Reducing Energy Costs and Emissions with Combustion Control

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Combustion in fired heaters and boilers is typically based on either volumetric flow control or pressure control of the fuel gas feeding the burner. Using mass flow control could help lower energy costs and emissions.

The heat energy supplied by fired heaters and boilers in a refinery or petrochemical plant is created by combustion, usually by burning natural gas or fuel gas made up of various refinery off-gases.

Automation and control engineers and fired-equipment subject matter experts have debated the optimal method to control heater firing over the years. The most common approach controls the fuel gas volumetric flowrate or pressure. In this control scheme, the outlet temperature of the heater cascades and resets a volumetric-flow controller or pressure controller. Under steady operating conditions, this technique provides adequate response and control of the heater. However, any disturbance caused by a change in the fuel supply composition can render this control method inadequate for the desired level of risk, fuel efficiency, or environmental compliance.

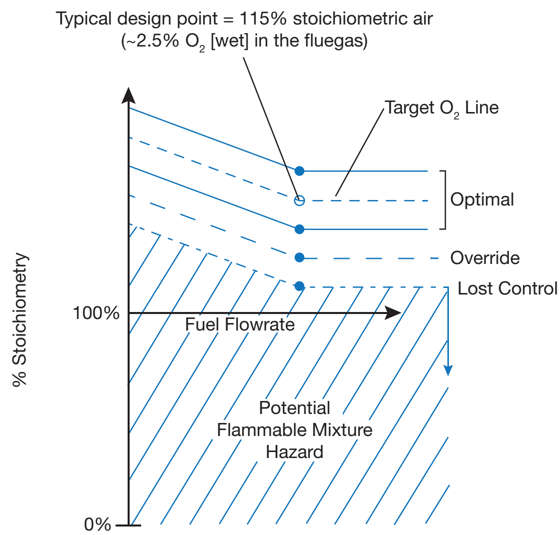
This article describes some of the challenges of controlling combustion in a fired heater or boiler, and suggests a better method of control that measures the mass flow or the actual energy of the fuel gas being directed to the burner. The article evaluates the economic benefits of several methods of fuel gas control for natural-draft fired heaters.

Combustion challenges

Figure 1 illustrates the relationship between the combustion fuel flowrate and the stoichiometric air requirement. At design conditions, about 15% more air than the stoichiometric amount (*i.e.,* 115% stoichiometric air) is supplied, which will produce the optimal amount of O_2 in the fluegas (*i.e.,* around 2.5%). Due to burner inefficiencies, the stoichiometric requirement for air is higher when the fuel gas flowrate to the fired heater is lower. If the amount of air present in the fired heater is less than the stoichiometric amount, overrides in the control system will kick in and may shut down the system. The overrides are meant to prevent a situation where the amount of air is so low that a flammable mixture exists in the heater.

Combustion efficiency is a function of the percentage of O_2 in the fluegas. A large amount of O_2 in the fluegas assures an added margin for safe furnace operation, but has negative implications for thermal efficiency and environmental compliance. A high level of O_2 in the fluegas can increase emissions, which can create permitting issues.

Depending on the burner type, an increase of 2% O_2 could increase NOx emissions by 25–30%. Excess air is



▲ **Figure 1.** In a typical fired heater, excess air is added to ensure safe operation and complete fuel combustion. However, too much air will result in high levels of O_2 in the fluegas — increasing emissions and making combustion less efficient. But, too little air can lead to sub-stoichiometric combustion, possibly damaging the heater or causing it to trip.

typically added to ensure more-thorough combustion of the fuel gas. However, for every molecule of oxygen added in the air, almost four molecules of nitrogen are along for the ride. The large amount of nitrogen lowers the thermal efficiency and increases NOx emissions. Enabling small reductions — even as little as 1% — of excess O_2 in the fluegas of fired heaters at an average-sized refinery or petrochemical plant can generate significant operational savings.

On the other hand, operating with too low a level of O_2 in the fluegas creates the risk of sub-stoichiometric (insufficient oxygen) combustion, possibly tripping the heater, or in the extreme case, causing damage to the heater. Sub-stoichiometric conditions can result when the composition of the fuel feeding the combustion suddenly changes to a richer fuel that has a higher heating value, requiring more oxygen. If this situation could be anticipated (*e.g.,* with feed-forward control), much of this challenge could be eliminated.

Reducing variability of the O_2 in the fluegas is the primary means of achieving the desired balance for safe, efficient, and environmentally friendly operation.

Fuel variability

At most refineries and petrochemical facilities, it is very common to have variability in heating fuel components. Fuel gas is constantly changing because it is made up of various refinery off-gases. The composition can vary when crude slates are changed, when process conditions change, or in the event of unit upsets or shutdowns.

When the composition of the fuel gas changes, so does the gross heating value of that fuel, which causes heating value variability as well as variability in the percentage of O_2 in the fluegas. As the gross heating value changes, the air required for combustion changes proportionally. Table 1 demonstrates the stoichiometric air required for the combustion of many of the components found in fuel gas, on a mass and volume basis, as well as the gross heating value on a mass and volume basis.

The table shows that the stoichiometric air required for combustion of hydrocarbons is significantly more consistent on a mass basis than on a volume basis. Hydrogen is an outlier that requires roughly twice as much air as methane; however, on a volumetric basis, hydrogen requires one-fourth as much air as methane and one-seventh as much air as ethane. Because the molecular weight of hydrogen is much lower than that of the hydrocarbons, its contribution to the overall heating value of the gas, and therefore the air requirement when measuring the gas on a mass basis, is significantly lower.

Table 1. Stoichiometric air required for combustion and energy content of various components found in fuel gas. Source: *(1–2)*.

Fuel Gas Component		Stoichiometric Air Required for Component		Gross Heating Value for Component	
		Mass Basis, kg air/kg HC	Volume Basis, m³ air/m³ HC	Mass Basis kJ/kg	Volume Basis, kJ/Nm³
Methane	CH_4	17.23	9.56	55,561	37,706
Ethane	C_2H_6	16.09	16.85	51,923	66,023
Propane	C_3H_8	15.67	24.30	50,402	93,967
i-Butane	C_4H_{10}	15.46	32.09	49,279	121,129
n-Butane	C_4H_{10}	15.46	31.97	49,574	121,837
i-Pentane	C_5H_{12}	15.33	40.47	48,995	149,483
n-Pentane	C_5H_{12}	15.33	40.27	49,090	149,781
n-Hexane	C_6H_{14}	15.24	45.35	48,390	176,347
Hydrogen	H_2	34.29	2.39	120,719	10,172

Control schemes

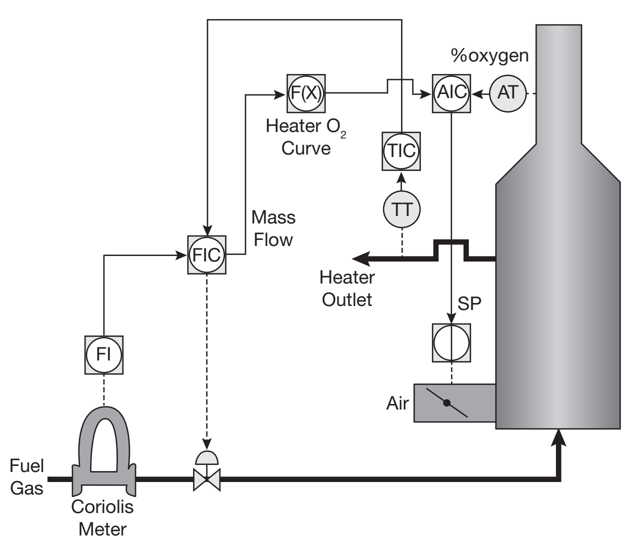
Figure 2 is an example of a control scheme for a natural-draft fired heater. The outlet temperature of the heater is used in a cascade control loop to control the setpoint of the mass flow of the fuel gas to the burner.

If the fuel flowrate setpoint is specified in mass, the energy content of the fuel gas will be kept more stable than with a volumetric flow setpoint, and the combustion air requirement will therefore be more stable. As demonstrated in Table 1, the volumetric flow, typically measured with a differential-pressure orifice meter, has little correlation to the heating value of the gas feeding the burner (and it will produce more variability in the stoichiometric air requirement).

As shown in Figure 2, an analyzer measures the oxygen in the fluegas, and this measurement is used to adjust the damper position on the inlet air line.

Variability in inert (noncombustible) components in the fuel gas is the one condition that this control scheme cannot compensate for. Because inerts have no heating value, the cost of adding an analyzer for noncombustibles may only be justifiable if the variability in the inerts exceeds 5–10%, depending on the balance of the components.

Mass flow control is not a traditional method of control. Volumetric flow and pressure control are the more traditional methods of control. This article demonstrates the benefits of a mass-based control scheme, with the option of adding either a calorimeter or specific gravity analyzer to measure actual energy content of the fuel gas when conditions warrant such a system.



▲ **Figure 2.** This natural-draft fired heater uses a Coriolis meter to measure the flow of fuel and a cascade control configuration to adjust the fuel flowrate based on the temperature of the outlet stream. An analyzer in the stack measures the oxygen content of the fluegas. Based on this measurement, a controller adjusts the setpoint of a damper to increase or decrease the airflow to the fired heater.

Two methods could be used to control the energy flow of the fuel gas. A calorimeter could be installed on the fuel gas header or fuel gas inlet to the heater, which would be especially beneficial in cases with extreme variability in inerts or in hydrogen (more than 75% variability). Another option is adding a specific gravity meter on the fuel gas inlet line. In order for a specific gravity meter to be effective (since it does not measure energy content in a general sense), data would need to be collected to establish and validate the relationship between the refinery fuel gas (RFG) heating value and the specific gravity of the gas.

Operational benefits

Measuring the mass flow of the fuel gas may make environmental reporting easier. Data on the fuel consumed in combustion operations has to be reported to environmental agencies, such as the U.S. Environmental Protection Agency (EPA). The information must be collected by instruments that meet regulatory requirements for accuracy and calibration or verification frequency.

A few Coriolis meter manufacturers offer a method to verify the accuracy of the meter over time. One such method, known as Smart Meter Verification (from Emerson), eliminates the need to calibrate transmitters or pull orifice plates or other primary elements to verify measurement accuracy. Most regulatory agencies recognize the meter manufacturer's recommended practice to verify accuracy. Running a program like Smart Meter Verification while the meters are fully functional during normal operations meets the requirement.

If a regulated metering point is found to be in error, the regulatory agency will often levy a fine against the facility; the amount of the fine will depend on how much time has passed since the last time the meter was proven to be accurate. Running accuracy checks at regular intervals and developing an audit trail can significantly reduce the risk of violations and fines.

Controlling the energy flow of the fuel gas can improve energy efficiency and offer regulatory compliance benefits, and reduce the risk of sub-stoichiometric combustion. Other benefits include:

- better fuel-to-air ratio control with changing fuel composition
- less O_2 in the fluegas (because less excess air is fed to the combustion process), which can reduce emissions and help to avoid permitting issues
- lower probability of insufficient air triggering heater trips
- ability to select an O_2 setpoint that is acceptable from safety, efficiency, and environmental perspectives
- more accurate and reliable emissions reporting
- operational cost savings.

Assessing economic benefits

The remainder of the article evaluates various methods of fuel gas control for natural-draft fired heaters *(3)*. The objective of this analysis is to calculate the net present value (NPV) for various control methods and to assess the impact of changing fuel compositions on indicated flow and the heat release to the burners. It considers each of the following control methods:

- pressure control
- pressure-corrected volumetric flow control
- temperature- and pressure-corrected volumetric flow control
- uncorrected volumetric flow control
- temperature-, pressure-, and molecular-weight-corrected volumetric flow control
- mass flow control
- mass flow with specific gravity analysis
- energy (Btu) control (assumed to be theoretical).

The goal of the fuel control scheme is to control the heat release to the burners. Whatever method is used, the control valve responds to the actions specified by the controller to keep the process at its setpoint. For example, if the fired heater uses pressure control, regardless of upstream pressure, temperature, or composition of the fuel gas, the pressure controller can only control the pressure of the fuel gas feeding the fired heater. However, the amount of fuel and its potential heat release can change considerably with variable composition and changes in the temperature.

We aim to evaluate rapid changes in the fuel gas header conditions — *i.e.,* where the coil outlet temperature controller (*e.g.,* TIC in Figure 2) cannot adjust the fuel flowrate quickly enough to avoid an unstable condition in the heater. The air flow control is assumed to be manually operated, and the operator cannot adjust the air flow very quickly, so a large step change in the O_2 content may occur.

The analysis has two parts. First, we evaluate how each control method would perform under changing temperature, pressure, and composition, and how that would impact the amount of O_2 in the fluegas. Then, we use the data from the first part to perform an NPV calculation for each control method.

Part 1: Evaluating fluegas deviation

We first performed a Monte Carlo simulation — a type of computational algorithm that uses repeated, random sampling to help the user visualize the potential outcomes (*i.e.,* amount of O_2 in the fluegas) for each type of control scheme. We performed 1,000 simulations per control type to calculate a steady-state condition and evaluate the condition after a step change. We used an Excel spreadsheet to perform the necessary calculations.

For each of the 1,000 simulations, the steady-state condition was determined by following the sequence of steps:

1. Fix the fuel gas pressure at the burner tip (this is a design condition of the fired heater).
2. Randomly select a fuel gas composition case.
3. Run burner tip calculations to find the fuel gas mass flowrate.
4. Calculate the reported fuel gas volumetric flowrate (assuming the fuel gas temperature and pressure are normally distributed).
5. Assume a normal distribution in the amount of O_2 about a fixed target, and calculate the air flowrate.

Burner tip calculations are readily available in the literature, for example, in *Perry's Chemical Engineers' Handbook*. The fixed target O_2 concentration should be constant for each control type being analyzed. As mentioned previously, the target is often around 2–2.5%, but can vary based on heater design or operating duty of the heater.

Next, a Monte Carlo simulation was performed to calculate an after-step-change condition and determine the resulting deviation in the amount of O_2 in the fluegas. The simulation steps are:

1. Randomly select a new fuel gas composition.
2. Calculate the fuel flowrate by equalizing one of the steady-state conditions (depending on the control type being simulated), *i.e.,* burner pressure, reported volumetric flow, etc.
3. Using the steady-state air flowrate (determined in the steady-state calculation Step 5), calculate the amount of O_2 in the fluegas.
4. Calculate the deviation in the calculated O_2 content from the fixed target O_2 content.

Then, for each method of control, a histogram of the deviation in O_2 was constructed (Figure 3). In each histogram, the x-axis is the deviation in the fluegas O_2 and the y-axis is the count or frequency (*i.e.,* the number of times the O_2 deviation had that value). The charts illustrate how frequently O_2 in the fluegas can vary, and by what percentage for a given control scheme.

The three example histograms in Figure 3 demonstrate the differences between pressure control, volumetric flow control, and mass flow control schemes. The volumetric and pressure control schemes are susceptible to much larger deviations than the mass flow control scheme.

For each method of control, a target O_2 amount was chosen from its histogram and used to calculate NPV in the next phase of the analysis. The target O_2 selected from the histogram results is slightly different than the target O_2 chosen previously (in Step 5 of the steady-state calculation). When a histogram showed a wide distribution in O_2 deviation for a particular control method, the software selected a slightly higher target O_2 to ensure that a change in fuel gas composition would not result in sub-stoichiometric conditions in the fired heater. For example, if the frequency chart showed that a composition change would cause the fluegas O_2 concentration to be negative (*e.g.,* –4%), the target was moved to the corresponding positive value (*e.g.,* 4%). This is the premise for the following NPV calculations.

Part 2: NPV calculation

A decision tree was used to perform the NPV calculation. This approach to evaluating the NPV associates a cost with the consequence of each action being evaluated. In this case, the costs associated with running in a particular control mode are evaluated.

Before constructing the decision tree, one of the most important costs to evaluate is the firing cost, which depends on the heater being evaluated. After the target O_2 content is chosen from the histogram, the simulator uses the histograms to determine how often the O_2 content is above that level. For every instance that it is higher, the simulator calculates the firing cost of the natural-draft fired heater and subtracts the firing cost at 0% deviation. The cost for the net firing rate is then inputted into the decision tree. In other words, the simulator determines how often each control scheme will be above target and it calculates how much it costs to be above that target.

Costs were also assigned to safe shutdown, minor explosion, and major explosion.

Although no costs were assigned to emissions or environmental considerations (as permitting levels, NOx emissions, and fines vary significantly by region and governing body), it is imperative to also consider these factors when evaluating the benefits of the different control methods.

Though the chance of having to shut down the heater is small, and the chance of having a minor or major explosion even smaller, these events can be factored into the NPV by multiplying their costs by the very low probabilities of the events occurring.

From there, we constructed a decision tree for each control scheme (Figure 4) and populated it with:

- cost data
- probability of a fuel gas step change in a 15-min period
- target O_2 content
- Monte Carlo simulation results for the specific control type
- probability of mitigation steps not working.

An example decision tree is shown in Figure 4. The numbers on each step represent the probability of advancing to the next step. Numbers circled in red are probabilities that are automatically calculated from the histograms generated in Part 1. Probabilities that are not circled in red can be manually populated based on experience with the heater under evaluation. The heater firing rate data (shown in the inset graph in Figure 4) is used as part of the NPV calculation.

Other risks that are represented in the decision tree — including reaching sub-stoichiometric O_2 levels in the

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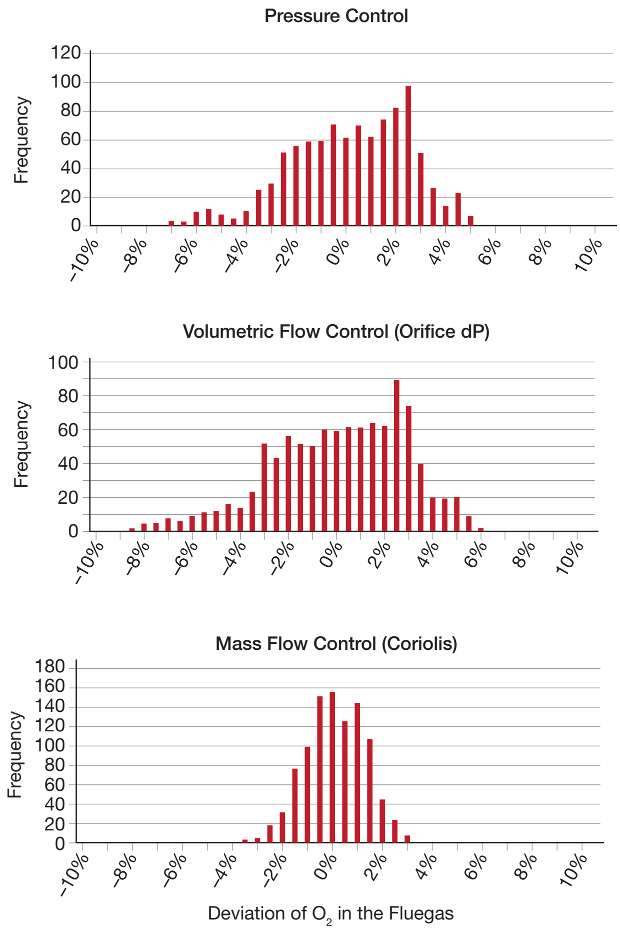
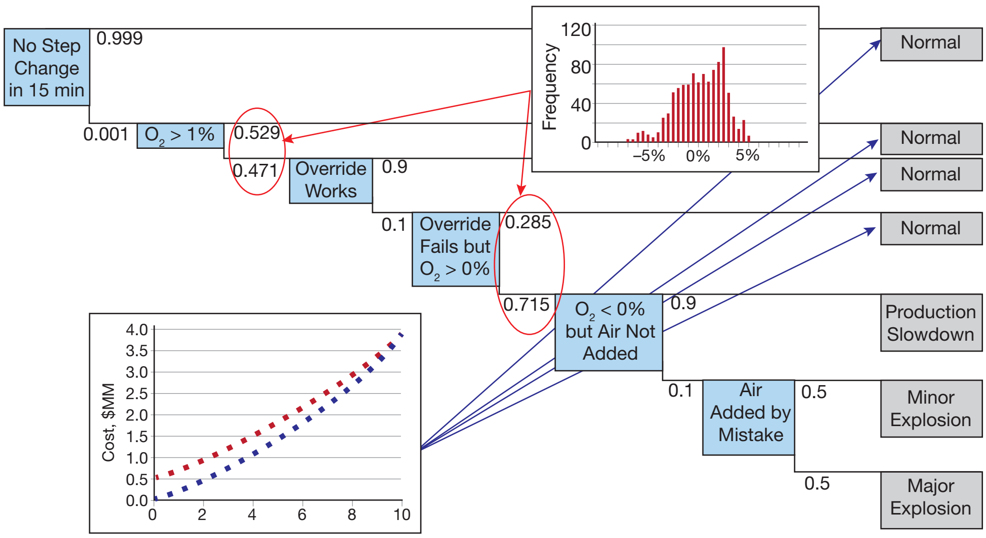


▲ **Figure 3.** Each control scheme was evaluated by 1,000 simulations. Each simulation had its own steady-state condition and a deviation in fuel gas composition from that at steady state. The algorithm then determined the deviation in the O_2 content of the fluegas and the frequency of a deviation of that size. These charts illustrate how frequently the O_2 in the fluegas can vary and by what percentage for a given control scheme.



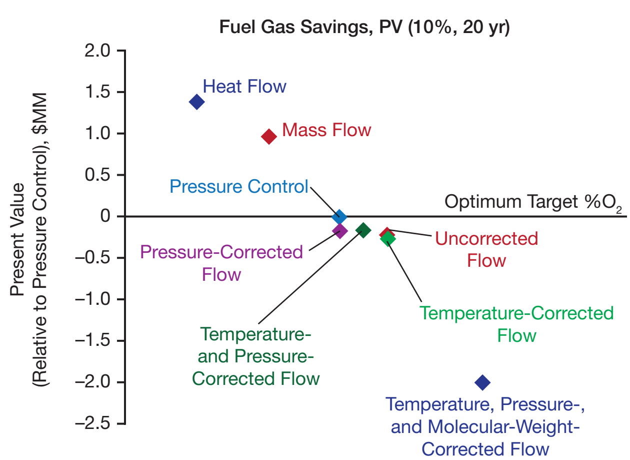
▲ **Figure 4.** In this example decision tree, the black numbers below each step are the probabilities of each step advancing. For example, on the third step, the override works 90% of the time, but 10% of the time it does not. The numbers circled in red are the probabilities obtained from the histogram compiled in Part 1. The other numbers (those that are not circled) are manually entered into the calculation. The inset graph represents the cost of operating the fired heater at the various O_2 levels. This demonstrates how the decision tree brings together all the data — O_2 deviation, firing rate, potential for shutdown or explosion — to determine a net present value.

fluegas that could result in an explosion or shutdown — are also factored into the NPV.

The simulation software pulled all relevant data from each decision tree to calculate the NPV for each of the eight control options (Figure 5). The NPV calculation used a time period of 20 years and a discount factor of 10%.

Theoretically, controlling the energy flow of the fuel gas using a calorimeter would have the lowest deviation in O_2 content, and result in the most stable fired heater operation. However, this method of control is not always economically feasible, as the cost and maintenance of the analyzer need to be considered.

According to Figure 5, controlling the fuel gas flow using a Coriolis mass flowmeter had an NPV nearly $1 million higher than the pressure control method. The other methods of control, including pressure-corrected volumetric flow, temperature- and pressure-corrected volumetric flow, temperature-corrected volumetric flow, uncorrected flow, and temperature-, pressure-, and molecular-weight-corrected flow control, offered no benefit over pressure control.



▲ **Figure 5.** Example net present value calculations for a natural-draft fired heater that heats crude oil before a distillation process in a refinery.

Closing thoughts

High levels of O_2 in fired heater fluegas can negatively impact thermal efficiency and can increase emissions. Improving control of the flow of fuel gas to the heater can help facilities tighten control of the O_2 in the fluegas, and keep the heater running in a more environmentally friendly and safe state.

In the analysis presented in this article, mass flow control was determined to be the best option for controlling fuel gas flow based on its high NPV. However, a new control scheme that uses a calorimeter or specific gravity meter to determine the energy content of the fuel gas may be even more effective at limiting O_2 deviation.

This method of calculating NPV can be translated to other types of fired heaters. Several studies have been performed at various refineries that show significant NPV benefits for the investment in the new mass flow control scheme. **CEP**

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