SUPPLEMENTAL MATERIALS ON
COMBUSTION EVALUATION

for

U.S. Environmental Protection Agency
APTI Course Number 427

Edited by:

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February 2017
Agenda for APTI Course No. 427
COMBUSTION EVALUATION

Sponsored by
SESARM
205 Corporate Center Dr., Ste. D
Stockbridge, GA 30281-7383

Location:
Alabama Dept. of Env. Mgmt.
1400 Coliseum Boulevard
Montgomery, Alabama
February 14-17, 2017

Course Moderator & Speaker
Taylor Beard, PhD, P.E.

Monday, February 13, 2017

Unit Time Subject Manual Pages
8:00-8:10 Registration and Introductory Comments
8:10-9:00 Pre-Test
1. 9:10-10:00 Introduction to Combustion Source Evaluation 1-1 to 1-13
2. 10:10-11:00 Combustion I: Basic Concepts 4-1 to 4-15
3. 11:10-12:00 Fuels I: General Features 3-1 to 3-19
12:00-1:00 Lunch
4. 1:00-1:50 Combustion II: Excess Air 4-15 to 4-24
5. 2:00-2:50 Combustion III: Chemical Energy 4-24 to 4-39
6. 3:00-3:50 Fuels II: Fuel Properties 3-19 to 3-44
7. 4:00-5:00 Combustion Systems I: Conventional Systems 2-1 to 2-29

Homework: Read Chapters 1, 2, 3 & 4; Work Review Exercises Chapters 1, 3 & 4.
Wednesday, February 15, 2017

<table>
<thead>
<tr>
<th>Unit</th>
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<th>Subject</th>
<th>Manual Pages</th>
</tr>
</thead>
<tbody>
<tr>
<td>8</td>
<td>8:00-8:50</td>
<td>Discuss Review Exercises</td>
<td>1-14, 3-45 &amp; 4-40</td>
</tr>
<tr>
<td>9</td>
<td>9:00-9:35</td>
<td>Combustion Systems II: Gas Incineration Systems</td>
<td>2-30 to 2-35</td>
</tr>
<tr>
<td>9</td>
<td>9:40-10:10</td>
<td>Combustion Systems III: Boilers &amp; Controls</td>
<td>2-36 to 2-47</td>
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<tr>
<td>11</td>
<td>10:55-11:30</td>
<td>Air Pollution Formation I: Acid Gases</td>
<td>5-1 to 5-10</td>
</tr>
<tr>
<td>12</td>
<td>11:30-12:00</td>
<td>Air Pollution Formation II: Particulates and Metals</td>
<td>5-10 to 5-20</td>
</tr>
<tr>
<td></td>
<td>12:00-1:00</td>
<td>Lunch</td>
<td></td>
</tr>
<tr>
<td>13</td>
<td>1:00-2:00</td>
<td>Air Pollution Formation III: NOx</td>
<td>5-20 to 5-33</td>
</tr>
<tr>
<td>14</td>
<td>2:10-2:40</td>
<td>Air Pollution Formation IV: Organics</td>
<td>5-33 to 5-41</td>
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<tr>
<td>15</td>
<td>2:50-3:50</td>
<td>Air Pollution Control I: Particulates</td>
<td>6-1 to 6-18</td>
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<td>16</td>
<td>4:00-4:30</td>
<td>Air Pollution Control II: Acid Gases</td>
<td>6-19 to 6-23</td>
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<td>17</td>
<td>4:30-5:00</td>
<td>Air Pollution Control III: Modification for NOx</td>
<td>6-23 to 6-41</td>
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Homework: Read Chapters 5, 6 & 7; Work Review Exercises Chapters 2 & 5.
Thursday, February 16, 2017

<table>
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<th>Subject</th>
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<tr>
<td>18.</td>
<td>8:00-8:40</td>
<td>Discuss Review Exercises</td>
<td>2-48 &amp; 5-42</td>
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<td>19.</td>
<td>8:50-9:30</td>
<td>Air Pollution Control IV: NOx Flue Gas Cleaning</td>
<td>6-41 to 6-49</td>
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<tr>
<td>20.</td>
<td>9:50-10:20</td>
<td>Emissions I: Efficiency Applications</td>
<td>7-1 to 7-11</td>
</tr>
<tr>
<td>21.</td>
<td>10:40-11:10</td>
<td>Emissions II: Monitoring Systems</td>
<td>7-11 to 7-16</td>
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<td>22.</td>
<td>11:10-12:00</td>
<td>Emissions III: Calculations</td>
<td>7-16 to 7-19</td>
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<tr>
<td>23.</td>
<td>12:00-1:00</td>
<td>Lunch</td>
<td></td>
</tr>
<tr>
<td>24.</td>
<td>1:00-1:50</td>
<td>Emissions IV: Engines, Turbines</td>
<td>7-19-7-21</td>
</tr>
<tr>
<td>25.</td>
<td>2:00-2:30</td>
<td>Emissions V: Gas &amp; Oil Boilers</td>
<td>7-21 to 7-24</td>
</tr>
<tr>
<td>26.</td>
<td>2:40-3:40</td>
<td>Emissions VI: Coal &amp; Wood-Fired Boilers</td>
<td>7-24 to 7-28</td>
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<tr>
<td>27.</td>
<td>3:50-5:00</td>
<td>Emissions Workshop V</td>
<td></td>
</tr>
</tbody>
</table>

Homework: Read Chapter 7; Work Review Exercises Chapter 6 &7.

Friday, February 17, 2017

<table>
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<tr>
<th>Unit</th>
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<th>Subject</th>
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<tbody>
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<td>28.</td>
<td>8:00-9:00</td>
<td>Discuss Review Exercises</td>
<td>6-50 &amp; 7-29</td>
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<td>29.</td>
<td>9:00-10:00</td>
<td>Emissions Workshop V</td>
<td></td>
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<td>30.</td>
<td>10:00-12:00</td>
<td>Post-Test</td>
<td></td>
</tr>
<tr>
<td>31.</td>
<td>12:00</td>
<td>Course Closing</td>
<td></td>
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<td>Combustion I, Basic Combustion</td>
<td>2-1</td>
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<td>3.</td>
<td>Fuels I, Fuel Features</td>
<td>3-1</td>
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<td>4.</td>
<td>Combustion II, Excess Air</td>
<td>4-1</td>
</tr>
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<td>5.</td>
<td>Combustion III, Chemical Energy</td>
<td>5-1</td>
</tr>
<tr>
<td>6.</td>
<td>Fuels II, Fuel Properties</td>
<td>6-1</td>
</tr>
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<td>7.</td>
<td>Combustion Systems I, Conventional</td>
<td>7-1</td>
</tr>
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<td>8.</td>
<td>Combustion Systems II, Gas Incineration</td>
<td>8-1</td>
</tr>
<tr>
<td>9.</td>
<td>Combustion Systems III, Boilers &amp; Controls</td>
<td>9-1</td>
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<tr>
<td>11.</td>
<td>Air Pollution Formation I, Acid Gases</td>
<td>11-1</td>
</tr>
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<tr>
<td>13.</td>
<td>Air Pollution Formation III, NOx</td>
<td>13-1</td>
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<tr>
<td>14.</td>
<td>Air Pollution Formation IV, Organics</td>
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<tr>
<td>15.</td>
<td>Air Pollution Control I, Particulates</td>
<td>15-1</td>
</tr>
<tr>
<td>16.</td>
<td>Air Pollution Control II, Acid Gases</td>
<td>16-1</td>
</tr>
<tr>
<td>17.</td>
<td>Air Pollution Control III, Modification for NOx</td>
<td>17-1</td>
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<td>18.</td>
<td>Air Pollution Control IV, NOx Flue Gas Cleaning</td>
<td>18-1</td>
</tr>
<tr>
<td>19.</td>
<td>Emissions I, Efficiency Applications</td>
<td>19-1</td>
</tr>
<tr>
<td>20.</td>
<td>Emissions II, Emissions Monitoring</td>
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<td>21.</td>
<td>Emissions III, Emissions Calculations</td>
<td>21-1</td>
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<tr>
<td></td>
<td>Emissions IV, Engines and Gas Turbines</td>
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</tr>
<tr>
<td>22</td>
<td>Emissions V, Gas &amp; Oil Burners</td>
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</tr>
<tr>
<td>23</td>
<td>Emissions VI, Coal &amp; Wood-Fired Boilers</td>
<td>24-1</td>
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<td>Emissions Workshop</td>
<td>25-1</td>
</tr>
<tr>
<td>25</td>
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</table>
APTI Course 427
Combustion Evaluation

Instructor:
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Associate Professor Emeritus
Mechanical Engineering
University of Virginia
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Administrative
- Post-test is similar to Pre-Test:
  - Open notes.
  - Multiple-choice.
- Presentation follows:
  - Agenda (Units 1 - 25).
  - Student Manual.
- Read ahead for each day.
- Daily homework (see agenda).
- Discussion of Review Exercises.

Chapter 1, Introduction
1. Significance of Combustion Sources
2. Carbon and Energy
3. Fuels
4. Air Pollution
5. Overview of Combustion Sources

Table 1-1. Examples of Sources and Fuels

<table>
<thead>
<tr>
<th>Source Type</th>
<th>Principal Fuels</th>
</tr>
</thead>
<tbody>
<tr>
<td>Steam-electric power plant</td>
<td>Bituminous coal, subbituminous coal, residual oil, natural gas (fossil fuels)</td>
</tr>
<tr>
<td>Waste-to-energy steam power plant</td>
<td>Wood, municipal solid waste, misc.</td>
</tr>
<tr>
<td>Factory boiler</td>
<td>Gas, No. 2 oil, No. 6 oil, site specific waste</td>
</tr>
<tr>
<td>Combustion turbine power plant</td>
<td>Natural gas or distillate oil</td>
</tr>
<tr>
<td>Cement kiln</td>
<td>Fossil fuels, tires, used oil, hazardous waste</td>
</tr>
<tr>
<td>Residential or commercial furnace</td>
<td>Natural gas or No. 2 oil</td>
</tr>
<tr>
<td>Trucks, cars &amp; railroad engines</td>
<td>Gasoline or diesel fuel</td>
</tr>
<tr>
<td>Incinerators</td>
<td>Natural gas, fumes, organic liquid and solids</td>
</tr>
</tbody>
</table>

Significance of Combustion Sources

Carbon and Energy
- All common fuels are hydrocarbons.
- Energy is derived from the oxidation of carbon and hydrogen.

Energy and Carbon Cycle
Fuel vs Combustor Design

- **Fuel Characteristics.**
- **Carbon Dioxide Emissions.**
- **Fuel characteristics affect combustor design.**
- **Some sources operate on several fuels.**
- **The many aspects of source design depend on fuel type.**

### Fuel Characteristics

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Chief Characteristic</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas</td>
<td>Mostly CH₄ (methane) - usually burns clean</td>
</tr>
<tr>
<td>LPG</td>
<td>Mostly C₃H₈ (propane) - higher density than CH₄</td>
</tr>
<tr>
<td>Light Oil (No. 2, Diesel)</td>
<td>Few contaminants - a mixture averaging CH₄</td>
</tr>
<tr>
<td>Heavy Oil (No. 4, No. 6, residual)</td>
<td>Black (close kind to tar), not readily pumped or burned when cold, sulfur and other contaminants</td>
</tr>
<tr>
<td>Coal (bituminous, anthracite, lignite)</td>
<td>Contaminated with sulfur, ash, rock &amp; water.  Composition - C to CH</td>
</tr>
<tr>
<td>Wood</td>
<td>Moderate ash, water content is high &amp; variable.  Typical composition - CH₂O</td>
</tr>
</tbody>
</table>

### Fuel Characteristics (cont.)

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Chief Characteristic</th>
</tr>
</thead>
<tbody>
<tr>
<td>Waste Oil</td>
<td>Distillate oil with some contaminants</td>
</tr>
<tr>
<td>Refinery gas, producer gas, coke oven gas</td>
<td>Gas mixtures with inerts plus some contaminants</td>
</tr>
<tr>
<td>Landfill gas, sewage treatment gases</td>
<td>Mostly CH₄ &amp; CO₂ with smelly contaminants</td>
</tr>
<tr>
<td>Solid wastes</td>
<td>Contaminated with almost anything</td>
</tr>
</tbody>
</table>

### Fuel Choices

- A source will use the least expensive fuel - that’s practical & permitted.
  - Limited by existing equipment
  - Environmental restrictions
- Clean fuels are expensive.
- Trade off between expensive fuel, expensive equipment, and permits.

### Air Pollution (outline)

- **Origin:**
  - Direct
  - Indirect
  - Dilution, transport, ambient impacts.
- **Pollutant emission rates.**
- **Types of pollutants.**
- **Emission controls.**
Estimating Emission Rates

- Emission Rates are proportional to:
  - Amount of fuel burned.
  - Fuel contaminant content.
- AP-42
  - Applicability & reliability

Emission Rates Units

Commonly expressed in units of:
- Lb / hour or tons / year
- ppm or lb / ft³ (corrected for dilution)
- Lb / million Btu
- Lb / ton of product

Types of Pollutants

- Products of incomplete combustion (PIC):
  - CO
  - Carbon,
  - Organic species
- Emissions formed from fuel contaminants:
  - Acid gases (e.g., SOx, HCl),
  - Particulates
  - Metals
- Nitrogen oxides (NOx)

USA (2000) Carbon Emissions

<table>
<thead>
<tr>
<th>Sector</th>
<th>Total Carbon</th>
<th>Electric*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transportation</td>
<td>496</td>
<td>1</td>
</tr>
<tr>
<td>Industrial</td>
<td>481</td>
<td>180</td>
</tr>
<tr>
<td>Residential</td>
<td>290</td>
<td>193</td>
</tr>
<tr>
<td>Commercial</td>
<td>243</td>
<td>183</td>
</tr>
<tr>
<td>Total</td>
<td>1,510</td>
<td>557</td>
</tr>
</tbody>
</table>

* Electric is part of the total
1/3 of the CO₂ from electric power plants; with 1/3 Transportation; 1/3 Indust./commerce/resid.

USA Sources of Sulfur Dioxide, 2011

<table>
<thead>
<tr>
<th>Source</th>
<th>%</th>
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</thead>
<tbody>
<tr>
<td>Electric Generation</td>
<td>71.3%</td>
</tr>
<tr>
<td>Other Fuels Combustion</td>
<td>12.6%</td>
</tr>
<tr>
<td>Industrial Processing</td>
<td>10.3%</td>
</tr>
<tr>
<td>Fires &amp; Misc.</td>
<td>3.3%</td>
</tr>
<tr>
<td>Off Road Engines &amp; Vehicles</td>
<td>2.0%</td>
</tr>
<tr>
<td>(Railroad, ships, aircraft, farm construction, industrial)</td>
<td></td>
</tr>
<tr>
<td>On Road Vehicles</td>
<td>0.5%</td>
</tr>
<tr>
<td>(Automobiles &amp; trucks)</td>
<td></td>
</tr>
</tbody>
</table>

USA Sources of Nitrogen Oxides, 2011

<table>
<thead>
<tr>
<th>Source</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>On Road Vehicles (Automobiles &amp; trucks)</td>
<td>38%</td>
</tr>
<tr>
<td>Off Road Engines &amp; Vehicles (Railroad, ships, aircraft, farm construction, industrial)</td>
<td>20%</td>
</tr>
<tr>
<td>Electric Generation (Railroad, ships, aircraft, farm construction, industrial)</td>
<td>13%</td>
</tr>
<tr>
<td>Other Fuels Combustion</td>
<td>11%</td>
</tr>
<tr>
<td>Biogenic, Fires, Misc.</td>
<td>10%</td>
</tr>
<tr>
<td>Process Equipment</td>
<td>8%</td>
</tr>
</tbody>
</table>
### Overview of Combustion Sources

- **Engines**
- **Boiler Systems**
- **Other Combustion Sources**
- **Various Sizes** (Small sources - manufacturer certified).

### Internal Combustion Engines

- **Two types**
  - Reciprocating & combustion turbines
- **Applications**
  - Transportation (air, land, sea),
  - Industry,
  - Power generation
- **Emissions**
  - Clean fuels mean NOx is the main issue.
- **Basic Configuration**
  - Factory built means that they are highly predictable.

### Boilers

- **Most common stationary combustion source.**
- **Available in large range of sizes.**
- **Can be configured to burn any fuel.**

### Steam Electric Generator Equipment & Flow Schematic
### Other Combustion Sources

- Cement Kilns
- Solid Waste Incinerators
- Hazardous Waste Incinerators
- Thermal Oxidizers

### Chapter Summary

- Significance of Combustion Sources
- Carbon and Energy
- Fuels
- Air Pollution
- Overview of Combustion Sources
Solution to Pre-test Problem 36:
Air required to burn a mole of ethylene :
\[ \text{C}_2\text{H}_4 + a \text{ O}_2 \rightarrow 2 \text{ CO}_2 + 2 \text{ H}_2\text{O} \]
2 \(a = 2 \times 2 + 2 = 6\); \(a = 3\)
Air required to burn a mole of ethyl alcohol
\[ \text{C}_2\text{H}_5\text{OH} + a \text{ O}_2 \rightarrow 2 \text{ CO}_2 + 3 \text{ H}_2\text{O} \]
1 + 2 \(a = 2 \times 2 + 3 = 7\); \(a = (7 - 1)/2 = 3\)
Therefore, a mole of each requires the same air.

Chapter 4: Combustion

1. Introduction
2. Combustion Mass Flows, Stoichiometry
3. Enthalpy of Combustion & Heating Values
4. Combustor Size and Residence Time

Basic Combustion

1. Chemical Balance
2. Heat Input Rate: Conservation of Energy
3. Fuels & Air Flow: Conservation of Mass
4. Stoichiometric Air & Excess Air
5. F-factor Applications

Chemical Balance (methane)

\[ \text{CH}_4 + 2\text{O}_2 \rightarrow \text{HEAT} + \text{CO}_2 + 2\text{H}_2\text{O} \]

fuel + air \rightarrow exhaust gas

- Chemical balance \rightarrow air flow matches fuel flow.
- Considerable water is generated.
- Nitrogen (most of the air) is not shown.

Missing Elements

- Nitrogen
  - Air is 78% \(\text{N}_2\), about 79.1% “inert” species.
  - Air is 20.9% \(\text{O}_2\).
  - so \(79.1 / 20.9 = 3.78 \text{ N}_2\) molecules per \(\text{O}_2\).
  - Fuel is <10% of the combustion mass flow.
- Extra air – excess air:
  - Required for complete combustion.
- Contaminants in the fuel:
  - Inorganic elements cause air pollution.

Heat Input Rate

Conservation of energy
- Fuel flow must be enough to satisfy the demanded load.

Design capacity, heat input, or firing rate:
- May be expressed as the maximum Btu/hr, horsepower, MW, steam flow rate, etc.
- Heat Transfer is the fundamental limit (million Btu/hr).
- Design capacity appears on name plate or original construction documents.
**Heat Input Rate**

- Rated capacity can change (small amount).
  - Up rated if original hardware was oversized.
  - Down rated from deterioration or deliberate change.

- Operating a system above rated capacity can greatly increase maintenance & repair costs.

- Boiler system components have some margin
  - Fuel feeders to handle substandard fuel.
  - Fans to accommodate air leaks.

**Boiler Operating Load Influences**

Units Are Designed for Maximum Temperatures and Pressures at Full Load (capacity).

Part Load Effects:
- Increase excess air requirements.
- Decreases combustion temperatures.

Operating Above the Rated Capacity:
- Reduces the combustion quality.
- Increased CO emissions.
- Increases NOx emissions.

**Example 4-1. Boiler oil flow**

- Determine the oil flow rate to a boiler operating at 85 million Btu/hr. Residual oil HHV is 150,000 Btu/gallon.

- **Solution (rearranging equation 4.2):**

  \[
  \text{Fuel flow rate} = \frac{\text{Firing rate}}{\text{Heating value}}
  \]

  \[
  \frac{85 \times 10^6 \text{ Btu/hr}}{150,000 \text{ Btu/gal}} = 567 \text{ gal/hr} = 9.4 \text{ gpm}
  \]

**Fuel & Air Flow – Conservation of Mass**

- Combustion requires fuel and air
- Total exhaust mass flow is the sum from Equation 4-3:
  \[
  \text{Fuel mass flow} + \text{Air mass flow} = \text{Exhaust gas mass flow}
  \]
- Fuel mass flow rate is often less than 10% of the total exhaust flow rate.
- Fuel flow varies with load.
- “Fuel / air” mass ratio should be fairly constant (value varies with the fuel).

**Excess Air**

- Stoichiometric air flow – amount of air required for the ideal chemical balance.
- Equivalence ratio = actual A/F over stoich A/F.
  - Equiv ratio = 1 when air flow is stoich.
  - Equiv ratio < 1 with insufficient air (starved air, smoking).
  - Equiv ratio > 1 with excess air.
- Excess air defined by:
  \[
  \text{Total air flow} = \text{Stoichiometric air} + \text{Excess air.}
  \]
Excess Air

- The amount of excess air required depends on the combustion system.
- Better combustion systems require smaller amounts of excess air.
  - The best oil & gas systems can operate at about 3% excess air without creating significant PIC emissions.

Excess Air Ranges, Efficiency is reduced with higher EA.

<table>
<thead>
<tr>
<th>Type of Combustion</th>
<th>Excess Air</th>
<th>% Oxygen</th>
</tr>
</thead>
<tbody>
<tr>
<td>Suspension firing: oil, gas, pulverized coal</td>
<td>5-15%</td>
<td>1-3%</td>
</tr>
<tr>
<td>Cyclone (crushed coal)</td>
<td>10-15%</td>
<td>2-3%</td>
</tr>
<tr>
<td>Stoker grate: coal, wood, solid waste</td>
<td>30-75%</td>
<td>5-9%</td>
</tr>
<tr>
<td>Fluidized bed</td>
<td>5-150%</td>
<td>1-13%</td>
</tr>
<tr>
<td>Combustion Turbine</td>
<td>250%</td>
<td>15%</td>
</tr>
<tr>
<td>Lean burn reciprocating engine</td>
<td>&gt;5%</td>
<td>&gt;1%</td>
</tr>
</tbody>
</table>

Low Excess Air (LEA)

- Reasons to operate at LEA:
  - Better thermal efficiency.
  - Lower NOx.
  - More load capacity on some boilers.
- Good combustion performance objectives
  - System capable of LEA.
  - Continuous operation at LEA.

Water Vapor in Exhaust Gas

Water is formed by combustion of hydrogen.

Typical flue gas moisture fractions:
- Natural gas 20% by vol.
- Oil 10% by vol.
- Coal 6% by vol.
- Green wood 18% by vol.
- Ambient air 2% by vol.

Water condenses when flue gas cools.

Effects of Water Vapor

- HHV [Btu/lb]
- Condensation
- Flame temperature
Combustion Mass Flow

1. Stoichiometric Air Flow
2. Excess Air
3. Water Vapor
4. Calculating Gas Volume and Density

Stoichiometric Air Flow

\[ CH_4 + 2O_2 \rightarrow HEAT + CO_2 + 2 H_2O \]

- Chemical balance defines air/fuel mass ratio
- Consider a chemical balance equation to find the air required by a specific fuel, using the:
  - fuel ultimate analysis data for C, H, S, O.
  - atomic and molecular weights.
  - air data (20.9% O\(_2\), etc).
- Find the exhaust gas composition (lb/lb-fuel).

Generalized Combustion with Stoichiometric Air

\[ C_nH_{2x}S_{y}O_{z}N_wCl_t + t H_2O + a O_2 + 3.78 a N_2 \]

\[ \rightarrow x CO_2 + \left( \frac{y}{2} - \frac{w}{2} + t \right) H_2O + z SO_2 + w HCl + \left( 3.78 a + \frac{v}{2} \right) N_2 \]

Note that the oxygen balance gives:

\[ a = x + \frac{y}{4} - \frac{w}{4} + \frac{z}{2} + \frac{u}{2} \]

Average USA Pipeline Natural Gas

See Slide 6-9, Supplemental Materials

Ultimate Analysis % by Weight

<table>
<thead>
<tr>
<th>Ultimate Analysis</th>
<th>% by Weight</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon</td>
<td>72.35</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>23.21</td>
</tr>
<tr>
<td>Sulfur</td>
<td>0.00</td>
</tr>
<tr>
<td>Oxygen</td>
<td>1.85</td>
</tr>
<tr>
<td>Nitrogen</td>
<td>2.59</td>
</tr>
<tr>
<td>Ash</td>
<td>0.00</td>
</tr>
<tr>
<td>Moisture</td>
<td>0.00</td>
</tr>
</tbody>
</table>

Subtotals 100.00

Assume 100 lbs of Natural Gas

<table>
<thead>
<tr>
<th>HHV (Btu/scf)</th>
<th>HHV (Btu/lb)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1,032</td>
<td>22,600</td>
</tr>
</tbody>
</table>

Divide Ultimate Analysis Values by Corresponding Atomic Weights

Get Pseudo-Molecule of Natural Gas

\[ x = \frac{C}{12} = \frac{72.35}{12} = 6.03; \quad y = \frac{H}{1} = \frac{23.21}{1} = 23.2 \]

\[ z = \frac{S}{32} = \frac{0.12}{32} = 0; \quad t = \frac{M}{18} = \frac{0}{18} = 0 \]

\[ u = \frac{O}{16} = \frac{1.85}{16} = 0.12; \quad v = \frac{N}{14} = \frac{2.59}{14} = 0.18 \]

\[ w = \frac{Cl}{35} = \frac{0}{35} = 0 \]

\[ a = x + \frac{y}{4} - \frac{w}{4} + z - \frac{u}{2} = 6.03 + \frac{23.2}{4} - 0.12 - \frac{0.12}{2} = 11.77 \]

Stoichiometric Combustion of Ave. Pipeline Natural Gas (100 lbm)

\[ C_{6.03}H_{23.2}O_{0.12}N_{0.18} + 11.77 O_2 + 44.51 N_2 \Rightarrow 6.03 CO_2 + 11.61 H_2O + 44.60 N_2 \]

Therefore:

\[ N_{\text{air}} = 11.77 + 44.51 = 56.28 \text{ moles - air} \]

\[ N_{\text{coal}} = 11.77 \text{ moles - fuel} \]
Wet Flue Gas Analysis for Stoichiometric Combustion of Pipeline Natural Gas

<table>
<thead>
<tr>
<th>lb-moles</th>
<th>Mole %</th>
<th>MW</th>
<th>lbm</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂</td>
<td>6.03</td>
<td>9.688</td>
<td>44</td>
</tr>
<tr>
<td>H₂O</td>
<td>11.61</td>
<td>18.649</td>
<td>18</td>
</tr>
<tr>
<td>O₂</td>
<td>0.00</td>
<td>0.000</td>
<td>32</td>
</tr>
<tr>
<td>N₂</td>
<td>44.60</td>
<td>71.663</td>
<td>28</td>
</tr>
<tr>
<td>Total</td>
<td>62.23</td>
<td>100.000</td>
<td>1,723.0</td>
</tr>
</tbody>
</table>

Pounds flue gas / pound fuel = 1,723/100 = 17.23

Example Ultimate Analysis
Wet Hog Fuel (Slide 6-45 Sup. Mtls.)

<table>
<thead>
<tr>
<th>Wood Hog Fuels</th>
<th>Western Ultimate Analysis</th>
<th>Mix 50/50</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon</td>
<td>25.675</td>
<td>2.78</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>3.025</td>
<td>0.94</td>
</tr>
<tr>
<td>Sulfur</td>
<td>0.025</td>
<td>0.006</td>
</tr>
<tr>
<td>Oxygen</td>
<td>20.475</td>
<td>2.78</td>
</tr>
<tr>
<td>Nitrogen</td>
<td>0.050</td>
<td>0.004</td>
</tr>
<tr>
<td>Ash</td>
<td>0.750</td>
<td>0.005</td>
</tr>
<tr>
<td>Moisture</td>
<td>50.000</td>
<td>0.004</td>
</tr>
<tr>
<td>Totals</td>
<td>100.000</td>
<td>100.000</td>
</tr>
</tbody>
</table>

Combustion of Hog Fuel (100 lbm) with Stoichiometric Air and 30% Excess Air

Stoichiometric Combustion:
\[ C_{22.3}H_{33.2}S_{0.04}O_{19.2}N_{0.004} + 2.78 \text{ H}_2\text{O} + 2.26 \text{ O}_2 + 8.53 \text{ N}_2 \]
\[ \Rightarrow 2.14 \text{ CO}_2 + .001 \text{ SO}_2 + 4.29 \text{ H}_2\text{O} + 8.53 \text{ N}_2 \]

Combustion with 30% Excess Air:
\[ C_{22.3}H_{33.2}S_{0.04}O_{19.2}N_{0.004} + 2.78 \text{ H}_2\text{O} + 2.94 \text{ O}_2 + 11.09 \text{ N}_2 \]
\[ \Rightarrow 2.14 \text{ CO}_2 + .001 \text{ SO}_2 + 4.29 \text{ H}_2\text{O} + 0.68 \text{ O}_2 + 11.09 \text{ N}_2 \]

Flue Gas Analysis for Combustion of Wet Western Mix Hog Fuel with 30% Excess Air

<table>
<thead>
<tr>
<th>Flue Gas</th>
<th>Wet Gas</th>
<th>Dry Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>lb-moles</td>
<td>Mole %</td>
</tr>
<tr>
<td>CO₂</td>
<td>2.14</td>
<td>11.76</td>
</tr>
<tr>
<td>H₂O</td>
<td>4.29</td>
<td>23.57</td>
</tr>
<tr>
<td>SO₂</td>
<td>0.001</td>
<td>0.004</td>
</tr>
<tr>
<td>O₂</td>
<td>0.68</td>
<td>3.72</td>
</tr>
<tr>
<td>N₂</td>
<td>11.09</td>
<td>60.95</td>
</tr>
<tr>
<td>Total</td>
<td>18.20</td>
<td>100.00</td>
</tr>
</tbody>
</table>

Combustion Mass Flows, Stoichiometry and f-Factors

- Objective: Show that firing rate can be calculated from stack data.
  - Primary data required are stack flow and O₂.
- This is true except when:
  - Very wet fuel is being fired.
  - Process adds some gas to the flow.
- Using stack data to get firing rate is useful:
  - When the firing rate is unknown or questioned.
  - To check emissions test data.
**f-Factor Application**

- **Definition of the f-Factor:**
  “Volume of exhaust gas generated by burning one million Btu of fuel with no excess air.”
  - Result is in units: [std ft\(^3\) flue gas/million Btu]
- **If one knows the:**
  - Actual exhaust gas flow rate, \(O_2\) and temperature
  - Fuel heating value (HHV) and f-Factor
- **One can determine:**
  - Heat Rate [million Btu/hr] and
  - Fuel Flow Rate [lb-fuel/hr].

**Example F-factor**

- \(V_{\text{stoichiometric flue gas}} = F_w \times H_T, \text{fuel energy rate}\)
- \(V_{\text{actual flue gas}} = F_w \times H_T, \text{fuel energy rate} \times (1 + EA)\)
  
or
- \(H_T, \text{fuel energy rate} = \frac{V_{\text{actual flue gas}}}{F_w \times (1 + EA)}\)

**Stack Flow & Firing Rate**

- **F-factor allows determining the fuel firing rate without measuring the fuel flow rate.**
- E.G. Stoich. Flow \(\left(\frac{\text{std ft}^3}{\text{hr}}\right)\) - Firing Rate \(\left(\frac{\text{mmBTU}}{\text{hr}}\right)\) \(\times F_w \left(\frac{\text{std ft}^3}{\text{mmBTU}}\right)\)
  
  **Note:** We still need to account for excess air to relate firing rate to the actual (total) stack flow.

**Example 4-2**

Stoichiometric exhaust flow is 45,000 scfm. What is the approximate oil or gas firing rate?

**Solution:**

- From Table 4-5, assume \(F_w = 10,500 \text{ (ft}^3/\text{mmBtu)}\)
  
  \[45,000 \text{ (ft}^3/\text{min}) \times 60 \text{ (min/hr)} / 10,500 \text{ (ft}^3/\text{mmBtu)} = 257 \text{ (mmBtu/hr)}\]
  
  - Note, if we know the fuel and firing rate, we can calculate the stoichiometric stack gas flow rate.
Chapter 3, Fuel Characteristics

1. Fuel Characteristics
2. Usage Trends
3. Fuel Analyses
4. Fuel Properties:
   Gas, Oil, Coal, Other Solid Fuels.

Some History

- Wood, the original fuel.
- Coal, more abundant and efficient.
- Oil, a cleaner fuel.
- Natural Gas, clean, cheap, abundant.

Fuel Categories

<table>
<thead>
<tr>
<th>Fuel Category</th>
<th>Examples</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solids</td>
<td>Bituminous coal, sub-bituminous coal, lignite, peat, wood</td>
</tr>
<tr>
<td>Liquids</td>
<td>Kerosene, No. 2 oil, No. 6 oil, coal-water emulsions, oil-emulsion</td>
</tr>
<tr>
<td>Gaseous Fuels</td>
<td>Natural gas, propane, landfill and biological gases</td>
</tr>
<tr>
<td>Wastes</td>
<td>Municipal and medical wastes, hazardous wastes, sewage sludge, tires</td>
</tr>
<tr>
<td>Biomass</td>
<td>Wood and wood waste, bagasse, straw</td>
</tr>
</tbody>
</table>

Natural Gas Production

- A perceived shortage caused production to drop in the 1970's.
- Its availability has resulted in power plants that can only burn gas.
- Distributed power generation may drive a continued increase in gas use.

<table>
<thead>
<tr>
<th>Fuel Source</th>
<th>Energy Use Expressed in Quadrillion BTU</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fossil Fuels</td>
<td></td>
</tr>
<tr>
<td>Coal</td>
<td>22.447 20.947 22.385 19.692 22.817</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>22.224 23.702 23.834 23.344 24.644</td>
</tr>
<tr>
<td>Petroleum</td>
<td>39.955 38.778 37.389 36.062 33.916</td>
</tr>
<tr>
<td>Total Fossil Fuels</td>
<td>84.626 86.225 83.499 78.439 81.431</td>
</tr>
<tr>
<td>Renewable Fuels</td>
<td></td>
</tr>
<tr>
<td>Hydroelectric Power</td>
<td>3.869 3.446 3.551 2.869 2.509</td>
</tr>
<tr>
<td>Geothermal Energy</td>
<td>0.181 0.186 0.192 0.200 0.212</td>
</tr>
<tr>
<td>Biomass</td>
<td>0.375 0.302 0.352 0.389 0.426</td>
</tr>
<tr>
<td>Solar Energy</td>
<td>0.058 0.076 0.089 0.086 0.100</td>
</tr>
<tr>
<td>Wind Energy</td>
<td>0.264 0.234 0.246 0.275 0.294</td>
</tr>
<tr>
<td>Total Renewable Fuels</td>
<td>8.076 8.524 7.230 7.587 8.049</td>
</tr>
<tr>
<td>Nuclear Energy</td>
<td>8.315 8.455 8.427 8.356 8.441</td>
</tr>
</tbody>
</table>

USA Energy Consumption

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>19.2</td>
<td>20.9</td>
<td>22.6</td>
<td>22.8</td>
<td>20.8</td>
</tr>
<tr>
<td>Nat. Gas</td>
<td>19.6</td>
<td>22.7</td>
<td>23.8</td>
<td>22.6</td>
<td>24.6</td>
</tr>
<tr>
<td>Oil</td>
<td>33.6</td>
<td>34.4</td>
<td>38.3</td>
<td>40.4</td>
<td>36.0</td>
</tr>
<tr>
<td>Nuclear</td>
<td>6.1</td>
<td>7.1</td>
<td>7.9</td>
<td>8.2</td>
<td>8.4</td>
</tr>
<tr>
<td>Hydro</td>
<td>3.0</td>
<td>3.2</td>
<td>2.8</td>
<td>2.7</td>
<td>2.5</td>
</tr>
<tr>
<td>Oth Renew</td>
<td>3.0</td>
<td>3.4</td>
<td>3.3</td>
<td>3.5</td>
<td>5.5</td>
</tr>
<tr>
<td>Total</td>
<td>84.5</td>
<td>91.7</td>
<td>98.7</td>
<td>100.2</td>
<td>97.8</td>
</tr>
</tbody>
</table>
Fuel Analyses

• Proximate Analysis (market and burning characteristics)
• Ultimate Analysis (elemental, mass)
• Ash Composition Data
• Size Distribution of Solid Fuels

Examples of Fuel Analysis

Reports % weight compositions on different bases, such as:

- As-received
- Air-dried
- Moisture free
- Mineral and ash free

Fuel Analysis - Concept

• Laboratory analysis of a fuel sample.

• Original purpose was to determine suitability for particular combustor equipment.
  - Octane (gasoline engines).
  - #6 Oil (temperature & viscosity issues).
  - Coal (ash melting temp for a boiler).

• Purpose has been expanded for environmental issues (e.g., sulfur content).

Types of Fuel Analysis

<table>
<thead>
<tr>
<th>Time of Analysis</th>
<th>Coal and Solid</th>
<th>Oil</th>
<th>Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proximate (Market)</td>
<td>Heating value per lb</td>
<td>Density or AF</td>
<td>Heating value per lb</td>
</tr>
<tr>
<td>Moisture</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Volatile</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fixed carbon</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ash</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Ultimate (Chemical)</th>
<th>C, H, S, N</th>
<th>Oxygen by difference</th>
<th>Moisture</th>
<th>Ash</th>
</tr>
</thead>
<tbody>
<tr>
<td>C, H, S, N</td>
<td>Oxygen by difference</td>
<td>Moisture</td>
<td>Ash</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Ash or Trace Element</th>
<th>SiO₂, Al₂O₃, TiO₂</th>
<th>Fe₂O₃, CaO, MgO</th>
<th>K₂O, Na₂O, Cl, Hg</th>
<th>Others by request</th>
</tr>
</thead>
<tbody>
<tr>
<td>SiO₂, Al₂O₃, TiO₂</td>
<td>Fe₂O₃, CaO, MgO</td>
<td>K₂O, Na₂O, Cl, Hg</td>
<td>Others by request</td>
<td>Others by request</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Others by request</th>
<th>C₆H₁₂O₆, CO₂, CH₄, CH₃OH</th>
</tr>
</thead>
<tbody>
<tr>
<td>C₂H₅OH, CH₃₂CO₂H</td>
<td>Others by request</td>
</tr>
<tr>
<td>CH₄, CO₂, H₂O</td>
<td>Others by request</td>
</tr>
</tbody>
</table>
Sample Acquisition

Lab sample should be representative.

- Oil & gas – easy.
- Coal, wood, other solid fuels.
- Municipal waste - Representative sampling is difficult.

Market Characteristics

- Primary characteristics
  - Heating Value.
  - Sulfur Content.
- Proximate Analysis (e.g., coal).
- Fuel Oil Secondary characteristics:
  (See Supplemental Materials)
  - Density (see Slide 15, p. 6-3).
  - Viscosity vs temp. (see Slide 17, p. 6-10).

Proximate Analysis

ASTM D271 (procedures to determine):
- Ash
- Fixed carbon
- Volatile matter
- Moisture (surface & inherent)

Proximate Analysis Examples

<table>
<thead>
<tr>
<th>COMPONENT</th>
<th>RDF % Weight</th>
<th>IL HV Coal % Weight</th>
</tr>
</thead>
<tbody>
<tr>
<td>Moisture</td>
<td>26.6</td>
<td>8.0</td>
</tr>
<tr>
<td>Ash</td>
<td>21.7</td>
<td>8.4</td>
</tr>
<tr>
<td>Volatile Matter</td>
<td>43.6</td>
<td>33.0</td>
</tr>
<tr>
<td>Fixed Carbon</td>
<td>8.1</td>
<td>50.6</td>
</tr>
<tr>
<td>Total</td>
<td>100.0</td>
<td>100.0</td>
</tr>
</tbody>
</table>

Heating Value

- Definitions:
  - Btu
  - Higher Heating Value (HHV)
  - Lower Heating Value (LHV)
- Fuel value can be expressed as [$/million-Btu].
  - Example: Natural Gas @ $14/mmBtu

Heating Values of Selected Fuels

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Basis</th>
<th>% Moisture</th>
<th>HHV, Btu/lb</th>
</tr>
</thead>
<tbody>
<tr>
<td>Methane</td>
<td>Dry</td>
<td>0.0</td>
<td>23,875</td>
</tr>
<tr>
<td>Fuel Oil, #2</td>
<td>As Received</td>
<td>0.0</td>
<td>19,430</td>
</tr>
<tr>
<td>Fuel Oil, #6</td>
<td>As Received</td>
<td>0.7</td>
<td>18,300</td>
</tr>
<tr>
<td>Coal, Bituminous</td>
<td>As Received</td>
<td>1.5</td>
<td>13,800</td>
</tr>
<tr>
<td>Coal, Subbitumin.</td>
<td>As Received</td>
<td>25.0</td>
<td>9,345</td>
</tr>
<tr>
<td>Wood, White Pine</td>
<td>Kiln Dried</td>
<td>8.0</td>
<td>8,900</td>
</tr>
<tr>
<td>Lignite, ND</td>
<td>As Received</td>
<td>37.0</td>
<td>7,255</td>
</tr>
<tr>
<td>RDF, Ames, IA</td>
<td>As Received</td>
<td>6.5</td>
<td>6,110</td>
</tr>
<tr>
<td>MSW, Ames, IA</td>
<td>As Received</td>
<td>24.2</td>
<td>4,830</td>
</tr>
<tr>
<td>Wood, Fresh Cut</td>
<td>As Received</td>
<td>50.0</td>
<td>4,450</td>
</tr>
</tbody>
</table>
Heating Value Uses

- HHV – total energy (exhaust at ambient temp)
- LHV → HHV minus water vapor energy.
  → HHV = \( m_w \times (\text{latent heat of vaporization}) \)
- Difference is about 1,000 [Btu/lb of water].

Higher and Lower Heating Values

<table>
<thead>
<tr>
<th>Fuel</th>
<th>HHV</th>
<th>LHV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas</td>
<td>22,200</td>
<td>20,000</td>
</tr>
<tr>
<td>No. 2 Oil</td>
<td>19,000</td>
<td>17,860</td>
</tr>
<tr>
<td>No. 6 Oil</td>
<td>18,200</td>
<td>17,300</td>
</tr>
<tr>
<td>Bituminous Coal</td>
<td>14,000</td>
<td>13,600</td>
</tr>
<tr>
<td>Doug Fir- Dry</td>
<td>9,000</td>
<td>8,400</td>
</tr>
</tbody>
</table>

Example 1. Fuel Use Calculation
Combustion process operates at 10 million-Btu/hr.
Fuel A: HHV = 11,000 Btu/lb.
Fuel B: HHV = 12,750 Btu/lb.

What fuel flow rates are needed for Fuels A and B?

Solution:

\[
\text{Rate}_{A} = \frac{10 \times 10^6 \text{ Btu/hr}}{11,000 \text{ Btu/lb}} = 909 \text{ lb/hr}
\]

\[
\text{Rate}_{B} = \frac{10 \times 10^6 \text{ Btu/hr}}{12,750 \text{ Btu/lb}} = 784 \text{ lb/hr}
\]

Example 2. Ash Quantities
Both fuels from Example 1 have an ash content of 10.5%. If the boiler operates 7,000 hours per year, what change will occur in the total quantity of ash for disposal? Assume none of the ash escapes into the atmosphere.

Solution:

\[
\text{Ash}_{A_{\text{coal}}} = 784 \frac{\text{lb coal}}{\text{hr}} \times 0.105 \frac{\text{lb ash}}{\text{lb coal}} \times 7,000 \frac{\text{hr}}{\text{yr}} = 576,000 \frac{\text{lb}}{\text{yr}}
\]

\[
\text{Ash}_{B_{\text{coal}}} = 909 \frac{\text{lb coal}}{\text{hr}} \times 0.105 \frac{\text{lb ash}}{\text{lb coal}} \times 7,000 \frac{\text{hr}}{\text{yr}} = 668,000 \frac{\text{lb}}{\text{yr}}
\]

So the ash quantity will increase by 92,000 lb/yr.

Sulfur Content

- Air emission source permits limit fuel S to control SO₂ emissions.

- Examples:
  - Coal limited to 1% S
  - Oil limited to 0.5% S
Impact of Moisture Content

• Amount of fuel required to fire a furnace:
  – Water adds weight.
  – Water absorbs energy converting to vapor.

• Water vapor in the flue gas effects:
  – Emission measurement procedures.
  – Performance of emission control equipment.

Volatile Matter

• Organic compounds that vaporize when the fuel is heated.

• Volatile matter supports ignition and rapid combustion.

Fixed Carbon

• Carbon remaining after heating (nonvolatile).

• Stoker furnace – fuel that will burn on the grate.

• Burn rate – slow (O\textsubscript{2} diffusion to the surface of the solid).

Ash or Mineral Content

• Inorganic solids.

• Furnace ash management.

• Indicator of potential particulate emissions.

Fuel Oil Market Properties

1. HHV
2. Density or specific gravity
3. Pour point
4. Viscosity (varies with Temp)
5. Water and sediment

Fuel Oil Density

• Oil is purchased by the gallon.

• HHV is measured on a mass basis [Btu/lb] and volume basis [Btu/gal].

• Density can be used as an indicator (inverse relationship) of Btu/lb.

  Sp.gr. @ 60 °F = 141.5 / (API + 131.5)
Ultimate Analysis

- Elemental analysis by ASTM D3176.
- Always totals to 100%.
- Used for flue gas & emissions analysis.
- Needed to calculate F-factors.

Ultimate Analysis Examples

<table>
<thead>
<tr>
<th>Analyte</th>
<th>Coal – As-Received</th>
<th>Coal – Dry Basis</th>
<th>No. 6 Oil</th>
</tr>
</thead>
<tbody>
<tr>
<td>Moisture</td>
<td>3.03</td>
<td>0</td>
<td>nil</td>
</tr>
<tr>
<td>Carbon</td>
<td>60.88</td>
<td>62.58</td>
<td>65.79</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>4.35</td>
<td>4.49</td>
<td>10.59</td>
</tr>
<tr>
<td>Nitrogen</td>
<td>1.12</td>
<td>1.16</td>
<td>0.83</td>
</tr>
<tr>
<td>Chlorine</td>
<td>0.12</td>
<td>0.12</td>
<td></td>
</tr>
<tr>
<td>Sulfur</td>
<td>4.20</td>
<td>4.42</td>
<td>2.13</td>
</tr>
<tr>
<td>Ash</td>
<td>19.18</td>
<td>19.78</td>
<td>0.10</td>
</tr>
<tr>
<td>Oxygen (diff)</td>
<td>7.23</td>
<td>7.45</td>
<td>1.37</td>
</tr>
<tr>
<td>Total</td>
<td>100.00</td>
<td>100.00</td>
<td>100.00</td>
</tr>
</tbody>
</table>

Ash Composition Data

- Solid material remaining after complete combustion.
- Various pathways in a combustor:
  - Boiler (siftings) ash
  - Bottom ash
  - Soot
  - Fly ash
- Example: 150 tons of 10% ash coal can form 15 tons of ash.

Example Ash Compositions

<table>
<thead>
<tr>
<th>Mineral</th>
<th>Ash No. 1</th>
<th>Ash No. 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>SiO₂</td>
<td>30.94</td>
<td>35.82</td>
</tr>
<tr>
<td>Al₂O₃</td>
<td>22.75</td>
<td>26.92</td>
</tr>
<tr>
<td>TiO₂</td>
<td>1.63</td>
<td>1.15</td>
</tr>
<tr>
<td>Fe₂O₃</td>
<td>30.37</td>
<td>0.73</td>
</tr>
<tr>
<td>CaO</td>
<td>1.59</td>
<td>0.81</td>
</tr>
<tr>
<td>MgO</td>
<td>0.64</td>
<td>1.07</td>
</tr>
<tr>
<td>K₂O</td>
<td>1.82</td>
<td>2.35</td>
</tr>
<tr>
<td>Na₂O</td>
<td>0.46</td>
<td>0.46</td>
</tr>
<tr>
<td>SrO</td>
<td>0.31</td>
<td>0.85</td>
</tr>
<tr>
<td>CaO</td>
<td>0.10</td>
<td>0.12</td>
</tr>
<tr>
<td>BaO</td>
<td>0.18</td>
<td>0.12</td>
</tr>
<tr>
<td>WO₃</td>
<td>0.10</td>
<td>0.00</td>
</tr>
<tr>
<td>Undetermined</td>
<td>0.19</td>
<td>2.36</td>
</tr>
</tbody>
</table>

Size Distribution of Solid Fuels

- Fuel Particle Size Matters:
  - Determines the burn rate.
  - Size influences carbon carry over.
- Measurement of Fuel Particle Sizes.
- Stoker Fuel Sizes.
- Pulverized Coal Size.
Example Measured Fuel Sizes

Table 3-7. Standard Sieve Size

<table>
<thead>
<tr>
<th>Mesh</th>
<th>Size (mm)</th>
<th>Size (inch)</th>
</tr>
</thead>
<tbody>
<tr>
<td>200</td>
<td>0.075</td>
<td>0.003</td>
</tr>
<tr>
<td>100</td>
<td>0.15</td>
<td>0.006</td>
</tr>
<tr>
<td>50</td>
<td>0.30</td>
<td>0.012</td>
</tr>
<tr>
<td>35</td>
<td>0.50</td>
<td>0.020</td>
</tr>
<tr>
<td>18</td>
<td>1.00</td>
<td>0.039</td>
</tr>
<tr>
<td>10</td>
<td>2.00</td>
<td>0.079</td>
</tr>
<tr>
<td>8</td>
<td>2.36</td>
<td>0.093</td>
</tr>
</tbody>
</table>

Stoker Fuel Sizes

- Larger particles take longer to burn. Combustion rate limited by air diffusion.
- 0.5 Inch is typical.
- Limits:
  - Particles < 2 mm can be blown out of the furnace.
  - Particles > 0.2 mm are too big to burn in suspension.

Example Stoker Coal Size Specification

- “Off spec” coal is usually cheaper than the good stuff.
- Wood or wood waste
  - Little control over size. Adapt the system.
- Municipal and medical wastes:
  - Mass burn.
  - RDF.

Pulverized Coal Size

- Powdered coal burns in suspension
  - The finer the better.
  - Finer sizes increase the grinding cost.
- 50, 100, 200 Mesh screens:
  - Generally 90% - 95% passes 200 mesh
  - Coal that is unable to pass a 50 Mesh screen is too large for suspension firing (requires a grate for bed burning).
Solution to Pre-test Problem 39:
\[ V_1 = 400,000 \text{ scfm} \]
\[ T_1 = 500 \text{ °F} + 460 = 960 \text{ °R} \]
\[ T_{\text{std}} = 68 \text{ °F} + 460 = 528 \text{ °R} \]
\[ \frac{P_{\text{std}} V_{\text{std}}}{T_{\text{std}}} = \frac{P_1 V_1}{T_1}; \text{ with } P_{\text{std}} = P_1 \]
\[ V_{\text{std}} = \frac{P_1 V_1 T_{\text{std}}}{T_1 P_{\text{std}}} = \frac{V_1 T_{\text{std}}}{T_1} = 400,000 \times \frac{528}{960} \]
\[ V_{\text{std}} = 220,000 \text{ scfm} \]

Excess Air, EA
1. Excess air is necessary for complete combustion.
   Insufficient air causes incomplete combustion & formation of PICs.
2. Management (control)
3. Oxygen measurement.
4. Diagnostic uses / calculations

Excess Air Management
- Combustor controls couple air flow to fuel flow to give an approximately correct air flow.
- Exhaust O₂ can be used to determine the approximate amount of excess air (equation 4-8).
  \[ \% \text{Excess Air} = \frac{\% O_2}{20.9 - \% O_2} \times 100 \]
- This equation assumes zero CO.

Improved Equation for Excess Air Using a Dry Gas Data (Orsat)
Assume CO₂m is % CO₂ in Dry Gas.
COm is % CO in Dry Gas.
O₂m is % O₂ in Dry Gas.
Therefore \[ N_{2m} = 100 \times (\text{CO}_2 + \text{CO} + \text{O}_2) \]
and \[ \text{EA} = \frac{\text{O}_2 \times 0.5 \text{CO}_m}{0.264 \times N_{2m} \times \text{O}_2 + 0.5 \text{CO}_m} \]

Equivalence Ratio, ER
\[ \text{ER} = \text{Equivalence Ratio} = (1 + \text{EA}) \]
\[ \text{ER} = \text{EA Correction Factor} = \frac{20.9}{20.9 - \% O_2} \ (4 - 9) \]
Also called the "excess air correction factor."
Note that the range of values is from 1 to infinity.
**Equivalence Ratio, ER**

(Actual A/F divided by stoich. A/F)

\[
EA = \frac{O_2}{20.9 - O_2} \times 100\% \quad \Rightarrow \text{using (eqn. 4.8)}
\]

ER (Equivalence Ratio) = Actual air \(\frac{\text{Stoich air}}{\text{Stoich}}\) \(\frac{(1 + EA) \cdot \text{Stoich}}{\text{Stoich}}\)

\[
ER = (1 + EA) = 1 + \frac{O_2}{20.9 - O_2}
\]

\[
ER = \frac{20.9}{20.9 - O_2} \quad \text{(eqn. 4.9)}
\]

**Excess Air vs. O2 & CO2**

- CO2 can be used to determine excess air – but value depends on fuel type.
- O2 is easier to use.
- CO2 use data from early measurement technology - the Orsat device.

**Total Exhaust Flow and Firing Rate**

Eqn. 4-10:

\[
\text{Exhaust Flow} = \text{Stoich. Flow} \times \left(\frac{20.9}{20.9 - O_2}\right)
\]

Eqn. 4-11:

\[
\text{Firing Rate} \left(\frac{\text{mmBTU}}{\text{hr}}\right) = \frac{\text{Exhaust Flow} \left(\frac{\text{ft}^3}{\text{hr}}\right) \times 20.9 - O_2}{20.9}
\]

\[
F_e = \frac{\text{ft}^3}{\text{hr mmBTU}}
\]

Note that a reciprocal relationship was used:

**Example 4-3**

Determine the firing rate of a source with 20,000 scfm stack flow at 4.0% O2.

Solution using equation 4-11:

\[
\frac{20,000 \text{ft}^3/\text{min}}{60 \text{min/hr}} \times \frac{20.9 - 4.0}{20.9} \times \frac{10,500 \text{mmBTU}}{\text{ft}^3} = 92.4 \text{mmBTU/hr}
\]

Note, we assumed a generic F-factor = 10,500

**Oxygen Measurement**

- O2 data are used for two purposes:
  - Excess air control.
  - Correction of emission measurements.

- Possible issues:
  - Uniformity in duct flows.
  - “Tramp” air which leaks into flue gas ducts upstream of gas sampling ports.
  - Interpreting the source of oxygen.

**Flue Gas Water Vapor Sources**

- Burned Fuel Hydrogen
- Evaporated Fuel Moisture
- Moisture in Combustion Air
Water from Fuel Hydrogen

Stoichiometric water vapor concentration is given below, where $y$ is the fuel H/C molecular ratio given by $12 \times (\%H / \%C)$:

$$V_w = \frac{y}{4.78 + 1.45 \times y} \times 100$$  

Eqn. 4-12

The exhaust concentration depends on the amount of air dilution (lower concentrations with higher ER), so:

$$V_w (\text{actual exhaust concentration}) = V_w \times \left(\frac{20.9 - \% O_2}{20.9}\right)$$

Water Vapor from Fuel Moisture

Fuel moisture can be calculated from equation 4-13:

$$\% \text{ Flue Gas Water Vapor} = 25 \times \left(\frac{w}{100 - 0.75 \times w}\right)$$

This is stoichiometric, so actual concentration is reduced by the amount of excess air.

In practice, measured data are preferred over a mass balance.

Calculating Gas Volume and Density

Ideal Gas Law: $PV = nRT$ or $nR = PV/T$

(See Student Manual, page 4-21.)

Where:

- $P$ is absolute pressure in [lb/ft$^2$]
- $V$ is volume in [ft$^3$]
- $n$ is number of moles
- $R$ is the universal gas constant
- $= 1.545$ [ft-lb/(mole °R)] = 0.7302 [atm ft$^3$/(mol °R)]
- $T$ is absolute temperature in degrees Rankine

Application of Ideal Gas Law to find Volume of 1 lb-mol at standard conditions

PV = nRT

For standard conditions, $T = 68$°F + 460 = 528°R

$P = 14.7$ [lbf/in$^2$] = 1 atm

$$\frac{V}{n} = \frac{RT}{P} = \frac{1.545 \text{ ft lbf}}{14.7 \text{ lbf/in}^2 \times 144 \text{ in}^2/\text{ft}^2} \times 528\text{°R}$$

$$\frac{V}{n} = 385 \text{ ft}^3/\text{lbmol}$$  

Volume per mole

Temperature Equivalents

Relative Temperatures:
- °C = ($°F - 32$)/1.8
- °F = (1.8) °C + 32

Absolute Temperatures:
- K (Kelvin) = °C + 273.15
- °C = K - 273
- °R (Rankine) = °F + 459.67
- °F = °R - 460

Absolute and Gage Pressure

• Absolute Pressure is equal to:
  Gage Pressure + Atmospheric Pressure

Example:

$$P [\text{psia}] = P [\text{psig}] + 14.7 [\text{psia}]$$

$$P [\text{in Hg}] = \Delta P [\text{in wc}] / 13.6 + P_{\text{bar}}$$
Calculating Gas Volumes at Different Conditions Using the Ideal Gas Law

\[ \frac{P_1 \cdot V_1}{T_1} = \frac{P_2 \cdot V_2}{T_2} \]

\[ V_1 = \frac{P_2 \cdot V_2 \cdot T_1}{P_1 \cdot T_2} = \frac{P_2}{P_1} \cdot \frac{T_1}{T_2} \cdot V_2 \]

Typically (1) is at standard conditions and (2) is at stack conditions:

\[ T_{std} = (68^\circ F + 460) = 528^\circ R \]

\[ P_{std} = 29.92 \text{ inches Hg} = 14.7 \text{ psia} \]

Example 4-4.
Stack test data for burning coal shows:
8,000 ft³/min at 310°F, a stack draft of 0.45 inches w.g. and barometric pressure of 28.67 inches Hg.
Determine the flow rate in scfm (std ft³/min).

First determine stack pressure:

\[ P_s = 28.67 - (0.45/13.6) = 28.64 \text{ inches Hg} \]

Next, use Eqn 4-14:

\[ V_{std} = 8,000 \text{ acfm} \times \left[ \frac{528^\circ R}{(460 + 310)^\circ R} \right] \times \frac{28.64}{29.92} = 5,251 \text{ scfm} \]

Example 4-5. Molecular weight & density

Find mole fractions (mf) of each constituent:

Stack data for coal burning shows:

mf-water vapor = .08 or 8%
mf-O₂ = .05 or 5%

Determine the density of the exhaust at STP.

Solution:

Use Fig 4-2: @ mf-O₂ = 5%, estimate mf-CO₂ = 14%

Next, determine N₂ by difference:

\[ %N₂ = 100 - 8 - 5 - 14 = 73\%; \text{ so mf-N₂} = .73 \]

Example 4-5. Molecular weight & density

Flue gas MW is sum of the mole fraction (mf) of each constituent times its MW.

\[ MW_{avg} = m_1 * MW_1 + m_2 * MW_2 + m_3 * MW_3 + m_4 * MW_4 \]

\[ MW_{avg} = [.73*28 + .14*44 + .05*32 + .08*18] \]

\[ MW_{avg} = 29.6 \text{ (lb/lb-mole)} \]

Finally, use equation 4-15 to determine the density (p) under standard conditions:

\[ p = 29.6 \text{ (lb/lb-mole)} / 385 \text{ (std ft³ / lb-mole)} = 0.077 \text{ (lb / std ft³)} \]

Wet & Dry Molecular Wt

EPA Method 2 relates wet (stack conditions) & dry exhaust gas MW values.

\[ MW_w = (1 - B_{ws}) \times MW_d + 18 \times B_{ws} \]

Where:  

- \( MW_d \) is for (stack) exhaust gas
- \( MW_w \) is for dry exhaust gas
- \( B_{ws} \) is the gas volume fraction of water
**Enthalpy of Combustion and Heating Values**

- Flame Structure - Primary and Dilution Zones
- Combustion Temperature Levels
- Energy Content of the Flue Gas

**Flame Structure**

- Combustion Temperatures:
  - Chemical reactions can occur at any temperature, but
  - Flames require at least 2,500°F.
  - Fire is either hot, or it goes out.
- Gas Turbine Combustor:
  - Hot primary zone followed by dilution.
- Boiler Combustor:
  - Hot flames followed by heat transfer.

**Gas Turbine Combustor**

- Primary Zone (3000°F)
- Combustor
- Dilution Zone
- Turbine Nozzle
- Engine Casing
- Air From Compressor
- Fuel Injector
- Engine Center Line

**Boiler Combustor**

- Combustion Air
- Ambient Temperature
- Windbox
- Burner
- Exhaust (350°F Typical)

**Physical & Chemical Processes**

- Fuel & air mixing & burning occur simultaneously in most commercial combustors
  - Chemistry is fast, so
  - Mixing usually limits the burning rate.
- A hot primary zone is a key element of flame stability.
  - Local peak temps are probably about 4,000°F.
  - Radiative cooling is very fast at these temps.

**Combustion Temperature Levels**

- Stoichiometric Flame Temperature
- Adiabatic Temperature with Excess Gas
- Local versus Average Temperature
Stoichiometric Flame Temperature

- Adiabatic Temperature:
  - Theoretical temperature with no heat loss.
  - Assume fire occurs in an insulated box.

- Basic Energy Balance:
  - Fuel energy released = Enthalpy increase of the exhaust gas above incoming air.
  - Can be used to derive “flame temperature” (the theoretical maximum combustion temperature).
  - Maximum $\Delta T_{AD}$ is about 4,000°F

Energy Balance

- Solve equation 4-16 for $\Delta T$ (the adiabatic temperature rise).

$$\Delta T(°F) = \frac{Q}{V \times C_p} \times \frac{385}{29}$$

- When Q is one mmBtu, the F-factor gives the volume:
  - $V$ (natural gas, appx) = 10,500 ft$^3$.
  - So $\Delta T$ can be calculated.

Combustion Temperature Control

- Fuel and/or Air Flow Modulation
- Heat Transfer to Surroundings
- Sink Materials
  - Fuel Moisture
  - Nitrogen
  - Excess Air
  - Flue Gas Recirculation
  - Water Sprays
Energy Balance

- Note: The Energy Balance equation (eqn. 4-16) was based on LHV.
- F-factors are based on HHV.
- Therefore, the volume (F-factor) must be adjusted by multiplying by HHV / LHV, as illustrated in the second solution to Example 4-6.
- With typical data, $\Delta T = 4,000^\circ F$.

Example 4-6

- A thermal oxidizer treats air from an oven at 250 °F. The stack oxygen measured during an emission test is 14.0%.
- What was the oxidizer temperature?

Solution 1:
From Figure 4-5, read $\Delta T = 1,350$ °F.
Next, add 250 °F to give $T = 1,600$ °F.

Example 4-6, Solution Comparisons

Solutions 1 & 2 differ because of the different approximations used for $F_w$.

The objective was to get an approximate (not exact) value. This can be used as a data quality control check.

Conclusion: The exhaust gas $O_2$ is related to a maximum average incinerator temperature.

Local vs. Average Temperature

- The average combustor exit temperature is lower than the peak combustion temperature for two reasons:
  1. Radiative heat loss from the flame, and
  2. Excess air continues to mix with burning fuel in the flame.
- Fuel-air mixing during combustion causes:
  - Non-uniform temperatures.
  - Local temperatures that approach adiabatic.

Flames: Diffusion vs Premix

- Most combustors mix fuel & air simultaneous with burning (diffusion flame combustion).
- High peak temperatures of diffusion flames cause incandescent carbon particles.
  - Yellow Flame Combustion.
- A few sources (e.g., gas-fired appliances, gasoline engines) premix fuel & air before combustion.
  - Blue Flame Combustion.
  - Flash Back when flame propagation velocity is greater than gas mixture velocity.
- Premix combustion temperatures depend on the Equivalence ratio (Fig. 4-5) or the Air/Fuel ratio.
Energy Content of the Flue Gas

- Flue gas has energy in two forms:
  - Latent Heat
  - Sensible Energy

- Specific Heat is the sensible energy required for 1 lb to increase its temperature 1 degree.

- Flue gas can give up some of this energy to useful work or for heat (e.g., produce steam).

- The remaining energy is lost up the stack exit.

Latent Heat of Water Vapor (eqn. 4-19):

\[
\frac{Q_{lh}}{Q_{total}} = \frac{\text{flue gas mass flow rate, lb/hr}}{\text{flue gas mass flow rate, lb/hr}} \times \frac{\% H_2O}{100} \times \frac{18}{29} \times 1000 \left( \frac{\text{BTU}}{\text{lb}} \right)
\]

Where:
- \(Q_{lh}\) = flue gas latent heat, Btu/hr
- \(W_{EG}\) = flue gas mass flow rate, lb/hr
- \(\% H_2O\) = concentration of water vapor in the E.G., % by volume
- 18 = molecular weight of water, lb \(H_2O/\text{lb-mole} \ H_2O\)
- 29 = molecular weight of E.G., lb E.G./lb-mole E.G.
- 18/29 = factor to convert water fraction from a volume to a mass basis

Latent Heat (cont.)

This is more useful expressed as a fraction of the total heat input. Use the F-factor with a value of 10,500 to simplify it.

Eqn 4-20:

\[
\frac{Q_{lh}}{Q_{total}} = \frac{\% H_2O}{100} \times \frac{20.9}{20.9 - \% O_2} \times \frac{F_A}{1000} \times \frac{18}{385}
\]

Example 4-7. Exhaust Latent Heat

What % of the fuel energy is carried by uncondensed water in the stack of a gas-fired source when data shows 4.5% \(O_2\) and 17% water vapor by volume?

\[
\frac{Q_{lh}}{Q_{total}} = \frac{17}{100} \times \frac{20.9}{20.9 - 4.5} \times 0.49 = 0.106
\]

So 10.6% of the fuel energy (HHV) is lost.

Latent Heat (cont.)

For dry fuel, the latent heat loss can be determined from fuel analysis alone – no stack data is required.

Table 4-6. Approximate Exhaust Latent Heat Energy

<table>
<thead>
<tr>
<th>Fuel</th>
<th>C/H Ratio</th>
<th>HHV (BTU/lb)</th>
<th>(Q_{lh}/Q_{total})</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas</td>
<td>CH(_{3.8})</td>
<td>23,000</td>
<td>0.094</td>
</tr>
<tr>
<td>Heavy Oil</td>
<td>CH(_{1.7})</td>
<td>18,500</td>
<td>0.060</td>
</tr>
<tr>
<td>Bitumin. Coal</td>
<td>CH(_{0.8})</td>
<td>13,500</td>
<td>0.042</td>
</tr>
</tbody>
</table>

Sensible Energy (eqn. 4-22)

\[
\frac{Q_S}{\text{Btu/hr}} = \frac{W_{EG}}{\text{lb/hr}} \times C_p \left( \frac{\text{Btu}}{\text{lb} \cdot ^\circ F} \right) \times \Delta T \left( ^\circ F \right)
\]

Where:
- \(Q_S\) = flue gas sensible heat, Btu/hr
- \(W_{EG}\) = E.G. mass flow rate, lb/hr
- \(C_p\) = E.G. specific heat, Btu/lb\(\cdot^\circ F\)
- \(\Delta T\) = temperature difference between the flue gas and ambient air, \(^\circ F\)
Sensible Energy (cont.)

This is more useful expressed as a fraction of the total heat input. Divide by eqn 4-11 and use the F-factor with a value of 10,500 to simplify it.

\[
\frac{Q_S}{Q_{tot}} = \frac{\Delta T \times 20.9}{20.9 - \% O_2 \times 10^3} \times \frac{C_s \times F_m}{MW_{F2}} \times 385
\]

Example 4-8. Sensible energy

Stack measurements show \( T = 375^\circ F \) and \( \% O_2 = 3.3\% \) when the ambient temperature is \( 50^\circ F \). What fraction of the fuel energy is lost in the form of hot gas? Use eqn. 4-24:

\[
\frac{Q_S}{Q_{tot}} = \frac{375 - 50}{4200} \times \frac{20.9}{20.9 - 3.3} = 0.092
\]

Specific Heat

**Table 4-7. Specific Heat [Btu/(lb-°F) or kcal/(kg-°C)]**

<table>
<thead>
<tr>
<th>Temperature</th>
<th>Air</th>
<th>( O_2 )</th>
<th>Water Vapor</th>
</tr>
</thead>
<tbody>
<tr>
<td>68°F</td>
<td>0.242</td>
<td>0.290</td>
<td>0.445</td>
</tr>
<tr>
<td>722</td>
<td>0.244</td>
<td>0.218</td>
<td>0.452</td>
</tr>
<tr>
<td>500</td>
<td>0.249</td>
<td>0.245</td>
<td>0.470</td>
</tr>
<tr>
<td>1100</td>
<td>0.290</td>
<td>0.296</td>
<td>0.528</td>
</tr>
<tr>
<td>2200</td>
<td>0.279</td>
<td>0.215</td>
<td>0.022</td>
</tr>
<tr>
<td>3000</td>
<td>0.297</td>
<td>0.325</td>
<td>0.073</td>
</tr>
<tr>
<td>3800</td>
<td>0.303</td>
<td>0.330</td>
<td>0.709</td>
</tr>
</tbody>
</table>

Example 4-9. Specific heat

What is the specific heat of a combustion source exhaust gas with 18% \( H_2O \) and a stack temperature of \( 475^\circ F \)?

Solution:

Assume \( C_{p\text{-dry-air}} = 0.25 \text{ Btu/lb-°F} \) (Tbl. 4-7) 
\( C_{p\text{-wv}} = 0.47 \text{ Btu/lb-°F} \) (Tbl. 4-7)

\[
C_p = (mf\text{-wv} \times C_{p\text{-wv}}) + (mf\text{-dry-air} \times C_{p\text{-dry-air}}) 
\]

\[
C_p = 0.18 \times 0.47 + (1-0.18) \times 0.25 = 0.29 \text{ Btu/lb-°F}
\]

Combustor Size and Residence Time

- Combustor Size
  - Volume will be designed proportional to firing rate.
  - Volume will be inversely proportional to pressure.
  - Fuel mixing and combustion rates affects design size.

- Combustion Loading
  - Expressed (defined) as Btu/(hr-ft²).
Example 4-10. Furnace loading

What is the thermal loading of a furnace with firebox dimensions of 7 ft x 8 ft x 25 ft, fired at design maximum rate of 120 million Btu / hr?

Solution:

The furnace volume is: \(7 \times 8 \times 25 = 1400 \text{ ft}^3\)

Thermal loading = \(\frac{120(10^6)}{1400} \approx 85,700 \text{ Btu}/(\text{hr} \cdot \text{ft}^3)\)

Combustor Size and Residence Time

- Concept of residence time has regulatory significance for waste combustors.
- Formula for average residence time is:

\[ t_{res} = \frac{\text{Furnace volume} \ [\text{ft}^3]}{\text{Actual gas flow} \ [\text{ft}^3 \ / \text{sec}]} \]

- Residence time is inversely related to thermal loading.

Example 4-11. Residence time

Determine the residence time of a thermal oxidizer with an exhaust flow of 2,600 std ft\(^3\)/min and an operating temperature of 1,450°F in a 350 ft\(^3\) chamber.

Solution:

First, determine the gas flow (actual ft\(^3\) per sec)

Actual flow = \(2,600 \times \frac{(1,450+460)}{528} / 60\)

= 157 acf/sec

Now use Equation 4-25:

Residence time = \(\frac{350}{157} \approx 2.2 \text{ seconds}\)

Conclusions

- Combustion is a complex process.
- Using exhaust gas data.
- Firing rate & thermal efficiency.

Chapter 4, Summary

- Basic combustion chemistry
- Laws of Conservation of Mass and Energy
- Definitions
- Calculations
- Energy balance
Review Exercise 4-1: First Solution
Find "dry exhaust gas" molecular weight.

\[ MW_{fg, dry} = \sum mf_i * MW_i \]

\[ O_2 : mf_i (dry) = 3.3\% \]
\[ CO_2 : mf_i (dry) = 13.5\% \text{(fig 4-2)} \]
\[ N_2 : mf_i (dry) = 100\% - mf_i (dry) - mf_f (dry) \]

\[ mf_f (dry) = 100 - 3.3 - 13.5 = 83.2\% \]

\[ MW_{fg, dry} = [0.33 * 32 + 0.135 * 44 + 0.832 * 28] = 30.3 \]

\[ H_2O : mf_i = 10\% = 0.10 \]

\[ MW_{fg, wet} = MW_{fg, dry} * (1 - mf_f) + mf_f * MW_f \]

\[ MW_{fg, wet} = 30.3 * 0.9 + 1 * 18 = 29.1 \] (See Example 4-5)

Review Exercise 4-1: Alternate Solution
Find exhaust gas molecular weight.

\[ MW_{fg} = \sum mf_i * MW_i \]

\[ O_2 : mf_f (dry) = 3.3\% \]
\[ CO_2 : mf_f (dry) = 13.5\% \text{(fig 4-2)} \]
\[ N_2 : mf_f (dry) = 100\% - mf_f (dry) - mf_f (dry) \]

\[ mf_f (dry) = 100 - 3.3 - 13.5 = 83.2\% \]

\[ mf_f (wet) = (0.9) * 0.832 = 0.749 \]

\[ MW_f = [0.030 * 32 + 0.122 * 44 + 0.749 * 28 + 0.1 * 18] \]

\[ MW_{fg} = 29.1 [lb/lb - mole] \]

Review Exercise 4-1: Find exhaust gas density at std T & P.

\[ MW_{fg} = 29.1 [lb/mole] \]

\[ \text{Density} = \frac{\text{mass/mol}}{\text{volume/mol}} \]

\[ \text{Density} = \frac{29.1 \text{ lb/mol}}{385 \text{ ft}^3/\text{mol}} = 0.076 [\text{lb/ft}^3] \]

Review Exercise 4-2: Max temp of gas-fired thermal oxidizer
Given : \[ T_n = 150 \, \text{°F} \]
\[ O_2 = 14.3 \] \text{lb/°F} \]

Following Example 4-6, page 4-30 (using Tbl. 3-4)

\[ F'_c = F_c * \frac{HHV}{LHV} = 10,610 \text{ [scf/10^6 Btu]} \]

\[ F'_c = 22,200 \text{ Btu/lb} \]

\[ F'_c = 11,777 \text{ [scf/10^6 Btu]} \]

Equation (4-18) : \[ \Delta T = \frac{10^6}{F_c} \frac{20.9 - O_2}{20.9} \]

\[ \Delta T = \frac{20.9 - 14.3}{20.9} \frac{385}{29} = 1.187 \]

\[ T_{max} = T_n + \Delta T = 150 + 1.187 = 1,337 \, \text{°F} \]

Review Exercise 4-3: Fraction of sensible energy loss up stack
Given : \[ T_{stack} = 400 \, \text{°F} \]
\[ T_{ambient} = 75 \, \text{°F} \]
\[ O_2 = 5\% \]

Equation (4-24) :

\[ \frac{O_f}{Q_T} = \frac{\Delta T}{\frac{20.9}{4200} - \frac{20.9 - O_2}{20.9 - 5}} \]

\[ O_f = 0.102 \Rightarrow 10\% \]

Review Exercise 4-4: Fuel Oil Flow Rate
Given : \[ Q_{fuel, input} = 90 \times 10^6 \text{ Btu/hr} \]

\[ HHV = 125,000 \text{ Btu/gal} \]

\[ m_{fuel} = \frac{Q_{fuel, input}}{HHV} = \frac{90 \times 10^6 \text{ Btu/hr}}{125,000 \text{ Btu/gal}} \]

\[ m_{fuel} = 720 \text{ gal/hr} = 12 \text{ gpm} \]
Review Exercise 4-5:
Volume correction, standard conditions

\[ V_i = 7,000 \text{ cfm} \]

\[ T_i = 310 \text{ °F} + 460 = 770 \text{ °R}; \ T_{ad} = 68 \text{ °F} + 460 = 528 \text{ °R} \]

\[ P_{in} = 28.0 \text{ in Hg}; \ \Delta P_{stack} = -0.05 \text{ in wg (negligible) } \]

\[ P_{ad} = 30.0 \text{ in Hg} \]

\[ \frac{P_{ad} V_{ad}}{T_{ad}} = \frac{P_i V_i}{T_i} \]

\[ V_{ad} = \frac{P_i V_i T_{ad}}{T_i P_{ad}} = V_i \cdot \frac{P_i}{P_{ad}} \cdot \frac{T_{ad}}{T_i} \]

\[ V_{ad} = 7,000 \cdot \frac{28}{30} = \frac{528}{770} = 4,480 \text{ scfm} \]
**Solution to Pre-test Problem 37:**

Given: output = 100 \cdot 10^6 \text{Btu/hr}

HHV oil = 150,000 \text{Btu/gal}

\[ \eta = 0.85 = \frac{\text{output}}{\text{input}} \]

\[ \text{input energy} = \frac{\text{output energy} \cdot \eta}{100 \cdot 10^6 \text{Btu/hr}} \]

\[ \text{input energy} = 117.6 \cdot 10^6 \text{Btu/hr} \]

\[ \text{input fuel} = \frac{\text{input energy}}{150,000 \text{Btu/gal}} \]

\[ \text{input fuel} = 784 \text{gal/hr} \]

**Solution to Pre-test Problem 38:**

Given wet lignite with:

HHV_{dry} = 11,500 \text{Btu/lb}

moisture fraction, mf = 40\% = 0.4

\[ \text{HHV}_{wet} = \text{HHV}_{dry} \cdot (1 - \text{mf}) \]

\[ \text{HHV}_{wet} = 11,500 \cdot (1 - 0.4) = 11,500 \cdot 0.6 \]

\[ \text{HHV}_{wet} = 6,900 \text{Btu/lb} \]

**Fuel Properties**

1. Gas Fuels
2. Fuel Oils
3. Coal
4. Other Solid Fuels

**Gas Fuels**

- **Advantages:**
  - Clean burning, clean handling.
  - Mixes with air.
- **Constituents:**
  - Natural gas is mostly methane (CH₄).
- **History:**
  - Original commercial gas made by heating coal.
- **Types:**
  - Natural Gas
  - Propane and Liquefied Petroleum Gas (LPG).
  - Waste Synthetic and Biological Gases.

**Natural Gas**

- Composition (mixture varies).
- Heating Values around 1,000 Btu/scf.
- Sour gas – with significant hydrogen sulfide, H₂S (e.g. >100 ppm).
- Sweet gas – free of H₂S (e.g. <24 ppm).
- Lean gas - high methane content.
  - Results in a relatively low heating value.
- Wet gas
  - Contains condensable organic compounds.

**Natural Gas Samples by Gas Field**

(Table 3-9)

<table>
<thead>
<tr>
<th>Constituent, % by Vol.</th>
<th>Pa</th>
<th>Cal</th>
<th>Ohio</th>
<th>Okla</th>
</tr>
</thead>
<tbody>
<tr>
<td>H₂, Hydrogen</td>
<td>-</td>
<td>-</td>
<td>1.82</td>
<td>-</td>
</tr>
<tr>
<td>CH₄, Methane</td>
<td>83.4</td>
<td>84.0</td>
<td>93.3</td>
<td>84.1</td>
</tr>
<tr>
<td>C₂H₄, Ethylene</td>
<td>-</td>
<td>-</td>
<td>0.25</td>
<td>-</td>
</tr>
<tr>
<td>C₃H₆, Ethane</td>
<td>15.8</td>
<td>14.8</td>
<td>-</td>
<td>6.7</td>
</tr>
<tr>
<td>CO₂, Carbon Monoxide</td>
<td>-</td>
<td>-</td>
<td>0.45</td>
<td>-</td>
</tr>
<tr>
<td>CO₂, Carbon Dioxide</td>
<td>-</td>
<td>1.7</td>
<td>0.22</td>
<td>0.8</td>
</tr>
<tr>
<td>N₂, Nitrogen</td>
<td>0.8</td>
<td>0.5</td>
<td>3.4</td>
<td>8.4</td>
</tr>
<tr>
<td>O₂, Oxygen</td>
<td>-</td>
<td>-</td>
<td>0.35</td>
<td>-</td>
</tr>
<tr>
<td>H₂S, Hydrogen Sulfide</td>
<td>-</td>
<td>-</td>
<td>0.18</td>
<td>-</td>
</tr>
</tbody>
</table>

6- 1
### Natural Gas Samples by Gas Field

**Table 3-9**

<table>
<thead>
<tr>
<th>Constituent</th>
<th>Ultimate, % by Wt.</th>
<th>Pa</th>
<th>Cal</th>
<th>Ohio</th>
<th>Okla</th>
</tr>
</thead>
<tbody>
<tr>
<td>S, Sulfur</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.34</td>
<td>-</td>
</tr>
<tr>
<td>H₂, Hydrogen</td>
<td>23.35</td>
<td>23.30</td>
<td>23.20</td>
<td>20.85</td>
<td></td>
</tr>
<tr>
<td>C, Carbon</td>
<td>75.25</td>
<td>74.72</td>
<td>69.12</td>
<td>64.84</td>
<td></td>
</tr>
<tr>
<td>N₂, Nitrogen</td>
<td>1.22</td>
<td>0.76</td>
<td>5.76</td>
<td>12.90</td>
<td></td>
</tr>
<tr>
<td>O₂, Oxygen</td>
<td>-</td>
<td>1.22</td>
<td>1.58</td>
<td>1.41</td>
<td></td>
</tr>
<tr>
<td>Specific Gravity</td>
<td>0.636</td>
<td>0.636</td>
<td>0.567</td>
<td>0.630</td>
<td></td>
</tr>
<tr>
<td>(Relative to Air)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>HHV (Btu/scf)</td>
<td>1.129</td>
<td>1.116</td>
<td>964</td>
<td>974</td>
<td></td>
</tr>
<tr>
<td>HHV (Btu/lb)</td>
<td>23,170</td>
<td>22,904</td>
<td>22,077</td>
<td>20,160</td>
<td></td>
</tr>
</tbody>
</table>

### Average USA Pipeline Natural Gas

**Table 3-9**

<table>
<thead>
<tr>
<th>Constituent</th>
<th>% by Vol.</th>
</tr>
</thead>
<tbody>
<tr>
<td>CH₄, Methane</td>
<td>93.10</td>
</tr>
<tr>
<td>C₂H₆, Ethane</td>
<td>3.20</td>
</tr>
<tr>
<td>C₃H₈, Propane</td>
<td>0.70</td>
</tr>
<tr>
<td>C₄H₁₀, n-Butane</td>
<td>0.40</td>
</tr>
<tr>
<td>CO₂, Carbon Dioxide</td>
<td>1.00</td>
</tr>
<tr>
<td>N₂, Nitrogen</td>
<td>1.60</td>
</tr>
<tr>
<td>Total</td>
<td>100.00</td>
</tr>
</tbody>
</table>

**Specific Gravity (relative to air)**: 0.609

**HHV (Btu/scf)**: 1,032 Btu/scf

**HHV (Btu/lb)**: 22,600 Btu/lb

### Propane and LPG

- **Properties**
  - Liquid at 15 psig → sold by the gallon.

- **Composition**
  - Mostly (97%) propane (C₃H₈).

- **Heating value** – 2,500 Btu/ft³-gas

- **Used where natural gas is not available.**

### Biological Waste and Synthetic Gases

- **Generated in anaerobic (oxygen exclusion)** micro-biological decomposition
- **Methane is the primary constituent**
- **Landfill gases** (formation rates vary with water and oxygen exclusion)
- **Biogas includes anaerobic digestion of sewage sludge.**
- **Syngas includes industrial by-product gases, synthetic natural gases (SNG) from coal and petroleum (e.g., naptha).**

### Fuel Oils

**Fuel oil classification using ASTM standards.**

<table>
<thead>
<tr>
<th>Grade</th>
<th>Flash Point, °C</th>
<th>Water and Sediment, (% by vol.)</th>
<th>Sulfur Content, (% by vol.)</th>
<th>Ash Content, (% by vol.)</th>
<th>Viscosity (centistokes)</th>
<th>Specific Gravity (by weight)</th>
</tr>
</thead>
<tbody>
<tr>
<td>No. 1</td>
<td>135</td>
<td>0.05-0.15</td>
<td>0.05-0.15</td>
<td>0.05-0.15</td>
<td>5-25</td>
<td>0.87-0.89</td>
</tr>
<tr>
<td>No. 2</td>
<td>135</td>
<td>0.05-0.15</td>
<td>0.05-0.15</td>
<td>0.05-0.15</td>
<td>15-50</td>
<td>0.87-0.89</td>
</tr>
<tr>
<td>No. 4</td>
<td>355-540</td>
<td>0.10</td>
<td>0.25-0.75</td>
<td>0.15-0.35</td>
<td>0.3-1.5</td>
<td>0.87-0.89</td>
</tr>
<tr>
<td>No. 5</td>
<td>355-540</td>
<td>0.10</td>
<td>0.25-0.75</td>
<td>0.15-0.35</td>
<td>0.3-1.5</td>
<td>0.87-0.89</td>
</tr>
<tr>
<td>No. 6</td>
<td>540-660</td>
<td>0.10</td>
<td>0.25-0.75</td>
<td>0.15-0.35</td>
<td>0.3-1.5</td>
<td>0.87-0.89</td>
</tr>
<tr>
<td>No. 7</td>
<td>540-660</td>
<td>0.10</td>
<td>0.25-0.75</td>
<td>0.15-0.35</td>
<td>0.3-1.5</td>
<td>0.87-0.89</td>
</tr>
</tbody>
</table>
Distillate vs. Residual

- Crude oil is refined to produce:
  - Distillate products (No. 2, etc.)
  - Residual Oils (#6, Bunker C)

- Composition
  - Distillates are fairly clean.
  - Most of the crude contaminants are concentrated in the residuals.

- Residual fuel is cheaper to buy, but more expensive to handle/use.
- #6 must be heated to pump or burn.

Common Fuel Oils

<table>
<thead>
<tr>
<th>Grade</th>
<th>Name</th>
<th>Color</th>
<th>API</th>
<th>Density, lb/gal</th>
<th>BTU/gallon</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>#2</td>
<td>Distillate</td>
<td>Amber</td>
<td>30-38</td>
<td>6.960-7.296</td>
<td>137,000-142,000</td>
<td>Home heating fuel</td>
</tr>
<tr>
<td>#6</td>
<td>Residual</td>
<td>Black</td>
<td>8-15</td>
<td>8.053-8.448</td>
<td>151,000-156,000</td>
<td>Heating required to pump and store</td>
</tr>
</tbody>
</table>

Fuel Oil Gravity & Heating Values

- As specific gravity decreases the density decreases \( \Rightarrow \) lower mass per unit volume [lb/gal].
- As density decreases, the fuel has higher hydrogen-to-carbon ratio.
  - Hydrogen Heating value: 61,000 [Btu/lb]
  - Carbon Heating value: 14,000 [Btu/lb]
- As density decreases, the energy content per pound [Btu/lb] is increased.
- As density decreases, the energy content per gallon [Btu/gal] is decreased.

Distillate Fuel Oil

- #2 Oil, Diesel, Kerosene
- Sulfur limits
  - #2 fuel oil limit is 0.5% by volume.
  - Highway diesel limit is 0.0015% (15 ppm)

Residual Oil

- Residual properties are tailored to the market.
- Ultimate residue is petroleum coke (solid).
- Marketable residual oil sulfur contents:
  - 2.2% in the 1970’s.
  - Typically 1% or less today.
- Residual oil has vanadium & other metals,
- #4 Oil is a blend that is thinner (easier to pump) than #6,
Oil Viscosity-Temp Relationship

Temperature, Degrees Fahrenheit

Viscosity Range

Oil – Water Emulsions

- Oil – water mixtures:
  - Heavy oil becomes pumpable (Oremulsion).

- Combustion applications:
  - Originally developed in Europe.
  - Improves atomization.
  - Some NOx reduction.

Coal-Water Emulsions

- Finely pulverized coal + water \rightarrow liquid.
  - Dispersant needed to keep coal in suspension.
- Allows coal to be transported in a pipeline.
- Allows coal firing in an oil burner system.
  - Coal ash content is 100 times that of oil.
  - Furnace systems not designed for coal, can not easily burn coal-water emulsions.

Coal

- Primary fuel for electric power generation

- Example properties (see Tables 3-12 to 3-15)

- Classification (see Table 3-12)
  - Anthracite (mainly fixed carbon, FC > 86%)
  - Older Bituminous (FC > 69%)
  - Younger Bituminous (FC < 69%, HHV >10,500)
  - Subbituminous (FC < 69%, 8,300<HHV<11,500)
  - Lignite (FC < 69%, HHV < 8,300 Btu/lb)

Analyses of Selected Coals

<table>
<thead>
<tr>
<th>Coal</th>
<th>Location</th>
<th>Moisture</th>
<th>Volatile</th>
<th>Fixed C</th>
<th>Ash</th>
<th>Sulfur</th>
<th>HHV (Btu/lb)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Anthracite</td>
<td>Lackawanna, PA</td>
<td>2.5</td>
<td>6.2</td>
<td>79.4</td>
<td>11.9</td>
<td>0.6</td>
<td>12,925</td>
</tr>
<tr>
<td>Low-Vol Bitum.</td>
<td>McDowell, WV</td>
<td>1.0</td>
<td>16.2</td>
<td>77.3</td>
<td>5.1</td>
<td>0.74</td>
<td>14,715</td>
</tr>
<tr>
<td>High-Vol Bitum.</td>
<td>Westmoreland, PA</td>
<td>1.5</td>
<td>30.7</td>
<td>56.6</td>
<td>11.2</td>
<td>1.82</td>
<td>13,325</td>
</tr>
<tr>
<td>Sub-Bitum A</td>
<td>Musselshel, MT</td>
<td>14.1</td>
<td>32.2</td>
<td>46.7</td>
<td>7.0</td>
<td>0.43</td>
<td>11,140</td>
</tr>
<tr>
<td>Sub-Bitum C</td>
<td>Campbell, WV</td>
<td>31.0</td>
<td>31.4</td>
<td>32.8</td>
<td>4.8</td>
<td>0.55</td>
<td>8,320</td>
</tr>
<tr>
<td>Lignite A</td>
<td>Mercer, ND</td>
<td>37.0</td>
<td>26.6</td>
<td>32.2</td>
<td>4.2</td>
<td>0.40</td>
<td>7,225</td>
</tr>
</tbody>
</table>

Geographic Distribution of Coal
Anthracite (Hard Coal)
- Source – mostly central Pennsylvania
- A premium fuel
- Slow burning, not smokey → residential use
- Usually low sulfur

Bituminous
- Tend to form sticky “bitumen” when heated.
- Volatile content 15% to 35% → fast burning.
- Primary fuel for electric utility PC boilers.
- Sulfur, ash & mercury content varies.

Subbituminous
Typically a western coal
e.g., Powder River Basin (PRB) Wyoming.
- Higher moisture content.
- Lower sulfur content.
- Higher ash content.

Lignite
- Young coal; older than peat.
- High moisture levels (30%).
- High volatile content.
- Low heating value (due to moisture).
- Susceptible to spontaneous combustion.

Other Coal Properties that Influence Combustion
- Agglomerating /Caking Tendencies
- Ash Softening and Fusion Temperatures
- Stoker Fuel Size Distributions
- Coal Size Terminology
- Grindability and Friability

Agglomerating/Caking Tendency
- Free Swelling Index by ASTM D720
  Scale of 0 (free burning) to 9 (severe swelling).
- Tendency to fuse and swell when burning compromises stoker operation.
- Coke from swelling coal is less dusty.
Ash Softening and Fusion Temperatures

- Ash melting temperature affects agglomeration and slag formation/deposits.
- ASTM Procedure D1857-68
  - Initial deformation temperature
  - Softening temperature
  - Fluid temperature
- Ash content determines thermal behavior.

Stoker Coal Size Distributions

- Most stoker coal is fired as purchased
  - Size distribution affects operation & emissions.
- Spreader stoker distributes according to size:
  - Fines may accumulates below spreader.
  - Oversize coal may pile up elsewhere.
- Burning 0.2 mm to 2 mm fines in suspension causes carbon carryover.

Grindability and Friability

- Grindability affects PC boiler operations.
  - Hard coal requires more energy for grinding.
  - May yield larger particle sizes.
- Hardgrove grindability (ASTM D4090)
- Friability -- Indicates how much dust will be generated.

Coal Size Terminology

<table>
<thead>
<tr>
<th>Coal Category</th>
<th>Size Description</th>
<th>Size Characteristics</th>
</tr>
</thead>
<tbody>
<tr>
<td>Run-of-mine</td>
<td>No size segregation</td>
<td></td>
</tr>
<tr>
<td>Lump</td>
<td>Larger than 6 inches</td>
<td></td>
</tr>
<tr>
<td>Egg</td>
<td>Smaller than 6 inches and larger than 2 inches</td>
<td></td>
</tr>
<tr>
<td>Nut</td>
<td>Smaller than 2 inches and larger than 1.25 inches</td>
<td></td>
</tr>
<tr>
<td>Stoker</td>
<td>Coal smaller than 1.25 inches and larger than 0.76 inches</td>
<td></td>
</tr>
<tr>
<td>Slack</td>
<td>Coal smaller than 0.76 inches</td>
<td></td>
</tr>
</tbody>
</table>

Source: DOE/EA-0494/837, Energy Information Administration

Contaminants:
Air Pollution Control

- Mercury
- Ash
- Sulfur
- Coal Cleaning
Mercury
- Forms Vapors & Particulates:
  - Elemental, oxide, chloride.
- Moves up the food chain.
- Control – activated carbon injection.
- Mercury Content (see Table 3-15).

Coal Sulfur
- Forms include:
  - Pyritic sulfur
  - Organic sulfur
  - Sulfates
- Pyritic sulfur
  - High density.

Coal Cleaning
- Used to remove rock, dirt, & pyritic sulfur.
- Can reduce ash by 25% to 50%.
- Techniques:
  - Washing (flotation)
  - Froth flotation

Other Solid Fuels
- Fossil Solid Fuels
- Peat
  - High moisture, low heating value.
- Wood
- Biomass Fuels
- Solid Wastes

Other Solid Fuels
- Coke – carbon residue from heating coal
  - Main use is for steel making.
- Metallurgical Coke
  - Ash is compatible with steel making.
- Petroleum Coke
  - High sulfur, low ash.
- Charcoal

<table>
<thead>
<tr>
<th>ULTIMATE ANALYSIS COMPARISONS (As Received)</th>
<th>Carbon</th>
<th>Hydrogen</th>
<th>Oxygen</th>
<th>Nitrogen</th>
<th>Sulfur</th>
<th>Chlorine</th>
<th>Moisture</th>
<th>Ash</th>
<th>HHV (Btu/lb)</th>
</tr>
</thead>
<tbody>
<tr>
<td>MSW</td>
<td>27.9</td>
<td>3.7</td>
<td>20.7</td>
<td>0.2</td>
<td>0.1</td>
<td>0.1</td>
<td>31.3</td>
<td>16.0</td>
<td>5,100</td>
</tr>
<tr>
<td>RDF</td>
<td>36.1</td>
<td>5.1</td>
<td>31.6</td>
<td>0.8</td>
<td>0.1</td>
<td>0.1</td>
<td>20.2</td>
<td>6.0</td>
<td>6,200</td>
</tr>
<tr>
<td>Bitum. Coal</td>
<td>72.8</td>
<td>4.8</td>
<td>6.2</td>
<td>1.5</td>
<td>2.2</td>
<td>0.0</td>
<td>3.5</td>
<td>9.0</td>
<td>13,000</td>
</tr>
</tbody>
</table>
Wood (see Table 3-16)

- Green Wood (forest products).
- Mixed Wood Waste.
- Dry Wood Waste (manufacturing).
- Sawdust and Sander Dust.

Green Wood

- Common fuel and forest products mills.
- Generated on site or purchased.
  - Debarking & sawing operations.
  - Chip trees too small to saw.
  - Chip logging slash.
- Green wood usually >30% moisture.
  - Clean burning can be a challenge.

Example Ultimate Analyses of Wet Waste Wood Fuel (Hog Fuel)

<table>
<thead>
<tr>
<th>Wood Hog Fuels</th>
<th>Western Hemlock</th>
<th>Douglas Fir</th>
<th>Western Mix 50/50</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ultimate Analysis</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Carbon</td>
<td>25.20</td>
<td>26.15</td>
<td>25.675</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>2.90</td>
<td>3.15</td>
<td>3.025</td>
</tr>
<tr>
<td>Sulfur</td>
<td>0.05</td>
<td>0.00</td>
<td>0.025</td>
</tr>
<tr>
<td>Oxygen</td>
<td>20.70</td>
<td>20.25</td>
<td>20.475</td>
</tr>
<tr>
<td>Nitrogen</td>
<td>0.05</td>
<td>0.05</td>
<td>0.050</td>
</tr>
<tr>
<td>Ash</td>
<td>1.10</td>
<td>0.40</td>
<td>0.750</td>
</tr>
<tr>
<td>Moisture</td>
<td>50.00</td>
<td>50.00</td>
<td>50.000</td>
</tr>
<tr>
<td>Totals</td>
<td>100.00</td>
<td>100.00</td>
<td>100.000</td>
</tr>
</tbody>
</table>

Mixed Wood Waste

- Source
  - Construction & demolition, pallets.
  - Can contain inorganic material.
- Usually dry, easy burning.
- Processing:
  - Shredded to facilitate conveyors & feeders
- Pollution impacts:
  - Pressure treated wood burns clean, but is highly regulated.
  - Paint & dirt tend to increase particulate emissions

Dry Wood Waste

- Heating value can be 8,000 to 10,000 Btu/lb.
  - Dry wood burns easily, cleanly.
- Sawdust, sander dust:
  - May be fired (blown) directly from the source (without storage).
  - Typically burned in suspension.
  - Fines >0.2 mm tend to create carbon carryover.

Biomass Fuels

- Burned directly or converted to liquid fuel.
- Fuel crops
  - Some wood fired boilers
  - Ethanol from corn
- Agricultural wastes (e.g., Bagasse)
Biomass Fuel Example

Table 3-17: Emission Properties

<table>
<thead>
<tr>
<th>Property</th>
<th>Analyzed (as-fired), % by wt</th>
<th>Yellow</th>
</tr>
</thead>
<tbody>
<tr>
<td>moisture</td>
<td>52.0</td>
<td></td>
</tr>
<tr>
<td>volatile matter</td>
<td>40.2</td>
<td></td>
</tr>
<tr>
<td>fixed carbon</td>
<td>0.1</td>
<td></td>
</tr>
<tr>
<td>ash</td>
<td>1.7</td>
<td></td>
</tr>
</tbody>
</table>

Ultimate

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydrogen, H₂</td>
<td>2.0</td>
</tr>
<tr>
<td>Carbon, C</td>
<td>29.4</td>
</tr>
<tr>
<td>Sulfur, S</td>
<td>trace to 0.5</td>
</tr>
<tr>
<td>Nitrogen, N</td>
<td>0.1</td>
</tr>
<tr>
<td>Oxygen, O₈</td>
<td>26.0</td>
</tr>
<tr>
<td>Moisture, H₂O</td>
<td>52.0</td>
</tr>
<tr>
<td>ash</td>
<td>1.7</td>
</tr>
</tbody>
</table>

Heating Value

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>DTHP</td>
<td>4,000</td>
</tr>
<tr>
<td>J/kg</td>
<td>9,304</td>
</tr>
</tbody>
</table>

Solid Waste Fuels

- Waste-to-Energy
  - Facilities with no energy recovery are incinerators.
- Municipal waste composition (Table 3-18)
  - Varies locally & seasonally.
  - Not amenable to simple fuel analysis.
- Problematic materials
  - Mercury (from batteries, electrical switches).
  - Explosive fuel tanks (compressed gas), and ammunition.

Medical Waste (Table 3-19)

- Similar to MSW but:
  - Moisture can be lower.
  - Heating value may be higher.
  - May have more chloride from PVC plastic.
- Regulated Medical Waste (some States)
  - Infectious, blood soaked, anatomical.
- Small hospital incinerators have largely disappeared.

Infectious Medical Waste Composition

- Plastics and Rubber 20-60%
- Paper and Textiles 50-70%
- Glass and Metals 10-20%
- Body Fluids and Moisture 10-40%
Chapter 2, Combustion Systems

1. Types of Combustion Systems
2. Fuel Storage, Handling and Processing
3. Combustion Air Pollution Controls
4. Steam System Components

Combustion Systems

- Knowing the system enables intelligent regulation.
- Combustor vs open burning:
  - Combustion zone is completely enclosed.
  - Controlled fuel & air flows.
  - Controlled air-fuel mixing.

Factors Limiting Combustion Rates

- **Gaseous Fuels:**
  - Turbulence.
  - Fuel / Air mixing.
- **Liquid Fuels:**
  - Evaporation / Distillation.
  - Surface area.
- **Solid Fuels:**
  - Distillation of volatiles.
  - Diffusion of oxygen to the surface of fixed carbon.

Combustion Source Components

- Diagram Key:
  1. Burner - Combustion Device
  2. Fuel Supply
  3. Air Supply (Fan)
  4. Control System
  5. Combustion or Emissions Monitor (Optional)

Types of Combustion Systems

- Engines and Turbines
- Boilers
- Thermal Oxidizers
- Other Combustion Systems

Engines and Turbines

- **Background**
  - Clean fuel use means fewer pollutants.
  - Uniform construction means predictable emissions.
- **Uses and Trends**
  - Traditional use: pumping & emergency power.
  - Increasing use for electric power generation.
  - More gas consumption.
Engines and Turbines

- Reciprocating Engines
- Combustion Turbines
- Combined Cycles and Cogeneration

Reciprocating Engines

Table 2-1. Types of Reciprocating Engines

<table>
<thead>
<tr>
<th>Type</th>
<th>Characteristics</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas</td>
<td>Gas mixed with the intake air, spark ignited</td>
</tr>
<tr>
<td>Diesel Fuel</td>
<td>Diesel oil auto-ignites and burns as it is injected, no spark required.</td>
</tr>
<tr>
<td>Dual Fuel</td>
<td>Essentially a gas fired diesel engine. A small amount of diesel fuel is injected to ignite the gas with no spark plug.</td>
</tr>
<tr>
<td>Lean Burn</td>
<td>Operates with more than 5% excess air</td>
</tr>
<tr>
<td>Rich Burn</td>
<td>Operates with less than 5% excess air</td>
</tr>
</tbody>
</table>

Combustion Turbines

- History
  - Evolved from aircraft engines.
- Power
  - Multiple units can be used in large applications.
- Fuels
  - Natural gas
  - Fuel oil.
- Efficiency
  - Depends on size, load & design.

Components of a Turbine

- Air
- Fuel
- Exhaust
- Compressor
- Shaft
- Turbine

Gas Turbine Reverse Flow Combustor
**Simple - Cycle Gas Turbine**

- Efficiency increases with pressure ratio.
- Efficiency increases with turbine - inlet temperature.
- Capacity decreases with pressure ratio.
- Continuous combustion system:
  - Materials problems at high combustor / turbine temperatures.
  - Designs decisions must balance durability, efficiency and capacity.

**Ambient Air Temperatures**

- Turbine capacity decreases as ambient air temperature increases.
  - Reduced output in summer.
  - Air flow rate decreases with increased ambient air temperatures (lower density).
- Efficiency decreases as ambient air temperature increases.

**Combined Cycles and Cogeneration**

Engine/turbine efficiency can be improved by using waste heat:

- **Regeneration** – heat compressor exit gases to reduce the required fuel.
- **Combined cycle** – exhaust heat used for steam to drive a steam turbine.
- **Cogeneration** - exhaust heat used in an industrial process, district heating, etc.

**Combined Cycle System**

**Heat Recovery Steam Generator, HRSG**

**A Basic Boiler**
Boilers

- History
  - Energy source for early steam engines.
  - Fuel = anything combustible.

- Types
  - Fire-tube
  - Water-tube

Conventional Fire-Tube Boiler

Waterwall Design Concept

Industrial Water-Wall Boiler,
(Fuel Oil or Natural Gas)

Steam Generator Equipment & Flow Schematic

Utility Pulverized Coal-Fired Water-Wall Boiler
### Comparative Sizes of Boilers

**Table 2.2. Examples of Boiler Size**

<table>
<thead>
<tr>
<th>Use</th>
<th>Generic Size</th>
<th>mmBTU/hr</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential heat</td>
<td>50,000 BTU/hr</td>
<td>0.05</td>
</tr>
<tr>
<td>Commercial building heat</td>
<td>100 Horsepower</td>
<td>3.3</td>
</tr>
<tr>
<td>Factory – medium size</td>
<td>30,000 lb/hr steam flow</td>
<td>40</td>
</tr>
<tr>
<td>Manufacturing - large</td>
<td>200,000 lb/hr steam flow</td>
<td>250</td>
</tr>
<tr>
<td>Electric Utility</td>
<td>500 MW (electric)</td>
<td>5,000</td>
</tr>
</tbody>
</table>

### Typical Oil Combustion Design Parameters

<table>
<thead>
<tr>
<th>Unit Type</th>
<th>Heat Input Million</th>
<th>Excess Air</th>
<th>Volumetric Heat Release</th>
<th>Residence Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residence</td>
<td>Btu/hr</td>
<td>%</td>
<td>Btu/hr-ft³</td>
<td>sec</td>
</tr>
<tr>
<td>Apartment</td>
<td>2.2</td>
<td>40</td>
<td>340,000</td>
<td>0.13</td>
</tr>
<tr>
<td>Ship’s Boiler</td>
<td>80</td>
<td>15</td>
<td>70,000</td>
<td>0.80</td>
</tr>
<tr>
<td>60 MW Power Plant</td>
<td>600</td>
<td>3</td>
<td>30,000</td>
<td>1.50</td>
</tr>
</tbody>
</table>

### Suspension Versus Grate Firing

- **Suspension Firing:**
  - Gas fuel, atomized oil, or powdered coal burns in suspension.
  - Residence time is about 1 second.

- **Grate Firing:**
  - ‘Chunks’ of solid fuel burn on a metal or refractory grate.
  - Residence time is minutes to hours.

### Basic Burner Design

- **Goals**
  - Flame stability
  - Complete combustion

- **Secondary Objectives**
  - Emission (NOx) control
  - Flame shape
  - Turn down
Burner Features

- Air flow rate & pattern control
- Gas fuel injectors
- Atomizer adjustments
- Pulverized coal injection
- Burner can be built for 2 or 3 fuels

Hemispherical Gas Spud Burner

Steam Atomized Oil Burner (Residual Oil)

Combination Gas-Oil Burner

Pulverized Coal System

Typical Large Burner
**Pulverized Coal Firing**

- Grinding mill feeds a set of burners.
- A large boiler has several mills.
- About 20% of the boiler air is for pneumatic transport.
- Challenge of uniform coal flows.
- Abrasive wear.

**Suspension Firing – Burner Arrangements**

- Molten sticky ash in suspension.
- Heat transfer issues.
- Soot blowers.
- Large ash accumulations.
- Combustion controls.
Stoker Firing

- General
  - It's the original furnace combustor.
- Fuels
  - Any solid.
- Size
  - Limited by grate surface area →
    - e.g., 1,000 sq.ft. (1,000 million Btu/hr)
- Use and Trends:
  - Industrial boilers, wood waste, MSW

Spreader Stoker

Stoker Components

Fuel Burning on a Grate

- Size of fuel particles
  - Burning time is proportional to size.
  - Size distribution determines grate speed.
  - Furnace air velocity can carry out particles smaller than 2 mm.
  - Suspended particles larger than 0.2 mm don't burn completely.
- Type of fuel
  - Wet fuel requires hot air & time to dry.
Fuel Feeders

Objective:
– Deliver fuel into the furnace.
– Achieve a uniform distribution on the grate (Match fuel & air distributions).

Types:
– Bottom feeders
– Spreaders
– MSW mass feed

Air Flow

• Air is supplied by a Forced Draft fan.
  – Induced Draft fan draws flue gas from the furnace.
• Air is distributed between under grate air and over-fire air.
  – Under grate air distribution won’t perfectly match the fuel distribution above.
  – Under grate air is needed for cooling.
    • Causes high excess air levels.
    • Limits the amount of over-fire air.

Over-Fire Air

• Over-fire air burns volatile fuel from the bed.
  – Mixing required to control CO emissions.
• Problems:
  – The amount of over-fire air is usually limited by grate cooling needs.
  – Geometric design of the over-fire air ports is critical to optimum emission performance.

Grate Concepts

• Grate Types:
  – Stationary - simple, allows water cooling.
  – Traveling - automatic ash transport.
  – Oscillating - stirs the fuel & transports.
• Pressure drop
  – 0.5" or more needed for even distribution.
  – Worn grate → poor air distribution.
FBC Advantages and Disadvantages

- Advantages
  - Fuel flexibility
  - Can burn low quality (cheap) fuels.
  - Low NOx & possible SOx control

- Disadvantages
  - High fan energy required.
  - Bed cooling incurs:
    - High excess air,
    - High erosion rates, or
    - Complexity – circulating fluid bed
  - Ash & bed solids management.
Special Combustion Systems

1. Thermal Oxidizers (pollution control devices).
   - Gas (fume) Incinerators.
   - High Temperature Oxidizers.
   - Catalytic Oxidizers.
2. Flares.
3. Cement Kilns.
4. Sludge Incinerators.

High Temperature Thermal Oxidizers

Hazardous Waste Legislation

RCRA - 1976

CERCLA - 1980
Comprehensive Environmental Response Compensation and Liability Act.

SARA - 1986:
Superfund Amendment and Reauthorization Act.

Hazardous Waste Terms

- POHC: Principal Organic Hazardous Constituent
- PIC: Products of Incomplete Combustion
- DE: Destruction Efficiency
- DRE: Destruction and Removal Efficiency

Basic Steps

- Analyze Wastes (properties).
- Determine Potential Emissions.
- Ensure Steady-State Incineration Operations.
- Provide Interlocks (for safety and to avoid exceedances).
- Monitor Combustion System (temperatures, gases, and ash content).
- Monitor APCD Operations.
- Inspect Combustion System and Materials Handling (receiving / storage / blending).

Special Requirements

- Combustion Chamber:
  Volume, auxiliary fuel & air supply
- Combustion Control Interlocks.
- Air Pollution Control
- Monitoring (calibration)
- Inspections and Record Keeping
- DRE for Specific Toxins
  (e.g., 99.99 % or 99.9999%).
- HCl Emissions Limits
- Particulate Emission Limits
  (e.g., 0.03 gr/dscf).
1984 RCRA
- 99.99% POHC DRE.
- 99% HCl Recovery (if more than 4 lbm/hr).
- 0.08 [grains/dscf] corrected to 50% EA.
- Trial Burn with Annual Stack Test:
  - EPA Method 5 for Particulates.
  - Source Assessment Sampling Train, SASS.
  - Volatile Organics Sampling Train, VOST.

Equation for Combustion Efficiency
(Based on converting CO to CO$_2$)
Assume: CO$_m$ is the Measured Dry Gas CO
Expressed as a Percentage
CO$_{2m}$ is the Measured Dry Gas CO$_2$
Expressed as a Percentage [%]

C.E. (%) = 100 x \[ \frac{CO_{2m}}{CO_{2m} + CO_m} \] or

C.E. (%) = 100 x \[ 1.00 - \frac{CO_m}{CO_{2m} + CO_m} \]

Combustion Efficiency
Example Calculation
Assume: CO$_m$ was measured at 5 ppm CO or 0.0005 %
CO$_{2m}$ was measured at 8.0 %

C.E. (%) = 100 x \[ \frac{CO_{2m}}{CO_{2m} + CO_m} \]

C.E. (%) = 100 x \[ \frac{8.0}{8.0 + 0.0005} \] = 99.99%

High Temperature Oxidizers
- 1,400 F should give complete destruction,
  - Provided mixing (design) is good.
  - A simple oxidizer is very effective.
- Oxidizers with 1,400 F exhausts use a lot of fuel.
- Heat exchangers cut fuel use dramatically
  - Heat exchangers can leak \Rightarrow emissions

Direct Flame Afterburner
Catalytic Oxidizers

- Similar to a simple oxidizer except for lower temperature, e.g., <700°F
  - Same requirement for uniform mixing.
- Destruction efficiency varies by chemical.
- Catalyst performance can deteriorate emissions.

Flares

- Concept: continuously burn waste gas.
- Traditional purpose: prevent flammable gas accumulation.
- Recent purpose: pollution control
  - Common at landfills.
  - Replaced by beneficial use in some cases.

Water-Gas Shift Reaction

\[ C + H_2O \text{(with Heat)} \rightarrow CO + H_2 \]

- Steam Injection in Flares.
- Manufacture of "water gas."

Cement Kilns
Cement Kilns

- High temperature, long residence time.
- Fuels – flexibility to burn cheap fuel.
  - Coal
  - Liquid & solid hazardous waste
- Emissions:
  - NOx
  - Volatiles from process

Rotating Hearth Burner

- Design is obsolete (grandfather cases).
- Counter flow heat exchanger.
  - Sludge volatiles are emitted.
- New sludge processors use fluid bed combustor or other treatment methods.
Boilers, Fuel Handling & Controls

- Natural Gas
- Oil
- Solid Fuels
  - Coal
  - Wood and Waste

Natural Gas

- Delivery
  - Piped direct to customer.
- Storage is in wells.
- An interruptible supply is cheaper.

Fuel Oil

- Delivery
  - Truck, rail, barge or ship.
  - Pipeline to large customers & distributors.
- Storage capacity is usually weeks or months.
  - #6 Oil must be kept hot to pump it.
  - Stratification can occur in large tanks.

Solid Fuels

- Coal
  - Primary users are electric utilities.
  - Delivery by unit train.
  - Storage piles:
    - Can accumulate moisture.
    - Fire potential.

- Wood and Waste
  - Used on site or delivered by truck
  - Moisture
    Initial high moisture will increase with rain.
  - Wood deteriorates (rots) ➔ no long term storage.
Combustion Controls

- Load Variations.
- Control Systems.
- Air Moving Components.

Load Types

- Base load
- Swing load
- Emergency
- Regulated facilities have variable loads – control system required.

Example: Systems Transients

![Graph showing CO and NOx load variations over time of day.]

Transient Example: MSW Fuel Variability

- Fuel Size
- Heating Value
- Fuel Moisture
- Volatility
- Fixed Nitrogen
- Ash (incombustibles)

Waterwall Unit Control Operations

An Increase in Fuel Moisture will cause:
- Gas temperature to drop.
- Less Energy Extraction in Radiant Boiler.

Gas temperature can be restored:
- Reduce air supply (excess air).
- Increase auxiliary fuel supply.
- Increase grate agitation.

Automatic Control System Functions

- Modulating Control (with quick responses).
- Sequential Control Logic.
- Process Monitoring.
**Example Control System, PLC**

- Load Signal
- PLC
- Fuel Valve
- Air
- Air Damper
- Fuel Gas

**Pneumatic Control System: Flow**

- Signal to
- Controller
- Transmitter
- Final Control
- Element
- Sensor
- Process Line

**Single-Element Control System: Draft**

- Furnace draft
- Furnace
- Furnace draft controller
- PCE

**Three-Element Control System: Level**

- Steam
- Steam
- PT
- Furnace
- Boiler
- Boiler
- PT
- PT
- PT
- LC
- SP
- SP

**Microprocesser Based Control System**

**Combustion Control Systems**

- Fuel flow responds to load demand.
- Air Flow must match (follow) fuel flow:
  - Keep the air-fuel ratio constant.
  - Mechanical coupling devices do a poor job.
  - PLC allows sophisticated flow matching.
- O₂ meter provides an indication of air-fuel ratio.
Gas - Side Control Parameters

- Air Flow Rate
- Opacity
- Oxygen Content
- Carbon Monoxide
- Draft
- Combustion Temperature
- Flue Gas Temperature
  Entering the APCD

Trim Control Features

- Oxygen Trim Control.
- Carbon Monoxide Control.
- Control of Temperature of Flue Gas Entering the APCD.

Air Moving Components

- Forced Draft (FD) fan
  Provides/controls combustion air flow.
- Induced Draft (ID) fans (on some units)
  - Keeps furnace at negative pressure.
  - ID fan controlled in unison with FD fan.
- Air heaters are used to capture energy from flue gas, thereby improving efficiency.
- Note: Pressures decrease in the flow direction, from FD fan to ID fan and ID fan to stack.

Methods of Controlling Air Flow

- Inlet damper (throttle)
- Variable swirl vane
- Variable V-belt drive pulley
- Variable - speed motor
  Adjustable frequency control

Centrifugal Fan with Inlet Vane Dampers
**Steam Generator Components**
- Boiler feed pump
- Economizer
- Steam drum
- Steam generator
- Downcomers
- Mud drum
- Superheater
- Makeup water
- Attemperator
- Blowdown

**Steam Turbine Systems**
- Components
  - High pressure turbine
  - Low pressure turbine
  - Reheat superheater
  - Condenser
- Efficiency
  - Sensitive to inlet temperature
  - Deteriorates with wear

**Factors Affecting Steam Temperature**
- Size of the superheater.
- Deposits on heat exchanger surfaces.
- Type of fuel.
- Excess air levels.
- Boiler load.
- Burners in service.

**Ash Handling**
- Boiler Surface Deposits
- Bottom and Fly Ash Management
- LOI and Introduction to Ash Chemistry

**Partitioning of Solid Residues**

<table>
<thead>
<tr>
<th>Combustion System</th>
<th>Example Weight %</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Bottom Ash</td>
</tr>
<tr>
<td>Pulverized Coal</td>
<td>10-30</td>
</tr>
<tr>
<td>RDF Spreader Stoker</td>
<td>30</td>
</tr>
<tr>
<td>Coal Spreader Stoker</td>
<td>60</td>
</tr>
<tr>
<td>Coal Cyclone</td>
<td>60-85</td>
</tr>
<tr>
<td>MSW Mass Burn - Grate</td>
<td>75-90</td>
</tr>
<tr>
<td>MSW Starved Air - Hearth</td>
<td>98</td>
</tr>
</tbody>
</table>
Boiler Surface Deposits
- Fuels & fuel ash characteristics.
- Surface deposits:
  - Soot
  - Slag
  - Clinkers
- Formation and Accumulation:
  - Chemical influences.
  - Operating conditions.

Deposit Control Methods
- Coal purchase specifications
- Removal:
  - Soot Blowing
  - Physical Slag Removal.
- Limit the load

LOI and Introduction to Ash Chemistry
- Ash carbon content (LOI)
  - High carbon content (>5%) wastes fuel and prevents beneficial use.
- Residence time & particle size vs carbon.
- Ash Chemistry
  - Volatile elements found in fine particles.

Other Ash Properties
Ash Color.
Ash Fusion Temperature.
Deposits Act as Insulation.
Inorganic Vapors Condense on Ash.
Ash Can Melt and Freeze.

Ash Treatment & Utilization
Treatment Before Disposal
- Chemical Extraction
- Chemical Additives
- Compaction
- Vitrification
Create Useful End-Products
- Road-Bed Aggregate
- Landfill Cover
- Ash/Concrete Blocks

Chapter Summary
- Types of combustion sources
- Conversion to mechanical energy
- Boilers
- Electric Power Plants
- Fuel and Air Flow
- Control Systems
- Waste heat
- Emission control
- Fuel Storage, Handling, and Processing
- Fly ash
Evolution of MWC Designs

- Single Chamber, Flue-Fed
- Multiple Chamber
- Refractory Wall Incineration
- Mass Burn Waste-to-Energy
- Modular
- RDF Waste-to-Energy

Refractory-Wall, Mass Burn

- High Excess Air
- High Gas Velocities
- Particle Entrainment
- Smoke
- Shut Down in Late 1970s

Refractory Wall Incinerator

Waterwall Mass Burn

- Waste-to-Energy
- European Designs
- ESP for Particulate Control

European Waterwall Incinerator Design

Waterwall Design Concept
Refractory Coated Waterwalls

Excess Air Ranges, Efficiency is reduced with higher EA.

Table 4-1. Typical Minimum Excess Air Levels

<table>
<thead>
<tr>
<th>Type of Combustion</th>
<th>Excess Air %</th>
<th>% Oxygen</th>
</tr>
</thead>
<tbody>
<tr>
<td>Suspension firing: oil, gas, pulverized coal</td>
<td>5-15%</td>
<td>1-3%</td>
</tr>
<tr>
<td>Cyclone (crushed coal)</td>
<td>10-15%</td>
<td>2-3%</td>
</tr>
<tr>
<td>Stoker grate: coal, wood, solid waste</td>
<td>30-75%</td>
<td>5-9%</td>
</tr>
<tr>
<td>Fluidized bed</td>
<td>5-150%</td>
<td>1-13%</td>
</tr>
<tr>
<td>Combustion Turbine</td>
<td>250%</td>
<td>15%</td>
</tr>
<tr>
<td>Lean burn reciprocating engine</td>
<td>&gt;5%</td>
<td>&gt;1%</td>
</tr>
</tbody>
</table>

Rotary Waterwall Mass Burn

- Mass Burn or RDF Fired
- Rotary Waterwall Section
- Fixed Waterwall Section

Modular Mass Burn

- Factory Manufactured
- Refractory-Wall
- Controlled-Air, Starved-Air

Starved-Air Units

Two Stage Combustion
Primary Chamber: Gasifier
- Sub-Stoichiometric Combustion
- Gasification of Solid Wastes
- Low Velocities
- Low Particle Entrainment
- More Air Increases Temperatures
Secondary Chamber: Gas Burning
- Excess Air Combustion
- More Air Decreases Temperatures
RDF Units

- Waste Processing of RDF.
- Utility Pulverized Coal Units:
  Suspended Firing.
- Spreader Stoker Units:
  Suspension & Grate Burning.
- Co-Firing with Coal.
Chapter 5, Air Pollution Formation

1. Introduction
2. Acid Gases
3. Particulate Matter
4. Metals
5. Nitrogen Oxides
7. Opacity

Introduction

- Types of Pollutants
- Actual Emission Rates
- Potential Emission Rates
- Clean Fuels

Types of Pollutants

- Products of Incomplete Combustion (PIC)
- Acid Gases
- Pollutants resulting from inorganic contaminants in the fuel
- NOx
- Ozone, PM2.5

Actual Emission Rates

- Measurements
- Mass balances
  - Gives an upper limit
- AP-42
  - Generic, not specific

AP-42: Emission Factors

- USEPA, Technology Transfer Network: Clearing House for Inventory and Emission Factors (CHIEF).
- World Wide Web, URL Code:
  
  http://www.epa.gov/ttn/chief/ap42/index.html

Potential Emissions

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Fuel Concentration</th>
<th>Pollutant Concentration</th>
<th>Primary Method of Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>0 - 2%</td>
<td>1 - 4%</td>
<td>SO2</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>H2O</td>
</tr>
<tr>
<td>Ash</td>
<td>&lt;0.01%</td>
<td>1%</td>
<td>Particulate</td>
</tr>
<tr>
<td>Nitrogen</td>
<td>&lt;1%</td>
<td>1%</td>
<td>NOx</td>
</tr>
<tr>
<td>Chloride</td>
<td>(low)</td>
<td>(low)</td>
<td>HCl</td>
</tr>
<tr>
<td>Sulfur</td>
<td>98%</td>
<td>85%</td>
<td>CO, CO2, HC</td>
</tr>
</tbody>
</table>

Notes:
[1] SO2 in the fuel does not convert to SO3 or sulfuric acid.
[2] Only organic nitrogen contributes to NOx formation.
Clean Fuels

- Natural gas
  - Clean burning
  - Benefits catalysts
  - Significant pollutants

- Distillate oil
  - Some sulfur content
  - No premixed combustion

Acid Gases

- Sulfur Oxides
- Hydrochloric Acid

USA SOURCES OF SULFUR DIOXIDE, 2010

<table>
<thead>
<tr>
<th>Source</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Utility Power Plants</td>
<td>64.0%</td>
</tr>
<tr>
<td>Other Fuels Combustion</td>
<td>23.2%</td>
</tr>
<tr>
<td>Industrial Processing</td>
<td>9.9%</td>
</tr>
<tr>
<td>Off-Road Engines and Vehicles</td>
<td>1.7%</td>
</tr>
<tr>
<td>Natural Fires</td>
<td>0.8%</td>
</tr>
<tr>
<td>On-Road Engines and Vehicles</td>
<td>0.4%</td>
</tr>
<tr>
<td>(Railroad, ships, aircraft, farm, construction, industrial)</td>
<td></td>
</tr>
</tbody>
</table>

Potential Emission Rates

Consider various fractions of conversion of contaminant into pollutants. Use eqn 5-1:

\[
\text{lb pollutant} = \frac{\text{lb contaminant}}{\frac{\text{mmBTU}}{\text{BTU}} / 10^7} \times \text{% contaminant/100}
\]

Example 5-1. Potential emissions

- Determine the potential SO₂ emission rate for 3% sulfur coal with HHV = 12,000 BTU/lb.

\[
0.03 \left( \frac{\text{lb SO₂}}{\text{lb coal}} \right) \times \frac{64}{32} \left( \frac{\text{lb of SO₂}}{\text{mmBTU}} \right) = 0.012 \left( \frac{\text{mmBTU}}{\text{lb coal}} \right)
\]

Fuel Sulfur Conversion

Sulfur Oxidation

\[\text{Fuel S} \xrightarrow{\text{Combustion Zone}} \text{SO₂ (gas)} \xrightarrow{98\% \text{ to the stack}} \text{H₂SO₄ (liquid)} \xrightarrow{\text{Cooling below -260°F}} \text{H₂O \cdot nH₂SO₄} (\text{solid}) \xrightarrow{\text{Cooling to ambient temperature}} \text{H₂O \cdot dilute H₂SO₄} \]
Problem: Find the max. S for an oil with an HHV of 18,100 Btu/lb and an emission limit of 0.6 lb SO₂/10⁶ Btu.

\[
E = \frac{64 \text{ lb SO}_2 \cdot S}{32 \text{ lb oil}} = \frac{2 \text{ S lb SO}_2}{\text{ lb oil}}
\]

\[
E = \frac{2 \text{ S lb SO}_2 / \text{ lb oil}}{18,100 \text{ [Btu/lb oil]}} = 0.6 \text{ lb SO}_2
\]

\[
S_{\max} = \frac{0.6 \text{ lb SO}_2}{10^6 \text{ Btu}} \cdot \frac{18,100 \text{ [Btu/lb oil]}}{2} = 0.0054 \text{ lb S/lb oil}
\]

\[
S_{\max} = 0.54\%
\]

**Conversion of Fuel Sulfur to SO₃**

- Small but uncertain
- Excess air influence
- Vanadium influence

**Ambient Sulfur Reactions**

\[
\text{SO}_2 + \text{H}_2\text{O} \Rightarrow \text{H}_2\text{SO}_3
\]

\[
2 \text{H}_2\text{SO}_3 + \text{O}_2 \Rightarrow 2 \text{H}_2\text{SO}_4
\]

\[
2 \text{SO}_2 + \text{O}_2 \Rightarrow 2 \text{SO}_3
\]

\[
\text{SO}_3 + \text{H}_2\text{O} \Rightarrow \text{H}_2\text{SO}_4
\]

**Example 5-2.**

If 2% of the sulfur in oil with 1.5% S is converted to SO₃, what is the flue gas concentration?

Solution: (a) Determine SO₃ emission rate (lb/mmBTU)

\[
\frac{0.015 \text{ lb S}}{0.0185 \text{ lb S/mmBTU}} \times \frac{80 \text{ lb SO}_2}{32 \text{ lb S}} \times 2\% = 0.0405 \text{ lb SO}_3 / \text{mmBTU}
\]

**Example 5-2.**

Convert this to ppm (wet) by volume

\[
0.0405 \left( \frac{\text{ lb SO}_3}{\text{ mmBTU}} \right) \times \frac{10,500 \text{ ft}^3 \text{ flue gas}}{80 \text{ lb SO}_2} = 18.6 \times 10^4 \text{ ppm SO}_3
\]

Correct this for a dilution level (3% O₂)

\[
18.6 \text{ ppm} \times \frac{20.9\% - 3\%}{20.9\%} = 15.8 \text{ ppm SO}_3 @ 3\% \text{ O}_2
\]
Sulfuric Acid Effects

- Plume impacts:
  - Regional visibility
  - Downwash

- Corrosion:
  - Damage
  - Fallout (deposition)

Equation For Acid Dew-Point:

\[
\frac{1,000}{T_{DP}} = 1.7842 + 0.0269 \left( \log P_{H_2O} \right) - 0.1029 \left( \log P_{SO_3} \right) + 0.0329 \left( \log P_{H_2O} \right) \left( \log P_{SO_3} \right)
\]

Where \( T_{DP} \) is in [degrees Kelvin] and gas pressures are in [atm].


Acid Dew Point vs Moisture & SO₃

Sulfuric Acid Dew Point

Review Exercise 5-2: Sulfur dioxide emissions from burning oil

Given: HHV = 18,500 Btu/lb oil

\[ S = \frac{0.01 \text{ lb S}}{\text{lb oil}} \]

\[ E = \frac{64 \text{ lb SO}_2 \cdot S}{32 \text{ lb S}} \cdot \frac{\text{lb S}}{\text{lb oil}} = 2S \frac{\text{lb SO}_2}{\text{lb oil}} \]

\[ E = 2S \left[ \frac{\text{lb SO}_2}{\text{lb oil}} \right] = 2 \cdot 0.01 \text{ lb SO}_2 \]

\[ \frac{E}{\text{HHV}} = \frac{1.08 \cdot 10^{-6} \text{ lb SO}_2}{\text{Btu}} = 1.08 \text{ lb SO}_2 \cdot 10^6 \text{ Btu} = 1.08 \text{ lb SO}_2 \cdot \text{mm Btu} \]
Review Exercise 5-6:
Max. flyash emissions from burning coal

Given: $\text{HHV} = 10,900 \text{ Btu/lb coal}$

$A = \frac{0.126 \text{ lb ash}}{\text{lb coal}}$

$E_{\text{max}} = A \frac{\text{lb ash}}{\text{lb coal}}$

$E = \frac{0.126 \text{ [lb ash / lb coal]}}{10,900 \text{ [Btu/lb coal]}} = 11.56 \cdot 10^{-6} \frac{\text{lb flyash}}{\text{Btu}}$

$E = \frac{11.6 \text{ lb flyash}}{10^6 \text{ Btu}} = 11.6 \frac{\text{lb flyash}}{\text{mm Btu}}$

---

Review Exercise 5-8:
Max sulfate emissions from burning oil

Given: $\text{HHV} = 18,100 \text{ Btu/lb oil}$

$S = \frac{0.009 \text{ lb S}}{\text{lb oil}}$

$0.025 \text{ S} \Rightarrow \text{Sulfate, SO}_4$

$E = \frac{96 \text{ lb SO}_4 \cdot 0.025 \cdot S}{32 \text{ lb S}} \frac{\text{lb S}}{\text{lb oil}} = \frac{0.075 \cdot S \text{ lb SO}_4}{\text{lb oil}}$

$E = \frac{0.075 \cdot S \text{ [lb SO}_4 / \text{lb oil]}}{18,100 \text{ [Btu/lb oil]}} = \frac{0.075 \cdot 0.009 \text{ lb SO}_4}{18,100 \text{ Btu}}$

$E = \frac{3.7 \cdot 10^{-5} \text{ lb SO}_4}{\text{Btu}} = \frac{0.037 \text{ lb SO}_4}{10^7 \text{ Btu}} = \frac{0.037 \text{ lb SO}_4}{\text{mm Btu}}$
**Particulate Matter**

- Particle Formation – two groups
  - Large Particles (mass)
  - Fine Particles (visibility)

- Enrichment of Some Chemicals in Fine Particles.

- Mass Emission Transients from Soot Blowing.

**Particle Formation - Large Particles**

- Volatiles Burn
- Coke Burns
- Coal Particle or Oil Droplets Evaporate
- Coke (Carbon)

**Particle Formation - Fine Particles**

- Formation mechanism

- 0.5 micron “limit:” Larger particles do not undergo Browning Motion, so these particles are generally too large for additional agglomeration.

**Pulverized Coal Particulates**

- Size
- Process
- Combustion residence time

**Flyash from Pulverized Coal Combustion**

**Example 5.3**

- Determine the particulate emissions from a PC furnace burning coal with 9% ash and 12,500 Btu/lb. Assume 10% retained as bottom ash and no controls.

**Solution:**

\[
\frac{0.9 \cdot 0.09 \text{ lb ash}}{1 \text{ mmBtu}} = 6.48 \frac{\text{lb part}}{\text{mmBtu}}
\]
#6 Oil Emissions

- #6 fuel oil droplets > 200 micrometers (> 0.2 mm) will require more than 1 second residence time for complete combustion, so incomplete combustion typically occurs.

- Particulate result from Ash and Sulfate

- Carbon forms include Coke and Soot (smoke).

Diffusion & Premix Flames

- Diffusion flames have variable mixing of fuel & air during the combustion process.

- High peak temperatures of diffusion flames (e.g., at equivalence ratio =1, Fig. 4-5) cause incandescent carbon particles.
  - Yellow Flame Combustion.

- Some sources (e.g., gas-fired appliances, gasoline engines) premix fuel & air before combustion.
  - Blue Flame Combustion.

- Premix combustion temperatures depend on the Air/Fuel Equivalence ratio (Fig. 4-5).

- Premixing avoids hot spots.

Smoke & Particulates

- Black Smoke
  - Carbon in Particulates

- Brown Smoke
  - Nitrogen Oxides

- White Smoke
  - Condensed Hydrocarbon Gases
  - Ammonium Chloride
  - Water Droplets (Not Smoke)

- Blue Smoke
  - Condensed Hydrocarbon Gases
  - Sulfate, (e.g., Ammonium Sulfate, SO$_3$ Mists)

Sulfuric Acid and Sulfate Particulate

- Coal-fired sulfate
- Oil-fired sulfate

Formation factors:
- Fuel sulfur content
- Vanadium
- Excess air
- Can deposit on flyash as flue gas temperatures drop.

Example 5.4

- A boiler burns #6 fuel oil with 1.4% sulfur and 18,500 Btu/lb. How much particulate is formed if 2% of the sulfur is oxidized to sulfate?

Solution:

\[
\frac{0.02 \cdot 0.014}{18,500} \cdot \frac{96 \text{ lb SO}_4}{\text{lb oil}} \cdot \frac{32 \text{ lb S}}{1 \text{ mmBtu}} = 0.045 \frac{\text{lb part}}{\text{mmBtu}}
\]
Enrichment of Some Elements in Fine Particles

<table>
<thead>
<tr>
<th>Element</th>
<th>Antimony</th>
<th>Cadmium</th>
<th>Chromium</th>
<th>Copper</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Osium</td>
<td>Nickel</td>
<td>Polassium</td>
<td>Selenium</td>
</tr>
</tbody>
</table>

Mass Emission Transients from Soot Blowing

- Most emissions are emitted directly
- Ash accumulation
- Soot blowers
  - Purpose
  - Typical operations
  - Air pollution impacts

Metals

- Volatility of Metals and Compounds
  - Determines fine or course particle size
  - Affects health risk
- Mercury

Volutility of Metals and Compounds

- Examples – Table 5-3
- Vapor species: Vapor pressure
- Chloride compounds

Metal Pathways in Combustion Units

High Melting Point (Non-Volatile) Metals
- Form Oxides, Chlorides, Sulfides
  - Remain in the Solid Residue (Ash)

Low Melting Point (Volatile) Metals
- Form Liquids which Solidify when Cooled
- Form Vapors which Condense when Cooled
- Are Adsorbed onto Fly Ash or Carbon or Remain as a vapor.

Mercury

- Combustion emissions – vapor phase
- Emission sources:
  - Municipal waste combustors
  - Coal-fired boilers
- Chemical forms
- Environmental fate
Mercury in the Environment

Forms of Mercury Emissions:
- Elemental (liquid & vapor)
- Oxidized (inorganic compounds)
  - e.g., mercuric chloride, mercuric sulfide
- Organic (formed by microorganisms)
  - e.g., methylmercury, ethylmercury
  - Bioaccumulates
  - Pathway to humans: consumption of contaminated fish.
  - Toxic to pregnant women, unborn & children.

Environmental Mercury Sources

- Naturally Occurring Emissions
  - Volcanoes, forest fires, & soil erosion.
  - Volatization from soil & water surfaces.
    - Natural & Re-emission.
- Anthropogenic (manmade) Emissions
  - Combustion
    - Coal-fired power plants.
    - Waste combustors.
  - Industrial sources (e.g., oil refining, boilers, electric arc furnaces, chlorine mfg.).

Control Strategy for Mercury

- Provide for Condensation and Adsorption
  - Inject Activated Carbon Powder
  - Limit APCD Temperatures
- Collect Mercury in the Particulates

Example 5-5. Mercury emissions

Determine daily mercury emissions for an 800-megawatt power plant. Plant heat rate is 9,900 BTU/kw-hr with a 60% utilization factor. It burns coal with 0.13 ppm mercury and HHV = 11,900 BTU/lb.

Solution:
(a) Determine emissions rate

\[
0.13 \times 10^{-6} \left( \frac{\text{lb Hg}}{\text{lb coal}} \right) \times 0.0119 \left( \frac{\text{mmBTU}}{\text{lb coal}} \right) \times 10.9 \times 10^{-6} \left( \frac{\text{lb Hg}}{\text{mmBTU}} \right)
\]

(b) Determine daily energy use:

\[
800,000 \times \frac{\text{NTU}}{\text{kw-hr}} \times 60\% \times 24 \left( \frac{\text{hr}}{\text{day}} \right) = 114,048 \left( \frac{\text{mmBTU}}{\text{day}} \right)
\]

(c) Multiply energy use x emissions rate:

\[
10.9 \times 10^{-6} \times 114,048 = 1.24 \text{ lb/day Hg emissions}
\]
Formation of Nitrogen Oxides

1. Overview of NOx.
2. Thermal NOx Formation.
3. Fuel NOx Formation.
4. Premixed and Diffusion Combustion.
5. NOx from Typical Combustion Systems.

USA SOURCES OF NITROGEN OXIDES, 2010

On-Road Engines and Vehicles: 31.3%
(Automobiles and Trucks)
Off-Road Engines and Vehicles: 19.6%
(Railroad, ships, aircraft,
farmland construction, industrial)
Other Fuels Combustion: 19.2%
Utility Power Plants: 17.4%
Industrial Processing: 9.6%
Miscellaneous: 2.9%

Overview of NOx

- NOx = sum of the NO2 and NO.
- Other oxides
- Ozone formation (photochemistry)
- All combustion makes some NOx:
  \[ \text{N}_2 + \text{O}_2 \leftrightarrow 2\text{NO} \]
- Ambient concentrations

Nitrogen Oxides

- Nitric Oxide (NO)
- Nitrogen Dioxide (NO2)
- Nitrous Oxide (N2O)
- Nitrogen Trioxide (N2O3)
- Nitrogen Pentoxide (N2O5)

NOx Environmental Concerns

Photochemical Smog
- Impairs Human Health, Respiration.
- Stunts Growth of Vegetables.
- Oxidizes Materials.

Acid Rain
- Damage to Structures.
- Damage to Water Quality & Fish Life.
- Sudden Release of Acids.

Ambient Concentrations of NOx
- Increases Resistance to Respiration.
- Disease (e.g., bronchitis, pneumonia).

Generalized Photochemical Reaction Equations

\[ \text{NO}_2 + \text{Solar Energy} \rightarrow \text{NO} + \text{O} \]
\[ \text{O} + \text{O}_2 \rightarrow \text{O}_3 \]
\[ \text{O}_3 + \text{NO} \rightarrow \text{NO}_2 + \text{O}_2 \]
\[ \text{O}_3 + \text{C}_x\text{H}_y \rightarrow \text{Stable Products} + \text{Radicals} \]
\[ \text{O}_3 + \text{C}_x\text{H}_y \rightarrow \text{Stable Products} + \text{Radicals} \]
Radicals + C_xH_y \rightarrow Stable Products + Radicals
Radicals + NO \rightarrow Radicals + NO_2
Radicals + NO_2 \rightarrow Stable Products
Radicals + Radicals \rightarrow Stable Products
Control Approaches

Two approaches:
- Combustion modification.
- Flue gas (back-end) control.

Formation of NOx

- FUEL NOx:
  Chemically-Bound Nitrogen in Fuel Combines with Oxygen.
  (Generally << 50% nitrogen $\rightarrow$ NO)

- THERMAL NOx:
  High Temperature Reaction of Oxygen and Nitrogen from Air.
  (Generally <<2% nitrogen $\rightarrow$ NO)

- Prompt NOx (Formation is unclear).

NOx Formation: Fuel Nitrogen

- Fuel impacts on NOx
  - Amount formed
  - Applicable control techniques

  - Upon combustion, the “fixed nitrogen” in the fuel can:
    - React with oxygen to form NO, or
    - React with another N atom to form $N_2$

- Fuel NOx is the primary formation mechanism for boilers (not for engines or gas fired boilers).

Averaged Emissions

Note: Table 5-4 shows a wider range of NOx emission factors.

<table>
<thead>
<tr>
<th>Combustion Source</th>
<th>AP-42 Units</th>
<th>Heat Input Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Combustion Turbine</td>
<td>67.3 lb/1000 gal fuel</td>
<td>0.6 lbmmBTU</td>
</tr>
<tr>
<td>Diesel Engine</td>
<td>550 lb/1000 gal fuel</td>
<td>3.1 lbmmBTU</td>
</tr>
<tr>
<td>Utility Boileriring No. 6 Oil</td>
<td>67.9 lb/1000 gal fuel</td>
<td>0.46 lbmmBTU</td>
</tr>
<tr>
<td>Commercial Boileriring No. 2 Oil</td>
<td>20 lb/1000 gal fuel</td>
<td>0.15 lbmmBTU</td>
</tr>
<tr>
<td>Pulverized Coal Boiler</td>
<td>3.1 lb/1000 coal</td>
<td>0.01 lbmmBTU</td>
</tr>
<tr>
<td>Wood Fireplace</td>
<td>1.9 lb/1000 wood</td>
<td>0.15 lbmmBTU</td>
</tr>
</tbody>
</table>

Example 5-6. Fuel NOx

A utility fires coal with 1.3% N and HHV = 13,200 Btu/lb. Find the of potential NOx emissions from fuel N (assuming worst case: all N $\rightarrow$ NO$_2$).

Solution:

$$\frac{0.013 \text{ lb N}}{0.0132 \text{ lb coal}} \times \frac{46 \text{ lb NO}_2}{14 \text{ lb N}} = 3.2 \text{ lb NO}_2\text{ mmBTU}$$

Note: NO will eventually oxidize to NO$_2$. 

13-2
Example 5-6. Fuel NOx (Better)

A utility fires coal with 1.3% N and HHV = 13,200 Btu/lb. Find the of potential NO emissions from fuel N (assuming 50% of fuel N \( \rightarrow \) NO, but none to NO\(_2\)).

Solution:

\[
\frac{0.5 \cdot 0.013 \text{ lb N}}{\text{lb coal}} \cdot \frac{30 \text{ lb NO}}{14 \text{ lb N}} = 1.05 \frac{\text{lb NO}}{\text{mmBtu} / \text{lb coal}}
\]

Note: NO will eventually oxidize to NO\(_2\).

Typical Fuel Nitrogen

Table 5-5. Typical Fuel Nitrogen Content

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Nitrogen (% by wt.)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>0.5 - 2</td>
</tr>
<tr>
<td>Residual Oil</td>
<td>0.3 - 0.6</td>
</tr>
<tr>
<td>No. 2 Oil</td>
<td>&lt; 0.1</td>
</tr>
</tbody>
</table>

Premixed vs Diffusion Flames

- Diffusion Flames (yellow)
  - Typical of most combustors
- Premixed Flames (blue)
  - Gas & gasoline reciprocating engines
  - Some low NOx combustors
- Temperatures of premixed & diffusion flames (Fig. 4-5)
- NOx formation depends upon O\(_2\) concentration.

NO\(_x\) from Typical Combustion Systems

- History of NOx control
  - Combustion modification versus flue gas control (back end).
- Combustor categories
  - Boilers and Furnaces (continuous).
  - Reciprocating Engines (cyclic).
  - Combustion Turbines (continuous).
- Emissions vary directly with load.
**NO\textsubscript{x} from Boilers and Furnaces**

- Operate best under constant load with steady combustion temperatures.
- Air & fuel flow control:
  - Matching air to fuel.
  - More excess air \(\rightarrow\) More NO\textsubscript{x}
  - Trade off: PIC vs NO\textsubscript{x} (Fig. 5-9).

**Fuel Effects on Boiler Emissions**

- Thermal NO\textsubscript{x} is mainly from:
  - Natural gas
  - Distillate oil
- Fuel NO\textsubscript{x} is mainly from:
  - Residual oil
  - Coal
  - Wood
  - MSW

**NO\textsubscript{x} from Reciprocating Engines**

- Cyclic temperatures & pressures.
- NO\textsubscript{x} emission levels vary with the stoichiometry of pre-mixed air/fuel mixtures (Fig. 5-10).
- Diesel versus gasoline engines:
  - Diffusion vs premix.
  - Lean burn vs Rich burn.
- Emissions trends.

**Combustion Turbines**

- Overview:
  - Aircraft derivative.
  - Continuous combustion (not cyclic, engine).
  - Traditional versus “low NO\textsubscript{x}” combustors.
- Fuel flexibility
- NO\textsubscript{x} emissions
  - Use of water injection.
  - Integration of engine & emission controls.
  - Ambient conditions.
Organic Products of Incomplete Combustion

1. Incomplete Combustion and Fuel-Air Mixing
2. Burner Geometry
3. Excess Air
4. Gas Incineration Temperatures
5. Dioxin-Furan Formation

Combustion Sources of Air Pollutants

- Fuel Dependent
- Combustion Quality Dependent
- Baghouse or Electrostatic Precipitator Temperature Dependent

Incomplete Combustion

- Products of Incomplete Combustion, (PIC)
  - Smoke & Particulates (e.g., carbon)
  - Carbon Monoxide (CO)
  - Volatile Organic Hydrocarbons (VOC).
  - Trace Organics: Dioxin/Furans.
- Startup & transient operation.
- CO used as surrogate for organics.

Elements of Complete Combustion

- Effective fuel-air mixing.
- Sufficient oxygen
- No quenching

3 T’s of Combustion

- Time (before quenching).
- Temperature.
- Turbulence (effective fuel air mixing; sufficient oxygen for the given fuel).

Excess Air (review)

- A basic requirement.
- Burner performance is characterized by LEA and appropriate mixing.
- Minimum & maximum excess air levels.
- Operating for low CO versus low NOx.
Burner Geometry

- Objective: Appropriate fuel-air mixing (no hot spots or un-mixed slip regions).
- Geometric design governs mixing:
  - Air flow pattern.
  - Fuel injection pattern.
- Good mixing → low PIC emissions.
- Low NOx combustion is more difficult.

Waste Incinerators

- Basic design is important
  - Minimize non-uniform combustion regions by appropriate mixing.
- Temperatures must be high enough.
- Appropriate residence time required.
- Good excess air control.

Dioxin-Furan Formation

- Dioxin (PCDD) and Furan (PCDF):
  - Stable & persistent.
  - Combustion generated.
- Toxicity (even very low levels are of concern).
- PIC formation requires:
  - Chlorine (aromatics).
  - Organic ring structure, (e.g., cellulose).
- Sources:
  - Poor combustion (transformer fires, forest fires)
**Dioxin & Furan Chemical Structures**

Example Dioxin (PCDD)

Example Furan (PCDF)

---

**Dioxin-Furan Formation**

- Formation in APCD
  - Temperatures above 500°F
  - Catalytic formation on ash from Cl₂ & organic PIC

- Avoidance methods:
  - Completely burn the fuel.
  - Cool flue gases before the particulate APCD

---

**Regulatory Basis for Dioxin/Furan Emission Limits**

Federal:
Total mass concentration of all Dioxins/Furans [ng/dscm].

Some States: Toxic Equivalent (TEQ) Limitation:
Determine mass of each isomer. Assigned Toxicity Level to each isomer. Multiply masses by Levels, and Add to obtain TEQ, [TEQ-ng/dscm] or [TEQ-gr/billion-dscf].

---

**Opacity**

- Regulatory background

- Method 9 (visual readings) versus Method 5 (stack test)

- Opacity vs. Particle Size

---

**Opacity vs. Emission Rate**

- Coal fired particulate emissions
- Residual oil-fired particulate
  - Mass emissions
  - Black plumes
  - White, brown, misc. plumes

- Sulfuric acid mist opacity.
Smoke & Particles

Black Smoke
- Carbon in particulates

Brown smoke
- Nitrogen oxides & particulates

White Smoke
- Condensed hydrocarbon vapors
- Ammonium chloride
- Water droplets (not smoke)

Blue Smoke
- Condensed hydrocarbon vapors
- Ammonium sulfate, SO₃ mists.

Conclusions

- Emission generating mechanisms
- Combustion influence on PIC and NOx
- Particulate emissions
  - Large particles
  - Fine particles

Chapter Summary

- Acid Gases
- Particulate Matter
- Metals
- Nitrogen Oxides
- Smoke, Carbon Monoxide & Organic Compounds
- Opacity
Chapter 6, Air Pollution Control

1. Introduction
2. Particulate Matter & Metal Emissions Control
3. Sulfur Oxides and Hydrogen Chloride Controls
4. Nitrogen Oxide Control
5. Carbon Monoxide & Organic Emissions

Introduction

- Pollutant formation:
  - Combustion zone formation, direct emission
  - \( \text{H}_2\text{SO}_4 \) and dioxins
- Emissions control:
  - Combustion zone
  - Flue gas cleaning
- Combination control devices
  - Bag house: acid gas capture
- Factors affecting emissions

Factors Affecting Emissions

- Fuel choices:
  - Heavy Metals,
  - NOx
  - \( \text{SO}_2 \)
- Fuel properties:
  - Catalyst (e.g., vanadium).
  - Precipitator performance
    (e.g., ash resistivity, sulfur, carbon).
  - Boiler slag
    (ash fusion temperature).
- Emissions control \( \rightarrow \) choices, trade-offs

Metal Pathways

High Melting Point (Non-Volatile) Metals:
- Form Oxides, Chlorides, Sulfides.
- Remain in the solid residue (ash).

Low Melting Point (Volatile) Metals:
- Form liquids which solidify when cooled.
- Form vapors which condense when cooled.
- Are adsorbed onto fly ash or carbon.
- Remain as vapor.

Control Strategy for Metal Air Pollutants

Provide for Condensation & Adsorption:
- Inject activated carbon powder.
- Inject alternative calcium-based vapor adsorbing powder.
- Control APCD temperature.

Collect the metals as particulates.

Types of Particle Collectors

- Collector choice depends on particle sizes, conditions, requirements.
- Four basic systems:
  - Inertial Collectors
  - Particulate Scrubbers
  - Fabric Filters
  - Electrostatic Collectors
  - Combinations
**Particle Motion vs. Gas Streamlines, Fig 6-1**

- Fine <0.5 microns
- Small 1-2 microns
- Large 5-10 microns

**Inertial Collectors, Fig 6-2**

- Applications
  - Industrial particle transport
  - Simple emissions control
- Collection efficiency
  - high only for large particles.
- Limitation – poor opacity control
- Factors affecting performance

**Particulate Scrubber: Venturi**

Comparative features:
- Collection performance
- Size
- Operating Cost, ΔP
- Waste water management
Example 6-1, Scrubber Water

A scrubber requires about 15 gpm of water per 1,000 cfm of inlet flow rate. The stack flow is 22,000 acfm @ 155°F. The scrubber inlet is 435°F at a pressure of 25 inches w.g.

How much water is required?

a. Determine the gas flow:

22,000 acfm * 435 °F / (155 °F + 460 °F) = 29.92 gpm

b. Determine water required:

\[ \frac{29.92 + 25}{13.6} = 30.163 \text{ acfm inlet} \]

\[ 15 \left( \frac{\text{gpm}}{\text{1000 cfm}} \right) * 30.163 \text{ cfm} = 452 \text{ gpm} \]

Fabric Filter Design & Operation

- Design Factor:
  - Air to Cloth Ratio \( \rightarrow \) Nominal Filtering Velocity
  - Cfm/ft\(^2 \rightarrow \) ft/min
- Collection efficiency approaches 100%.
- Similar to a vacuum cleaner.
- Cleaning:
  - Pulse jet
  - Reverse flow
- Pressure drop varies with filter cake.

Baghouse Filter Mechanism

- Filter cake collection:
  - Impaction.
  - Interception.
  - Diffusion.
- Filter materials:
  - Matching the dust.
  - Temperature limits.
Fabric Filter Failure Modes

- Bag life
- Dust accumulation
  - Temporary
  - Blinding

Baghouse Leak (torn bag) Detection

- Triboelectric Monitors (measures gas conductivity changes due to static electric charges from particles passing or impacting a probe).
- Electrostatic Charge Induction Monitors
- Opacity monitor – not sensitive
- Pressure drop – long term indicator

Baghouse Pressure Drop

- Variation over time
- Indicative of flow rate

- Example
  - $\Delta P$ drops 2% (not detectable).
  - If 1% flow leaks through holes ➔ Significant reduction in particle collection.

Example 6-2. Baghouse $\Delta P$

A new baghouse has a collection efficiency of 99.95%. The bags develop leaks where 0.7% of the gas bypasses the fabric. Determine the emissions increase and the $\Delta P$ decrease?

Solution:
The particulate emissions will increase from 0.05% to $(0.7 + 0.05) = 0.75\%$ of the inlet particulate. Emissions will be increased by a factor of: $(0.75/0.05) = 15$.

The gas flow through the baghouse is constant, but now $99.3\% = 100\% - 0.7\%$ of the gas passes thru the fabric. Therefore, $\Delta P$ will decreased by factor of $0.993^2 = 0.986$ or 1.3% less than the original $\Delta P$.

Baghouse Gas Temperature

- Indicator of potential for Dioxin/Furan catalytic formation on fly-ash (not other emissions).
- Low temperature:
  - Blinding (due to condensation).
- Severe high temperature excursions can cause:
  - Fires, complete failure.

Fabric Filter Operational Problems

- Low Pressure Drop: Over Cleaning.
- High Pressure Drop: Blinding
  Under Cleaning.
- Fabric Deterioration or Fires:
  - Improper Flue Gas Cooling
  - Surges of Burning Flue Gas
- Corrosion:
  - Improper Insulation.
  - Leaking Gaskets.
  - Improper Temperature Control.
  - Improper Air Dryer Operation.
Electrostatic Precipitator

- Relatively High Collection efficiency.
- Advantages – low ΔP, rugged.
- Reliable Operation.
- Simple Internal Components.

Types of ESPs

- Dry precipitators
  - Hot side
  - Cold side
- Wet precipitators
  - Seldom used.

Electrostatic Precipitator, Fig. 6-5

Electrostatic Precipitator

- Electrical control mechanism.
- ESP performance.
- Flow velocity & distribution.

Electro-Static Precipitator Features

ESP Corona & Collector Plate
Factors Influencing ESP Performance

- Specific Collection Area
  Area/Gas Flow Rate.
- Particle Size Distribution
- Gas Stream Properties
  Uniform Velocity Needed.
- Electrical Resistivity of Ash
  Temp. & Composition (Sulfur, Carbon).
- Physical Spacing
  Wire-to-Plate and Plate-to-Plate.

Collector Combinations

- Static electrical charging of flue gas particles upstream of a Fabric Filter.
- Combination Venturi and Packed Bed Scrubber applications for both particulates and gaseous emissions control.

Dust Collector Special Considerations

- APCD Fire Prevention:
  – Temperature controls (quench).
  – By-Pass stack.
- Operational Considerations:
  – Start up (preheat before operating).
  – Upsets (inflow of cold air: condensation).
  – Hopper blockages.

Oil Fired Particulate

- Emission levels
  – Usually no dust collector
  – 0.05 to 0.1 lb/million Btu
Acid Gas Control

- Historic approaches to SO\textsubscript{x} Control
  - Fuel Switching.
  - 1990 Clean Air Act Amendments.
  - Flue gas cleaning.

- SO\textsubscript{2} and HCl Control

Fuel Switching

- Sulfur emission limit vs fuel sulfur cap.
- Flue gas control vs fuel switching.
- Boiler limitations on fuel switching:
  - Coal to oil.
  - Oil to natural gas.
  - Bituminous to Sub-bituminous coal.

Flue Gas Desulfurization

- Types of acid gas scrubbers:
  - Wet: Packed Tower
  - Semi-Dry: Spray Dry Absorber, SDA
  - Dry Sorbent Injection, DSI

- Creates a liquid or solid waste
  - Requires treatment or disposal.

Example Acid Gas Reagent Reactions

- Lime: \( \text{CaO} + 2\text{H}_2\text{O} + \text{SO}_2 + 0.5\text{O}_2 \rightarrow \text{CaSO}_4 \cdot 2\text{H}_2\text{O} \)
- Slaked Lime: \( \text{Ca(OH)}_2 + \text{H}_2\text{O} + \text{SO}_2 + 0.5\text{O}_2 \rightarrow \text{CaSO}_4 \cdot 2\text{H}_2\text{O} \)
- Hydrated Lime: \( \text{Ca(OH)}_2 + 2\text{HCl} \rightarrow \text{CaCl}_2 + 2\text{H}_2\text{O} \)
- Sodium Bicarbonate: \( \text{NaHCO}_3 + \text{HCl} \rightarrow \text{NaCl} + \text{H}_2\text{O} + \text{CO}_2 \)
- Soda Ash: \( \text{Na}_2\text{CO}_3 + 2\text{HCl} \rightarrow 2\text{NaCl} + \text{H}_2\text{O} + \text{CO}_2 \)

Example Acid Gas Removal Efficiencies

<table>
<thead>
<tr>
<th>Equipment</th>
<th>HCl</th>
<th>SO\textsubscript{2}</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wet Scrubber &amp; SDA</td>
<td>95 - 99.9</td>
<td>90 - 99</td>
</tr>
<tr>
<td>Dry Sorbent Injection</td>
<td>90 - 99</td>
<td>60 - 85</td>
</tr>
</tbody>
</table>

Wet Scrubbers

- Principle (gas washing)
- Components
  - Contactor supplied equipment.
  - Waste water management
- Side effects
  - Mist carries out PM2.5 and H\textsubscript{2}SO\textsubscript{4}
Wet Scrubber Operations

- Absorption and Chemical Reactions.
- Recirculation of Caustic Solution.
- Blowdown for Removal of Salts.
- Maintenance of Scrubber pH.
- Control Inlet Temperature.
- Provide Required Pressure Drop.

Wet Scrubber Applications

Advantages
- Handles Gases & Particulates.

Disadvantages
- May Not be Able to Meet Standards.
- High Pressure Drop (Energy Cost).
- Liquid Residue Produced.
- Corrosion and Erosion of Metals.

Semi-Dry Scrubbers (Spray Dry Absorber, SDA)

- All water evaporates
- Dry exhaust
- Efficiency
- Many applications

Spray Dry Absorber System

1. LIME FEEDER
2. LIME SLAKER
3. FEED TANK
4. HEAD TANK
5. SPRAY ABSORBER
6. DUST COLLECTOR
7. STACK

Spray Dry Absorber - Fabric Filter

Boiler System with SDA & Fabric Filter
Spray Dryer Atomizer & Reaction Chamber

- Slurry Atomized to Fine Droplets:
  - High Speed Rotary Atomizer or
  - High Pressure Air Atomizer
- Reaction Chamber Provides Residence Time for Acid Absorption on the Slurry Droplets.
- Slurry Droplets are Dried by Hot Flue Gas.
- Flue Gases are Cooled by Evaporation.
- Particulates Collected by a Fabric Filter.

Spray Dryer Operational Considerations

Slurry flow keyed to acid gas concentration.
Adequate drying of droplets (Maintain atomizer).
Overall drying conditions:
- Exit dry bulb temperature,
- Exit wet bulb temperature,
- Exit dry bulb-wet bulb difference, or
- Inlet-exit dry bulb difference.
Slurry water content keyed to:
- Exit dry bulb temperature.
- Air leakage prevention.
- Maintenance of hopper temperatures.

Spray Dryer Operational Problems

1. Slurry Droplets Sticking on Wall
2. Liquid Carryover
3. Caking of Solids on Fabric Filter
4. Ash Hopper & Removal System Plugging

Dry Scrubbers (Dry Sorbent Injection, DSI)

- Dry chemistry – integral dust collector
- Reagent
  - Proprietary powders
  - Lots of effective surface area
- Performance
  - Fairly good for SO₄

Dry Scrubber – Dry Sorbent Injection

Dry Sorbent Operational Problems

Ash Removal from Collection Hopper
- Air Impactors.
- Vibrators.
- Hopper Heaters & Insulation.
- Maintenance of Air Seals.
Summary: SO\textsubscript{x} and HCl Control

- SO\textsubscript{x} issues
  - Wet scrubbers don’t work on small particles
  - Visible plume
  - Corrosive
  - Impact of downwash plumes
- Acid condensation
- Dry scrubbing reagent efficiency
- HCl – Higher collection efficiency than for SO\textsubscript{x}. 
Nitrogen Oxide Control

NOx controls:
Very low NOx possible when firing natural gas (higher emissions from other fuels).

1. Combustion Modifications
2. Premixed vs. Diffusion Flames
3. Flue Gas Control (Back End) Systems
4. Combinations

Combustion Modification for NOx Control

- Excess Air Control
  - Stoichiometric control in engines
- Flame Temperature Reduction
  - Including the use of heat sinks
- Staged Combustion
  - Over-fire air ports
  - Low NOx burners

Excess Air Control

- Always the 1st step.
- NOx formation depends on excess air.
- Trade off with CO & PIC.
- Air flow control requirements.

Low Excess Air Influences on NOx and CO

Non-Selective Catalytic Reduction (NSCR) in Reciprocating Engines

\[ \text{NO}_x + \text{CO} \rightarrow \text{N}_2 + \text{CO}_2 \]
\[ \text{NO}_x + \text{HC} \rightarrow \text{N}_2 + \text{H}_2\text{O} + \text{CO}_2 \]

- Uses a ceramic base with a thin layer of platinum catalyst.
- Requires precise fuel/air flow control, i.e., fuel injector applications, not carburetors.

Temperature Reduction for Control of Thermal NOx

- Formation varies with peak temperature.
- Once formed, NOx is “frozen” (limited reduction reactions, dissociation).
- Cooling methods (inject a heat sink):
  - Water (steam) injection
  - Cool air supply.
  - Gas recirculation.
  - Raise excess air (for premixed flames).
- Retard engine ignition to reduce temp.
Water Injection, Fig. 6-6

Water Injection Controls Thermal NOx

- Used to allow increased fuel combustion and thrust without knock (explosion) in military airplane engines in 1940s.
- Now used exclusively in gas turbines.
  - Small reduction in efficiency.
  - Practical
- Clean water (or steam) is required.

Flue Gas Recirculation, FGR Controls Thermal NOx

- Generally part of a “low NOx” package.
- Most effective with low nitrogen fuel.
- Induced FGR limited to low S fuel.
- Injection point varies with application.

Engine Ignition Timing Controls Thermal NOx

- Retarded ignition timing reduces an engine's peak combustion temperature.
- Power output reduced.
- NOx emissions are reduced. e.g., 20%-25% reduction.
Staged Furnace Combustion

- Stratified combustion:
  - Burners out of Service.
  - Reburning.

- Staged combustion:
  - Fuel rich (sub-stoichiometric) primary zone.
  - Fuel $\rightarrow N_2$; Temperature drops.
  - Air added for complete combustion in a secondary zone.
  - Success depends on uniformity, mixing.

Reburning

- Concept
  - Normal combustion zone (reduced load).
  - Reburn fuel above (remaining load).
  - Fuel takes oxygen from NOx.
  - Over fire-air to complete combustion.

- Low NOx means:
  - Longer, cooler flames.
  - Tendency to smoke.

Low NOx Burners

- Staging can be axial, radial, circumferential.

- Achieves variable fuel & air distributions:
  - First fuel rich (sub-stoichiometric),
  - Then fuel lean (excess air).

- Manufacturer provides control system to maintain precise air flow and mixing.

- Separate air flow and direction dampers.
Low NOx Burners, Like Fig. 6.11

Combination Gas-Oil Burner, Low NOx

NOx Control:
Premixed vs. Diffusion Flames

- Most burners are diffusion-type.
- Gas fuel is required for pre-mix combustion.
  - Natural gas has very low “fixed-N.”
- Premix allows lean, cool combustion.
  - Turbine combustor.
  - Reciprocating engine.

Fig. 6-12 Premix & Diffusion Flames, Theoretical Differences

Combustion Turbine Burner

- Water injection
- Dry-low NOx (lean premix) combustor
  - Startup challenge.
  - See Figure 5-10 (lean combustion).

Dry Low NOx Combustion, Fig. 6-13
Dry Low NOx Emissions

- Startup emissions
  - Simple cycle applications.
  - Combined cycle applications.
- Ambient conditions & corrections.
- Inlet fogging
- Engine fuel (emissions) control.

Reciprocating Engines

- NOx Control Methods
  - Ignition retard.
  - Modifying the air-fuel ratio.
  - Exhaust gas recirculation.
  - Combustion chamber modifications (gas fuel).
- Feasibility of lean operation.
Flue Gas NOx Control (Back End)

- Broad application
  - Large NOx reductions, but expensive.
- Reagent: Ammonia, Urea
- Reagent reaction methods
  - SNCR, higher temperature
  - SCR, lower temperature
- NOx + NH₃ → N₂ + H₂O
  - Flow control required.
- NSCR with Rich Burning (engines).

SNCR Exxon “Thermal De-Nox”

Selective Non-Catalytic Reduction, Fig. 6-17

Selective Non-Catalytic Reduction (SNCR)

- Narrow temperature window
  - Boiler applications
  - Load following challenge
- Mixing space
  - Complex injection grid
  - Limits retrofits
- 50%-70% reduction

SNCR Performance Factors

- Reagent Selection
- Temperature Region: 1,600 to 1,800°F
- CO Concentration
- Residence Time
- Reagent Injection Rate, Keyed to NO
- Gas Mixing Efficiency

Competing Reactions of Ammonia

Reduction:

4 NH₃ + 4 NO + O₂ → 4 N₂ + 6 H₂O
2 NH₃ + NO + NO₂ → 2 N₂ + 3 H₂O

Oxidation (Flue Gas too Hot):

NH₃ + 1.25 O₂ → NO + 1.5 H₂O

No Reaction (Cool Flue Gas, Ammonia Slip):

NH₃ → NH₃
Chemical Decomposition and Reactions of Urea, \( \text{CO(\text{NH}_2)_2} \)

\[
\text{CO(\text{NH}_2)_2} \rightarrow \text{NH}_3 + \text{HNCO} \\
\text{(Iso-Cyanuric Acid)} \\
\text{NH}_3 + \text{HNCO} + 2\text{NO} + 0.5 \text{O}_2 \rightarrow 2\text{N}_2 + \text{CO}_2 + 2 \text{H}_2\text{O}
\]

Urea-based “NOxOUT” SNCR Control System

Operational Problems with Selective Non-Catalytic Reduction (SNCR)

Furnace Temperature Variations
- Spacial and Temporal Variations.
- NO Increases when \( T > 2,000 \) °F.

Ammonia Slip:
- Ammonia Can React to Form Ammonium Chloride, White Smoke.

Selective Catalytic Reduction (SCR)

- Temperature window relaxed
  - Broad application (engines)
  - No “load following”

- Catalysts
  - Compatibility & lifetime
  - Size

- NOx reductions
Selective Catalytic Reduction (SCR)

Radiant Furnace & Part of Convection Section

Air Compressor

Mixing Chamber

Additional Convection Sections

Liquid NH₃

Vaporizer

Catalyst

Stack

T -> 700 to 900 °F

Selective Catalytic Reduction with Wet Scrubber

Selective Catalytic Reduction Fig. 6-18

Chesapeake Energy Center
Anhydrous Ammonia Tanks- Two 15,000 gallon Tanks

Water Spray Nozzles
Ammonia Detectors
Safety Shut-off Valves

Containment Dike

Kincaid SCR's
SCR Catalysts

- Precious metal (platinum)  $450^\circ - 550^\circ F$
- Vanadium/titanium catalysts  $550^\circ - 800^\circ F$
- Iron-Zeolite catalysts  $800^\circ - 1000^\circ F$

Non-Selective Catalytic Reduction
NSCR with Rich Burning

- Air flow control challenge
- Applications: engines.
- Control Efficiency.

NOx Controls: 4. Combinations

<table>
<thead>
<tr>
<th>Technology</th>
<th>Utility Boiler</th>
<th>Package Boilers</th>
<th>Steam Boiler</th>
<th>Combustion Turbine</th>
<th>Gas-fired Engine</th>
<th>Diesel Engine</th>
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<tr>
<td>Excess Air Control</td>
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<td>maple</td>
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<td>??</td>
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<tr>
<td>Flue Gas Recirc</td>
<td>yes</td>
<td>maybe</td>
<td>??</td>
<td>na</td>
<td>maybe</td>
<td>yes</td>
</tr>
<tr>
<td>Reductants</td>
<td>yes</td>
<td>??</td>
<td>yes</td>
<td>na</td>
<td>na</td>
<td>no</td>
</tr>
<tr>
<td>Water Injection</td>
<td>??</td>
<td>??</td>
<td>no</td>
<td>yes</td>
<td>maple</td>
<td>maple</td>
</tr>
<tr>
<td>DeSOx</td>
<td>na</td>
<td>na</td>
<td>na</td>
<td>na</td>
<td>yes</td>
<td>yes</td>
</tr>
<tr>
<td>SNCR</td>
<td>maybe</td>
<td>maybe</td>
<td>no</td>
<td>no</td>
<td>yes</td>
<td>no</td>
</tr>
<tr>
<td>SCR</td>
<td>yes</td>
<td>yes</td>
<td>yes</td>
<td>yes</td>
<td>yes</td>
<td>yes</td>
</tr>
</tbody>
</table>
Trade-offs with NO\textsubscript{x}

- Most low NOx combustors increase PIC.
- NOx limits can trigger CO limits.

Catalytic Control Systems

- Oxidation catalysts
  - Turbines & engines
  - Combined cycle systems
- Temperature range
- Destruction efficiency

Hydrocarbon Capture

- Dioxins/Furans
- Inject activated carbon powder.

Chapter Summary

- Particulate Matter & Metal Emissions Control
- Sulfur Oxides and Hydrogen Chloride Controls
- Nitrogen Oxide Control
- Carbon Monoxide & Organic Emissions
Efficiency Definitions & Applications

- Air Pollution Control Device Collection Efficiency.
- Combustion Efficiency.
- Thermal Efficiency.
- Power Plant Efficiency.
APCD Collection Efficiency

Efficiency: \( \eta = \frac{\text{output}}{\text{input}} \)

Collection Efficiency = \( \frac{\text{Mass Collected}}{\text{Mass Input}} \)

Minimum Required:

Collection Efficiency = \( \frac{\text{Input} - \text{Allowable}}{\text{Input}} \)

---

Efficiency of Various Systems

- Combustion Efficiency, based on CO => CO₂
  Supplemental Materials, Unit 8, Slide 8
- Thermal Efficiency, based on Energy

<table>
<thead>
<tr>
<th>System</th>
<th>Combustion Efficiency</th>
<th>Thermal Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>Boiler, gas-fired</td>
<td>100%</td>
<td>82%</td>
</tr>
<tr>
<td>Steam/Elec. Coal Power</td>
<td>95%</td>
<td>4%</td>
</tr>
<tr>
<td>Plant</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Simple Cycle Gas Turbine</td>
<td>100%</td>
<td>38%</td>
</tr>
<tr>
<td>Combined Cycle Gas Turbine</td>
<td>100%</td>
<td>55%</td>
</tr>
<tr>
<td>Cogeneration System</td>
<td>100%</td>
<td>50%-60%</td>
</tr>
</tbody>
</table>

---

Combined Cycle & Cogeneration Energy Systems

- Combustion turbine (or engine) generator.
- Recaptured waste heat applications:
  - Steam cycle generator.
  - Waste heat: depends upon a customer.
- Cogeneration.
  Difficult to match waste heat to electric load.

---

Thermal Efficiency, Eqn. 7.1

Loss due to CO

Derivation (page 7-4) uses HHV₇₀=315 Btu/scf
Note the use of the Equivalence Ratio.

\[
\% \text{ Energy Loss} = 0.00027 \cdot \text{ppm CO} \cdot \frac{20.9}{20.9 - \% \text{ O}_2}
\]

Where:
- ppm CO = CO concentration in E.G., dry basis
- \% \text{ O}_2 = Oxygen concentration in E.G., by volume, dry basis

---

Example 7-1, CO Heat Loss

How much heat is being lost out the stack of a natural gas-fired source, due to CO = 800 ppm when \( \% \text{ O}_2 = 4.2\% \)?

**Solution:**

Insert the values for CO and \( \% \text{ O}_2 \) into Equation 7-1.

\[0.00027 \cdot 800 \cdot \frac{20.9}{(20.9-4.2)} = 0.27\%

---

Thermal Efficiency, Eqn. 7.2

- Loss due to carbon in the ash

\[
\% \text{ Energy Loss} = \% \text{A} \times \% \text{C}/100 \times \frac{14100}{\text{HHV}}
\]

Where:
- \% \text{A} = coal ash content, % by wt.
- \% \text{C} = fly ash carbon content (LOI), % by wt.
- 14100 = heating value of pure carbon, Btu/lb
- HHV = heating value of the coal, Btu/lb
Example 7-2. Carbon heat loss

Fly ash from a coal fired source has 4% combustibles, and the coal has 11% ash and 12,700 Btu/lb.

What is the approximate energy loss?

Solution:

Insert the data in Equation 7-2.

\[ \text{11\%} \times \text{4\%} / 100 \times 14,100 / 12,700 = 0.49\% \]

Thermal Efficiency

\[ \% \text{ Thermal Efficiency} = \frac{\text{Useful Output Energy}}{\text{Energy Input}} \]

\[ \% \text{ Thermal Efficiency} = 100\% - \% \text{ Energy Losses} \]

Thermal Efficiency, Eqn. 7-3

Thermal Efficiency, Eqn. 7.4, page 7.7

Thermal Efficiency

- Water vapor energy loss term from equations 4-20 & 4-21 (page 4-33) or Slide 5-21 in the Supplemental Mats.

- Sensible heat loss term from equation 4-24 (page 4-35) or Slide 5-25 in the Supplemental Materials.

- Equation 7-4 is a simplification of the ASME test procedure (assumes only sensible & latent energy losses).

- See Example 7-3

Thermal Efficiency: Losses

1. Sensible losses of hot exhaust gases venting to atmosphere.

2. Heat of vaporization losses from venting uncondensed water to atmosphere.

3. Unburned fuel in either the exhaust gases or discarded ashes.

4. Radiation/convection losses from the outside walls of the furnace and cooling water losses (reciprocating engines).

5. Miscellaneous small losses such as the energy in hot ashes that are discarded.

Thermal Efficiency, Eqn. 7.4, page 7.7

Thermal Efficiency

\[ \text{Thermal Efficiency} = 100 \left( 1 - \frac{\Delta T}{4200} \right) \left( \frac{20.9 - \%O_2}{20.9 - \%O_2} \right) \left( \frac{0.49 \cdot \%H_2O}{100} \right) \left( \frac{20.9}{20.9 - \%O_2} \right) \]

\[ = 100 \left( 1 - \frac{\Delta T}{4200} \right) \left( \frac{20.9}{20.9 - \%O_2} \right) \left( \frac{0.49 \cdot \%H_2O}{100} \right) \]

Where:

\( \Delta T = \) Exhaust temperature minus ambient temp.

and

\%H_2O and \%O_2 are measured exhaust concentrations after the last heat exchanger.
Example 7-3. Thermal Efficiency

Determine the approximate efficiency of an oil-fired boiler where the stack temperature is 350°F, ambient temperature is 50°F, stack O₂ is 5% and stack water vapor content is estimated at 11%.

Solution:
Entering these values in Equation 7-4 gives:

\[
100 \times \left( 1 - \frac{350-50}{4200} \times \frac{20.9}{20.9-5} - 0.49 \times \frac{11}{100} \times \frac{20.9}{20.9-5} \right) = 83.5\%
\]

Example 7-4.

• How much energy is required to operate a 150-megawatt (MW) power plant with a heat rate of 10,200 Btu/kW-hr?

Multiply the output by the heat rate.
150,000 kW * 10,200 Btu / kW-hr = 1,530 mmBtu/hr

• What is the overall thermal efficiency?

Efficiency is the ratio of ideal energy reqd. to actual energy reqd.: 3,410 / 10,200 = 0.334 = 33.4%

Example 7-5. CO₂ Emissions

For a power plant that burns No. 6 oil at a rate of 1,530 million Btu/hr, what is the CO₂ emissions rate?

Solution:
Take the CO₂ emission rate from Table 7-2 and multiply by the heat input.

1,530 mmBtu/hr * 180 lb CO₂/mmBtu = 275,400 lb CO₂/hr

Power Plant Efficiency

• Large high-pressure boiler
  – Boiler efficiency (last example 84%).
• Overall heat rate = input/output
  Example power plant = 10,000 Btu/kW-hr
  Units conversion factor: 3,410 Btu/kW-hr
  Efficiency = output/input = 1/(PNHR)
  = 3,410 Btu/kW-hr/10,000 Btu/kW-hr
  Efficiency = 0.34 → 34%
• Air heaters are used to capture energy from flue gas, reducing stack ΔT, and thereby improving efficiency.

CO₂ Emissions, Eqn. 7-5

\[
\frac{\text{lb CO}_2}{\text{mmBtu}} = \frac{\% \text{ fuel C} \times 44}{100 \times \text{HHV/10}^6} \times \frac{12}{10^6}
\]

Table 7-2. CO₂ Typical Emission Rates

<table>
<thead>
<tr>
<th>Fuel</th>
<th>CO₂ lb/mmBTU</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas</td>
<td>120</td>
</tr>
<tr>
<td>No. 2 Oil, Diesel</td>
<td>165</td>
</tr>
<tr>
<td>No. 6 Oil</td>
<td>180</td>
</tr>
<tr>
<td>Bituminous Coal</td>
<td>185</td>
</tr>
<tr>
<td>Lignite</td>
<td>218</td>
</tr>
<tr>
<td>Carbon</td>
<td>260</td>
</tr>
</tbody>
</table>
Purpose of Instrumentation

1. Supervision of Operations
2. Automatic Control Signals
3. Management Data
4. Pollutant Emissions Surveillance

Monitored Parameters

- Temperatures:
  - Combustion.
  - Flue gas entering the APCD.
  - Steam.
- Pressure:
  - Steam.
  - Draft (vacuum pressure condition).
- Flow Rates:
  - Liquid flow rates (gpm).
  - Solid flow rates (pounds/hr).
  - Steam flow rates (Load).

Temperature Measurements

- Thermometer - Expansion of a Liquid.
- Dial Thermometer - Expansion of Metals.
- Thermocouple – Thermoelectric Potential.
- Thermistor/RTD – Electrical Resistance.
- Optical Pyrometer – Infrared Energy.
- Temperature Paint - Change of Color.
- Temperature Slides - Melt at Set Temp.

Thermocouple Temperature Measurement Equipment

Pressure Measurements

Manometers - Height of a Column of Liquid
  - U- Tube, Single-Leg, Inclined
  - Bourdon Tube Gages - Bending of a Curved Tube
Mechanical/Electrical Devices
  - Diaphragm Gages
  - Bellows Gages
  - Differential Pressure (DP) Cells
  - Linear Variable Dif. Transformers (LVDTs)

Bourdon Tube Gage
Manometer Pressure Measurement

Measurement of Fluid Flow

<table>
<thead>
<tr>
<th>Device</th>
<th>Application</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pitot Static Tube</td>
<td>Combustion Air Flow</td>
</tr>
<tr>
<td>Orifice Plate</td>
<td>High Steam &amp; Water Flow</td>
</tr>
<tr>
<td>(Large Pressure</td>
<td></td>
</tr>
<tr>
<td>Drop)</td>
<td></td>
</tr>
<tr>
<td>Venturi</td>
<td>High Steam &amp; Water Flow</td>
</tr>
<tr>
<td>(Small Pressure</td>
<td></td>
</tr>
<tr>
<td>Drop)</td>
<td></td>
</tr>
<tr>
<td>Propeller-Type</td>
<td>Medium Air &amp; Water Flow</td>
</tr>
<tr>
<td>Rotameter</td>
<td>Low Water Flow</td>
</tr>
</tbody>
</table>

Pitot Tube for Velocity Measurement

Orifice Plate - Pressure Difference

Emissions Variability

- Reasons for emission variations:
  - Load changes.
  - Start-up.
  - Fluctuations in fuel properties.
  - Operator implemented changes.
  - Natural short term fluctuations.
  - Changes in atmospheric conditions.

- Examples: NOx and PIC fluctuations.

Boiler Operating Load Influences

Units Are Designed for Maximum Temperatures and Pressures at Full Load (capacity).

Part Load Effects:
- Increase excess air requirements.
- Decreases combustion temperatures.

Operating Above the Rated Capacity:
- Reduces the combustion quality.
- Increased carbon monoxide emissions.
- Increases nitrogen oxide emissions.
Emission Fluctuations

Table 7-3. Typical Variation in Emission Rates

<table>
<thead>
<tr>
<th>Source and Cause of Variation: Time Scale</th>
<th>NOx</th>
<th>PIC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Boiler - operator instigated changes (1 hr)</td>
<td>±15%</td>
<td>± to Excessive</td>
</tr>
<tr>
<td>Boiler - natural draft fluctuations (15 sec.)</td>
<td>±5%</td>
<td>±50%</td>
</tr>
<tr>
<td>Reciprocating engine - atmospheric change (12 hr)</td>
<td>±5%</td>
<td>±10%</td>
</tr>
<tr>
<td>Gas Turbine - atmospheric changes (12 hr)</td>
<td>±10%</td>
<td>±10%</td>
</tr>
<tr>
<td>Waste combustor - waste properties (15 min)</td>
<td>±15%</td>
<td>±75%</td>
</tr>
</tbody>
</table>

Measurement Methods

- **Methods**
  - Continuous Emission Monitoring Systems (CEM)
  - Federal Reference Method Sampling Trains
  - Parametric Emission Monitoring (PEM)
- **Supporting data for direct measurements:**
  - O₂ or CO₂ concentration
  - Exhaust flow rate
  - Exhaust moisture content
  - Fuel flow rate or power output
  - Ambient conditions

Continuous Monitoring System (CEMS)

Extraction Type of Gas Analyzer

- Extraction of Gas Sample by a Probe.
- Removal of Particulates.
- Removal or Compensation for Water.
- Transport to Remote Detector / Analyzer.
- Conversion from Wet Basis to Dry Basis.

Continuous Emission Monitoring Systems (CEMS)

- Opacity
- Carbon Dioxide
- Oxygen
- Carbon Monoxide
- Sulfur Dioxide
- Nitrogen Oxides

Double Pass Opacity Monitor
CEMS Analyzer Requirements

- Routine Calibration
  - Zero Gas or Filter
  - Span Gas or Filter
- Zero Drift (daily)
- Calibration Drift (daily)
- Relative Accuracy Test Audit (RATA)
- Delivery System Bias Checks
  - Probe Blockage or Leaks

Stack Testing Methods

- Particulates: Methods 5 & 17
- Hydrogen Chloride: Method 26
- Multi-Metals: Method 29
- Dioxin/Furan: Method 23

Method 5 Particulate Sampling Train

Municipal Waste Combustor Parameters Monitored under Good Combustion Practice

Carbon Monoxide (Surrogate for dioxin/furan)
- Opacity: Not to exceed 10%
- Load: Not to exceed 110% of load of most recent dioxin test.
- Temperature of Flue Gas into APCD
  - Not to exceed by 30°F that of most recent dioxin test.
Solution to Pre-test Problem 33:

Correct gas concentration to $Y = 7\% \text{ O}_2$:

200 ppm $\text{SO}_2\text{,meas} @ \text{O}_2\text{,meas} = 9\%$

Eqn (7 - 6a):

$$\text{SO}_2 @ 7\% \text{ O}_2 = \text{SO}_2\text{,meas} \frac{20.9 - Y}{20.9 - \text{O}_2\text{,meas}}$$

$$\text{SO}_2 @ 7\% \text{ O}_2 = 200 \frac{20.9 - 7}{20.9 - 9} = 200 \cdot 1.168$$

$$\text{SO}_2 @ 7\% \text{ O}_2 = 234 \text{ ppm} > 200 \text{ ppm}$$

Solution to Pre-test Problem 34:

CO emissions in [lb/hr] units can be determined if you have concentration, actual stack flow rate & stack temperature. Answer is:

equation 7 - 8:

$$A \frac{\text{lb}}{\text{hr}} = \text{exhaust flow} \frac{\text{scf}}{\text{hr}} \frac{\text{ppmw A}}{1,000,000} \frac{\text{MW}_A}{385}$$

Example Conversion of CO₂ from a Wet Basis to a Dry Basis

Assume: $\text{CO}_2\text{,w} = 7.64\% \text{ CO}_2$ on a Wet Basis

$\text{H}_2\text{O}_\text{w} = 16.2\%$ which is equivalent to a Mole Fraction of 0.162

$$\text{CO}_2 \text{ (dry basis)} = \text{CO}_2\text{,w} \times \left[ \frac{1.0}{1.0 - \text{H}_2\text{O}_\text{w}} \right] = \frac{7.64\%}{1.0 - 0.162}$$

$$= \frac{7.64\%}{0.838} = 9.1\%$$

Example 7-6. Dilution correction

If measured NOx = 135 ppm and $\text{O}_2 = 4.7\%$,
Determine the NOx concentration corrected to 3% $\text{O}_2$?

Solution: Insert data into equation (7-6a):

$$\text{ppm} @ Y\% \text{ O}_2 = \text{ppm (meas)} \cdot \left( \frac{20.9 - Y\%}{20.9 - \% \text{ O}_2\text{,(meas)}} \right)$$

$\text{ppm} @ X\% \text{ CO}_2 = \text{ppm (meas)} \cdot \left( \frac{X\%}{\% \text{ CO}_2\text{,(meas)}} \right)$

Where: Y % $\text{O}_2$ and X % $\text{CO}_2$ specified by the applicable emission standard for the source.
Example Conversion of CO to 7% O₂ Basis

Assume:  
\[ \text{CO}_m = 100 \text{ ppm} \]
\[ \text{O}_2m = 10.7 \% \text{ (dry gas)} \]

\[
\text{CO (@ 7\% O}_2) = \text{CO}_m \left( \frac{20.9 - 7}{20.9 - \text{O}_2m} \right)
\]
\[ = 100 \left( \frac{13.9}{20.9 - 10.7} \right) \]
\[ = 136 \text{ ppm @ 7\% O}_2 \]

Example Conversion of PM to a 7% O₂ Basis

Let: \[ \text{PM}_m = 0.035 \text{ gr/dscf} \text{ (particulate matter)} \]
\[ \text{O}_2m = 10.7 \% \text{ (measured dry gas O}_2) \]

\[
\text{PM (@ 7\% O}_2) = \text{PM}_m \left( \frac{20.9 - 7}{20.9 - \text{O}_2m} \right) = 0.035 \left( \frac{13.9}{20.9 - 10.7} \right)
\]
\[ = 0.0477 \text{ gr/dscf @ 7\% O}_2 \]

Improved Equation 7-6b, for Converting Gas Concentrations to a 12% CO₂ Basis

Assume: \[ \text{HCl}_m \] is the Measured Dry Gas HCl Expressed in [ppm] or [%].
\[ \text{CO}_m \] is the Measured Dry Gas CO Expressed as [%].
\[ \text{CO}_2m \] is the Measured Dry Gas CO₂ Expressed as [%].

\[
\text{HCl (@ 12\% CO}_2) = \text{HCl}_m \left( \frac{12}{\text{CO}_2m + \text{CO}_m} \right)
\]
\[ = 280 \left( \frac{12}{9.11 + 0.01} \right) \]
\[ = 368 \text{ ppm} \]

Example Conversion to 12% CO₂

Assume: \[ \text{HCl}_m = 280 \text{ ppm} \]
\[ \text{CO}_m = 100 \text{ ppm = 0.01 \%} \]
\[ \text{CO}_2m = 9.11 \% \text{ (dry gas)} \]

\[
\text{HCl (@ 12\% CO}_2) = \text{HCl}_m \left( \frac{12}{\text{CO}_2m + \text{CO}_m} \right)
\]
\[ = 280 \left( \frac{12}{9.11 + 0.01} \right) \]
\[ = 368 \text{ ppm} \]

Equivalence of Gas Concentrations

Mole Fraction x 100 \[ \rightarrow \] Percentage
Mole Fraction x 1,000,000 \[ \rightarrow \] ppm
Percentage x 10,000 \[ \rightarrow \] ppm

Emissions in lb/million Btu, Eqn. 7-7

\[
A \left( \frac{\text{lb}}{\text{mmBTU}} \right) = \frac{\text{A (ppmvdv)}}{1,000,000} \times \frac{\text{MW}_A}{385} \times F_d \times \frac{20.9}{20.9 - \%O_2}
\]

Where:
\[ \text{ppmvdv A} = \text{measured concentration of air pollutant A} \]
\[ \text{MW}_A = \text{molecular weight of A, 46 for NO}_2, 64 \text{ for SO}_2\text{, etc.} \]
\[ \%O_2 = \text{measured oxygen, \% by vol., dry basis} \]
\[ 385 = \text{std ft}^3 / \text{lb-mole of ideal gas} \]
\[ F_d = \text{dry F-factor, std ft}^3 / \text{million Btu} \]

- bituminous coal: 9.780
- oil: 9.190
- natural gas: 8.710
- wood: 9.240
Completion of Calculation for Emissions [lb/hr] for known firing rate:

Determine emissions in [lb/ million Btu] and
Use known fuel use (firing rate):

Equation 7-9:

\[
\text{Emissions (lb/hr)} = \text{Emissions (lb/mmBTU)} \times \text{Firing Rate (mmBTU/hr)}
\]

Alt: Eqn. 7-8 for Emissions in lb/hr

From measure stack flow and ppm wet

\[
A \left(\frac{\text{lb}}{\text{hr}}\right) = \text{exhaust flow} \left(\frac{\text{scf}}{\text{hr}}\right) \times \frac{\text{ppmw of A}}{1,000,000} \times \frac{\text{MW}_{A}}{385}
\]

Where:

- A = pollutant species mass flow rate.
- MW_{A} = molecular weight of species A.
- exhaust flow = the total (wet) flue gas flow in standard cubic feet per hour.
- ppmw A = measured in a wet (not dried) sample.
- 385 = number of standard cubic feet of gas in a pound mole @ 68°F. (MW_{A}/385 = gas density in lb/ft³).

We will have an example of the use of these equations in the Alternative Solution to the problem presented in the next section. See page 22-4 in the Supplemental Materials.
Reciprocating Engines & Gas Turbines

Industrial Reciprocating Engines:
- Designed for either Gasoline or Diesel Fuel
- Uncontrolled NOx emissions factors of Table 6.1, p. 6-41 (e.g. 4.64 lb NOx/mmBtu for Rich-Burn Spark Ignition Engine) are very high compared to other combustion units (Table 5.4, page 5.23).

Combustion (gas) Turbine Characteristics:
- Usually burns natural gas, with oil as a backup fuel (interruptible contract).
- Simple cycle efficiency improved with heat recovery.

Combustion Turbines

- Emissions and Control
  - PIC: Low, due to excess air and catalyst.
  - Low NOx combustors for gas
  - Steam injection for oil
  - SCR for gas & oil firing
  - SCR temperature issues
- Combined cycle with SCR
  - Startup issues (HRSG requires controlled heat up rate).

Example: NOx Emission Standard Compliance Question.

- Simple Gas Turbine burning natural gas
- Std: Max = 65 ppm NOx (dry @ 15% \(O_2\))
- Unit Max NOx = 52.5 lbm/hr
  - Assume: 85% of NO\(_x\) mass is NO and 15% is NO\(_2\).
  - Assume: 90% of molecules are NO and 10% NO\(_2\).
- Given: Power output = 41,426 [hp]
  - Exhaust gas flow rate = 438,193 [acfm]
  - Flue gas temp = 737 °F = 1,197 °R
  - Unit efficiency = 32.5% (see Tbl. 7-1)
- Question: Will the unit meet the standard?

Assumptions:
- Fuel is Ave. pipeline natural gas (Slide 6-9)
- HHV natural gas = 1,032 \(\frac{ft^3}{lb}\)
- Specific gravity of NG = 0.609
- Standard temperature = 68 °F ⇒ 528 °R
- Density of standard air = 0.075 \(\frac{lb}{ft}\)
- \(MW_{air} = 28.97 \frac{lb}{lb\ - mole}\)

Exhaust is at atmospheric pressure.
Flue Gas Volume Corrected to Standard Conditions

Ideal Gas: $n \cdot R \cdot V_n = \frac{P \cdot V_n}{T_m} = \frac{P \cdot V}{T_s}$

$V = V_n \cdot \frac{P \cdot T_s}{P \cdot T_m} = V_n \cdot \frac{T_s}{T_m}$

where: Measured Pressure is Standard Pressure.

$T$ values are absolute temperatures [°R].

$V_n = 438,193 \text{ [acfm]} = \frac{528 \text{ [°R]}}{1,197 \text{ [°R]}}$

$V = 193,300 \text{ [scfm]} = 11.6 \times 10^6 \text{ [ft/hr]}

Power Conversion from [hp] to [Btu/hr]

$W = 41,426 \text{ [hp]} \times \frac{33,000 \text{ [ft-lbf]}}{\text{min - hp}} \times \frac{1 \text{ [Btu]}}{778 \text{ [ft-lbf]}}$

$W = 1.76 \times 10^6 \text{ Btu/min} \Rightarrow 105 \times 10^6 \text{ Btu/hr}$

Determine Fuel Firing Rate:

$Q_n = \frac{W}{\eta} = \frac{105 \times 10^6 \text{ [Btu/hr]}}{0.325} = 323 \times 10^6 \text{ Btu/hr}$

$V_{NG} = \frac{Q_n}{\text{HHV}} = \frac{323 \times 10^6 \text{ [Btu/hr]}}{1,032 \text{ [Btu/ft$^{3}$]}} = 313,000 \text{ ft}$^{3}$\text{ /hr}$

$m_{NG} = 313,000 \text{ ft}$^{3}$\text{ /hr} \times 0.609 \times 0.075 \text{ [lbm/ft}$^{3}$]$

$m_{NG} = 14,300 \text{ [lbm/hr]}

where the specific gravity of natural gas is 0.609, and the density of standard air is 0.075 [lbm/ft$^{3}$].

Generalized Combustion with Stoichiometric Air

$C_xH_yS_zO_uN_vCl_w + tH_2O + aO_2 + 3.78aN_2$

$\rightarrow xCO_2 + \left(\frac{y}{2} - \frac{w}{4} + t\right)H_2O + zSO_2$

$+ wHCl + \left(3.78a + \frac{v}{2}\right)N_2$

Note that the oxygen balance gives:

$a = x + \frac{y}{2} - \frac{w}{4} + z - \frac{u}{2}$

Average USA Pipeline Natural Gas


<table>
<thead>
<tr>
<th>Ultimate Analysis</th>
<th>% by Weight</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon</td>
<td>72.35</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>23.21</td>
</tr>
<tr>
<td>Sulfur</td>
<td>0.00</td>
</tr>
<tr>
<td>Oxygen</td>
<td>1.85</td>
</tr>
<tr>
<td>Nitrogen</td>
<td>2.59</td>
</tr>
<tr>
<td>Ash</td>
<td>0.00</td>
</tr>
<tr>
<td>Moisture</td>
<td>0.00</td>
</tr>
</tbody>
</table>

Subtotals 100.00

Specific Gravity (relative to air) 0.609

HHV (Btu/scf) 1,032 Btu/scf

HHV (Btu/lb) 22,600 Btu/lb

Divide Ultimate Analysis Values by Corresponding Atomic Weights

Get Pseudo-Molecule of Natural Gas

$x = C = \frac{72.35}{12} = 6.03; \quad y = H = \frac{23.21}{1} = 23.2$

$z = S = \frac{0}{32} = 0; \quad t = M = \frac{0}{18} = 0$

$u = O = \frac{1.85}{16} = 0.12; \quad v = N = \frac{2.59}{14} = 0.18$

$w = Cl = \frac{0}{35} = 0$

$a = x + \frac{y}{4} - \frac{w}{4} + z - \frac{u}{2} = 6.03 + \frac{23.2}{4} - 0.12 = 11.77$
Stoichiometric Combustion of Ave. Pipeline Natural Gas (100 lbm)

\[ C_{6.03}H_{23.2}O_{0.12}N_{0.18} + 11.77O_2 + 44.51N_2 \Rightarrow \]

\[ 6.03CO_2 + 11.61H_2O + 44.60N_2 \]

Therefore:

\[ N_{\text{air,rich}} = 11.77 + 44.51 = 56.28 \text{ moles - air mole - fuel} \]

Side Calculations (continued)

\[
\text{Moles Air:} \quad \frac{29.540 \text{ moles - air}}{14,300 [\text{lbm/hr}]/100 [\text{lbm/mole}]} = 206.6 \text{ moles air/mole fuel} \\
\text{Excess Air:} \quad \frac{N_{\text{air,excess}}}{N_{\text{fuel}}} = \frac{206.6 + 56.28}{36.28} = 2.67 = 267\% \quad \text{(see Tbl. 4-1)} \\
\text{Max Moles NO:} \quad \frac{0.15 \times 52.5 \text{ lbm/hr}}{28.97} = 0.47 \text{ moles/hr} \\
\text{Max Moles NO:} \quad \frac{0.17 \text{ lbm NO}}{46} = 0.0037 \text{ lbm NO/mole fuel} \\
\text{Moles NO:} \quad \frac{14.300 [\text{lbm/hr}]/100 [\text{lbm/mole}]}{28.97} = 0.0104 \text{ lbm NO/mole fuel} \\
\text{Moles NO2:} \quad \frac{14.300 [\text{lbm/hr}]/100 [\text{lbm/mole}]}{28.97} = 0.0012 \text{ lbm NO2/mole fuel} \\
\]

Combustion of Natural Gas with Excess Air and 0.0104 moles NO & 0.0012 moles NO2 per Mole Fuel

\[ C_{6.03}H_{23.2}O_{0.12}N_{0.18} + 11.77(1 + \text{EA})O_2 + 44.51(1 + \text{EA})N_2 \Rightarrow \]

\[ 6.03CO_2 + 11.61H_2O + 0.0104 \text{ NO} + 0.0012 \text{ NO}_2 + 11.77(\text{EA})O_2 + [44.51(1 + \text{EA}) + 0.18/2]N_2 \]

Dry Flue Gas Analysis

<table>
<thead>
<tr>
<th>Product</th>
<th>lb-moles</th>
<th>Mole %</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂</td>
<td>6.03</td>
<td>3.0</td>
</tr>
<tr>
<td>O₂</td>
<td>31.44</td>
<td>15.6</td>
</tr>
<tr>
<td>NO</td>
<td>0.0104</td>
<td>0.0052</td>
</tr>
<tr>
<td>NO₂</td>
<td>0.0012</td>
<td>0.0006</td>
</tr>
<tr>
<td>N₂</td>
<td>163.43</td>
<td>81.3</td>
</tr>
</tbody>
</table>

Total 200.91 100.0
Conversion of NOx Concentration to 15% O₂

Given: \( NO_x = 0.0052 + 0.0006\% = 0.0058 \) ppm
\( O_{2\text{m}} = 15.6\% \) (dry gas)

Std: Max = 65 ppm NOx (dry @ 15% O₂)

\( NO_x (@ 15\% O_2) = NO_x = \frac{20.9 - 15}{20.9 - O_{2\text{m}}} \) (eqn. 7-6a)

\[ NO_x (@ 15\% O_2) = 58 \left( \frac{5.9}{20.9 - 15.6} \right) = 58 \left( \frac{5.9}{5.3} \right) \]

Therefore, it would just satisfy the standard.

Alternate Solution:

If the NOx is 90% NO and 10% NO₂, will it meet the NOx standard?

Strategy: Use eqn 7.7 and eqn 7.9:

\[ \text{eqn } 7.7: \frac{\text{lb NOx}}{\text{mmBtu}} = \frac{\text{ppm} \times \text{A}}{\text{MW}_A \times \text{F}} \]

\[ \text{eqn } 7.9: \frac{\text{lb NOx}}{\text{hr}} = \frac{\text{A mmBtu}}{\text{Firing Rate}} \]

\[ \text{lb NOx} \times \text{mmBtu} = 65 \text{ ppm NOx} \times (0.9 \times 30 + 0.1 \times 46) \]

\[ \text{lb NOx} \times \text{mmBtu} = 8,710 \text{ scfm} \times 20.9 \]

\[ \text{lb NOx} \times \text{mmBtu} = 0.165 \text{ lb NOx mmBtu} \]

Alternate Solution:

How much NOx does the 65 ppm standard allow?

Use \( \frac{\text{lb NOx}}{\text{mmBtu}} \rightarrow 0.165 \text{ lb NOx}\)

\[ \frac{\text{lb NOx}}{\text{hr}} = \frac{\text{A}}{\text{mmBtu}} \times \text{Firing Rate} \times \frac{\text{mmBtu}}{\text{hr}} \] (eqn. 7.9)

\[ \frac{\text{lb NOx}}{\text{hr}} = 0.165 \times 323 \times \frac{\text{mmBtu}}{\text{hr}} = 53.2 \frac{\text{lb NOx}}{\text{hr}} \]

The allowable is 53.2 and the measured value 52.5, so it appears that the unit will meet the standard.
Natural Gas & Oil Fired Boilers

1. Characteristics of Boilers
2. Nitrogen Oxides Control
3. Sulfur Oxides Control
4. Particulate Emissions

Natural Gas Emission Factors (AP-42)

<table>
<thead>
<tr>
<th>Combustor Type</th>
<th>CO</th>
<th>NOx</th>
<th>SO2</th>
<th>PM</th>
</tr>
</thead>
<tbody>
<tr>
<td>Large Wall Fired Boilers</td>
<td>Uncontrolled, Pre NSPS</td>
<td>300</td>
<td>A</td>
<td>84</td>
</tr>
<tr>
<td>No. 2 Fuel Oil, Normally Firing</td>
<td>1575</td>
<td>A</td>
<td>0.75</td>
<td>C</td>
</tr>
<tr>
<td>No. 5 Fuel Oil, Normally Firing with Low NOx Burner</td>
<td>1575</td>
<td>A</td>
<td>0.75</td>
<td>C</td>
</tr>
<tr>
<td>No. 6 Fuel Oil, Tangential Firing</td>
<td>1575</td>
<td>A</td>
<td>0.75</td>
<td>C</td>
</tr>
<tr>
<td>No. 6 Fuel Oil, Tangential Firing, Low NOx Burner</td>
<td>1575</td>
<td>A</td>
<td>0.75</td>
<td>C</td>
</tr>
<tr>
<td>No. 6 Fuel Oil, Normally Firing</td>
<td>1575</td>
<td>A</td>
<td>0.75</td>
<td>C</td>
</tr>
<tr>
<td>No. 6 Fuel Oil, Normally Firing with Low NOx Burner</td>
<td>1575</td>
<td>A</td>
<td>0.75</td>
<td>C</td>
</tr>
<tr>
<td>No. 6 Fuel Oil, Tangential Firing</td>
<td>1575</td>
<td>A</td>
<td>0.75</td>
<td>C</td>
</tr>
<tr>
<td>No. 6 Fuel Oil, Tangential Firing, Low NOx Burner</td>
<td>1575</td>
<td>A</td>
<td>0.75</td>
<td>C</td>
</tr>
<tr>
<td>No. 6 Fuel Oil, Normally Firing</td>
<td>1575</td>
<td>A</td>
<td>0.75</td>
<td>C</td>
</tr>
<tr>
<td>No. 6 Fuel Oil, Normally Firing with Low NOx Burner</td>
<td>1575</td>
<td>A</td>
<td>0.75</td>
<td>C</td>
</tr>
<tr>
<td>No. 6 Fuel Oil, Tangential Firing</td>
<td>1575</td>
<td>A</td>
<td>0.75</td>
<td>C</td>
</tr>
<tr>
<td>No. 6 Fuel Oil, Tangential Firing, Low NOx Burner</td>
<td>1575</td>
<td>A</td>
<td>0.75</td>
<td>C</td>
</tr>
</tbody>
</table>

Emission Factors, Large Fuel Oil Boilers

> 100 million Btu/hr, AP-42

Characteristics of Boilers

- Size range (of interest)
- Fuels/Emissions
  - Control equipment
  - PIC usually low
- Longevity
  - Some new, many older boilers
**Gas & Oil NOx Control**
- Combustion NOx controls:
  - Low excess air and burner adjustments.
  - Staged combustion on large furnaces using combinations of burners.
  - Low and Ultra-Low NOx burners.
  - Over-fire air.
  - Flue gas recirculation.
  - Natural gas reburning.
  - Switching fuel.
- SCR and SNCR

**Gas & Oil SOx Control**
- SO\textsubscript{2} Control
  - Fuel specification
  - Dry, Semi-Dry & Wet Scrubbers
- SO\textsubscript{3} Control in response to plume visibility
  - Reducing oil sulfur content
  - Very low excess air operation
  - Fuel additives

**Gas & Oil Particulate Emissions**
- Natural gas & distillate oil
- Residual oil
- Pulverized coal
- Solid fuels

**Gas & Oil Particulate**
- ESP
- Ash levels
- Disposal
  - Reinjection
  - Sale
  - Landfill

**Example 1: Stoichiometric Combustion of Special Gas Mixture**
- Consider a special byproduct synthetic fuel composed of 60% hydrogen and 40% methane.
- Determine the coefficients of a balanced ideal (perfect) combustion equation for burning this fuel under stoichiometric conditions.

**Example 1: Stoichiometric Combustion of Special Gas Mixture**
\[0.6 \text{H}_2 + 0.4 \text{CH}_4 + a \text{O}_2 + b \text{N}_2 \Rightarrow c \text{CO}_2 + d \text{H}_2\text{O} + b \text{N}_2\]

Air: Nitrogen - to - Oxygen Compositions
\[79/20.9 = 3.78 \text{ so, } b = 3.78 a\]
Carbon Balance: \[0.4 = c\]
Oxygen Balance: \[2 a = 2 c + d\]
Hydrogen Balance: \[0.6 (2) + 0.4 (4) = 2 d\]
Balancing the Chemical Equations

Carbon Balance : $0.4 = c$
Oxygen Balance : $2a = 2c + d$

or $a = c + \frac{d}{2}$

Hydrogen Balance : $0.6 (2) + 0.4 (4) = 2d$
so $d = 0.6 + 0.4(2) = 1.4$

Oxygen Balance : $a = 0.4 + 0.7 = 1.1$
$b = 3.78a = 3.78 (1.1) = 4.16$

Example 1: Stoichiometric Combustion of Special Gas Mixture

$0.6 \text{H}_2 + 0.4 \text{CH}_4 + a \text{O}_2 + b \text{N}_2$
$\Rightarrow c \text{CO}_2 + d \text{H}_2\text{O} + b \text{N}_2$

$0.6 \text{H}_2 + 0.4 \text{CH}_4 + 1.1 \text{O}_2 + 4.16 \text{N}_2$
$\Rightarrow 0.4 \text{CO}_2 + 1.4 \text{H}_2\text{O} + 4.16 \text{N}_2$

Example 2: Combustion of Fuel Oil

Assume: No. 6 Fuel Oil (somewhat similar to the oil in Table 3-5) with Stoichiometric Air.
Find:
1. Flue gas gravimetric analysis.
2. Volume of flue gas per lbm fuel oil (at 1 atm. pressure and 500 °F).
3. CO$_2$ Percentage in dry flue gas.
4. SO$_2$ Concentration [ppm].
5. Maximum fraction of Nitrogen in air that becomes NOx, if 200 ppm NOx in flue gas.

Ultimate Analysis of Example No. 6 Fuel Oil

<table>
<thead>
<tr>
<th>Element</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon</td>
<td>88.52 %</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>10.87 %</td>
</tr>
<tr>
<td>Oxygen</td>
<td>0.06 %</td>
</tr>
<tr>
<td>Nitrogen</td>
<td>0.10 %</td>
</tr>
<tr>
<td>Sulfur</td>
<td>0.40 %</td>
</tr>
<tr>
<td>Inorganic (ash)</td>
<td>0.05 %</td>
</tr>
<tr>
<td>Total</td>
<td>100.00</td>
</tr>
</tbody>
</table>

Generalized Combustion with Stoichiometric Air

$C_x\text{H}_y\text{S}_z\text{O}_w\text{N}_v\text{Cl}_t + t \text{H}_2\text{O} + a \text{O}_2 + 3.78 \text{ a N}_2$
$\Rightarrow x \text{CO}_2 + \left(\frac{y}{2} - \frac{w}{4} + t\right) \text{H}_2\text{O} + z \text{SO}_2$
$+ w \text{HCl} + \left(3.78 a + \frac{v}{2}\right) \text{N}_2$

Note that the oxygen balance gives:

$a = x + \frac{y}{4} - \frac{w}{4} + z - \frac{u}{2}$

Pseudo-Molecule: No. 6 Fuel Oil

$x = \frac{C}{12} = \frac{88.52}{12} = 7.38$
$y = \frac{H}{1} = \frac{10.87}{1} = 10.87$
$z = \frac{S}{32} = \frac{0.40}{32} = 0.0125$
$u = \frac{O}{16} = \frac{0.06}{16} = 0.004$
$v = \frac{N}{14} = \frac{0.10}{14} = 0.007$

with \(t = w = 0\), since moisture and chlorine = 0
and \(a = (x + y/4 - w/4 + z - u/2) = 10.1\)
Theoretical Combustion of the Example No. 6 Fuel Oil:

\[ C_{7.38}H_{(0.37)}SO_{(0.0125)}O_{(0.004)}N_{(0.007)} + 10.1O_2 + 38.2N_2 \rightarrow \]

\[ 7.38CO_2 + 5.44H_2O + 38.2N_2 + 0.0125SO_2 \]

Example 2.1: Flue Gas Molar and Gravimetric Analysis

<table>
<thead>
<tr>
<th>Wet Flue Gas</th>
<th>lb-moles</th>
<th>MW</th>
<th>lbm</th>
<th>Weight %</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO(_2)</td>
<td>7.38</td>
<td>44</td>
<td>324.6</td>
<td>21.74</td>
</tr>
<tr>
<td>H(_2)O</td>
<td>5.44</td>
<td>18</td>
<td>97.8</td>
<td>6.55</td>
</tr>
<tr>
<td>SO(_2)</td>
<td>0.0125</td>
<td>64</td>
<td>0.8</td>
<td>0.05</td>
</tr>
<tr>
<td>O(_2)</td>
<td>0.00</td>
<td>32</td>
<td>0.0</td>
<td>0.00</td>
</tr>
<tr>
<td>N(_2)</td>
<td>38.20</td>
<td>28</td>
<td>1,069.6</td>
<td>71.65</td>
</tr>
<tr>
<td>Total</td>
<td>51.02</td>
<td>1,492.8</td>
<td>100.0</td>
<td></td>
</tr>
</tbody>
</table>

Example 2.2: Volume of Flue Gas

\[ V = \frac{n \cdot R_u \cdot T}{P} \]

where \( P \) : Absolute Pressure
\( V \) : Volume
\( n \) : Number of moles of gas
\( T \) : Absolute Temperature
\( R_u \) : Universal Gas Constant
\( R_u \) : 1.545 [ft - lb]/[lb - mol deg R] or
\( R_u \) : 0.7302 [atm - ft\(^3\)]/[lb - mol deg R]

Example 2.3: \( CO_2 \) Concentration in Dry Flue Gas

<table>
<thead>
<tr>
<th></th>
<th>lb-moles</th>
<th>Mole %</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO(_2)</td>
<td>7.38</td>
<td>16.2</td>
</tr>
<tr>
<td>SO(_2)</td>
<td>0.0125</td>
<td>0.0274</td>
</tr>
<tr>
<td>O(_2)</td>
<td>0.00</td>
<td>0.0</td>
</tr>
<tr>
<td>N(_2)</td>
<td>38.20</td>
<td>83.8</td>
</tr>
<tr>
<td>Total</td>
<td>45.59</td>
<td>100.0</td>
</tr>
</tbody>
</table>
Example 2.4: SO$_2$ Concentration in Dry Flue Gas

SO$_2$ Mole Fraction = 0.0274 % → 274 [ppm SO$_2$]

since 1.0 % = 10,000 [ppm]

The flue gas O$_2$ → 0, so it should be corrected to 7% O$_2$ using equation (7-6a):

SO$_2$ (at 7% O$_2$) = 274 \left[ \frac{20.9 - 7}{20.9 - 0} \right] = 182 [ppm]

Example 2.5: Maximum fraction of N$_2$ in air that becomes NOx, if NOx= 200 ppm

Note that Nitrogen generally does not react, but "goes along for the ride."

For this example, NOx in flue gas is 200 ppm = 0.02%

Dry flue gas is 83.7% N$_2$ and N$_2$ + O$_2$ → 2 NO

Therefore, 100 ppm of N$_2$ was used to make NO;

or, \[ \frac{0.01}{83.7} = 0.00012, \Rightarrow 0.01\% \text{ of the nitrogen.} \]
Coal and Wood-Fired Boilers

- Characteristics of Pulverized Coal Boilers
- Characteristics of Spreader Stoker Boilers
- Nitrogen Oxides Control
- Sulfur Oxides and Particulate Matter

## Characteristics of PC Boilers

- Fuel flexibility - PC design vs gas/oil design
- Design and operation are influenced by:
  - Heat transfer area
  - Soot blowers
  - Gas flow passage size
  - Fire box size
  - Temperature control with excess air
- Emissions Controlled – NOx, particulate, SOx

### AP-42 Emission Factors

#### Bituminous Coal

<table>
<thead>
<tr>
<th>Combustor Type</th>
<th>SOx Emis. Factor (lb/ton)</th>
<th>NOx Emis. Factor (lb/ton)</th>
<th>CO Emis. Factor (lb/ton)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pulverized Coal</td>
<td>Dry bottom, Wall-fired, Pre-NSPS 38S A 22 A 0.5 A</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Dry bottom, Wall-fired, NSPS 38S A 11 A 0.5 A</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Dry bottom, Tangentially-fired, Pre-NSPS 38S A 15 A 0.5 A</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Dry bottom, Tangentially-fired, NSPS 38S A 9.7 A 0.5 A</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Dry bottom, Tangentially-fired, LNB 38S A 10 A 0.5 A</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wet bottom, Wall-fired, Pre-NSPS 38S A 31 D 0.5 A</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wet bottom, Tangentially-fired, NSPS 38S A 14 E 0.5 A</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cyclone Furnace 38S A 33 A 0.5 A</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Spreader Stoker 38S B 11 B 5 A</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

#### Sub-Bituminous Coal

<table>
<thead>
<tr>
<th>Combustor Type</th>
<th>SOx Emis. Factor (lb/ton)</th>
<th>NOx Emis. Factor (lb/ton)</th>
<th>CO Emis. Factor (lb/ton)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pulverized Coal</td>
<td>Dry bottom, Wall-fired, Pre-NSPS 35S A 12 C 0.5 A</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Dry bottom, Wall-fired, NSPS 35S A 7.4 A 0.5 A</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Dry bottom, Tangentially-fired, Pre-NSPS 35S A 8.4 B 0.5 A</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Dry bottom, Tangentially-fired, NSPS 35S A 7.2 B 0.5 A</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wet bottom, Wall-fired, Pre-NSPS 35S A 24 E 0.5 A</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wet bottom, Tangentially-fired, NSPS 35S A 14 E 0.5 A</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cyclone Furnace 35S A 17 C 0.5 A</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Spreader Stoker 35S B 6.8 B 5 A</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### AP-42 PM Emission Factors

#### Bituminous & Sub-Bituminous Coal

<table>
<thead>
<tr>
<th>Combustor Type</th>
<th>Filterable PM-10 Emis. Factor (lb/ton)</th>
<th>Filterable PM-10 Emis. Factor (lb/ton)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pulverized Coal</td>
<td>Dry bottom, Wall-fired 10A A 2.3A E</td>
<td></td>
</tr>
<tr>
<td>Wet bottom 10A B 2.3A E</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Dry bottom, Tangentially-fired, Cyclone Furnace 2A 17 B 2.6A E</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Spreader Stoker 3A B 6.0 B 17 E</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Spreader Stoker with Multiclone 17 B 17 E</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Spreader Stoker with Multiclone &amp; No Re-injection 12 A 3.0 B 7.0 E</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### SO2 Emission Factor

- Theoretical Emission Factor:
  \[ F_{SO_2} = \frac{S[\text{lb} S]}{100[\text{lb of fuel}]} \cdot 2 \cdot \frac{\text{lb} SO_2}{100 \text{ lb fuel}} \cdot 2000 \text{ lb fuel} \]

- AP-42 Emiss. Factor: 38 S [lb SO2 / ton fuel]
- < 40 S, since some S does not go to SO2 or SO3.
PC NO\textsubscript{x} Control

Combustion control
- Similar to oil
- Fuel – air distribution issues

Sulfur Oxides and Particulate Matter

- Alternative coal supplies - impacts
- ESP problems with low S coal
- Side effects - interaction of changes

Wood Firing and Stoker Furnaces

- Stokers can burn coal, wood, MSW, and/or RDF.
- Characteristics of Stoker Furnaces
- Particulate Matter Emissions
- Nitrogen Oxides Control
- PIC and Dioxin-furans

AP-42 Emission Factors for PM from Wood Residue Combustion

| Fuel                  | PM Control Device | PM \textsubscript{E} 0.3 Filterable PM \textsubscript{E} 2.5 Filterable PM \textsubscript{E} 0.3 Filterable PM \textsubscript{E} 0.3 Filterable PM \textsubscript{E} 2.5 Filterable PM Factor | Factor | Factor | Factor | Factor | Factor |
|-----------------------|-------------------|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|
| Bark & Bark & Wet Wood| No Control        | 0.08 E             | 0.58 D             | 0.58 D             | 0.58 D             | 0.58 D             | 0.58 D             |
| Dry Wood              | No Control        | 0.00 A             | 0.56 D             | 0.56 D             | 0.56 D             | 0.56 D             | 0.56 D             |
| Wet Wood              | No Control        | 0.00 A             | 0.56 D             | 0.56 D             | 0.56 D             | 0.56 D             | 0.56 D             |
| Bark                  | Mechanical Collector | 0.04 D          | 0.58 D             | 0.58 D             | 0.58 D             | 0.58 D             | 0.58 D             |
| Dry Wood              | Mechanical Collector | 0.05 C           | 0.32 D             | 0.32 D             | 0.32 D             | 0.32 D             | 0.32 D             |
| Wet Wood              | Mechanical Collector | 0.01 A           | 0.27 D             | 0.27 D             | 0.27 D             | 0.27 D             | 0.27 D             |
| All Fuels             | Electrolyzed Gravel | 0.00 D          | 0.074 D             | 0.074 D             | 0.074 D             | 0.074 D             | 0.074 D             |
| All Fuels             | Wet Scrubber       | 0.004 A           | 0.065 D             | 0.065 D             | 0.065 D             | 0.065 D             | 0.065 D             |
| All Fuels             | Fabric Filter       | 0.004 A           | 0.065 D             | 0.065 D             | 0.065 D             | 0.065 D             | 0.065 D             |
| All Fuels             | Electrostatic Precipitator | 0.004 A | 0.065 D             | 0.065 D             | 0.065 D             | 0.065 D             | 0.065 D             |

Characteristics of Stoker Furnaces

- Bed combustion control
- Over bed combustion control
- Air use
  - Amount required
  - Trade offs

Stoker Particulate Emissions

- Grate retention of particulate
  - Carryover
  - Fuel size
  - Feeder mechanism

- Built in multi-clones

- Typical uncontrolled emissions
  0.3 – 0.7 lb/million Btu
Nitrogen Oxides Control

- Grate area formation → no control
- Reburning (can work)
- SNCR and SCR

PIC and Dioxin-furans

- Over fire control of smoke, CO & VOC
  - CO levels used as a surrogate for dioxin/furan and other hazardous air pollutant emissions.
- Older stoker problems
  - Designs inappropriate for MSW
  - Furnace temperature control
  - Over-fired air design
- Newer stoker designs work much better.

Example Emission Standard Comparison Calculation

- Wood Waste Burner Particulate Emission
- Given: 0.2 lb/1,000 lbm flue gas (wet)
- Express in Units of gr/dscf @ 7% O₂
- Assumptions:
  - Western Mix Hog Fuel @ 50% Moisture.
  - Combustion @ 30% Excess Air.
  - Standard temperature is 68 °F.

Generalized Combustion with Stoichiometric Air

\[
C_xH_yS_zO_uN_vCl_w + tH_2O + aO_2 + 3.78 \cdot aN_2 \\
\rightarrow \ xCO_2 + \left(\frac{y}{2} - \frac{w}{2} - t\right)H_2O + zSO_2 \\
+ \ wHCl + \left(3.78 \cdot a + \frac{v}{2}\right)N_2
\]

Note that the oxygen balance gives:

\[
a = x + \frac{y}{4} - \frac{w}{4} + z - \frac{u}{2}
\]

Example Ultimate Analysis of Wood (dry basis)

<table>
<thead>
<tr>
<th>Wood Hog Fuels Ultimate Analysis</th>
<th>Western Hemlock</th>
<th>Douglas Fir</th>
<th>Western Mix 50/50</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon</td>
<td>50.4</td>
<td>52.3</td>
<td>51.35</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>5.8</td>
<td>6.3</td>
<td>6.05</td>
</tr>
<tr>
<td>Sulfur</td>
<td>0.1</td>
<td>0.0</td>
<td>0.05</td>
</tr>
<tr>
<td>Oxygen</td>
<td>41.4</td>
<td>40.5</td>
<td>40.95</td>
</tr>
<tr>
<td>Nitrogen</td>
<td>0.1</td>
<td>0.1</td>
<td>0.10</td>
</tr>
<tr>
<td>Ash</td>
<td>2.2</td>
<td>0.8</td>
<td>1.55</td>
</tr>
<tr>
<td><strong>Totals</strong></td>
<td><strong>100.00</strong></td>
<td><strong>100.00</strong></td>
<td><strong>100.00</strong></td>
</tr>
<tr>
<td><strong>HHV dry</strong></td>
<td><strong>8,620</strong></td>
<td><strong>9,050</strong></td>
<td><strong>8,835</strong></td>
</tr>
</tbody>
</table>

Conversion of Dry property values to Wet property values

For example:

- HHV (dry) is the known dry fuel HV.
- HHV (wet) is the desired wet fuel HHV.
- H₂O is the moisture fraction in the wet fuel.

\[
HHV \text{ (wet)} = HHV \text{ (dry)} \cdot (1.0 - H_2O)
\]
Example Ultimate Analysis of Wet Western Mix Wood Hog Fuel

<table>
<thead>
<tr>
<th>Component</th>
<th>Western Ultimate Analysis Mix 50/50</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon</td>
<td>25.675</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>3.025</td>
</tr>
<tr>
<td>Sulfur</td>
<td>0.025</td>
</tr>
<tr>
<td>Oxygen</td>
<td>20.475</td>
</tr>
<tr>
<td>Nitrogen</td>
<td>0.050</td>
</tr>
<tr>
<td>Ash</td>
<td>0.750</td>
</tr>
<tr>
<td>Moisture</td>
<td>50.000</td>
</tr>
<tr>
<td>Totals</td>
<td>100.000</td>
</tr>
</tbody>
</table>

HHV wet [Btu/lb] 4,418

Divide Ultimate Analysis Values by Corresponding Atomic Weights: Pseudo-Molecule of Hog Fuel

\[
x = \frac{C}{12} = \frac{25.675}{12} = 2.14; \quad y = \frac{H}{1} = \frac{3.025}{1} = 3.025
\]

\[
z = \frac{S}{32} = \frac{0.025}{32} = 0.0001; \quad t = \frac{M}{18} = \frac{50}{18} = 2.778
\]

\[
u = \frac{O}{16} = \frac{20.475}{16} = 1.28; \quad v = \frac{N}{14} = \frac{0.05}{14} = 0.0004
\]

\[
w = \frac{Cl}{35} = \frac{0}{35} = 0
\]

\[
a = x + \frac{y}{4} + \frac{z}{2} = 2.14 + \frac{3.025}{4} + 0.0001 \times \frac{1.28}{2} = 2.26
\]

Combustion of Hog Fuel (100 lbm) with Stoichiometric Air and 30% Excess Air

Stoichiometric Combustion:

\[
C_{21.4}H_{32.2}S_{0.001}O_{1.28}N_{0.001} + 2.78H_2O + 2.26O_2 + 8.53N_2
\]

\[
\Rightarrow 2.14CO_2 + 0.001SO_2 + 4.29H_2O + 8.53N_2
\]

Combustion with 30% Excess Air:

\[
C_{21.4}H_{32.2}S_{0.001}O_{1.28}N_{0.001} + 2.78H_2O + 2.94O_2 + 11.09N_2
\]

\[
\Rightarrow 2.14CO_2 + 0.001SO_2 + 4.29H_2O + 0.68O_2 + 11.09N_2
\]

Wet Flue Gas Analysis

Wood Waste at 30% EA (assuming 385 ft³/mol for 68 °F std.)

<table>
<thead>
<tr>
<th>Component</th>
<th>lb-moles</th>
<th>Mole %</th>
<th>MW</th>
<th>lbm</th>
<th>Std Vol [ft³]</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂</td>
<td>2.14</td>
<td>11.756</td>
<td>44</td>
<td>94.1</td>
<td>825</td>
</tr>
<tr>
<td>H₂O</td>
<td>4.29</td>
<td>23.574</td>
<td>18</td>
<td>77.2</td>
<td>1,654</td>
</tr>
<tr>
<td>SO₂</td>
<td>0.001</td>
<td>0.004</td>
<td>64</td>
<td>0.1</td>
<td>0</td>
</tr>
<tr>
<td>O₂</td>
<td>0.68</td>
<td>3.720</td>
<td>32</td>
<td>21.7</td>
<td>261</td>
</tr>
<tr>
<td>N₂</td>
<td>11.09</td>
<td>60.945</td>
<td>28</td>
<td>310.6</td>
<td>4,276</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>18.20</strong></td>
<td><strong>100.000</strong></td>
<td><strong>503.6</strong></td>
<td><strong>7,017</strong></td>
<td></td>
</tr>
</tbody>
</table>

Dry Flue Gas Analysis

Wood Waste at 30% EA

<table>
<thead>
<tr>
<th>Component</th>
<th>lb-moles</th>
<th>MW</th>
<th>lbm</th>
<th>Mole %</th>
<th>Std Vol [ft³]</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂</td>
<td>2.14</td>
<td>44</td>
<td>94.1</td>
<td>15.383</td>
<td>825</td>
</tr>
<tr>
<td>SO₂</td>
<td>0.001</td>
<td>64</td>
<td>0.1</td>
<td>0.0056</td>
<td>0</td>
</tr>
<tr>
<td>O₂</td>
<td>0.68</td>
<td>32</td>
<td>21.7</td>
<td>4.868</td>
<td>261</td>
</tr>
<tr>
<td>N₂</td>
<td>11.09</td>
<td>28</td>
<td>310.6</td>
<td>79.744</td>
<td>4,276</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>13.91</strong></td>
<td><strong>426.4</strong></td>
<td><strong>100.000</strong></td>
<td><strong>5,363</strong></td>
<td></td>
</tr>
</tbody>
</table>

Use Equation 7-6a to Convert PM Concentrations to 7% O₂

Assume: PMₘₐₙ is the measured Dry Gas PM expressed in [gr/dscf] or [mg/dscm]

O₂ₘₐₙ is the measured Dry Gas O₂ expressed as [%].

PM @ Y% O₂ = PM (meas) \left( \frac{20.9 - Y\%}{20.9 - \% O₂ \text{ (meas)}} \right)

PM @ 7% O₂ = PM (meas) \left( \frac{20.9 - 7}{20.9 - \% O₂ \text{ (meas)}} \right)
Final Calculation - Answer:

\[
0.2 \text{ lbm part m}
1,000 \text{ lbm fg}
= \frac{0.2 \text{ lbm part}}{1,000 \text{ lbm fg}} \times \frac{7,000 \text{ gr}}{\text{lbm part}} \times \frac{503.6 \text{ lbm fg}}{100 \text{ lbm fg}} \times \frac{100 \text{ lbm f}}{5,363 \text{ dscf}}
= 0.131 \frac{\text{gr}}{\text{dscf}} @ 4.87 \% \text{ O}_2
\]

PM_{rad} = PM_{meas} \times \frac{20.9 - 7.0}{20.9 - O_{2, meas}} = 0.131 \frac{\text{gr}}{\text{dscf}} \times \frac{13.9}{16.03}

\[
0.2 \text{ lbm part m}
1,000 \text{ lbm fg}
= 0.114 \frac{\text{gr}}{\text{dscf}} @ 7\% \text{ O}_2
\]

Chapter Summary

- Energy Use and CO\(_2\) Emissions
- Emissions Monitoring & Measurement
- Reciprocating Engines & Combustion Turbines
- Natural Gas, No. 2 and No. 4 Oil Fired Boilers
- Coal Fired Boilers
- Wood Firing and Stoker Furnaces

Review Exercise 7-2:
Find efficiency loss associated with CO

\[O_{2, meas} = 6.2\%\]
\[CO_{meas} = 320 \text{ ppm}\]
Equation 7-1:

\[
\% \text{ Energy Loss} = 0.00027 \cdot \frac{\text{ppm CO}}{20.9 - O_{2, meas}}
\]

\[
\% \text{ Energy Loss} = 0.00027 \cdot 320 \cdot \frac{20.9}{20.9 - 6.2}
\]

\[
\% \text{ Energy Loss} = 0.123\%
\]

Review Exercise 7-3:
Find efficiency loss associated with C

Flyash carbon content = 7.1\%
Coal HHV = 11,800 \text{ Btu lb} & ash content = 13.2\%
Like equation 7-2:

Energy Loss = \frac{\% A}{100} \cdot \frac{\% C}{100} \cdot \frac{14,100}{\text{HHV}}

Energy Loss = 0.132 \frac{\text{lb ash}}{\text{lb coal}} \cdot 0.071 \frac{\text{lb C}}{\text{lb ash}} \cdot \frac{14,100}{\text{Btu lb C}}

Energy Loss = 0.0112 = 1.12\%

Review Exercise 7-6:
Find approximate thermal efficiency

\[T_{h} = 290 \, ^\circ \text{F}, \; T_{i} = 48\, ^\circ \text{F}\]
\[O_{2} = 2.9\%, \; H_{2}O = 14\%\]
Equation 7-4:

\[
\text{Efficiency} = 100 \left[ 1 - \frac{\Delta T}{4,200} - \frac{0.49 - H_{2}O\%}{100} \right]
\]

\[
\text{Efficiency} = 100 \left[ 1 - \frac{20.9}{20.9 - O_{2}} \right] \cdot \frac{290 - 48}{4,200} \cdot \frac{0.49 - 14}{100}
\]

\[
\text{Efficiency} = 100 \left[ 1 - (1.16) \cdot (0.0576 + 0.0686) \right]
\]

\[
\text{Efficiency} = 100 \cdot (1 - 0.146) = 85.4\%
\]
Review Exercise 7-7:
Find Input Energy (firing rate)
(Consider Example 7-4, page 7-7)
Output = 480 MW = 480,000 kW
Heat Rate = 9,750 Btu/kW-hr
H = Output · Heat Rate
H = 480,000 kW · 9,750 Btu/kW-hr
H = 4.68 · 10^9 Btu/hr = 4,680 mmBtu/hr

Review Exercise 7-8:
Find Daily CO₂ Emissions
Firing Rate, H = 375 mmBtu/hr
Emission Factor for Coal (Table 7-2) = 185 lb CO₂/mmBtu
Emission = Emission Factor · Firing Rate · time
Emission = 185 lb CO₂/mmBtu · 375 mmBtu/hr · 24 hr
Emission = 1.656 · 10^4 lb CO₂/day

Review Exercise 7-10:
Correct Concentration to 3% O₂
Correct gas concentration to Y = 3% O₂:
225 ppm CO_{meas} @ O_{2,meas} = 5.3%
Eqn (7 - 6a):
CO @ 3% O₂ = CO_{meas} \frac{20.9 - Y}{20.9 - O_{2,meas}}
CO @ 3% O₂ = 225 · \frac{20.9 - 3}{20.9 - 5.3} = 225 · 1.147
CO @ 3% O₂ = 258 ppm
**Emission Calculations Workshop**

1. Pollutant Emissions from 500 MWe Coal-Fired Power Plant.
3. Use of F-factor to determine grain loading.
4. Grain loading of SO\(_2\) from burning natural gas

---

**Problem 1: Pollutant Emissions from 500 MWe Coal-Fired Power Plant.**

At rated capacity, determine:
1. Input energy and coal firing rate.
2. Uncontrolled particulate emissions [lb/hr].
3. SO\(_2\), NO\(_x\) & CO emission rate [lb/hr].
4. Uncontrolled particulate and SO\(_2\) emissions [lb/million Btu].
5. Degree of control required to meet standard: 0.05 [lb particulate/million Btu].

---

**Problem 1.1: Solution for Input Energy and Coal Firing Rate:**

- Output Energy = 500 MWe \(\times\) 1,000 kW = 3,413 Btu kW - hr
- Input Energy = 1.7 \(\times\) 10\(^7\) Btu/hr
- Efficiency = 0.34
- Fuel Rate = \(\frac{5 \times 10^7 \text{ Btu/hr}}{12,540 \text{ Btu/lbm}}\) = 398,700 lb - coal/hr
- Fuel Rate = \(\frac{398,700 \text{ lb - coal/hr}}{2,000 \text{ lb/ton}}\) = 199 ton/hr

---

**Example Ultimate Pittsburgh Coal (From Table 3-13)**

<table>
<thead>
<tr>
<th>Given Basis</th>
<th>Calculated Wet Basis</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon</td>
<td>74.0 % 70.2 %</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>5.1 % 4.8 %</td>
</tr>
<tr>
<td>Oxygen</td>
<td>7.9 % 7.5 %</td>
</tr>
<tr>
<td>Nitrogen</td>
<td>1.6 % 1.5 %</td>
</tr>
<tr>
<td>Chlorine</td>
<td>0.0 % 0.0 %</td>
</tr>
<tr>
<td>Sulfur</td>
<td>2.3 % 2.2 %</td>
</tr>
<tr>
<td>Inorganic (ash)</td>
<td>9.1 % 8.6 %</td>
</tr>
<tr>
<td>Moisture</td>
<td>5.2 %</td>
</tr>
<tr>
<td>Total:</td>
<td>100.0 % 100.0 %</td>
</tr>
</tbody>
</table>

---

**Problem 1.2: Solution for Uncontrolled Particulate Emissions [lb/hr]**

- Particle Mass Emission Factor = 10 \(\times\) A = 10 \(\times\) 8.6 = 86.0 lb/ton
- Particle Emission Rate = Factor \(\times\) Fuel Rate
  \[= 86.0 \frac{\text{lb}}{\text{ton}} \cdot 199 \frac{\text{ton}}{\text{hr}}
  = 17,110 \frac{\text{lb}}{\text{hr}}\]
Problem 1.3: Solution for SO₂ [lb/hr]

\[
\text{SO}_2 \text{ Emission Factor} = 38 \cdot S = 38 \cdot 2.2 = 83.6 \text{ lb/ton} \\
\text{SO}_2 \text{ Emission} = \text{Factor} \cdot \text{Fuel Rate} \\
= 83.6 \frac{\text{lb}}{\text{ton}} \cdot 199 \text{ hr} = 16,640 \frac{\text{lb}}{\text{hr}}
\]

Problem 1.3: Solution for NOx and CO [lb/hr]

\[
\text{NOx Emission Factor} = 10 \text{ lb/ton} \\
\text{NOx Emission} = \text{Factor} \cdot \text{Fuel Rate} \\
= 10 \frac{\text{lb}}{\text{ton}} \cdot 199 \frac{\text{ton}}{\text{hr}} = 1,990 \frac{\text{lb}}{\text{hr}} \\
\text{CO Emission Factor} = 0.5 \text{ lb/ton} \\
\text{CO Emission} = \text{Factor} \cdot \text{Fuel Rate} \\
= 0.5 \frac{\text{lb}}{\text{ton}} \cdot 199 \frac{\text{ton}}{\text{hr}} = 99.5 \frac{\text{lb}}{\text{hr}}
\]

Problem 1.4: Solution for Uncontrolled Particulate Emissions [lb/million Btu]

\[
\text{Process PM Emissions} = \frac{\text{Particle Emission Rate}}{\text{Fuel Input Rate}} \\
= \frac{17,110 \frac{\text{lb}}{\text{hr}}}{5 \cdot 10^7 \text{ Btu/hr}} \\
= \frac{17,110}{5,000 \cdot \text{million Btu/hr}} = 3.4 \frac{\text{lb particulate}}{\text{million Btu}}
\]

Problem 1.4: Solution for Uncontrolled SO₂ Emissions [lb/million Btu]

\[
\text{ProcessSO}_2 \text{ Emissions} = \frac{\text{SO}_2 \text{ Emission Rate}}{\text{Fuel Input Rate}} \\
= \frac{16,640 \frac{\text{lb}}{\text{hr}}}{5 \cdot 10^7 \text{ Btu/hr}} \\
= \frac{16,640}{5,000 \cdot \text{million Btu/hr}} = 3.33 \frac{\text{lb SO}_2}{\text{million Btu}}
\]

Problem 1.5: Degree of Control to Meet 0.05 [lb-particulate/million Btu]

\[
\text{Degree of Control} = \eta = \frac{\text{Required Collection}}{\text{Input}} = \frac{\text{Input} - \text{Allowable}}{\text{Input}} \\
= \frac{(3.4 - 0.05) \frac{\text{lb particulate}}{\text{million Btu}}}{3.4 \frac{\text{lb particulate}}{\text{million Btu}}} = \frac{3.35}{3.4} = 0.985 \\
\text{Degree of Control} = 98.5\%
\]

Problem 2: Pollutant Emissions from Hog-Fuel Fired Boiler

Fuel: Hog Fuel @ 50% moisture
Boiler efficiency: 78%
Grate area: 500 sq. ft. water cooled vibrating grate
Grate firing rate: 1.2 million Btu/hr-ft²
Steam conditions: 820°F at 900 psia (superheat)
Steam energy gain: 1,280 Btu/lb-steam
PM emissions std.: 0.085 lb-PM/million Btu
Conversion of Dry HHV to Wet HHV

Assume

HHV (dry) is the known dry fuel HHV.
HHV (wet) is the desired wet fuel HHV.
H₂O is the mass fraction of water in the wet fuel.

\[
HHV \text{ (wet)} = HHV \text{ (dry)} \times (1.0 - H_2O)
\]

Example Ultimate Analysis of Wet Western Mix Wood Hog Fuel (slide 24-19)

<table>
<thead>
<tr>
<th>Wood Hog Fuel Ultimate Analysis Mix 50/50</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon</td>
</tr>
<tr>
<td>Hydrogen</td>
</tr>
<tr>
<td>Sulfur</td>
</tr>
<tr>
<td>Oxygen</td>
</tr>
<tr>
<td>Nitrogen</td>
</tr>
<tr>
<td>Ash</td>
</tr>
<tr>
<td>Moisture</td>
</tr>
<tr>
<td><strong>Totals</strong></td>
</tr>
<tr>
<td>HHV wet [Btu/lb]</td>
</tr>
</tbody>
</table>

Problem 2: Pollutant Emissions from Hog-Fuel Fired Boiler

Typical Flue Gas Data Analysis Indicates About:
- 15.4 % carbon dioxide (dry gas basis)
- 4.9 % oxygen (dry gas basis)

Determine:
1. Fuel Firing Rate [tons/hr]
2. Superheat steam flow rate [lb/hr]
3. Percent excess air
4. Maximum SO₂ emissions [ppm-dry]
5. Maximum potential ash produced [lb/MMBtu]
6. Estimated flyash assuming 40% bottom ash
7. Degree of control for particulate emissions

Problem 2.1: Solution for Fuel Firing Rate

Input energy = Grate area x Grate firing rate
Input energy = 500 ft² x 1.2 · 10⁶ Btu/hr - ft²
= 600 · 10⁶ Btu/hr

Fuel rate = \( \frac{\text{Input energy}}{\text{HHV}} \) = \( \frac{600 \times 10^6 \text{ Btu/hr}}{4,418 \text{ Btu/lb}} \)
= 135,800 lb/hr \( \Rightarrow \) 67.9 tons/hr

Problem 2.2: Solution for Superheat Steam Flow Rate

Output energy = boiler efficiency x Input energy
Output energy = 0.78 x 600 · 10⁶ Btu/hr
= 468 · 10⁶ Btu/hr

Steam rate = \( \frac{\text{Output energy}}{\text{Steam energy gain}} \) = \( \frac{468 \times 10^6 \text{ Btu/hr}}{1,280 \text{ Btu/lb}} \)
= 365,600 lb/hr \( \approx \) 366,000 lb - steam/hr
Problem 2.3: Solution for Excess Air Using Equation 4-8:

Given Dry Gas Analysis: 4.9% \( \text{O}_2 \)

\[
\% \text{ Excess Air} = \frac{\% \text{ O}_2}{20.9 - \% \text{ O}_2} \quad \text{eqn 4-8}
\]

\[
\% \text{ Excess Air} = \frac{4.9}{20.9 - 4.9} = 0.306 \approx 30\%
\]

Therefore, max. \( \text{SO}_2 \) is 56 ppm dry.

Problem 2.4: Find Max. PM Emissions [lb/million Btu]. Assume 40% bottom ash & 60% fly ash.

Fuel Ash Content = 0.75 lb - ash/100 lb - hog fuel
\[= 0.0075 \text{ lb - ash/lb - hog fuel} \]

Fuel HHV = 4,418 Btu/lb - hog fuel

Max. Ash = \[\frac{0.0075 \text{ lb - ash/lb - hog fuel}}{4,418 \text{ Btu/lb - hog fuel}}\]
\[= 1.7 \times 10^{-9} \text{ [lb - ash/Btu]} = 1.7 \frac{\text{lb - ash}}{\text{million Btu}} \]

Max. Flyash = 0.6 x 1.7 \frac{\text{lb - ash}}{\text{million Btu}} = 1.02 \frac{\text{lb - ash}}{\text{million Btu}}

Problem 2.5: Degree of Control Required to Meet the 0.085 lb-PM/million Btu Std.

\[
\text{Degree of Control} = \frac{\text{Required Collection}}{\text{Input}}
\]

\[
\text{Input - Allowable} = \frac{\text{Input}}{\text{Required Collection}}
\]

\[
\frac{(1.02 - 0.085) \text{ lb particulate}}{\text{million Btu}} = \frac{0.935}{1.02} = 0.917
\]

Degree of Control \( \approx 92\% \)

Problem 3: Use of F-factor to Convert Particulate Grain Loading Units

Stack Testing Data for a Bituminous Coal-fired Boiler Indicates:
- 2.0 [grains/dscf].
- 9 % oxygen (dry gas basis).
- 150 ppm CO (dry gas basis).

Determine the particulate emissions in [grains/million Btu] units.
Problem 4: Grain Loading of SO$_2$ from a Gas-Fired Heater

Find: SO$_2$ emission [gr/100 dscf]  
Fuel: Natural Gas  
Heating Value: 1,020 Btu/scf-ng  
Firing Rate: 1.85 mmBtu/hr  
Operating Time: 8,760 [hr/yr]  
Emission Factor: 0.6 lb-SO$_2$/mm scf-ng  
F-factor: $F_d = 8,710$ dscf/mm Btu  
(AP-42 on-line)  
(Table 4-5, page 4-13)

Problem 4: Grain Loading of SO$_2$ from a Gas-Fired Heater

Find SO$_2$ Emission using Emission Factor, Firing rate & HHV

\[ m_{SO_2} = 0.6 \times \frac{lb \ SO_2}{mm \ scf - ng} \times \frac{1 \ scf - ng}{1 \ mm Btu} \times \frac{mm Btu}{1,020 \ Btu} \]

\[ m_{SO_2} = 0.001088 \ \frac{lb \ SO_2}{hr} \]

\[ n_{SO_2} = \frac{0.001088 \ lb \ SO_2/hr}{64 \ lb \ SO_2/mol} = 0.000017 \ \frac{mol \ SO_2}{hr} \]

Find the Concentration of SO$_2$ [ppm]

\[ C_{SO_2} = \frac{n_{SO_2}}{n_{fg}} = \frac{0.000017 \ moles \ SO_2/hr}{41.85 \ moles \ fg/hr} \]

\[ C_{SO_2} = 0.000000406 \]

\[ C_{SO_2} \Rightarrow 0.406 \ ppm \ SO_2 \]

Problem 4: Grain Loading of SO$_2$ from a Gas-Fired Heater

Find the Dry Flue Gas Flow Rate using $F_d$ [dscf/mm Btu]

For stoichiometric conditions (i.e., zero $O_2$):

\[ F_d = 8,710 \ \frac{dscf}{mm \ Btu} \]  
(Table 4-5, page 4-13)

\[ V_d = 8,710 \ \frac{dscf - fg}{mm \ Btu} \times 1.85 \ \frac{mm \ Btu}{hr} = 16,113 \ \frac{dscf - fg}{hr} \]

\[ n_{fg} = \frac{16,113 \ dscf - fg/hr}{385 \ scf/mol} = 41.85 \ \frac{moles - fg}{hr} \]

Find the Concentration of SO$_2$ [gr/dscf]

\[ C_{SO_2} = \frac{m_{SO_2}}{V_{fg}} = \frac{0.001088 \ lb \ SO_2/hr}{16,113 \ dscf - fg/hr} \times 7,000 \ \frac{grains}{lb} \]

\[ C_{SO_2} = 0.000473 \ \frac{grains \ SO_2}{dscf} \]

\[ C_{SO_2} \Rightarrow 0.0473 \ \frac{grains \ SO_2}{100 \ dscf} \]

This is considerably below the allowable Standard.
Problem 5: Combustion Modification

Modification: Oxygen Trim Control
Fuel: Sprg. Crk. Subbituminous
(Table 3-13 Corrected)
Firing Rate 230 Tons-coal/hr
Operating Time 7,880 [hr/yr]
Fuel Costs 0.67 [$/million Btu]
Flue Gas Temp. 355 °F
Ave. Air Temp. 75 °F

Dry Flue Gas Analysis Before and After Modification

<table>
<thead>
<tr>
<th>GAS</th>
<th>BEFORE</th>
<th>AFTER</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO2</td>
<td>14.55</td>
<td>15.82</td>
</tr>
<tr>
<td>O2</td>
<td>4.88</td>
<td>3.55</td>
</tr>
<tr>
<td>CO</td>
<td>0.05</td>
<td>0.01</td>
</tr>
<tr>
<td>N2</td>
<td>80.49</td>
<td>80.59</td>
</tr>
<tr>
<td>SO2</td>
<td>0.03</td>
<td>0.03</td>
</tr>
<tr>
<td>Total</td>
<td>100.00</td>
<td>100.00</td>
</tr>
</tbody>
</table>

Problem 5: Initial Solution Strategy

Compute:
1. Compute $F_w$ for this fuel.
2. Sensible heat loss (before & after).
3. Changed carbon monoxide heat loss.
4. Fuel heat input rate [Btu/yr] and the corresponding changed flue gas energy loss.
5. Cost Savings associated with modification.

Properties of Spring Creek Wyoming Subbituminous Coal, HHV = 9,190 Btu/lb

<table>
<thead>
<tr>
<th>Component</th>
<th>Dry Basis</th>
<th>Wet Basis</th>
</tr>
</thead>
<tbody>
<tr>
<td>Weight</td>
<td>Weight</td>
<td></td>
</tr>
<tr>
<td>Carbon</td>
<td>70.30</td>
<td>53.358</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>5.00</td>
<td>3.795</td>
</tr>
<tr>
<td>Sulfur</td>
<td>0.35</td>
<td>0.266</td>
</tr>
<tr>
<td>Oxygen</td>
<td>17.69</td>
<td>13.427</td>
</tr>
<tr>
<td>Nitrogen</td>
<td>0.96</td>
<td>0.729</td>
</tr>
<tr>
<td>Ash</td>
<td>5.70</td>
<td>4.326</td>
</tr>
<tr>
<td>Moisture</td>
<td>24.100</td>
<td></td>
</tr>
<tr>
<td>Subtotals</td>
<td>100.0</td>
<td>100.000</td>
</tr>
</tbody>
</table>

Problem 5.1, $F_w$ for Subbituminous Coal (eqn. 4-6)

$$F_w = \frac{10^6}{HHV} \left[ 5.56\cdot \%H + 1.53\cdot \%C + 0.57\cdot \%S \\
+ 0.14\cdot \%N - 0.46\cdot \%O + 0.21\cdot \%H_2O \right]$$

$$F_w = \frac{10^6}{9,190} \left[ 5.56\cdot 3.8 + 1.53\cdot 53.36 + 0.57\cdot 0.27 \\
+ 0.14\cdot 0.72 - 0.46\cdot 13.43 + 0.21\cdot 24.14 \right]$$

$$F_w = 11,090 \text{ scf/mmBtu}$$ (Compare with Table 4-5)

Problem 5.2, Sensible Energy

$$\frac{Q_w}{Q_{tot}} = \Delta T \cdot \frac{20.9}{20.9 - \%O_2} \cdot \frac{C_p}{10^6} \cdot \frac{MW_{fg}}{385}$$ (eqn. 4 - 23)

Using $F_w = 11,090$ for lignite and $MW_{fg} = 29.6 \text{ lb/lb-mol}$ (from example on page 4 - 24).

$$\frac{Q_w}{Q_{tot}} = \Delta T \cdot \frac{20.9}{20.9 - \%O_2} \cdot \frac{0.26\cdot 11,090}{10^6} \cdot \frac{29.6}{385}$$

$$\frac{Q_w}{Q_{tot}} = \frac{\Delta T}{4,511} \cdot \frac{20.9}{20.9 - \%O_2}$$ (like eqn. 4 - 24)
Problem 5.2, Sensible Energy

\[
\frac{Q_i}{Q_{\text{tot}}} = \frac{\Delta T}{4.511} \cdot \frac{20.9}{20.9 - \%O_2} \quad \text{(like eqn. 4 - 24)}
\]

\[
\begin{align*}
\frac{Q_i}{Q_{\text{tot}} \text{ before}} & = \frac{355 - 75}{4.511} \cdot \frac{20.9}{20.9 - 4.88} = 0.0810 \\
\frac{Q_i}{Q_{\text{tot}} \text{ after}} & = \frac{355 - 75}{4.511} \cdot \frac{20.9}{20.9 - 3.55} = 0.0748 \\
\Delta Q_e & = (0.0810 - 0.0748) \cdot Q_{\text{tot}} = 0.0062 \cdot Q_{\text{tot}}
\end{align*}
\]

Problem 5.3: Carbon Monoxide Loss

\[
% \text{CO Energy Loss} = 0.00027 \cdot \text{CO (ppm)} \cdot \frac{20.9}{20.9 - \%O_2} \quad \text{(eqn 7.1)}
\]

\[
\begin{align*}
% \text{CO Energy Loss}_{\text{before}} &= 0.00027 \cdot 500 \cdot \frac{20.9}{20.9 - 4.88} = 0.176\% \\
% \text{CO Energy Loss}_{\text{after}} &= 0.00027 \cdot 100 \cdot \frac{20.9}{20.9 - 3.55} = 0.325\%
\end{align*}
\]

Therefore:
\[
\Delta \text{Energy Loss}_{\text{CO}} = 0.0014 \cdot Q_{\text{tot}} \text{ and}
\]
\[
\Delta \text{Energy Loss}_{\text{CO}} = (0.0062 + 0.0014) \cdot Q_{\text{tot}}
\]

\[
\Delta \text{Energy Loss}_{\text{CO}} = 0.0076 \cdot Q_{\text{tot}}
\]

Problem 5.4: Fuel Heat Input and Corresponding Energy Savings

\[
\begin{align*}
Q_{\text{tot}} &= 230 \text{ ton} \cdot 2,000 \text{ lb/ton} \cdot 7,880 \text{ hr/yr} \cdot 9,190 \text{ Btu/lb} \\
Q_{\text{tot}} &= 3.331 \cdot 10^{11} \text{ Btu/yr} = 33,310,000 \text{ mmBtu/yr}
\end{align*}
\]

\[
\begin{align*}
\Delta \text{Energy Loss} &= 0.0076 \cdot Q_{\text{tot}} = 0.0076 \cdot 33,310,000 \text{ mmBtu/yr} \\
\Delta \text{Energy Loss} &= 253,200 \text{ mmBtu/yr}
\end{align*}
\]

Problem 5.5: Cost Savings Associated with the Modification

\[
\Delta \text{Energy Loss} = 253,200 \text{ mmBtu/yr}
\]

\[
\begin{align*}
\text{Fuel Cost} &= 0.67 \frac{\$}{\text{mmBtu}} \\
\text{Cost Savings} &= 253,200 \text{ mmBtu/yr} \cdot 0.67 \frac{\$}{\text{mmBtu}} \\
\text{Cost Savings} &= 169,600/\text{yr}
\end{align*}
\]

Problem 5A: Alternate Solution Strategy

Compute:

1. Excess air levels.
2. Reduced flue gas flow rate.
3. Changed flue gas energy loss [Btu/lb-fuel].

Problem 5A. 1, Excess Air Using Dry Gas Data

Assume:

- \( \text{CO}_{2m} \) is Percent CO\(_2\) in Dry Gas.
- \( \text{CO}_m \) is Percent CO in Dry Gas.
- \( \text{O}_{2m} \) is Percent O\(_2\) in Dry Gas.
- \( \text{N}_{2m} \) is Percent N\(_2\) in Dry Gas.

\[
EA = \frac{\text{O}_{2m} - 0.5 \cdot \text{CO}_m}{0.264 \cdot \text{N}_{2m} - \text{O}_{2m} + 0.5 \cdot \text{CO}_m}
\]
Problem 5A.1: Excess Air, Before & After

<table>
<thead>
<tr>
<th>Before Modified</th>
<th>After Modified</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO = 0.05</td>
<td>CO = 0.01</td>
</tr>
<tr>
<td>O₂ = 4.88</td>
<td>O₂ = 3.55</td>
</tr>
<tr>
<td>N₂ = 80.49</td>
<td>N₂ = 80.59</td>
</tr>
</tbody>
</table>

\[ EA = \frac{0.264N_{2m} - 0.5CO_m}{O_{2m} - 4.88 - 0.5 - 0.05} \]

\[ EA_{before} = \frac{0.264 \times 80.49 - 4.88 + 0.5 - 0.05}{3.55 - 0.5 - 0.01} = 0.30 \]

\[ EA_{after} = \frac{0.264 \times 80.59 - 4.88 + 0.5 - 0.01}{3.55 - 0.5 - 0.01} = 0.20 \]

Find the change in exhaust flow rate

Flue gas density = 0.075 \( \frac{lb - fg}{scf} \)

\[ \Delta F_{\text{flue gas}} = 4,688,000 [\text{scf/hr}] \times 0.075 \frac{lb - fg}{scf} \]

\[ \Delta F_{\text{flue gas}} = 351,000 [\text{lb - fg/hr}] \]

This F-factor solution will be compared with the following solution using combustion fundamentals.

Prob. 5A.2 Find the reduced flue gas flow rate using F-factors.

\[ \text{Flue gas} = F_w \cdot (1 + EA) \quad (\text{eqn. 4 - 10}) \]

\[ \text{Flue gas}_1 = 11,090 \cdot (1.30) = 14,417 \text{ scf/mmBtu} \]

\[ \text{Flue gas}_2 = 11,090 \cdot (1.20) = 13,308 \text{ scf/mmBtu} \]

\[ \Delta \text{Flue gas} = 1,109 \text{ scf/mmBtu} \]

\[ \text{Firing rate} = 230 \frac{T}{hr} \cdot 2,000 \frac{lb}{T \cdot 9.190 \frac{Btu}{lb \cdot 10^6 Btu}} \]

\[ \text{Firing rate} = 4,227 \text{ mmBtu/hr} \]

\[ \Delta \text{Flue gas} = 1,109 \text{ scf/mmBtu} - 4,227 \text{ mmBtu/hr} \]

\[ \Delta \text{Flue gas} = 4,688,000 \text{ scf/hr} \]

Prob. 5A.2, Using Generalized Combustion for Stoichiometric Air

\[ C_xH_yS_zO_uN_vCl_w + t H_2O + a O_2 + 3.78 \cdot a N_2 \]

\[ \rightarrow x \text{ CO}_2 + \left( \frac{y}{2} + t \right) \text{ H}_2\text{O} + z \text{ SO}_2 \]

\[ + w \text{ HCl} + \left( 3.78 \cdot a + \frac{v}{4} \right) \text{ N}_2 \]

Note that the oxygen balance gives:

\[ a = x + \frac{y}{4} + \frac{w}{4} + z - \frac{u}{2} \]

Pseudo-Molecule of Coal: Divide Ultimate Analysis Values by Atomic Weights:

\[
\begin{align*}
\text{x} = & \frac{53.358}{12} = 4.447 \\
\text{y} = & \frac{3.795}{11} = 0.345 \\
\text{z} = & \frac{0.266}{16} = 0.0083 \\
\text{t} = & \frac{24.10}{18} = 1.339 \\
\text{u} = & \frac{13.427}{16} = 0.839 \\
\text{v} = & \frac{0.729}{35} = 0.021 \\
\text{w} = & \frac{0.0083}{32} = 0.00521 \\
\end{align*}
\]

Determination of Stoichiometric Air

Therefore, since:

\[ x = 4.447; \quad y = 3.795; \quad w = 0; \]

\[ z = 0.0083 \text{ and } u = 0.839 \]

The oxygen balance gives:

\[ a = x + \frac{y}{4} + \frac{w}{4} + z - \frac{u}{2} \]

\[ a = 4.447 + \frac{3.795}{4} + 0 - 0.839 \cdot \frac{0.0083}{2} \]

\[ a = 4.984 \approx 4.98 \]
Combustion of Subbituminous Coal (100 lbm)

With no Excess Air:
\[ C_{46.5}H_{1.35}S_{0.344}O_{0.446}N_{0.001} + 1.34 H_2O + 4.98 O_2 + 18.84 N_2 \Rightarrow 4.45 CO_2 + 3.24 H_2O + 0.008 SO_2 + 18.87 N_2 \]

With Excess Air:
\[ C_{46.5}H_{1.35}S_{0.344}O_{0.446}N_{0.001} + 1.34 H_2O + (1 + EA) [4.98 O_2 + 18.84 N_2] \Rightarrow 4.45 CO_2 + 3.24 H_2O + 0.008 SO_2 + EA \cdot 4.98 O_2 + [0.025 + (1 + EA) \cdot 18.84] N_2 \]

Solution: Stoichiometric Combustion of Subbituminous Coal (100 lbm)

\[ C_{46.5}H_{1.35}S_{0.344}O_{0.446}N_{0.001} \Rightarrow 4.45 CO_2 + 3.24 H_2O + 0.008 SO_2 + 18.87 N_2 \]

\[ \frac{m_{air}}{mol - fuel} = \sum N_i \cdot MW_i \]

\[ = 4.45 \cdot 44 + 3.24 \cdot 18 + 0.008 \cdot 64 + 18.87 \cdot 28 \]

\[ \frac{m_{air}}{mol - fuel} \Rightarrow 782.7 \text{ lb-fluegas} \]

\[ \frac{1 \text{ mol-fuel}}{100 \text{ lb-fuel}} = 7.8 \text{ lb-fluegas} \]

\[ \frac{m_{air}}{mol - fuel} = [4.98 \cdot 32 + 18.84 \cdot 28] \]

\[ \frac{1 \text{ mol-fuel}}{100 \text{ lb-fuel}} = 6.87 \text{ lb-air} \]

Problem 5A.2: Flue Gas, Before & After Modification

\[ m \cdot fg = \text{Stoichi. Flue Gas + EA - Stoichi. Air} \]

\[ m \cdot fg_{before} = 7.38 + 0.30 \cdot 6.87 = 9.44 \text{ lb-fuel} \]

\[ m \cdot fg_{after} = 7.38 + 0.20 \cdot 6.87 = 8.75 \text{ lb-fuel} \]

\[ \Delta m \cdot fg = 9.44 - 8.75 = 0.69 \text{ lb-fuel} \]

\[ \Delta m \cdot fg \rightarrow [0.69 \text{ lb-fuel} / 460,000 \text{ lb-fuel/hr}] = 317,400 \text{ lb-fuel/hr} \]

The F-factor calculation was 10% too high.

Specific Heat of Flue Gas

See example problem 4-9, p. 4-36.

Specific Heat of Flue Gas

Depends upon composition & temperature.

For T-average = (355+75)/2 = 215 ~ 212 °F
with EA = 20% = 0.20 (see next page)

\[ C_p = m_{H_2O} \cdot C_{H_2O} + m_{CO_2} \cdot C_{CO_2} + m_{air} \cdot C_{air} \]

\[ C_p = 0.213 \cdot 0.218 + 0.063 \cdot 0.452 + 0.725 \cdot 0.244 \]

\[ C_p = 0.252 \Rightarrow 0.25 \]

Details for Specific Heat Calculation:

PRB Coal at 20% EA; Wet Gas Analysis
Problem 5A.3: Reduced Energy Loss

\[ \Delta q = \text{Reduced flue gas flow rate, \([lb-gas / lb-coal]\)} \]
\[ \times \text{flue gas specific heat, \([Btu / lb fg-F]\)} \]
\[ \times \text{temperature difference, \([F]\)} \]

\[ \Delta q = \Delta m_{\text{flue gas}} \cdot C_p \cdot \Delta T_{\text{net-stack}} \]

\[ \Delta m_{\text{flue gas}} = 317,400 \frac{\text{lb flue gas}}{\text{hr}} \]

\[ \Delta q = 317,400 \frac{\text{lb flue gas}}{\text{hr}} \cdot 0.25 \frac{\text{Btu}}{\text{lb fg - F}} \cdot (355 - 75) \degree F \]

\[ \Delta q = 22,200,000 \frac{\text{Btu}}{\text{hr}} \]

Problem 5A.4: Annual Cost Savings

Average Savings \([\$/yr]\) =

\[ \text{Reduced Heat Loss \([Btu/hr]\)} \]
\[ \times \text{Burnig Time \([hr/yr]\)} \]
\[ \times \text{Unit Energy Cost \([$/Btu]\)} \]

Cost Savings = \(\Delta q \cdot \text{Time} \cdot \text{Unit Energy Cost}\)

Cost Savings = 22,200,000 \(\frac{\text{Btu}}{\text{hr}} \cdot 7,880 \frac{\text{hr}}{\text{yr}} \cdot \$0.67 \frac{\$/\text{million Btu}}{} \]

Cost Savings = \(\$117,200\) per year

Note: There would also be some savings associated with the reduced CO loss.