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**MEMORANDUM**

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| **TO**: | Lisa Thompson<br>U.S. EPA/Office of Air Quality Planning and Standards<br>Sector Policies and Programs Division |
| **FROM:** | Eastern Research Group, Inc. (ERG) |
| **DATE:** | August 2021 |
| **SUBJECT:** | Revised (2021) Methodology for Estimating Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants |

## 1.0 Introduction

The EPA is amending the national emission standards for hazardous air pollutants (NESHAP) for industrial, commercial, and institutional (ICI) boilers and process heaters at major sources of hazardous air pollutants (HAP) under regulatory citation 40 CFR part 63, subpart DDDDD.

These impacts were calculated for existing units and new units projected to be operational by the year 2029, eight years after the amendments are expected to be promulgated. The impacts shown in this analysis are incremental impacts that are expected to be additional to the impacts previously claimed by the January 2013 final rulemaking for the ICI boiler and process heater major source NESHAP.

The development of the emission limits in the final amendments, and a detailed description of the cost equations used to estimate costs for various control technologies is presented in other memoranda.[1,2] This memorandum is organized as follows:

1.0 Introduction

2.0 Dataset Used to Assess the Impacts

3.0 Methodology and Results for Estimating Cost Impacts

4.0 Methodology and Results for Estimating Emission Reductions

5.0 Methodology and Results for Estimating Secondary Impacts

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[1] Eastern Research Group, Inc. Revised MACT Floor Analysis (August 2021) for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source.

[2] Eastern Research Group, Inc. Revised (August 2021) Methodology for Estimating Control Costs for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source.

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Appendix A-1 – Compliance Data for ICI Boilers and Process Heaters through December 2020

Appendix A-2 – Extrapolation of Existing Sources Impacted by Revised Emission Limits

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Appendix C-1 – Baseline Emission Factors

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Appendix C-4 – Emission Reductions from New Units

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Appendix D-2 – Secondary Impacts from New Units

## 2.0 Dataset Used to Assess the Impacts

Since the final rule became effective in 2013, the EPA has compiled and collected compliance data from both new and existing boilers available through the Compliance and Emissions Data Reporting Interface (CEDRI) and WebFIRE through December 31, 2020. Additional compliance information was provided to EPA from trade associations such as the Council for Industrial Boiler Operators (CIBO). Collectively, the compliance dataset contains data on 577 existing boilers firing a variety of fuels and fifteen new boilers, all of which belong in one of the biomass subcategories. A complete list of the compliance data is available in Appendix A-1.

The compliance data for hydrogen chloride (HCl), mercury (Hg), filterable particulate matter (PM), and carbon monoxide (CO) was reviewed and compared to the final emission limits to evaluate which boilers were not currently meeting the more stringent final emission limits.

In researching company ownership for the Regulatory Impact Analysis (RIA), the EPA also identified one facility that had exceedances of the revised Hg and PM emission limits. However, the mill will shut down prior to these amendments going into place. This facility was removed from the impact analysis.[3]

For existing units that were missing compliance data for certain pollutants, the EPA estimated the number of units that may be impacted by the final limits by applying an equation factoring in the ratio of boilers in the subcategory that had compliance data for a particular pollutant and the amount of units that

[3] Facility ID that is shutdown is PAAppvion. https://www.usnews.com/news/best-states/pennsylvania/articles/2021-02-16/paper-mill-operating-since-1866-to-close-pandemic-cited. Facility shutdown occurred on April 3, 2021.

exceeded the limit for each subcategory. The total number of units to be impacted for each combination of pollutant and subcategory estimated was calculated using Equation 1.

$$\textbf{Equation 1}: Exceedance + \frac{Exceedance}{Units\ with\ Data} \times Units\ without\ Data$$

The results of the number of existing units impacted by each of the emission limits are shown in Appendix A-2. Collectively, considering real exceedance data and extrapolated estimates for units that were missing compliance data, and all of the pollutants together there are 49 existing units impacted, 40 existing biomass units and 9 existing coal units were anticipated to be impacted. The exact list of existing units impacted are shown in Appendix B-1a.

For new units, there was one unit with missing HCl compliance data from the 15 biomass units. We added this one unit to the four units that exceeded the revised emission limit for new sources. In order to account for additional new units that would come online and be subject to the more stringent emission limits over the eight-year period following the promulgation of the final rule, the EPA extrapolated the set of 15 boilers to account for new boiler building over the next eight years. Only four of the 15 boilers exceeded the final emission limit for HCl. This is 0.5 (4 boilers /8 years of compliance data from January 2013 through December 2020) boilers per year.

Over eight years, there are four new model boilers (0.5*8), with an exceedance of HCl. In total, these four extrapolated boilers were added to the five new boilers that had missing data or exceeded the HCl limit, yielding nine new biomass boilers that were estimated to be impacted by the final HCl emission limit, four with actual exceedances, one with no HCl compliance data, and four more based on the projected units over the next 8 years.

For PM, one of the 15 new boilers were impacted. To extrapolate the number of boilers impacted over the next 8 years, 1 boiler divided by 8 years of compliance data, or 0.125 boilers per year, yields one additional new boiler impacted over the next 8-year period. A total of two biomass boilers were estimated to be impacted by the PM emission limit, one with actual exceedance and one based on the projected units over the next 8 years. The calculations are detailed in Appendix A-4.

The exact list of new units impacted are shown in Appendix B-2a.

## 3.0 Methodology and Results for Estimating Cost Impacts

*3.1 Control Costs*

In each case where there as an exceedance of the HCl, Hg, or PM emission limits, the cost impacts analysis compares the baseline emissions, based on what was reported in the compliance data, to the corresponding final emission limit for the unit’s subcategory. The cost of a control device was applied to the unit if its baseline emissions exceeded their applicable final emission limit, using the logic discussed below, according to each type of pollutant requiring control.

*Mercury Control*

Fabric filters — a new fabric filter installation was expected to achieve most of the Hg emission reductions in the rule. Where baseline Hg emissions were found to be greater than the MACT floor, the cost of a fabric filter was estimated for an individual boiler or process heater.

*Particulate Matter and Metallic HAP Control*

When baseline PM emissions exceeded the emission limits, the cost of an electrostatic precipitator (ESP) was estimated, unless a fabric filter had already been included in the cost analysis for Hg reduction, or unless an ESP was already reported to be installed as a baseline control and the unit still required more than 20 percent PM emission reductions. If PM emissions were not available, TSM8 baseline emissions were used, and the cost of a fabric filter was estimated if a fabric filter was not already installed.

*Hydrogen Chloride Control*

When HCl baseline emissions were greater than the MACT floor, the cost of adding a packed bed scrubber, increasing the sorbent rate on an existing scrubber, or installing a combination fabric filter and dry injection (DIFF) system was estimated. Scrubbers and DIFF were estimated to be able to attain similar levels of hydrogen chloride control.

In some cases, the compliance data was very close to the final emission limit, and it was assumed that other compliance strategies would be adopted instead of a full installation of a new add-on air pollution control device. For example, units within 4 percent of the emission limits for Hg or HCl were assumed to be able to achieve incremental reductions to the lower limit by changing fuel blending or adjusting fuel contracts. In three cases, a unit with an PM baseline value 19 or 20 percent higher than the limit was assumed to upgrade its ESP to a more efficient ESP instead of totally replacing its control device. In six cases, units with an existing sorbent injection or wet scrubber system for HCl control were estimated to be able to increase the injection rate in order to achieve the additional reductions required by the more stringent emission limits.

*Carbon Monoxide and Organic HAP Control*

For CO, there were eight existing biomass units that exceeded the CO stack-test limit changes. In all of these cases, it was assumed that the source would install a CO CEMS and demonstrate compliance with the CEMS-based limit instead of installing controls for the more stringent stack test-based emission limit. The costs to install and operate the CO CEMS were applied in each of these cases.

This impacts analysis represents incremental costs beyond those already accounted for in the January 2013 final rule. For existing units, an additional check was made to see if the control strategy expected to be necessary to meet the final emission limit had previously been costed out. If so, the same control was not accounted for in this revised analysis to avoid double counting of the costs. For example, if an ESP had been estimated for a particulate unit in 2013, and the unit had not installed an ESP to comply with the limits based on the more recent compliance dataset, the costs for an ESP would not have been accounted for on that unit.

*3.2 Testing and Monitoring Costs*

Testing costs were not accounted for in the analysis as the final amendments do not change the requirements for testing. Furthermore, the impacts analysis in the 2013 final rule estimated annual testing frequency for all units subject to emission limits, which is a conservatively high estimate of the testing costs considering that many units have switched to natural gas or qualified for a less frequent testing schedule as a result of some of the compliance flexibilities offered in the rule.

The final changes to emission limits will impact monitoring requirements, since the types of monitors vary depending on the equipment installed on the unit to control emissions. For units expected to install packed bed wet scrubbers, the one-time capital and an annualized capital and O&M cost for a scrubber parametric monitor was included in the cost analysis. If a unit was expected to install DIFF, the cost to monitor sorbent injection rate and add a bag leak detection monitor was included in the analysis, based on the unit's hours of operation. For units expected to install a fabric filter, the one-time capital and an annualized capital and O&M cost for a bag leak detection monitor was included in the cost analysis. In the case of CO, if a unit switches from a stack-test based compliance strategy to a CO CEMS-based compliance strategy there will be a cost incurred to purchase, install, calibrate, and operate the CEMS.

## 3.3 Results

As noted in the Cost Methodology memorandum, for this analysis, all compliance costs were estimated in 2016 dollars and the total capital investment for the control device and monitoring costs are annualized using an interest rate of 5.5 percent over the life of the equipment. The year dollars and interest rate for annualizing capital costs are the same as those for the proposal.[4] Such costs are considered private costs, for they represent the direct compliance costs to affected units and are not the social costs (the overall cost of society) of the final rule.

A summary of the costs that includes impacts for both new and existing units is shown in Table 1. The details of the incremental capital and annualized costs of the final changes are presented in Appendix B-1 for existing units and Appendix B-2 for new units. This main analysis of costs presents those that are the total undiscounted costs after eight years after promulgation (2022 to 2029), the years that are reflected in the estimates of present value and equivalent annualized values for costs in the Regulatory Impact Analysis (RIA).

In addition, in order to address the question of whether the choice of control technology for this rule is affected by the interest rate used in the cost analysis, we find that there is but a single selection of control technologies for ICI boilers to meet each emission limit except for those for HCl when we vary the interest rate. A sensitivity analysis was conducted for HCl controls varying the interest rate of 5.5 percent to 10 and 15 percent, respectively. Since the source is anticipated to select the least expensive control (based on annual costs) and thus act to comply while minimizing control costs where multiple HCl control strategies can achieve the revised emission limit in the rule, this sensitivity analysis evaluated whether or not a different control would be selected at a higher interest rate. The application of higher interest rates did not change the selected control technology for HCl for any of the new or existing sources. Thus, the choice of control technologies to meet the final emissions limits are insensitive to interest rates included in the cost analysis. The results of the sensitivity analysis are included as part of Appendix B-1 for existing units and Appendix B-2 for new units.

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[4] The 5.5 percent interest rate is higher than the bank prime rate, an interest rate normally applied for annualizing capital in a cost analysis such as this. This interest rate reflective of the rate of debt for large financial institutions and corporations and is set by the Federal Reserve Board. We use a higher interest rate in this cost analysis to allow for consistency with the rate used in the proposal cost analysis.

*Table 1. Summary of Incremental Costs from Final Amendments*

| Estimates of Private Compliance Costs (2016$) | | | | |
|---|---|---|---|---|
| **Cost type** | **Total Capital Investment (TCI)** | **Operating and Maintenance (O&M)** | **Annualized Capital Costs** | **Total Annual Cost (TAC)** |
| DIFF* | $1,909,990 | $849,944 | $158,990 | $1,008,934 |
| ESP | $1,480,291 | $130,272 | $124,378 | $254,650 |
| FF | $156,718,682 | $22,530,925 | $12,961,859 | $35,492,784 |
| Packed Bed Scrubber | $38,571,982 | $8,348,733 | $3,796,069 | $12,144,802 |
| Testing and Monitoring Costs | $2,178,172 | $336,506 | $325,065 | $661,571 |
| **Total** | **$200,859,118** | **$32,196,380** | **$17,366,361** | **$49,562,741** |

*DIFF costs include costs of installing a new DIFF or increasing sorbent injection rate on an existing system to improve control efficiency.

## 4.0 Methodology and Results for Estimating Emission Reductions

Incremental emission reductions were quantified for HCl, Hg, PM, particulate matter less than 2.5 microns (PM2.5), sulfur dioxide ($SO_2$), hydrogen fluoride (HF), total non-mercury selected metals (TSM8).[5]
For HCl, Hg, and PM the reductions were calculated by subtracting the annual emissions at the level of the final emission limits from the emissions based on the current compliance data. One of the units was missing compliance data for mercury and its baseline emissions were set equal to the MACT floor emission limit for that subcategory.

For HF and $SO_2$, the baseline emission factors were obtained from reported emission test results in the database for the final rule[6], if the control device for the targeted pollutant group of acid gases had not changed. If no test data were available, or the test data did not represent the current control configuration on the unit, these gaps were filled by looking up the fuel and control device installed on the unit in the compliance dataset in Appendix A-1 and obtaining the appropriate baseline emission factor for that group. The baseline emission factors were the same as those used in the final rule and can be found in the docket for this rule.[7] A copy of the baseline emission factors is shown in Appendix C-1. The source of the baseline emission factor used in the emission reduction analysis for each pollutant is listed for existing and new units in Appendices C-3 and C-4, respectively. A percent reduction was calculated for HCl by comparing the baseline to the final emission limit for the appropriate subcategory. It was assumed that each

[5] TSM8 metals include arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, and selenium. Estimates of reductions in antimony and cobalt were not quantified and are expected to be small.
[6] Emissions Database for Boilers and Process Heaters Containing Stack Test, CEM, & Fuel Analysis Data Reporting under ICR No. 2286.01 & ICR No.2286.03 (version 8). Docket ID Item No. EPA-HQ-OAR-2002-0058-3830.
[7] Eastern Research Group, Inc. Revised August 2012 Development of Baseline Emission Factors for Boilers and Process Heaters at Commercial, Industrial, and Institutional Facilities. Docket ID Item No. EPA-HQ-OAR-2002-0058-3832.

combustion unit would achieve an identical percent reduction from baseline emissions for HF and $SO_2$ as was achieved for HCl.

For TSM8, some sources had TSM8 compliance data. When compliance data was not available, the baseline emission factors were obtained by looking up the fuel and control device installed on the unit in the compliance dataset in Appendix A-1 and obtaining the appropriate baseline emission factors for that group. The baseline emission factors were the same as those used in the final rule. A copy of the baseline emission factors is shown in Appendix C-1. The source of the baseline emission factor used in the emission reduction analysis for each pollutant is listed for existing and new units in Appendices C-3 and C-4, respectively. A percent reduction was also calculated for PM, by comparing the baseline PM to the final emission limit for the appropriate subcategory. It was assumed that each combustion unit would achieve an identical percent reduction from baseline emissions for TSM8 as was achieved for PM.

PM2.5 is a select portion of total filterable PM based on particle size, so it was assumed that a portion of total filterable PM will always be PM2.5. PM2.5 emissions were assumed to be a fraction of total filterable PM emissions based on fuel and control device configuration installed on the unit. Since the control device was assumed to change in some cases to meet the final emission limits, the fraction of PM2.5 was first estimated as a fraction of the baseline PM emissions and the baseline level of control according to the compliance dataset. A separate PM2.5 fraction was estimated based on the fraction of the controlled PM emissions after the new final limits took effect as well as any changes to the control device configurations expected to be installed to meet the PM limits. Details on the fractions for each fuel and control device group are presented in Appendix C-2. To calculate emission reductions for PM2.5, the post-controlled estimates of PM2.5 were subtracted from baseline estimate of PM2.5 emissions.

To convert emission reductions from an emission rate on a heat input basis to an annual emission rate, Equation 2 was used:

$$\text{Annual Emission Rate (tpy)} = ER_{HI} * DC * 0.0005 * Op_{hours} \qquad \textbf{(Equation 2)}$$

*Where:*
$ER_{HI}$ = emission rate (lb/mmBtu)
DC = design capacity (mmBtu/hr)
0.0005 = conversion factor, lbs per ton
$Op_{hours}$ = annual operating hours, assumed 8424 (hours/year)

To convert emission reductions from a concentration basis to an annual emission rate, Equation 3 was used:

$$\text{Annual Emission Rate (tpy)} = ER_C * 0.000001 * Q_S * 60 * Op_{hours} * MW * 0.0026 * 0.0005 * (20.946 - O_2) / (20.946 - \text{Std } O_2) \qquad \textbf{(Equation 3)}$$

*Where:*
$ER_C$ = emission concentration (ppm @ 3% $O_2$)
0.000001 = conversion factor, ppm to parts
$Q_S$ = exhaust flowrate (dscfm)
60 = conversion factor, minutes to hours

$Op_{hours}$ = annual operating hours assumed 8424 (hours/year)
MW = molecular weight of pollutant, in lb per lb-mole
0.0026 = conversion factor, lb-mole per dry standard cubic foot of gas
0.0005 = conversion factor, lb per ton
20.946 = percentage of oxygen in ambient air
$O_2$ = percentage of oxygen assumed in exhaust gas
Std. $O_2$ = 3 percent oxygen in standardized emission concentration.

Converting concentrations to an annual emission rate required an oxygen concentration and exhaust flowrate estimated for each specific fuel type. The development of these assumptions and estimates is presented in the docket for this rule.[8]

The emission reductions are summarized in Table 2 below and the details for existing and new units are presented in Appendices C-3 and C-4.

There were six emission limits that became less stringent as a result of the revised MACT floor emission limit calculations. No emission increases were estimated to result from these six emission limits. Two of the six limits are for filterable PM at new and existing process gas subcategories. Based on the reported compliance data, there are no boilers or process heaters subject to those subcategories and therefore emission increases could not be quantified. The remaining four limits are for TSM8 emission limits in various biomass subcategories, including both new and existing dry biomass stokers and new and existing suspension burners. For these cases, the filterable PM limit is the primary standard and the TSM8 emission limit is an alternate standard that facilities can elect to comply with instead of the PM standard. Upon review of the compliance data available for new and existing boilers in these four biomass subcategories, all were found to be complying with the PM limit rather than the TSM8 limit. There are 23 units in these four subcategories, including 14 existing suspension burners, no new suspension burners, eight existing dry biomass stokers and one new dry biomass stoker. Additionally, all of these units already have PM controls in place and, thus, emissions would not increase even with an increase in the TSM8 limit.

***Table 2. Summary of Incremental Annual Emission Reductions from Final Amendments***

| | Annual Reductions, tpy | | | | | | |
|---|---|---|---|---|---|---|---|
| **Source Type** | **Hg** | **HCl** | **HF** | **$SO_2$** | **PM** | **PM2.5** | **TSM8** |
| *Existing-Biomass* | 1.65E-03 | 13.57 | 0.10 | 42.68 | 521.43 | 392.54 | 3.84 |
| *Existing-Coal* | 2.12E-03 | 44.10 | 0.91 | 514.65 | 54.43 | 47.52 | 0.12 |
| *New-Biomass* | 0 | 52.27 | 1.90 | 583.49 | 9.90 | 6.43 | 0.14 |
| ***Total*** | **3.77E-03** | **110** | **2.9** | **1,141** | **586** | **446** | **4.1** |

[8] Eastern Research Group, Inc. Revised (November 2011) Methodology for Estimating Control Costs for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source. November 2011. Docket ID Item No. EPA-HQ-OAR-2002-0058-3875.

## 5.0 Methodology and Results for Estimating Secondary Impacts

Secondary impacts include the solid waste, water, wastewater, and electricity required to operate air pollution control devices that are anticipated to be required to meet the more stringent final emission limits. This section documents the inputs and equations used to estimate these secondary impacts.

The secondary impacts were calculated by applying control cost algorithms described in the docket for this rule.[9] Where the baseline emissions for each unit exceeded the final emission limits, as noted above in section 3.0, the controls and their associated secondary impacts were sized for the corresponding unit's needs to meet each emission limit.

*5.1 Wastewater and Water Impacts*

The water required to create a slurry in the packed scrubber and the wastewater generated by the effluent of a packed bed scrubber were calculated for every unit expected to install a scrubber to meet the HCl limits in the final rule. Both the water and wastewater calculations required the use of several constants and variables. The constants including the density of gas, moles of salt needed per mole of hydrogen chloride in the exhaust gas, the molecular weight of the salt used, the fraction of the waste stream treated, and the molecular weight of the gas. Operating hours per year were assumed to be 8,424. The variables used to estimate the quantity of water required and wastewater generated were calculated based on characteristics reported for each unit in the compliance dataset. The variables included: exhaust flow rate from the combustion unit to the control device in actual cubic feet per minute, the inlet loading of hydrogen chloride to the control device (mole fraction), and the efficiency of the control device in removing hydrogen chloride from the exhaust gas (percent reduction). The total national water and wastewater amounts in Appendices D-1 and D-2 were determined by adding the per unit water and wastewater estimates for all new and existing units, respectively.

*5.2 Solid Waste Impacts*

Solid waste is generated from collecting dust and fly ash in fabric filters or ESP control devices or spent caustic from increasing the caustic injection rate. Solid waste impacts were estimated for every unit expected to install a fabric filter for mercury control or a DIFF or additional sorbent for HCl control or install an ESP to meet PM emission limits. The total national solid waste amounts in Appendices D-1 and D-2 were determined by adding the per unit solid waste estimates for all new and existing units, respectively. To estimate the solid waste contribution from each of these control devices, the variables were calculated based on characteristics reported for each unit in the compliance dataset. The calculations used to estimate each variable and the quantity of solid waste generated are provided in the docket for this rule.[10] The solid waste (dust, fly ash) generated by the use of an electrostatic precipitator was calculated when an electrostatic precipitator was determined to be necessary to meet the NESHAP emission limits for PM. Estimates of the solid waste collected in an ESP were based on several variables, including: Exhaust flow rate from the combustion unit to the control device (acfm); the inlet loading of particulate matter to the control device (gr/acfm); operating hours (hr/year) and the efficiency of the control device required to meet the more stringent final PM emission limits. The solid waste generated from the collection of dust and fly ash in a fabric filter was calculated when a fabric filter was determined to be necessary to meet the final emission limits for particulate matter and/or mercury. The calculation required the use of three variables, including: exhaust flow rate from the combustion unit to the control device (dscfm); operating hours (hr/year) and the inlet loading of particulate matter to the control device

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[9] Ibid.

[10] Ibid.

(gr/acfm). Operating hours per year were assumed to be 8,424. The solid waste generated from increased caustic was calculated for those units where additional caustic was expected to achieve the final NESHAP emission limits for HCl. The calculation required the use of three variables, including: exhaust flow rate from the combustion unit to the control device (dscfm); operating hours (hr/year), and the required removal efficiency for HCl.

*5.3 Electricity Impacts*

The amount of electricity required to operate a control device was calculated for a packed scrubber, electrostatic precipitator, fabric filter, and DIFF. These impacts were assessed for every unit that was estimated to require HCl, Hg, and PM control. Electricity requirements are one output of the cost algorithms used in the analyses, so no additional calculations were necessary. For some units, an electrical demand from multiple control devices was estimated. The total national electricity demand in Table 3 was determined by adding the per unit electricity demand estimates for all new and existing units, respectively. To estimate the electricity demand from each of these control devices, a set of variables was calculated based on characteristics reported for each existing unit in the 2008 survey[11] and subsequent data gathering activities and for the characteristics assigned to each new model unit. The constants, variables, and calculations used to estimate each variable and the electricity demand to operate the control devices are provided in the docket for this rule.[12]

*5.4 Greenhouse Gas Emissions from Electricity Usage*

Since carbon dioxide is generated from electricity production, an estimate of carbon dioxide emissions was generated for the electricity impacts of the add-on air pollution control devices. The total electricity usage from all control devices nationwide was multiplied by the national average carbon dioxide emission factor for carbon dioxide emissions from EPA's 2019 e-GRID to obtain the expected annual carbon dioxide emissions.[13] Carbon dioxide emissions were only estimated for boilers required to install a fabric filter, ESP, wet scrubber, or DIFF system, since those controls generate an increased electricity demand.

*5.5 Results*

Table 3 summarizes the secondary impacts at new and existing units. The detailed results of the secondary analysis are shown in Appendices D-1 and D-2.

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[11] Survey Database Containing Results of the 2008 Questionnaire. The latest database containing the compiled answers is at Docket ID Item No. EPA-HQ-OAR-2002-0058-3830.

[12] Eastern Research Group, Inc. Revised (November 2011) Methodology for Estimating Control Costs for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source. November 2011. Docket ID Item No. EPA-HQ-OAR-2002-0058-3875.

[13] Environmental Protection Agency. eGRID version 2019. National Average, Total output emission rates. Data accessible https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid.

*Table 3. Summary of Incremental Secondary Impacts from Final Amendments*

| Impact | New Units | Existing Units | Total |
|---|---|---|---|
| Water (gal/yr) | 161,648 | 587,595 | 749,243 |
| Wastewater (gal/yr) | 62,775 | 224,902 | 287,677 |
| Solid Waste (tons/yr) | 50 | 1,490 | 1,540 |
| Purchased Electricity (kW-hr/yr) | 14,497,743 | 59,940,372 | 74,438,115 |
| $CO_2$ Emissions from Purchased Electricity tons/yr) | 6,410 | 26,501 | 32,910 |
| Cost to handle wastewater ($/yr) | | | $1,924 |
| Cost to handle solid waste ($/yr) | | | $73,900 |