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EPA would like to acknowledge the work of the University of North Carolina (UNC) Institute for the Environment in updating and re-organizing this document.
## Document Revision History

<table>
<thead>
<tr>
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<th>Description</th>
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<tr>
<td>June 9, 2010</td>
<td>First version of Cost Equations Documentation</td>
</tr>
<tr>
<td>August 31, 2011</td>
<td>Major update to include new CoST cost equations</td>
</tr>
<tr>
<td>October 25, 2011</td>
<td>Edits to reflect the current state of the software and control measures database</td>
</tr>
<tr>
<td>July 3, 2014</td>
<td>Integration of edits and comments from previous version; addition of Industrial, Commercial, and Institutional (ICI) boiler equations</td>
</tr>
<tr>
<td>August 29, 2014</td>
<td>Reorganization of document; addition of appendix for listing the SQL queries used by the CoST equations; addition of appendix for tables of parameter values used by the CoST cost equations</td>
</tr>
<tr>
<td>September 4, 2014</td>
<td>Fixed page/chapter numbering and integration of edits and comments from previous version</td>
</tr>
<tr>
<td>August 27, 2015</td>
<td>Added Equation Type 13 for ICI boiler NOx controls; reorganized section headers</td>
</tr>
<tr>
<td>September 30, 2016</td>
<td>Removed sections for equation types 9, 10, and 11 (these IPM control measures are now obsolete and replaced by Equation Type 1); updated control equation parameters for Equation Type 1</td>
</tr>
<tr>
<td>January 11, 2017</td>
<td>Updated Equation Type 2 to the current form; added Equation Types 2a and 2b; updated example cost equation calculations to use only active measures, including new screen shots; replaced source code in appendix with reference to EPA CoST GitHub repository; updated all control measures and parameters in appendix to be current with January 2017 control measures database; added appendix with complete list of SCCs for all control measures; created internal cross-references for all tables and figures to allow automatic numbering</td>
</tr>
<tr>
<td>April 12, 2017</td>
<td>Integrated comments from EPA on January 11 version; updated all example calculations to use NEI2014 inventory sources and current control measures</td>
</tr>
<tr>
<td>August 2, 2017</td>
<td>Updated equation examples following review of the current equations</td>
</tr>
<tr>
<td>April 20, 2018</td>
<td>Revised Section 1. Introduction to include discussion of converting emissions inventory units (design capacity, exhaust gas flow rate) to the units required for each cost equation. Removed unit conversions discussions and examples from remainder of the document</td>
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1 Introduction

The purpose of EPA’s Control Strategy Tool (CoST) is to model the emissions reductions and costs associated with control strategies applied to sources of air pollution. It was developed as a replacement to EPA’s AirControlNET (ACN) software. CoST overlays a detailed database of control measure information on EPA emissions inventories to compute source- and pollutant-specific emissions reductions and associated costs at various geographic levels (national, regional, and/or local). The Control Measures Database (CMDB) contained in CoST is composed of control measure and cost information for reducing the emissions of criteria pollutants (e.g., NO\textsubscript{x}, SO\textsubscript{2}, VOC, PM\textsubscript{10}, PM\textsubscript{2.5}, and NH\textsubscript{3}) as well as CO and Hg from:

- Point sources in the U.S. electric power sector, as reflected in EPA’s application of the Integrated Planning Model (IPM) (ptipm emissions inventory sector),
- Point sources other than those contained in IPM (ptnonipm),\(^1\)
- Nonpoint sources (nonpt), and\(^2\)
- Mobile sources (onroad and nonroad).\(^3\)

CoST estimates the costs of emissions control technologies in one of two ways:

1) Cost equations are used to determine engineering costs that take into account several variables for the source when data are available for those variables, or

2) A simple cost factor in terms of dollars per ton of pollutant reduced is used to calculate the annual cost of the control measure.

For nonpoint sources, there are control measures, but the measures don’t use cost equations. Cost equations are used for some point sources (ptipm and ptnonipm sources). This document describes the cost equations used in CoST.

This document provides a list of equations and associated variables assigned to specific control measures in CoST. The application of these equations is based on the individual emissions inventory records to which they are applied and the specific characteristics of those records. For example, Equation Type I calculates capital cost largely based on a unit’s generating capacity in megawatts (MW) and is scaled based on the original control cost calculations. It is applicable to NO\textsubscript{x}, SO\textsubscript{2}, and PM\textsubscript{2.5} emissions at ptipm\(^4\) electric generating unit (EGU) sources. For this equation type, variable and fixed operating and maintenance (O&M) costs are also estimated.

Typically, each equation type is applied either to a pollutant-source combination or to a more general grouping of pollutants and sources. The scaling factors, additional variables, and cross-references by control measure and equation type are detailed in this document.


\(^2\) Ibid.

\(^3\) Ibid.

\(^4\) “ptipm” refers to the sector of EPA’s National Emissions Inventory that is composed of point sources included in EPA’s Integrated Planning Model (IPM).
The remainder of this document is divided into chapters by the primary pollutant to be controlled. Chapters 2, 3, and 4 focus on NO\textsubscript{x}, SO\textsubscript{2}, and PM, respectively. Each chapter is further divided into two major sections; the first focuses on IPM equation types and the second focuses on the non-IPM equation types. Table 1-1 presents the control equipment types and pollutants for each equation type. Table 1-2 includes control equipment abbreviations and related descriptions.

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<th>Equipment Type</th>
<th>Primary Pollutants</th>
<th>Section</th>
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<td>1</td>
<td>NO\textsubscript{x}: LNB, LNBO, LNC1, LNC2, LNC3, NGR, SCR, SNCR</td>
<td>NO\textsubscript{x}, SO\textsubscript{2}, PM\textsubscript{2.5}</td>
<td>2.1.1, 3.1.1, 4.1.1</td>
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<td>2</td>
<td>SO\textsubscript{2}: FGD</td>
<td>SO\textsubscript{2}</td>
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<tr>
<td>2a</td>
<td>PM\textsubscript{2.5}: fabric filters</td>
<td>PM\textsubscript{2.5}</td>
<td>4.2.1</td>
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<tr>
<td>2b</td>
<td>LNB, Dry Low NOx Combustion, Air to Fuel Ratio Controller, SCR, Catalytic Combustion, EMx and Dry Low NOx Combustion, EMx and Water Injection, SCR+Dry Low NOx Combustion, SCR+steam injection, SCR+water injection, Steam Injection, Water Injection</td>
<td>NO\textsubscript{x}</td>
<td>2.2.1</td>
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<tr>
<td>3</td>
<td>LNB, SCR</td>
<td>NO\textsubscript{x}</td>
<td>2.2.2</td>
</tr>
<tr>
<td>3</td>
<td>low emissions combustion</td>
<td>NO\textsubscript{x}</td>
<td>2.2.3</td>
</tr>
<tr>
<td>3</td>
<td>FGD, sulfuric acid plant</td>
<td>SO\textsubscript{2}</td>
<td>3.2.1</td>
</tr>
<tr>
<td>3</td>
<td>ESP, fabric filter, paper filter, Venturi scrubber, impingement-plate scrubber</td>
<td>PM</td>
<td>4.2.1</td>
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<tr>
<td>4</td>
<td>SCR, SCR-95%, ULNB, Excess O2 Control</td>
<td>NO\textsubscript{x}</td>
<td>2.2.4</td>
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<tr>
<td>5</td>
<td>FGR, LNB, SCR, SNCR</td>
<td>NO\textsubscript{x}</td>
<td>2.2.5</td>
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<tr>
<td>6</td>
<td>fabric filters</td>
<td>PM</td>
<td>4.2.2</td>
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<tr>
<td>7</td>
<td>ESP</td>
<td>PM</td>
<td>4.2.3</td>
</tr>
<tr>
<td>8</td>
<td>wet scrubber</td>
<td>SO\textsubscript{2}</td>
<td>3.2.2</td>
</tr>
<tr>
<td>9</td>
<td>DIFF system</td>
<td>PM</td>
<td>4.2.4</td>
</tr>
<tr>
<td>10</td>
<td>increased caustic injection rate for existing dry injection control</td>
<td>SO\textsubscript{2}</td>
<td>3.2.3</td>
</tr>
<tr>
<td>11</td>
<td>spray dryer absorber</td>
<td>SO\textsubscript{2}</td>
<td>3.2.4</td>
</tr>
<tr>
<td>cost per ton</td>
<td>episodic ban, seasonal ban, LNB, AF Ratio, AF + IR, Mid-Kiln Firing, SCR, SNCR, ULNB, LEA, low emission combustion, and many others</td>
<td>NO\textsubscript{x}</td>
<td>2.2.1.3</td>
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<tr>
<td>Equipment Abbreviation</td>
<td>Equipment Description</td>
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<td>------------------------</td>
<td>------------------------------------------------------------</td>
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<tr>
<td>AF Ratio</td>
<td>Air/Fuel ratio controls</td>
<td></td>
<td></td>
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<tr>
<td>DIFF System</td>
<td>dry injection &amp; fabric filter system</td>
<td></td>
<td></td>
</tr>
<tr>
<td>ESP</td>
<td>electrostatic precipitator</td>
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<tr>
<td>Excess O2 Control</td>
<td>excess oxygen control to combustor</td>
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</tr>
<tr>
<td>FGD</td>
<td>flue gas desulfurization</td>
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<tr>
<td>FGDW</td>
<td>FGD wet scrubber</td>
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<tr>
<td>FGR</td>
<td>flue gas recirculation</td>
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<td></td>
</tr>
<tr>
<td>IR</td>
<td>Ignition timing retard (for internal combustion engines)</td>
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<tr>
<td>LEA</td>
<td>low excess air</td>
<td></td>
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</tr>
<tr>
<td>LNB</td>
<td>low NOx burner</td>
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<tr>
<td>LNBO</td>
<td>low NOx burner technology with overfire air</td>
<td></td>
<td></td>
</tr>
<tr>
<td>LNC1</td>
<td>low NOx burner technology w/closed-coupled OFA</td>
<td></td>
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</tr>
<tr>
<td>LNC2</td>
<td>low NOx burner technology w/separated OFA</td>
<td></td>
<td></td>
</tr>
<tr>
<td>LNC3</td>
<td>low NOx burner technology w/close coupled/separated OFA</td>
<td></td>
<td></td>
</tr>
<tr>
<td>LSD</td>
<td>lime spray dryer</td>
<td></td>
<td></td>
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<tr>
<td>NGR</td>
<td>natural gas reburning</td>
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<tr>
<td>SCR</td>
<td>selective catalytic reduction</td>
<td></td>
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</tr>
<tr>
<td>SCR-95%</td>
<td>selective catalytic reduction with over 95% NOx efficiency</td>
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<tr>
<td>SCR+LNB</td>
<td>both selective catalytic reduction and low NOx burner technology</td>
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<tr>
<td>SCR+steam injection</td>
<td>selective catalytic reduction with steam injection</td>
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<tr>
<td>SCR+water injection</td>
<td>selective catalytic reduction with water injection</td>
<td></td>
<td></td>
</tr>
<tr>
<td>SDA</td>
<td>spray dryer absorber</td>
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<td></td>
</tr>
<tr>
<td>SNCR</td>
<td>selective noncatalytic reduction</td>
<td></td>
<td></td>
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<tr>
<td>SNCR-Urea</td>
<td>selective noncatalytic reduction – urea</td>
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<tr>
<td>SNCR-Ammonia</td>
<td>selective noncatalytic reduction – ammonia</td>
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<tr>
<td>ULNB</td>
<td>ultra-low NOx burner</td>
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</tbody>
</table>

The source code for the CoST cost equations are available in the EPA GitHub repository at the link below. This repository will be continually updated with the latest version of the CoST cost equations.

https://github.com/USEPA-OAQPS/emf/blob/master/EMF/deploy/db/cost/functions/cost_equations_v2.sql

### 1.1 Capital Recovery Factor Equation

Throughout the document we provide equations to estimate annualized capital costs using a capital recovery factor. The following equation is used to estimate the capital recovery factor (CRF) for the case of discrete interest compounding (i.e., not continuous compounding).

\[
\text{Capital Recovery Factor} = \frac{\text{Interest Rate} \times (1 + \text{Interest Rate}^\text{Equipment Life})}{(1 + \text{Interest Rate})^\text{Equipment Life} - 1}
\]

Where:
- \( \text{Interest Rate} \) = annual interest rate
• *Equipment Life* = expected economic life of the control equipment

### 1.2 Emissions Inventory Unit Conversions

The cost equations in this document use various parameters from the emissions inventory to determine the size of the emissions unit, which in turn is used to calculate the capital and other operating costs. Each equation requires specific units for the emissions inventory parameter used in the equation. Nearly all of the units for the emissions inventory parameters used in the equations are prescribed in the format of the inventory (see the SMOKE User’s Manual for the required units). For example, the exhaust gas flow rate must be reported as cubic feet per second. However, SMOKE provides flexibility for reporting the design capacity units. This requires a conversion of the units used in the emissions inventory to the units required for each cost equation.

#### 1.2.1 Design Capacity Unit Conversions

The unit conversions for design capacity are relatively straightforward, as shown in the following equation:

\[
Design \text{ Capacity}_{\text{equation}} = Design \text{ Capacity}_{\text{inventory}} \times Conversion \text{ Factor} \times Combustion \text{ Efficiency}
\]

Where:

- *Design Capacity*\text{equation} = capacity of the emission process in units required by the CoST equation
- *Design Capacity*\text{inventory} = capacity of the emission process in units reported in the emissions inventory
- *Conversion Factor* = standard factor used to convert from emission inventory units to cost equation units
- *Combustion Efficiency* = the ratio of the useful energy output by the system to the energy input to the system

The following standard conversion factors are used in the CoST unit conversion algorithm, which first converts inventory units to a common unit (Megawatt Thermal {MWt}) and then converts MWt to the units required for each individual CoST equation. The factors used to convert from inventory units to MWt are as follows:

- 1 MWt = 3.412 million British Thermal Units per hour (MMBtu/hr or E6BTU/HR)
- 1 MWt = 1000 Kilowatt Thermal (KWt)
- 1 MWt = 0.000746 Horsepower (HP)
- 1 MWt = 0.000981 Boiler Horsepower (BLRHP)

---

The combustion efficiency is based on the Source Classification Code (SCC) and is retrieved from the CoST SCC table. The combustion efficiency is the ratio of the useful energy output by the system to the energy input to the system. Most of the CoST equations are based on the size of the unit in terms of the energy input to the system. In that case, the combustion efficiency is not needed and effectively treated as 100% in the CoST unit conversion algorithm. However, for electric generating units (EGUs), the CoST equations are based on the size of the unit in terms of useful energy output from the system. In the electric power industry, there are two values assigned to a unit’s design capacity: megawatts electric (MWe) and megawatts thermal (MWt). The former refers to the electricity output capability of the plant, and the latter refers to the input energy required. The efficiency of an EGU is equal to the ratio of the electric output of the plant to the thermal overall power need to generate the electricity. For example, a coal-fired power plant rated at 1000 MWe will require supply of 3000 MWt of heat (e.g., approximately 10,236 MMBTU/HR) from burning coal for every 1000 MW of electricity it produces. The efficiency is specified for each SCC in the SCC table of the Control Measure Database. Typical values are 33 to 35% for coal-fired plants.

1.2.2 Exhaust Gas Flowrate Unit Conversions

The exhaust gas flowrate in the emissions inventory must be reported as cubic feet per second, and it is assumed that the flowrate reported in the emissions inventory is at actual stack conditions. Some of the cost equations in this document were developed using the actual flow rate, but others use the flow rate corrected to standardized properties of temperature and moisture content. The following terminology is used when discussing the flowrate in this document:

\[
F_a = F_{\text{inventory}} \times 60
\]

\[
F_s = (F_a) \left( \frac{520}{460 + T} \right)
\]

\[
F_d = (F_a) \left( \frac{460 + 68}{460 + T} \right) \left( 1 - \frac{\%\text{Moist}}{100} \right)
\]

Where:

- \(F_{\text{inventory}}\) = Stack gas flowrate (ft\(^3\)/s) from the emissions inventory
- \(F_a\) = Actual exhaust flowrate (acfm)
- \(F_s\) = Exhaust flowrate at standard temperature (scfm)
- \(F_d\) = Exhaust flowrate at standard temperature on a dry basis (dscfm)
- 60 = Seconds to minutes conversion factor
- \(T\) = Stack gas temperature (°F) from the emissions inventory
- \(\%\text{Moist}\) = Stack gas moisture content (%) from the CMDB equations table
2 NOx Control Cost Equations

This chapter is divided into two main sections – IPM and non-IPM sources. The types of cost equations, indicated below, for point source NOx controls are described in their appropriate sections.

- Equation Type 1 for IPM sector external combustion boilers
- Equation Types 2 and 2b for gas-fired turbine point sources and internal combustion engines
- Equation Type 2a for glass manufacturing
- Equation Type 12 for gas-fired process heaters at petroleum refineries
- Equation Type 13 for non-IPM boilers, or industrial, commercial, and institutional (ICI) boilers
- Default cost per ton equations for non-IPM point sources

This chapter describes each equation type, presents the relevant parameters, and provides example calculations. The example calculations provided are prepared using version 2.15 of the CoST software. Appendix A provides tables of parameters and values used with each equation type.

2.1 IPM Sector (ptipm) NOx Control Cost Equations

Equation Type 1 is the only cost equation applicable to IPM sector (ptipm) point sources requiring NOx emission reductions. These sources are electric generating units. All of the cost data in CoST for ptipm sources are originally from the Integrated Planning Model (IPM) v3.0; while we have incorporated the IPM data into CoST, we generally rely on output from IPM for input to analyses of costs for EGU sources and controls. NOx control technologies for Equation Type 1 are:

- Low NOx Burner (LNB)
- Low NOx Burner and Over Fire Air (LNBO)
- Low NOx Coal-and-Air Nozzles with Cross-Coupled Overfire Air (LNC1)
- Low NOx Coal-and-Air Nozzles with Separated Overfire Air (LNC2)
- Low NOx Coal-and-Air Nozzles with Cross-Coupled and Separated Overfire Air (LNC3)
- Natural Gas Reburn (NGR)
- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)

2.1.1 Equation Type 1 for NOx- Utility Boilers

The data for this equation type were developed based on a series of model plants. The capacities of these model plants are used along with scaling factors and the emissions inventory’s unit-
specific boiler characteristics (e.g., boiler capacity, stack parameters) to generate a control cost for an applied technology.

2.1.1.1 Cost Equations

Capital Cost Equations

The purpose of a capital cost analysis is to put potential uses of capital (e.g., money, equipment) in the same economic terms. This allows a direct comparison to be made between these potential uses. The capital cost equations in CoST provide an estimate of the annualized capital cost of multiple technologies for direct comparison.

When developing Equation Type 1, multiple model plants were designed and the calculations were then simplified. CoST calculates the capital cost associated with a control measure by applying a scaling factor to the calculations for an appropriate model plant; the scaling factor is calculated based on the ratio of the model plant’s capacity to the capacity of a boiler measured in megawatts (MW).

\[
Scaling\ Factor = \left( \frac{Scaling\ Factor\ Model\ Size}{Capacity} \right)^{Scaling\ Factor\ Exponent}
\]

Where:
- \(Scaling\ Factor\ Model\ Size\) = boiler capacity of the model plant (MW)
- \(Scaling\ Factor\ Exponent\) = an empirical value based on the specific control measure
- \(Capacity\) = capacity of the boiler (MW) (from the units used in the emissions inventory converted to MW, see Section 1.2.1 for a discussion of unit conversions)

The capital cost associated with these NO\textsubscript{x} control measures is a straightforward calculation of the capital cost multiplier, the unit’s boiler capacity (MW) (from emissions inventory), and the scaling factor that was calculated.

\[
Capital\ Cost = Capital\ Cost\ Multiplier \times Design\ Capacity \times Scaling\ Factor \times 1,000
\]

Where:
- \(Capital\ Cost\ Multiplier\) = an empirical value based on the specific control measure ($/kW)
- \(Design\ Capacity\) = capacity of the boiler (MW)
- 1,000 = unit conversion factor

Finally, the following equation calculates the annualized capital cost. This is the cost of capital only; it does not include costs due to operations and maintenance.

\[
Annualized\ Capital\ Cost = Capital\ Cost \times Capital\ Recovery\ Factor
\]

Where the Capital Cost and the Capital Recovery Factor have been calculated previously.
**Operation and Maintenance Cost Equations**

Operation and maintenance (O&M) costs, which are also calculated on an annual basis, are in addition to the capital cost of equipment. These O&M costs are divided into fixed costs and variable costs. Fixed costs are incurred because the equipment exists whether or not it is in operation. Examples of fixed costs are property taxes, insurance, and administrative charges. The fixed O&M cost component is also based on the unit’s capacity.

\[ Fixed\ O&M = Fixed\ O&M\ Cost\ Multiplier \times Design\ Capacity \times 1,000 \]

Where:
- \( Fixed\ O&M\ Cost\ Multiplier \) = an empirical value based on the control measure ($/kW)
- \( Design\ Capacity \) = capacity of the boiler (MW) (from the emissions inventory)
- \( 1,000 \) = unit conversion factor

The variable portion of the O&M costs includes an additional estimate for the unit’s capacity factor, which is a factor reflecting the unit’s utilization.

\[ Variable\ O&M = Variable\ O&M\ Cost\ Multiplier \times Design\ Capacity \times Capacity\ Factor \times 8,760 \]

Where:
- \( Variable\ O&M\ Cost\ Multiplier \) = an empirical value based on the specific control measure ($/MWh)
- \( Capacity\ Factor \) = the capacity factor captures the amount of actual power generated by a power plant as compared to its design capacity or rated output\(^8\)
- \( 8,760 \) = assumed number of hours of operation per year

The total annual operations and maintenance cost is then the sum of the annual fixed and variable O&M costs.

\[ Total\ O&M\ Cost = Fixed\ O&M + Variable\ O&M \]

**Total Annualized Cost Equation**

The annualized cost is then estimated using the unit’s capital cost times the CRF (derived with an annual interest rate and equipment lifetime expectancy) and the sum of the fixed and variable O&M costs.

\[ Total\ Annualized\ Cost = Annualized\ Capital\ Cost + Total\ O&M\ Cost \]

### 2.1.1.2 Example Calculations

This section provides example calculations for an application of Equation Type 1. The example scenario is a utility boiler – coal/wet bottom/tangential/bituminous (SCC 10100211) that requires

---

\(^8\) If a power plant’s design capacity is 500 MW, but the plant runs at 400 MW, it’s capacity factor is 80 percent.
NOx control. The control measure abbreviation is NSCR UBCT1, the control measure is SCR and the control efficiency is 90%.

**Example Equation Type 1 Variables**

Capacity (MW) for the boiler is taken from the emissions inventory:

\[
\text{Capacity (MW)} = 61.98
\]

\[
\text{Capital Recovery Factor} = 0.0703 \text{ (assumes equipment life of 30 years and interest rate of 5.7%, which is provided by IPM)}
\]

The following values are shown in the View Control Measure screen in Figure 2-1.9

\[
\text{Capital Cost Multiplier (}$/\text{kW}$\text{)} = 349
\]

\[
\text{Fixed O&M Cost Multiplier (}$/\text{kW}$\text{)} = 1.86
\]

\[
\text{Variable O&M Cost Multiplier (}$/\text{MWh}$\text{)} = 1.3
\]

\[
\text{Scaling Factor Model Size (MW)} = 0
\]

\[
\text{Scaling Factor Exponent} = 0
\]

\[
\text{Capacity Factor} = 1
\]

\[
\text{Year for Cost Basis} = 2011
\]

---

9 The combustion efficiency value is in the SCCs tab in the control measure database.
Figure 2-1. Equation Type 1 for NO$_x$ - Example Screenshot from CoST

**Annualized Capital Cost Equation**

Scaling Factor $= \left( \frac{\text{Scaling Factor Model Size}}{\text{Capacity}} \right)^{\text{Scaling Factor Exponent}}$

Scaling Factor $= \left( \frac{0}{61.98} \right)^0$

Scaling Factor $= 1$

Capital Cost $= \text{Capital Cost Multiplier} \times \text{Capacity} \times \text{Scaling Factor} \times 1,000$

Capital Cost $= 349 \times \frac{\$}{kW} \times 61.98 \, MW \times 1 \times 1,000 \times \frac{kW}{MW}$

Capital Cost $= \$21,631,481 \ (2011\$)$

Annualized Capital Cost $= \text{Capital Cost} \times \text{Capital Recovery Factor}$

Annualized Capital Cost $= \$21,631,481 \times 0.0703$

Annualized Capital Cost $= \$1,521,392 \ (2011\$)$
**Operation and Maintenance Cost Equation**

\[
\text{Fixed O&M} = \text{Fixed O&M Cost Multiplier} \left( \frac{\$}{kW} \right) \times \text{Capacity (MW)} \times 1,000
\]

\[
\text{Fixed O&M} = 1.86 \frac{\$}{kW} \times 61.98 \text{ MW} \times 1,000 \frac{kW}{MW}
\]

\[
\text{Fixed O&M} = \$115,285 \text{ (2011$)}
\]

\[
\text{Variable O&M} = \text{Variable O&M Cost Multiplier} \left( \frac{\$}{MWh} \right) \times \text{Capacity (MW)} \times \text{Capacity Factor}
\]

\[
\times 8,760 \text{ (Hours Per Year)}
\]

\[
\text{Variable O&M} = 1.3 \frac{\$}{MWh} \times 61.98 \text{ MW} \times 1.0 \times 8,760 \text{ Hours}
\]

\[
\text{Variable O&M} = \$705,843 \text{ (2011$)}
\]

\[
\text{Total O&M Cost} = \text{Fixed O&M} + \text{Variable O&M}
\]

\[
\text{Total O&M Cost} = \$115,285 + \$705,843
\]

\[
\text{Total O&M Cost} = \$821,129 \text{ (2011$)}
\]

**Total Annualized Cost Equation**

\[
\text{Total Annualized Cost} = \text{Annualized Capital Cost} + \text{Total O&M Cost}
\]

\[
\text{Total Annualized Cost} = 1,521,392 + 821,129
\]

\[
\text{Total Annualized Cost} = 2,342,520 \text{ (2011$)}
\]

### 2.2 Non-IPM Sector (ptnonipm) NO\textsubscript{x} Control Cost Equations

Control costs for some non-EGU point sources where NO\textsubscript{x} is the primary pollutant to be controlled are discussed in this section. Equation Type 2 estimates the costs of NO\textsubscript{x} controls for natural gas-fired turbines and internal combustion engines (ICE). Equation Type 2 originally also covered Industrial, Commercial, and Institutional (ICI) boilers, but costs of NO\textsubscript{x} controls for ICI boilers are now estimated by Equation Type 13. Equation Type 12 estimates emissions control measures for gas-fired process heaters at petroleum refineries. Finally, default cost per ton factors are used for some additional source types.

#### 2.2.1 Equation Type 2 for NO\textsubscript{x} – Natural Gas Turbines and ICEs

Costs for low NO\textsubscript{x} burners applied to natural gas-fired turbines and lean burn ICE are estimated using Equation Type 2. Equation Type 2 uses the design capacity from the input emissions inventory (converted from emissions inventory units to the unit {MMBtu/hour} required by the cost equations, see Section 1.2.1), as well as a scaling component, such as a capital cost multiplier, that is based on the original Alternative Control Technology or Control Technology
Guidelines (ACT/CTG) analyses used to derive these estimates.\textsuperscript{10} NOx control technologies for Equation Type 2 are:

- LNB
- Dry Low NOx Combustion
- Air to Fuel Ratio Controller
- SCR
- Catalytic Combustion
- EMx and Dry Low NOx Combustion
- EMx and Water Injection
- SCR + Dry Low NOx Combustion
- SCR + Steam Injection
- SCR + Water Injection
- Steam Injection
- Water Injection

Equation Type 2-based costs are estimated for units that have a design capacity not exceeding 2,000 million Btu per hour (MMBtu/hour). For those sources above the capacity threshold, default costs per ton are used (see Section 2.2.1.3).

2.2.1.1 Cost Equations

**Capital Cost Equation**

The O&M costs are calculated by subtracting the annualized capital costs, or the product of capital costs $\times$ capital recovery factor (CRF), from the total annualized costs. The CRF value is calculated in CoST using the equipment life and interest rate specified when setting up a CoST run.

\[
\text{Capital Cost} = \text{Capital Cost Multiplier} \times (\text{Design Capacity})^\text{Capital Cost Exponent} + \text{Capital Cost Base}
\]

Where:

- **Capital Cost Multiplier** = an empirical value based on the specific control measure
- **Capital Cost Exponent** = an empirical value based on the specific control measure
- **Design Capacity** = the emissions unit design capacity (MMBtu/hour)
- **Capital Cost Base** = value based on the linear fit of the equation to empirical data; not applicable to all control measures

\[
\text{Annualized Capital Cost} = \text{Capital Cost} \times \text{Capital Recovery Factor}
\]

Where the **Capital Cost** and the **Capital Recovery Factor** have been calculated previously.

\textsuperscript{10} RTI 2014, Section 3.
Total Annualized Cost Equation

Total Annualized Cost
\[ \text{Total Annualized Cost} = \text{Annual Cost Multiplier} \times (\text{Design Capacity})^{\text{Annual Cost Exponent}} + \text{Annual Cost Base} \]

Where:
- \( \text{Annual Cost Multiplier} \) = an empirical value based on the specific control measure
- \( \text{Annual Cost Exponent} \) = an empirical value based on the specific control measure
- \( \text{Design Capacity} \) = the emissions unit design capacity (MMBtu/hour)
- \( \text{Annual Cost Base} \) = value based on the linear fit of the equation to empirical data; not applicable to all control measures

Operation and Maintenance Cost Equation

Total O&M Cost = Total Annualized Cost – Annualized Capital Cost

Where the Total Annualized Cost and the Annualized Capital Cost were calculated previously.

2.2.1.2 Example Calculations

This section provides an example calculation for an application of Equation Type 2. The example scenario is a Natural Gas Turbine that uses catalytic combustion to control NO\(_x\). The control measure abbreviation is NCATCGTNG, and the control measure is catalytic combustion.

Example Equation Type 2 Variables

Design Capacity (MMBtu/hour) from the emissions inventory = 8.9
Capital Recovery Factor = 0.1098 (assumes equipment life of 15 years and interest rate of 7%)

Many of the following values are shown in the View Control Measure screen in Figure 2-2.

Capital Cost Multiplier = $20,668.0
Capital Cost Exponent = 0.57
Capital Cost Base = N/A
Annual Cost Multiplier = $4,254.2
Annual Cost Exponent = 0.82
Annual Cost Base = N/A
Year for Cost Basis = 1999
Equation Type 2 Example

All costs are in 1999 U.S. dollars because that is the base year for the references for these equations and for the capital-to-annual ratios.

**Capital Cost Equation**

\[
\text{Capital Cost} = \text{Capital Cost Multiplier} \times (\text{Design Capacity})^{\text{Capital Cost Exponent}} + \text{Capital Cost Base}
\]

**Capital Cost** = $20,668 \times 8.9^{0.57}

**Capital Cost** = $71,854 (1999$)

Use an implicit price deflator ratio to convert from 1999$ to 2000$. 

---

*Figure 2-2. Equation Type 2 for NO\(_x\) - Example Screenshot from CoST*
Capital Cost = $71,854 (1999$) \times \frac{81.887 (2000$)}{80.065 (1999$)}

Capital Cost = $73,489 (2000$)

Annualized Capital Cost = Capital Cost \times Capital Recovery Factor
Annualized Capital Cost = $73,489 \times 0.1098
Annualized Capital Cost = $8,069 (2000$)

Total Annualized Cost Equation
Total Annualized Cost = Annual Cost Multiplier \times (Design Capacity)^{Annual Cost Exponent}
Total Annualized Cost = $4,254.20 \times 301.0^{0.82}
Total Annualized Cost = $25,546 (1999$)

Convert to 2000$ using the implicit price deflator ratio:
Total Annualized Cost = $25,546 (1999$) \times \frac{81.887 (2000$)}{80.065 (1999$)}
Total Annualized Cost = $26,127 (2000$)

Operation and Maintenance Cost Equation
Total O&M Cost = Total Annualized Cost − Annualized Capital Cost
Total O&M Cost = $26,127 − $8,069
O&M Cost = $18,058 (2000$)

2.2.1.3 Non-IPM Sector (ptnonipm) NOx Cost per Ton Calculations

When a source qualifies for Equation Type 2 except for the emissions unit capacity (design capacity > 2,000 MMBtu/hour), default cost per ton values are assigned and applied to the annual emissions reduction achieved by the applied control measure.

Total Annualized Cost Equation

When no control is currently in place for the source:

Total Annualized Cost = Emissions Reductions \times Default Cost Per Ton

Where:
- Emissions Reductions = calculated by CoST (tons/year)
- Default Cost per Ton = an empirical value based on the specific control measure

2.2.1.4 Non-IPM Sector (ptnonipm) NOx Cost per Ton Example

This section provides example calculations for an application of this cost per ton method for NOx control on a nitric acid manufacturing industrial process (SCC 30101301) that uses non-selective
catalytic reduction controls (NNSCRNAMF). Figure 2-3 illustrates the Efficiencies tab of the View Control Measure screen for NNSCRNAMF.

**Example Equation Type 2 Variables**

*Capital Recovery Factor* = 0.1098 (assumes equipment life of 15 years and interest rate of 7%)
*NOₓ Emission Reduction* = 24.5 tons/year
*Capital to Annual Ratio* = 2.4
*Default Cost per Ton Reduced* = 550.0 (1990$)
*Year for Cost Basis* = 1990

**Figure 2-3: NOₓ Control Measure Cost per Ton Non-IPM Sector – Example Screenshot from CoST**

![Example Screenshot from CoST](image)

**Example Calculation when no control measure is in place for the source (Default Reduction)**

**Total Annualized Cost Equation**

\[
\text{Total Annualized Cost} = \text{Emissions Reductions} \times \text{Default Cost Per Ton}
\]

\[
\text{Total Annualized Cost} = 24.5 \times 550
\]

\[
\text{Total Annualized Cost} = 13,475 \text{ (1990$)}
\]

Use an implicit price deflator ratio to convert from 1990$ to 2000$.

\[
\text{Total Annualized Cost} = 13,475 \times \frac{81.887 \text{ (2000$)}}{66.773 \text{ (1990$)}}
\]

\[
\text{Total Annualized Cost} = 16,525 \text{ (2000$)}
\]
Capital Cost Equation

\[ \text{Capital Cost} = \text{Total Annualized Cost} \times \text{Capital to Annual Ratio} \]

\[ \text{Capital Cost} = \$16,525 \times 2.4 \]
\[ \text{Capital Cost} = \$39,660 (2000\$) \]

Annualized Capital Cost = Capital Cost \times Capital Recovery Factor

\[ \text{Annualized Capital Cost} = \$39,660 \times 0.1098 \]
\[ \text{Annualized Capital Cost} = \$4,354 (2000\$) \]

Operation and Maintenance Cost Equation

\[ \text{Total O&M Cost} = \text{Total Annualized Cost} - \text{Annualized Capital Cost} \]

\[ \text{Total O&M Cost} = \$16,525 - \$4,354 \]
\[ \text{Total O&M Cost} = \$12,171 (2000\$) \]

2.2.2 Equation Type 2a for NO\textsubscript{x} – Glass Manufacturing

Equation Type 2a is used to calculate NO\textsubscript{x} reductions from glass manufacturing.\textsuperscript{11} NO\textsubscript{x} control technologies for Equation Type 2a include LNB and SCR.

2.2.2.1 Cost Equations

Capital Cost Equation

\[ \text{Capital Cost} = \text{Capital Cost Multiplier} \times \text{Emissions Reduction}^{\text{Capital Cost Exponent}} + \text{Capital Cost Base} \]

Where:

- \text{Capital Cost Multiplier} = \text{an empirical value based on the specific control measure}
- \text{Capital Cost Exponent} = \text{an empirical value based on the specific control measure}
- \text{Emissions Reduction} = \text{the change in emissions resulting from application of the control technology (tons/day)}
- \text{Capital Cost Base} = \text{value based on the linear fit of the equation to empirical data; not applicable to all control measures}

Total Annualized Cost Equation

\[ \text{Total Annualized Cost} = \text{Annual Cost Multiplier} \times \text{Emissions Reduction}^{\text{Annual Cost Exponent}} + \text{Annual Cost Base} \]

Where:

- \text{Annual Cost Multiplier} = \text{an empirical value based on the specific control measure}

\textsuperscript{11} RTI 2014, Section 4.
• **Annual Cost Exponent** = an empirical value based on the specific control measure
• **Emissions Reduction** = the change in emissions resulting from the application of the control technology (tons/day)
• **Annual Cost Base** = value based on the linear fit of the equation to empirical data; not applicable to all control measures

### 2.2.2.2 Example Calculations

**Equation Type 2a Example for NO\textsubscript{x}**

This section provides example calculations for an application of Equation Type 2a. The example scenario is for a container glass manufacture melting furnace (SCC 30501402) that uses a low NOx burner (NLNBUGMCN). Figure 2-34 illustrates the Equations tab of the View Control Measure screen for NLNBUGMCN.

**Example Equation Type 2a Variables**

- **Capital Recovery Factor** = 0.1424 (assumes equipment life of 10 years and interest rate of 7%)
- **Emissions Reduction** = 40 tons/year or 0.109589 tons/day (from CoST)
- **Capital Cost Multiplier** = $30,930.0
- **Capital Cost Exponent** = 0.45
- **Capital Cost Base** = 0
- **Annual Cost Multiplier** = $9,377.0
- **Annual Cost Exponent** = 0.4
- **Annual Cost Base** = 0
- **Year for Cost Basis** = 2007
Figure 2-4. Equation Type 2a for NOx - Example Screenshot from CoST

**Capital Cost Equation**

\[
\text{Capital Cost} = \text{Capital Cost Multiplier} \times \text{Emissions Reduction}^{\text{Capital Cost Exponent}} + \text{Capital Cost Base}
\]

\[
\text{Capital Cost} = 30,930.0 \times 0.109589^{0.45} + 0.0
\]

\[
\text{Capital Cost} = 11,436 \text{ (2007$)}
\]

\[
\text{Annualized Capital Cost} = \text{Capital Cost} \times \text{Capital Recovery Factor}
\]

\[
\text{Annualized Capital Cost} = 11,436 \times 0.1424
\]

\[
\text{Annualized Capital Cost} = 1,628 \text{ (2007$)}
\]
**Annual Cost Equation**

Total Annualized Cost  
= Annual Cost Multiplier × Emissions Reduction \(^{\text{Annual Cost Exponent}}\) + Annual Cost Base

Total Annualized Cost = $9,377.0 × 0.109589^{0.4} + 0.0  
Total Annualized Cost = $3,872 (2007$)

**Operation and Maintenance Cost Equation**

Total O&M Cost = Total Annualized Cost − Annualized Capital Cost  
Total O&M Cost = $3,872 − $1,628  
Total O&M Cost = $2,244 (2007$)

### 2.2.3 Equation Type 2b for NO\(_x\) – Natural Gas ICEs

Equation Type 2b is used to calculate NO\(_x\) control costs for natural gas lean burn or clean burn ICE with low emissions combustion (LEC) control technology\(^{12}\). LEC control technology is described as retrofit kits that allow engines to operate on extremely lean fuel mixtures to minimize NO\(_x\) emissions. The LEC control technology retrofit may include: (1) redesign of cylinder head and pistons to improve mixing (on smaller engines), (2) precombustion chamber (on larger engines), lower cost, simple versions, (3) turbocharger, (4) high energy ignition system, (5) aftercooler, and (6) air-to-fuel ratio controller.

Based on the cost calculations for engines of varying power (hp), Equation Type 2b was developed for the capital cost and annual costs for LEC on natural gas lean burn engines.

#### 2.2.3.1 Cost Equations

**Capital Cost Equations**

Calculate single control technology total capital costs with the following equation:

\[
\text{Capital Cost} = \text{Capital Cost Multiplier} \times e^{(\text{Capital Cost Exponent} \times \text{Design Capacity})}
\]

Where:
- **Capital Cost Multiplier** = an empirical value based on the specific control measure
- **Capital Cost Exponent** = an empirical value based on the specific control measure
- **Design Capacity** = emissions unit capacity (converted from emissions inventory units to the unit {hp} required by the cost equations, see Section 1.2.1)

Calculate single control technology annual costs with the following equation:

\[\text{Annual Cost} = \text{Annual Cost Multiplier} \times e^{(\text{Annual Cost Exponent} \times \text{Emissions Reduction})}\]

---

\(^{12}\) RTI 2014, Section 5.
**Annual Cost Equation**

\[
\text{Annual Cost} = \text{Annual Cost Multiplier} \times e^{(\text{Annual Cost Exponent} \times \text{Design Capacity})}
\]

Where:
- \(\text{Annual Cost Multiplier}\) = an empirical value based on the specific control measure
- \(\text{Annual Cost Exponent}\) = an empirical value based on the specific control measure
- \(\text{Design Capacity}\) = emissions unit capacity (hp)

### 2.2.3.2 Example Calculations

**Equation Type 2b Example for NO\(_x\)**

This section provides example calculations for an application of Equation Type 2b. The example scenario is for a 175 hp natural gas industrial 4-cycle lean burn internal combustion engine (SCC 20200254) with LEC, lean burn controls (NLECICENG). Figure 2-5 illustrates the Equations tab of the View Control Measure screen for Low Emission Combustion: Lean Burn ICE - NG.

**Example Equation Type 2b Variables**

- \(\text{Capital Recovery Factor}\) = 0.1424 (assumes equipment life of 10 years and interest rate of 7%)
- \(\text{Control Device}\) = LEC
- \(\text{Capital Cost Multiplier}\) = $16,019
- \(\text{Capital Cost Exponent}\) = 0.0016
- \(\text{Annual Cost Multiplier}\) = $2,280.8
- \(\text{Annual Cost Exponent}\) = 0.0016
- \(\text{Design Capacity (hp)}\) = 175
- \(\text{Cost Year}\) = 2001
Figure 2-5. Equation Type 2b for NOx - Example Screenshot from CoST

**Capital Cost Equation**

\[
\text{Capital Cost} = \text{Capital Cost Multiplier} \times e^{(\text{Capital Cost Exponent} \times \text{Design Capacity})}
\]

\[
\text{Capital Cost} = 16,019 \times e^{(0.0016 \times 175)}
\]

**Capital Cost** = $21,195 (2001$

**Annualized Capital Cost** = $21,195 \times 0.1424

Annualized Capital Cost = $3,017.72 (2001$

**Annual Cost Equation**

\[
\text{Annual Cost} = \text{Annual Cost Multiplier} \times e^{(\text{Annual Cost Exponent} \times \text{Design Capacity})}
\]

\[
\text{Annual Cost} = 2,280.8 \times e^{(0.0016 \times 175)}
\]

Total Annualized Cost = $3,017.79 (2001$

**Operation and Maintenance Cost Equation**

\[
\text{Total O&M Cost} = \text{Total Annualized Cost} - \text{Annualized Capital Cost}
\]

Total O&M Cost = $3,017.79 – $3,017.72

Total O&M Cost = $0.07 (2001$

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2.2.4 Equation Type 12 for NO\textsubscript{x} – Petroleum Industry Process Heaters

For a select set of gas-fired process heaters at petroleum refineries, control costs are estimated using stack flowrate and temperature represented by Equation Type 12.\textsuperscript{13} Control technologies for Equation Type 12 are as follows:

- Excess O3 Control - 80 ppmv NO\textsubscript{x} outlet concentration
- Ultra-Low NO\textsubscript{x} Burner (ULNB) - 40 ppmv NO\textsubscript{x} outlet concentration
- Selective Catalytic Reduction (SCR) - 20 ppmv NO\textsubscript{x} outlet concentration
- SCR-95% - 10 ppmv NO\textsubscript{x} outlet concentration

Control costs are estimated for units that have a positive stack flowrate and temperature value. For those sources with missing stack flowrate or temperature, no costs are calculated.

2.2.4.1 Emissions Reduction Equations

This subsection presents an alternative way to calculate emissions reduction potential from process heaters at petroleum refineries.\textsuperscript{14} This Equation Type uses the exhaust flowrate at standard temperature ($F_s$) in standard cubic feet per minute (scfm) (see Section 1.2.2 for discussion of flowrate unit conversions).

**Mole Fraction of NO\textsubscript{x} in outlet gas**

The equations that are used to convert from inventory emissions to the concentration of NO\textsubscript{x} in the stack gas are shown here.

\[
VFR_{NOx} = E_{NOx} \times 2,000 \times \left(\frac{1}{46.0}\right) \times \left(\frac{1}{O_{Phrs}}\right) \times \left(\frac{1}{60}\right) \times 379.7
\]

\[
C_{NOx} = \left(\frac{VFR_{NOx}}{F_s}\right) \times 10^6
\]

Where:

- $VFR_{NOx}$ = Volumetric Flow Rate (ft\textsuperscript{3}/minute)
- $E_{NOx}$ = Annual NO\textsubscript{x} emissions from the emissions inventory (tons/year)
- 2,000 = lbs/ton
- 46.0 = NO\textsubscript{x} molecular weight (grams/mol)
- $O_{Phrs}$ = Annual operating hours from the emissions inventory (hours)
- 60 = Minutes per hour conversion factor
- 379.7 = Volume of NO\textsubscript{x} under standard conditions (ft\textsuperscript{3}/mol)
- $F_s$ = Exhaust flowrate at standard temperature (scfm)
- $C_{NOx}$ = Outlet mole fraction of NO\textsubscript{x} (ppmv)

\textsuperscript{13} U.S. EPA 2015, page 6.
\textsuperscript{14} U.S. EPA 2015, page 3.
### NOx Emissions Reductions

\[
\text{Reduction}_{NOx} (%) = \frac{C_{NOx} - CMC_{NOx}}{C_{NOx}}
\]

\[NOx_{\text{reduced}} = NOx \times \text{Reduction}_{NOx}\]

\[NOx_{\text{controlled}} = NOx - NOx_{\text{reduced}}\]

Where:
- \(CMC_{NOx}\) = Control Measure of NOx (ppmv)
- \(\text{Reduction}_{NOx}\) = NOx Emissions Reduction Percentage (%)
- \(NOx\) = NOx Emissions before Control (tons/year)
- \(NOx_{\text{reduced}}\) = Reduced NOx Emissions (tons/year)
- \(NOx_{\text{controlled}}\) = NOx Emissions after Control (tons/year)

#### 2.2.4.2 Cost Equations

**Capital Cost Equation**

The conditions in the stack are determined from the emissions inventory being processed. This Equation Type uses the exhaust flowrate at standard temperature \((F_s)\) in standard cubic feet per minute (scfm) (see Section 1.2.2 for discussion of flowrate unit conversions).

**Total Capital Investment (TCI)**

\[
\text{TCI} = (\text{Fixed TCI} + \text{Variable TCI}) \times \left(\frac{\text{Stack Flowrate (scfm)}}{150,000}\right)^{0.6}
\]

Where:
- *Fixed TCI* = an empirical value based on the specific control measure\(^{15}\)
- *Variable TCI* = an empirical value based on the specific control measure\(^{16}\)

**Operating Cost Equation**

**Annual Operating Cost (AOC)**

\[
\text{AOC} = (\text{Fixed AOC} + \text{Variable AOC}) \times \left(\frac{\text{Stack Flow Rate (scfm)}}{150,000}\right)
\]

Where:
- *Fixed AOC* = an empirical value based on the specific control measure
- *Variable AOC* = an empirical value based on the specific control measure

\(^{15}\) MACTEC 2005.

\(^{16}\) Ibid.
• Stack Flow Rate = expected flow rate out of the stack in standard cubic feet per minute (scfm)

Total Annualized Cost Equation

Total Annualized Cost = AOC + CRF × TCI

2.2.4.3 Example Calculations

This section provides example calculations for an application of Equation Type 12. The example scenario is a gas-fired process heater at a petroleum refinery (SCC 30600102). The NOx control mechanism is excess oxygen control (NPRGPHEO2C). Figure 2-6 illustrates the Equations tab of the View Control Measure screen for the Petroleum Refinery Gas-Fired Process Heaters: Excess O2 Control.

Example Equation Type 12 Variables

Capital Recovery Factor = 0.2439 (assumes equipment life of 5 years and interest rate of 7%)
Stack Flowrate = 48.984 ft³/sec
Stack Temperature (°F) = 600 °F
Fixed Total Capital Investment (TCI) = $20,000
Variable TCI = $0
Fixed Annual Operating Cost (AOC) = $4,000
Variable AOC = $0
Year for Cost Basis = 2006
**Capital Cost Equation**

**Stack Flow Rate (scfm)**

\[ \text{Stack Flow Rate (scfm)} = 48.984 \times 60 \times \left( \frac{520}{600 + 460} \right) \]

**Stack Flow Rate (scfm)** = 1,442 \( \frac{ft^3}{min} \)

**Total Capital Investment (TCI)**

\[ \text{TCI} = (\text{Fixed TCI} + \text{Variable TCI}) \times \left( \frac{\text{Stack Flowrate (scfm)}}{150,000} \right)^{0.6} \]

\[ \text{TCI} = ($20,000 + 0.0) \times \left( \frac{1,442}{150,000} \right)^{0.6} \]

\[ \text{TCI} = $1,232 \text{ (2006$)} \]

**Operating Cost Equation**

**Annual Operating Cost (AOC)**

\[ \text{Annual Operating Cost (AOC)} = (\text{Fixed AOC} + \text{Variable AOC}) \times \left( \frac{\text{Stack Flow Rate (scfm)}}{150,000} \right) \]
Annual AOC = ($4,000 + 0.0) \times \left( \frac{1,442}{150,000} \right)
Annual AOC = $38 (2006$)

Total Annualized Cost Equation

Total Annualized Cost = Annual AOC + CRF x TCI
Total Annualized Cost = $38 + 0.2439 \times 1,232
Total Annualized Cost = $339 (2006$)

Mole Fraction of NOx in outlet gas

\[ VFR_{NOx} = E_{NOx} \times 2,000 \times \left( \frac{1}{46.0} \right) \times \left( \frac{1}{OPHrs} \right) \times \left( \frac{1}{60} \right) \times 379.7 \]

\[ 1.680 \left( \frac{ft^3}{\text{minute}} \right) = 53.33 \times 2,000 \times \left( \frac{1}{46.0} \right) \times \left( \frac{1}{8736} \right) \times \left( \frac{1}{60} \right) \times 379.7 \]

\[ C_{NOx} = \left( \frac{VFR_{NOx}}{F_S} \right) \times 10^6 \]

\[ 1164.98 (ppmv) = \left( \frac{1.680}{1,442} \right) \times 10^6 \]

NOx Emissions Reductions

\[ Reduction_{NOx} (%) = \frac{C_{NOx} - CMC_{NOx}}{C_{NOx}} \]

\[ 93.13 \% = \frac{1164.98 - 80.0}{1164.98} \]

\[ NOx_{reduced} = NOx \times Redcution_{NOx} \]

\[ 49.67 (\text{tons/year}) = 53.33 \times 93.13(\%) \]

\[ NOx_{controlled} = NOx - NOx_{reduced} \]

\[ 3.66 (\text{tons/year}) = 55.33 - 49.67 \]
2.2.5 Equation Type 13 for NOx – ICI Boilers

Equation Type 13 is used to calculate NOx control costs for a range of sizes of ICI boilers.\textsuperscript{17} NOx control technologies for Equation Type 13 are:

- Flue Gas Recirculation (FGR)
- Low NOx Burner (LNB)
- Low NOx Burner and Flue Gas Recirculation
- Selective Non-Catalytic Reduction (SNCR)
- Selective Catalytic Reduction (SCR)
- Low NOx Burner and Selective Non-Catalytic Reduction
- Low NOx Burner and Selective Catalytic Reduction

Equation Type 13 was derived based on a review of previous ICI boiler control costs calculations and outputs from the EPA Coal Utility Environmental Cost (CUECost) model.\textsuperscript{18} The costs were generated for control devices on five boiler sizes (i.e., 100, 200, 300, 400, and 500 MMBtu/hour). Although control device costs do not rise in strict proportion to size, the plotted results demonstrated that control costs versus boiler size showed a power-law relationship and this relationship was used to derive Equation Type 13.

2.2.5.1 Cost Equations

Capital Cost Equations

In finding that there are no cost savings from combining different ICI boiler control technologies, control costs for each technology can be treated as additive when multiple control options are available. Calculate single control technology total capital costs with the following equation:

\[ \text{Capital Cost} = \text{Size Multiplier 1} \times \text{Boiler Size} \left( \frac{\text{MMBtu}}{\text{hour}} \right)^{\text{Exponent 1}} \]

Duel control technology total capital costs are calculated as an extension of the single control technology equation:

\[ \text{Capital Cost (Dual Control Technology)} = \text{Size Multiplier 1} \times \text{Boiler Size} \left( \frac{\text{MMBtu}}{\text{hour}} \right)^{\text{Exponent 1}} + \text{Size Multiplier 2} \times \text{Boiler Size} \left( \frac{\text{MMBtu}}{\text{hour}} \right)^{\text{Exponent 2}} \]

\textsuperscript{17} ERG 2010, Section II, pages 4 through 7.
\textsuperscript{18} ERG 2010.
Where:
- **Size Multiplier and Exponent** = empirical values for each control technology that are based on a power law curve fitting of ICI boiler control costs versus boiler sizes
- **Boiler Size** = ICI boiler hourly heat output

**Operation and Maintenance Cost Equations**

\[
O&M\ Cost = \text{Known Costs} + \text{Size Multiplier 1} \times \text{Boiler Size} \left(\frac{\text{MMBtu}}{\text{hour}}\right)^{\text{Exponent 1}} \\
+ \text{Size Multiplier 2} \times \text{Boiler Size} \left(\frac{\text{MMBtu}}{\text{hour}}\right)^{\text{Exponent 2}} \\
+ \text{Flowrate Multiplier} \times \text{Boiler Exhaust Flowrate} \left(\frac{\text{ft}^3}{\text{s}}\right) \\
+ \text{Emissions Multiplier} \times \text{Boiler Emissions} \left(\frac{\text{tons}}{\text{year}}\right)
\]

Where:
- **Size Multiplier and Exponent** = empirical values for each control technology that are based on a power law curve fitting of ICI boiler control costs versus boiler sizes
- **Boiler Size** = ICI boiler hourly heat output (MMBtu/hour)
- **Flowrate Multiplier** = empirical value based on the specific control measure
- **Boiler Exhaust Flowrate** = expected flowrate from the boiler in cubic feet per second
- **Emissions Multiplier** = empirical value based on the specific control measure
- **Boiler Emissions** = annual boiler emissions rate (tons/year)

**Total Annualized Cost Equation**

\[
\text{Annualized Cost} = \text{Capital Cost} \times \text{CRF} + \text{Total O&M Cost}
\]

### 2.2.5.2 Example Calculations

**Equation Type 13 Example for NOx**

This section provides example calculations for an application of Equation Type 13. The example scenario is for a grade 1 & 2 distillate oil ICI external combustion boiler (SCC 10200501) with an output of 250 MMBtu/hour that is using a low NOx burner for the primary controls and flue gas recirculation for the secondary controls (NLNBFIBDO).

**Example Equation Type 13 Variables**

*Capital Recovery Factor = 0.1315 (assumes equipment life of 15 years and interest rate of 10%)*
*Control Device (Single) = LNB*
*Control Device (Dual) = LNB + FGR*
*Cost Year = 2008*
Boiler Size (MMBtu) = 250
Capital Cost Size Multiplier 1 = $5,460.27
Capital Cost Exponent 1 = 0.65
Capital Cost Size Multiplier 2 = $86,330.02
Capital Cost Exponent 2 = 0.22
O&M Known Costs = $389,766.80
O&M Size Multiplier 1 = $218.40
O&M Size Exponent 1 = 0.65
O&M Size Multiplier 2 = $3,453.20
O&M Size Exponent 2 = 0.22
Flowrate Multiplier = 19.3
Boiler Exhaust Flowrate (ft$^3$/s) = 33.33
Emissions Multiplier = 0.0
Boiler Emissions (tons/year) = 100

Figure 2-7: Equation Type 13 for NO$_x$ - Example Screenshot from CoST

Capital Cost Equation (Single Device)

\[
\text{Capital Cost} = \text{Size Multiplier 1} \times \text{Boiler Size} \left(\frac{\text{MMBtu}}{\text{hour}}\right)^{\text{Exponent 1}}
\]

\[
\text{Capital Cost} = $5,460.27 \times 250^{0.65}
\]

\[
\text{Capital Cost} = $197,640 (2008$)
\]
Control Strategy Tool (CoST) Cost Equations

Capital Cost Equation (Dual Device)

Capital Cost (Dual Control Technology)
\[ \text{Capital Cost} = \text{Size Multiplier 1} \times \text{Boiler Size} \left( \frac{\text{MMBtu}}{\text{hour}} \right)^{\text{Exponent 1}} \]
\[ + \text{Size Multiplier 2} \times \text{Boiler Size} \left( \frac{\text{MMBtu}}{\text{hour}} \right)^{\text{Exponent 2}} \]
\[ \text{Capital Cost} = 5,460.27 \times 250^{0.65} + 86,330.02 \times 250^{0.22} \]
\[ \text{Capital Cost} = 488,517 (2008\$) \]

Operation and Maintenance Cost Equation

\[ \text{O&M Cost} = \text{Known Costs} + \text{Size Multiplier 1} \times \text{Boiler Size} \left( \frac{\text{MMBtu}}{\text{hour}} \right)^{\text{Exponent 1}} \]
\[ + \text{Size Multiplier 2} \times \text{Boiler Size} \left( \frac{\text{MMBtu}}{\text{hour}} \right)^{\text{Exponent 2}} \]
\[ + \text{Flowrate Multiplier} \times \text{Boiler Exhaust Flowrate} \left( \frac{\text{ft}^3}{\text{s}} \right) \]
\[ + \text{Emissions Multiplier} \times \text{Boiler Emissions} \left( \frac{\text{tons}}{\text{year}} \right) \]
\[ \text{O&M Cost} = 389,766.80 + 218.4 \times 250^{0.65} + 3,453.20 \times 250^{0.22} + 19.3 \times 33.33 + 0.0 \times 100 \]
\[ \text{O&M Cost} = 409,950 (2008\$) \]

Annual Cost Equation (Single Device)

\[ \text{Annual Cost} = \text{Capital Cost} \times \text{CRF} + \text{O&M Cost} \]
\[ \text{Annual Cost} = 197,640 \times 0.1315 + 409,950 \]
\[ \text{Annual Cost} = 435,935 (2008\$) \]

Annual Cost Equation (Dual Device)

\[ \text{Annual Cost} = \text{Capital Cost} \times \text{CRF} + \text{O&M Cost} \]
\[ \text{Annual Cost} = 488,517 \times 0.1315 + 409,950 \]
\[ \text{Annual Cost} = 474,177 (2008\$) \]
3 SO₂ Control Cost Equations

This chapter is divided into two main sections – IPM and non-IPM sources. The types of cost equations, indicated below, for point source SO₂ controls are described in their appropriate sections.

- Equation Type 1 for IPM external combustion boilers
- Equation Type 3 for non-IPM external combustion boilers, process heaters, primary metals, glassmaking furnaces
- Equation Type 16 for non-IPM external combustion boilers and select industrial processes
- Equation Type 18 for the same non-IPM sources as equation type 16
- Equation Type 19 for the same non-IPM sources as equation type 16

This chapter describes each equation type, presents the relevant equation parameters, and provides example calculations. The example calculations provided are prepared using version 2.15 of the CoST software.

3.1 IPM Sector (ptipm) SO₂ Control Cost Equations

IPM sector (ptipm) point sources using control cost equations for SO₂ emissions reductions are limited to Equation Type 1. In Equation Type 1, model plant capacities are used along with scaling factors and the emissions inventory’s unit-specific boiler characteristics to generate a control cost for an applied technology. SO₂ control technologies for Equation Type 1 include lime spray dryer and limestone forced oxidation.

The parameters for the equation used to calculate control costs for SO₂ from ptipm sources are based on boiler capacity. Controls will not be applied to a source if the inventory record for the source has a blank boiler capacity field. As such, default cost per ton values for SO₂ controls are not used for ptipm point sources.

3.1.1 Equation Type 1 for SO₂ – Utility Boilers

Equation Type 1 involves the application of a scaling factor to adjust the capital cost associated with a control measure to the boiler size (MW) based on the original control technology’s documentation.\(^1\)\(^9\) A scaling factor and exponent for model plant size are not used for this estimate.

Restrictions on source size are also shown for the controls that use Equation Type 1. When an application restriction reflects a minimum and maximum capacity, the control is not applied unless the capacity of the source in the inventory falls within that range.\(^2\)\(^0\)

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\(^{19}\) U.S. EPA 2013, Table 5.3 on page 5-4.

\(^{20}\) An application restriction defines an upper and/or lower capacity (MW) bound for which an equation is applicable.
3.1.1.1 Cost Equations

Capital Cost Equations

The capital cost associated with these tipm SO2 control measures is a straightforward calculation of the capital cost multiplier, the unit’s boiler capacity (in MW), and the scaling factor exponent.

\[
Scaling \ Factor = \left( \frac{Model \ Plant \ Capacity}{Actual \ Capacity} \right)^{Scaling \ Factor \ Exponent}
\]

Where:
- \( Model \ Plant \ Capacity \) = the boiler capacity (MW) of the model plant
- \( Scaling \ Factor \ Exponent \) = an empirical value based on the specific control measure
- \( Actual \ Capacity \) = the boiler capacity (MW) obtained from the emissions inventory and converted to MW (see Section 1.2.1 for a discussion of unit conversions)

\[
Capital \ Cost = Capital \ Cost \ Multiplier \times Capacity \times Scaling \ Factor \times 1,000
\]

Where:
- \( Capital \ Cost \ Multiplier \) = an empirical value based on the specific control measure ($/kW)
- \( Capacity \) = the boiler capacity (MW) obtained from the emissions inventory
- \( 1000 \) = conversion factor to convert the \( Capital \ Cost \ Multiplier \) from $/kW to $/MW.

Annualized Capital Cost = \( Capital \ Cost \times CRF \)

Operation and Maintenance Cost Equations

The fixed O&M component is based on the unit’s capacity. The variable O&M includes an estimate for the unit’s capacity factor. The capacity factor accounts for the amount of actual power generated by a power plant as compared to its design capacity or rated output. A value of 1.00 would represent a unit operating at 100% capacity.

The annualized cost is then estimated using the unit’s capital cost times the CRF (derived with an annual interest rate and equipment lifetime expectancy) and the sum of the fixed and variable O&M costs.

\[
Fixed \ O&M = Fixed \ O&M \ Cost \ Multiplier \times Capacity \times 1,000
\]

Where:
- \( Fixed \ O&M \ Cost \ Multiplier \) = an empirical value based on the specific control measure ($/kW)
- \( Capacity \) = obtained from the emissions inventory
- \(1000\) = a conversion factor to convert the Fixed O&M Cost Multiplier from $/kW to $/MW

Variable O&M = Variable O&M Cost Multiplier \(\times\) Capacity \(\times\) Capacity Factor \(\times\) 8,760

Where:
- Variable O&M Cost Multiplier = an empirical value based on the specific control measure ($/MWh)
- Capacity Factor = an empirical value based on the specific control measure
- Capacity = obtained from the emissions inventory (MW)
- 8,760 = the number of hours the equipment is assumed to operate a year

Total O&M Cost = Fixed O&M + Variable O&M

Total Annualized Cost Equation

Total Annualized Cost = Annualized Capital Cost + Total O&M Cost

3.1.1.2 Example Calculations

Equation Type 1 Example for SO\(_2\)

This section provides example calculations for an application of Equation Type 1 where SO\(_2\) is the primary pollutant for this control technology. The example is for a utility external combustion wet bottom tangential fired coal boiler (SCC 10100211) that uses a lime spray dryer applicable to 25 to 49 MW boilers for its control equipment (SLSDUBC1).

Example Equation Variables

Figure 3-1 illustrates the Equations tab of the View Control Measure screen for the Lime Spray Dryer; Utility Boilers – 25 to 49 MW.

Capital Recovery Factor = 0.1010 (assumes equipment life of 15 years and interest rate of 5.7%, which is provided by IPM)
Capacity = 40 MW
Scaling Factor Model Size = 0
Scaling Factor Exponent = 0
Capital Cost Multiplier ($/kW) = 894
Fixed O&M Cost Multiplier ($/kW) = 29.6
Variable O&M Cost Multiplier ($/MWh) = 2.8
Capacity Factor = 1
Year for Cost Basis = 2011
Annualized Capital Cost

\[
\text{Scaling Factor} = \left(\frac{\text{Scaling Factor Model Size}}{\text{Capacity}}\right)^{\text{Scaling Factor Exponent}}
\]

\[
\text{Scaling Factor} = \left(\frac{0}{40}\right)^0 = 1.0
\]

\[
\text{Capital Cost} = \text{Capital Cost Multiplier} \times \text{Capacity} \times \text{Scaling Factor} \times 1,000
\]

\[
\text{Capital Cost} = 894 \frac{\$}{kW} \times 40 \text{ MW} \times 1.0 \times 1,000 \frac{kW}{\text{MW}}
\]

\[
\text{Capital Cost} = \$35,760,000 (2011\$)
\]

\[
\text{Annualized Capital Cost} = \text{Capital Cost} \times \text{Capital Recovery Factor}
\]

\[
\text{Annualized Capital Cost} = \$35,760,000 \times 0.1010
\]

\[
\text{Annualized Capital Cost} = \$3,610,117 (2011\$)
\]

Operation and Maintenance Cost

\[
\text{Fixed O&M} = \text{Fixed O&M Cost Multiplier} \left(\frac{\$}{kW}\right) \times \text{Capacity}(\text{MW}) \times 1,000
\]
Fixed O&M = 29.60 $\frac{\text{S}}{\text{kW}} \times 40.0 \text{ MW} \times 1,000 \frac{\text{kW}}{\text{MW}}
Fixed O&M = $1,184,000 (2011$)

Variable O&M = Variable O&M Cost Multiplier \left( $\frac{\text{S}}{\text{MWh}} \right) \times \text{Capacity (MW)} \times \text{Capacity Factor} \times 8,760 \text{ (Hours Per Year)}
Variable O&M = 2.8 $\frac{\text{S}}{\text{MWh}} \times 40 \text{ MW} \times 1.0 \times 8,760 \text{ Hours}
Variable O&M = $981,120 (2011$)

Total O&M Cost = Fixed O&M + Variable O&M
Total O&M Cost = $2,165,120 (2011$)

Total Annualized Cost
Total Annualized Cost = Annualized Capital Cost + Total O&M Cost
Total Annualized Cost = $3,610,117 + 2,165,120
Total Annualized Cost = $5,775,237 (2011$)

3.2 Non-IPM Sector (ptnonipm) SO$_2$ Control Cost Equations

Ptnonipm point sources using control cost equations for SO$_2$ emission reductions are represented by Equation Types 3, 16, 18, and 19. The equation types vary by control measure. Each equation uses the source’s stack flowrate (in ft$^3$/minute) as the primary variable to estimate cost. Cost equations and default cost per ton reduced values are taken from the original Alternative Control Technology, Control Technology Guidelines (ACT/CTG), or other EPA analyses used to derive these estimates.

Equation Types 16 and 18 were developed for the ICI boilers and process heater National Emission Standards for Hazardous Air Pollutants (NESHAP) for major sources (Boiler MACT). Equation Type 19 was developed for the commercial and industrial solid waste incinerator NESHAP (CISWI). The equations to calculate flowrates for Equation Types 16 and 18 are provided in section 1.2.2.

3.2.1 Equation Type 3 for SO$_2$ – External Combustion Boilers and Industrial Processes

SO$_2$ control technologies for Equation Type 3 include flue gas desulfurization. Cost equation parameters used in Equation Type 3 are found in Control Measure Evaluations: The Control Measure Data Base for the National Emissions Trends Inventory (ControlNET).\textsuperscript{21} This Equation Type uses the exhaust flowrate at actual stack conditions ($F_a$) in actual cubic feet per minute (acfm) (see Section 1.2.2 for discussion of flowrate unit conversions).

\textsuperscript{21} U.S. EPA 2001, Table IV-2, page 49.
3.2.1.1 Cost Equations

Annualized Capital Cost Equation for Flowrate ≥ 1,028,000 acfm

Capital Cost
\[ \text{Capital Cost} = \text{Retrofit Factor} \times \text{Gas Flowrate Factor} \times \text{Capital Cost Factor} \times \text{Exhaust Flowrate} \times 0.9383 \]

Where:
- Retrofit Factor = 1.1
- Gas Flowrate Factor = 0.486 kW/acfm
- Capital Cost Factor = $192/kW
- Exhaust Flowrate = exhaust flowrate at actual stack conditions (\( F_a \)) in actual cubic feet per minute (acfm)
- De-escalation factor (to adjust dollar years from 1995 to 1990) = 0.9383

Annualized Capital Cost = Capital Cost \times CRF

Annualized Capital Cost Equation for Flowrate < 1,028,000 acfm

Capital Cost
\[ \text{Capital Cost} = \left( \frac{1,028,000}{\text{Exhaust Flowrate}} \right)^{0.6} \times \text{Retrofit Factor} \times \text{Gas Flowrate Factor} \times \text{Capital Cost Factor} \times \text{Exhaust Flowrate} \times 0.9383 \]

Where:
- Retrofit Factor = 1.1
- Gas Flowrate Factor = 0.486 kW/acfm
- Capital Cost Factor = $192/kW
- Exhaust Flowrate = exhaust flowrate at actual stack conditions (\( F_a \)) in actual cubic feet per minute (acfm)
- De-escalation factor (to adjust dollar years from 1995 to 1990) = 0.9383

Annualized Capital Cost = Capital Cost \times CRF

Operation and Maintenance Cost Equations

Fixed O&M Cost = Gas Flowrate Factor \times Fixed O&M Rate \times Exhaust Flowrate

Where:
- Gas Flowrate Factor = 0.486 kW/acfm
- Fixed O&M Rate = $6.9/kW
- Exhaust Flowrate = exhaust flowrate at actual stack conditions (\( F_a \)) in actual cubic feet per minute (acfm)

Variable O&M Cost = Gas Flowrate Factor \times Variable O&M Rate \times Hours per year \times Exhaust Flowrate
Where:

- **Gas Flowrate Factor** = 0.486 kW/ acfm
- **Variable O&M Rate** = $0.0015/kWh
- **Hours per year** = 8,736
- **Exhaust Flowrate** = exhaust flowrate at actual stack conditions \( F_a \) in actual cubic feet per minute (acfm)

**Total O&M Cost** = **Fixed O&M Cost + Variable O&M Cost**

**Total Annualized Cost Equation**

The following equation applies whether the annualized capital cost is calculated based on the standard (≤1,028,000 acfm) or large (>1,028,000 acfm) size:

**Total Annualized Cost** = **Annualized Capital Cost + Total O&M Cost**

Where **Annualized Capital Cost** and **Total O&M Cost** were calculated previously.

### 3.2.1.2 Example Calculation

This section provides example calculations for an application of Equation Type 3. The example scenario is an ICI external combustion boiler burning pulverized anthracite coal (SCC 10300101) using flue gas desulfurization (FGD) as the primary control technology for SO\(_2\) (SFGDSSGCO). Figure 3-2 illustrates the Equations tab of the View Control Measure screen for the FGD: Bituminous/Subbituminous Coal (Commercial/Institutional Boilers).

**Example Equation Variables**

- **Capital Recovery Factor** = 0.1098 (assumes equipment life of 15 years and interest rate of 7%)
- **Exhaust Flowrate** = 100,962 \( \frac{ft^3}{min} \)
- **Retrofit Factor** = 1.1
- **Gas Flow Rate Factor** = 0.486 kW/ acfm
- **Capital Cost Factor** = $192/kW
- **Year for Cost Basis** = 1990
Annualized Capital Costs for Flowrate < 1,028,000 acfm

\[ \text{Capital Cost} = \left( \frac{1,028,000}{\text{Exhaust Flowrate}} \right)^{0.6} \times \text{Retrofit Factor} \times \text{Gas Flowrate Factor} \times \text{Capital Cost Factor} \times \text{Exhaust Flowrate} \times 0.9383 \]

\[
\begin{align*}
\text{Capital Cost} &= \left( \frac{1,028,000}{100,962 \text{ ft}^3/\text{min}} \right)^{0.6} \times 1.1 \times 0.486 \frac{\text{kW}}{\text{acfm}} \times \frac{192 \text{ kW}}{\text{kW}} \times 100,962 \frac{\text{ft}^3}{\text{min}} \times 0.9383 \\
\text{Capital Cost} &= \$39,121,901 \text{ (1990$)}
\end{align*}
\]

Use an implicit price deflator ratio to convert from 1990$ to 2000$.

\[
\begin{align*}
\text{Capital Cost} &= \$39,121,901 \times \frac{81.887 \text{ (2000$)}}{66.773 \text{ (1990$)}} \\
\text{Capital Cost} &= \$47,989,367 \text{ (2000$)}
\end{align*}
\]

Annualized Capital Cost = Capital Cost \times Capital Recovery Factor

Annualized Capital Cost = \$47,989,367 \times 0.1098
Annualized Capital Cost = \$5,268,974 \text{ (2000$)}
**Operation and Maintenance Cost**

\[
\text{Fixed O&M Cost} = \text{Gas Flowrate Factor} \times \text{Fixed O&M Rate} \times \text{Exhaust Flowrate}
\]

\[
\text{Fixed O&M Cost} = 0.486 \frac{\text{kW}}{\text{acfm}} \times 6.90 \frac{\text{kW}}{\text{kW}} \times 100,962 \frac{\text{ft}^3}{\text{min}}
\]

\[
\text{Fixed O&M Cost} = \$338,566 \text{ (1990$)} \times \frac{81.887 \text{ (2000$)}}{66.773 \text{ (1990$)}}
\]

\[
\text{Fixed O&M Cost} = \$415,200 \text{ (2000$)}
\]

\[
\text{Variable O&M Cost} = \text{Gas Flowrate Factor} \times \text{Variable O&M Rate} \times \text{Hours per year} \times \text{Exhaust Flowrate} \times 60
\]

\[
\text{Variable O&M Cost} = 0.486 \frac{\text{kW}}{\text{acfm}} \times 0.0015 \frac{\text{kWh}}{\text{kW}} \times 8736 \text{ h} \times 100,962 \frac{\text{ft}^3}{\text{min}} \text{Variable O&M Cost}
\]

\[
\text{Variable O&M Cost} = \$642,981 \text{ (1990$)} \times \frac{81.887 \text{ (2000$)}}{66.773 \text{ (1990$)}}
\]

\[
\text{Variable O&M Cost} = \$788,519 \text{ (2000$)}
\]

\[
\text{Total O&M Cost} = \text{Fixed O&M Cost} + \text{Variable O&M Cost}
\]

\[
\text{Total O&M Cost} = \$415,200 + \$788,519
\]

\[
\text{Total O&M Cost} = \$1,203,719 \text{ (2000$)}
\]

\[
\text{Total Annualized Cost}
\]

\[
\text{Total Annualized Cost} = \text{Annualized Capital Cost} + \text{Total O&M Cost}
\]

\[
\text{Total Annualized Cost} = \$5,268,974 + \$1,203,719
\]

\[
\text{Total Annualized Cost} = \$6,472,694 \text{ (2000$)}
\]

**3.2.2 Equation Type 16 for SO₂ – ICI Boilers: Wet Scrubber**

Equation Type 16 is used to calculate control costs for using wet scrubbers on various external combustion boilers and industrial processes.\(^{22}\) This control technology provides extensive SO₂ control (95%) and minimal PM reduction (50% to 94%). This Equation Type uses the exhaust flowrate at either actual stack conditions \((F_a)\) in actual cubic feet per minute (acfm) or at standard temperature \((F_s)\) in standard cubic feet per minute (scfm), depending on the equation (see Section 1.2.2 for discussion of flowrate unit conversions).

The equations that are used to convert from inventory emissions to the mole fraction of SO₂ in the stack gas are shown here.

\(^{22}\) ERG 2013, Appendix B, pages B-4 and B-5.
**Mole Fraction of SO₂ in outlet gas**

\[
VFR_{SO2} = E_{SO2} \times 2,000 \times \left(\frac{1}{64.06}\right) \times \left(\frac{1}{OP_{Hrs}}\right) \times \left(\frac{1}{60}\right) \times 379.7
\]

\[
C_{SO2} = \left(\frac{VFR_{SO2}}{F_s}\right)
\]

Where:
- \(VFR_{SO2}\) = Volumetric Flow Rate (ft³/minute)
- \(E_{SO2}\) = Annual SO₂ emissions from the emissions inventory (tons/year)
- 2,000 = lbs/ton
- 64.06 = SO₂ molecular weight (grams/mol)
- \(OP_{Hrs}\) = Annual operating hours from the emissions inventory (hours)
- 60 = minutes/hour
- 379.7 = Volume of SO₂ under standard conditions (ft³/mol)
- \(F_s\) = Exhaust flowrate at standard temperature (scfm)
- \(C_{SO2}\) = Outlet mole fraction of SO₂

### 3.2.2.1 Cost Equations

**Total Capital Investment**

\[
TCI = [(2.88)(#Scrub)(F_a)] + [(1076.54)(#Scrub)\sqrt{F_a}] + [(9.759)(F_a)] + [(360.463)\sqrt{F_a}]
\]

Where:
- \(#Scrub\) = if \(F_a < 149602\), then \(#Scrub = 1\)
  - if \(149602 \leq F_a < 224403\), then \(#Scrub = 2\)
  - if \(224403 \leq F_a < 299204\), then \(#Scrub = 3\)
  - if \(299204 \leq F_a < 374005\), then \(#Scrub = 4\)
  - if \(F_a \geq 374005\), then \(#Scrub = 5\)
- \(F_a\) = Actual exhaust flowrate (acfm)
Total Annualized Costs

\[
TAC = \left[ (\#Scrub)(TCI) \left( \frac{(i)(1 + i)^{EqLife}}{(1 + i)^{EqLife} - 1} \right) \right] + [(0.04)(TCI)] \\
+ \left\{ (20.014)(\#Scrub)(F_a)(OpHrs) \left[ C_{SO2} - \left( \frac{100 - 98}{100 - 98(C_{SO2})} \right) \right] \right\} \\
+ [(16.147)(\#Scrub)(OpHrs)] \\
+ \left\{ (1.17 \times 10^{-5})(F_a)(OpHrs)(\#Scrub) \left[ \left( 479.85 \left( \frac{1}{\sqrt{F_a}} \right)^{1.18} \right) + (6.895) \right] \right\} \\
+ [(1.33 \times 10^{-5})(OpHrs)(\#Scrub)(F_a)]
\]

Where:
\[
\#Scrub = \begin{cases} 
1 & \text{if } F_a < 149602 \\
2 & \text{if } 149602 \leq F_a < 224403 \\
3 & \text{if } 224403 \leq F_a < 299204 \\
4 & \text{if } 299204 \leq F_a < 374005 \\
5 & \text{if } F_a \geq 374005 
\end{cases}
\]

\[
TCI = \text{Total Capital Investment (\$)}
\]

\[
i = \text{Annual interest rate}
\]

\[
EqLife = \text{Estimated equipment life (years)}
\]

\[
F_a = \text{Actual exhaust flowrate (acfm)}
\]

\[
C_{SO2} = \text{Mole fraction of SO}_2 \text{ in exhaust gas}
\]

\[
OpHrs = \text{Annual operating hours of unit (hours per year)}
\]

3.2.2.2 Example Calculations

This section provides example calculations for an application of Equation Type 16. The example is a wet bottom pulverized bituminous coal EGU boiler (SCC: 10100201) with a wet scrubber for SO2 control (SWSICIBC).

Example Equation Variables

\[
\text{Capital Recovery Factor} = 0.1098 \text{ (assumes equipment life of 15 years (EqLife) and interest rate of 7\% (i))}
\]

\[
\#Scrub = 1
\]

\[
F_a = 924.88 \frac{ft^3}{sec} \times 60 = 55,493 \frac{ft^3}{min}
\]

\[
T = 500 \text{ °F}
\]

\[
E_{SO2} = 100 \text{ tons/year}
\]

\[
OpHrs = 2,688 \text{ operating hours per year}
\]

\[
\text{Year for Cost Basis} = 2008
\]
Mole Fraction of SO\(_2\) in outlet gas

\[
F_s = (F_a) \left( \frac{520}{460 + T} \right)
\]

\[
F_s = (55,493) \left( \frac{520}{460 + 500} \right)
\]

\[
F_s = 30,058.7 \frac{ft^3}{min}
\]

\[
VFR_{SO2} = E_{SO2} \times 2,000 \times \left( \frac{1}{64.06} \right) \times \left( \frac{1}{OpHrs} \right) \times \left( \frac{1}{60} \right) \times 379.7
\]

\[
VFR_{SO2} = 100 \times 2,000 \times \left( \frac{1}{64.06} \right) \times \left( \frac{1}{2688} \right) \times \left( \frac{1}{60} \right) \times 379.7
\]

\[
VFR_{SO2} = 7.35 \frac{ft^3}{min}
\]

\[
C_{SO2} = \left( \frac{VFR_{SO2}}{F_s} \right)
\]

\[
C_{SO2} = \frac{30,058.7}{7.35}
\]

\[
C_{SO2} = 2.4 \times 10^{-4} \text{ mole fraction SO}_2
\]

Total Capital Investment

\[
TCI = [(2.88)(#Scrub)(F_a)] + [(1076.54)(#Scrub)\sqrt{F_a}] + [(9.759)(F_a)] + [(360.463)\sqrt{F_a}]
\]

\[
= [2.88](1)(55493)] + [(1076.54)(1)\sqrt{55493}] + [(9.759)(55493)] + [(360.463)\sqrt{55493}]
\]

\[
= $1,039,887 (2008$)
\]

Total Annualized Costs

\[
TAC = \left[ (\#Scrub)(TCI) \left( \frac{(i)(1 + i)^{EqLife}}{(1 + i)^{EqLife} - 1} \right) \right] + [(0.04)(TCI)]
\]

\[
+ \left\{ (20.014)(\#Scrub)(F_a)(OpHrs) \left[ C_{SO2} - (C_{SO2}) \frac{100 - 98}{100 - 98(C_{SO2})} \right] \right\}
\]

\[
+ [(16.147)(\#Scrub)(OpHrs)]
\]

\[
+ \left\{ (1.17 \times 10^{-5})(F_a)(OpHrs)(\#Scrub) \left[ \left( 479.85 \right) \left( \frac{1}{\sqrt{F_a}} \right)^{1.18} \right] + (6.895) \right\}
\]

\[
+ [(1.33 \times 10^{-5})(OpHrs)(\#Scrub)(F_a)]
\]
\[
= [(1)(1,309,887)\left(\frac{(0.07)(1 + 0.07)^{15}}{(1 + 0.07)^{15} - 1}\right)] + [(0.04)(1,309,887)] + \{(20.014)(1)(55493)(2688)\left(2.4 \times 10^{-4}\right)
- (2.4 \times 10^{-4})\left(\frac{100 - 98}{100 - (98)(2.4 \times 10^{-4})}\right)\} + [(16.147)(1)(2688)]
+ \{(1.17 \times 10^{-5})(55493)(2688)(1)\left[\left(\frac{479.85}{\sqrt{55493}}\right)^{1.18}\right] + (6.895)\}\}
+ [(1.33 \times 10^{-5})(2688)(1)(55493)]
= 929,935 (2008$)^{23}
\]

### 3.2.3 Equation Type 18 for SO\(_2\) – ICI Boilers: Increased Caustic Injection Rate

Equation Type 18 is used to calculate control costs for using caustic injection on various external combustion boilers and industrial processes.\(^{24}\) This equation is used for an increased caustic injection rate for existing dry injection control. Therefore, no new capital investment is required.

This Equation Type uses both the exhaust flowrate at standard temperature \((F_s)\) in standard cubic feet per minute (scfm) and at standard temperature on a dry basis \((F_d)\) in dry standard cubic feet per minute (dscfm), depending on the individual equation (see Section 1.2.2 for discussion of flowrate unit conversions).

#### Concentration of SO\(_2\) in outlet gas

The equations that are used to convert from inventory emissions to the concentration of SO\(_2\) in the stack gas are shown here.

\[
VFR_{SO2} = E_{SO2} \times 2,000 \times \left(\frac{1}{64.06}\right) \times \left(\frac{1}{OPHrs}\right) \times \left(\frac{1}{60}\right) \times 379.7
\]

\[
C_{SO2} = \left(\frac{VFR_{SO2}}{F_s}\right) \times 10^6
\]

Where:
- \(VFR_{SO2}\) = Volumetric Flow Rate (ft\(^3\)/minute)
- \(E_{SO2}\) = Annual SO\(_2\) emissions from the emissions inventory (tons/year)
- \(2,000\) = lbs/ton

---

\(^{23}\) Note that in the example CoST equations inventory distributed with CoST, a second source is picked up by this control measure. The second source was intended for use in Eq. 17 but qualified for this control as well. See the detailed control strategy results for plant ID 13 in the CoST control strategies viewer to see the results that are consistent with the example calculation shown in this document.

\(^{24}\) ERG 2013, Appendix B, page B-8.
64.06 = SO₂ molecular weight (grams/mol)

\( O_{\text{Hrs}} \) = Annual operating hours from the emissions inventory (hours)

60 = minutes/hour

379.7 = Volume of 1 mol SO₂ under standard conditions (ft³/mol)

\( F_s \) = Exhaust flowrate at standard temperature (scfm)

\( C_{SO2} \) = Outlet concentration of SO₂, dry parts per million by volume (ppmvd)

### 3.2.3.1 Cost Equations

#### Total Capital Investment

\[ TCI = 0 \]

No variables are used in this calculation.

#### Total Annualized Costs

\[ TAC = (\$0.00000387)(C_{SO2})(F_d)(O_{\text{Hrs}}) \]

Where:

- \( C_{SO2} \) = Concentration of SO₂ in stack gas, dry parts per million by volume (ppmvd)
- \( F_d \) = Exhaust flowrate at standard temperature on a dry basis (dscfm)
- \( O_{\text{Hrs}} \) = Annual operating hours of the unit (hours/year)

### 3.2.3.2 Example Calculations

This section provides example calculations for an application of Equation Type 18. The example is an EGU boiler burning grade 6 residual oil (SCC: 10100401) with an increased caustic injection rate for existing dry injection SO₂ control (SICIRIBRO).

Note that for the Boiler MACT rulemaking, sources that responded to the survey reported average annual operating hours for the relevant combustion units. For facilities that did not report annual operating hours, it was assumed that the unit was in operation for 8,424 hours per year, reflecting two weeks of boiler down time per year.

Figure 3-3 illustrates the Equations tab of the View Control Measure screen for the Increased Caustic Injection Rate emissions control method for SO₂.
Figure 3-3: Equation Type 18 for SO\textsubscript{2} - Example Screenshot from CoST

Example Equation Variables

\[ F_a = 2,100 \frac{ft^3}{sec} \times 60 = 126,000 \frac{ft^3}{min} \]
\[ T = 450 ^\circ F \]
\[ E_{SO2} = 50 \text{ tons/year} \]
\[ OpHrs = 8,424 \text{ operating hours per year} \]
\[ \% Moist = 9.08\% \]
\[ Year for Cost Basis = 2008 \]

Flowrate calculations

\[ F_s = (F_a) \left( \frac{520}{460 + T} \right) \]
\[ F_s = (126,000) \left( \frac{520}{460 + 450} \right) \]
\[ F_s = 72,000 \frac{ft^3}{min} \]
\[ F_d = (F_a) \left( \frac{460 + 68}{460 + T} \right) \left( 1 - \frac{\% Moist}{100} \right) \]
\[ F_d = (126,000) \left( \frac{460 + 68}{460 + 450} \right) \left( 1 - \frac{9.08}{100} \right) \]
\[ F_d = 66,470 \, \frac{ft^3}{min} \]

**Concentration of SO\textsubscript{2} in outlet gas**

\[ VFR_{SO2} = E_{SO2} \times 2,000 \times \left( \frac{1}{64.06} \right) \times \left( \frac{1}{Op_{Hrs}} \right) \times \left( \frac{1}{60} \right) \times 379.7 \]
\[ VFR_{SO2} = 50 \times 2,000 \times \left( \frac{1}{64.06} \right) \times \left( \frac{1}{8424} \right) \times \left( \frac{1}{60} \right) \times 379.7 \]
\[ VFR_{SO2} = 1.17 \, \frac{ft^3}{min} \]
\[ C_{SO2} = \left( \frac{VFR_{SO2}}{F_s} \right) \times 10^6 \]
\[ C_{SO2} = \left( \frac{1.17}{72,000} \right) \times 10^6 \]
\[ C_{SO2} = 16.3 \, ppmvd \]

**Total Capital Investment**

TCI = $0

**Total Annualized Costs**

\[ TAC = ($3.87 \times 10^{-6}) (C_{SO2}) (F_d) (Op_{Hrs}) \]
\[ TAC = ($3.87 \times 10^{-6}) (16.3) (66,470) (8,424) \]
\[ TAC = $35,294 \, (2008\$) \]

3.2.4 **Equation Type 19 for SO\textsubscript{2} – ICI Boiler: Spray Dry Absorber**

Equation Type 19 is used to calculate control costs for using spray dry absorbers on various external combustion boilers and industrial processes.\textsuperscript{25} This control technology, which provides less-than-extensive SO\textsubscript{2} control (80%) and no reduction in PM, was used for the CISWI NESHAP. This Equation Type uses the exhaust flowrate at actual stack conditions \((F_a)\) in actual cubic feet per minute (acfm), at standard temperature \((F_s)\) in standard cubic feet per minute (scfm), and at standard temperature on a dry basis \((F_d)\) in dry standard cubic feet per minute (dscfm) (see Section 1.2.2 for discussion of flowrate unit conversions).

**Concentration of SO\textsubscript{2} in outlet gas**

The equations that are used to convert from inventory emissions to the concentration of SO\textsubscript{2} in the stack gas are show here.

\[ VFR_{SO2} = E_{SO2} \times 2,000 \times \left( \frac{1}{64.06} \right) \times \left( \frac{1}{Op_{Hrs}} \right) \times \left( \frac{1}{60} \right) \times 379.7 \]

\textsuperscript{25} ERG 2013, Appendix B, page B-9.
\[ C_{SO2} = \left( \frac{VFR_{SO2}}{F_s} \right) \times 10^6 \]

Where:
- \( VFR_{SO2} \) = Volumetric Flow Rate (ft\(^3\)/minute)
- \( E_{SO2} \) = Annual SO\(_2\) emissions from the emissions inventory (tons/year)
- 2,000 = lbs/ton
- 64.06 = SO\(_2\) molecular weight (grams/mol)
- \( Op_{Hrs} \) = Annual operating hours from the emissions inventory (hours)
- 60 = minutes/hour
- 379.7 = Volume of 1 mol SO\(_2\) under standard conditions (ft\(^3\)/mol)
- \( F_s \) = Exhaust flowrate at standard temperature (scfm)
- \( C_{SO2} \) = Outlet concentration of SO\(_2\), dry parts per million by volume (ppmvd)

### 3.2.4.1 Cost Equations

#### Total Capital Investment

\[ TCI = \left( \frac{143.76}{F_d} \right) + \left( 0.610 \left( \frac{\sqrt{F_a}}{\#Ducts} \right)^2 \right) + \left[ 17412.26 e^{0.017} \left( \frac{\sqrt{F_a}}{\#Ducts} \right) \right] \]

\[ + \left[ 53.973 e^{0.014} \left( \frac{\sqrt{F_a}}{\#Ducts} \right) \right] + 931911.04 \]

Where:
- \( F_d \) = Exhaust flowrate at standard temperature on a dry basis (dscfm)
- \( F_a \) = Actual exhaust flowrate (acfm)
- \#Ducts = if \( F_d \leq 154042 \), then \#Ducts = 1
  
  if \( F_d > 154042 \), then \#Ducts = \( F_d/154042 \)

#### Total Annualized Costs

\[ TAC = \left( Op_{Hrs} \right) \left[ \left( 1.62 \times 10^{-3} \right) \left( F_d \right) \right] + \left[ \left( 6.84 \times 10^{-7} \right) \left( C_{SO2} \right) \left( F_d \right) \right] + \left[ \left( 3.72 \times 10^{-5} \right) \left( F_a \right) \right] + \left( 21.157 \right) + \left[ 7.2 \times 10^{-2} + \left( \frac{i(1+i)^{EqLife}}{(1+i)^{EqLife}-1} \right) \right] \left( TCI \right) \]

Where:
- \( F_d \) = Exhaust flowrate at standard temperature on a dry basis (dscfm)
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\[ F_a = \text{Actual exhaust flowrate (acfm)} \]
\[ OPHrs = \text{Annual operating hours of unit (hours/year) from the emissions inventory} \]
\[ C_{SO2} = \text{Concentration of SO}_2 \text{ in stack gas (dry parts per million by volume [ppmvd])} \]
\[ TCI = \text{Total Capital Investment ($)} \]
\[ i = \text{annual interest rate} \]
\[ E_{Life} = \text{Estimated equipment life (years)} \]

3.2.4.2 Example Calculations

This section provides example calculations for an application of Equation Type 19. The example is an ICI boiler burning grade 6 residual oil (SCC: 10300401) with a spray dry absorber for SO\(_2\) control (SSDAIBRO). Figure 3-4 illustrates the View Control Measure screen for the Spray Dryer Absorber emissions control method for SO\(_2\).

Figure 3-4: Equation Type 19 for SO\(_2\) - Example Screenshot from CoST

Example Equation Variables

Capital Recovery Factor = 0.1098 (assumes equipment life of 15 years \((E_{Life})\) and interest rate of 7\% \((i)\)
\[ F_a = 2,100 \frac{ft^3}{sec} \times 60 = 126,000 \frac{ft^3}{min} \]

\[ T = 450 \ ^\circ F \]

\# Ducts = 1

\[ E_{SO2} = 75 \text{ tons/year} \]

\[ OpHrs = 2,688 \text{ operating hours per year} \]

\% Moist = 9.08%

\[ Year \text{ for Cost Basis} = 2008 \]

**Flowrate calculations**

\[ F_s = (F_a) \left( \frac{520}{460 + T} \right) \]

\[ F_s = 126,000 \left( \frac{520}{460 + 450} \right) \]

\[ F_s = 72,000 \frac{ft^3}{min} \]

\[ F_d = (F_a) \left( \frac{460 + 68}{460 + T} \right) \left( 1 - \frac{\% \text{Moist}}{100} \right) \]

\[ F_d = (126,000) \left( \frac{460 + 68}{460 + 450} \right) \left( 1 - \frac{9.08}{100} \right) \]

\[ F_d = 66,470 \frac{ft^3}{min} \]

**Concentration of SO\(_2\) in outlet gas**

\[ VFR_{SO2} = E_{SO2} \times 2,000 \times \left( \frac{1}{64.06} \right) \times \left( \frac{1}{OpHrs} \right) \times \left( \frac{1}{60} \right) \times 379.7 \]

\[ VFR_{SO2} = 75 \times 2,000 \times \left( \frac{1}{64.06} \right) \times \left( \frac{1}{2,688} \right) \times \left( \frac{1}{60} \right) \times 379.7 \]

\[ VFR_{SO2} = 5.513 \frac{ft^3}{min} \]

\[ C_{SO2} = \left( \frac{VFR_{SO2}}{F_s} \right) \times 10^6 \]

\[ C_{SO2} = \left( \frac{5.513}{72,000} \right) \times 10^6 \]

\[ C_{SO2} = 76.57 \text{ ppmvd} \]
**Total Capital Investment**

\[ TCI = [(143.76)(F_d)] + [(0.610)\left(\frac{\sqrt{F_d}}{\#Ducts}\right)^2] + [(17412.26)e^{(0.017)}\left(\frac{\sqrt{F_d}}{\#Ducts}\right)] \\
+ [(53.973)e^{(0.014)\left(\frac{\sqrt{F_d}}{\#Ducts}\right)}] + (931911.04) \\
= [(143.76)(66,470)] + [(0.610)\left(\frac{126,000}{1}\right)^2] + [(17412.26)e^{(0.017)}\left(\frac{126,000}{1}\right)] \\
+ [(53.973)e^{(0.014)\left(\frac{126,000}{1}\right)}] + (931911.04) \\
= $17,842,666 (2008\$)

**Total Annualized Costs**

\[ TAC = (O_{P_{Hrs}})[(1.62 \times 10^{-3})(F_d)] + [(6.84 \times 10^{-7})(C_{SO2})(F_d)] + [(3.72 \times 10^{-5})(F_d)] \\
+ (21.157)] + \left\{ \left[7.2 \times 10^{-2} + \left(\frac{i(1+i)^{Eq\_Life}}{(1+i)^{Eq\_Life} - 1}\right)\right](TCI) \right\} \\
TAC = (2688)[(1.62 \times 10^{-3})(66,470)] + [(6.84 \times 10^{-7})(76.57)(66,470)] \\
+ [(3.72 \times 10^{-5})(126,000)] + (21.157)] \\
+ \left\{ \left[7.2 \times 10^{-2} + \left(\frac{0.07(1 + 0.07)^{15}}{(1 + 0.07)^{15} - 1}\right)\right]($17,842,666) \right\} \\
= $3,611,973 (2008\$)^{26}

---

Note that in the example CoST equations inventory distributed with CoST, a second source is picked up by this control measure. The second source was intended for use in Eq. 18 but qualified for this control as well. See the detailed control strategy results for SCC 10300401 and plant ID 15 in the CoST control strategies viewer to see the results that are consistent with the example calculation shown in this document.
4 Particulate Matter Control Cost Equations

This chapter is divided into two main sections – IPM and non-IPM sources. The types of cost equations for point source particulate matter < 2.5 microns (μm) in diameter (PM$_{2.5}$) controls, indicated below, are described in their appropriate sections.

- Equation type 1 for IPM fabric filter
- Equation type 14 for non-IPM fabric filter
- Equation type 15 for non-IPM ESP
- Equation type 17 for non-IPM dry injection and fabric filter (DIFF)

The subsections in this chapter describe each equation type, present the relevant equation parameters, and provide example calculations. The example calculations provided are prepared using version 2.15 of the CoST software.

4.1 IPM Sector (ptipm) PM Control Cost Equations

Equation Type 1 is used in the control cost calculation for IPM sector PM controls. In Equation Type 1, model plant capacities are used along with scaling factors and the emissions inventory’s unit-specific boiler characteristics to generate a control cost for an applied technology.

Restrictions on source size are also shown for the controls that use Equation Type 1. When an application restriction reflects a minimum and maximum capacity, the control is not applied unless the capacity of the source in the inventory falls within that range.

4.1.1 Equation Type 1 for PM$_{2.5}$ – Utility Boilers (Coal)

Equation Type 1 uses a pulse jet type fabric filter to control PM$_{2.5}$ emissions from coal utility boilers. Equation Type 1 involves the application of a scaling factor to adjust the capital cost associated with a control measure to the boiler size (MW) based on the original control technology’s documentation.

4.1.1.1 Cost Equations

Capital Cost Equations

The Equation Type 1 capital cost for ptipm PM$_{2.5}$ control measures uses a capital cost multiplier, the unit’s boiler capacity (in MW), and the scaling factor exponent. For PM$_{2.5}$ controls, the scaling factor is 1.0.

Capital Cost = Capital Cost Multiplier × Capacity × Scaling Factor × 1,000

Where:

---

27 U.S. EPA 2013, Table 5.17 on page 5-30.
• \textit{Capital Cost Multiplier} = an empirical value based on the specific control measure ($/kW)
• \textit{Capacity} = boiler capacity from the emissions inventory (MW) (from the units used in the emissions inventory converted to MW, see Section 1.2.1 for a discussion of unit conversions)
• \textit{Scaling Factor} = 1.0
• 1000 = conversion factor to convert the \textit{Capital Cost Multiplier} from $/kW to $/MW

\textit{Annualized Capital Cost} = \textit{Capital Cost} \times \textit{Capital Recovery Factor}

Where the \textit{Capital Cost} and the \textit{Capital Recovery Factor} have been calculated previously.

\textit{Operation and Maintenance Cost Equations}

The fixed O&M component is based on the unit’s capacity. The variable O&M includes an estimate for the unit’s capacity factor. The capacity factor accounts for the amount of actual power generated by a power plant as compared to its design capacity or rated output. A value of 1.00 would represent a unit operating at 100% capacity. The annualized cost is then estimated using the unit’s capital cost times the CRF and the sum of the fixed and variable O&M costs.

\textit{Fixed O&M} = \textit{Fixed O&M Cost Multiplier} \times \textit{Capacity} \times 1,000

Where:
• \textit{Fixed O&M Cost Multiplier} = an empirical value based on the specific control measure ($/kW)
• \textit{Capacity} = boiler capacity from the emissions inventory (MW)
• 1000 = a conversion factor to convert the Fixed O&M Cost Multiplier from $/kW to $/MW

\textit{Variable O&M} = \textit{Variable O&M Cost Multiplier} \times \textit{Capacity} \times \textit{Capacity Factor} \times 8,760

Where:
• \textit{Variable O&M Cost Multiplier} = an empirical value based on the specific control measure ($/MWh)
• \textit{Capacity Factor} = an empirical value based on the specific control measure
• \textit{Capacity} = boiler capacity from the emissions inventory (MW)
• 8,760 = the number of hours the equipment is assumed to operate a year

\textit{Total O&M Cost} = \textit{Fixed O&M} + \textit{Variable O&M}

\textit{Total Annualized Cost Equation}

\textit{Total Annualized Cost} = \textit{Annualized Capital Cost} + \textit{Total O&M Cost}
Where the \textit{Annualized Capital Cost} and the \textit{O&M Cost} were calculated previously.
4.1.1.2 Example Calculations

Equation Type 1 Example for PM$_{2.5}$

This section provides example calculations for an application of Equation Type 1 to an EGU boiler burning pulverized anthracite coal (SCC: 10100101) in which PM$_{2.5}$ is the primary pollutant for this control technology. The example is for a 75 MW utility boiler that uses a pulse jet type fabric filter for its control equipment (PFPJPJUBC1).

Example Equation Variables

Figure 4-1 illustrates the Equations tab of the View Control Measure screen for the Fabric Filter (Pulse Jet Type); Utility Boilers – Coal – 25 to 99 MW.\textsuperscript{28}

*Capital Recovery Factor* = 0.1010 (assumes equipment life of 15 years and interest rate of 5.7%, which is provided by IPM)

*Capacity* = 25.5 MW  
*Scaling Factor* = 1.0  
*Capital Cost Multiplier* ($/kW) = 274  
*Fixed O&M Cost Multiplier* ($/kW) = 1.00  
*Variable O&M Cost Multiplier* ($/MWh) = 0.06  
*Capacity Factor* = 1  
*Year for Cost Basis* = 2011

\textsuperscript{28} The combustion efficiency value is in the SCCs tab in the control measure database.
Figure 4-1: Equation Type 1 for PM2.5 - Example Screenshot from CoST

Annualized Capital Cost

\[\text{Capital Cost} = \text{Capital Cost Multiplier} \times \text{Capacity} \times \text{Scaling Factor} \times 1,000\]

\[\text{Capital Cost} = 274 \times \frac{\text{kW}}{\text{kW}} \times 25.5 \text{ MW} \times 1.0 \times 1,000 \times \frac{\text{kW}}{\text{MW}}\]

\[\text{Capital Cost} = \$6,987,000 \text{ (2011$)}\]

Annualized Capital Cost = Capital Cost \times \text{Capital Recovery Factor}

Annualized Capital Cost = $6,987,000 \times 0.1010

Annualized Capital Cost = $705,366 \text{ (2011$)}

Operation and Maintenance Cost

\[\text{Fixed O&M} = \text{Fixed O&M Cost Multiplier} \left(\frac{\$}{\text{kW}}\right) \times \text{Capacity (MW)} \times 1,000\]

\[\text{Fixed O&M} = 1.00 \times \frac{\text{\$}}{\text{kW}} \times 25.5 \text{ MW} \times 1,000 \times \frac{\text{kW}}{\text{MW}}\]

\[\text{Fixed O&M} = \$25,500 \text{ (2011$)}\]

\[\text{Variable O&M} = \text{Variable O&M Cost Multiplier} \left(\frac{\$}{\text{MWh}}\right) \times \text{Capacity (MW)} \times \text{Capacity Factor} \times 8,760 \text{ (Hours Per Year)}\]
Variable O&M = 0.06 $\frac{\text{MWh}}{} \times 25.5 \text{ MW} \times 1.0 \times 8,760 \text{ Hours}

Variable O&M = $13,403 (2011$)

Total O&M Cost = Fixed O&M + Variable O&M

Total O&M Cost = $25,500 + $13,403

Total O&M Cost = $38,903 (2011$)

Total Annualized Cost

Total Annualized Cost = Annualized Capital Cost + Total O&M Cost

Total Annualized Cost = $705,366 + $38,903

Total Annualized Cost = $744,269 (2011$)

4.2 Non-IPM Sector (ptnonipm) PM Control Cost Equations

Equation Types 8, 14, 15, and 17 are used to calculate PM control costs for non-IPM point sources. Equation Type 8 uses the unit’s stack flowrate (in scfm) as the primary variable for control cost calculation. The control costs for Equation Type 8 are based on calendar year 1995. If a unit’s stack flow is either missing or less than 5 cubic feet per minute (cfm), then the control cost equation is not applied to the specific unit and instead a default cost per ton calculation is used.

Equation Types 14, 15 and 17 were developed for the ICI boilers and process heater NESHAP for major sources (Boiler MACT). The control costs calculated by these equations are based on the calendar year 2008.

Although applicability and control costs are based on PM$_{10}$ emissions, these equations may also be used to estimate control costs of PM$_{2.5}$ reductions. Some PM control measures are primarily directed at reducing larger particulates (PM$_{10}$) while others are primarily for the purpose of reducing fine particulates (PM$_{2.5}$). The CMDB identifies the form of PM to which each control measure is primarily applicable.

4.2.1 Equation Type 8 for PM – ICI Boilers

The parameters for Equation Type 8 can be found in Stationary Source Control Techniques Document for Fine Particulate Matter.$^{29}$ The control efficiencies for both PM$_{10}$ and PM$_{2.5}$ are provided in this table. This Equation Type uses the exhaust flowrate at actual stack conditions ($F_a$) in actual cubic feet per minute (acfm) (see Section 1.2.2 for discussion of flowrate unit conversions).

---

$^{29}$ U.S. EPA 1998, Section 5.2.6, pages 5.2-21, 5.2-23, and 5.2-25; Section 5.3.6, pages 5.3-22, 5.3-23, and 5.3-29; and Section 5.4.6, pages 5.4-25, 5.4-26, and 5.4-33.
4.2.1.1 Cost Equations

Capital Cost Equation

Total Capital Cost = Typical Capital Cost × Exhaust Flowrate

Where:
- Typical Capital Cost = based on the specific control measure
- Exhaust flowrate = exhaust flowrate at actual stack conditions ($F_a$) in actual cubic feet per minute (acfm)

Annualized Capital Cost = Capital Cost × CRF

Where the Capital Cost and the Capital Recovery Factor were calculated previously.

Operation and Maintenance Cost Equation

Total O&M Cost = Typical O&M Cost × Exhaust Flowrate

Where:
- Typical O&M Cost = based on the specific control measure
- Exhaust flowrate = exhaust flowrate at actual stack conditions ($F_a$) in actual cubic feet per minute (acfm)

Total Annualized Cost Equation

Total Annualized Cost
= Annualized Capital Cost + 0.04 × Total Capital Cost + Total O&M Cost

Where:
- 0.04 = 4% of the Capital Cost, which represents fixed annual charge for taxes, insurance, and administrative costs.

Annualized Capital Cost and Total O&M Cost were calculated previously.

4.2.1.2 Example Calculations

This section provides example calculations for an application of Equation Type 8 to a non-EGU plant. The example scenario is for a bauxite ore crushing and handling process at a primary metal production facility (SCC: 30300001) using a dry ESP – wire plate type for PM control (PDESPMPAM). Figure 4-2 is the View Control Measures screen for a Dry ESP – Wire Plate Type.
Figure 4-2: Equation Type 8 for PM$_{2.5}$ - Example Screenshot from CoST

Example Equation Variables

- **Capital Recovery Factor** = 0.0944 (assumes equipment life of 20 years and interest rate of 7%)
- **Typical Capital Cost** ($/acfm) = 27.0
- **Typical O&M Cost** ($/acfm) = 16.0
- **PM$_{10}$ Emissions Reductions** = 162.78 tons
- **Exhaust Flowrate** = 283.69 ft$^3$/sec
- **Year for Cost Basis** = 1995

**Capital Cost Equation**

\[
\text{Capital Cost} = \text{Typical Capital Cost} \times \text{Exhaust Flowrate} \times 60
\]

\[
\text{Capital Cost} = \frac{27}{\text{acfm}} \times \frac{283.69}{\text{sec}} \times 60 \frac{\text{sec}}{\text{min}}
\]

\[
\text{Capital Cost} = 459,578 \text{ (1995$)}
\]
Use an implicit price deflator ratio to convert from 1995$ to 2000$.

\[
\text{Capital Cost} = \$459,578 \text{ (1995$)} \times \frac{81.887 \text{ (2000$)}}{75.324 \text{ (1995$)}}
\]

\[
\text{Capital Cost} = \$499,621 \text{ (2000$)}
\]

Annualized Capital Cost = Capital Cost × Capital Recovery Factor
Annualized Capital Cost = $499,621 × 0.0944

**Operation and Maintenance Cost Equation**

\[
\text{O&M Cost} = \text{Typical O&M Cost} \times \text{Exhaust Flowrate} \times 60
\]

\[
\text{O&M Cost} = \$16/\text{acfm} \times 283.69 \frac{\text{ft}^3}{\text{sec}} \times 60 \frac{\text{sec}}{\text{min}}
\]

\[
\text{O&M Cost} = \$272,342 \text{ (1995$)}
\]

\[
\text{O&M Cost} = \$272,342 \text{ (1995$)} \times \frac{81.887 \text{ (2000$)}}{75.324 \text{ (1995$)}}
\]

\[
\text{O&M Cost} = \$296,072 \text{ (2000$)}
\]

**Total Annualized Cost Equation**

\[
\text{Total Annualized Cost} = \text{Annualized Capital Cost} + 0.04 \times \text{Capital Cost} + \text{O&M Cost}
\]

\[
\text{Total Annualized Cost} = \$47,161 + 0.04 \times \$499,621 + \$296,072
\]

\[
\text{Total Annualized Cost} = \$363,217 \text{ (2000$)}
\]

4.2.1.3 **Equation Type 8 for PM Control Cost per Ton Calculations**

When the exhaust flowrate is either less than 5.0 cfm or unavailable in the inventory, Equation Type 8 defaults to a cost per ton equation.

\[
\text{Capital Cost} = \text{Emissions Reduction} \times \text{Default Capital Cost Per Ton}
\]

\[
\text{O&M Cost} = \text{Emissions Reduction} \times \text{Default O&M Cost Per Ton}
\]

\[
\text{Total Annualized Cost} = \text{Emissions Reduction} \times \text{Default Annualized Cost Per Ton}
\]

Where:
- \text{Emissions Reduction} = \text{emissions reduction (tons/year)} \text{ calculated by CoST}
- \text{Default Capital Cost per Ton} = \$710.0/\text{ton}
- \text{Default O&M Cost per Ton} = \$41.0/\text{ton}
- \text{Default Annualized Cost per Ton} = \$110.0/\text{ton}
4.2.2 Equations Type 14 for PM – Fabric Filter Control on ICI Boilers

Equation Type 14 is used for fabric filters when approximately 99% PM control is required and no SO2 reduction is needed.\(^{30}\) This Equation Type uses the exhaust flowrate at actual stack conditions (Fa) in actual cubic feet per minute (acfm), at standard temperature (Fs) in standard cubic feet per minute (scfm), and at standard temperature on a dry basis (Fd) in dry standard cubic feet per minute (dscfm) (see Section 1.2.2 for discussion of flowrate unit conversions).

**Concentration of PM in outlet gas**

The equations that are used to convert from inventory emissions to the concentration of PM\(_{2.5}\) in the stack gas are shown here.

\[
C_{PM} = E_{PM} \times 1.725 \times \left(\frac{15.4323584}{F_d}\right)
\]

Where:
- \(E_{PM}\) = Annual PM emissions from the emissions inventory (tons/year)
- 1.725 = (grams/minute PM)/(tons/year PM)
- 15.4323584 = grains/gram of PM
- \(F_d\) = Exhaust flowrate at standard temperature on a dry basis (dscfm)
- \(C_{PM}\) = Outlet concentration of PM, grains per dry standard cubic foot (gr/dscf)

### 4.2.2.1 Cost Equations

**Total Capital Investment Equation**

\[
TCI = (105.91)(F_d) + 699754.7 + \left[ (0.560)\left(\frac{\sqrt{F_a}}{\#Ducts}\right)^2 \right] + \left[ (1096.141)e^{(0.017)}\left(\frac{\sqrt{F_a}}{\#Ducts}\right) \right]
+ \left[ (33.977)e^{(0.014)}\left(\frac{\sqrt{F_a}}{\#Ducts}\right) \right]
\]

Where:
- \(F_d\) = Exhaust flowrate at standard temperature on a dry basis (dscfm)
- \(F_a\) = Actual exhaust flowrate (acfm)
- \#Ducts = if \(F_d \leq 154042\), then \#Ducts = 1

\(^{30}\) ERG 2013, Appendix B, page B-1.
if $F_d > 154042$, then $#\text{Ducts} = F_d / 154042$

**Total Annualized Costs Equation**

$$TAC = [(17.44)(OP_{Hrs})] + \left\{ (TCI) \left[ (0.072) + \left( \frac{(i)(1 + i)^{EqLife}}{(1 + i)^{EqLife} - 1} \right) \right] \right\}$$

$$+ \left\{ (F_a) \left[ (4.507) + (1.24 \times 10^{-5})(OP_{Hrs}) - (4.184) \left( \frac{(i)(1 + i)^{EqLife}}{(1 + i)^{EqLife} - 1} \right) \right] \right\}$$

$$+ \left\{ (F_d)(OP_{Hrs})[(3.76 \times 10^{-3}) + (1.81 \times 10^{-3})(C_{PM})] \right\}$$

Where:

- $F_d$ = Exhaust flowrate at standard temperature on a dry basis (dscfm)
- $OP_{Hrs}$ = Annual operating hours of unit from the emissions inventory (hours/year)
- $TCI$ = Total Capital Investment ($)
- $F_a$ = Actual exhaust flowrate (acfm)
- $C_{PM}$ = Concentration of PM in stack gas (grains per dry standard cubic foot [gr/dscf])
- $i$ = Interest rate
- $EqLife$ = Estimated equipment life (years)

**4.2.2.2 Example Calculations**

The example scenario for Equation Type 14 is for an industrial boiler that is burning grade 6 residual oil (SCC: 10200401). The boiler uses a fabric filter as its emissions control equipment for PM (PFFICIBRO). Figure 4-3 illustrates the View Control Measure screen for the Fabric Filter emissions control method for ICI boilers (Residual Oil) emitting PM.
**Example Equation Variables**

Capital Recovery Factor = 0.1098 (assumes equipment life of 15 years ($Eq_{Life}$) and interest rate of 7% ($i$))

#Ducts = 1

$F_a = 924.88 \frac{ft^3}{sec} \times 60 = 55,493 \frac{ft^3}{min}$

$T = 450 \degree F$

$Op_{Hrs} = 2,688$ operating hours per year

$E_{PM} = 300$ tons/year

% Moist = 9.08%

Year for Cost Basis = 2008

**Flowrate calculations**

$F_d = (F_a) \left( \frac{460 + 68}{460 + T} \right) \left( 1 - \frac{\% Moist}{100} \right)$

$F_d = (55,493) \left( \frac{460 + 68}{460 + 450} \right) \left( 1 - \frac{9.08}{100} \right)$

---

*Figure 4-3: Equation Type 14 for PM2.5 - Example Screenshot from CoST*
\[ F_d = 29,274 \frac{ft^3}{min} \]

**Concentration of PM in outlet gas**

\[ C_{PM} = E_{PM} \times 1.725 \times \left( \frac{15,432,358,400}{F_d} \right) \]

\[ C_{PM} = 300 \times 1.725 \times \left( \frac{15,432,358,400}{29,274} \right) \]

\[ C_{PM} = 0.273 \text{ gr/dscf} \]

**Total Capital Investment**

\[ TCI \]

\[ = (105.91)(F_d) + 699,754.7 + \left[ (0.560)\left( \frac{\sqrt{F_a}}{\#Ducts} \right)^2 \right] + \left[ (1096.141)e^{(0.017)\left( \frac{\sqrt{F_a}}{\#Ducts} \right)} \right] + \left[ (33.977)e^{(0.014)\left( \frac{\sqrt{F_a}}{\#Ducts} \right)} \right] \]

\[ TCI = (105.91)(29,274) + 699,754.7 + \left[ (0.560)\left( \frac{\sqrt{55,493}}{1} \right)^2 \right] + \left[ (1096.141)e^{(0.017)\left( \frac{\sqrt{55,493}}{1} \right)} \right] + \left[ (33.977)e^{(0.014)\left( \frac{\sqrt{55,493}}{1} \right)} \right] \]

\[ TCI = \$3,892,334 \text{ (2008$)} \]

**Total Annualized Costs**

\[ TAC \]

\[ = [(17.44)(Op_{Hrs})] + \left\{ (TCI) \left[ (0.072) + \left( \frac{(i)(1 + i)^{EqLife}}{(1 + i)^{EqLife} - 1} \right) \right] \right\} + \left\{ (F_a)(4.507) + (1.24 \times 10^{-5})(Op_{Hrs}) - (4.184)\left( \frac{(i)(1 + i)^{EqLife}}{(1 + i)^{EqLife} - 1} \right) \right\} + \left\{ (Op_{Hrs})[3.76 \times 10^{-3}] + (1.81 \times 10^{-3})(C_{PM}) \right\} \]

\[ TAC = [(17.44)(2688)] + \left\{ (3892,334) \left[ (0.072) + \left( \frac{(0.07)(1 + 0.07)^{15}}{(1 + 0.07)^{15} - 1} \right) \right] \right\} + \left\{ (55,493) \left[ (4.507) + (1.24 \times 10^{-5})(2688) - (4.184)\left( \frac{(0.07)(1 + 0.07)^{15}}{(1 + 0.07)^{15} - 1} \right) \right] \right\} + \left\{ (29,274)(2688)[3.76 \times 10^{-3}] + (1.81 \times 10^{-3})(0.273) \right\} \]

\[ TAC = \$1,315,676 \text{ (2008$)} \]
4.2.3 Equation Type 15 for PM – Electrostatic Precipitator Controls on ICI Boilers

Equation Type 15 is used for electrostatic precipitators (ESP) when approximately 98% PM control is required and no SO\textsubscript{2} reduction is needed.\(^3\) Note that it is assumed that the pressure drop through the ESP is 0.38 inches of water (in H\textsubscript{2}O). This Equation Type uses the exhaust flowrate at actual stack conditions \((F_\text{a})\) in actual cubic feet per minute (acfm) (see Section 1.2.2 for discussion of flowrate unit conversions).

**PM emissions in lb/MMBtu**

The equation to convert from inventory emissions in tons/year to lb/MMBtu is shown here.

\[
E_{PM} = E_{I PM} \times 2000 \times \left( \frac{1}{365} \right) \times \left( \frac{1}{24} \right) \times \left( \frac{1}{3.412 \times \text{Design Capacity}} \right)
\]

Where:
- \(E_{PM}\) = Annual PM emissions (lb/MMBtu)
- \(E_{I PM}\) = Annual PM emissions from the emissions inventory (tons/year)
- 2000 = lbs/ton
- 365 = days/year
- 24 = hours/day
- Design Capacity = Unit design capacity from inventory (MMBtu/hour)

4.2.3.1 Cost Equations

**Total Capital Investment Equation**

\[
TCI = \left\{ (12.265)(EC_1)[(5.266)(F_\text{a})]^{EC_2} \right\} + [(0.784)\left( \frac{F_\text{a}}{\#Ducts} \right)] + (\#Ducts) \left\{ (2237.13)\left( e^{(0.017)}\left( \frac{\sqrt{F_\text{a}}}{\#Ducts} \right) \right) \right\} + (69.345)\left( e^{(0.014)}\left( \frac{\sqrt{F_\text{a}}}{\#Ducts} \right) \right) + (17588.69)
\]

Where:
- \(EC_1\) = First equipment cost factor for ESP
  - if \(F_\text{a} \geq 9495\), \(EC_1 = 57.87\)
  - if \(F_\text{a} < 9495\), \(EC_1 = 614.55\)
- \(F_\text{a}\) = Actual exhaust flowrate (acfm)
- \(EC_2\) = Second equipment cost factor for ESP
  - if \(F_\text{a} \geq 9495\), \(EC_1 = 0.8431\)

\(^3\) ERG 2013, Appendix B, pages B-2 and B-3.
if \( F_a < 9495 \), \( EC_2 = 0.6276 \)

\[
\text{#Ducts} = \begin{cases} 
1 & \text{if } F_a < 308084 \\
2 & \text{if } 308084 \leq F_a < 462126 \\
3 & \text{if } 462126 \leq F_a < 616168 \\
4 & \text{if } F_a \geq 616168
\end{cases}
\]

**Total Annualized Costs Equation**

\[
TAC = [(10.074)(O_pHrs)] + [(0.052)(F_a)] \\
+ \left\{ (6.56 \times 10^{-3}) \left[ 1.04 + \left( \frac{(i)(1+i)^{EqLife}}{(1+i)^{EqLife}-1} \right) \right] \left( (EC_1)((5.266)(F_a))^{EC_2} \right) \right\} \\
+ [(0.021)(O_pHrs)(E_{PM})(DC)] \\
+ \left\{ (1.17 \times 10^{-5})(F_a)(O_pHrs) \left[ (1.895) + \left( \frac{1}{\sqrt{F_a}} \right)^{1.18} \right] \right\} \\
+ [(7.15 \times 10^{-4})(O_pHrs)(F_a)] \\
+ \left\{ (0.04 + \left( \frac{(i)(1+i)^{EqLife}}{(1+i)^{EqLife}-1} \right)) \right( \text{#Ducts} \left[ (0.783) \left( \frac{\sqrt{F_a}}{\text{#Ducts}} \right)^2 \right] \right) \\
+ (2237.44) \left( e^{(0.0165)\left( \frac{\sqrt{F_a}}{\text{#Ducts}} \right)} \right) + (69.355) \left( e^{(0.0140)\left( \frac{\sqrt{F_a}}{\text{#Ducts}} \right)} \right) + (17591.15) \right\}
\]

Where:

- \( O_pHrs \) = Annual operating hours of unit (hours/year)
- \( F_a \) = Actual exhaust flowrate (acfm)
- \( i \) = Interest rate
- \( EqLife \) = Estimated equipment life, years
- \( EC_1 \) = First equipment cost factor for ESP
  - If \( F_a \geq 9495 \), \( EC_1 = 57.87 \)
  - If \( F_a < 9495 \), \( EC_1 = 614.55 \)
- \( EC_2 \) = Second equipment cost factor for ESP
  - If \( F_a \geq 9495 \), \( EC_2 = 0.8431 \)
  - If \( F_a < 9495 \), \( EC_2 = 0.6276 \)
- \( E_{PM} \) = PM emission rate, pounds per million British thermal units (lb/MMBtu)
- \( DC \) = Design capacity of boiler from inventory (MMBtu/hour)
- \( \text{#Ducts} \) = \( \text{#Ducts} \)

### 4.2.3.2 Example Calculations

The example scenario for Equation Type 15 is for an ICI boiler burning grade 4 distillate oil (SCC 10300504) that uses an ESP as its emissions control equipment for PM (PESPICIB).
Example Equation Variables

Capital Recovery Factor = 0.1098 (assumes equipment life of 15 ($Eq_{Life}$) years and interest rate of 7% ($i$))

$EC_1 = 57.87$

Exhaust Flowrate = 924.88

$EC_2 = 0.8431$

#Ducts = 1

$Op_{Hrs} = 2,688$

$EI_{PM} = 240$ tons/year

Design Capacity (DC) = 180 MMBtu/hour = 52.75 MW

Year for Cost Basis = 2008

Flowrate calculations

$F_a = $ Exhaust Flowrate $\times 60$

$F_a = 924.88 \times 60$

$F_a = 55,493$ acfm

PM emissions in lb/MMBtu

$E_{PM} = EI_{PM} \times 2000 \times \left(\frac{1}{365}\right) \times \left(\frac{1}{24}\right) \times \left(\frac{1}{3.412 \times DC(MW)}\right)$

$E_{PM} = 240 \times 2000 \times \left(\frac{1}{365}\right) \times \left(\frac{1}{24}\right) \times \left(\frac{1}{3.412 \times 52.75}\right)$

$E_{PM} = 0.3044$ lb/MMBTU

Total Capital Investment

$TCI$

$= \{(12.265)(EC_1)(5.266)(F_a)^{EC_2} + \left(0.784\right)\left(\frac{F_a}{#Ducts}\right)\}

+ (\#Ducts) \left\{\left(2237.13\right)(e^{(0.017)\left(\frac{\sqrt{F_a}}{#Ducts}\right)}) + \left(69.345\right)(e^{(0.014)\left(\frac{\sqrt{F_a}}{#Ducts}\right)})\right\} + (17588.69)\}$

$TCI$

$= \{(12.265)(57.87)(5.266)(55493)^{0.8431} + \left(0.784\right)\left(\frac{55493}{1}\right)\}

+ (1) \left\{\left(2237.13\right)(e^{(0.017)\left(\frac{\sqrt{55493}}{1}\right)}) + \left(69.345\right)(e^{(0.014)\left(\frac{\sqrt{55493}}{1}\right)})\right\} + (17588.69)\}$

$= 28,977,396$ (2008$)
Total Annualized Costs

\[ TAC \]
\[ = [(10.074)(Op_{Hrs})] + [(0.052)(F_a)] \]
\[ + \{ (6.56 \times 10^{-3})\left(1.04 + \left( \frac{(i)(1 + i)^{Eq\Life}}{(1 + i)^{Eq\Life} - 1} \right) \right) (EC_1)[(5.266)(F_a)]^{EC_2} \} \]
\[ + [(0.021)(Op_{Hrs})(E_{PM})]\left( DC \frac{MMBtu}{hr} \right) \]
\[ + \left\{ (1.17 \times 10^{-5})(F_a)(Op_{Hrs}) \left[ (1.895) + \left( 479.85 \left( \frac{1}{F_a} \right)^{1.18} \right) \right] \right\} \]
\[ + [(7.15 \times 10^{-4})(Op_{Hrs})(F_a)] \]
\[ + \left\{ 0.04 + \left( \frac{(i)(1 + i)^{Eq\Life}}{(1 + i)^{Eq\Life} - 1} \right) \right\} (#Ducts) \left[ 0.783 \left( \frac{F_a}{#Ducts} \right)^2 \right] \]
\[ + (2237.44) \left( e^{(0.0165)}\left( \frac{\sqrt{F_a}}{#Ducts} \right) \right) + (69.355) \left( e^{(0.0140)}\left( \frac{\sqrt{F_a}}{#Ducts} \right) \right) + (17591.15) \]
17 is presented in this section instead of Section 3.2 because the primary reduction is achieved for PM. This Equation Type uses the exhaust flowrate at actual stack conditions \( F_a \) in actual cubic feet per minute (acfm), at standard temperature \( F_s \) in standard cubic feet per minute (scfm), and at standard temperature on a dry basis \( F_d \) in dry standard cubic feet per minute (dscfm) (see Section 1.2.2 for discussion of flowrate unit conversions).

**Concentration of PM in outlet gas**

The equations that are used to convert from inventory emissions to the concentration of PM\(_{2.5}\) in the stack gas are shown here.

\[
C_{PM} = E_{PM} \times 1.725 \times \left( \frac{15.4323584}{F_d} \right)
\]

Where:
- \( E_{PM} \) = Annual PM emissions from the emissions inventory (tons/year)
- 1.725 = (grams/minute PM)/(tons/year PM)
- 15.4323584 = grains/gram of PM
- \( F_d \) = Exhaust flowrate at standard temperature on a dry basis (dscfm)
- \( C_{PM} \) = Outlet concentration of PM, grains per dry standard cubic foot (gr/dscf)

**Concentration of SO\(_2\) in outlet gas**

The equations that are used to convert from inventory emissions to the concentration of SO\(_2\) in the stack gas are shown here.

\[
VFR_{SO2} = E_{SO2} \times 2,000 \times \left( \frac{1}{64.06} \right) \times \left( \frac{1}{Op_{Hrs}} \right) \times \left( \frac{1}{60} \right) \times 379.7
\]

\[
C_{SO2} = \left( \frac{VFR_{SO2}}{F_s} \right) \times 10^6
\]

Where:
- \( VFR_{SO2} \) = Volumetric Flow Rate (ft\(^3\)/minute)
- \( E_{SO2} \) = Annual SO\(_2\) emissions from the emissions inventory (tons/year)
- 2,000 = lbs/ton
- 64.06 = SO\(_2\) molecular weight (grams/mol)
- \( Op_{Hrs} \) = Annual operating hours from the emissions inventory (hours)
- 60 = minutes/hour
- 379.7 = Volume of 1 mol SO\(_2\) under standard conditions (ft\(^3\)/mol)
- \( F_s \) = Exhaust flowrate at standard temperature (scfm)
- \( C_{SO2} \) = Outlet concentration of SO\(_2\), dry parts per million by volume (ppmvd)
4.2.4.1 Cost Equations

**Total Capital Investment Equation**

\[
TCI = [(143.76)(F_d)] + [(0.610)(\sqrt{\frac{F_a}{#Ducts}})^2] + [(1757.65)(e^{0.017}(\sqrt{\frac{F_a}{#Ducts}}))] \\
+ [(59.973)(e^{0.014}(\sqrt{\frac{F_a}{#Ducts}}))] + (931911.04)
\]

Where:
- \(F_d\) = Exhaust flowrate at standard temperature on a dry basis (dscfm)
- \(F_a\) = Actual exhaust flowrate (acfm)
- \(#Ducts\) = if \(F_d\leq 154042\), \(#Ducts = 1\)  
  if \(F_d > 154042\), \(#Ducts = F_d/154042\)

**Total Annualized Costs Equation**

\[
TAC = [(1.62 \times 10^{-3})(O_{pHrs})(F_d)] + [(17.314)(O_{pHrs})] + [(1.05 \times 10^{-6})(C_{SO2})(F_d)(O_{pHrs})] \\
+ [(3.72 \times 10^{-5})(O_{pHrs})(F_a)] + [(1.81 \times 10^{-4})(O_{pHrs})(C_{PM})(F_d)] \\
+ [(0.847)\left(1 - \frac{(i)(1+i)^{EqLife}}{(1+i)^{EqLife} - 1}\right)(F_d)] \\
+ [(0.04) + \left(\frac{(i)(1+i)^{EqLife}}{(1+i)^{EqLife} - 1}\right)][(0.032)(TCI)] + [(0.606)(\sqrt{\frac{F_a}{#Ducts}})^2] \\
+ [(1757.65)(e^{0.017}(\sqrt{\frac{F_a}{#Ducts}}))] + [(53.973)(e^{0.014}(\sqrt{\frac{F_a}{#Ducts}}))] + (13689.81)
\]

Where:
- \(F_d\) = Exhaust flowrate at standard temperature on a dry basis (dscfm)
- \(O_{pHrs}\) = Annual operating hours of unit, from emissions inventory (hours/year)
- \(C_{SO2}\) = Concentration of SO\(_2\) in stack gas, dry ppm by volume (ppmvd)
- \(F_a\) = Actual exhaust flowrate (acfm)
- \(C_{PM}\) = Concentration of PM in the stack gas (gr/dscf)
- \(i\) = Interest rate
- \(EqLife\) = Estimated equipment life (yrs)
- \(#Ducts\) = if \(F_d \leq 154042\), \(#Ducts = 1\) 
  if \(F_d > 154042\), \(#Ducts = F_d/154042\)
### 4.2.4.2 Example Calculations

The example calculation for Equation Type 17 is for a dry bottom pulverized bituminous coal ICI boiler (SCC: 103002016) using a dry injection fabric filter system for PM and SO$_2$ controls (PDIFFIBBC). Figure 4-4 illustrates information from the View Control Measures screen showing the Dry Injection/Fabric Filter (DIFF) System for Equation Type 17.

![Figure 4-4: Equation Type 17 for PM$_{2.5}$ - Example Screenshot from CoST](image)

<table>
<thead>
<tr>
<th>Equation Type</th>
<th>Variable Name</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Type 17</td>
<td>Pollutant</td>
<td>PM2.5-PRI</td>
</tr>
<tr>
<td>Type 17</td>
<td>Cost Year</td>
<td>2008</td>
</tr>
<tr>
<td>Type 17</td>
<td>Stack Gas Moisture Content, %</td>
<td>4.68</td>
</tr>
</tbody>
</table>

**Example Equation Variables**

- **Capital Recovery Factor** = 0.1098 (assumes equipment life of 15 years ($E_{Eq\text{Life}}$) and interest rate of 7\% ($i$))
- **Exhaust Flowrate** = 924.88 acfs
- **$T$** = 450 °F
- **$E_{PM}$** = 300 tons/year
- **$E_{SO2}$** = 120 tons/year
- **% Moist** = 4.68\%
- **#Ducts** = 1
- **$OpHrs$** = 2688 hours/year
- **Year for Cost Basis** = 2008
Flowrate calculations

\[ F_a = \text{Exhaust Flowrate} \times 60 \]

\[ F_a = 924.88 \times 60 \]

\[ F_a = 55,493 \text{ acf/m} \]

\[ F_d = (F_a) \left( \frac{460 + 68}{460 + T} \right) \left( 1 - \frac{\%\text{Moist}}{100} \right) \]

\[ F_d = (55,493) \left( \frac{460 + 68}{460 + 450} \right) \left( 1 - \frac{4.68}{100} \right) \]

\[ F_d = 30,691 \text{ dscf/m} \]

\[ F_s = (F_a) \left( \frac{520}{460 + T} \right) \]

\[ F_s = (55,493) \left( \frac{520}{460 + 450} \right) \]

\[ F_s = 31,710 \text{ scf/m} \]

Concentration of PM in outlet gas

\[ C_{PM} = E_{PM} \times 1.725 \times \left( \frac{15.4323584}{F_d} \right) \]

\[ C_{PM} = 300 \times 1.725 \times \left( \frac{15.4323584}{30,691} \right) \]

\[ C_{PM} = 0.26 \text{ gr/dscf} \]

Concentration of SO\(_2\) in outlet gas

\[ VFR_{SO2} = E_{SO2} \times 2,000 \times \left( \frac{1}{64.06} \right) \times \left( \frac{1}{OpHrs} \right) \times \left( \frac{1}{60} \right) \times 379.7 \]

\[ VFR_{SO2} = 120 \times 2,000 \times \left( \frac{1}{64.06} \right) \times \left( \frac{1}{2688} \right) \times \left( \frac{1}{60} \right) \times 379.7 \]

\[ VFR_{SO2} = 8.82 \text{ ft}^3/\text{min} \]

\[ C_{SO2} = \left( \frac{VFR_{SO2}}{F_s} \right) \times 10^6 \]

\[ C_{SO2} = \left( \frac{8.82}{31,710} \right) \times 10^6 \]

\[ C_{SO2} = 278.2 \text{ ppmvd} \]
**Total Capital Investment**

\[
TCI = [(143.76)(F_d)] + \left[ (0.610) \left( \frac{\sqrt{F_a}}{\#Ducts} \right) \right] + \left[ (1757.65) \left( e^{0.017} \left( \frac{\sqrt{F_a}}{\#Ducts} \right) \right) \right] + \left[ (59.973) \left( e^{0.014} \left( \frac{\sqrt{F_a}}{\#Ducts} \right) \right) \right] + (931911.04)
\]

\[
TCI = [(143.76)(30691)] + \left[ (0.610) \left( \frac{\sqrt{55493}}{1} \right) \right] + \left[ (1757.65) \left( e^{0.017} \left( \frac{\sqrt{55493}}{1} \right) \right) \right] + \left[ (59.973) \left( e^{0.014} \left( \frac{\sqrt{55493}}{1} \right) \right) \right] + (931911.04)
\]

\[TCAI = $5,475,959 \text{(2008$)}\]

**Total Annualized Costs**

\[
TAC = [(1.62 \times 10^{-3})(Op_{Hrs})(F_d)] + [(17.314)(Op_{Hrs})] + [(1.05 \times 10^{-6})(C_{SO2})(F_d)(Op_{Hrs})] + [(3.72 \times 10^{-5})(Op_{Hrs})(F_a)] + [(1.81 \times 10^{-4})(Op_{Hrs})(C_{PM})(F_d)] + \left[ (0.847) \left( 1 - \left( \frac{(i)(1 + i)^{EqLife}}{(1 + i)^{EqLife} - 1} \right) \right) \right] (F_d) + \left[ (0.04) + \left( \frac{(i)(1 + i)^{EqLife}}{(1 + i)^{EqLife} - 1} \right) \right] \left[ ((0.032)(TCI)] + \left[ (0.606) \left( \frac{\sqrt{F_a}}{\#Ducts} \right) \right] \right] + \left[ (1757.65) \left( e^{0.017} \left( \frac{\sqrt{F_a}}{\#Ducts} \right) \right) \right] + \left[ (53.973) \left( e^{0.014} \left( \frac{\sqrt{F_a}}{\#Ducts} \right) \right) \right] + (13689.81)
\]

\[
TAC = [(1.62 \times 10^{-3})(2688)(30691)] + [(17.314)(2688)] + [(1.05 \times 10^{-6})(278.2)(30691)(2688)] + [3.72 \times 10^{-5}(2688)(55493)] + [(1.81 \times 10^{-4})(2688)(0.26)(30691)] + \left[ (0.847) \left( 1 - \left( \frac{(0.07)(1 + 0.07)^{15}}{(1 + 0.07)^{15} - 1} \right) \right) \right] (55493) + \left[ (0.04) + \left( \frac{(0.07)(1 + 0.07)^{15}}{(1 + 0.07)^{15} - 1} \right) \right] \left[ ((0.032)(5475959)] + \left[ (0.606) \left( \frac{55493}{1} \right) \right] \right] + \left[ (1757.65) \left( e^{0.017} \left( \frac{\sqrt{55493}}{1} \right) \right) \right] + \left[ (53.973) \left( e^{0.014} \left( \frac{\sqrt{55493}}{1} \right) \right) \right] + (13689.81)
\]

\[TAC = $303,555 \text{(2008$)}\]
5 References


RTI International 2014. “Update of NOx Control Measure Data in the CoST Control Measure Database for Four Industrial Source Categories: Ammonia Reformers, NonEGU Combustion Turbines, Glass Manufacturing, and Lean Burn Reciprocating Internal Combustion Engines.”


