

## **Final Report**

### **Xcel Renewable Development Fund Project (RD-56)**

## **Generating Electricity with Biomass Fuels at Ethanol Plants**

### **Chapter/Task 8 – Evaluation of Control Technologies**

**This chapter describes potential technologies that can be used to control emissions such as NO<sub>x</sub>, SO<sub>2</sub>, and particulates that arise from biomass fuel combustion. It was primarily prepared by project participants at RMT Inc.**

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## **RD56: Generating Electricity with Biomass Fuels at Ethanol Plants Report for Task 8, "Evaluation of Control Technologies"**

### **Background of the Task**

Combustion or gasification of biomass co-products feed streams using any of the technologies considered in this project have the potential to produce emissions of criteria pollutants such as particulate matter (PM), sulfur dioxide (SO<sub>2</sub>), oxides of nitrogen (NO<sub>x</sub>), carbon monoxide (CO), and volatile organic compounds (VOCs). Depending on feed material composition, combustion/gasification technology, combustion/gasification conditions, and operating procedures, small amounts of hazardous air pollutants (HAPs) which are a subcomponent of the total VOC emissions, may also be produced. These emissions must comply with local, state, and federal requirements at the eventual exhaust point from the combustion/emission control system, as well as with local, state, and federal requirements applicable to the ambient air surrounding the fuel ethanol facility.

Raw emissions can be affected by the feed materials, the combustion/gasification technology, and the combustion/gasification operating conditions, while final emissions can be affected by the post-combustion/gasification controls applied to the raw emissions. Designing and implementing overall systems to maximize fuel utilization, minimize capital cost, minimize maintenance cost, and achieve stringent emissions requirements is challenging. It is especially challenging if the fuel mix and composition are variable and contain potentially problematic components.

### **Effects of Feed Materials on Raw Emissions**

(For a more detailed discussion, see the "Combustion Tests/Emissions Tests" chapter of this report.)

The most obvious effect that feed materials have on raw emissions results from the chemical makeup of the feed material. For any given combustion/gasification system, careful management of feed materials can have a significant impact on raw emissions, and hence on post-combustion/gasification units and on ultimate emissions. For example, syrup has a much higher sulfur content than corn stover, so combusting syrup will result in raw emissions with a much higher SO<sub>2</sub> content. The comparative nitrogen content of the feed materials will have a similar effect. A combustion/gasification system can only be designed for a certain latitude in the chemical composition of the feed material, and diligent management is needed to keep emissions within acceptable ranges.

The physical characteristics of the feed material can affect raw emissions. For example, corn stover has very low density in the unprocessed state. Adding corn stover to a system not specifically designed to handle it may result in the entrainment of the corn stover in a combustion-poor area of the unit, and so result in excessive PM in the raw emissions. A similar effect could occur with distillers dried grains (DDG) or distillers dried grains with solubles (DDGS) fines. Densification would change the bulk density of these feed materials, and so change the projected PM in the raw emissions. As with chemical composition, a system design can accommodate only a certain range of variability in the physical characteristics of the feed material.

A more subtle effect of feed material composition emerged in the computational fluid dynamics (CFD) modeling performed for this project. CFD modeling showed that the moisture content of the feed material has a significant impact on the NO<sub>x</sub> content of the raw emissions. (For a more detailed discussion of the effects of moisture content, see the “Combustion Tests/Emission Tests” chapter of this report.) Higher moisture content also significantly affects the design and operation of the post-combustion/gasification emission control systems.

## **Effects of Combustion/Gasification Technology on Raw Emissions**

(For a more detailed discussion, see the “Combustion Tests/Emissions Tests” chapter of this report.)

Achieving the required characteristics of ultimate emissions is a controlling factor in the selection of combustion/gasification technology. For example, a combustion turbine can only combust essentially clean gaseous fuels, so a gasification system with gas cleaning before the combustion turbine is needed for use of biomass as fuel. This reduces the potential emissions from most feed materials; however, the high temperatures developed in a combustion turbine may result in higher generation of thermal NO<sub>x</sub>.

Gasification operates at lower temperatures than combustion, and so generation of thermal NO<sub>x</sub> is lessened. On the other hand, if the syngas is directly combusted without cooling for gas cleaning, PM may increase, and thermal NO<sub>x</sub> may result from the combustion.

A major advantage of fluidized bed combustion or gasification is that materials can be added, usually limestone, to sequester the sulfur that is present at a high concentration in the feed materials. This may preclude the need for additional sulfur removal after combustion/gasification.

## Effects of Combustion/Gasification Operating Conditions on Raw Emissions

(For a more detailed discussion, see the “Combustion Tests/Emissions Tests” chapter of this report.)

Four primary operating factors affect raw emissions. First, a general rule (assuming the same cold leg temperature) for a combustion process is that the higher the combustion temperature, the more efficient the combustion process. However, thermal NO<sub>x</sub> increases with temperature. Especially considering the high nitrogen content of the ethanol plant co-products, NO<sub>x</sub> generation in the raw emissions is an important factor. Capital cost also increases for systems designed for increasing temperature and pressure.

Second, combustion of biomass produces ash. The ash will soften and melt at different temperatures, depending on the oxygen content and the chemical composition of the ash. The alkaline metal content of the ash is the most important factor. Both the ethanol co-products and the corn stover have high alkaline metal content, and exhibit ash fusion beginning at low (around 1,100°F [590°C]) to medium (around 1,600°F-1,800°F [870°C-980°C]) temperatures, with the highest temperature for fluid ash being around 2,700°F [1,480°C]). Unplanned ash fusion can cause plant shutdown and high repair costs.

Third, various chemicals can be added to the combustion/gasification system to impact raw emissions. As described above, limestone (calcium carbonate [CaCO<sub>3</sub>]) is often added to sequester sulfur. Ammonia may be added to impact NO<sub>x</sub>. Other chemicals may be added to impact ash thermal characteristics, or to alter the chemical makeup of the ash. These chemical additions may have a significant impact on raw emissions.

Fourth, the configuration of the combustion chamber, burner, air feeds, fuel inlets, and chamber outlets can all significantly affect the composition of raw emissions. Indeed, a specialized area of combustion expertise utilizing computational fluid dynamics (CFD) has arisen to impact raw emissions, especially NO<sub>x</sub>, from combustion units. Chemical inputs can be incorporated into the CFD data set. CFD can also be used to estimate raw emissions from a combination of feed materials.

### Modeling of Raw Emissions

The CFD modeling described in the “Combustion Tests/Emissions Tests” chapter of this report predicted raw emissions for the critical criteria pollutants except PM. The results are shown in the tables in that chapter. Engineering development of a specific combustion/gasification system, and refinement of the modeling to predict the minimum raw emissions for such a configuration for each pollutant, are beyond the scope of this project. However, the techniques applied in this project may be beneficially applied to an actual system.

## Post-Combustion/Gasification Emission Control Techniques

Based on the results of emission predictions performed as part of this project, and the identification of the expected emission rate(s) and regulatory limitations generally applicable to each source of criteria and hazardous air pollution emissions, emission scenarios were established for which a review of potential emission control technologies was conducted.

For each emission scenario and pollutant, potential emission control options were identified, including both demonstrated and likely potential techniques, and certain add-on or process modifications. Technically feasible control options and combinations were evaluated and ranked based on potential emission reduction.

The energy, environmental, and economic impact of each control option was reviewed in accordance with procedures developed by the United States Environmental Protection Agency (USEPA) Office of Air Quality and Planning Standards (OAQPS) and the Office of Management and Budget (OMB). The energy and economic impacts were evaluated through an estimate of the total capital investment for purchase and installation, and the total annual costs for operation, maintenance, and ownership of the control technology option.

The results of the emission control technology assessment were then summarized to help determine the optimal emission control alternative(s).

## Methodology

The United States Environmental Protection Agency (USEPA) has developed a methodology commonly used in evaluating the technical and economic feasibility of emission control technology. This methodology was described in the October 1990 *New Source Review Workshop Manual*, and consists of a five-step analysis, as follows:

1. Identify all available emission control technologies, both demonstrated and proposed, as well as add-on or process modifications, applicable to the proposed source and pollutant.
2. Eliminate technically infeasible control technology options. Technical infeasibility may be determined based on the ability of a given control technology to control a particular pollutant, or based on the ability of the technology to effectively control the pollutant.
3. Rank the remaining control technology options by pollutant control effectiveness.
4. Evaluate control technology options to determine the most effective option, considering energy, environmental, and economic impacts. The energy and economic impacts are evaluated through a determination of the total capital investment for purchase and installation, and the total annual costs for operation, maintenance, and ownership of the control technology option.
5. Select the "best" emission control options for the proposed source.

This methodology was applied in this project in reviewing the control technology options described in the following section.

## Control Technologies Evaluated

The methodology described in the previous section was applied in this project to the control technology options identified in Table CTXX below, to determine which option(s) would likely be necessary and the energy, environmental, and economic impact of the emission control technology option(s) needed to comply with local, state, and federal requirements at the exhaust point from the combustion/gasification system and in the ambient air surrounding the fuel ethanol facility.

The project proposal included an evaluation of potential alternative control technologies for the pollutants identified in Table CTXX. However, no demonstrated or proposed alternative control technologies for these pollutants have come to light in the course of this project. Table CTXX identifies the available emission control technologies that may be applicable to regulated pollutants at ethanol plants. Regarding pollutant control effectiveness, the listed technologies are generally capable of producing acceptable levels of pollutant control if properly designed and operated. The selection of the “best” pollutant control option will be impacted by economic, environmental, and energy considerations, and by site-specific factors.

**Table CTXX**  
**Summary of Potentially Applicable Emission Control Technology Options, by Pollutant**

PM	SO <sub>2</sub>	NO <sub>x</sub>	CO	VOCs/HAPs
<i>Demonstrated Control Technologies</i>				
<ul style="list-style-type: none"> <li>▪ Combustion conditions</li> <li>▪ Cyclones</li> <li>▪ Electrostatic precipitation</li> <li>▪ Fabric filtration</li> <li>▪ Wet scrubbing</li> </ul>	<ul style="list-style-type: none"> <li>▪ Combustion additives</li> <li>▪ Dry scrubbing</li> <li>▪ Fuel selection</li> <li>▪ Wet scrubbing</li> </ul>	<ul style="list-style-type: none"> <li>▪ Combustion conditions or controls</li> <li>▪ Fuel selection</li> <li>▪ Low NO<sub>x</sub></li> <li><u>Burners</u></li> <li>▪ Selective catalytic reduction (SCR)</li> <li>▪ Selective noncatalytic reduction (SNCR)</li> </ul>	<ul style="list-style-type: none"> <li>▪ Catalytic oxidation</li> <li>▪ Combustion conditions or controls</li> </ul>	<ul style="list-style-type: none"> <li>▪ Adsorption</li> <li>▪ Catalytic oxidation</li> <li>▪ Condensation</li> <li>▪ Thermal oxidation</li> </ul>

A brief description of the potentially applicable emission control technologies listed in Table CTXX is provided below, organized by type of pollutant.

## **PM Control**

PM in emissions is generally divided into two categories by size. PM with a diameter of less than or equal to 10  $\mu\text{m}$  is referred to as PM<sub>10</sub>, and is regarded as coarse, whereas PM with a diameter of less than or equal to 2.5  $\mu\text{m}$  is referred to as PM<sub>2.5</sub>, and is regarded as fine. PM of certain types and within certain size ranges can be controlled by devices treating the flue gas, as described below. The combustion conditions impact the nature and quantity of PM created during combustion, and so also impact the selection, the operation, and the efficiency of downstream control devices.

### *Combustion Conditions*

Combustion conditions are described in more detail in the “NO<sub>x</sub> Control” section below. The discussion here will briefly describe PM control as influenced by combustion conditions.

In all the analyses performed for this project, complete combustion of feed material is assumed. Given this condition, the primary factors influencing PM generation, and thus PM control, are combustion temperature, flue gas volume, and ash particle size.

Lower combustion temperatures may be desired to help control NO<sub>x</sub>, to prevent ash fusion, or to allow less costly materials of construction (such as bags in a baghouse) in the PM emission control system capital costs. Lower combustion temperature can be achieved by changing the fuel to air ratio, generally by additional excess air. This results in a larger flue gas volume, and therefore in larger (and so more costly) PM emission control devices. Combustion systems generally become more efficient with higher combustion temperatures, accompanied by PM emission control considerations the opposite of those for lower combustion temperatures. The overall design of the combustion and emission control system is a tradeoff among these factors. Given the generally lower ash fusion temperatures and the generally higher nitrogen content of the ethanol co-products, combustion systems using the co-products will tend to operate at a temperature lower than for a coal- or natural gas-fired system.

Ash particle size is influenced by several factors, but for this project, the primary factor is the type of combustion or gasification unit and the operating conditions. Fluidized bed units tend to produce a very fine ash. Samples

analyzed as part of this project showed all ash particles passing a #40 sieve and 83 percent passing a #200 sieve. The ash is relatively benign, as long as it is kept dry, and is readily collected by the several types of PM control devices described below. If significant imbalance were to occur in the bed, or if short circuiting were to occur, larger, possibly agglomerative, particulate could leave the unit and cause problems in the PM collector.

### *Cyclones*

Cyclones are used to reduce the inlet loading of particulate matter (PM) to other downstream collection devices by removing larger, abrasive particles. Cyclones, themselves, are generally not adequate to meet stringent air pollution regulations, but serve as precleaners for more expensive control devices, such as fabric filters or electrostatic precipitators (ESPs). Removal of PM is by centrifugal and inertial forces, induced by forcing particulate-laden gas to change direction. Cyclones are used to control PM, primarily PM greater than 10 micrometers ( $\mu\text{m}$ ) and smaller than 200  $\mu\text{m}$ . They are unable to handle sticky or tacky materials.

The collection efficiency of cyclones varies as a function of particle size and cyclone design. Cyclone efficiency generally increases with the following operational characteristics:

- Particle size and/or density
- Inlet duct velocity size of cyclone
- Number of gas revolutions during residence in the cyclone
- Dust loading
- Smoothness of the cyclone's inner wall

A common factor contributing to decreased control efficiencies in cyclones is the leakage of air into the dust outlet. Cyclone efficiency will decrease with increases in the following operational characteristics:

- Flue gas viscosity
- Flue gas density
- Flue gas exit diameter
- Flue gas inlet duct area

Cyclones perform more efficiently with higher pollutant loadings, provided that the device does not become choked. Higher pollutant loadings are generally associated with higher flow designs. Typical gas flow rates for a

single cyclone unit are 0.5 to 12 cubic meters/second ( $\text{m}^3/\text{s}$ ) or 1,060 to 25,400 standard cubic feet per second (scfm). Flow rates higher than approximately  $10 \text{ m}^3/\text{s}$  (21,200 scfm) usually employ multiple cyclones operating in parallel (often referred to as multiclones) up to approximately  $50 \text{ m}^3/\text{s}$  or 106,000 scfm. Inlet gas temperatures are limited by the materials of construction of the cyclone, and have been operated at temperatures as high as  $540^\circ\text{C}$  ( $1000^\circ\text{F}$ ). The density of PM in the flue gas prior to precleaning typically ranges from 2.3 to 230 grams per standard cubic meter ( $\text{g}/\text{m}^3$ ) and as high as  $16,000 \text{ g}/\text{m}^3$  for specialized applications.

Cyclones have relatively low collection efficiencies for PM less than  $10 \mu\text{m}$  in size. The control efficiency range for conventional single cyclones is estimated to be 30 to 90 percent for PM 10, and 0 to 40 percent for PM 2.5. High-efficiency single cyclones are 60 to 95 percent efficient for PM 10, and 20 to 70 percent for PM 2.5 and come with higher pressure drops, which require more energy to move the waste gas. Cyclone design is generally driven by meeting a specified pressure-drop limitation, rather than a specified control efficiency. High throughput cyclones are 10 to 40 percent for PM 10, and 0 to 10 percent for PM 2.5, and may require a multiclone design.

Cyclones have a low capital cost in comparison to other pollution control technologies and require a relatively small space. As a rule, smaller units controlling a waste stream with a low PM concentration will be more expensive (per unit of gas flow rate and per quantity of PM controlled) than a large unit controlling a waste stream with a high PM concentration.

The capital cost (2002 dollars) for a single conventional cyclone under typical operating conditions ranges from \$4,600 to \$7,400 per  $\text{m}^3/\text{s}$  (\$2.20 to \$3.50 per scfm).

Except for the fan providing the gas throughput, cyclones have no moving parts, and therefore few maintenance requirements and low operating costs. Waste management costs are lower than for wet devices, as the collected waste is dry and is collected in a hopper.

Pressure drop is an important parameter because it relates directly to operating costs and control efficiency. Higher control efficiencies for a given cyclone can be obtained by higher inlet velocities, but this also increases the pressure drop. When both high-efficiency (which requires a small cyclone diameter) and large throughput are desired, a multiclone with a number of parallel cyclone units with a common gas inlet and outlet can be used. Higher pressure drops

translate to higher energy usage and operating costs. Several designs can be considered to achieve the optimum combination of collection efficiency and pressure drop.

Typical annual O&M costs (2002 dollars) are \$1,500 to \$18,000 per m<sup>3</sup>/s (\$0.70 to \$8.50 per scfm) of gas treated.

### *Fabric Filtration*

Fabric filtration is usually accomplished in devices called baghouses. A baghouse has compartments containing rows of fabric bags or pleated cartridges. The gas stream to be cleaned is forced through the baghouse (usually by means of an induced draft fan located downstream of the baghouse), and PM above a certain size is retained on the upstream face of the bags. The cleaned gas stream goes to additional treatment or, if sufficiently cleaned, is vented to the atmosphere. The bag banks in the baghouse are operated cyclically, alternating between relatively long periods of filtering and short periods of cleaning, during which collected dust is removed from the bags and deposited in a hopper for subsequent disposal. Cleaning can be accomplished by shaking, by using pulsed jet cleaners, or by reversing the airflow.

Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter at efficiencies generally in excess of 99 or 99.9 percent. Gas temperatures up to about 500°F can be accommodated in some configurations and with specialized fabrics. Most of the energy used to operate the baghouse system is to maintain the specified pressure drop across the bags and ducting.

Limitations are imposed by gas characteristics (especially temperature, combustibility, and corrosivity) and particle characteristics (such as stickiness and abrasiveness) that affect the fabric or the removal of the captured PM from the fabric. An important design parameter is the gas-to-cloth ratio; i.e., the ratio of the volume of flue gas to the surface area of the cloth comprising the bags. The typical controlling operating parameter is the pressure drop across the filter system, which affects energy use, collection efficiency, and the physical condition of the system.

The capital cost of a baghouse system depends on many factors, including the gross area of the cloth, the choice of fabric material, the structure of the baghouse, and the choice of cleaning method. Cloth area is primarily determined by the flue gas volumetric flow rate, PM loading, and the emission

limits imposed on the system. Fabric material choice is impacted by the temperature of the flue gas; the material's resistance to chemicals, acids, or alkali; the need to withstand abrasion; the agglomerative characteristics of the PM; and the cost. Fabric costs vary significantly, ranging from (about \$1/ft<sup>2</sup> for cotton to about \$30/ft<sup>2</sup> for specialized synthetic fibers. The cost of the bags varies from less than 15 percent to more than 100 percent of the cost of the bare baghouse. The baghouse structure and cleaning method, and therefore the cost, is site specific and application specific, and depends on many of the same factors as for the bags.

Typical baghouse capital costs (2002 dollars) are \$13,000 to \$55,000 per sm<sup>3</sup>/s (\$6 to \$26 per scfm).

The filter bags have a typical operating life of 2 to 4 years. Other operating materials are generally not required for baghouses, with the exception of precoat materials for sticky or corrosive particles, which would not be expected in the ethanol plant applications considered in this project. Adsorbents may be injected when the baghouse is used for simultaneous removal of PM and gaseous pollutants. Maintenance labor typically varies from 1 to 2 hours per shift for major baghouses.

Electricity is needed to operate baghouse system fans and cleaning equipment. Pulsed jet cleaners additionally require compressors. Fuel costs may be associated with the heating of the baghouse to avoid condensation.

Typical annual O&M costs (2002 dollars) are \$11,000 to \$50,000 per m<sup>3</sup>/s (\$5 to \$24 per scfm).

### *Electrostatic Precipitators*

An electrostatic precipitator (ESP) is a particulate control device that uses electrical forces to move particles entrained within an exhaust stream onto collector plates. ESPs are applicable to PM 10, PM 2.5, and HAPs that are in particulate form, such as many metals (except mercury, which emits as a vapor).

The two basic operational types of ESPs are "dry" and "wet." As the terms imply, the dry type operates in gas stream environments without condensation or added water, while the wet type can operate in condensing environments, and water is often added for effectiveness or safety purposes. Dry ESPs are not suitable for sticky particles. Wet ESPs can collect sticky particles and mists, as well as highly resistive or explosive dusts. Wet ESPs are often used to control

acid mists and can provide incidental control of some volatile organic compounds.

ESPs in general are not well suited for use in processes that are highly variable because they are sensitive to fluctuations in gas stream conditions (flow rates, temperatures, particulate and gas composition, and particulate loadings). ESPs are also not well suited for sites that have limited space, as the units must be relatively large to obtain the low gas velocities necessary for efficient PM collection. ESPs are capable of operating under high pressure to 1,030 kPa (150 psi) or under vacuum conditions.

ESPs can handle large volumetric gas flow rates, with typical gas flow rates for dry ESPs ranging from 100 to 500 standard cubic meters per second ( $\text{m}^3/\text{s}$ ) (200,000 to 1,000,000 scfm). Typical gas flow rates for wet ESPs range from 50 to 250  $\text{m}^3/\text{s}$  (100,000 to 500,000 scfm).

Pollutant inlet concentrations to an ESP are typically from 2 to 110  $\text{g}/\text{m}^3$ . It is common to pretreat a waste stream, usually with a water spray or scrubber, to bring the temperature and pollutant concentration into a manageable range. Highly toxic flows with concentrations below 1  $\text{g}/\text{m}^3$  are also sometimes controlled with ESPs. When much of the pollutant loading consists of relatively large particles, mechanical collectors such as cyclones or spray coolers may be used to reduce the load on the ESP, especially at high inlet concentrations.

ESP size is related to many design parameters. Higher collection areas relative to gas flow lead to better removal efficiencies. Collection areas normally are in the range of 40 to 160  $\text{m}^2/\text{m}^3/\text{s}$  of gas flow (200-800  $\text{ft}^2/1000$  scfm). ESP size is an important factor in determining particle collection efficiency, as size determines particle residence time. Maximizing electric field strength will also maximize ESP collection efficiency. Collection efficiency is affected by dust electrical resistivity (for dry ESPs), gas temperature, effluent chemical composition, and particle size distribution. Typical design efficiencies for new ESPs are between 99 and 99.9%.

In dry ESPs, mechanical rapping is used to dislodge the accumulated dust layer. The rapping also projects some of the particles (up to 12% for coal fly ash) back into the gas stream with some of the re-entrained particles processed again by later sections of the ESP. Particles re-entrained in the last section of the ESP are not recaptured and escape. Captured dust is removed through a valve into a dust-handling system, such as a pneumatic conveyor, to a hopper for disposal.

For dry ESPs, care must be taken in measuring resistivity because it is affected by operating temperature, moisture, gas composition, particle composition, and surface characteristics. Gas conditioning equipment that injects an agent into the gas stream ahead of the ESP to improve performance by changing dust resistivity may be used. The conditioning agent most used is sulfur trioxide (SO<sub>3</sub>). Dry ESPs can operate at high temperatures, up to 700°C (1,300°F). The operating gas temperature and the chemical composition of the dust are key factors influencing dust resistivity and must therefore be carefully considered in the design of an ESP.

In wet ESPs, the collectors are either intermittently or continuously washed by a spray of liquid, usually water, eliminating the re-entrainment of particles found in dry ESPs. The humid atmosphere that results from the washing in a wet ESP enables the ESP to collect high-resistivity particles, absorb gases, or cause pollutants to condense, and cools and conditions the gas stream. The frequent washing of the plates also limits particle buildup on the collectors. The collection hoppers used by dry ESPs are replaced with a drainage system. The wet effluent is collected, and often treated on-site. The spray water may be recirculated after treatment. Wet ESPs are limited to operating at stream temperatures under approximately 80 to 90°C (170 to 190°F), and generally must be constructed of noncorrosive materials.

ESPs generally have high capital costs. The cost ranges for ESPs of conventional design under typical operating conditions are shown below. Costs can be substantially higher than shown for pollutants that require an unusually high level of control, or that require the ESP to be constructed of special materials such as stainless steel or titanium. In general, smaller units controlling a low concentration waste stream will not be as cost effective as a large unit cleaning a high-pollutant load flow.

For dry ESPs, typical capital costs (2002 dollars) range from \$21,000 to \$70,000 per m<sup>3</sup>/s (\$10 to \$33 per scfm).

For wet ESPs, capital and operating costs are generally higher due to noncorrosive material requirements, increased water usage, and treatment and disposal of wet effluent.

Typical capital costs (2002 dollars) range from \$42,000 to \$85,000 per m<sup>3</sup>/s (\$20 to \$40 per scfm).

ESPs minimally hinder flue gas flow and have very low pressure drops, so energy requirements for air handling and operating costs tend to be low. ESPs are capable of very high efficiencies, even for very small particles.

Relatively sophisticated maintenance personnel are required for ESPs, and special precautions and equipment are needed to safeguard personnel from the high voltage and from ozone that is produced by the negatively charged electrode during gas ionization.

For dry ESPs, the annual O&M costs (2002 dollars) typically range from \$6,400 to \$74,000 per m<sup>3</sup>/s (\$3 to \$35 per scfm).

For wet ESPs, the annual O&M costs (2002 dollars) typically range from \$11,000 to \$85,000 per m<sup>3</sup>/s (\$5 to \$40 per scfm).

### ***Wet Scrubbers***

Wet scrubbers can be used to control materials that are soluble in the scrubbing fluid (usually water, sometimes with additives), and can also be used to control certain particulates, especially those that are problematic to other control technologies because of their physical (such as sticky) or chemical (such as highly acidic or basic) characteristics. In an ethanol plant, wet scrubbers are commonly used on the fermentation vessels, where they capture ethanol and certain other organic vapors, as well as mists. The term flue gas desulfurization (FGD) applies when a wet scrubber is used to control sulfur dioxide (SO<sub>2</sub>). For PM applications, wet scrubbers usually generate waste in the form of a slurry, creating the need for both wastewater treatment and solid waste disposal.

Various techniques of wet scrubbing exist, and their applicability to the control of VOC, PM, and SO<sub>2</sub> varies as follows:

- Venturi - Typically, venturi scrubbers are applied where it is necessary to obtain high collection efficiencies for fine PM. The waste gas stream accelerates in a "throat" section, where the gas contacts atomized scrubbing liquid. After the throat section, the mixture decelerates, and further impacts occur causing the droplets to agglomerate. Once the particles have been captured by the liquid, the wetted PM and excess liquid droplets are separated from the gas stream by an entrainment section, which usually consists of a cyclonic separator and/or a mist eliminator. PM collection efficiencies range from 70 percent to greater than 99 percent.
- Spray water tower - Spray scrubbers consist of chambers in which the gas stream contacts liquid droplets generated by spray nozzles that are usually

arranged in successive banks. The gas-liquid contact is driven by a combination of liquid pressure and flow rate. Collection efficiencies for PM range from 70 percent to greater than 99 percent. Spray tower scrubbers generally are not used to control fine PM because of the high liquid-to-gas ratio needed. SO<sub>2</sub> removal efficiencies vary from 80 percent to greater than 99 percent, depending upon the type of reagent used and the spray tower design. For VOC, the typical collection efficiency ranges from 50 percent to 95 percent, with efficiencies greater than 99 percent for spray tower absorbers.

- Impingement-plate/tray-tower - This type of scrubber has a chamber with plates mounted horizontally, wherein the scrubbing liquid flows down the tower while the gas stream flows upward (countercurrent) and gas-liquid contact occurs on the plates. Like a sieve, the plates are equipped with openings that allow the gas to pass through. PM collection efficiencies range from 50 percent to 99 percent, depending upon the application. As collection is via inertial impaction, efficiency decreases as particle size decreases. Short residence times will also lower scrubber efficiency for small particles. For SO<sub>2</sub> control, removal efficiencies vary from 90 percent to greater than 99 percent, depending upon the type of reagent used and the plate tower design.
- Packed bed - Chambers with layers of variously-shaped packing material provide a large surface area for liquid-particle contact. Scrubbing liquid is evenly introduced above the packing and flows down through the bed with the gas stream either countercurrent or crosscurrent to the liquid. Packed-bed wet scrubbers are limited to applications in which dust loading is low, and collection efficiencies range from 50 percent to 90 percent.
- Orifice - Used to control PM, orifice scrubbers pass the particle-laden waste gas stream over a pool of scrubbing liquid at a high velocity, entraining the stream as droplets as it enters an orifice. The entrained liquid droplets then atomize as they flow through the orifice and agglomerate essentially in the same manner as a venturi scrubber. Orifice scrubber collection efficiencies range from 80 percent to 99 percent.
- Fiber bed - In fiber-bed scrubbers, moisture-laden waste gas passes through beds or mats of packing fibers, such as spun glass, fiberglass, or steel. These scrubbers are used to collect fine and/or soluble PM or are used as mist eliminators to collect liquid aerosols, including inorganic (e.g., sulfuric acid mist) and VOC. Insoluble and/or coarse PM will clog the fiber bed with time, and VOCs that are difficult to condense will not be collected efficiently. Fiber-bed scrubber collection efficiencies for PM and VOC mists generally range from 70 to greater than 99 percent, depending upon the size of the aerosols to be collected and the design of the scrubber and the fiber beds.

Operational procedures for the removal of the captured pollutants from wet scrubbers vary. For PM applications, wet scrubbers generate waste in the form of a slurry, creating the need for both wastewater treatment and solid waste management. In some cases, the collected solids may have value and can be sold or recycled. For FGD applications, the slurry or sludge is removed from the scrubber and, depending upon the liquid used to react with the SO<sub>2</sub>, the waste-reacted sludge is disposed, recycled, or regenerated. For slurries that produce calcium sulfate and sulfite, the waste can be oxidized and sold as gypsum. For VOC absorption, the water or other solvent must be treated to remove the captured pollutant from the solution. The recovered solvent may be treated and recycled back into the system.

A summary of the common pollutant applications of each technique is found in the table below, along with estimated capital costs (in 1999 dollars). Costs are for wet scrubbers of conventional design under typical operating conditions, and are given per unit of waste gas flow rate.

**Common Pollutant Applications of Wet Scrubbers, With Costs  
(1999 dollars)**

SCRUBBING TECHNIQUE	PM CONTROL	SO <sub>2</sub> CONTROL	VOC CONTROL	CAPITAL COSTS (\$/scfm)	ANNUAL O&M (\$/scfm)
Venturi	PM10 - PM2.5 or less	Yes	Incidental	2.5 to 21	5 to 120
Spray tower	PM10 - PM2.5	Yes	Yes	2 to 6	2 to 30
Impingement	PM10 - PM2.5	Yes	No	4 to 11	3 to 44
Packed bed	No	Yes	Yes	11 to 55	15 to 49
Orifice	PM10 - PM2.5 or less	No	No	5 to 17	4 to 70
Fiber bed	PM 2.5 or less	No	Yes	1 to 3	2 to 36

Wet scrubbing is likely not the preferred means of particulate or SO<sub>2</sub> control for the combustion and gasification processes considered in this project. Other control technologies produce good control with less potential maintenance and lower energy use. Many ethanol plants are located in geographic areas with cold winters, where freezing is a concern with wet emission control systems. Wet scrubbers produce a wastewater stream and a solid residue that must be

managed. Wet scrubber systems to control SO<sub>2</sub> are complex, require high maintenance, and produce a potentially troublesome sludge.

## SO<sub>2</sub> Control

In general, acceptable SO<sub>2</sub> emissions can be obtained by one or more of the following overall techniques: limiting the amount of sulfur in the feed material; adding sulfur capturing chemicals to the combustion process; or removing SO<sub>2</sub> from the flue gas.

All of the ethanol plant co-products contain sufficient sulfur, generally from around 0.4 to 0.8 percent, to be problematic for uncontrolled emission. Corn stover generally contains about an order of magnitude less sulfur than the co-products. Since a primary objective of this project is the maximum utilization of the ethanol plant co-products, and since the co-products contain so much more sulfur than does corn stover, controlling SO<sub>2</sub> emissions by the choice of feed materials is impractical.

Adding sulfur-capturing chemicals (typically limestone) to the combustion chamber or to the hot flue gases is a well established technique for SO<sub>2</sub> emission control. The technique works especially well for fluidized beds. Project partner plant Corn Plus adds limestone to the fluidized bed combustion unit in which its syrup is burned. The sulfur is captured in the form of calcium sulfate, or gypsum, which is removed in a flue gas baghouse. The exact process and the exact amount of limestone used are proprietary to Corn Plus. However, typical application rates for coal are in the range of XX pounds of limestone for each YY pounds of sulfur to be sequestered. The valuable nutrient and excess lime content of the co-product combustion ash make the ash a potential source of revenue for the plant.

SO<sub>2</sub> can be removed from flue gas by several methods, but the most common are wet scrubbing or dry scrubbing. Wet scrubbing is described in the "PM Control" section above. In dry scrubbing, the chemical used to capture the SO<sub>2</sub>, usually powdered limestone, is added to hot flue gases. The resultant calcium sulfate is captured in a PM control device, often a baghouse. It may be possible to beneficially reuse the collected PM, although the volume of collected PM at a typical ethanol plant (as opposed to, say, a coal-fired power plant) may be insufficient for economic reuse in any but basic (such as agricultural liming) applications.

## NO<sub>x</sub> Control

Various oxides of nitrogen (NO<sub>x</sub>) may be formed during any combustion. The quantity and types of NO<sub>x</sub> formed depend primarily on the fuels used and the combustion conditions. These factors are discussed below.

Three general types of NO<sub>x</sub> may be formed during combustion: thermal NO<sub>x</sub>, prompt NO<sub>x</sub>, and fuel NO<sub>x</sub>. Thermal NO<sub>x</sub> is formed from nitrogen and oxygen present in air, and forms at combustion temperatures of approximately 2,400°F (1,315°C) or greater. The longer the time that the combustion remains above the thermal NO<sub>x</sub> formation temperature, the greater the amount of thermal NO<sub>x</sub> that will form. Thermal NO<sub>x</sub> thus is not dependent on the fuel type, but on the combustion temperature and retention time at that temperature. Prompt NO<sub>x</sub> is formed from nitrogen in the air that combines with fuel in fuel-rich conditions during combustion, and subsequently oxidizes along with the fuel to form NO<sub>x</sub>. The production of prompt NO<sub>x</sub> thus is influenced by the fuel type. Fuel NO<sub>x</sub> is formed when the nitrogen inherent in the fuel oxidizes during combustion. Since the sole source of fuel NO<sub>x</sub> is the fuel, production of fuel NO<sub>x</sub> depends completely on the fuel type. Ethanol plant co-products are high in nitrogen, and thus have high fuel NO<sub>x</sub> potential.

Six primary methods of controlling NO<sub>x</sub> are used, with the seventh method being a combination of the six:

- Reducing combustion temperature
- Reducing residence time at peak temperature of combustion
- Reducing the NO<sub>x</sub>
- Oxidating the NO<sub>x</sub>
- Lowering the nitrogen content of the combustion air prior to combustion
- Injecting adsorbents and absorbents

Reducing combustion temperature avoids the temperatures at which nitrogen in the air becomes ionized and generates higher concentrations of thermal NO<sub>x</sub>. At lower temperatures, the stoichiometric ratio (i.e., the exact mix that fully completes a reaction) of compounds that enter into the NO<sub>x</sub> reaction is not present, either through dilution via an excess of fuel, air, flue gas, or steam, or combustion control of the fuel/air ratio.

The usual control methods of reducing combustion temperature are as follows:

- Flue gas recirculation
- Fuel reburning
- Low NO<sub>x</sub> burners
- Combustion optimization
- Less excess air
- Injection of water or steam
- Overfire air

- Air staging
- Reduced air preheat
- Catalytic combustion

These techniques can generally be used for different combustion systems, including fluidized bed systems.

Cooled oxygen-depleted flue gas can be added into the combustion air to dilute energy and lower temperature, or can be added with additional fuel. This flue gas recirculation control method reduces the oxygen content of combustion air and causes heat to be diluted in a greater mass of flue gas, lowering the NO<sub>x</sub> concentration that is generated. If combustion temperature is held to below 1,400°F, the thermal NO<sub>x</sub> formation will be negligible.

Low NO<sub>x</sub> burners reduce the temperature of combustion products with an excess of fuel, air, flue gas, or steam. Low NO<sub>x</sub> burners cost about \$150 per ton (1999 dollars) of NO<sub>x</sub> prevented, and produce up to 80 percent reduction in NO<sub>x</sub> generation. They provide a stable flame that has several different zones, and can operate with many variations. For example, the first zone can be primary combustion, the second zone can be fuel reburning with fuel added to chemically reduce NO<sub>x</sub>, and the third zone can be final combustion in low excess air to limit the temperature.

The amount of excess airflow for combustion correlates to the amount of NO<sub>x</sub> generated. Limiting the net excess airflow to under 2 percent can strongly limit the NO<sub>x</sub> content of flue gas. Although there are fuel-rich and fuel-lean zones in the combustion region, the overall net excess air is limited when using this approach.

When primary combustion uses a fuel-rich mixture, the use of overfire air completes the combustion. Because the fuel-air mixture is always non-stoichiometric when combustion is occurring, the temperature is held down. After all other stages of combustion, the remainder of the fuel is oxidized in the overfire air.

Water or steam can be added to dilute the NO<sub>x</sub> combustion reaction. Fuel-rich mixtures limit the amount of oxygen available, whereas fuel-lean mixtures limit temperature by diluting energy input. However, since the typical ethanol co-product contains substantial water, adding water or steam is an unlikely control technique.

While lowering combustion temperature with the above control methods lowers NO<sub>x</sub> formation, it can also decrease combustion efficiency. Combustion control measures seek to find an optimum combustion efficiency and to control emissions at that efficiency.

Reduction of the residence time of combustion air at high temperatures can be accomplished by restricting the area of highest temperature to a small region in which the combustion air becomes flue gas, immediately followed by injection of fuel, steam, more combustion air, or recirculating flue gas. This short residence time at peak temperature keeps the majority of nitrogen in the air from becoming ionized. Therefore, the control methods of reducing combustion air residence time at peak temperatures are as follows:

- Design of the combustion region
- Injection of fuel
- Injection of steam
- Injection of air
- Recirculation of flue gas

While some low-  $\text{NO}_x$  burners are based partially on the principle of  $\text{NO}_x$  reduction (as opposed to the oxidation of  $\text{NO}_x$ ), the usual methods of  $\text{NO}_x$  control through chemical reduction are as follows:

- Fuel reburning
- Selective catalytic reduction
- Selective non-catalytic reduction

The reduction of  $\text{NO}_x$  employs a substance to remove oxygen from nitrogen oxides and reduce the number of electrons available for chemical reaction (the “valence”) of nitrogen to zero. Types of reducing technologies include selective catalytic reduction (SCR), which uses ammonia; selective non-catalytic reduction (SNCR), which uses ammonia or urea; and fuel reburning. An emerging technology is based on the use of non-thermal plasma, along with a reducing agent.

SCR is capable of  $\text{NO}_x$  reduction efficiencies in the range of 70 to 90 percent on  $\text{NO}_x$  concentrations as low as 20 parts per million (ppm), which is generally greater than low- $\text{NO}_x$  burners and SNCR. Higher reductions are possible, but generally not cost-effective. The  $\text{NO}_x$  reduction reaction is effective within a given temperature range, which depends on the type of catalyst used and the flue gas composition. SCR operates at temperatures from 480°F to 800°F (250°C to 427°C), which is a lower and broader range than for SNCR. Capital costs are significantly higher than for other types of  $\text{NO}_x$  controls due to the large volume of catalyst that is required. The cost of the catalyst is approximately \$10,000 / $\text{m}^3$  (\$2830 / $\text{ft}^3$ ) in 1999 dollars. The O&M costs of using SCR are driven by the reagent usage, catalyst replacement, and increased electrical power usage.

The O&M cost and the cost per ton of pollutant removed are greatly impacted by the capacity factor and whether SCR is utilized seasonally or year round.

NO<sub>x</sub> reduction levels by SNCR, alone, range from 30 to 50 percent. For SNCR applied in conjunction with combustion controls, such as low NO<sub>x</sub> burners, reductions of 65 to 75 percent can be achieved. The waste gas stream must be within a temperature range of from 1,600°F to 2,100°F (870°C to 1,150°C). SNCR is less effective at lower levels of uncontrolled NO<sub>x</sub>, which are typically from 200 ppm to 400 ppm. SNCR is better suited for applications with high levels of PM in the waste gas stream than SCR. The capital costs of SNCR for industrial boilers greater than 100 MMBtu/hr ranges from \$900 to \$2,500 /MMBtu/hr (1999 dollars), and are among the lowest of all NO<sub>x</sub> reduction methods. Annual O&M costs are approximately \$100 to \$500 /MMBtu/hr (1999 dollars).

For both SCR and SNCR, excess or unreacted ammonia may require cleaning downstream equipment to lessen plugging and corrosion, and the plume visibility and resale or disposal of ash may be affected.

NO<sub>x</sub> control through oxidation consists of the following methods:

- Injection of oxidant
- Non-thermal plasma reactor

As NO<sub>x</sub> has a greater solubility in water at a higher valence, the oxidation of NO<sub>x</sub> involves raising the valence of the nitrogen ion to allow water to absorb it. This is accomplished either by using a catalyst, injecting hydrogen peroxide (H<sub>2</sub>O<sub>2</sub>), creating ozone (O<sub>3</sub>) within the airflow, or injecting ozone into the airflow. Non-thermal plasma (used without a reducing agent) can be used to oxidize NO<sub>x</sub>. A scrubber must be added to the process to absorb N<sub>2</sub>O<sub>5</sub> (the anhydride of nitric acid) emissions to the atmosphere. Any resultant nitric acid (HNO<sub>3</sub>) can be collected for commercial sale or first neutralized and then sold (usually as a calcium or ammonia salt).

Lowering the nitrogen content present during combustion is accomplished by using oxygen instead of air (or reducing the air in excess of that needed for combustion) used in the combustion process, or by using a low-nitrogen fuel to form less fuel NO<sub>x</sub>. Use of oxygen produces an intense flame that must be diluted to lower the temperature, though if air is the quench medium, thermal NO<sub>x</sub> will still be formed as the air is heated by hot flue gas. Use of oxygen also has a high capital and operating cost. For some applications, using ultra-low-nitrogen content fuels with oxygen can nearly eliminate fuel and prompt NO<sub>x</sub>. This is impractical for ethanol co-products, as the intrinsic nitrogen content is quite high, and even considerable blending with alternative low-nitrogen fuels (such as corn stover) will not yield a reduction in NO<sub>x</sub> to levels that do

not require emission control by other means. Control of NO<sub>x</sub> through lower nitrogen during combustion is therefore relegated to the following methods:

- Using oxygen instead of air
- Reducing the net excess air
- Using auxiliary low-nitrogen fuel

Treating flue gas by injecting adsorbents and absorbents, such as ammonia, powdered limestone, aluminum oxide, or carbon, can remove NO<sub>x</sub> and other pollutants (principally sulfur). The sorbent control methods are based on the area of application:

- In the combustion chambers
- In the flue gas ducts
- In the flue gas baghouse

Sorbent treatment can be applied in the combustion chamber, flue, and baghouse. The sorption method most commonly employs a dry sorbent, but slurries also have been used. NO<sub>x</sub> control by sorption is followed by fabric filtration and/or electrostatic precipitation to remove the sorbent, and in some cases, the spent product is a saleable commodity.

No single NO<sub>x</sub> control technology is superior for all combustion systems, boilers, or fuels. Low NO<sub>x</sub> burners are among the least expensive emission control technologies. SCR is more expensive, but can obtain up to 94 percent control efficiency. Many of the methods can be combined to achieve a lower NO<sub>x</sub> concentration than can be achieved by any one method, alone. Low NO<sub>x</sub> burners can be used in conjunction with SCR or SNCR, and water or steam injection can be used with SCR. Fuel reburning and SCR can be used together.

Other control technologies intended to primarily reduce concentrations of sulfur can also strongly affect NO<sub>x</sub>. Selective catalytic reduction of NO<sub>x</sub> can utilize the N<sub>2</sub> that is formed in the selective oxidation of sulfur dioxide to sulfur trioxide. Tandem application of NO<sub>x</sub> control techniques, such as SNCR followed by SCR in the duct and then sorption before an ESP, can achieve an overall reduction of 90 percent in NO<sub>x</sub> and 80 percent in SO<sub>x</sub> without lowering NO<sub>x</sub> generation with low NO<sub>x</sub> burners.

In practice, reduction in NO<sub>x</sub> emissions can be complex. The choice of NO<sub>x</sub> control technology depends on the type of combustion system, the type of boiler or other energy conversion device, and the type of fuel used. Available technologies will be narrowed by consideration of turndown ratio (range of firing positions between full capacity and

shutdown), stability of combustion, applicability of low NO<sub>x</sub> burners to the system, air supply controls, fuel impurities, and cost, among other factors.

The design of the boiler or gas turbine has a major effect on NO<sub>x</sub> formation. Larger combustors tend to have more intense combustion with higher combustion temperatures and longer residence time for flue gases, though designs that incorporate staging of the combustion can lessen the formation of NO<sub>x</sub>. The ethanol co-products under consideration for combustion have a high moisture content, which drives boiler design for thermal efficiency as well as emission control.

## **CO Control**

### *Catalytic Oxidation*

Catalytic oxidation is described in detail in the "VOCs Control" section below.

### *Combustion Conditions or Controls*

The "Combustion Conditions and Controls" discussion in the "NO<sub>x</sub> Control" section above also applies to CO control. In optimizing the combustion conditions and controls for NO<sub>x</sub> control, optimization can also be achieved for CO. Since post-combustion CO control is typically less costly than NO<sub>x</sub> control, achievement of the NO<sub>x</sub> requirement usually takes precedence. Key factors in achieving CO minimization in the combustion zone are sufficient excess oxygen, sufficiently high temperature, sufficient turbulence, and sufficient retention time.

## **VOC Control**

### *Adsorption*

Emissions of volatile organic compounds (VOCs) and organic hazardous air pollutants (HAPs) can be controlled, recovered, recycled, or concentrated for additional treatment by adsorption technology. In the adsorption process, pollutants are physically held (adsorbed) onto the surface of the absorption material. This differs from the absorption process, in which materials are trapped in pores and interstitial spaces throughout the bulk of the absorption material. Adsorption is generally used for processes that generate VOC emissions at relatively low concentrations (as low as 20 parts per million [ppm]) at relative high airflows (greater than 5,000 scfm) to concentrate VOCs prior to final treatment, recycling, or destruction. Adsorbed pollutants are generally released (desorbed) by washing, heat, vacuum, or pressure.

Adsorbers are typically used to reduce VOC concentrations from between 400 and 2,000 ppm to under 50 ppm. Lower or higher influent concentrations may be handled, but the process may become technically difficult or uneconomical using adsorbents. Higher VOC influent concentrations may be more economically controlled by technologies such as incinerators, membrane separators, and condensers. An adsorber system can achieve 95-98 percent control efficiency at influent concentrations between 500 and 2,000 ppm in air.

Adsorption systems may typically use carbon, zeolite, or polymer adsorbents. Zeolite is a naturally occurring alumino-silicate crystal. De-aluminizing zeolite creates an adsorbent material that has an affinity for nonpolar substances, such as many VOCs. Polymer adsorbents are plastic granules or beads. Polymers generally desorb faster than carbon. Like carbon, polymers are not highly selective as to which VOC they will adsorb. The adsorption operating characteristics, including concentration, temperature, and pressure, are different for each type of adsorbent and each type of pollutant. Some vapors are best controlled by a mixture of adsorbents. Adsorption is exothermic, so adsorption gives off heat and causes a temperature rise in the adsorber bed. Carbon or metals on the carbon have been known to catalyze the oxidation of some pollutants, which can result in bed temperatures high enough to cause fires in the bed, consuming part or all of the carbon. Some polymers and zeolites are less sensitive to humidity and less subject to fire, crumbling, or powdering than carbon. Therefore, they require less frequent replacement. Carbons are lower in cost per unit (at least initially). The cost per pound of carbon is about \$2.00 (1998 dollars), while the cost per pound of polymers or zeolite up to 20 times higher. However, zeolites and polymers need to be changed out infrequently, whereas carbon needs to be replaced more frequently, including when a bed fire has occurred.

After as few as five cycles of adsorption and regeneration, the adsorption capacity of carbon decreases by about 50% of its original capacity, while zeolites maintain about 90% of their original adsorption capacity, and polymers maintain about 50% to 90% of their original adsorption capacity. This "working capacity" can have a significant effect on the cost of installing, operating, and maintaining an adsorber.

Regeneration of the adsorbent (desorbing) needs to occur before all of the adsorbent has become saturated. Regeneration is often accomplished by raising the temperature (often with steam), by applying vacuum, or by applying pressure. The desorbed VOCs are sometimes purified and then recovered for reuse or for sale. Otherwise, the VOCs are destroyed, typically by flameless

oxidation, thermal incineration, or catalytic incineration. A vapor concentrator can be use with the desorbed VOCs to provide more economical treatment in either combustion or condensation devices.

An important design parameter is the emission residence time in the adsorption system, and therefore the physical size of the system. While shorter adsorption times result in smaller adsorber systems and lower capital costs, higher annual costs may result because the adsorbent must be regenerated more frequently. Also, the system size must be compatible with the production facility's schedule, including the schedule of the individual unit processes contributing the VOCs to the emissions. Unless redundancies are built in, the system needs to be sized to avoid regeneration in the midst of a production run.

Adsorber system costs depend on a variety of facility, operational, regulatory, sizing, and cost parameters. For that reason, accurate generic system cost estimates are essentially infeasible. Facility and sizing parameters include the exhaust gas volumetric flow rate, temperature, pressure, VOC composition, VOC loading, moisture content, and particulate characteristics. Operational factors include production schedules, planned outages, and raw material variability. Regulatory factors include the required degree of VOC control, provisions for operation during regeneration, O&M requirements in permits, and the ambient air quality status of the area. The cost of retrofitting an adsorption system at an existing facility will usually be higher than the cost of installing a new facility.

Capital costs increase with both increasing gas flow rate and VOC emission rate. Larger flow rates require larger and more costly adsorber vessels, decanters, condensers, and other equipment. As the emission rate increases, more adsorbent is needed. As a general example, Table 1 shows estimated capital costs (1998 dollars) for two differing gas flow rates and two emission rates for toluene, using a carbon adsorption system.

**Table 1**  
**Cost of Thermal Swing ("regenerative") Carbon Adsorption Systems**

GAS FLOW RATE (scfm)	TOLUENE EMITTED (lb/hr)	CAPITAL COSTS (1988 \$)	
		1,000 \$	\$/scfm
5,000	50	240	48
	250	430	87
50,000	250	1,100	22
	1,250	1,700	3

Operation costs for adsorption systems include the cost of replacement adsorbent, electricity for the air movers, energy for bed regeneration, and labor. If there is a favorable market value to the recovered VOC, the current market price of a reusable or marketable VOC can significantly offset the cost of emission control.

### *Catalytic Oxidation*

VOCs, CO, and for some applications, PM can be destroyed by oxidation via use of a catalyst. Catalytic incinerators operate similarly to thermal incinerators. Hot gas with pollutants pass through a catalyst bed, where the pollutants are oxidized with oxygen from the air. The catalyst enables oxidation at lower reaction temperatures than in thermal incinerators, and therefore allows for smaller incinerator size.

Catalysts are of various types, but the most common are metals. Single or mixed metal oxide catalysts can tolerate almost any organic compound. Most of these catalysts are supported by a mechanically strong carrier such as alumina. Catalysts such as chromia/alumina, cobalt oxide, and copper oxide/manganese oxide have been used for oxidation of gases containing chlorinated compounds. Platinum-based catalysts are active for oxidation of sulfur-containing VOCs, although such catalysts are rapidly deactivated by the presence of chlorine.

Catalytic incinerators can be used to reduce pollutants from a variety of stationary sources. In an ethanol plant, the most common use is for oxidation of CO from thermal oxidizer systems. Catalytic oxidation is most suited to systems with moderate exhaust volumes, when there is little variation in the type and concentration of pollutant emission, and where catalyst poisons or other fouling contaminants such as silicone, sulfur, heavy hydrocarbons, and certain particulates are not present.

Destruction efficiency is dependent upon pollutant composition and concentration, operating temperature, oxygen concentration, catalyst characteristics, and the volumetric flow of gas entering the catalyst per volume of the catalyst. Increases in temperature and catalyst volume increase pollutant destruction efficiency. A catalytic unit operating at about 450°C (840°F) with a catalyst bed volume of 0.5 to 2 cubic feet (ft<sup>3</sup>) per 1,000 scfm of offgas passing through the device can achieve 95 percent VOC destruction efficiency. Higher destruction efficiencies of 98 to 99 percent are achievable, but require larger catalyst volumes and/or higher temperatures, and are usually designed on a

site-specific basis. The maximum design exhaust temperature of the catalyst is typically 1,000° to 1,250°F (540° to 675°C) .

Catalytic incinerators can be used effectively at very low inlet loadings, as low as 1 part per million by volume (ppmv) or less. For safety considerations, as with thermal incinerators, the maximum concentration of the organics in the gas must be well below the lower explosive limit (LEL) of the compound being controlled. The level of CO in the thermal oxidizer exhaust from an ethanol plant is well below the LEL.

Because of the sensitivity of catalytic incinerators to inlet stream flow conditions, which may cause catalyst deactivation, some pretreatment, such as removal of particulate matter (PM), may be required. The amount of PM in the thermal oxidizer exhaust from an ethanol plant is usually low enough to not be a problem.

Catalytic oxidizers have a relatively high initial cost. Typical costs for packaged catalytic incinerators of conventional design with fixed beds under typical operating conditions and referenced to the volumetric flow rate of the waste stream treated are shown below. Costs for a gas pretreatment and any post-oxidation acid gas treatment system are not included. Costs can be substantially higher than the ranges shown when used for low-pollutant concentration streams (less than around 100 ppmv).

Capital costs (2002 dollars) are estimated to range from \$47,000 to \$191,000 per m<sup>3</sup> /s (\$22 to \$90 per scfm).

Costs would likely be lower for an ethanol plant application, because no separate firing would likely be needed if the catalytic oxidizer system treated the flue gas from the thermal oxidizer. However, efficient heat recovery upstream of the catalytic oxidation system may require reheat for efficient operation.

Operation costs are dominated by the cost of supplemental fuel required in the incinerator, if such supplemental fuel is required. Compared to thermal incineration, alone, catalytic oxidation has fewer fuel requirements and lower operating temperatures with reduced fire hazards. Spent catalyst that cannot be regenerated or recycled will need to be disposed.

Typical annual O&M costs (2002 dollars) are estimated to range from \$8,500 to \$53,000 per m<sup>3</sup>/s (\$4 to \$25 per scfm).

### *Condensation*

Some VOCs can be recovered in some circumstances by condensation, and in some cases it is possible to recycle or reuse the recovered material. The ethanol production process includes extensive use of condensation to capture the distilled ethanol product. Regarding the use of condensation as an emission control technology for combustion systems, however, condensation is essentially infeasible. Condensation systems can be costly and can consume considerable water and energy. Good candidates for condensation are small-volume, moderate-temperature, clean, uncomplicated emission streams with a high content of one or a few VOCs with recoverable value. None of these conditions apply to the biomass combustion emission streams considered in this project. Therefore, condensation is not further considered.

### *Thermal Oxidation*

Thermal oxidation, or incineration, is the process of oxidizing combustible materials by raising the temperature of the material above the point where it will spontaneously ignite in the presence of oxygen for sufficient time to complete the conversion to oxides, ash, and water. VOCs and certain PM are commonly destroyed by incineration. PM formed as a result of partial combustion (such as in product driers operating at higher temperatures) can also be destroyed in various degrees, depending on the specific design of the thermal oxidation unit. Time, temperature, turbulence (for mixing), and the availability of oxygen all affect the rate and efficiency of the combustion process.

Thermal oxidizers can be used to reduce emissions from many VOC sources. They can handle certain fluctuations in influent flow, but are generally not suited to influent streams with highly variable flow because of altered residence time and inadequate mixing, which decrease the completeness of combustion. Thermal oxidizers are a proven method for destroying VOCs, with efficiencies up to 99.9999 percent possible.

There are four basic types of thermal oxidizers. One type is a flare, which may be either open or enclosed. A flare uses auxiliary fuel (usually natural gas) to initiate combustion of a pollutant gas stream. For most flare applications, the quantity and concentration of the combustible pollutant gas are sufficient to contribute major thermal input to the flare, even to the point of being self-sustaining, after combustion is initiated. Flares are typically used in an ethanol plant for incinerating the off gases from product loading, since the off gases are

low volume with relatively high concentrations of ethanol or denaturant (gasoline).

A second type of thermal oxidizer uses a combustion chamber with auxiliary fuel (usually natural gas), and exhausts the products of combustion. Fuel consumption of such systems is high. However, the capital costs of such systems are low, and the effectiveness of pollutant destruction is high. Because more efficient and effective thermal oxidizer systems are now available, large systems without heat recovery are rare.

A third type of thermal oxidizer is essentially a modified boiler. The waste gas stream enters the unit either as a component of the makeup air or as a separate stream. Thermal oxidation of the waste components occurs incidental to the combustion process, which is usually fired with natural gas or coal. The thermal oxidizer serves as a steam generation unit, either directly or with the use of a heat recovery steam generator (HRSG). While these designs have certain advantages, especially for small plants, they have three main drawbacks. First, combustion of the pollutants may result in conditions, such as acid gases, agglomerative combustion products, clogging, and corrosion from excessive moisture, detrimental to the thermal oxidizer system. Second, the introduction of the pollutant stream likely lowers the overall efficiency of the steam generator, because of the components of the waste gas stream, the variability of the waste gas stream, and the inability to optimize the steam generation system for the primary fuel supply. Third, such arrangements may result in an inconsistent elimination of the pollutants, and may even create additional pollutants (such as carbon monoxide and condensable PM).

The fourth basic type of thermal oxidizer is regenerative or recuperative, often referred to as an RTO. These systems contain multiple beds of (usually) ceramic material. To initiate the process, auxiliary fuel (usually natural gas) is used to heat one of the beds to a sufficiently high temperature to combust the pollutants. The pollutant stream is introduced into the heated bed, where combustion of the pollutants raises the temperature of the bed further. Additional natural gas may be introduced to increase the temperature. The hot gases leaving the active bed pass through another bed, which absorbs heat. When the second bed reaches a sufficiently high temperature, the waste gas flow is reversed; i.e., the waste gas (and sometimes additional natural gas) is combusted in the second bed, and the hot gases flow through the first bed, maintaining its temperature. The cycle is then repeated. Bed switching may occur as often as every minute. Multiple beds are often used to maintain consistent operation and to perform O&M on the system without bypassing.

RTOs are very fuel efficient, often exceeding 95 percent thermal efficiency, and are also very effective, producing pollutant destruction of 98 percent or more.

Using a separate system to incinerate pollutants allows the plant steam generation system to be optimized. RTOs are now widely used at fuel ethanol plants.

For all thermal oxidizers, key operational parameters are combustion temperature and retention time in the combustion zone. The shorter the retention time, the higher the reactor temperature must be. Design of systems involves striking a balance between larger size (which increases retention time but also increases capital cost) and higher operating temperature (which allows for a smaller size, but adds some additional cost). Thermal destruction of most organic compounds occurs between 590°C and 650°C (1,100°F and 1,200°F). To balance retention time and temperature, many RTOs are designed to provide around 1 second of residence time to the waste gas, with typical operating temperatures of around 730 to 790°C (1,350 to 1,450°F). Steam generator type thermal oxidizers tend to operate at a higher temperature, which increases the efficiency of the unit.

Flare type thermal incinerators can be used over a fairly wide range of organic vapor concentrations. Except for flares, for safety reasons the concentration of the organics in the waste gas is kept well below the lower explosive limit (LEL) of the specific compound being controlled. For operational reasons, the concentrations of VOCs in the waste gas must remain in the range that the equipment was designed to handle; too high of concentrations can result in overheating and severe damage to equipment. If needed, the waste gas may be diluted with ambient air to lower the concentrations.

The following are cost ranges (expressed in 2002 dollars) for packaged thermal incinerators of conventional design under typical operating conditions. Costs can be substantially higher than in the ranges shown when used for low to moderate VOC concentration streams (less than around 1,000 to 1,500 ppmv). Thermal incinerators are also not generally cost-effective for low-concentration, high-flow organic vapor streams.

Capital costs (2002\$) range from \$53,000 to \$190,000 per m<sup>3</sup>/s (\$25 to \$90 per scfm).

Thermal incinerator operating costs are relatively high owing to supplemental fuel costs. Recuperative incinerators recover waste heat energy from the exhaust gases and operate at a lower cost.

Annual O&M costs (2002 dollars) range from \$11,000 to \$160,000 per m<sup>3</sup>/s (\$5 to \$75 per scfm).

## **Results of Control Technology Evaluation**

The control technologies were evaluated considering relative energy, economic, and environmental impacts. The results are based on information from the literature and on the experience of the technical team with such systems. The summary results of the control technology evaluations are presented in tables CTXX through CTXX.