-term food storage, in-flight catering and research and development (R&D). In dry ice blasting, dry ice pellets are used to replace sandblasting when removing paint from surfaces. It aids in reducing the cost of disposal and cleanup. For rubber and plastics industry uses, flash is removed from rubber objects by tumbling them with crushed dry ice in a rotating drum. In cryogenic tunnel and spiral freezers, high-pressure liquid CO_2 is injected through nozzles that convert it to a mixture of CO_2 gas and dry ice "snow" that covers the surface of the food product. As it sublimates (goes directly from solid to gas states), refrigeration is transferred to the product. Dry ice is also used extensively in the pharmaceuticals and biotech industries.

Demand for CO_2

According to data available from SRI Consulting (March 2010), the global demand for CO_2 is estimated at 80 million tons per year (tpy) based on SRI data. Of this amount, 50 million tpy are used for EOR in North America, while the remaining 30 million tpy is used in all other uses, predominantly the mature industries of beverage carbonation and food industry.

SRI estimates future demand will be 140 million tpy based on predicted growth of current technologies such as EOR, urea fertilizer and the implementation and commercialization of demonstration projects for the remaining technologies in line with their prospective development timeframes.

CO_2 Market opportunities

For industrial gas distributors, the growth potential in the CO_2 product market is strong. Consolidation in the merchant CO_2 business in the U.S. shows interest in this segment of the industrial gas business. Legislation and voluntary commitments to reduce the use of Hydrofluorocarbon (HFC)-based refrigerants have opened growth opportunities, especially for CO_2 producers, according to SRI Consulting.

An emerging use of CO_2 is in algae production. Algae can be a source for applications including fuel, renewable oil markets, chemical markets, in nutritionals and in health sciences. CO_2 can be separated from flue gas emissions, purified and sold to commercial interests for use in algae production. Figure 3 is a flow diagram that demonstrates how the process of capturing, separating and infusing CO_2 for use in algae farming operations takes place. GT

Dr. Sudhir Brahmbhatt is president of Technology Services Inc., located in Glencoe, Mo.

Flowmeters enable energy management

Building owners, manufacturers and institutions must seek ways to make their facilities more energy efficient with less environmental impact.

By Bob Griffin, P. Eng

IN TODAY'S BUSINESS CLIMATE, KEEPING ENERGY COSTS IN LINE HAS NEVER BEEN MORE IMPORTANT. Energy has become a hot topic for businesses, governments and consumers. For many, finding new and better ways to reduce energy usage and increase energy efficiency is a high priority. As a result, energy management is receiving a lot of emphasis.

Measurement is fundamental to energy management because to control it, you first must measure it. For example, building and campus managers invoice tenants for electricity, water, natural gas, boiler water for heating and chilled water for air conditioning and cooling. These utilities must be measured, and their use accumulated with respect to time to produce accurate billing.

This article focuses on flow measurement technologies as they apply primarily to natural gas. Topics involving steam and water are included for comparison and/or context as needed. Flowmeter types are discussed as well, although the list is not exhaustive.

Fundamentals of flow

Mass flow rate can be calculated from the density of the substance being measured, the cross-sectional area through which the substance is flowing and the substance's velocity relative to the area of interest. This is reasonably straightforward if the density is constant. Flow measurement is a quantification of an amount of fluid or gas passing through a pipe or a duct. Flow can be quantified as a volumetric flow rate such as gal/min, or a mass flow rate such as lb/hr. The rate is always some unit of measure with respect to some unit of time.

The density of some fluids may change when subjected to changes in temperature, pressure or composition. Some fluids also may have combined phases or entrained gas bubbles. Varying densities make mass flow measurement more complex — but more so with gases than with liquids.

There are many technologies and designs for measuring flow, but not every flow measurement technology lends itself to energy monitoring applications. For a flow measurement technology to be a good candidate for use in energy monitoring applications, it must be cost-effective, noninvasive and easy and inexpensive to install. The technology must also have reliability and accuracy appropriate for the application.

In manufacturing, flow measurement is essential to operate a process plant that manufactures products from raw materials or adds value to a product. The demand for accurate flow measurement instruments is driven by business demands or environmental restrictions such as a need for tighter process controls leading to reduced emissions and increased efficiency.

Flowmeter types

Each flow sensing technology and each flowmeter has advantages and disadvantages. Flow sensing technologies in widely used flowmeter devices on the market include:

- Differential pressure (DP)
- Positive displacement
- Coriolis (or mass flow)
- Vortex
- Turbine.

DP devices include orifices, venturi tubes, flow nozzles, pitot tubes, averaging pitot tubes and V-cone. Positive displacement devices include rotary lobe, diaphragm and turbine.

Note that there are many more flowmeter types on the market. However, devices intended primarily for fluids are not covered in this article.

DP flowmeters

DP flowmeter operation requires placing a flow-restricting device such as an orifice plate, flow nozzle, pitot tube, or venturi tube in the fluid, gas or steam flow path, and measuring the pressure differential across it. Orifice plates are the most widely used restriction and typically create the most pressure loss (see Figure 1). The rate of steam flow varies with the square root of the pressure drop across this restriction. A DP transmitter measures the drop in pressure across the restriction.

Although orifice-type DP flowmeters typically have a low initial cost, no moving parts, and can be installed inexpensively, they have a high-pressure loss, low rangeability, and lose accuracy over time. Orifice plates can eventually wear enough to affect flowmeter calibration.

Many flow measurement instruments installed today are based on DP-sensing technologies. DP transmitters account for around half of all flow measurement transmitters shipped annually. The improvements in measurement range, accuracy, repeatability and the ability to make multiple measurements, provided by intelligent multivariable pressure transmitters have added life to this mature but still viable technology.

Positive displacement flowmeters

Positive displacement meters measure flow by mechanically displacing a moving part in the meter, then counting the number of displacements per unit of time. Each count represents a volumetric amount of fluid. At each count, the fluid passes through the meter. The energy required to drive the moving parts of the meter is supplied by the pressure of the fluid being metered.

Rotary lobe flowmeters. A rotary lobe flowmeter directly measures the actual volume of fluid that passes through it at the actual operating pressure. Two counter-rotating lobed impellers rotate within a casing. Gas or liquid flowing through the meter drives the impellers, which trap a known volume of gas in the interspace. The flow volume is proportional to the speed of rotation.

The volume is measured by counting revolutions and multiplying the count by the known volume displaced with each revolution. Counting can be accomplished mechanically or electronically. The most common arrangement is to embed magnets in the lobes. These are sensed by proximity switch pickups mounted in the meter casing. Switches driven by the magnets activate local digital displays or are input to an integral electronic system for processing, correction and remote communication.

Rotary lobe meters are used mainly for natural gas billing for commercial and industrial customers when loads exceed 1,000 cubic feet per hour (CFH). They are used mainly for gases and liquids in industry and in oil and gas production. They also have been used in industrial submetering applications for energy management. The main reasons for their use are high accuracy and ruggedness. ANSI/ASC B 109.3 approves these meters for custody transfer.

Rotary lobe flowmeter advantages include:

- High accuracy.
- Low cost due to large production quantities.
- Very low turn-down ratio.
- Able to meter fluids with low Reynolds Number.
- Reliable and rugged. Low maintenance costs.

Other factors include:

- The volume flow must be corrected to standard conditions when operating at fluid temperatures and pressures outside the calibration range. This function is done automatically when the meter is used as a billing meter.
- A bypass with manual isolation valves is recommended in case of mechanical failure.

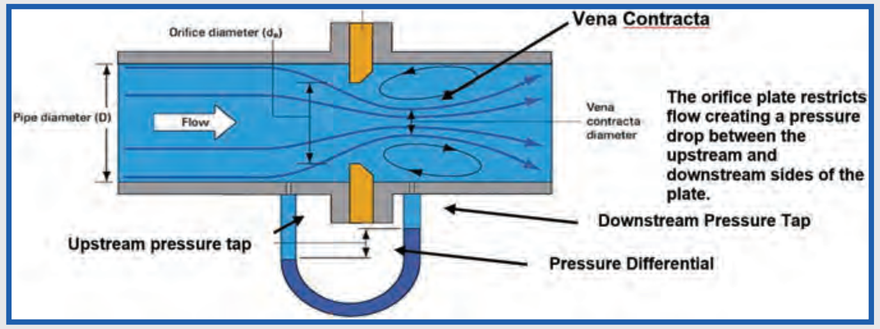


FIGURE 1: Cross section of an orifice plate flowmeter showing flow direction. Courtesy: Spirax Sarco Steam Engineering Tutorials

Diaphragm flowmeters. A diaphragm flowmeter comprises an outside casing charged with natural gas (or other gas) and houses two gas bellows (diaphragms). Each diaphragm has a slide valve that alternately opens and closes the inlet valve and the outlet valve to each diaphragm. As gas flows into the meter, the bellows fill up and empty alternately by means of slide valves, which act as counters. As each valve closes and then opens, one known volume of gas is counted. A mechanical linkage connects each valve to a counter that registers a count and a display that shows it on a dial. The gas is discharged into the meter casing and to the meter outlet. The two sets of bellows and valves operate alternately to provide a continuous gas flow. The mechanism is driven by gas pressure on the bellows and the result is a small pressure drop across the meter.

Diaphragm meters employed in billing applications for natural gas are installed with a pressure regulator upstream to maintain constant pressure. This eliminates the need for a pressure correction transmitter. Temperature variations can cause error. However, in practice, the temperature changes are minor when gas is supplied via underground piping.

Diaphragm flowmeter advantages include:

- Inexpensive and accurate.
- Can be used for small energy management projects.
- Pulse output and communications capabilities are available.

Diaphragm flowmeter disadvantages include:

- Should be used with clean gases only.
- Large, heavy and expensive in large sizes.

Turbine flowmeters. Turbine flowmeters are available in a wide range of sizes, types and prices. They are used in many applications in industry and for billing purposes by water and gas utilities. Utility-type turbines for metering gas and water are approved for custody transfer. Turbine flowmeters are approved by AGA report 7. They are normally supplied with corrected mass flow reading electronic outputs and communication capability. A prominent use of turbine meters is metering and billing large volume customers (see Figure 2).

Industrial turbine flowmeters are also available as inline and insertion

FIGURE 2: Utility-type turbine flowmeter for natural gas custody transfer. Courtesy: Enbridge Gas Distribution Inc.

types. Insertion turbine flowmeters are available in a wide range of sizes and materials from ½ inch to 36 inches and larger. Because of their ability to meter large pipe flows, they are often used for stack gas monitoring. They cover a wide range of applications in industry for metering steam, water, air flow and other gases.

Industrial turbine flowmeters directly measure the velocity of the fluid or gas stream, QV. Together with the velocity measurement, the mass flow can be calculated with P and T inputs. A flow computer or multi-variable smart transmitter at the meter is required.

A rotor with attached blades is suspended in the fluid or gas stream on free running bearings. The rotational speed (RPM) of the rotor is directly proportional to the fluid or gas velocity. There are several ways of counting rotations of turbines including from magnetic and electrical transducers embedded in the rotor or blades. These transducers produce a weak pulse or sine wave electronic output, which is converted electronically to a flow velocity QV, then to a 4-20 mA output signal from the transmitter. The mass flow is calculated by multiplying the volumetric flow by the fluid density. Mass flow equals flow velocity times density times pipe area.

$$Qm = QV * \rho * A$$

A corrected mass flow requires additional inputs including pressure and temperature.

Inline industrial turbine flowmeters are suited to energy management applications because they are available in a wide range of diameters and are lower in cost.

Industrial, inline turbine flowmeter advantages include:

- Good accuracy and repeatability.
- Wide size range.
- Minimal upstream straight lengths of pipe required.
- May be low cost.
- Low installation cost, insertion type.

Industrial, inline turbine flowmeter disadvantages include:

- High installation cost, in-line type.
- Moving parts-susceptible to contaminants.

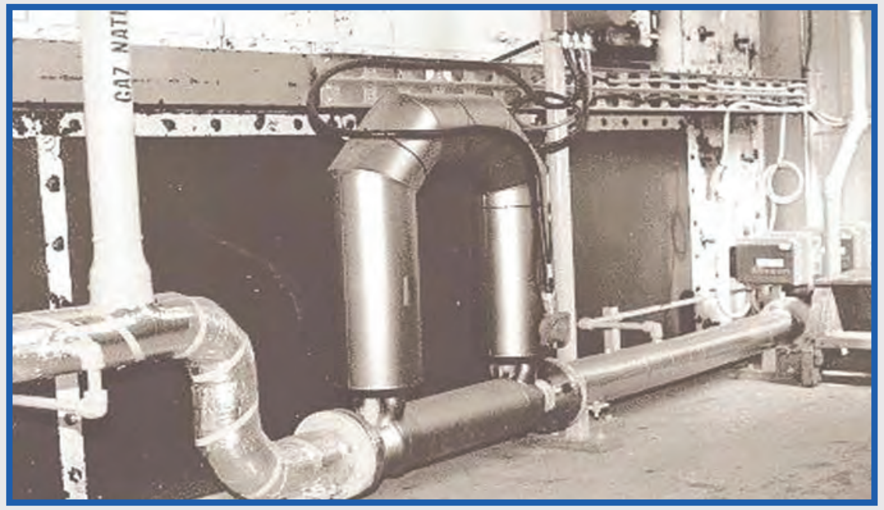
Coriolis flowmeters

Coriolis flowmeter technology provides direct mass flow measurement that is independent of changes in pressure, temperature, density and fluid viscosity. Coriolis flowmeters come in a variety of configurations including U-tube, twin U-tube, bent tube and straight tube designs, all of which operate on the following principle:

- The fluid or gas to be measured enters one end of the flow tube, which is subjected to an external oscillating drive, an electromechanical oscillator that vibrates at the natural frequency of the tube (around 10 kHz) depending on tube design and fluid or gas density. Flow tubes are commonly made from 316 stainless steel or other metals such as titanium depending on the application.
- As fluid or gas streams through the flow tube, it is subjected to an upward or downward force caused by the external oscillation driver. The Coriolis Force opposes the driving force, pushing upward on the tube from the inflow side and downward on the outflow side, causing the tube to twist. The twisting motion is also an oscillation.
- Sensors located on each leg of the flow tube detect the position and frequency of the tube as it twists. There is a phase shift between the two sensors as mass flow changes. This phase shift is directly proportional to the mass flow of the fluid or gas.
- The Coriolis meter is equipped with a microprocessor-based signal processing system that interprets the raw signals from the sensors and the frequency shift being measured, converting these to signals that can be used by standard instrument and data systems such as 4-20 mA, pulse and voltage outputs.

The Coriolis flowmeter has a wide range of applications. The first applications were in the petroleum and chemical

FIGURE 3: Coriolis mass flowmeter for natural gas measurement. Courtesy: Emerson Automation Solutions



industries measuring many kinds of liquids, mainly for process control purposes. Because of its high accuracy, it is also used for custody transfer in the oil and gas industry, AGA report 11. Coriolis flowmeters have been used to measure high viscosity fluids, slurries and mixed phase fluids such as oil and water, water with bubbles, pulverized coal in air, etc.

Compatible fluids include crude oil, cryogenic liquids, polymers, asphalt, fuel oil, paints, nitric acid, phosphoric acid, molten sulfur, sodium hydroxide and tar sands. Food products include beer, fruit juice, milk, pie fillings and peanut butter.

More recently, design improvements and increased precision have made Coriolis flowmeters a candidate for metering gases. They are capable of metering industrial gases and have been used for customer transfer of natural gas for large users (see Figure 3). They also can be applied to low temperature gaseous or liquid oxygen, nitrogen and CO_2.

Coriolis mass flowmeter advantages include:

- Direct mass flow reading, no correction for pressure or temperature.
- High turndown ratio: 20:1 is standard, 100:1 as required.
- No need for straight pipe runs upstream and downstream.
- Capable of metering multiple liquids, gases, slurries and mixed-phase flow.
- Stainless flow tubes are standard.
- Capable of metering cryogenic gases, some models.
- Very high accuracy and repeatability.
- Low maintenance.
- Custody transfer approvals.

Coriolis mass flowmeter disadvantages include:

- High cost compared to most other meters.
- Moderate PPL, except straight-through Coriolis.

Vortex flowmeters

Vortex flowmeter operation is based on a principle called the "von Karman effect." The von Karman effect makes use of fluid passing a non-streamlined or "bluff" body placed in the flow stream generates vortices that are shed from the rear of the body. These vortices can be detected, counted and displayed. The frequency of the vortices is proportional to the flow rate of the fluid or gas. The shedding frequency and the fluid velocity have a near-linear relationship under ideal conditions.

Typical vortex flowmeter applications include direct steam measurement, both at the boiler and point of use, and natural gas measurements for boiler fuel flow. Steam is the most difficult fluid to measure because of the high pressures and temperatures involved, and because measurement parameters vary according to steam type. Vortex flowmeters are preferred for steam flow measurement because of their ability to tolerate these high process pressures and temperatures.

Vortex flowmeters are very reliable. They also have wide rangeability, which means they can measure steam flow at varying velocities. Other advantages of vortex meters include ease of installation, low maintenance, moderate installed costs and good accuracy. However, they are somewhat sensitive to vibration and inlet flow.

Multivariable vortex flowmeters include pressure and temperature sensors. In addition to flow rate, temperature and pressure, the flowmeter uses these sensors to determine volumetric flow, fluid density and mass flow. Multivariable vortex flowmeters perform the necessary mass flow compensation without a separate flow computer. GT

MORE info

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Bob Griffin, P. Eng. is an industrial energy consultant.

LDC Focus

Spotlight on Black Hills Energy

Black Hills Energy is ready to make tomorrow even better than today

OVER THE COURSE OF ITS 138-YEAR HISTORY, BLACK HILLS ENERGY, based in Rapid City, S.D., has been guided by its values and mission of improving life with energy. The utility company provides essential energy services to help advance the well-being of its customers and communities. The company is humbled and motivated by this responsibility and considers it a privilege to provide electricity and natural gas to nearly 1.3 million businesses and families in its eight-state service territory.

Last year, Black Hills Energy announced climate goals to reduce electric emissions intensity 40% by 2030 and 70% by 2040 and reduce natural gas emissions intensity 50% by 2035. The company is well on its way to achieving these goals, with 30% reduction in electric emissions and 33% reduction in natural gas emissions since 2005.

Black Hills Energy's natural gas utilities serve more than one million customers in six states. The company operates a gas system above industry standards, with no cast-iron pipe since 2014 and nearly 99% of its infrastructure comprised of protected steel or plastic, materials with the lowest emissions factors.

Pipeline replacement

Black Hills Energy's comprehensive, programmatic integrity management program monitors its natural gas pipeline systems and plans upgrades to its pipeline networks to enhance safety, improve system reliability and reduce or eliminate methane emissions (see Figure 1). The program assesses risk and prioritizes the replacement or upgrading of pipeline to proactively replace vintage and at-risk materials while achieving greenhouse gas (GHG) emissions reduction goals. Since 2005, Black Hills Energy has reduced its distribution system's GHG emissions by approximately 33,000 metric tons (CO2e) while expanding our system by more than 6,000 miles to serve its customers.

The company's comprehensive damage prevention strategy increases system safety and lowers the potential for methane to be released from a damaged natural gas pipeline. By conducting outreach and education, Black Hills Energy helps prevent pipeline hits and mitigate emissions.

Renewable natural gas. Black Hills Energy's natural gas supply includes renewable natural gas (RNG) from landfills and wastewater treatment facilities. The company receives RNG into its pipelines from three facilities in Nebraska and one in Iowa, capturing methane that would otherwise vent into the atmosphere. In addition, the utility is actively pursuing dozens of RNG projects and has identified more than 60 potential RNG projects across its service territories. Black Hills Energy sees great potential to generate RNG supplies throughout its vast agricultural service area. For example, two of its current RNG Projects, the Lincoln Water Resource Recovery Facility project and the Sarpy County Landfill Gas Project, Neb., produces enough pipeline quality RNG to fuel about 8,000 homes a year.

Expanded leak detection and surveying. By collecting detailed emissions data from its system, Black Hills Energy can identify new opportunities for reductions. In addition to its regular system-wide leak surveying, the company conducts additional leak surveys of its aboveground natural gas equipment to help determine fugitive emissions from its system. In 2020, the utility began surveying two additional states, Colorado and Nebraska, which joined Arkansas in its surveying program as required by the EPA Greenhouse Gas reporting program. The additional surveys conducted helped the company identify fugitive emissions from its system that otherwise would not have been found as quickly. **GT**

FIGURE 1: Black Hills Energy plans upgrades to its pipeline networks to enhance safety, improve system reliability and reduce or eliminate methane emissions. Courtesy: Black Hills Energy