Industrial Sector

Part 3 of 6 Supporting Documents

Sector-Specific Issues and Reporting Methodologies Supporting the General Guidelines for the Voluntary Reporting of Greenhouse Gases under Section 1605(b) of the Energy Policy Act of 1992

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Examples

Figures

Tables

3.0 Industrial Sector

This document supports and supplements the General Guidelines for reporting greenhouse gas information under Section 1605(b) of the Energy Policy Act (EPAct) of 1992. The General Guidelines provide the rationale for the voluntary reporting program and overall concepts and methods to be used in reporting. Before proceeding to the more specific discussion contained in this supporting document, you should read the General Guidelines. Then read this document, which relates the general guidance to the issues, methods, and data specific to the industrial sector. Other supporting documents address the electricity supply sector, the residential and commercial buildings sector, the transportation sector, the forestry sector, and the agricultural sector.

The General Guidelines and supporting documents describe the rationale and processes for estimating emissions and analyzing emissions-reducing and carbon sequestration projects. When you understand the approaches taken by the voluntary reporting program, you will have the background needed to complete the reporting forms.

The General Guidelines and supporting documents address four major greenhouse gases: carbon dioxide, methane, nitrous oxide, and halogenated substances. Although other radiatively enhancing gases are not generally discussed, you will be able to report nitrogen oxides (NO_x), nonmethane volatile organic compounds (NMVOCs), and carbon monoxide (CO) after the second reporting cycle (that is, after 1996).

The Department of Energy (DOE) has designed this voluntary reporting program to be flexible and easy to use. For example, you are encouraged to use the same fuel consumption or energy savings data that you may already have compiled for existing programs or for your own internal tracking. In addition, you may use the default emissions factors and stipulated factors that this document provides for some types of projects to convert your existing data directly into estimated emissions reductions. The intent of the default emissions and stipulated factors is to simplify the reporting process, not to discourage you from developing your own emissions estimates.

Whether you report for your whole organization, only for one project, or at some level in between, you will find guidance and overall approaches that will help you in analyzing your projects and developing your reports. If you need reporting forms, contact the Energy Information Administration (EIA) of DOE, 1000 Independence Avenue, SW, Washington, DC 20585.

3.1 Industry: Overview

This supporting document provides technical guidance on reporting both industrial greenhouse gas emissions and the effects of projects you undertake to reduce those emissions. Guidance is provided for reporting activities that have reduced greenhouse gas emissions at an industrial site, by reducing on-site fossil fuel consumption, changing the composition of fossil fuel use, or reducing direct emissions from industrial processes; and at off-site locations, by reducing electricity purchases resulting in lower fossil fuel use at electric power generating plants.

The industrial sector is diverse, encompassing extraction and production of basic materials, conversion of materials into intermediate products, and manufacture of final goods. These activities give rise to emissions of various greenhouse gases, as illustrated in Table 3.1.

The industrial activities that produce greenhouse gas emissions may be classified into two groups: energy-related emissions (for example, from fossil energy consumption) and other emissions from industrial process operations (for example, from coal mining or cement production). This supporting document provides guidance for reporting emissions and emissions reductions associated with both groups of activities. This supporting document provides technical assistance and illustrative examples to support each of the steps involved in estimating emissions and emissions reductions for the industrial sector. Note that each example is provided for illustrative purposes only; other appropriate ways of evaluating these hypothetical projects may exist.

3.1.1 Reporting Entities

A typical industrial reporter could be a corporation or company, a subsidiary, or a single plant or establishment. If you have multiple subsidiaries or establishments, you may wish to combine some or all of them into a single report, or you may wish to report separately for each subsidiary or establishment.

Table 3.1. Industrial Sources of Greenhouse Gases

Greenhouse Gas	**Major Industrial Sources**
Carbon Dioxide (CO_2)	Fossil fuel combustion Cement production
Methane (CH_4)	Coal mining Oil and natural gas system operation Landfill operation Stationary combustion
Nitrous Oxide (N_2O)	Adipic acid production Stationary combustion
Halogenated substances (CFCs, HCFCs, PFCs, etc.)	Deliberate manufacture and use Use or production in industrial processes

3.1.2 Sector-Specific Issues

The industrial sector is complex and diverse. The number and type of potential emissions-reducing activities in industry is large, and analyzing emissions-reduction projects may involve a number of calculations. For example, you may need to determine the effects of projects on the use of various fuels and electricity, on energy related and non-energy related emissions, and on emissions in other sectors in addition to the industrial sector (for example, a project that reduces emissions from an industrial process may also change within-plant or between-plant transportation requirements).

In spite of this complexity, you may find it worthwhile to collect information on the effects of your projects. Many organizations have found that conducting energy audits and analyzing the costs and energy savings associated with the audit findings identifies many cost-effective ways to save energy. If you have such information, you may find reporting under the EPAct 1605(b) program to be especially straightforward. In addition, various surveys collect data on energy use in manufacturing. If you are a survey participant, you may be able to use the data you gather for these surveys as a basis for developing your EPAct Section 1605(b) report.

You may also be able to take advantage of other existing information. For example, under the Motor Challenge program, the Department of Energy is collecting information on the use and effects of electric motor systems. If you become a participant in the Motor Challenge program, you can use the information developed for that program as a basis for preparing your EPAct Section 1605(b) report.

You should maintain records in your files containing the detailed calculations and data you used to estimate your emissions and emissions reductions.

You may choose to report through a third party, which could aggregate the emissions reductions for a group of entities with similar characteristics. The third party could ease the reporting burden on individual companies and provide an additional layer of confidentiality, since the contributions of any individual entity would not need to be identified in the report. (You should familiarize yourself with the confidentiality discussion in the General Guidelines.) A third party may also provide technical assistance in conducting the emissions-reducing projects and reporting. In this case, the emissions reduction might be reported jointly. Possible third parties include trade associations, engineering/energy service companies, and energy utility companies.

The reasons for third-party reporting could vary, depending on the type of third party. A trade association might wish to represent its industry's actions for public relations purposes or simply to provide additional confidentiality. An engineering/energy service company might wish to display its ability to save its clients money through its energy-saving measures or advice on environmental controls. A utility company could be jointly involved in demand-side management programs that reduce emissions. If you involve another party in identifying, implementing, or paying for the emission-reducing project, you should identify this party in your report to track possible multiple reporting. Similarly, if you are providing data on emission reductions to several third parties—for example, two trade associations of which you are a member—you should identify those parties.

A third-party reporter would develop aggregated reports and track the individual contributions of reporting entities. The third party would not be responsible for verification or certification; that responsibility remains with you as the reporting entity. If you report your emissions through a third party, you should retain in your files the information you used to compute your emissions and emissions reductions.

3.2 Organization of This Supporting Document

As described in the General Guidelines, EPAct Section 1605(b) addresses the reporting of annual emissions as well as emissions reductions and carbon sequestration. Section 3.3 provides guidance on reporting emissions, especially at the whole entity level. Section 3.4 builds on the discussion of project analysis in the General Guidelines and provides a framework for understanding how your emission reduction project relates to the reference cases, project effects, and estimation approaches described in the General Guidelines.

Rather than focus on specific industries, the remainder of this supporting document is organized by type of emissions-producing activity (energy use or industrial process operation). Table 3.2 indicates how the document is organized and where you can find guidance for reporting emissions reductions for each type of activity. Sections 3.5 through 3.10 and Appendices 3.A through 3.F discuss methods for estimating emissions reductions. Section 3.5 provides general guidance for computing emissions reductions from energy savings, including the special cases of energy savings from fuel switching and cogeneration. Section 3.6 provides guidance for computing reductions of halogenated substance emissions. Sections 3.7 through 3.9 provide specific guidance for computing reductions in methane emissions from coal mines, natural gas systems, and landfills, respectively. Finally, Section 3.10 provides guidance for computing reductions in nitrous oxide emissions from adipic acid plants. Note that some types of energy savings projects you may undertake will address the energy use of the buildings that house your industrial operations. These include projects to reduce the energy used for lighting, heating, cooling, and ventilation. Specific guidance for reporting emissions reductions resulting from decreased building energy use may be found in the supporting document for the residential and commercial buildings sector.

. . . . **Table 3.2** Where to Find Guidance for Reporting Industrial Emissions and Emissions Reductions

Type of Emissions or Reductions	Location
Total Emissions	Section 3.3
Reductions in Emissions from Energy Use	Section 3.5
Reductions in Emissions of Halogenated Substances from Halogenate Manufacture and Use and from Aluminum Production	Section 3.6
Reductions in Methane Emissions from Natural Gas Systems	Section 3.7
Reductions in Methane Emissions from Landfills	Section 3.8
Reductions in Methane Emissions from Coal Mines	Section 3.9
Reductions in Nitrous Oxide Emissions from Adipic Acid Plants	Section 3.10

The most important greenhouse gas emitted from fuel combustion is carbon dioxide. Thus, carbon dioxide is the focus of the guidance on reporting emissions reductions related to energy use.

Carbon dioxide also is emitted directly from some manufacturing processes as an inherent byproduct of the production process—for example, carbon dioxide is created during the production of cement.(a) There are no economically feasible technologies available at this time to capture and dispose of carbon dioxide emissions. Thus, no specific guidance is provided for reporting reductions of carbon dioxide emissions that result directly from industrial processes (that is, unrelated to energy use). However, if you operate a cement plant or other carbon dioxide-emitting plant and you reduce production, close a plant, or in some other way reduce direct carbon dioxide emissions (for example, through a fundamental process change that reduces or eliminates the production of carbon dioxide), you may report the accompanying emissions reduction. In your project analysis, you will need to evaluate all the potential effects of your project, including an increase in production elsewhere to supply the market you are no longer supplying (see the General Guidelines, "How Should I Analyze Projects I Wish to Report?"). Any such emissions reduction report should conform to the principles for good project analysis described in the General Guidelines.

Similarly, no specific guidance is provided for reporting reductions of methane or nitrous oxide emissions from sources other than coal mines, natural gas systems, landfills, and adipic acid plants. You may report reductions from other sources in accordance with the project analysis principles described in the General Guidelines and this supporting document.

In general, you may report any type of project that reduces greenhouse gas emissions so long as you are able to perform a credible project analysis and meet the minimum reporting requirements described in the General Guidelines ("What Are the Minimum Reporting Requirements?"). You are not restricted to reporting only those projects mentioned explicitly in this document.

3.3 Estimating and Reporting Greenhouse Gas Emissions

The General Guidelines, "What is Involved in Reporting Emissions?" explain that reporting information on greenhouse gas emissions for the baseline period of 1987 through l990 and for subsequent calendar years on an annual basis is considered an important element of this program. If you are able to report emissions information for your entire organization, you should consider providing a comprehensive accounting so that your audience can gain a clear understanding of your overall activities.   As noted in the General Guidelines, some users of the database may find your reported estimates of emission reductions more credible when accompanied by data on your organization's total emissions for the year of the reduction, as well as for the baseline years 1987 through 1990 and subsequent years. You may wish to report this information for all or as much of your organization as possible, particularly if it would be important to users of your report.

(a) Carbon dioxide is created during the calcination process when calcium carbonate ($CaCO_3$) is heated in a cement kiln to form lime (CaO) and carbon dioxide. Lime is also manufactured for other purposes, but cement production is the largest nonenergy source of industrial carbon dioxide emissions.

A comprehensive emissions report would include your entity's total emissions from all on-site sources—building energy use, industrial process energy use, transportation energy use, on-site electricity generation, and direct emissions from industrial processes—as well as electric utility emissions associated with your purchased electricity. DOE encourages you to submit as comprehensive a report as possible, considering the feasibility and costs of obtaining the necessary data and the potential uses for your report.

Your emissions may be direct (from fuel use on-site or from industrial processes, coal mines, landfills, or natural gas systems) or indirect (from off-site generation of electricity you purchase) or a combination thereof. To report direct energy-related emissions, you can determine the amount and type of energy consumed as fuel(b) in the reporting year and, for each fuel, multiply the fuel use by the corresponding emission factor in the table in Appendix B or your site-specific emissions factor. To calculate emissions resulting from electricity purchases, you may use the default state level factors in Appendix C or calculate utility-specific factors using the guidance in the supporting document for the electricity supply sector. You will also need to determine your non-energy-related emissions (from industrial processes). For each gas, you should sum the emissions from direct energy use, electricity use, and industrial processes, and report the total.

Table B.1 in Appendix B provides emissions factors for various fuels. When the exact form of a fossil fuel is not known—for example, coal is burned, but the type is not identifiable—you should use an average emission/unit energy value for that fuel when computing total emissions. If you have specific data for your fuels and equipment indicating that an emission factor different from that in Table B.1 should be used, or if you use a fuel (such as a waste fuel) that is not listed in Table B.1, you are encouraged to use your own emissions factor. You must document the source of the emissions factor in your report.

The case of biomass fuels present a special challenge to estimating emissions factors. In general, the emissions associated with switching to a biomass fuel depend on the reference case. For example, if the biomass represents waste from your operation that would have been burned in the reference case, your burning of that waste fuel represents no additional emissions. In this case, you could credibly assert that the emissions factor for your waste fuel is zero. Alternatively, if your biomass fuel comes from a managed source, determining the appropriate emissions factor is more complex. The supporting documents for forestry and agriculture provide some guidance on the computation of emission rates for such biomass-based fuels and the possible carbon sequestration that would arise if the biomass fuel source were a managed source. The carbon sequestration must be reported separately, however.

The case in which the biomass fuel would have been left to decay in the reference case is even more complex. In reality, the gas emitted from decaying biomass is a mixture of carbon dioxide and methane, with more methane emitted the more anaerobic the decay process. (For example, the fraction of methane in the emissions is higher if the biomass is wet.)

A conservative approach would assume that, for the biomass left to decay in the reference case, all the gas emitted was carbon dioxide. In this case, the amount of carbon dioxide assumed to be emitted from biomass sources would be the same in the project case and the reference case. In that case, any change in net emissions arises from reductions in the burning of fossil fuels.

(b) "Consumed as fuel" refers to the combustion of energy sources for heat and power rather than their use as feedstocks for chemical processes.

A less conservative approach would account for the methane emissions that occurred in the reference case but are no longer occurring in the project case. In this case, you would be able to report an emissions reduction for methane. At the same time, you would have to report a smaller carbon dioxide emissions reduction (which makes up only a fraction of the reference case emissions rather than all of them). However, it requires considerably more data and analysis to take this approach. Also, attempting this approach without all the necessary data and analysis could cause some users of the database to lose confidence in your report. If you choose this approach to evaluate emissions reductions associated with using biomass fuels, you should explain carefully how you computed your reductions and what studies or other sources you used in doing so.

You may currently be reporting data on energy consumption to government or private organizations. You may wish to use these data in computing your total energy-related emissions. For example, the Energy Information Administration uses the Manufacturing Energy Consumption Survey (MECS) to collect data from a sample of manufacturers on the use of both electricity and direct fuels. Also, the Bureau of the Census uses the Census of Manufactures (CM) and the Annual Survey of Manufactures (ASM) to collect data on electricity consumption for the manufacturing industries. Although the data as reported are confidential, you can use the data you reported to these surveys as the basis for computing your total emissions. For example, if you are part of the MECS sample, the detailed data on fuel use that you reported could be used as a basis for computing carbon dioxide emissions from fossil fuel combustion and electricity use. Specifically, on the MECS reporting form, column 2, line 4, page 1, "total electricity received on-site," and column 9, lines A1-12, B1-8, C1-8, page 3, "energy sources consumed on-site," would provide the basis for calculating total emissions. If you are reporting your total entity emissions, you would need to compute separately any emissions from transportation vehicles, any non-energy related emissions from industrial processes and add these to your manufacturing energy-related emissions.

Some industry associations also collect energy data from their members for internal purposes. For example:

- The American Iron and Steel Institute collects energy data from its members.
- The Chemical Manufacturers Association surveys energy use and has adopted an Energy Efficiency Continuous Improvement Program.

You may wish to use data you reported to an industry association as the basis for computing your total energy-related emissions.

3.4 Performing Project Analysis

Your project may be defined as your entire organization, where you report the change in total emissions for your organization; several activities, perhaps as part of an energy efficiency program (these may include activities, such as materials processing, outside your organization); or only one activity, undertaken for its projected cost savings (such as a motor replacement project) or as a pilot project (such as an experimental industrial process change).

Your analysis of emissions reductions projects in the industrial sector should follow the process described in the General Guidelines:

1. Establish the reference case as a basis for comparison with the project.

2. Identify the effects of the project.

3. Estimate emissions for the reference case and the project.

The General Guidelines describe two types of reports: standard project reports and reporter-designed project reports. Standard project reports are those that use only default values provided in these guidelines—specifically, emissions factors (emissions per unit energy) and stipulated factors (standard energy savings or emissions reduction values for specific types of projects). Few standard projects exist for the industrial sector at this time. Most reports will use emissions factors together with energy savings estimates, but you will need to estimate the energy savings associated with your projects on a case-by-case basis. You will also need to compute the direct process emissions reductions associated with your project on a case-by-case basis. Thus, the rest of this chapter discusses only reporter-designed project reports. In a few instances (for example, methane emissions from natural gas systems), standard equations and default coefficients are available; these have been included where appropriate.

The project analysis process for the industrial sector is illustrated in Figure 3.1.

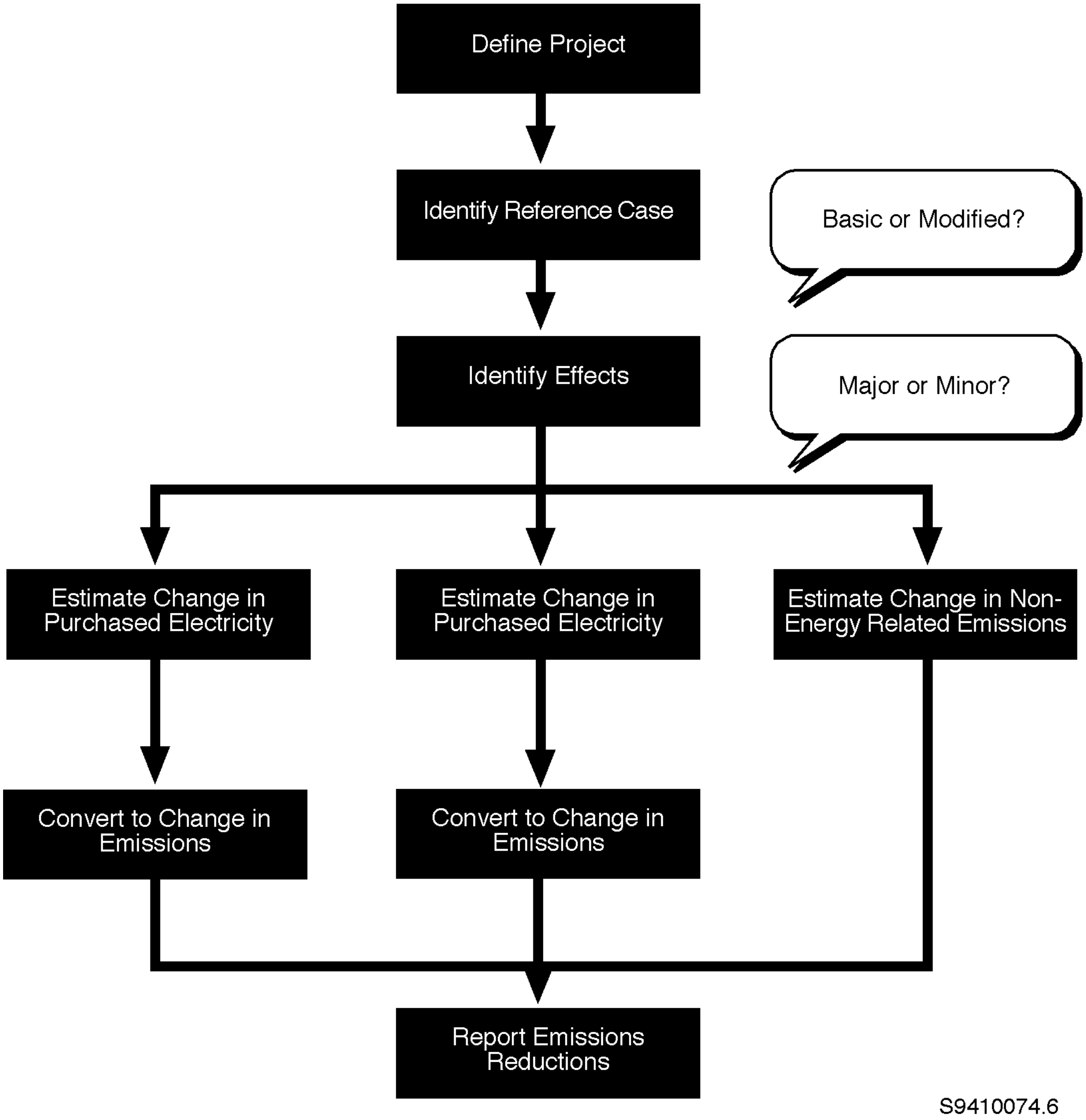

Figure 3.1. Project Analysis in the Industrial Sector Can Involve Both Energy-Related and Non-Energy-Related Emissions

3.4.1 Establish the Reference Case

As described in the General Guidelines (""What Should the Project Be Compared To?"), under this program you may choose a basic or a modified reference case. You should be thoroughly familiar with that discussion before proceeding with project analysis.

A basic reference case uses only historical emissions data as a basis for comparison with project emissions. Depending on the nature of and circumstances associated with your reporting, a basic reference case may provide a suitable and appropriate benchmark against which to compare project emissions. Some users of the EPAct 1605(b) database may have more confidence in reports that use a basic reference case than in reports that use a modified reference case.

In some cases, you may determine that a modified reference case is more appropriate. If so, you may choose to also report the emissions change using a basic reference case, to enable users of the database to evaluate U.S. emissions reduction efforts with respect to a historic baseline.

You should consider the obsolescence of your existing equipment as a factor in developing your reference case. This will be most important for developing a modified reference case. Three scenarios are possible:

- Your project involves replacing old equipment (of any vintage) with newer, more efficient equipment. Or, you expand production at your plant at the same time that you replace old equipment. You may use the current, before-project emissions (total or per unit production) as a basis for computing the reference case.

- You expand capacity using new, efficient equipment in the new capacity but your existing capacity uses obsolete equipment. In this case, it is not credible to assert that the new capacity would have used the obsolete equipment "but for" your project. Rather, you should use current equipment standards and/or appropriate industry averages to compute the modified reference case emissions. Your emissions reduction would result from the extent to which the efficiency of your new equipment exceeds these values.

- Your current capacity uses equipment that reflects current equipment standards and average (or better) industry practice. In this case, the reference case for expanded capacity could be based on the emissions (total or per unit production) of your current capacity.

You should use these guidelines to account appropriately for technology obsolescence when computing reference cases.

The remainder of this section discusses one type of modified reference case that is based on emissions per unit production. If you do not need this information, you can skip to Section 3.4.2.

A form of modified reference case that may be of particular interest to you as an industrial reporter is a reference case that accounts for production growth or capacity additions. In each of these situations, total emissions may be growing, but you may have taken steps to decrease the emissions per unit of production. In particular, many emission-reducing opportunities arise when new capacity investment decisions are being made.

In simple terms, you could compute emissions per unit of production before the emissions-reducing project is conducted or new, efficient capacity is added, and then determine what emissions "would have been" if the higher output were produced at the "old" emissions rate, possibly modified to account for technology obsolescence. This value is the modified reference case. Current emissions are compared to the reference emissions to determine the reportable reduction. (To be evaluated using a modified reference case based on unit production, the new capacity must produce outputs that you are currently producing, although it need not be in the same location as the existing capacity.)

If you add capacity to produce a good that you are not currently producing, or if you need to account for technology obsolescence for expanded capacity, then you must turn to sources other than your own production history to determine the emissions per unit production for the reference case. You should provide a credible estimate for the reference case. While no definitive guidance is available on sources for such estimates, possible sources include engineering firms that build similar facilities and trade associations that have data on industry averages of energy use and output. Because these sources are not within your control, care should be taken to ensure that the data are credible. You are responsible for certifying the accuracy of your report, so reference case estimates for such cases should be conservative (that is, they should not overstate the emissions per unit of production). If you have documented information that indicates your company considered and evaluated lower-efficiency options for the new capacity but chose a higher efficiency option, you may be able to use such data to estimate your reference case. In using these data, you should avoid the use of "straw man" proposals that maximize your reported emissions reductions. Instead, use conservative estimates of reference case emissions.

Measuring the "unit of production" presents many challenges. Few entities produce a single homogeneous product. Even for basic materials industries such as paper, steel, and glass, changes in product mix might cause the emissions per ton of product to rise, while allowing emissions per dollar value of shipments (or dollar of value added) to stay constant or to even decline (if the dollar value of the product is rising). It is difficult to say which measure of production is "correct." Higher-value products produced with the same level of emission per ton of product may be beneficial to the economy, because economic growth occurs without increased emissions. Valuing output in monetary terms also is complicated by the need to use price deflators to compare this measure of output across time periods.

Given the difficulties in using a dollar value (shipments or value added) measure of output, you should use only physical measures of output (for example, tons of steel, numbers of items) to compute emissions per unit of production. You may calculate emissions per unit of production for your entire entity or for discrete projects. In the latter case, you need not measure production in terms of your final, saleable product. A well-defined, intermediate product can be used as the basis for a modified reference case based on unit production. This approach would be useful if you have a primary processing stage, but also several finishing stages that produce different final products. Another useful measure of intermediate product as a unit of production is an energy service. For example, if "delivered steam" is viewed as an intermediate product, then a unit-of-production approach may capture the emissions reductions associated with expanding steam capacity coupled with improved efficiencies.

In summary, when you are using a modified reference case (mref) based on emissions per unit of production, you would compute the reference and project case emissions as follows:

$$\text{Emissions}_{mref} = \text{Emission Rate}_{old} \bullet \text{Production}_{new}$$

$$\text{Emissions}_{proj} = \text{Emission Rate}_{new} \bullet \text{Production}_{new}$$

where the "old" emissions rate is the emissions per unit production before the project or for the existing capacity (accounting appropriately for technology obsolescence), the "new" emission rate is the emissions per unit production after the project or for the new capacity, and the "new" production is the production level after the project or for the new capacity.

For comparison purposes, the basic reference case (bref) emissions would be computed as follows:

$$\text{Emissions}_{bref} = \text{Emissions Rate}_{old} \bullet \text{Production}_{old}$$

where the "old" production is the production level before the project or for the existing capacity (accounting appropriately for technology obsolescence).

3.4.2 Identify the Effects of the Project

Your report should address all the effects of your project that you can identify, as described in the General Guidelines. You should quantify these effects whenever possible. To determine whether you have identified all project effects, you should consider questions such as the following:

- Has production been reduced somewhere in your organization that was replaced by other similar productive activities within or outside of your organization? (Any emissions reductions that result from a plant closure should be so identified.)

- Have you begun purchasing energy services, materials, or goods that were previously produced internally, or have you shifted production to outside the boundaries of the project you are reporting?

Example 3.1 - Modified Reference Case

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

A primary aluminum smelting facility in Texas upgraded the control system on one of its potlines,(a) resulting in improvements in energy efficiency. At the same time its production increased from 350 million pounds of aluminum per year to 450 million pounds per year. Careful records are kept on energy consumption for the smelting process. After sufficient time passed to account for short term fluctuations in process parameters, the plant engineers estimated that the energy intensity of smelting dropped from 6.8 kWh/lb to 6.6 kWh/lb. Because the facility did not have information on the specific emissions factor for its purchased electricity, it used the combined emissions factor for Texas from Appendix C to estimate carbon dioxide emissions.

Before the project the total electricity used for smelting was

$$6.8\ \frac{\text{kWh}}{\text{lb}} \bullet 350\text{x}10^{6}\ \frac{\text{lb}}{\text{year}} = 2.38\text{x}10^{9}\ \frac{\text{kWh}}{\text{year}}$$

In Appendix C the carbon dioxide emission factor for Texas is given as 0.776 short tons (ST) per megawatt hour (MWh). (Other greenhouse gases were ignored for purposes of this example.) Thus, before the project total emissions were

$$2.38\text{x}10^{9}\ \frac{\text{kWh}}{\text{year}} \bullet 0.776\ \frac{\text{ST CO}_2}{\text{MWh}} \bullet \frac{1\ \text{MW}}{1000\ \text{kW}} = 1.85\ \frac{\text{million ST CO}_2}{\text{year}} \quad .$$

This is the basic reference case.

The plant production increased from 350 to 450 million pounds per year at the same time that the energy intensity of smelting decreased. Without the energy efficiency program the emissions level with the increased production (the modified reference case) would have been

$$6.8\ \frac{\text{kWh}}{\text{lb}} \bullet 450\text{x}10^{6}\ \frac{\text{lb}}{\text{year}} = 3.06\text{x}10^{9}\ \frac{\text{kWh}}{\text{year}}$$

However, with the energy efficiency program, emissions were

$$3.06\text{x}10^{9}\ \frac{\text{kWh}}{\text{year}} \bullet 0.776\ \frac{\text{ST CO}_2}{\text{MWh}} \bullet \frac{1\ \text{MW}}{1000\ \text{kW}} = 2.37\ \frac{\text{million ST CO}_2}{\text{year}}$$

$$6.6\ \frac{\text{kWh}}{\text{lb}} \bullet 450\text{x}10^{6}\ \frac{\text{lb}}{\text{year}} = 2.97\text{x}10^{9}\ \frac{\text{kWh}}{\text{year}}$$

$$2.97\text{x}10^{9}\ \frac{\text{kWh}}{\text{year}} \bullet 0.776\ \frac{\text{ST CO}_2}{\text{MWh}} \bullet \frac{1\ \text{MW}}{1000\ \text{kW}} = 2.3\ \frac{\text{million ST CO}_2}{\text{year}}$$

Thus,

$$\begin{aligned}\text{Annual Emissions Reduction} &= \text{Emissions}_{\text{ref}} - \text{Emissions}_{\text{proj}} \\ &= 2.37 \text{ million ST CO}_2 - 2.3 \text{ million ST CO}_2 = 0.07 \text{ million ST CO}_2\end{aligned}$$

As a result of its control system upgrade, the smelting plant could report a 70,000 ST per year emissions reduction relative to the modified reference case, even though actual carbon dioxide emissions went up by 450,000 ST per year relative to the basic reference case.

(a) A potline is a series of electrolytic cells used to produce primary aluminum from alumina.

Example 3.2 - Modified Reference Cases Using Intermediate Products

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

(a) A steel mill increased its electric-arc furnace capacity and upgraded to a more efficient transformer. The mill produced a variety of construction products, but the output of the furnace could be measured in tons of steel poured. Electricity use per ton of "steel poured" (and used to produce final goods) could have been computed from metered energy consumption and internal accounts of steel furnace output. These data, before and after the project, could have been used to compute the modified reference case and the reduction in carbon dioxide emissions.

(b) An organization added new boiler capacity but also implemented several boiler/steam-efficiency improvements. By measuring the amount of steam delivered (with no change in pressure and temperature) as an intermediate output, the organization developed a modified unit-of-production reference case.

Example 3.3 - Identifying Project Effects

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

(a) A reporting entity with two facilities reduced its energy use in the first facility by consolidating its materials processing in the second facility. The first facility's energy use declined but the second facility's energy use increased. However, the consolidation improved efficiency and reduced total energy use by the two facilities.

The entity could report only the emissions reductions resulting from net reductions in energy use. It could choose to either

(1) consider the first facility as the project and report the increased energy use at the second facility as an off-site project effect subtracting it from the reduced energy use being reported for the first facility, or

(2) report the net change in energy use at the entity-wide level.

Energy use and associated greenhouse gas emissions at both facilities must be accounted for because the reduction in energy use at the first location *caused* energy use to increase at the second location.

(b) An entity with two facilities implemented an electricity-efficiency program in one facility and reduced consumption by 50 percent. In the second facility it began to make a new product whose production required large amounts of electricity. The entity's total electricity consumption rose or stayed constant.

In this case, the entity could report the efficiency program and its related emissions reductions even if total emissions were increasing. The increases in electricity consumption and associated emissions at the second location *were not caused by* the actions taken to reduce electricity use at the first location. However, the entity may choose to also report its total emissions, recognizing that this would make its report more credible in the eyes of some reviewers.

Projects in the industrial sector run the gamut from discrete, well-defined projects (for example, replacing 10 motors with high-efficiency motors or replacing the use of a halogenated blowing agent with a nonhalogenated agent) to projects that can have both reinforcing and antagonistic effects within and outside of a reporting entity (for example, a set of efficiency projects that involve cogeneration, motor upgrades, and fuel switching). When projects begin to interact such that the effects of each project cannot clearly be separated out, you should consider reporting your entity-level emissions reduction rather than the emissions reduction associated with individual projects. For example, you may wish to compute the emissions associated with your total energy use before and after the project. After accounting for other effects (for example, associated with outsourcing or cogeneration), you can report the reduction in total entity emissions. If you choose to report in this way, your report should identify the specific projects that you undertook to reduce emissions, even though you may not be able to estimate the emissions reduction associated with each individual project.

3.4.3 Estimate Emissions for the Reference Case and the Project

Your analysis of emissions for the reference case and the project and your report must meet the minimum reporting requirements described in the General Guidelines ("What Are the Minimum Reporting Requirements?"). Your report will lose credibility if you do not use estimation practices commonly acceptable in the professional community. You may want to review the guidance provided in Sections 3.5 through 3.10 of this supporting document that describes procedures for estimating energy savings and emissions reductions for several types of emissions-reducing measures.

The guidelines recognize three categories of data:

Physical Data. This is information that describes the activities involved in your project and must be included in every report. For example, how many and what type of motors were replaced? What types of operational practices were improved? What types of process changes were made? Section 3.5.1 describes the Assessment Recommendation Code (ARC) system, which is used to identify actions taken to reduce energy use. All other actions, and energy-related actions not listed in the ARC system, should be identified clearly in your report.

Default data. This is information provided in the supporting documents to assist you in evaluating the emissions or sequestration effects of your project. Using default data increases your ease of reporting (in some cases, allowing you to report when you might not otherwise have enough data). However, using default data may decrease precision and, because the defaults are generally conservative, your emissions reductions may appear lower than they actually are. There are two categories of default data:

> *Emissions factors*. These are factors that allow you to convert information about a change in energy use to an estimated change in greenhouse gas emissions. Some emissions factors are rather precise. For example, the change in direct emissions of carbon dioxide from a reduction in methane combustion is essentially constant, regardless of when or where the change took place. Other emissions factors, and particularly those for off-site emissions, are less precise. For example, Appendix C provides emissions factors for electricity on a state-by-state basis. However, the effect that a change in electricity consumption has on emissions will vary by location within the state, the time of day, and the season that a change occurs.

Stipulated factors. These are factors that allow you to convert physical data about your project into estimates of changes in energy use or greenhouse gas emissions. The supporting documents provide this information for a few types of projects where the scope and nature of the project can be clearly defined and where the effects on emissions can be predicted with relative certainty.

Few stipulated factors are available for the industrial sector at this time, particularly for energy savings; those factors provided in this supporting document address non-energy-related emissions. (For example, Table 3.5 in Section 3.7.3 provides stipulated emissions reduction factors for selected natural gas system projects.) An exception is a project that affects the energy use of industrial buildings (primarily lighting, heating, cooling, and ventilation). The supporting document for the residential and commercial buildings sector provides stipulated factors for converting information about certain building energy-efficiency projects into estimates of fuel savings. These estimates can be combined with default emissions factors to estimate reductions in greenhouse gas emissions. You should refer to the supporting document for the residential and commercial buildings sector for technical guidance on analyzing building-related projects.

Reporter-Generated Data. These are data you develop as a basis for estimating the effects of your project. There are two categories of reporter-generated data:

Measured Data. These are data collected directly from the project that you use in estimating your project's accomplishments. For example, you may measure emissions or emissions reductions directly or meter energy use or other parameters (such as production) at the level of an entire entity or at a lower level (for example, a plant within an organization, a production line within a plant, a portion of a natural gas system).

Engineering Data. These are data that you derive from various sources, such as engineering manuals, manufacturer's equipment specifications, surveys, academic literature, and professional judgment.

Your choice of estimation methods will be constrained by the availability of data. For example, you may estimate emissions reductions from an efficiency project using measured data as well as engineering estimation. Using several methods and comparing the results may increase the confidence that users of the EPAct 1605(b) database will have in your estimations.

3.5 Estimating Emissions Reductions Associated with Energy Use

This section describes how to estimate energy savings for energy conservation, fuel switching, cogeneration, and recycling projects and how to translate the computed savings into emissions reductions. When the actions that reduce energy consumption include a reduction in production or closure of a plant or production line (without replacing that activity elsewhere), this action is reportable; however, no specific guidance for such reports is provided here. Note that you should identify these as the emissions-reducing activities in your report and take care to ensure that all project effects are accounted for.

Many types of activities may be undertaken to reduce energy use and associated emissions of carbon dioxide and other greenhouse gases. These include the following:

- use of energy efficient equipment and processes
- switching from high-emitting fuels to lower-emitting fuels
- cogenerating steam and electricity
- improving operational and maintenance practices
- recycling input materials
- undertaking efforts to improve productivity—that is, to produce the same level of goods and services with fewer inputs.

All of these types of activities have the potential to reduce emissions and can be reported to the EPAct Section 1605(b) program. Other emissions-reducing projects that are not explicitly mentioned can also be reported.

3.5.1 Identification of Activities

The activities you undertook to reduce energy use should be identified using the DOE's Assessment Recommendation Codes (ARCs), which are listed in Appendix 3.A of this supporting document. The ARC system is a hierarchical categorization of activities—for example, combustion systems are ARC 2.1, boilers are ARC 2.1.2, and boiler tube maintenance is 2.1.2.3.2. Activities that reduce energy use directly are listed in Section 2 of the ARCs. However, activities in other sections that are directed at waste minimization, recycling, and productivity enhancements may reduce energy use as a byproduct of their primary focus. You should identify the ARC codes corresponding to all activities you undertook that contribute to the emissions reduction you are reporting. If your project is not listed in the ARC system, you should describe it in your report. Be sure to identify the numbers of projects (for example, number of motor replacements).

The major categories of the ARC system that address reduced energy use are shown in Table 3.3.

Table 3.3 Major ARC System Categories

ARC Category	ARC Section
Combustion Systems	2.1
Thermal Systems	2.2
Electrical Power	2.3
Motor Systems	2.4
Industrial System Design	2.5
Miscellaneous Operational Changes	2.6
Buildings and Grounds	2.7
Administrative	2.8
Alternative Energy Usage	2.9
Shipping, Distribution, and Transportation	2.10

These categories include some actions that are common to the residential and commercial buildings sector (for example, Buildings and Grounds, ARC 2.7) and the transportation sector (for example, Shipping, Distribution, and Transportation, ARC 2.10). You should consult the supporting documents for the residential and commercial buildings sector and the transportation sector, respectively, for technical guidance on reporting energy savings and associated emissions reductions for these actions.

The ARC system is least likely to be complete in describing industry-specific process changes or improvements in management and other productivity-enhancing activities. When the ARCs are not adequate to describe your project, you should briefly describe the project using standard industry terminology.

3.5.2 Identifying the Effects of the Project

You must identify the effects of your project(s), as described in Section 3.4.2 of this supporting document and in the General Guidelines. Your report should address all the effects that you can identify - not just the obvious, intended effects, but also less noticeable, unintended effects. You should quantify these effects whenever possible.

3.5.3 Estimating Project Effects

If your project affects the use of a single fuel, your annual emissions reduction of a given greenhouse gas can be computed very simply:

$$\text{Emissions Reduction} = \left(E_{\text{reference}} - E_{\text{project}}\right) \bullet F_j$$

where E = annual energy use, in Btu or kWh or a multiple thereof; and
F_j = emissions factor (emissions per unit energy) for fuel j, obtained from Appendix C (for electricity) or Appendix B (for other fuels), or computed using your own data.

In the case of electricity use you should compute the emissions reduction or increase for both carbon dioxide and nitrous oxide (N_2O); for on-site fuel combustion you need only be concerned with carbon dioxide. (You can also report changes in the emissions of other affected gases.) Example 3.4 illustrates the calculation process for a change in electricity use.

When more than one fuel is affected you will need to perform the calculations separately for each fuel and sum the overall effects for each activity and greenhouse gas. For each gas, the emissions reduction (or increase) for *n* fuels would be computed as follows:

$$\text{Emissions Reduction} = \sum_{j=1}^{n} (E_{j,\text{reference}} - E_{j,\text{project}}) \bullet F_j$$

where E_j = annual energy use, in Btu or kWh or a multiple thereof, for fuel j
F_j = emissions factor (per unit energy) for fuel j, obtained from Appendix C (for electricity) or Appendix B (for other fuels), or computed using your data.

Examples 3.5 and 3.6 illustrate the calculation process for changes in multiple fuels.

Example 3.4 - Estimating Project Effects for Reduction in Use of a Single Fuel

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

As a result of an energy audit, an integrated pulp and paper mill located in Washington determined that compressor motors used to provide air to the wastewater treatment system were operating at only about 40 percent of rated load, or 80 horsepower. Because the load is relatively constant, the mill decided to replace these 200 horsepower motors with 100 horsepower high-efficiency motors. The plant uses six of these motors.

Other changes at the plant had affected total electricity use, so plant-wide electricity purchase records could not be used to compute the electricity savings from the motor replacement program. Also, motor electricity use was not metered separately from other electricity uses. Thus, engineering estimation was required to compute motor electricity use. Because the number of motors and their operating conditions did not change, the plant engineer chose a basic reference case computed using data from the year just prior to the motor replacement project.

Manufacturer's data were used to determine the nominal, full load efficiency of the motors. The original motors were rated at 90.2 percent efficiency, the new motors at 95.4 percent efficiency. While the new motors were expected to operate at about the rated efficiency for the actual load conditions (80 percent), the low loading on the original motors was likely to impact the performance. A literature value of 88 percent was found for half-load performance of a similar motor. Since no information was available for the efficiency of the motor when operating at only 40 percent of rated capacity, this value was used to estimate energy savings.

The wastewater treatment process was a continuous operation, so the motors ran 24 hours a day year round. Plant maintenance records indicated that, on average, the motors were down for an average of two days per year for maintenance on both the motors and the aeration system. The new motors were expected to operate in the same way, for an annual operating time of 8,712 hours. Electrical power consumption was calculated by dividing the actual load by the motor efficiency and converting to kilowatts, then multiplying by annual hours of operation.

Reference case energy consumption:

$$\frac{80 \text{ hp / motor}}{0.88} \bullet 0.7457 \frac{\text{kW}}{\text{hp}} = 67.8 \text{ kW / motor}$$

$$67.8 \frac{\text{kW}}{\text{motor}} \bullet 8712 \frac{\text{hours}}{\text{year}} \bullet 6 \text{ motors} \bullet \frac{1 \text{ MW}}{1{,}000 \text{ kW}} = 3{,}544 \frac{\text{MWh}}{\text{year}}$$

Project case energy consumption:

$$\frac{80 \text{ hp / motor}}{0.954} \bullet 0.7457 \frac{\text{kW}}{\text{hp}} = 62.5 \text{ kW / motor}$$

$$62.5 \frac{\text{kW}}{\text{motor}} \bullet 8712 \frac{\text{hours}}{\text{year}} \bullet 6 \text{ motors} \bullet \frac{1 \text{ MW}}{1{,}000 \text{ kW}} = 3{,}267 \frac{\text{MWh}}{\text{year}}$$

The reduction in electricity use was thus 277 MWh/year. Because the mill did not have information on the specific emissions factor associated with its purchased electricity, it used the combined emissions factor for Washington from Appendix C to compute the corresponding emissions reductions. In its report, the mill identified its action as ARC 2.4.1.2.1 (replace oversize motors with optimum size) and ARC 2.4.1.2.4 (use most efficient type of electric motors).

	CO_2	N_2O
Emission Factor (lb/MWh)	306	0.0461
Annual Emission Reduction (lb)	84,762	12.8

Example 3.5 - Estimating Project Effects for Changes in Multiple Fuels

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

Lumber produced at a facility in Georgia was dried in steam-heated kilns. The primary fuel used to generate the steam was natural gas, but because of an interruptible contract for delivery of this fuel, the boiler was outfitted to burn No. 2 fuel oil as well. In upgrade operations a new, higher efficiency boiler was installed. The mill estimated that emissions from the steam system would drop due to improved boiler efficiency.

Because production levels are expected to remain constant, there will be no changes in steam demand. The plant engineer therefore chose a basic reference case. However, because fuel use varied from year to year as a result of the interruptible natural gas contract, the plant engineer computed the reference case energy use from the average oil and gas purchases (based on plant records) for the three years prior to replacing the boiler. Project case fuel use will differ from the reference case because of the improved boiler efficiency as well as year-to-year fluctuations in the fuel mix. In the first year after the boiler was replaced, natural gas consumption increased from 147 million cubic feet (the reference case average) to 155 million cubic feet, while fuel oil consumption decreased from 219,000 gallons (the reference case average) to 105,000 gallons.

Emissions reductions were calculated from the net change in energy consumption and the emission factors in Appendix B. Natural gas has an energy value of 1,032 Btu/cubic foot, so the energy content of the natural gas used and the associated emissions were calculated as

$$\text{Natural gas use}_{ref} = 147 \text{ million cubic ft} \bullet 1{,}032 \frac{\text{Btu}}{\text{cubic ft}} = 152 \text{ billion Btu}$$

$$\text{Emissions}_{ref} = 152 \text{ billion Btu} \bullet 58.2\text{x}10^{6} \frac{\text{ST CO}_2}{\text{quad}} \bullet \frac{1 \text{ quad}}{10^{15} \text{ Btu}} = 8{,}846 \text{ ST CO}_2$$

$$\text{Natural gas use}_{proj} = 155 \text{ million cubic ft} \bullet 1{,}032 \frac{\text{Btu}}{\text{cubic ft}} = 160 \text{ billion Btu}$$

$$\text{Emissons}_{proj} = 160 \text{ billion Btu} \bullet 58.2\text{x}10^{6} \frac{\text{ST CO}_2}{\text{quad}} \bullet \frac{1 \text{ quad}}{10^{15} \text{ Btu}} = 9{,}312 \text{ ST CO}_2$$

No. 2 fuel oil is a form of distillate fuel oil, so the energy value of this fuel was calculated as

$$\text{Oil use}_{ref} = 219{,}000 \text{ gallons} \bullet 138{,}700 \frac{\text{Btu}}{\text{gallon}} = 30.4 \text{ billion Btu}$$

$$\text{Emissions}_{ref} = 30.4 \text{ billion Btu} \bullet 79.9\text{x}10^{6} \frac{\text{ST CO}_2}{\text{quad}} \bullet \frac{1 \text{ quad}}{10^{15} \text{ Btu}} = 2{,}429 \text{ MT CO}_2$$

$$\text{Oil use}_{proj} = 105{,}000 \text{ gallons} \bullet 138{,}700 \frac{\text{Btu}}{\text{gallon}} = 14.6 \text{ billion Btu}$$

$$\text{Emissions}_{proj} = 14.6 \text{ billion Btu} \bullet 79.9\text{x}10^{6} \frac{\text{ST CO}_2}{\text{quad}} \bullet \frac{1 \text{ quad}}{10^{15} \text{ Btu}} = 1{,}167 \text{ ST CO}_2$$

Example 3.5 - (cont'd)

As a result of the project, natural gas use and associated emissions went up and oil use and associated emissions went down relative to the reference case. The resulting changes in emissions are

For natural gas:

$$\text{Emissions}_{ref} - \text{Emissions}_{proj} = -\ 466 \text{ ST } CO_2 \text{ (an increase)}$$

For oil:

$$\text{Emissions}_{ref} - \text{Emissions}_{proj} = 1{,}262 \text{ ST } CO_2 \text{ (a decrease)}$$

No other effects within or outside the plant were anticipated. The total reportable emissions decrease is 796 short tons of carbon dioxide. In its report, the mill identified its action as ARC 2.1.2.2.4 (replace boiler). In subsequent years, the lumber facility will monitor its annual fuel consumption and compute a new emissions reduction for each year relative to the same basic reference case used for this year's calculation.

However, if you are not reporting entity-wide fuel use reductions, you may not have data (metered or from plant records) on fuel use for the specific energy use categories affected by your project (for example, motors, boilers). In this case, you will need to use engineering estimation to derive the energy use for the reference case and project case. You should be sure to account for the actual utilization rate of your equipment. Example 3.6 illustrates this type of calculation.

Example 3.6 - Estimating Project Effects for Multiple Projects and Fuels

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

A lumber mill (such as that in Example 3.5) that dried its lumber in steam-heated kilns undertook two projects: replacement of the obsolete boiler and insulation of the steam lines between the boiler and the kiln. In this case, the use of natural gas and oil for uses other than in the boiler obscured the actual changes in energy consumption associated with these projects. Emissions reductions were calculated on the basis of the estimated efficiency of the existing system and the estimated results of the two projects.

Annual production of lumber at the mill is 54 million board feet (bf), but only half of this is dried. The estimated steam use in the kiln was 6,075 Btu/bf, but 10 percent of the steam energy generated was lost in the steam pipes. The old boiler operated at 80 percent efficiency. The overall efficiency of the boiler/steam delivery system was thus 72 percent (80% x 90%), such that 8,438 Btu/bf (6,075/0.72) of input energy was required for the boiler.

The total reference case energy use in the boiler was calculated from the energy intensity of drying, the production level, and the fraction of production that is dried:

$$\text{Energy use}_{ref} = 8{,}438\ \frac{\text{Btu}}{\text{bf}} \bullet 54\text{x}10^{6} \text{ bf} \bullet 0.5 = 227.8 \text{ billion Btu}$$

On average the boiler was operated 10 months of the year on natural gas and 2 months on oil. Thus, of the total energy input, 83 percent was supplied by natural gas (189.1 billion Btu) and 17 percent was supplied by oil (38.7 billion Btu). For this example, these fuel shares are assumed to remain constant between the (basic) reference case and the project case.

Example 3.6 - (cont'd)

Reference case emissions were calculated using the emissions factors from Appendix B.

For natural gas:

$$\text{Emissions}_{ref} = 189.1 \times 10^9 \text{ Btu} \bullet 58.2 \times 10^6 \frac{\text{ST CO}_2}{\text{quad}} \bullet \frac{1 \text{ quad}}{10^{15} \text{ Btu}} = 11{,}006 \text{ ST CO}_2$$

For oil:

$$\text{Emissions}_{ref} = 38.7\text{x}10^9 \text{ Btu} \bullet 79.9\text{x}10^6 \frac{\text{ST CO}_2}{\text{quad}} \bullet \frac{1 \text{ quad}}{10^{15} \text{ Btu}} = 3{,}092 \text{ ST CO}_2$$

Total reference case carbon dioxide emissions were thus 14,098 short tons.

After the project the boiler efficiency was expected to increase to 84 percent and losses from the steam pipes were expected to decrease 80 percent, to 2 percent of steam energy produced. The improved efficiency of the boiler/steam delivery system is thus 82.3 percent (84% x 98%). In order to deliver 6,075 Btu, the boiler will consume only 7,382 Btu of fuel. Total boiler energy use was thus:

$$\text{Energy use}_{proj} = 7{,}382 \frac{\text{Btu}}{\text{bf}} \bullet 54\text{x}10^6 \text{ bf} \bullet 0.5 = 199.3 \text{ billion Btu}$$

Based on the assumption that fuel shares remained constant, 165.4 billion Btu was natural gas and 33.9 billion Btu was oil. Project case emissions are computed below.

For natural gas:

$$\text{Emissions}_{proj} = 165.4\text{x}10^9 \text{ Btu} \bullet 58.2\text{x}10^6 \frac{\text{ST CO}_2}{\text{quad}} \bullet \frac{1 \text{ quad}}{10^{15} \text{ Btu}} = 9{,}626 \text{ ST CO}_2$$

For oil:

$$\text{Emissions proj} = 33.9\text{x}10^9 \text{ Btu} \bullet 79.9\text{x}10^6 \frac{\text{ST CO}_2}{\text{quad}} \bullet \frac{1 \text{ quad}}{10^{15} \text{ Btu}} = 2{,}709 \text{ ST CO}_2$$

Total project case emissions were thus 12,335 short tons of carbon dioxide, for a reportable emissions reduction of 1,763 short tons. In its report, the mill identified its actions as ARC 2.1.2.2.4 (replace boiler) and ARC 2.2.1.3.1 (insulate steam lines).

In Examples 3.5 and 3.6, the reporting entity could use data on entity-wide fuel use to compute emissions if (1) it is reporting at the entity level or for a collection of projects, or (2) it is reporting for specific projects, and no other changes have occurred that affect energy use.

As illustrated in Example 3.7, some fuel switching projects involve the substitution of electrotechnologies for fossil fuel-fired technologies, with a resulting decrease in emissions.

Example 3.7 - Estimating Project Effects for Electrification

***Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors*.**

A food processing company in New Jersey is considering replacing its equipment that removes water from a product. Currently, the company evaporates the water by firing natural gas. The alternative method under consideration is freeze concentration. The company is considering the change for energy efficiency reasons but has decided to determine the associated emissions reduction benefit for possible reporting to the DOE's voluntary program.

For the plant's level of production, 800 lbs of water must be removed per hour, 40 hours per week, 50 weeks per year. The total amount of energy required to do this using natural gas is 540 Btu/lb; the total amount of energy required using freeze concentration (powered by electricity) is 100 Btu/lb. Because the company did not have information on the specific emissions factor associated with its purchased electricity, it used the combined emissions factor for New Jersey from Appendix C to compute electricity-related emissions.

For natural gas:

$$\text{Energy consumption}_{\text{ref}} = 800\ \frac{\text{lb}}{\text{hr}} \bullet 40\ \frac{\text{hr}}{\text{wk}} \bullet 50\ \text{wk} \bullet 540\ \frac{\text{Btu}}{\text{lb}} = 8.64\text{x}10^{8}\ \text{Btu}$$

Using an emissions factor from Appendix B,

$$\text{Emissions}_{\text{ref}} = 8.64\text{x}10^{8}\ \text{Btu} \bullet 58.2\text{x}10^{6}\ \frac{\text{ST CO}_2}{\text{quad}} \bullet \frac{1\ \text{quad}}{10^{15}\ \text{Btu}} = 50.3\ \text{ST CO}_2$$

For electricity:

$$\text{Energy consumption}_{\text{proj}} = 800\ \frac{\text{lb}}{\text{hr}} \bullet 40\ \frac{\text{hr}}{\text{wk}} \bullet 50\ \text{wk} \bullet 100\ \frac{\text{Btu}}{\text{lb}} = 1.6\text{x}10^{8}\ \text{Btu}$$

$$= \frac{1.6\text{x}10^{8}\ \text{Btu}}{3412\ \text{Btu/kWh}} = 4.69\text{x}10^{4}\ \text{kWh}$$

Using the electricity emissions factor for New Jersey from Appendix C,

$$\text{Emissions}_{\text{proj}} = 4.69\text{x}10^{4}\ \text{kWh} \bullet \frac{1\ \text{MWh}}{10^{3}\ \text{kWh}} \bullet 0.387\ \frac{\text{ST CO}_2}{\text{MWh}} = 18.2\ \text{ST CO}_2$$

$$\text{Emissions reduction} = \text{Emissions}_{\text{ref}} - \text{Emissons}_{\text{proj}} = 50.3\ \text{ST CO}_2 - 18.2\ \text{ST CO}_2 = 32.1\ \text{ST CO}_2$$

Some additional types of projects that affect energy intensity are described in Example 3.8.

Example 3.8 - Additional Projects That Affect Energy Intensity

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

- Air was substituted for steam to atomize oil (ARC 2.2.1.5.10). This was reflected in a lower energy intensity (energy use per unit of output) of the activity of atomizing oil. In other words, the demand for the energy service of steam to atomize oil was reduced or eliminated.

- Scrap glass was recycled internally by an entity as an input feedstock (ARC 3.5.2.1.1). This was reflected in a lower energy intensity, for the activity of producing primary glass.

- A smaller boiler was installed to increase the high fire duty cycle. This was reflected in a lower energy intensity of the activity of delivering steam. It also implied a smaller capacity and a higher utilization rate that should be accounted for in the project analysis.

3.5.4 Estimating Project Effects: Fuel Switching

When your project consists of switching from a higher-emitting fuel source to a lower-emitting fuel source, you should compute the emissions with the old fuel and new fuel and report the difference (if emissions have decreased) using the methods described in Section 3.5.3. When one of the fuels involved is electricity, the electricity emissions factors in Appendix C of this supporting document should be used unless you have more specific factors from your electricity supplier.

If you switch from purchasing electricity to generating your own (for example, using a diesel generator, a set of photovoltaic cells, or a boiler), emissions reductions may occur (unless the purchased electricity was generated with hydroelectric, renewable, or nuclear fuels). You should provide the carbon emissions rate for your self-generated electricity to compute the emissions reduction. To compute this, you will need the heat rate (Btu/kWh) for your electricity-generating equipment and fuel. You would multiply the heat rate by the carbon dioxide emissions factor for your fuel (from Appendix B) to obtain the emissions rate (metric tons/kWh). If you have data on the specific carbon content of your fuel that differ from Table B.1, you are encouraged to use them. You must document the source of your data in your report. If the fuel for your self-generation is renewable (for example, photovoltaic), the appropriate carbon dioxide emissions rate (zero) would be used to compute the project case emissions (which may also be zero in this case).

3.5.5 Estimating Project Effects: Cogeneration

One type of project that involves changes in more than one fuel (usually fuel combusted on site and purchased electricity) is cogeneration, which is defined as the combined generation and use of electricity and steam or heat, where both were previously produced or purchased separately. Under these conditions, cogeneration improves efficiency and reduces greenhouse gas emissions by displacing electricity purchases with power created from an "existing" source or demand for steam. To accurately account for the net greenhouse gas emissions reductions from cogeneration, you will need to measure or estimate two elements: the increase (if any) in fuel input and the displacement of purchased electricity. Converting boiler steam systems to produce electricity and useful steam sometimes involves an increase in steam output (temperature, pressure, etc.) and a corresponding increase in energy input. These increases may or may not be offset by boiler efficiency improvements or replacement with gas turbines, but usually are more than offset by the emissions savings related to displacement of purchased electricity. The steps in estimating the effects of a cogeneration project are described below.

Step 1: Compute the change in input fuel use. (The increased carbon dioxide emissions from increased fuel use must be subtracted from the emissions reduction derived from displacing purchased electricity.) This analysis assumes that the steam output of the old boiler and the new cogeneration system are the same—that is, the system is sized to the steam demand at the plant. If capacity is being expanded, a reference case modified to account for the increased production may be appropriate.

Three possible data sources can be used to compute the change in carbon dioxide emissions resulting from changes in input fuel use:

- **Entity-wide fuel use**—If the cogeneration system is the only change that affects energy use, entity-wide data can be used for the reference and project cases.

- **Measured "before and after" energy input**—Since the cogeneration system may be a significant portion of your organization, you may have kept records of fuel use for the original steam production.

- **Engineering estimation**—Since engineering estimation relies on the accuracy of assumptions about utilization rates and energy intensities, it is less desirable than measured data but can be used if such data are not available or if other changes at your organization have made it impossible to accurately infer the change in energy input to the cogeneration system.

Step 2: Measure or estimate the central station electricity generation that is displaced by cogenerated power. Three methods are available for deriving this value:

- **Metered output from the cogeneration units**—This is the most accurate and the preferred method to estimate the displaced central-station electricity generation.

- **Engineering estimates of the output from the cogeneration units**—The accuracy of this method is contingent on the accuracy of the utilization and heat rates of the cogeneration unit(s).

- **Sum of reduction in purchases and sales to the grid**—These two factors may be used as proxies for the information that would have been provided by metered data or reliable engineering estimates. The sum of the two proxies should be equal to the output of the cogeneration system.

    - *Reduction in electricity purchases*. If other actions or project effects do not reduce electricity use in your organization, the reduction in electricity purchases will reflect the output of the cogeneration system. You can use this information to report electricity displaced internal to the plant.

    - *Sales to the utility or other transfers*. Sales of electricity to an electric utility also displace the need for the utility to generate power. This amount can be reported as part of the output of the cogeneration system.

The sum of these two values can be used to compute the displaced central station electricity generation.

Step 3: Apply emissions factors from Appendix B (for fuel input) and Appendix C (for displaced electricity) and sum the effects on emissions. (Alternatively, you can use and document your own emissions factors.) The effect will generally be a reduction in emissions resulting from displaced electricity and an increase resulting from increased fuel input.

Electric utility programs may be involved in your installation of cogeneration units. If a utility or an energy service company is involved in your cogeneration project, you should identify the utility or company in your report. "Involvement" includes any contracts for the purchase of cogenerated electricity from you. (This is reported to help track any multiple reporting of emissions reductions.)

The cogeneration system may represent a significant portion of your operations, and you may have metered data on electricity generation and sales to the grid that you can use in computing your emissions reductions. If you have such metered data, you should use them in preference to engineering estimates. Also, you may be reporting data on cogeneration to the Bureau of the Census or other organizations. If so, you may be able to use these data in computing your emissions reductions. For example, as a cogenerator you already may be filing EIA Form 867, "Annual Nonutility Power Producer Report." Also, data reported to EIA in the MECS include the data necessary to compute reductions in fuel use for cogeneration at the entity-wide level. If you report to the MECS, you may be able to use these data to compute emissions reductions if the cogeneration is your only change that affects energy use.

Example 3.9 illustrates the process of computing net emissions reductions for a cogeneration project.

Example 3.9 - Estimating the Effects of Cogeneration Projects

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

A wood products company located in Montana built a 6 MW cogeneration facility adjacent to its sawmill. In the facility, bark and other wood wastes (hog fuel) from the manufacture of lumber were used to fuel a steam boiler. High pressure steam was used to generate electricity, with low pressure steam extracted and sent back to kilns used for lumber drying at the sawmill. Prior to construction of the cogeneration system, steam for the kilns had been produced from wood wastes in a conventional boiler and electricity had been purchased. Excess hog fuel had been burned. The mill operates 8,000 hours per year. The project effects were evaluated relative to a basic reference case that was computed using data for the year prior to the project.

Change in Input Fuel Use

The hog fuel is a biomass fuel source. Because the fuel used did not change, and before the project excess hog fuel was burned, there is no difference between the reference and projected case emissions from hog fuel. In this case, it was not necessary to compute the change (if any) in input fuel use.

Displaced Electricity

The cogeneration facility obtained "qualified facility" status under the Public Utilities Regulatory Policies Act of 1978. Displaced electricity consumption was computed based on the metered output of the cogeneration unit together with information on energy use in the cogeneration facility, sales to the grid, and decreased purchases. For the reference case, the electricity use at the mill was 11 million kWh per year. In the project case, this amount was no longer purchased from the utility. The annual electricity production of the cogeneration unit was 48 million kWh, which left 37 million kWh for potential sale to the grid. However, 4 million kWh/yr of electricity was consumed in the cogeneration facility itself. Also, line losses between the plant and the grid reduced delivered energy by about 5 percent. Thus, the net electricity sold to the grid was 31.4 million kWh per year. Therefore, 42.4 million kWh per year (the sum of the sales and the decreased purchases) of electricity originally generated elsewhere was displaced.

Change in Emissions

Emissions changes were computed for carbon dioxide only; the mill could have chosen to complete the calculations for other gases in Table C.1. Because the company did not have specific information on the emissions factor associated with its purchased and displaced electricity, it used the combined emissions factor for Montana from Appendix C to compute emissions changes.

The net reduction in carbon dioxide emissions due to displaced electricity purchases were computed as follows:

$$42.4\text{x}10^{6}\ \frac{\text{kWh}}{\text{yr}} \bullet 0.777\ \frac{\text{ST CO}_2}{\text{MWh}} \bullet \frac{1\ \text{MWh}}{1000\ \text{kWh}} = 3.29\text{x}10^{4}\ \frac{\text{ST CO}_2}{\text{year}}$$

Thus, the total net reduction in carbon dioxide emissions was $3.29\text{x}10^{4}$ short tons per year. In its report, the wood products company identified its action as ARC 2.3.4.1.4 (burn waste to produce steam to drive a steam turbine generator set and use steam exhaust for heat) and identified the utility as a potential reporter.

3.5.6 Estimating Project Effects: Recycling

You may report recycling projects for which you can develop a sound analysis of project effects. The on-site effects of projects that replace virgin raw materials with recycled inputs, such as aluminum scrap and post-consumer recycled aluminum, may be the easiest type of recycling project effects to analyze.

> **Example:** You may be able to compute the difference in the amount of energy required to work with the recycled aluminum versus primary aluminum. Additional effects, such as a possible reduction in primary aluminum production, may be more difficult to analyze, as the production that you no longer require may be sold to another buyer.
>
> **Example:** Use of coal ash in the production of cement can reduce the amount of carbon dioxide produced, since the volume of carbon dioxide emitted during this process is directly proportional to the lime content of the cement (EIA 1993).(c) Also, cement production uses nearly all of the lime obtained from calcination, so measuring lime content in finished cement is an effective means for determining the amount of carbon dioxide emitted (Griffin 1989, quoted in EIA 1993).
>
> In the United States, most of the structural cement produced is Portland cement, which typically contains 60 to 67 percent of lime by weight (EIA 1993). If you are a cement manufacturer, you can determine the annual carbon dioxide emissions from your production in tons using the following equation:

$$\text{Emissions} = F_1 \bullet \frac{44 \text{ g/mole } CO_2}{56.08 \text{ g/mole } CaO} \bullet P$$

where E = annual carbon dioxide emissions, in tons
F_1 = lime content of cement, by weight (fraction)
P = annual production of cement, in tons.

> This would constitute the reference case for emissions directly from cement manufacture. (Emissions associated with energy used to manufacture cement would be computed as described elsewhere in this document).
>
> If you mix fly ash with cement and sell this mixture in place of 100 percent cement, your project case emissions from production of this mixture would be those associated with manufacturing less than 100 percent cement. The emissions reduction would be associated with the amount of cement that did not have to be produced because it was replaced by the fly ash.

(c) Carbon dioxide is created during the calcination process in which calcium carbonate is heated in a kiln to form lime (calcium oxide). One molecule of calcium carbonate decomposes into one molecule of carbon dioxide and one molecule of calcium oxide. The lime ultimately combines with silicates to form dicalcium or tricalcium silicates, which are two of the four major compounds in powdered cement (EIA 1993).

> You should account for additional project effects where possible, including the shift in sales from you to other manufacturers of 100 percent cement. You may wish to report jointly with the electricity generators who produced the fly ash.

In analyzing recycling projects, your report should be based on sound data and analysis methods and should meet the minimum reporting requirements described in the General Guidelines. In particular, if you report emission reductions associated with diverting waste material from landfills, you should document the studies you relied upon in developing your report.

3.6 Estimating Reductions of Halogenated Substance Emissions

This section provides guidance for reporting reductions in emissions of halogenated substances, which include chlorofluorocarbons (CFCs), hydrofluorocarbons (HFCs), hydrochlorofluorocarbons (HCFCs), and other gases. Sections 3.6.1 through 3.6.4 discuss all of these gases as a group; Section 3.6.5 discusses the emission of perfluorocarbons (PFCs) from aluminum production.

Emissions of halogenated substances may be classified into three groups:

Manufacturing Emissions. These arise from spills, leaks, and vents during the manufacture, storage, transport, and transfer of halogenated substances and from the manufacture of other industrial products (primarily aluminum). These emissions include halogenated byproducts released during the production of other halogenated substances.

Immediate Use Emissions. These are related to the use of halogenated substances and occur at the time of use or within one year of use. For example, these emissions result from the use of halogenates as solvent cleaners, pesticides, aerosol propellants, tobacco puffers, sterilants, adhesives, coatings, inks, and blowing agents for open-cell foams.

Delayed Emissions. These emissions result from using, maintaining, and disposing of materials, equipment, and systems that contain halogenates. These emissions occur more than one year after they are incorporated into the materials, equipment and systems. Most delayed emissions are refrigerants used in industrial processes, commercial food storage, motor vehicle air conditioners, and appliances.

Two general categories of emissions-reducing activities are addressed:

- **fugitive emissions reductions**—activities to reduce emissions from the manufacture and use (immediate and delayed) of halogenated substances

- **industrial process emissions reductions**—projects to reduce perfluorocarbon emissions from aluminum production.

Six categories of specific emissions-reducing actions are listed in Table 3.4. You should identify in your report which of these actions you took to reduce your emissions. If you took more than one action, you should identify the appropriate category for each. You should pay careful attention to the reporting restrictions in Table 3.4 regarding Group 1 and Group 2 substances.(d) If your actions are not listed in Table 3.4, you should describe the actions you took. Your report should address separately the individual halogenates that your projects affect.

Table 3.4. Categories of Emissions—Reducing Actions for Halogenates

Process changes. Projects that alter halogenate handling, *in situ* conditions, end-of-the-pipe procedures, equipment, appliance design, and process design and whose objective is to permanently avoid, transform, or otherwise restrict halogenate emissions, excluding capture-and-recovery operations.

Substitution. Projects that reduce immediate-use or delayed emissions by the total replacement of any presently used halogenate with an alternative chemical, technology, or manufacturing process. Emissions resulting from the use of substitutes that are also halogenates should be treated as project effects.

Destruction. Projects that destroy recovered quantities of halogenates consistent with the procedures, technologies, and criteria of relevant EPA rules and international agreements (UNEP 1992), even for projects involving Group 2 substances. Destruction may not be reported to the EPAct Section 1605(b) program if it is used concurrently to obtain Group 1 production or consumption allowances from EPA (40 CFR 82, subpart A).

Recycling and reclamation. Projects that recycle or reclaim recovered halogenated substances, such as the capture and sale of manufacturing emissions or the capture and recycle of halogenated substances from appliances. Where applicable, rules (40 CFR 82, subparts B and F) on recovery and reprocessing should be adhered to.

Leakage control. Projects that minimize annual emission rates and thereby defer emissions from immediate-use or delayed sources through enhanced maintenance, servicing, and equipment that limit leaks, spills, and other types of releases from processes and systems.

Improved appliances. Leakage control projects based on improvements in the design and manufacture of any existing line of halogenate-using appliances that reduce annual emission rates and further delay emissions. Projects that alter the quantity or type of halogenate that an appliance uses or contains would be classified under *process changes* or *substitution* actions, respectively.

Reductions in individual halogenates should be listed separately in your report. Your report could cover multiple sources of emissions and multiple projects to control them, although each emissions-reducing activity should be classified according to Table 3.4.

For a group of similar projects, you may be able to report the number of projects and the total emissions reduction. Although you should retain in your files the detailed calculations used in computing the reduction, you need not report all the technical details on each project. For example, a supermarket chain that reconfigures and refurbishes the system used to charge its refrigeration units may combine the leak reductions

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(d) This section discusses all halogenated substances as a group. For regulatory purposes, halogenates are divided into two groups: Group 1 comprises gases that deplete stratospheric ozone and are covered by Title VI of the Clean Air Act (40 CFR 82); Group 2 comprises compounds that are not ozone depleters and are often intended as substitutes for Group 1 substances.

for all of its stores, reporting the total emissions reduction and the number of projects.

If you undertake projects that other entities would also be in a position to report, you should identify these potential reporters. For example, entities that destroy emissions that have been recovered by another party should identify the recoverer. If you know that the recoverer is reporting the reductions to the EPAct Section 1605(b) program, you should also provide this information.

3.6.1 Fugitive Emissions Reductions: Establishing the Reference Case

Recall that the reference case is what emissions "would have been" but for the project. In some cases you will be able to use a basic reference case. This will be appropriate for most manufacturing and immediate use emissions. For these emissions, in some cases it may be appropriate to use a reference case modified only to account for production growth or capacity addition (see Section 3.4.1). Your unit of production for the reference case might be the quantity of halogenate produced or quantity of other industrial product or intermediate product produced. You will need to measure emissions per unit production directly or use engineering estimation to arrive at a reference case value.

In the case of delayed emissions, you may need to use a modified reference case. Because virtually 100 percent of the halogenated substances incorporated into materials, systems, and equipment is assumed to be released eventually, you may know precisely the total emissions reduced but will need to determine the likely time frame over which the emissions would have occurred. You will need to indicate this period in your report, even if only simple engineering assumptions are used to compute it. You may then distribute and report the emissions reduction in one of two ways:

1. Determine the total time period over which the emissions would have occurred. Divide emissions by the total number of years in that period and assign that amount to each year.

2. Allocate the reductions according to an engineering model's projected scenario of each year's avoided emissions, summarizing and documenting the modeled projections in your report.

For delayed emissions, then, the reference case is this future emissions path (an equal amount each year or an annual amount determined by engineering models) and the actual project case emissions may be zero (for example, in the case of total destruction). When the project case emissions are zero, computing the reference case emissions gives you the project effects if there are no other project effects that must be considered. You should take care to account for residual emissions in determining whether your project case emissions are zero.

You should indicate in your report which approach you took to developing the reference case for delayed emissions. Your report for future years should indicate that each year's projected reduction did indeed occur (that is, it was not negated by other effects) and you should indicate in the final year that the project has ended.

3.6.2 Fugitive Emissions Reductions: Identifying the Effects of the Project

Recall that your report should identify all the effects of your project. Projects to reduce halogenate emissions are not anticipated to have significant effects on emissions of other (non-halogenate) greenhouse gases. Nevertheless, you should identify and describe potential adverse (or reinforcing) effects on energy consumption or other activities that give rise to greenhouse gas emissions. You should quantify these effects if at all possible.

Some projects that reduce emissions of certain halogenates may affect emissions of *other* halogenates or may affect other emission sources of the same halogenate. You must identify these effects and quantify them if possible.

You should also account for other project effects arising from activity shifting, outsourcing, lifecycle emissions shifting, market effects, and any other sources.

3.6.3 Fugitive Emissions Reductions: Estimation Methods

Compared with other types of greenhouse gas emissions, halogenate emissions often lack straightforward emission factors that are widely applicable. Where they exist, such factors tend to be project specific and require that you use engineering estimates, analyses of chemical balances, direct monitoring, or empirical averages of halogenate losses in your calculations.

As was the case for energy-related emissions, only two methods are applicable for estimating halogenate emissions: direct measurement and engineering estimation. No default values (emissions factors or stipulated factors) are available.

Direct Measurement. For projects involving the extraction or containment of halogenated substances for subsequent destruction, recycling, or reclamation, direct measurements based on chemical tests or on the amount held in standard containers offer a straightforward way to determine reportable quantities. You must ensure that reported quantities are not significantly biased due to the presence of other matter (for example, lubricants) with the recovered halogenate. Direct measurement may also prove feasible or even necessary (at least intermittently) for determining emissions exhaust rates or the effectiveness of destruction operations. For destruction that is 98 percent or more effective, you can assume that the halogenated substance in question is completely destroyed.

Engineering Estimation. For a variety of projects—especially ones involving leakage control and process changes—engineering calculations, stoichiometric analyses, averaged or assumed rates of leakage, and other approaches may be important methods for estimating total reductions of halogenate emissions or useful emission factors.

3.6.4 Fugitive Emissions Reductions: Data Sources and Examples

In many cases, you can report or verify data on key activities or actual emissions using data that you may already report to the EPA. Because the Clean Air Act (CAA) and other statutes govern the production, consumption, handling, and substitution of Group 1 halogenates, the rules and technical information that EPA has issued may offer guidance for compiling data and reporting under the EPAct Section 1605(b) program. These rules and technical information include the following:

- **EPA's Toxic Release Inventory** contains publicly available information concerning chemical releases, off-site treatment and disposal, recycling, energy recovery, on-site treatment, and pollution prevention activities at manufacturing facilities throughout the United States. Known stratospheric ozone depleters are one of the groups of chemicals specified in the inventory.

- **Sections 603, 608, 609, and 612 of the CAA, and proposed rules under Section 112 of the Act** contain requirements for record keeping, reporting, handling, disposal, recovery, recycling, and reclamation of ozone depleters and refrigerants and stipulate safe, legally acceptable substitutes for Group 1 substances due to be banned.

These government activities as well as initiatives in the private sector and Action #40 of the Climate Change Action Plan (October 1993) may also provide important technical factors that can be used or adapted for estimating halogenate emissions reductions.

The following four examples illustrate how to estimate emission reductions for projects involving fugitive emissions.

Example 3.10 - Fugitive Halogenate Emissions Reductions Resulting From Process Changes

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

An insulation manufacturer purchased "X" pounds of a particular halogenated substance. Adoption of an alternative manufacturing process resulted in a decrease in the quantity of the halogenate required per board foot of insulation, such that only "Y" pounds must be purchased each year. The halogenate incorporated in the insulation was assumed to eventually be completely released (delayed emissions). Also, some of the purchased halogenate may have leaked out at the time of use.

The manufacturer can report an annual emissions reduction of "X" minus "Y" after accounting for the time period over which the emissions would have occurred. (If production of insulation varied from year to year and especially if it was trending upwards, the manufacturer might have preferred to calculate emissions based on units of production and the quantity needed per board foot of insulation.) The reporting entity may have chosen to report an annual emissions reduction (over the time period over which emissions would have occurred) based on a modeled scenario of releases over time or may have divided the total emissions reduction by the number of years over which it would have been emitted and reported that amount each year.

Example 3.11 - Fugitive Halogenate Emissions Reductions Resulting From Substitution

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

As part of a program to decrease the effects of its operations on global warming, a manufacturer of open-cell foam switched from CFC-11 to HFC-134a as a blowing agent. The amount of HFC-134a required for the same level of production was 110 percent of the amount of CFC-11 needed.

This manufacturing activity was assumed to generate only immediate use emissions. Using a basic reference case in the year before the project, the manufacturer reported as its emissions reduction the amount of CFC-11 that was used and emitted in the reference year. (The project case emissions of this CFC-11 were zero.) However, HFC-134a is also a halogenated substance and the manufacturer knew that its emissions must be accounted for. Thus, its report to the EPAct Section 1605(b) program identified the amount of each gas (CFC-11 and HFC-134a) emitted in both the reference and project cases. The report identified the category of emissions-reducing action (from Table 3.4) as "substitution."

Example 3.12 - Fugitive Halogenate Emissions Reductions Resulting From Improved Appliances

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

A maker of residential refrigerators developed an improved model that, based on empirical tests and engineering estimates, emitted less per year of a certain halogenate than did the previous versions. The refrigerator manufacturer reported the emissions reduction per unit sold and the number of units sold per year, and reported each year's sales and emissions reductions in subsequent years. To track multiple reporting, the manufacturer identified consumers as potential additional reporters of these reductions.

Example 3.13 - Fugitive Halogenate Emissions Reductions Resulting From Recycling and Reclamation

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

A municipality or utility instituted and contracted for an appliance pickup program or special processing stations at local landfills or scrap yards to remove refrigerants from household and commercial devices. The municipality or utility reported the yearly total of each halogenate that is recovered and recycled or reclaimed for sale. The emissions reduction report indicated the time period over which each reported halogenate would have eventually been released. In this case, for each halogenate, the time period is an average of assumed leakage profiles for the many types and vintages of equipment that had been processed. For each gas, the municipality or utility may have elected to allocate the emissions reductions evenly over the time period. Alternatively, if the majority of emissions would have been concentrated in future years of the time period, the municipality or utility may have wished to use an appropriate engineering model to determine the emissions profile and registered annual reductions accordingly.

3.6.5 Industrial Process Emissions from Aluminum Production

Industrial process emissions of halogenated substances arise as byproducts of the manufacture of another substance (that is, other than halogenates). An important emissions source is aluminum production, which results in emissions of perfluorocarbons (PFCs). Detailed guidance is provided here for this source. If you have other industrial processes that emit halogenated substances as byproducts, you may report so long as your report meets the standards for good project analysis discussed in the General Guidelines and this supporting document.

The production of aluminum results in emissions of several greenhouse gases, including carbon dioxide and two PFCs, CF_4, and C_2F_6. Carbon dioxide emissions are primarily the result of energy use (typically electricity); guidelines for reporting carbon dioxide emissions and emissions reductions are provided earlier in this chapter. Emissions of the two perfluorocarbons occur as a result of anode effects during the reduction of alumina in the primary smelting process. Details on the processes that give rise to these emissions, the practices for reducing them, and related regulations and programs may be found in Appendix 3.B. The remainder of this section provides specific guidance on reporting PFC emissions and emissions reductions.

Emissions reductions activities will primarily involve operational and management changes that reduce the frequency and duration of anode effects. For example, the frequency of these effects can be reduced by incremental improvements in (1) managing alumina additions and other process parameters, (2) algorithms controlling automated processes, (3) training of personnel, and (4) quality control of anode manufacture to reduce subsequent carbon dust formation. The average duration of anode effects can be reduced by improving the suppression response of potroom(e) personnel.

Establishing the Reference Case

Your report should describe the specific activities you undertook to reduce PFC emissions. You may choose a basic or a modified reference case for your report (see the definitions in the General Guidelines and Section 3.4 of this supporting document), which may cover all or a portion of your facility. While the primary effect of the project will be to reduce PFC emissions, you should describe and compute any other effects on energy use and associated carbon dioxide emissions.

Estimating Emissions

The calculation methodology presented here includes some default emissions factors. You are encouraged, however, to base your estimates on actual emissions measurements for your facility. Measurement protocols will be defined in the future as part of EPA's voluntary program with the aluminum industry to reduce emissions (see Appendix 3.B). When available, these protocols will improve the accuracy of default emission factors.

(e) The potroom is the room containing the electrolytic cells used to produce primary aluminum from alumina.

The methodology described here calculates PFC emissions per unit production of aluminum as a function of several operating variables. These operating variables are altered as a result of the emissions-reducing activities you undertake. Total annual emissions and emissions reductions are then calculated based on reported annual production levels, which, in turn, are based on physical measures of output. The key variables used are the frequency (anode effects per day) and duration (minutes per effect) of the anode effects.(f) If possible you should monitor these variables (preferably on a continuous basis) and use your facility-specific data in the calculations.

You can use the following equation to compute emissions of CF_4 per unit production:

$$X\left(\frac{\text{kg } CF_4}{\text{MT Al}}\right) = A\left(\frac{\text{kg } CF_4 \text{ / AE min}}{\text{kAmp}}\right) \bullet B\left(\frac{\text{AE min}}{\text{AE}}\right) \bullet C\left(\frac{\text{AE}}{\text{day}}\right) \bullet \left(\frac{1}{\text{CE}}\right) \bullet 124.2\left(\frac{\text{kAmp days}}{\text{MT Al}}\right)$$

where X = the kg of CF_4 emitted per metric ton of aluminum production
A = the kg of CF_4 emitted during each minute of an anode effect, per kAmp of current
B = the average duration of anode effects, expressed in anode effect minutes per effect
C = the average frequency of anode effects, expressed in anode effects per day
1/CE = the inverse of the current efficiency for aluminum smelting
124.2 = the electric current required to produce a metric ton of aluminum, assuming 100 percent efficiency, in kAmp days per metric ton of aluminum.

You should use facility-specific data for the emissions factors A and B. Your report should include the values you used for *C* (anode effects per day), CE (current efficiency), A, and B.

The emissions factor for C_2F_6 currently is estimated to be an order of magnitude lower than that for CF_4. Therefore, the emission calculation methodology for C_2F_6 is as follows:

$$Y\left(\frac{\text{kg } C_2F_6}{\text{MT Al}}\right) = 0.1 \bullet X\left(\frac{\text{kg } CF_4}{\text{MT Al}}\right)$$

3.7 Estimating Methane Emissions Reductions from Natural Gas Systems

The U.S. natural gas system comprises a complex interconnected set of facilities that include production facilities, gas production facilities, transmission pipelines, storage and injection/withdrawal facilities, and distribution systems. Methane is the principal component of natural gas; therefore, leaks from the wide variety of components, processes, and activities that make up the natural gas system contribute to methane emissions. This section provides technical guidance on estimating emissions and emissions reductions from

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(f) The reported anode effect duration depends on the exact definition of an anode effect. Definitions may vary somewhat, depending, for example, on the voltage level used to define the start and end of the anode effect. Your report should carefully describe the definitions you used in developing your estimates.

natural gas systems. Details on the U.S. natural gas system, total U.S. methane emissions from this system, technologies available for reducing emissions, and related regulations and programs may be found in Appendix 3.C.

Methane emissions from the natural gas system can be classified into three groups:

- **normal operations**, including compressor engine exhaust emissions, emissions from pneumatic devices, and fugitive emissions (small chronic leaks from components that store or convey gas)

- **routine maintenance**, including equipment blowdown and venting, well workovers, and scraper (pigging) operations

- **system upsets** including emissions due to sudden, unplanned pressure changes or mishaps.

You may report reductions of these emissions if you are a legal entity that controls a natural gas system and you undertake emission reduction projects. Typical reporting entities could be gas distribution companies, gas transmission companies, integrated gas companies (both transmission and distribution), combination utilities (gas and other utilities, such as electricity and water), and production companies. You may choose to report your emissions reductions through a third party, such as a trade association.

If you currently report information about your system under existing safety and other regulatory programs, you may wish to make use of this information in estimating your emissions and emissions reductions. You may be able to take advantage of the emission reduction estimating techniques and reporting system developed under the EPA's Natural Gas STAR program in developing your EPAct Section 1605(b) report.

In some cases oil and gas resources are owned by one party (or group of parties), and a second party is responsible for withdrawing and marketing the resource. A typical example is an oil and gas company running a production field in which there are a variety of property owners. The company pays the property owners royalties based on the amount of oil and gas produced and marketed. In this case, the company running the field may be in the best position to estimate emissions reductions and could be the reporting entity, unless contractual arrangements among the parties specify otherwise.

A reporting entity may report separately for its individual operating units. For example, an integrated company may report separately for its distribution system and its transmission system. A distribution system may decide to submit separate reports for individual operating districts within the overall distribution system. Similarly, a production company may decide to report separately for each production field, possibly reporting separately for its production well/gathering pipeline unit and its gas processing plant. While there is flexibility in defining the scope of the report, the report should reflect the full extent of the projects undertaken to reduce emissions.

You should describe the equipment upgrade, change in operating or maintenance practice, or other action(s) you took to reduce emissions. You should describe in physical terms the number of projects or the amount of the gas system to which your project applies—for example, miles of pipeline, number of valves, or number of compressor stations. If you currently report projects you have undertaken (not just committed to undertake) to the Natural Gas STAR program, you could use that information as a basis for preparing your EPAct Section 1605(b) report.

Activities to reduce methane emissions in natural gas systems include the following:

- replacing high-bleed pneumatic devices with low- or no-bleed designs
- recovering methane from gas dehydrators and using it for fuel in glycol regeneration boilers
- implementing directed inspection and maintenance programs to reduce fugitive emissions from seals, valves, fittings, assemblies, corroded pipeline, and gate stations
- replacing or repairing leaking subsurface pipeline
- replacing reciprocating engines with turbine engines for compression
- installing catalytic converters on reciprocating engines
- using portable evacuation compressors (rather than venting) to remove gas from sections of pipe to be repaired
- using "smart" regulators in distribution systems
- using metallic coated seals
- using sealant and cleaner injections in valves
- using composite wraps in pipeline repair.

At this time, you may report methane emissions reductions achieved by any means. These include direct reductions at the point of end use achieved by reducing gas demand—that is, demand-side management (DSM) activities. It will be difficult to develop a credible report of indirect emissions reductions (that is, from the natural gas system) resulting from DSM activities. This is because gas system methane emissions are not a simple function of gas throughput or deliveries. If you report such reductions you should document the basis for your estimates in your report.

3.7.1 Establishing the Reference Case

The reference case should encompass the portion of the gas system affected by the emission reduction project. For natural gas systems, methane is often the only greenhouse gas affected by a project. However, in cases where projects involve changes in combustion requirements (for example, for compressor engines) or substitution of electric devices for gas-pressure driven devices, the implications for carbon dioxide emissions must also be considered. In these situations the reference case should include both carbon dioxide and methane emissions.

3.7.2 Identifying the Effects of the Project

You must identify the effects of your project, including potential impacts on other portions of your system and outside the system. In some cases, the project may affect parts of the natural gas system that are not directly under the influence of the project. If these impacts affect emissions, these effects should be identified and should be quantified whenever possible.

Generally, for the natural gas system itself, shifting of emissions from one activity to another is not a significant problem because the system facilities themselves must be maintained and operated to keep the system running.

3.7.3 Estimating Emissions

To estimate reference case and project case emissions from natural gas systems, you will need to characterize your system components and practices, select or estimate emissions factors, and apply the emissions factors to the system characterization. A system characterization consists of the following:

- Define each type of component that contributes to the emissions being included in the reference case.
- Count or estimate the number of components.
- Define each operating practice that contributes to emissions being included in the reference case.
- Count or estimate the frequency with which the operating practices are undertaken.

These data may be obtained through system inspections and surveys and by reviewing operating reports. Because natural gas systems are often very large and complex, it may be appropriate to focus this effort only on those emissions sources that are affected by the emissions-reducing projects. For example, if the project only affects fugitive emissions at distribution system pressure regulating facilities, you may wish to characterize only these facilities. In some cases, the characterization must be made based on assessments of what the components or practices would have been had the project not been undertaken (the modified reference case).

Once the system is characterized, emission factors for the components and practices are needed. If possible, you should measure emissions from a representative set of components or operating events to obtain system-specific emissions factors. If these are not available, emissions factor estimates based on previous studies can be used, or engineering estimation may be used to develop emissions factors.

Finally, the emissions factors should be applied to the system characterization to estimate emissions. This process would be replicated for each emissions type and greenhouse gas affected by the project.

An alternative to the approach described above is to measure or estimate emissions reductions directly. The preferred basis for estimating emissions reductions is actual field measurements. Examples of measurement approaches include the following:

Fugitive Emissions. For projects that reduce fugitive methane emissions (that is, leaks), changes in the number of leaks and the average leak rate could be measured. The number of leaks could be measured using equipment that detects methane, such as an organic vapor analyzer. Standard methods for detecting leaks have been developed by the EPA and are used in various state inspection and maintenance programs. Leak rates could be measured by isolating leaks and conducting mass flow measurements. Alternatively, the leak rate could be assumed to remain unchanged, so that only the change in leak frequency contributes to emissions reductions.

Pneumatic Devices. For projects that reduce emissions by replacing high-bleed pneumatic devices with low-bleed devices, the emissions from each type of device can be measured as the volume of gas released when the device is actuated multiplied by the frequency of activation. Activation frequency can be measured by observing the device in operation. The volume released can be estimated from the gas pressure and the device size.

Engine Exhaust. For projects that reduce methane emissions in engine exhaust by substituting turbine engines for reciprocating engines, the emission reduction can be estimated by measuring the methane in the exhaust per unit of fuel from each engine and multiplying by the fuel that each engine would use. Carbon dioxide emissions would also be calculated based on fuel use using the emissions factors in Appendix B.

While these techniques can be used to measure emissions and emissions reductions directly, it is often costly to do so. If direct measurement is not feasible, stipulated factors can be used for estimating emissions reductions for specific projects that have been well defined and evaluated. The EPA Natural Gas STAR program has developed such factors, which are listed in Table 3.5. To apply these factors, you should characterize your project in terms of the units listed in the table. For emissions factors that you estimate for your system, you should state the basis for your estimation in your report. You should describe carefully the basis for any emissions reduction factors you estimate that exceed the values in Table 3.5.

Table 3.5 Stipulated Emissions Reduction Factors for Natural Gas Systems

Emissions Reduction Project	Units for Measuring the Extent of the Project	Emission Reduction per Unit
Directed inspection/maintenance program at compressor stations(a)	Number of compressor stations	8.54 million cf/yr per compressor station
Directed inspection/maintenance program at city gate stations(b)	Number of gate stations	1.19 million cf/yr per gate station
Replace high-bleed pneumatic devices at transmission facilities	Number of devices replaced	70 thousand cf/yr per device(c)
Directed inspection/maintenance program at production facilities	Number of wellsites(d)	31.5 thousand cf/yr per wellsite
Replace high-bleed pneumatic devices at production facilities	Number of devices replaced	70 thousand cf/yr per device(c)
Recover gas vented during pipeline blowdowns	Per blowdown	Estimated on a case-specific basis(e)
Recover emissions from dehydrator using a flash tank separator	Number of flask tank separator/gas recovery units installed	0.15 thousand cf/million cf of gas throughput plus 90 percent of the gas used to drive the glycol circulation pump(f)
Use turbines instead of reciprocating engines	Per substitution	Estimated on a case-specific basis(g)

(a) Compressor station includes the compressor engines and all other associated components used to maintain gas pressure in transmission pipelines.
(b) Gate station includes all components at the surface facility.
(c) Emissions per device vary by device size and type. Reported value is an average.
(d) Wellsite includes the gas wellhead and associated treatment facility equipment such as heaters, gas/liquid separators, and dehydrators.
(e) Emissions from blowdowns are estimated on a case-specific basis. Emissions reductions from the use of portable evacuation compressors can be estimated at 80 percent of the gas released per blowdown.
(f) Gas may be used to drive the glycol circulation pump. Gas use and emissions from the pump are on the order of 0.8 thousand cf/million cf of gas throughput, 90 percent of which can be recovered using the flash tank separator. Estimates must also be adjusted for the methane portion of the gas (for example, 90 percent on a volume basis).
(g) Reciprocating engines emit 0.510 metric tons per million cf of fuel use; turbines emit 0.009 metric tons/million cf of fuel use. Emissions reductions resulting from the use of turbines instead of reciprocating engines are determined on a case-specific basis after estimating the change in fuel use.

Note: Only directed inspection/maintenance programs at compressor stations and city gate stations have been formally adopted by the National Gas STAR program as cost effective for all participants. The cost effectiveness of other practices is determined on a case-by-case basis.

Source: EPA Natural Gas STAR Program.

3.8 Estimating Methane Emissions Reductions from Landfills

Methane is produced in municipal solid waste landfills when organic matter in the refuse is decomposed by bacteria under anaerobic conditions. Landfills are the largest anthropogenic source of methane emissions in the United States. This section provides technical guidance on estimating emissions and emissions reductions from landfills. Details on total U.S. methane emissions from landfills, technologies available for reducing emissions, and related regulations and programs may be found in Appendix 3.D.

Entities can reduce methane emissions from landfills through two general approaches: modifying waste management practices to reduce the amount of waste landfilled, and recovering the methane and using it as an energy source or flaring it. Using or flaring recovered methane in the only method currently available for reducing emissions from current landfills and from landfills that will contain degradable waste in the future. Recovered gas can be used to generate electricity or can be sold as a medium-Btu fuel to fire industrial boilers, chillers, or similar equipment. Technologies and processes under development to use landfill gas include fuel cells and the production of liquid fuels and industrial chemicals.

You may report reductions of landfill methane emissions if you own the landfill and you undertake emissions reductions projects, or if you contract with a third party to collect and market the recovered gas. In the latter case, you may wish to agree on which party will report the reductions; the report should indicate the other party as a potential reporter, to track possible multiple reporting.

Your report should describe the amount of the landfill (surface area and the waste in place) that are under the influence of the landfill gas collection system and the specific activities you undertook to reduce emissions.

3.8.1 Establishing the Reference Case

No reliable method exists to estimate the amount of methane emissions that would have been emitted from a landfill in the absence of emissions-reducing projects. Therefore, a reference case will not be required for landfill emissions reduction projects. Your emissions reductions can be estimated directly as the amount of methane you recover.

3.8.2 Estimating Emissions Reductions

The most accurate basis for estimating emissions reductions is actual field measurements. You can use the measured amount of landfill gas that is recovered from the landfill and utilized (that is, combusted on-site or sold for combustion off-site) as the estimate of the emissions reduced.

In addition to measuring the volume of gas produced, you must also monitor the methane concentration in the gas. To determine the avoided methane emissions, you must correct the total volume of gas produced based on measured methane concentrations. For example, if you recover 1 billion cubic feet of gas (based on metered flow) with a methane concentration of 50 percent in air, your reportable avoided emissions are 1 billion x 0.5 = .5 billion cubic feet (on a 100 percent methane basis).

In some cases, direct measurements of methane recovery will be unavailable and it may be necessary for you to make engineering estimates of the recovery volume. Possible projects where engineering estimates could be employed include the use of methane at the landfill site for power generation or as fuel in co-located facilities.

Engineering estimates of methane emissions avoided should be determined based on the fuel requirements of the project's methane utilization option. For example, if methane recovered from the landfill is being used in an on-site turbine, an engineering estimate could be prepared by using data on the electricity output of the turbine and the efficiency of the generator. This information would enable you to estimate the fuel input into the turbine, which would represent avoided methane emissions.

The amount of methane recovered is an overestimate of actual methane emissions reduced because in the absence of the gas recovery system, a portion of the methane produced in the landfill would be oxidized as it migrates out of the landfill. Withdrawing the gas with a collection system prevents this oxidation step. The extent of oxidation that will occur depends on local conditions and is not well defined. Because no single oxidation adjustment factor is available at this time, the amount of gas collected and utilized should be used as the estimate of emissions reduced. That is, a default value of zero will be used for the oxidation factor. However, if you have site-specific information that allows you to compute an oxidation factor for your landfill, you should use this value rather than the default value.

While no stipulated emission reduction values are available for landfill methane emissions, you should use the following guidelines in determining whether your estimated emissions reduction falls within the expected range:

- Total emissions can be reduced by up to 85 percent

- In nearly all cases, emissions reductions are expected to be less than 6 kg of methanol per ton of refuse in the landfill. Most emissions reductions will be well below this figure.(g)

If your estimated emissions reduction exceeds these values, your report should provide a full description of the basis for your estimate.

(g) This upper bound estimate is based on a maximum estimate of about 16 m^3/min of methane per million metric tons of refuse. This maximum is about 100 percent larger than the average emissions factor for non-arid landfills reported in EPA 1993a.

3.9 Estimating Methane Emissions Reductions from Coal Mines

Methane and coal are formed together during coalification, a process in which ancient biomass is converted into coal by biological and geological forces. Methane is stored in coal seams and within surrounding rock and released when coalbed pressure is reduced through natural erosion, faulting, or mining. This section provides technical guidance on estimating emissions and emissions reductions from coal mines. Details on total U.S. coal mining emissions, technologies available for reducing emissions, and related regulations and programs may be found in Appendix 3.E.

The major approaches for recovering and using coal mine methane are as follows (see Appendix 3.D for more detailed descriptions):

- **Gob Wells**. Gob wells are drilled from the surface to a point just above the coal seam. As mining advances under the well, the methane-charged coal and strata around the well fractures. The methane emitted from this fractured area flows into the gob well and up to the surface. Initially, gob wells produce nearly pure methane. Over time, however, ventilation air from mine working areas may flow into the gob area and dilute the methane.

- **In-mine Horizontal Boreholes**. In-mine boreholes are drilled inside the mine (as opposed to from the surface), and they operate to drain methane from unmined areas of the coal seam shortly before mining. The recovery efficiency of this technique is low—approximately 10 to 20 percent of methane that would otherwise be emitted. However, the methane produced is typically over 95 percent pure.

- **Advance (Pre-Mining) Degasification**. With this method, vertical wells are drilled into the coal seams several years in advance of mining. Depending on the length of time that the wells are in place, the majority of the methane that would otherwise be emitted to the atmosphere when the coal was extracted can be recovered before mining begins. An advantage of this recovery method is that a nearly pure methane can be recovered. A disadvantage of this method is that it may be difficult for some mines to plan where they will mine many years in advance of the actual mining.

Options for utilizing recovered methane include injecting (nearly pure) methane into a pipeline, using methane (which can be mixed with ventilation air) as a fuel in an on-site generator, co-firing methane in a nearby boiler, and selling low Btu gas (methane mixed with mine air) to nearby industrial users. Emerging technologies and practices for reducing methane emissions from coal mining include technologies for separating methane from carbon dioxide, oxygen, and/or nitrogen and technologies to use ventilation air as the combustion fuel for on-site turbines or boilers.

You may report reductions of coal mining emissions if you are a legal entity that controls a coal mine(s) and you undertake emissions reduction processes. The coal mining company would have the most accurate information about measures taken to reduce emissions and their effects. A third party could contract to withdraw and market the coalbed methane; in this case, the report should identify the other party as a potential reporter, to track multiple reporting.

You may report separately for your individual operating units (for example, coal mines) or you may combine all your projects into a single report, taking care to account for all potential project effects within and outside of your organization. You may report emissions reductions resulting from reducing the quantity of coal produced or from reducing production at a gassy mine in favor of increasing production at a less gassy mine. However, if you report such reductions, you should provide documentation of the production shifts in your report and identify whether the production you reduced may have been offset by increased production by another entity.

3.9.1 Establishing the Reference Case

The reference case is complicated by the potential for pre-mining gasification as much as 10 years before mining begins and by the potential for poor quality of emissions estimates. In some cases, the precision of the reference case emissions estimates is much poorer than the precision of the emissions reduction estimates. For these reasons, a reference case will not be established as a separate step; rather, the quantity of recovered gas will be used to estimate emissions reductions directly.

3.9.2 Estimating Emissions Reductions

The method for determining emissions reductions depends on whether methane is recovered during or prior to mining.

- **Methane Recovery During Mining**. The quantity of methane recovered each year from gob wells or horizontal boreholes would be the reportable emissions reduction for that year, corrected to account for methane content (see below).

- **Pre-Mining Degasification**. When methane is recovered in advance of mining, the recovery generally occurs several years before the methane would have been emitted. As the coalbed is mined through, each year you should estimate the emissions reduction associated with the amount of coal mined that year, and report that amount to the EPAct Section 1605(b) program.

In many cases, direct measurements of methane recovery may be available at various points in the gas collection and/or treatment system. (However, in some cases actual measurements will not be available and engineering estimates must be used.) Possible sources of direct measurements include the following:

- **At the wellhead**—Many mines will monitor methane production from each well or block of wells within a particular mining section to assess the effectiveness of the methane drainage program and optimize methane recovery. If the produced gas is used, direct measurements taken at the point of production are an accurate means of determining avoided emissions.

- **At point of compression or treatment**—Depending on the type of utilization, it may be necessary to treat and/or compress the methane recovered by the mine. Where methane is injected into pipelines, for example, gas must be cleaned and compressed to meet pipeline specifications. Measurements may be taken by the gas producer at various points in these systems.

- **At the point of sale**—If the recovered methane is sold, measurements will likely be made at the point of sale.

In addition to measuring the volume of gas produced, you must also monitor the methane concentration in the gas. (See the discussion in Section 3.8.) Measurements of methane concentrations (that is, gas quality) are readily available for most methane utilization projects at coal mines. Where gas is being sold to pipelines, for example, mines must continuously monitor gas composition to ensure that pipeline specifications are met. For other gas uses, measurements of gas composition may also be taken to ensure that the specifications of the gas user are met. Finally, for those methane recovery technologies employed in close conjunction with mining (that is, gob wells or in-mine drainage systems), the Mining Safety and Health Administration requires monitoring of the operating methane recovery system to ensure that methane concentrations do not drop into the explosive zone.

While no stipulated emission reduction values are available for coal mine methane emissions, you should use the following guidelsnes in determinisg whether your eitimated emissionn reduction falls within the expected range:

- Total emissions can be reduced by up to 70 percent

- In nearly all cases, emissions reductions are expected to be less than 60 kg of methane per ton of coal mined; most emissions reductions would be less than 30 kg of methane per ton of coal mined.(h)

If your estimated emissions reduction exceeds these values, your report should provide a full description of the basis for your estimate.

3.10 Estimating Reductions of Nitrous Oxide Emissions from Adipic Acid Plants

Nitrous oxide is produced as a waste gas during the production of adipic acid, which is used primarily in the manufacture of nylon. The production of nitric acid, an input to the adipic acid production process, also produces nitrous oxide emissions. This section provides technical guidance on estimating emissions and emissions reductions from adipic acid plants; you can use the same guidance to report emissions reductions

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(h) The upper figure is estimated assuming that 70 percent of the emissions are recovered from a coal mine with methane emissions of 4,000 ft^3 per ton of coal mined. Only a small number of mines in the U.S. have a gas content this high. Most U.S. mines have methane emissions of less than 2,000 ft^3 per ton of coal mined, which was used to estimate the lower value.

from nitric acid production. Details on the adipic acid industry, its emissions, and related regulations and programs may be found in Appendix 3.F.

Nitrous oxide (N_2O) emissions from adipic acid plants can be reduced by collecting or destroying the gas. Although thermal decomposition of N_2O is effective, its energy requirements are substantial. In addition, it produces NO_x emissions, which are also undesirable. Other promising alternatives being investigated by adipic acid manufacturers include conversion of N_2O to NO for recovery/reuse in the nitric acid production process; and catalytic decomposition of N_2O to N_2, O_2, and a small amount of residual NO_x.

You may report reductions of nitrous oxide emissions if you undertake projects to reduce emissions at adipic acid or other plants. You may report for a collection of plants, a single plant, or a portion of a plant, taking care to account for all potential project effects within and outside your organization.

3.10.1 Establishing the Reference Case

You may choose a basic or modified reference case as defined in the General Guidelines. The year you choose for a basic reference case should be indicative of normal operations. Nitrous oxide would be reported as the principal greenhouse gas affected by your project. However, in cases where projects involve changes in combustion requirements or electricity purchases, you must also consider the implications for carbon dioxide emissions. In this case, the reference case should include both carbon dioxide and nitrous oxide.

3.10.2 Estimating Emissions Reductions

While extensive emissions data have not been published, it appears that nitrous oxide emissions measurement does not pose significant difficulties. You could estimate reference case and project case emissions using stoichiometric models and verify the estimates through field measurements. You could then use the validated models to estimate emissions.

3.11 Bibliography

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Appendix 3.A

Assessment Recommendation Codes

Assessment Recommendation Codes

The Assessment Recommendation Codes are taken from the U.S. Department of Energy's Energy Analysis and Diagnostic Center program, which provides energy and waste-minimization audits to small and medium-sized companies. You should indicate the appropriate ARC or ARCs for your project in your report. If your project is not adequately described in the ARC list, you should describe the project clearly in your report. You are not limited to reporting projects contained in the ARC list.

2. Energy Management

  2.1 Combustion Systems

    2.1.1 Furnaces, Ovens and Directly Fired Operations

      2.1.1.1 Operational Improvements
        2.1.1.1.1 Control Pressure on Steamer Operations
        2.1.1.1.2 Heat Oil to Proper temperature for Good Atomization
        2.1.1.1.3 Reduce Combustion Air Flow to Optimum
        2.1.1.1.4 Limit and Control Secondary Combustion Air in Furnace Operations to the Amount Required for Proper Furnace Operation
        2.1.1.1.5 Eliminate Combustible Gas in Flue Gas
        2.1.1.1.6 Improve Combustion Control Capability

      2.1.1.2 Hardware
        2.1.1.2.1 Use Soft Insulation in Cycling Furnaces to Facilitate Heating Up and Cooling Down
        2.1.1.2.2 Resize Charging Openings or Add a Movable Door on Fuel-Fired Equipment
        2.1.1.2.3 Install Automatic Stack Damper

      2.1.1.3 Maintenance
        2.1.1.3.1 Repair Faulty Insulation in Furnaces, Boilers, etc.
        2.1.1.3.2 Repair Faulty Louvers and Dampers
        2.1.1.3.3 Adjust Burners for Efficient Operation
        2.1.1.3.4 Eliminate Leaks in Combustible Gas Lines
        2.1.1.3.5 Repair Furnaces and Oven Doors So That They Seal Efficiently

    2.1.2 Boilers

      2.1.2.1 Operation
        2.1.2.1.1 Move Boiler to More Efficient Location
        2.1.2.1.2 Operate Boilers on High Fire Setting
        2.1.2.1.3 Direct Warmest Air to Combustion Intake

      2.1.2.2 Hardware
        2.1.2.2.1 Replace Obsolete Burners with More Efficient Ones
        2.1.2.2.2 Install Turbulators
        2.1.2.2.3 Install Smaller Boiler (Increase High Fire Duty Cycle)
        2.1.2.2.4 Replace Boiler

      2.1.2.3 Maintenance
        2.1.2.3.1 Establish Burner Maintenance Schedule for Boilers
        2.1.2.3.2 Keep Boiler Tubes Clean
        2.1.2.3.3 Analyze Flue Gas for Proper Air/Fuel Ratio

      2.1.2.4 Blowdown
        2.1.2.4.1 Reduce Excessive Boiler Blowdown
        2.1.2.4.2 Minimize Boiler Blowdown with Better Feedwater Treatment
        2.1.2.4.3 Use Heat From Boiler Blowdown to Preheat Boiler Feed Water

- 2.1.3. Combustion of Waste Products
  - 2.1.3.1 General
    - 2.1.3.1.1 Burn Waste Paper for Heat
    - 2.1.3.1.2 Install Solid Waste Incinerator for Heat
    - 2.1.3.1.3 Burn Wood By-Products for Heat
    - 2.1.3.1.4 Burn Waste Oil for Heat
- 2.1.4 Convert to More Efficient Fuel
  - 2.1.4.1 Electric to Fossil Fuel
    - 2.1.4.1.1 Replace Electrically-Operated Equipment with Fossil Fuel Equipment
  - 2.1.4.2 Fossil Fuel to Electric
    - 2.1.4.2.1 Replace Fossil Fuel Burning Equipment with Electrical Equipment
    - 2.1.4.2.2 Use Electric Heat in Place of Fossil Fuel Heating System
    - 2.1.4.2.3 Replace Gasfired Absorption Air Conditioners with Electric Units
  - 2.1.4.3 Alternate Fossil Fuel
    - 2.1.4.3.1 Burn a Less Expensive Grade of Fuel
    - 2.1.4.3.2 Convert Combustion Equipment to Burn Natural Gas
    - 2.1.4.3.3 Convert Combustion Equipment to Burn Oil
    - 2.1.4.3.4 Convert Oil or Gas Burners to Combustion of Coal
    - 2.1.4.3.5 Replace Gasoline with Diesel, LPG, or Natural Gas
  - 2.1.4.4 Other
    - 2.1.4.4.1 Replace Purchased Steam with Electric Heating
    - 2.1.4.4.2 Replace Purchased Steam with Other Energy Source
    - 2.1.4.4.3 Use Steam Sparging or Injections in Place of Indirect Heating
    - 2.1.4.4.4 Replace Steam Jets on Vacuum System with Electric Motor Driven Vacuum Pumps

2.2 Thermal Systems

- 2.2.1 Steam
  - 2.2.1.1 Traps
    - 2.2.1.1.1 Install Steam Trap
    - 2.2.1.1.2 Use Correct Size Steam Traps
    - 2.2.1.1.3 Repair or Replace Steam Traps
    - 2.2.1.1.4 Shut Off Steam Traps on Super Heated Steam Lines When Not in Use
  - 2.2.1.2 Condensate
    - 2.2.1.2.1 Increase Amount of Condensate Returned
    - 2.2.1.2.2 Cover Condensate Storage Tanks
    - 2.2.1.2.3 Insulate Condensate Lines
    - 2.2.1.2.4 Insulate Feedwater Tank
    - 2.2.1.2.5 Repair Insulation on Condensate Lines
    - 2.2.1.2.6 Install De-Aerator in Place of Condensate Tank
    - 2.2.1.2.7 Replace Barometric Condensers with Surface Condensers
    - 2.2.1.2.8 Return Steam Condensate to Boiler Plant
    - 2.2.1.2.9 Flash Condensate to Produce Lower Pressure Steam
    - 2.2.1.2.10 Use Steam Condensate for Hot Water Supply (Non Potable)
  - 2.2.1.3 Leaks and Insulation
    - 2.2.1.3.1 Insulate Steam Lines
    - 2.2.1.3.2 Repair Faulty Insulation on Steam Lines
    - 2.2.1.3.3 Repair Leaks in Lines and Valves
    - 2.2.1.3.4 Eliminate Leaks in High Pressure Reducing Stations
    - 2.2.1.3.5 Repair and Eliminate Steam Leaks
  - 2.2.1.4 Distillation
    - 2.2.1.4.1 Operate Distillation Columns Efficiently

2.2.1.4.2 Upgrade Distillation Hardware

2.2.1.5 Other
2.2.1.5.1 Clean Steam Coils in Processing Tanks
2.2.1.5.2 Maintain Steam Jets Used for Vacuum System
2.2.1.5.3 Optimize Operation of Multi-Stage Vacuum Steam Jets
2.2.1.5.4 Reduce Excess Steam Bleeding
2.2.1.5.5 Use Minimum Steam Operating Pressure
2.2.1.5.6 Substitute Hot Process Fluids for Steam
2.2.1.5.7 Close Off Unneeded Steam Lines
2.2.1.5.8 Use Heat Exchange Fluids Instead of Steam in Pipeline Tracing Systems
2.2.1.5.9 Turn Off Steam Tracing During Mild Weather
2.2.1.5.10 Substitute Air for Steam to Atomize Oil

2.2.2 Heating

2.2.2.1 Operation
2.2.2.1.1 Use Optimum Temperature
2.2.2.1.2 Use Minimum Safe Oven Ventilation

2.2.2.2 Hardware
2.2.2.2.1 Use Immersion Heating in Tanks, Melting Pots, Etc.
2.2.2.2.2 Convert Liquid Heaters from Underfiring to Immersion or Submersion Heating
2.2.2.2.3 Enhance Sensitivity of Temperature Control and Cutoff

2.2.3 Heat Treating

2.2.3.1 General
2.2.3.1.1 Heat Treat Parts Only to Required Specifications or Standards
2.2.3.1.2 Minimize Non-essential Material in Heat Treatment Process
2.2.3.1.3 Use Batch Firing with Kiln "Furniture" Designed Specifically for the Job

2.2.4 Heat Recovery

2.2.4.1 Flue Gas - Recuperation
2.2.4.1.1 Use Waste Heat from Hot Flue Gases to Preheat Combustion Air
2.2.4.1.2 Use Flue Gas Heat to Preheat Boiler Feedwater
2.2.4.1.3 Use Hot Flue Gases to Preheat Wastes for Incinerator Boiler

2.2.4.2 Flue Gas - Other Uses
2.2.4.2.1 Install Waste Heat Boiler to Provide Direct Power
2.2.4.2.2 Use Waste Heat from Hot Flue Gases to Generate Steam for Processes or Resale
2.2.4.2.3 Install Waste Heat Boiler to Produce Steam
2.2.4.2.4 Use Heat in Flue Gases to Preheat Products or Material Going into Ovens, Dryers, etc.
2.2.4.2.5 Use Flue Gases to Heat Process or Service Water
2.2.4.2.6 Use Waste Heat from Hot Flue Gases to Heat Space Conditioning Air
2.2.4.2.7 Use Waste Heat from Hot Flue Gases to Preheat Incoming Fluids
2.2.4.2.8 Use Hot Flue Gases in Radiant Heater for Space Heating, Ovens, Dryers, etc.

2.2.4.3 Other Process Waste Heat
2.2.4.3.1 Preheat Boiler Makeup Water with Waste Process Heat
2.2.4.3.2 Preheat Combustion Air with Waste Heat
2.2.4.3.3 Re-use or Recycle Hot or Cold Process Exhaust Air, or Exchange Heat with Incoming Air
2.2.4.3.4 Use Hot Process Fluids to Preheat Incoming Process Fluids
2.2.4.3.5 Recover Waste Heat from Equipment
2.2.4.3.6 Recover Heat from Oven Exhaust
2.2.4.3.7 Heat Water with Exhaust Heat
2.2.4.3.8 Recover Heat from Exhausted Steam
2.2.4.3.9 Recover Heat from Hot Waste Water
2.2.4.3.10 Recover Heat from Engine Exhausts
2.2.4.3.11 Recover Heat from Air Compressor
2.2.4.3.12 Recover Heat from Compressed Air Dryers

        - 2.2.4.3.13 Recover Heat from Refrigeration Condensers
        - 2.2.4.3.14 Recover Heat from Transformers

    - 2.2.4.4 Miscellaneous
        - 2.2.4.4.1 Use Cooling Air Which Cools Hot Work Pieces for Space Heating or Make-Up Air in Cold Weather
        - 2.2.4.4.2 Use "Heat Wheel" or Other Heat Exchanger to Cross-Exchange Building Exhaust Air with Make-up Air
        - 2.2.4.4.3 Use Recovered Heat from Lighting Fixtures for Useful Purpose, that is, to Operate Absorption Cooling Equipment
        - 2.2.4.4.4 Recover Heat in Domestic Hot Water Going to Drain
        - 2.2.4.4.5 Use Exhaust Heat from Building for Snow and Ice Removal from Walks, Driveways, Parkways, Parking Lots, etc.
        - 2.2.4.4.6 Heat Service Hot Water with Air Conditioning Equipment
        - 2.2.4.4.7 Recover Heating or Cooling Effect from Ventilation Exhaust Air to Precondition Incoming Ventilation Air

- 2.2.5 Heat Containment

    - 2.2.5.1 Insulation
        - 2.2.5.1.1 Insulate Bare Equipment
        - 2.2.5.1.2 Increase Insulation Thickness
        - 2.2.5.1.3 Cover Open Tanks with Floating Insulation to Minimize Energy Losses
        - 2.2.5.1.4 Cover Open Tanks
        - 2.2.5.1.5 Use Optimum Thickness Insulation
        - 2.2.5.1.6 Use Economic Thickness of Insulation for Low Temperatures

    - 2.2.5.2 Isolate Hot Systems from Cold Systems
        - 2.2.5.2.1 Isolate Steam Lines to Avoid Heating Air Conditioned Areas
        - 2.2.5.2.2 Isolate Hot or Cold Equipment
        - 2.2.5.2.3 Reduce Infiltration to Refrigerated Areas; Isolate Hot Equipment from Refrigerated Areas
        - 2.2.5.2.4 Avoid Cooling of Process Streams or Materials That Must Subsequently be Heated
        - 2.2.5.2.5 Eliminate Cooling of Process Streams Which Subsequently Must Be Heated and Vice Versa

    - 2.2.5.3 Minimize Infiltration
        - 2.2.5.3.1 Resize Charging Openings or Add Movable Cover or Door
        - 2.2.5.3.2 To Drive Off Combustible Solvents, Use Only Amount of Air Necessary to Prevent Explosion Hazard and to Protect Personnel
        - 2.2.5.3.3 Replace Air Curtain Doors with Solid Doors

- 2.2.6 Cooling

    - 2.2.6.1 Cooling Towers
        - 2.2.6.1.1 Operate Cooling Tower at Constant Outlet Temperature to Avoid Subcooling
        - 2.2.6.1.2 Use Cooling Tower Water Instead of Refrigeration when Outside Temperatures Allow
        - 2.2.6.1.3 Use Antifreeze in Cooling Towers to Allow Winter Use
        - 2.2.6.1.4 Use Either Cooling Tower or Economizer Cooling to Replace Chiller Cooling

    - 2.2.6.2 Chillers and Refrigeration
        - 2.2.6.2.1 Modify Refrigeration System to Enable Compressor to Operate at a Lower Pressure
        - 2.2.6.2.2 Utilize a Less Expensive Cooling Method
        - 2.2.6.2.3 Minimize Condenser Cooling Water Temperature
        - 2.2.6.2.4 Use Cold Waste Water to Cool Chiller Feed Water
        - 2.2.6.2.5 Chill Water to the Highest Temperature Possible
        - 2.2.6.2.6 Avoid Frost Formation on Evaporators
        - 2.2.6.2.7 Use Multiple-effect Evaporators

    - 2.2.6.3 Other
        - 2.2.6.3.1 Shut Off Cooling if Cold Outside Air Will Cool Process
        - 2.2.6.3.2 Use Outside Cold Water Source as a Continuous Supply of Cooling Water
        - 2.2.6.3.3 Use Waste Heat Low Pressure Steam for Absorption Refrigeration
        - 2.2.6.3.4 Use Outside Air for Freezing
        - 2.2.6.3.5 Use Highest Temperature for Chilling or Cold Storage

2.2.6.3.6 Utilize Pond or Lake as a Heat Sink
2.2.6.3.7 Use Cascade System of Recirculating During Cold Weather to Avoid Sub-Cooling

2.2.7 Drying

2.2.7.1 Use of Air
2.2.7.1.1 Utilize Outside Air Instead of Conditioned Air for Drying

2.3 Electrical Power

2.3.1 Demand Management

2.3.1.1 Thermal Energy Storage
2.3.1.1.1 Heat Water During Off-Peak Periods and Store for Later Use
2.3.1.1.2 Store Heated/Cooled Water for Use During Peak Demand Periods
2.3.1.1.3 Make Ice During Off Peak Hours for Cooling

2.3.1.2 Other
2.3.1.2.1 Use Power During Off-Peak Periods
2.3.1.2.2 Use Fossil Fuel Powered Generator During Peak Demand Periods
2.3.1.2.3 Locate Causes of Electrical Power Demand Charges, and Reschedule Plant Operations to Avoid Peaks
2.3.1.2.4 Recharge Batteries on Materials Handling Equipment During Off-Peak Demand Periods
2.3.1.2.5 Consider Three or Four Days Around-the-Clock Operation Rather Than One or Two Shifts Per Day
2.3.1.2.6 Shift from Daytime to Nighttime Operation
2.3.1.2.7 Schedule Routine Maintenance During Non-Operating Periods
2.3.1.2.8 Overlap the Work Hours of Custodial Services with Normal Day Hours
2.3.1.2.9 Use Demand Controller or Load Shedder

2.3.2 Power Factor

2.3.2.1 General
2.3.2.1.1 Use Power Factor Controllers
2.3.2.1.2 Optimize Plant Power Factor

2.3.3 Generation of DC Power

2.3.3.1 General
2.3.3.1.1 Replace DC Equipment with AC Equipment
2.3.3.1.2 Install Efficient Rectifiers

2.3.4 Cogeneration

2.3.4.1 General
2.3.4.1.1 Use Steam Pressure Reduction to Generate Power
2.3.4.1.2 Use Waste Heat to Produce Steam to Drive a Steam Turbine-Generator
2.3.4.1.3 Burn Fossil Fuel to Produce Steam to Drive a Steam Turbine-Generator and Use Steam Exhaust for Heat
2.3.4.1.4 Burn Waste to Produce Steam to Drive a Steam Turbine Generator Set and Use Steam Exhaust for Heat
2.3.4.1.5 Use a Fossil Fuel Engine-Generator Set to Cogenerate Electricity and Heat
2.3.4.1.6 Use Combined Cycle Gas Turbine Generator Sets with Waste Heat Boilers Connected to Turbine Exhaust
2.3.4.1.7 Use Waste Heat with a Closed-Cycle Gas Turbine-Generator Set to Cogenerate Electricity and Heat
2.3.4.1.8 Use Existing Dam to Generate Electricity
2.3.4.1.9 Replace Electric Motors with Back Pressure Steam Turbines and Use Exhaust Steam for Process Heat

2.3.5 Other

2.3.5.1 Transformers
2.3.5.1.1 Use Plant Owned Transformers or Lease Transformers from Utility
2.3.5.1.2 De-Energize Excess Transformer Capacity
2.3.5.1.3 Consider Power Loss as Well as Initial Loads and Load Growth in Down-Sizing Transformers

- 2.3.5.2 Conductor Size
    - 2.3.5.2.1 Reduce Load on Electrical Conductor to Reduce Heating Losses
    - 2.3.5.2.2 Increase Electrical Conductor Size to Reduce Distribution Losses

2.4 Motor Systems

- 2.4.1 Motors

    - 2.4.1.1 Operation
        - 2.4.1.1.1 Utilize Energy-Efficient Belts and Other Improved Mechanisms

    - 2.4.1.2 Hardware Upgrade
        - 2.4.1.2.1 Replace Over-Size Motors and Pumps with Optimum Size
        - 2.4.1.2.2 Size Electric Motors for Peak Operating Efficiency
        - 2.4.1.2.3 Use Multiple Speed Motors or ASD for Variable Pump, Blower and Compressor Loads
        - 2.4.1.2.4 Use Most Efficient Type of Electric Motors

- 2.4.2 Air Compressors

    - 2.4.2.1 Operations
        - 2.4.2.1.1 Reduce the Pressure of Compressed Air to the Minimum Required
        - 2.4.2.1.2 Eliminate or Reduce Compressed Air Used for Cooling Product, Equipment, or for Agitating Liquids
        - 2.4.2.1.3 Eliminate Permanently the Use of Compressed Air
        - 2.4.2.1.4 Cool Compressor Air Intake with Heat Exchanger
        - 2.4.2.1.5 Remove or Close off Unneeded Compressed Air Lines
        - 2.4.2.1.6 Eliminate Leaks in Inert Gas and Compressed Air Lines and Valves
        - 2.4.2.1.7 Use Compressor Air Filters
        - 2.4.2.1.8 Substitute for Compressed Air Cooling with Either Water or Air Cooling
        - 2.4.2.1.9 Do Not Use Compressed Air for Personal Cooling

    - 2.4.2.2 Hardware Upgrade
        - 2.4.2.2.1 Install Compressor Air Intakes in Coolest Locations
        - 2.4.2.2.2 Install Adequate Dryers on Air Lines to Eliminate Blowdown
        - 2.4.2.2.3 Install Direct Acting Units in Place of Compressed Air Pressure System in Safety System
        - 2.4.2.2.4 Upgrade Controls on Screw Compressors

- 2.4.3 Other

    - 2.4.3.1 Operations
        - 2.4.3.1.1 Recover Mechanical Energy
        - 2.4.3.1.2 Improve Lubrication Practices
        - 2.4.3.1.3 Provide Proper Maintenance and Lubrication of Motor Driven Equipment

    - 2.4.3.2 Hardware
        - 2.4.3.2.1 Upgrade Obsolete Equipment
        - 2.4.3.2.2 Use or Replace with Energy Efficient Substitutes
        - 2.4.3.2.3 Use Optimum Size and Capacity Equipment
        - 2.4.3.2.4 Replace Hydraulic or Pneumatic Equipment with Electric Equipment
        - 2.4.3.2.5 Upgrade Conveyors

2.5 Industrial System Design

- 2.5.1 Miscellaneous Strategies

    - 2.5.1.1 Thermal
        - 2.5.1.1.1 Convert from Indirect to Direct Fired Systems
        - 2.5.1.1.2 Use Continuous Equipment Which Retains Process Heating Conveyors Within the Heated Chamber
        - 2.5.1.1.3 Use Direct Flame Impingement or Infrared Processing for Chamber Type Heating
        - 2.5.1.1.4 Use Shaft Type Furnaces for Preheating Incoming Material

    - 2.5.1.2 Mechanical
        - 2.5.1.2.1 Redesign Flow to Minimize Mass Transfer Length

2.5.1.2.2 Replace High Resistance Ducts, Pipes, and Fittings
2.5.1.2.3 Reduce Fluid Flow Rates
2.5.1.2.4 Use Gravity Feeds Wherever Possible
2.5.1.2.5 Size Air Handling Grills, Duct, and Coils to Minimize Air Resistance

2.5.1.3 Other
2.5.1.3.1 Modify Dye Beck
2.5.1.3.2 Modify Textile Dryers
2.5.1.3.3 Convert from Batch to Continuous Operation
2.5.1.3.4 Redesign Process
2.5.1.3.5 Change Product Design to Reduce Processing Energy Requirements
2.5.1.3.6 Use Small Number of High Output Units Instead of Many Small Inefficient Units
2.5.1.3.7 Avoid Electrically-Powered Animated Displays

2.6 Miscellaneous Operational Changes

2.6.1 Maintenance

2.6.1.1 Miscellaneous
2.6.1.1.1 Reduce Hot Water Temperature to the Minimum Required
2.6.1.1.2 Use Cold Water for Cleanup Whenever Possible
2.6.1.1.3 Maintain Air Filters by Cleaning or Replacement
2.6.1.1.4 Adjust Vents to Minimize Energy Use
2.6.1.1.5 Remove Unneeded Service Lines to Eliminate Potential Leaks
2.6.1.1.6 Periodically Calibrate the Sensors Controlling Louvers and Dampers on Buildings
2.6.1.1.7 Establish Equipment Maintenance Schedule
2.6.1.1.8 Keep Equipment Clean
2.6.1.1.9 Keep Solid Fuels Dry

2.6.2 Cut Back or Turn Off Equipment

2.6.2.1 Turn Off Equipment Not In Use
2.6.2.1.1 Turn Off Equipment When Not in Use
2.6.2.1.2 Turn Off Equipment During Lunch Breaks, Reduce Operating Time of Equipment
2.6.2.1.3 Turn Off Steam or Hot Water Lines Leading to Space Heating Units During Mild Weather
2.6.2.1.4 Shut Off Pilots in Standby Equipment
2.6.2.1.5 Shut Off Air Conditioning in Winter Heating Season
2.6.2.1.6 Shut Off Cooling Water When Not Required
2.6.2.1.7 Shut Off All Laboratory Fume Hoods When Not in Use
2.6.2.1.8 Conserve Energy by Efficient Use of Water Cooler and Vending Machines

2.6.2.2 Schedule Equipment For Optimal Performance
2.6.2.2.1 Use Most Efficient Equipment at Its Maximum Capacity and Less Efficient Equipment Only When Necessary
2.6.2.2.2 Use Drying Oven (Batch Type) on Alternate Days or Other Optimum Schedule to Run Equipment with Full Loads
2.6.2.2.3 Schedule Use of Elevators to Conserve Energy
2.6.2.2.4 Schedule Baking Times of Small and Large Components to Minimize Use of Energy

2.6.2.3 Automatic Equipment Operation
2.6.2.3.1 Utilize Controls to Operate Equipment Only When Needed
2.6.2.3.2 Install Set-back Timers

2.6.2.4 Run Equipment In Off-Loaded Mode
2.6.2.4.1 Reduce Temperature of Process Heating Equipment When on Standby
2.6.2.4.2 Minimize Operation of Equipment Required to be Maintained in Standby Condition

2.7 Building and Grounds

2.7.1 Lighting

2.7.1.1 Level

        - 2.7.1.1.1 Reduce Illumination to Minimum Necessary for Effective Operation and Safety
        - 2.7.1.1.2 Reduce Exterior Building and Grounds Illumination to Minimum Safe Level

    - 2.7.1.2 Operation
        - 2.7.1.2.1 Utilize Daylight Whenever Possible in Lieu of Artificial Light
        - 2.7.1.2.2 Disconnect Ballasts
        - 2.7.1.2.3 Keep Lamps and Reflectors Clean

    - 2.7.1.3 Hardware
        - 2.7.1.3.1 Lower Light Fixtures in High Ceiling Areas
        - 2.7.1.3.2 Install Timers on Light Switches in Little Used Areas
        - 2.7.1.3.3 Use Separate Switches on Perimeter Lighting Which May be Turned Off When Natural Light is Available
        - 2.7.1.3.4 Use Photocell Controls
        - 2.7.1.3.5 Utilize Higher Efficiency, Lower Wattage Lamps or Ballasts
        - 2.7.1.3.6 Use More Efficient Light Source
        - 2.7.1.3.7 Add Area Lighting Switches to Allow Smaller Areas to be Darkened When Not in Use

- 2.7.2 Space Heating and Cooling

    - 2.7.2.1 Maintenance
        - 2.7.2.1.1 Clean Air Conditioning Refrigerant Condensers to Reduce Compressor Horsepower-Check Cooling Water Treatment
        - 2.7.2.1.2 Install or Upgrade Insulation on HVAC Distribution Systems

    - 2.7.2.2 Operation
        - 2.7.2.2.1 Maintain Space Temperature Lower During the Winter Season and Higher During the Summer Season
        - 2.7.2.2.2 Air Condition Only Space in Use
        - 2.7.2.2.3 Cool Smallest Space Necessary
        - 2.7.2.2.4 Reduce or Eliminate Space Heating/Cooling During Non-Working Hours
        - 2.7.2.2.5 Close Outdoor Air Dampers During Warm-up or Cool-down Periods Each Day
        - 2.7.2.2.6 Use Computer Programs to Optimize HVAC Performance
        - 2.7.2.2.7 Use Water Sparingly on Air Conditioning Exchanger to Improve Heat Transfer and Increase Air Conditioner Efficiency
        - 2.7.2.2.8 Direct Hot Exhaust Air Outdoors in Summer; Avoid Introducing High-Moisture Exhaust Air into Air Conditioning System
        - 2.7.2.2.9 Avoid Introducing Hot, Humid, or Dirty Air Into HVAC System

    - 2.7.2.3 Hardware
        - 2.7.2.3.1 Use Radiant Heater for Spot Heating Rather Targeting Entire Area
        - 2.7.2.3.2 Install Timers and/or Thermostats
        - 2.7.2.3.3 Separate Controls of Air Handlers from AC/Heating Systems
        - 2.7.2.3.4 Use Heat Pump for Space Conditioning
        - 2.7.2.3.5 Change Zone Reheat Coils to Low Pressure Variable Air Volume Boxes
        - 2.7.2.3.6 Lower Ceiling to Reduce Conditioned Space
        - 2.7.2.3.7 Use Properly Designed and Sized HVAC Equipment
        - 2.7.2.3.8 Improve Interior Air Circulation with Destratification Fans or other Methods
        - 2.7.2.3.9 Revise Smoke Cleanup from Operations
        - 2.7.2.3.10 Use Direct Air Supply to Exhaust Hoods
        - 2.7.2.3.11 Lower Compressor Pressure Through A/C System Modification
        - 2.7.2.3.12 Interlock Heating and Air Conditioning Systems to Prevent Simultaneous Operation

    - 2.7.2.4 Utilize Evaporation
        - 2.7.2.4.1 Reduce Air Conditioning Load by Evaporating Water from Roof
        - 2.7.2.4.2 Utilize an Evaporative Air Pre-cooler or Other Heat Exchanger in AC System

    - 2.7.2.5 General
        - 2.7.2.5.1 Reschedule and Rearrange Multiple-Source Heating Systems to Minimize Redundant Heating and to Burn Least Expensive Fuels

- 2.7.3 Ventilation

- 2.7.3.1 General
    - 2.7.3.1.1 Revise Conference Room Ventilation System to Shut Off When Room is Not in Use
    - 2.7.3.1.2 Minimize Use of Outside Make-Up Air for Ventilation Except When Used for Economizer Cycle
    - 2.7.3.1.3 Recycle Air for Heating, Ventilation and Air Conditioning to Maximum Extent
    - 2.7.3.1.4 Reduce Ventilation Air
    - 2.7.3.1.5 Reduce Building Exhausts and Thus Make-up Air; Reduce Ventilation Air to Minimum Safe Levels
    - 2.7.3.1.6 Centralize control of exhaust fans to Ensure Their Shutdown, or Establish Program to Ensure Manual Shutdown

- 2.7.4 Building Envelope

    - 2.7.4.1 Infiltration
        - 2.7.4.1.1 Replace Broken Windows and/or Window Sash
        - 2.7.4.1.2 Keep Doors and Windows Shut to Retain Heated or Air Conditioned Air
        - 2.7.4.1.3 Keep Loading Dock Doors Closed When Not In Use
        - 2.7.4.1.4 Install Air Seals Around Truck Loading Dock Doors
        - 2.7.4.1.5 Close Holes and Openings in Building Such as Broken Windows
        - 2.7.4.1.6 Install Weather Stripping on Windows and Doors
        - 2.7.4.1.7 Eliminate Unused Roof Openings, Seal Unneeded Dampers, Louvers, and Flues
        - 2.7.4.1.8 Utilize Sensors Controlling Roof and Wall Openings

    - 2.7.4.2 Solar Loading
        - 2.7.4.2.1 Reduce Glazed Areas in Buildings
        - 2.7.4.2.2 Plant Trees or Shrubs Near Windows to Shield From Sunlight
        - 2.7.4.2.3 Reduce Heat Gain by Window Tinting
        - 2.7.4.2.4 Shade Windows From Summer Sun

    - 2.7.4.3 Other
        - 2.7.4.3.1 Insulate Walls, Ceilings, and Roofs
        - 2.7.4.3.2 Use Proper Thickness of Insulation on Building Envelope
        - 2.7.4.3.3 Use Double or Triple Glazed Windows to Maintain Higher Relative Humidity and to Reduce Heat Losses
        - 2.7.4.3.4 Install Storm Windows and Doors

- 2.8 Administrative

    - 2.8.1 General

        - 2.8.1.1 Utility Costs
            - 2.8.1.1.1 Check for Accuracy of Utility Meters
            - 2.8.1.1.2 Combine Gas Meters
            - 2.8.1.1.3 Purchase Gas Directly from a Contract Gas Supplier
            - 2.8.1.1.4 Change Rate Schedules or Make Other Changes in Electric Service
            - 2.8.1.1.5 Base Fuel Oil Charges on Usage Rather than Area Occupied
            - 2.8.1.1.6 Check for Accuracy of Power Meter

        - 2.8.1.2 Fiscal
            - 2.8.1.2.1 Apply for Tax-Free Status for Energy Purchases
            - 2.8.1.2.2 Use Utility Controlled Power Management
            - 2.8.1.2.3 Pay Utility Bills on Time

- 2.9 Alternative Energy Usage

    - 2.9.1 General

        - 2.9.1.1 Solar
            - 2.9.1.1.1 Use Solar Heat to Heat Make-up Air
            - 2.9.1.1.2 Use Solar Heat to Heat Water
            - 2.9.1.1.3 Use Solar Heat for Heat

- 2.10 Shipping, Distribution and Transportation

- 2.10.1 General
  - 2.10.1.1 Shipping
    - 2.10.1.1.1 Consolidate Freight Shipments and/or Deliveries
    - 2.10.1.1.2 Reduce Delivery Schedules
  - 2.10.1.2 Vehicles
    - 2.10.1.2.1 Consider Intermediate or Economy Size Autos and Trucks for Company Sales and Plant Fleets
    - 2.10.1.2.2 Size Trucks to Job
    - 2.10.1.2.3 Add Air Shields to Long Distance Trucks to Increase Fuel Mileage
    - 2.10.1.2.4 Shut Down Truck Engines While Loading, Unloading, or Waiting
    - 2.10.1.2.5 Schedule Regular Maintenance to Maintain Efficiency of Truck Engines
    - 2.10.1.2.6 Increase Efficiency of Trucks
    - 2.10.1.2.7. Adjust and Maintain Fork Lift Trucks for Most Efficient Operation

- 3 Waste Minimization/Pollution Prevention
  - 3.1 Operational Upgrades
    - 3.1.1 Change Procedures and/or Equipment
      - 3.1.1.1 Process Specific
        - 3.1.1.1.1 Cover Ink Containers When Not in Use
        - 3.1.1.1.2 Use Dedicated Presses for Each Color
        - 3.1.1.1.3 Use Glass Marbles to Raise Fluid Levels of Chemicals to the Brim to Reduce Contact with Atmospheric Oxygen
        - 3.1.1.1.4 Reuse High Ferrous Metal Dust as Raw Material
        - 3.1.1.1.5 Order Paint Pigments in Paste Form Instead of Dry Powder to Eliminate Hazardous Dust Waste
        - 3.1.1.1.6 Repair or Upgrade Grate Conveyors to Minimize Loss of Coal Fines
      - 3.1.1.2 Apply Material Streams Completely
        - 3.1.1.2.1 Use More Efficient Adhesive Applicators
      - 3.1.1.3 Stripping
        - 3.1.1.3.1 Use Mechanical Stripping Methods
        - 3.1.1.3.2 Use Cryogenic Stripping
      - 3.1.1.4 Scheduling Change
        - 3.1.1.4.1 Schedule Jobs to Minimize the Need for Cleanup (Light Colors Before Dark)
        - 3.1.1.4.2 Schedule Production Runs to Minimize Color Changes
      - 3.1.1.5 Desulfurization/Slag Management
        - 3.1.1.5.1 Treat Desulfurization Slag in a Deep Quench Tank Instead of Spraying Water onto an Open Pile to Reduce Air Emissions
        - 3.1.1.5.2 Use High Quality Scrap (Low Sulfur) to Reduce Hazardous Sludge Generation
        - 3.1.1.5.3 Alter Product Requirements to Eliminate Unnecessary Use of Desulfurizing Agent (Calcium Carbide)
        - 3.1.1.5.4 Use an Alternative Desulfurizing Agent to Eliminate Hazardous Slag Formation
      - 3.1.1.6 Eliminate/Reduce an Operation
        - 3.1.1.6.1 Eliminate/Reduce an Operation
      - 3.1.1.7 Change Product Specs
        - 3.1.1.7.1 Change Product Specs
        - 3.1.1.7.2 Revise Raw Material Specs
        - 3.1.1.7.3 Use a Different Raw Material
        - 3.1.1.7.4 Use a Recycled Raw Material
      - 3.1.1.8 Change Product Packaging
        - 3.1.1.8.1 Use Less Wasteful Packaging
      - 3.1.1.9 Byproduct Use
        - 3.1.1.9.1 Eliminate a Byproduct

3.1.1.9.2 Make a New Byproduct

3.1.1.10 Other
3.1.1.10.1 Change Procedures/Equipment
3.1.1.10.2 Add a New Operation
3.1.1.10.3 Change Operating Conditions
3.1.1.10.4 Reduce Scrap Production
3.1.1.10.5 Convert from Batch Operation to Continuous Processing
3.1.1.10.6 Use Automatic Flow Control
3.1.1.10.7 Use Silhouette Entry Cover to Reduce Evaporation Area
3.1.1.10.8 Closely Monitor Solutions and Make Small Additions to Maintain Solution Strength Instead of Large Infrequent Additions

3.1.2 Avoid Mixing Waste Streams

3.1.2.1 Dragout Reduction
3.1.2.1.1 Slow Insertion and Withdrawal of Parts from Vapor Degreasing Tank to Prevent Vapor Drag-out
3.1.2.1.2 Allow Drainage Before Withdrawing Object
3.1.2.1.3 Preinspect Parts to Prevent Drag-in of Solvents and Other Cleaners
3.1.2.1.4 Reduce Solution Drag-Out to Prevent Solution Loss
3.1.2.1.5 Extend Solution Life by Minimizing Drag-In
3.1.2.1.6 Prevent Solution Drag-Out from Upstream Tanks
3.1.2.1.7 Reduce Drag-In with Better Rinsing to Increase Solution Life
3.1.2.1.8 Lower the Concentration of Plating Baths
3.1.2.1.9 Use Drag-Out Reduction Methods (Gravure)-See Surface Coating

3.1.2.2 Rinsing Strategies

3.1.2.2.1 Use Reactive Rinsing
3.1.2.2.2 Reduce Water Use with Counter Current Rinsing
3.1.2.2.3 Use Fog Nozzles over Plating Tanks and Spray Rinsing Instead of Immersion Rinsing
3.1.2.2.4 Mechanically and Air Agitate Rinse Tanks for Complete Mixing
3.1.2.2.5 Use a Still Rinse as the Initial Rinsing Stage
3.1.2.2.6 Use Counter Current Washing in Photo Processors
3.1.2.2.7 Use Counter-Current Rinsing to Reduce Rinse Water Volume (Gravure)

3.1.2.3 Other
3.1.2.3.1 Avoid Contamination of Scrap Glass and Reuse as Feed Stock
3.1.2.3.2 Develop Segregated Sewer Systems for Low Suspended Solids, High Suspended Solids, Strong Wastes, and Sanitary Sewer
3.1.2.3.3 Use Separate Treatments for Each Type of Solution and Sell Sludge to a Recycler
3.1.2.3.4 Segregate Spent Solvents (by Color) and Reuse in Subsequent Washings
3.1.2.3.5 Use Squeegees to Prevent Chemical Carry-over in Manual Processing Operations

3.1.3 CAD/CAM

3.1.3.1 General
3.1.3.1.1 Optimize Dye Design

3.2 Equipment Upgrades

3.2.1 General

3.2.1.1 Fault Tolerance
3.2.1.1.1 Install Redundant Key Pumps and Other Equipment to Avoid Losses Caused by Equipment Failure and Routine Maintenance

3.2.1.2 Painting Operations
3.2.1.2.1 Convert to Electrostatic Powder Coating
3.2.1.2.2 Convert from Water Curtain Spray Booths to a Dry System

3.2.1.3 Process Specific Upgrades

3.2.1.3.1 Install Mixers on Each Cleaning Tank
3.2.1.3.2 Increase Freeboard Space and Install Chillers on Vapor Degreasers
3.2.1.3.3 Eliminate Chemical Etching and Plating by Using Alternative Printing Technologies (Presensitized Lithographic, Plastic or Photopolymer, Hot Metal, or Flexographic)
3.2.1.3.4 Use High Purity Anodes to Increase Solution Life
3.2.1.3.5 Extend Solution Life with Filtering or Carbonate Freezing
3.2.1.3.6 Use "Wash-Less" Processing Equipment
3.2.1.3.7 Use Induction Furnaces Instead of Electric Arc or Cupola Furnaces to Reduce Dust and Fumes

3.2.1.4 Tank Design
3.2.1.4.1 Use Cylindrical Tanks with Height to Diameter Ratios Close to One to Reduce Wetted Surface
3.2.1.4.2 Use Tanks with a Conical Bottom Outlet Section to Reduce Waste Associated with the Interface of Two Liquids

3.2.1.5 Automate Tasks
3.2.1.5.1 Install Web Break Detectors to Prevent Excessive Waste Paper
3.2.1.5.2 Use Automatic Cleaning Equipment
3.2.1.5.3 Convert to Robotic Painting
3.2.1.5.4 Automate Ink Key Setting System
3.2.1.5.5 Use Ink Water Ratio Sensor
3.2.1.5.6 Use Automatic Ink Levelers
3.2.1.5.7 Use Automated Plate Benders
3.2.1.5.8 Automate Ink Mixing
3.2.1.5.9 Use Electronic Imaging and Laser Plate Making
3.2.1.5.10 Use an Automatic Plate Processor
3.2.1.5.11 Increase Use of Automation

3.2.1.6 System Monitoring
3.2.1.6.1 Closely Monitor Chemical Additions to Increase Bath Life

3.3 Post Generation Treatment/Minimization

3.3.1 General

3.3.1.1 Neutralization
3.3.1.1.1 Adjust pH for Neutralization
3.3.1.1.2 Utilize Oxidation/Reduction for Neutralization
3.3.1.1.3 Use Other Methods for Neutralization

3.3.1.2 Removal of Contaminants
3.3.1.2.1 Use Screening, Magnetic Separation to Remove Contaminants
3.3.1.2.2 Use Filtration, Centrifuging to Remove Contaminants
3.3.1.2.3 Use Decanting, Flotation to Remove Contaminants
3.3.1.2.4 Use Cyclonic Separation to Remove Contaminants
3.3.1.2.5 Use Distillation, Evaporation to Remove Contaminants
3.3.1.2.6 Use Absorption, Extraction to Remove Contaminants
3.3.1.2.7 Use Adsorption, Ion Exchange to Remove Contaminants
3.3.1.2.8 Utilize Other Methods to Remove Contaminants

3.3.1.3 Material Concentration
3.3.1.3.1 Use Evaporation to Concentrate Material
3.3.1.3.2 Use Reverse Osmosis to Concentrate Material
3.3.1.3.3 Use Other Waste Concentration Methods

3.4 Water Use

3.4.1. General

3.4.1.1 Close Cycle Water Use
3.4.1.1.1 Employ a Closed Cycle Mill Process to Minimize Waste Water Production
3.4.1.1.2 Recovery Metals from Rinse Water (Evap., Ion Exchange, R.O., Electrolysis, Electrodialysis) and Reuse Rinse Water

- 3.4.1.1.3 Treat and Reuse Rinse Waters
- 3.4.1.1.4 Replace City Water with Recycled Water via Cooling Tower
- 3.4.1.1.5 Recover and Reuse Cooling Water
- 3.4.1.1.6 Meter Recycled Water (To Reduce Sewer Charges)

- 3.4.1.2 Limit Use
  - 3.4.1.2.1 Minimize Water Usage
  - 3.4.1.2.2 Carefully Control Water Level in Mass Finishing Equipment
  - 3.4.1.2.3 Use Counter Current Rinsing to Reduce Waste Water
  - 3.4.1.2.4 Eliminate Leaks in Water Lines and Valves
  - 3.4.1.2.5 Meter Waste Water
  - 3.4.1.2.6 Use Flow Control Valves on Equipment to Optimize Water Use
  - 3.4.1.2.7 Minimize Water Use in Lavatories by Choosing Appropriate Fixtures and Valves
  - 3.4.1.2.8 Replace Water Cooling on Processes with Air Cooling Where Possible
  - 3.4.1.2.9 Use Minimum Cooling Water to Bearings

- 3.4.1.3 Water Quality

  - 3.4.1.3.1 Minimize Contamination of Water Before Treatment
  - 3.4.1.3.2 Use Deionized Water in Upstream Rinse Tanks
  - 3.4.1.3.3 Clean Fouling from Water Lines Regularly

- 3.4.1.4 Chlorination
  - * 3.4.1.4.1 Replace the Chlorination Stage with an Oxygen or Ozone Stage
  - 3.4.1.4.2 Recycle Chlorination Stage Process Water
  - 3.4.1.4.3 Use Water from the Countercurrent Washing System in the Chlorination Stage
  - 3.4.1.4.4 Perform High Consistency Gas Chase Chlorination

- 3.5 Recycling

  - 3.5.1 Liquid Waste

    - 3.5.1.1 Oil
      - 3.5.1.1.1 Filter and Reuse Hydraulic Oil

    - 3.5.1.2 Ink
      - 3.5.1.2.1 Recycle Waste Ink and Cleanup Solvent

    - 3.5.1.3 White Water
      - 3.5.1.3.1 Recycle White Water
      - 3.5.1.3.2 Reuse Rich White Water in Other Applications

    - 3.5.1.4 Other
      - 3.5.1.4.1 Recover Dye from Waste Waters
      - 3.5.1.4.2 Treat and Reuse Equipment Cleaning Solutions
      - 3.5.1.4.3 Return Spent Solutions to the Manufacturer
      - 3.5.1.4.4 Recycle Spent Tanning Solution
      - 3.5.1.4.5 Recover and Reuse Spent Acid Baths
      - 3.5.1.4.6 Utilize a Central Coolant System for Cleaning and Reuse of Metal Working Fluid
      - 3.5.1.4.7 Reprocess Spent Oils on Site for Reuse

  - 3.5.2 Solid Waste

    - 3.5.2.1 General
      - 3.5.2.1.1 Reuse Scrap Glass as Feed Stock
      - 3.5.2.1.2 Regrind and Reuse Scrap Plastic Parts
      - 3.5.2.1.3 Reuse Scrap Printed Paper for Make-ready
      - 3.5.2.1.4 Avoid Contamination of Flashing and Reject Castings and Reuse as Feed Stock
      - 3.5.2.1.5 Avoid Contamination of End Pieces and Reuse as Feed Stock
      - 3.5.2.1.6 Recycle Nonferrous Dust

    - 3.5.2.2 Sand

3.5.2.2.1 Recycle Casting Sand
3.5.2.2.2 Use Sand for Other Purposes (for example, Construction Fill, Cover for Municipal Landfills)

3.5.2.3 Metals
3.5.2.3.1 Sell Used Plates to an Aluminum Recycler
3.5.2.3.2 Avoid Contamination of End Pieces and Reuse as Feed Stock
3.5.2.3.3 Recover Metals from Spent Solutions and Recycle
3.5.2.3.4 Recycle Processing Baths for Nickel Recovery
3.5.2.3.5 Recycle Film for Silver Recovery
3.5.2.3.6 Recover Metals from Casting Sand
3.5.2.3.7 Recycle Scrap Metal to Foundry
3.5.2.3.8 Segregate Metals for Sale to a Recycler
3.5.2.3.9 Separate (Flotation, Magnetic) and Recycle Scrap to Foundry
3.5.2.3.10 Separate Iron from Slag and Remelt

3.5.3 Other

3.5.3.1 Use In-process Recycling Whenever Possible
3.5.3.1.1 Recover and Reuse Waste Material
3.5.3.1.2 Salvage and Re-Use Process Waste
3.5.3.1.3 Increase Amount Of Waste Recovered For Resale

3.6 Waste Disposal

3.6.1 General

3.6.1.1 Sludge Maintenance
3.6.1.1.1 Use Alternative Flocculants to Minimize Sludge Volume
3.6.1.1.2 Use Filter or a Filter Press and Drying Oven to Reduce Sludge Volume
3.6.1.1.3 Remove Sludge from Tanks on a Regular Basis
3.6.1.1.4 Remove Sludge from Tanks on a Regular Basis
3.6.1.1.5 Use Precipitating Agents in Waste Water Treatment that Produce the Least Quantity of Waste

3.6.1.2 Other
3.6.1.2.1 Return Spent Solutions to the Manufacturer
3.6.1.2.2 Use a Less Expensive Method of Waste Removal
3.6.1.2.3 Install Equipment (for example, Compactor) to Reduce Disposal Costs

3.7 Maintenance

3.7.1 Cleaning/Degreasing

3.7.1.1 Mechanical Cleaning
3.7.1.1.1 Use an Industrial Vacuum for Spill Cleanup Instead of Absorbent
3.7.1.1.2 Use Squeegees Mops and Vacuums for Floor Cleaning
3.7.1.1.3 Use Mechanical Wipers for Cleaning of Vessels
3.7.1.1.4 Use Squeegees to Recover Clinging Product Prior to Rinsing

3.7.1.2 Minimize Amount of Cleaning
3.7.1.2.1 Eliminate the Need for Cleaning with Improved Handling Practices
3.7.1.2.2 Maximize Production Runs to Reduce Cleanings
3.7.1.2.3 Use Continuous Processing to Eliminate the Need for Inter-Run Cleaning
3.7.1.2.4 Install Dedicated Mixing Equipment to Optimize Reuse of Used Rinseate and to Preclude the Need for Inter-Run Cleaning
3.7.1.2.5 Shorten Paint Lines as Much as Possible to Reduce Line Cleaning Waste
3.7.1.2.6 Use Peel Coatings on Raw Materials to Eliminate Need for Cleaning

3.7.1.3 Minimize Rag Use
3.7.1.3.1 Use a Rag Recycle Service
3.7.1.3.2 Reuse Rags Until Completely Soiled
3.7.1.3.3 Use Rags Sized for Each Job
3.7.1.3.4 Wash and Reuse Rags On-Site

- 3.7.1.3.5 Minimize Use of Rags Through Worker Training
- 3.7.1.3.6 Use Press Cleanup Rags as Long as Possible Before Discarding

- 3.7.1.4 Miscellaneous
  - 3.7.1.4.1 Minimize Part Contamination Before Washing
  - 3.7.1.4.2 Use Liquid Spray (Water Based) Adhesive Instead of Bar Abrasives to Prevent Over Use of Material and Easier Part Cleaning
  - 3.7.1.4.3 Improve Cleaning Efficiency by Maintaining Cleaning System (Rollers Cleanup Blade)
  - 3.7.1.4.4 Use Dry Cleaning Methods Whenever Possible
  - 3.7.1.4.5 Use High Pressure Wash Systems
  - 3.7.1.4.6 Use Disposable Liners in Tanks
  - 3.7.1.4.7 Use Teflon Lined Tanks
  - 3.7.1.4.8 Clean Lines with Pigs Instead of Solvents or Aqueous Solutions
  - 3.7.1.4.9 Use Clean In Place (CIP) Systems
  - 3.7.1.4.10 Clean Equipment Immediately After Use

- 3.7.2 Spillage

  - 3.7.2.1 Operations
    - 3.7.2.1.1 Modify Material Application Methods to Prevent Material Spillage
    - 3.7.2.1.2 Improved Material Handling (Mixing and Transfer) to Avoid Spills
    - 3.7.2.1.3 Use More Efficient Spray Method for Gelcoat Application
    - 3.7.2.1.4 Reduce or Eliminate Waste
    - 3.7.2.1.5 Avoid Inserting Oversized Object to Reduce Piston Effect

  - 3.7.2.2 Hardware
    - 3.7.2.2.1 Improve Process Control to Prevent Spills of Material
    - 3.7.2.2.2 Minimize Overflows or Spills by Installing Level Controls in Process Tanks and Storage Tanks
    - 3.7.2.2.3 Install Shrouding on Machines to Prevent Splashing of Metal Working Fluids
    - 3.7.2.2.4 Use Pumps and Piping to Decrease the Frequency of Spillage During Material Transfer

- 3.7.3. Other

  - 3.7.3.1 Leak Reduction
    - 3.7.3.1.1 Maintain Machines with a Regular Maintenance Program to Prevent Oil Leaks
    - 3.7.3.1.2 Implement a Regular Maintenance Program to Reduce Emissions from Leaky Valves and Pipe Fittings

  - 3.7.3.2 Other
    - 3.7.3.2.1 Implement a Regular Maintenance Program to Keep Racks and Tanks Free of Rust, Cracks, or Corrosion.
    - 3.7.3.2.2 Apply a Protective Coating to Racks and Tanks
    - 3.7.3.2.3 Implement a Machine and Coolant Sump Cleaning Program to Minimize Coolant Contamination

- 3.8 Material Changes

  - 3.8.1 Reduce Use of Solvents

    - 3.8.1.1 Minimize Solvent Usage/Maximize Solvent Life
      - 3.8.1.1.1 Maintain Water Separator and Completely Dry Parts to Avoid Water Contamination of Solvent
      - 3.8.1.1.2 Use Deionized Water for Make-up and Rinse Water to Increase Solution Life
      - 3.8.1.1.3 Prevent Excessive Solvent Usage During Cleaning (Operator Training)
      - 3.8.1.1.4 Automate Paint Mixing-Use Compressed Air Blowout for Line Cleaning Prior to Solvent Cleaning

    - 3.8.1.2 Minimize Emissions
      - 3.8.1.2.1 Cover Solvent and Resin Containers to Minimize Evaporative Losses
      - 3.8.1.2.2 Use Tight-Fitting Lids on Material Containers and Solvent Cleaning Tanks to Reduce VOC Emissions
      - 3.8.1.2.3 Use Tight Fitting Lids on Material Containers to Reduce VOC Emission
      - 3.8.1.2.4 Install Floating Covers on Tanks of Volatile Materials to Reduce Evaporation
      - 3.8.1.2.5 Remove Rollers from the Machines and Clean in a Closed Solvent Cleaner

- 3.8.1.3 Material Replacement
  - 3.8.1.3.1 Use Water-Based Adhesives
  - 3.8.1.3.2 Use Less Toxic and Volatile Solvent Substitutes
  - 3.8.1.3.3 Convert to Aqueous Cleaning
  - 3.8.1.3.4 Use Water-Based Cutting Fluids During Machining to Eliminate Need for Solvent Cleaning
  - 3.8.1.3.5 Use Low VOC or Water Based Paint
  - 3.8.1.3.6 Use Less Toxic Solvents
  - 3.8.1.3.7 Use Soy or Water-Based Inks

- 3.8.1.4 Solvent Recovery
  - 3.8.1.4.1 Regenerate Cleaning Solvent On-Site and Reuse
  - 3.8.1.4.2 Distill Contaminated Solvents for Reuse
  - 3.8.1.4.3 Recycle Cleaning Solvent and Reuse

3.8.2 General

- 3.8.2.1 Liquid
  - 3.8.2.1.1 Use Alternatives for Acids and Alkaline (for example, Water, Steam, Abrasive)
  - 3.8.2.1.2 Use Reactive Rinsing to Extend Bath Life
  - 3.8.2.1.3 Use Water Based or Greaseless Binders to Increase Wheel Life
  - 3.8.2.1.4 Use Non-Phenolic Strippers to Reduce Toxicity Associated with Phenol and Acid Additives
  - 3.8.2.1.5 Convert to Aqueous Cleaning System
  - 3.8.2.1.6 Convert to Less Toxic Hydrocarbon Cleaners
  - 3.8.2.1.7 Replace Hexavalent Chromium Solutions with Trivalent Solutions
  - 3.8.2.1.8 Use Cyanide Free Solutions Whenever Possible
  - 3.8.2.1.9 Replace Cadmium-based Solutions with Zinc Solutions
  - 3.8.2.1.10 Use Water-Based Image Processing Chemicals
  - 3.8.2.1.11 Use Water-Based Developers and Finishers

- 3.8.2.2 Solid
  - 3.8.2.2.1 Use Silver Free Films
  - 3.8.2.2.2 Use Building Materials Which Require Less Energy to Produce
  - 3.8.2.2.3 Alter Raw Materials to Reduce Air Emissions
  - 3.8.2.2.4 Purchase High Volume Materials in Returnable Bulk Containers

4\. Direct Productivity Enhancements

4.1 TQM (Total Quality Management)

4.1.1 Lower Raw Material Costs

- 4.1.1.1 Recycling
  - 4.1.1.1.1 Market Waste Material as Clean-Up Rags
  - 4.1.1.1.2 Sell Combustible Waste or Byproducts as Fuel

- 4.1.1.2 Volume Discounting
  - 4.1.1.2.1 Consider Use of Bulk Materials Where Possible
  - 4.1.1.2.2 Purchase Adhesive in Bulk Containers

4.1.2 Administrative

- 4.1.2.1 Fiscal Management
  - 4.1.2.1.1 Purchase Equipment Instead of Leasing

4.1.3 Manufacturing

- 4.1.3.1 JIT (Just In Time Manufacturing)

- 4.1.3.2 Minimize Equipment Down Time
  - 4.1.3.2.1 Install An Uninterruptable Power Supply

- 4.1.3.3 Miscellaneous Operation Enhancements

    - 4.1.3.3.1 Use Only Amount of Packaging Material Necessary
    - 4.1.3.3.2 Optimize Production Lot Sizes and Inventories
    - 4.1.3.3.3 Maintain Clean Conditions Before Painting to Avoid Surface Contamination Resulting in Paint Defects

  - 4.1.3.4 Utilize Available Resources
    - 4.1.3.4.1. Adopt In-House Material Generation

- 4.1.4 Other

  - 4.1.4.1 Worker Training
    - 4.1.4.1.1 Train Operators for Maximum Operating Efficiency

  - 4.1.4.2 Utilize Available Space
    - 4.1.4.2.1 Expand Operations into Unused Space

Application codes

A suffix is used with the Assessment Recommendation codes listed above in this manual to designate the general area of application of the recommendation. Therefore, a similar strategy applied to a space heating boiler or a process furnace would be distinguishable. The codes are:

Number		Application	Examples
1	Manufacturing Process	Process Heat Recovery, Variable Speed Drives on Process Equipment	Active Cooling of Injection Molds
2	Process Support	Air Compressors, Steam, Nitrogen, Cogeneration	
3	Building and Grounds	Lights, HVAC	
4	Administrative	Taxes, Inventory Control, Sale of Wastes	

Source: *Energy Conservation Program Guide For Industry and Commerce*. 1974. National Bureau of Standards Handbook 115, U.S. Government Printing Office, Washington, DC.

Appendix 3.B

Perfluorocarbon Emissions and Emissions Reductions in the Aluminum Production Industry

Perfluorocarbon Emissions and Emissions Reductions in the Aluminum Production Industry

This appendix presents background information on the aluminum production industry, a brief summary of perfluorocarbon emission reduction options, and a description of related regulations and programs.

B.1 Industry Background

The production of aluminum results in emissions of several greenhouse gases, including carbon dioxide and two perfluorocarbons (PFCs), CF_4 and C_2F_6. (Carbon dioxide emissions are primarily the result of energy inputs used in the production process, typically fossil fuel-derived electricity.) Emissions of these PFCs occur during the reduction of alumina in the primary smelting process.(a) The aluminum production industry is thought to be the largest source of these two greenhouse gases.

Aluminum is produced by the electrolytic reduction of alumina (Al_2O_3) in the Hall-Heroult reduction process. Alumina is dissolved in molten cryolite (Na_3AlF_6), which acts as the electrolyte and is the reaction medium. An electric potential is applied to the cryolite/alumina solution through carbon anodes and cathodes, reducing the alumina to produce molten aluminum. During production, the amount of alumina present slowly decreases as it is reduced to aluminum. Alumina is therefore added on a continual basis to maintain an adequate concentration in the reaction vessel. PFCs can be formed during disruptions of the production process known as anode effects, which are characterized by a sharp rise in voltage across the pot. The PFCs can be produced through two mechanisms: direct reaction of fluorine with the carbon anode, and electrochemical formation. In both cases the fluorine originates from dissociation of the molten cryolite.

In the United States, aluminum is produced by 13 companies at 23 facilities. Total U.S. production was approximately 4 million metric tons in 1990. Other major producing countries include Canada and Australia. Considerable excess capacity exists worldwide, and no new facilities are planned in the U.S.

Because CF_4 and C_2F_6 are inert, and therefore pose no health or local environmental problems, there has hitherto been little study of the magnitude of emissions. The current estimate of the emissions factor for CF_4 emissions during anode effects is 0.003 lb CF_4 per minute per kAmp (1.4×10^{-3} kg/min/kAmp).(b) This emissions factor corresponds to emissions of between 0.3 and 0.9 kg CF_4 per metric ton of aluminum produced. Total U.S. emissions are therefore estimated to range from roughly 1,200 to 3,700 metric tons of CF_4. Emissions of C_2F_6 are estimated to be an order of magnitude lower, and therefore range from 120 to 370 metric tons.

(a) PFCs are not emitted during the smelting of recycled aluminum.

(b) One kAmp, a measure of electric current, is 1000 amps.

Anode effects and the associated production of PFCs do, however, have some impact on smelting efficiencies, and aluminum producers have therefore already begun to develop methods to reduce their occurrence. Anode effects, which may last from less than one to several minutes, result in several operational disadvantages, including the following:

- an incremental loss of electrolytic (process) material
- short-term disruption of the production process
- the need for manual attention to suppress anode effects in non-automated pots, or for anode effects that cannot be suppressed automatically.

In general, anode effects occur when (1) too little alumina is being added to the reaction process, (2) localized fluctuations occur in the current density, or (3) pot temperatures are too low. Anode effects occur for both planned and unplanned reasons. Planned anode effects are induced by the intentional "starving" of alumina from the process, and are used to establish a lower limit of alumina addition, thereby avoiding possible sludging from excess material; these effects are also used to eliminate carbon dust near the anode (which can cause various operational problems). Unplanned causes of anode effects include unintentional reduction of alumina addition, inter-electrode spacing fluctuations, and process temperature drops.

B.2 Emissions Reductions Actions

Practices for reducing emissions of PFCs focus on reducing the frequency and duration of anode effects. In both cases, emission reduction activities will primarily involve operational and management changes. For example, the frequency of anode effects can be reduced by incremental improvements in (1) managing alumina additions and other process parameters, (2) algorithms controlling automated processes, (3) training of personnel, and (4) quality control of anode manufacture to reduce subsequent carbon dust formation. The average duration of anode effects can be reduced by improving the suppression response of potroom(c) personnel.

B.3 Related Regulations and Programs

There are no emissions regulations for CF_4 or C_2F_6 in the United States. However, over the past couple of years, U.S. aluminum producers have begun to take steps to reduce emissions from this source. Aluminum companies are working with the U.S. EPA in a voluntary program to reduce emissions. Because of the relatively limited knowledge concerning the relationship of emissions and operating parameters, one of the first steps being taken is an industry measurement plan. This measurement plan will improve estimates of

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(c) The potroom is the room containing the electrolytic cells used to produce primary aluminum from alumina.

total emissions, will develop better emissions factors for specific operating conditions, and will standardize measurement protocols.

In the future, the voluntary program will provide a flexible mechanism for developing, implementing, and reporting emission reduction efforts. The guidelines for the voluntary reporting of activities under the 1605(b) program are consistent with the continuing development of this program.

B.4 References

U.S. Environmental Protection Agency (EPA). 1993. *Proceedings—Workshop on Atmospheric Effects, Origins, and Options for Control of Two Potent Greenhouse Gases:* CF_4 *and* C_2F_6. Global Change Division, Office of Air and Radiation, Washington, DC.

Appendix 3.C

Methane Emissions and Emissions Reductions in the Natural Gas Industry

Methane Emissions and Emissions Reductions in the Natural Gas Industry

This appendix presents background information on the natural gas industry, an overview of its emissions, information on promising emissions reduction options, and a description of related regulations and programs.

C.1. Industry Background

Methane is the principal component of natural gas; therefore, leaks from the wide variety of components, processes, and activities that make up the natural gas system contribute to methane emissions. In 1990 the U.S. natural gas system accounted for about 10 to 15 percent of U.S. methane emissions, or about 2.2 to 4.3 Tg per year, with a central estimate of about 3.0 Tg (d) per year (USEPA 1993a). In the absence of efforts to reduce emissions, methane emissions from the natural gas industry are expected to increase by about 10 to 25 percent over the next 20 years as the size of the industry and the amount of gas handled increases (USEPA 1993a).

Based on an array of available technologies, it is technically feasible to reduce methane emissions from the natural gas system by about 33 percent (USEPA 1993b). Some of these technologies are estimated to be profitable: the value of the gas emissions avoided exceeds the costs of implementing the technology. Using these profitable technologies, methane emissions from natural gas systems can be reduced profitably by about 25 percent (USEPA 1993b). This estimate of the potential for profitable methane reductions reflects the continued development of new technologies in the natural gas industry.

The main barriers to realizing these emission reductions are informational and regulatory. Information regarding the profitability of the options for reducing emissions must be disseminated. In some cases the technologies are relatively new, and their operating characteristics and costs are not widely known. Rate regulations also pose a barrier because in some cases companies are able to recover the cost of lost gas from customers, so that the incentive for avoiding emissions is substantially reduced.

C.1.1 Industry Structure

The U.S. natural gas system is composed of a complex interconnected set of facilities that can be divided into the following main segments:

- **Production**. Gas is withdrawn from underground formations using on- and off-shore wells, frequently in conjunction with oil. Gathering lines are generally used to bring the crude oil and raw gas streams to one or more collection points within a production field where the gas is separated and dried, often using glycol dehydrators.

(d) Tg = Teragram = 1 million metric tons.

- **Gas processing**. Natural gas is usually processed in gas plants to remove water, oil, hydrogen sulfide, and heavier hydrocarbons (that is, condensate) from the gas. The processed gas is injected into the natural gas transmission system.

- **Transmission pipelines**. Transmission facilities transport gas from production fields, processing plants, storage facilities, and other sources of supply over long distances to distribution centers or large-volume customers. In addition to the large-diameter high-pressure pipelines, these facilities include metering stations, maintenance facilities, and compressor stations.

- **Storage and injection/withdrawal facilities**. During periods of low (high) gas demand, natural gas is injected into (withdrawn from) underground storage reservoirs. The storage and injection/withdrawal facilities include a variety of processes and equipment, including compressors, wells, separators, and dehydrators.

- **Distribution Systems**. Distribution systems are extensive networks of generally small-diameter, low-pressure pipelines. Gas enters distribution networks from transmission systems at "gate stations," where the pressure is reduced for distribution within cities or towns. Pressure regulating and metering facilities are located throughout the distribution system.

While firms in the natural gas industry vary significantly in size and breadth of services, a relatively small number of large firms dominate. Within the distribution segment, which has over 300 private and public owned entities, 20 firms serve about half of all natural gas customers and account for about half of all distribution main mileage (Watts 1989; AGA 1991). Similarly, while there are over 100 transmission companies, 20 companies account for nearly two-thirds of the total transmission and gathering system pipeline mileage (Watts 1989; AGA 1991).

Although the production and processing sectors include a number of large firms, including the major oil companies, these sectors are less concentrated than the other sectors of the industry. More than 250,000 gas wells and over 275,000 oil wells market gas, and over 700 gas processing facilities. Although there are a few large processing plants, the processing segment is not dominated by a small number of large facilities.

The breadth of services offered by companies in the gas industry also varies. *Integrated* gas companies obtain gas operating revenues from both retail gas distribution and gas transmission.(e) *Distribution* and *transmission* companies obtain their gas operating revenues almost exclusively from distribution or transmission activities, respectively.(f) Finally, there are *combination* companies that supply both gas and another

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(e) Examples of integrated companies: Southern California Gas; Lone Star Gas; Michigan Consolidated Gas; and Arkla, Inc.

(f) Examples of distribution companies: Northern Illinois Gas; Brooklyn Union Gas; and Atlanta Gas Light. Examples of transmission companies: Northern Natural Gas; El Paso Natural Gas; and Columbia Gas Transmission.

utility, such as electricity or water.(g)

C.1.2 Methane Emissions

In 1990 about 3 Tg of methane was emitted from the diverse set of facilities that comprise the natural gas system (USEPA 1993a). The emissions can be divided into the following three main types:

- **Normal operations** including compressor engine exhaust emissions, emissions from pneumatic devices,(h) and fugitive emissions (that is, small chronic leaks from components designed to store or convey gas and liquids)

- **Routine maintenance** including equipment blowdown and venting, well workovers, and scraper (pigging) operations

- **System upsets** including emissions due to sudden, unplanned pressure changes or mishaps.

Fugitive emissions across all segments of the system are estimated to be the largest individual source of emissions, accounting for about 38 percent of the estimated total. Pneumatic devices are the second largest individual source, accounting for approximately 20 percent of the total estimated emissions. Methane emitted in engine exhaust (principally reciprocating engines used to drive pipeline compressors) is the third largest source of emissions. Together, fugitive emissions, pneumatic devices and engine exhaust account for nearly 75 percent of total estimated methane emissions from the U.S. natural gas system (USEPA 1993a). Table C.1 summarizes the emissions by industry sector and emissions type.

As shown in Table C.1, considerable uncertainty remains regarding current estimates of emissions. While a great deal of progress has been made in quantifying emissions, more work is warranted in some areas. A joint research program sponsored by the Environmental Protection Agency and the Gas Research Institute (GRI) is collecting data to improve the emissions estimates.

(g) Examples of combination companies: Pacific Gas and Electric; Public Service Electric and Gas Company; Consolidated Edison Company of New York, Inc.

(h) Pneumatic devices, used primarily in the production and transmission segments, use compressed gas as a source of energy. The compressed natural gas in the pipeline is often used, and hence, the devices release small amounts of gas as part of their normal function.

Table C.1. Methane Emissions From the U.S. Natural Gas System (Tg/yr)

Emissions Type	**Field Production**	**Processing**	**Injection/ Withdrawal**	**Transmission**	**Distribution**	**Engine Exhaust**	**Total**
Normal Operations							
Pneumatic devices	**0.43**[c]	**0.00**	**<0.001**	**0.20**	NE	—	**0.63**
range	(0.17 - 1.3)	(0.00 - 0.00)		(0.08 - 0.6)			
Dehydrator Vents	**0.11**	**0.04**	NE	**0.03**	NE	—	**0.18**
range	(0.04 - 0.33)	(0.02 - 0.12)		(0.01 - 0.09)			
Fugitive emissions	**0.39**	**0.01**	**<0.001**	**0.43**	**0.29**	—	**1.12**
range	(0.15 - 1.17)	(0.00 - 0.03)		(0.17 - 1.29)	(0.12 - 0.87)		
Engines Exhaust:	—[d]	—	—	—	—	**0.41**	**0.41**
range						(0.27 - 0.64)	
Engine Other[a]	**0.02**	**0.03**	**0.01**	**0.07**	NE	—	**0.13**
range	(0.01 - 0.06)	(0.01 - 0.09)	(0.00 - 0.03)	(0.03 - 0.21)			
Other[b]	**0.02**	**<0.01**	**<0.001**	**0.05**	NE	—	**0.07**
range	(0.01 - 0.06)			(0.02 - 0.15)			
Routine Maintenance	**0.07**	**<0.01**	**0.01**	**0.22**	**<0.01**	—	**0.32**
range	(0.03 - 0.21)		(0.00 - 0.03)	(0.09 - 0.66)			
Systems Upsets	**0.04**	**<0.001**	**<0.01**	**0.03**	**0.04**	—	**0.11**
range	(0.02 - 0.12)			(0.01 - 0.09)	(0.02 - 0.12)		
Total 1990 Methane Emissions	**1.08**	**0.09**	**0.02**	**1.03**	**0.33**	**0.41**	**2.97**
range	(0.43 - 3.24)	(0.04 - 0.27)	(0.01 - 0.06)	(0.41 - 3.09)	(0.13 - 0.99)	(0.27 - 0.64)	(1.70 - 5.95)

(a) Includes emissions from compressor station blowdowns, compressors starts/stops and compressor scrubber operations.
(b) Includes inlet flare activity, emissions due to orifice changes and scrubber operations at metering stations and pipelines.
(c) Includes emissions from heaters, separators, gas dehydrators and gathering pipelines.
(d) Emissions from engine exhaust are estimated separately.
NE-Not estimated, emissions are believed to be negligible.

Source: USEPA (1993b).

C.2 Technologies for Reducing Emissions

C.2.1 Currently Available Technologies

Through the more widespread use of a variety of technologies and practices, which are currently available and have been shown to be cost-effective in a number of settings, methane emissions from the U.S. natural gas system can be reduced profitably by about 0.8 Tg and 0.9 Tg in 2000 and 2010, respectively (USEPA 1993b). These emission reductions are equivalent to about 18 million metric tons of carbon dioxide.(i) Furthermore, reducing emissions saves gas that would otherwise be wasted, thus producing annual energy savings equivalent to 0.83 Tg(j) of natural gas.

The emissions reduction options identified and evaluated by USEPA (1993b) include the following:

- Production and processing:
  - *Pneumatic devices* are used throughout gas production on heaters, separators, gas dehydrators, and gathering pipelines. Their operation results in intentional releases of methane. Options to reduce emissions from these devices include replacing high-bleed pneumatics at the end of their useful life with low- or no-bleed designs where technically appropriate. This is a very cost-effective option for production facilities, and could reduce methane emissions by about 0.24 Tg/yr in 2000.
  - *Gas dehydrators* remove moisture from the gas stream. Glycol is generally used to absorb the moisture. When the glycol is regenerated, water vapor, methane, and volatile organic compounds (VOCs) are emitted. The principal option for reducing these methane emissions is to install a flash tank separator and use the recovered methane for fuel in the glycol regeneration boiler. This option is generally cost effective and could reduce emissions by about 0.12 Tg/yr in 2000. This option may be required in states, such as Louisiana and California, that are developing programs to reduce toxic air emissions from gas dehydrators.
  - *Fugitive emissions* are unintentional and are usually continuous releases associated with leaks caused by a failure that breaches the integrity of the system, such as a damaged seal or corroded pipeline.

(i) This estimate of equivalent carbon dioxide emissions assumes a global warming potential (GWP) of 22 for methane which is consistent with IPCC (1992). However, significant uncertainty remains in methane's GWP, and if a different value is chosen, the estimate of the carbon dioxide-equivalent emissions would need to be modified accordingly.

(j) 1 Tg of methane is approximately 52 billion cubic feet of gas (one cubic foot of gas has about 19.2 grams of methane at 1 atmosphere and 60°F).

The primary option for reducing fugitive emissions is the implementation of directed inspection and maintenance (I/M) programs. While this option could reduce methane emissions by about 0.19 Tg/yr in 2000, the cost of the program exceeds the value of the gas saved, and is consequently not considered profitable.

- Gas transmission:

  - *Fugitive emissions* in the transmission stage are associated with leaks from pipeline corrosion and inadequately sealed valves, fittings, and assemblies. These components are concentrated at compressor stations, which alone account for about 75 percent of the fugitive emissions from this stage. The primary option for reducing these fugitive emissions is the implementation of directed inspection and maintenance (I/M) programs at compressor stations. This option is cost effective, and could reduce methane emissions by about 0.24 Tg/yr in 2000.

  - *Pneumatic devices* are also used throughout the transmission stage. Replacing high-bleed pneumatics at the end of their useful life with low- or no-bleed designs where technically appropriate throughout this stage is very cost-effective. By replacing the high-bleed devices, methane emissions can be reduced by about 0.12 Tg/yr in 2000.

  - *Reciprocating engines* are used throughout the industry to drive compressors that transport gas, but are most highly concentrated in the transmission stage. In 1990, reciprocating engines in the transmission stage were estimated to emit about 0.18 Tg/yr. The major option for reducing emissions from reciprocating engines involves the greater use of turbine engines for compression in transmission pipelines, as new transmission lines are constructed and as old reciprocating units are replaced. This option could reduce emissions by about 0.07 Tg/yr in 2000 and 0.13 Tg/yr in 2010. However, many operational factors must be considered when choosing between turbines and reciprocating engines, and this choice must be made site by site.

  - *Venting during routine maintenance* of pipelines occurs when the natural gas must be removed from a section of pipe for safety reasons during repairs. Options for reducing these emissions include using portable evacuation compressors (PECs) to pump the gas from the section of pipe to be repaired to an adjoining section. The utilization of PECs could reduce emissions by about 0.02 Tg/yr in 2000. While this technology has been used cost effectively in Canada, differences in pipeline design and operations between the two countries cause this technology not to be cost effective in the United States with current gas prices.

- Gas distribution:

  - *Fugitive emissions from gate stations* are an important source of methane from distribution systems. These emissions may be reduced through implementation of directed inspection and maintenance programs. This option is cost effective and could reduce methane emissions by about 0.10 Tg/yr in 2000.

- *Fugitive emissions from subsurface piping* are an important source of methane emissions in the distribution system. These emissions are reduced when pipeline segments are rehabilitated, either through complete replacement of the leaking pipe or joint, or through insertion of repair materials into the old pipe. According to Watts (1990), for every two miles of main or service pipeline added in the late 1980s, about one mile of existing line was replaced, usually with plastic. The costs for these repairs generally far exceed the value of saved gas and are justified principally on the basis of reducing potential safety hazards to the public.

C.2.2 Emerging Technologies for Reducing Emissions

A number of new or improved technologies and practices for reducing methane emissions are being developed. These emerging technologies address emissions from each stage of the U.S. gas system. In many cases, these technologies are already being field tested, or are in limited use, and it is expected that they will be used more extensively in the near future. The technologies identified in USEPA (1993b) as most likely to have an impact on efforts to reduce emissions include the following:

- Installing catalytic converters on reciprocating engines
- Using "smart" regulators in distribution systems
- Using metallic coated seals
- Using sealant and cleaner injections in valves
- Using composite wraps for pipeline repair.

C.3 Relationship to Existing Regulations and Programs

C.3.1 EPA's Natural Gas STAR Program

The Natural Gas STAR Program is a voluntary agency-industry initiative to reduce methane emissions. Its objectives are to promote the implementation of cost-effective technologies and practices that reduce methane emissions; and encourage the development and implementation of new technologies and practices that can further reduce emissions or lower the cost of reducing emissions. Those companies that agree to participate sign a Memorandum Of Understanding (MOU) outlining the responsibilities of each party. Under the MOU, the company agrees to implement and report on cost-effective Best Management Practices (BMPs) and technologies.

In addition to the BMPs, other practices that reduce emissions undertaken by the company may also be conducted under the Natural Gas STAR Program. The company would provide verification that the emission reduction was achieved. Based on this additional information provided by companies participating in the program, new BMPs may be added to the program, and information describing new opportunities for reducing emissions will be disseminated.

An initial implementation plan must be prepared by each company, describing how it proposes to reduce emissions. Annual reports are required subsequently to document progress toward reducing emissions. The annual reports, a fundamental part of the program, describe the actions taken by the companies, the costs incurred, and the emissions reductions achieved. The reporting system is being developed so that it does not duplicate existing reporting under Department of Transportation (DOT) safety programs (see below).

To facilitate reporting, standard methods have been developed for estimating emissions reductions associated with the BMPs. In addition, provisions are included for updating and improving the emissions reductions estimates as new information becomes available. Each company makes its own estimates of emissions reductions achieved, which are reviewed by EPA. The EPAct Section 1605(b) reporting guidelines described here are designed so that the annual reports prepared under the Natural Gas STAR Program can be used as the basis for estimating and reporting emissions reductions.

For its part, EPA agrees to remove any unjustified regulatory barriers to implementing the BMPs, and to reduce the costs and risks, if any, of high efficiency/low emissions devices and technologies. EPA is also developing training courses which describe the technical and economic characteristics of the BMPs. Both EPA and the Natural Gas STAR Partners (that is, the companies) agree to publicize the program's participation and membership to increase the awareness of the capability of the program.

To date, transmission companies representing about 25 percent of the U.S. transmission system have joined the program. In the distribution segment, companies have joined that serve about 25 percent of the natural gas customers in the United States.

C.3.2 Other Existing Regulations and Programs

Several key programs and initiatives affect methane emissions from the U.S. natural gas system and efforts to reduce emissions. The Office of Pipeline Safety (OPS) of the Department of Transportation (DOT) implements a program of minimum Federal safety standards for the transportation of natural gas by pipeline. The programs in California that go beyond the Federal safety requirements to reduce fugitive emissions of reactive organic gases (ROGs) from oil and gas production sites also reduce methane emissions. Methane emissions will also be reduced by the initiatives underway to reduce toxic emissions from glycol dehydrators used to dry natural gas.

C.3.2.1 Federal Safety Standards and Reporting Requirements

To prevent the incidence of death, personal injury, or property damage that may arise from the release of gas from pipelines or gas facilities, the OPS implements a program of safety requirements that regulates the quality of materials used in the gas system, the design and installation of components; leak prevention and maintenance measures; and operating procedures.(k) As a companion to these safety requirements, OPS has promulgated annual and incident reporting requirements under 49 CFR Part 191.

The annual reports required by OPS contain substantial information about the facilities that comprise natural gas transmission and distribution systems. As with EPA's Natural Gas STAR Program, the reporting guidelines do not duplicate the information that is already reported to OPS.

C.3.2.2 California Directed I/M Programs

Directed inspection and maintenance (I/M) programs have been mandated at oil and gas production and processing facilities, chemical plants, and pipeline transfer stations in several air quality management districts in California. By implementing the programs, these facilities have reduced ROG emissions by about 40 to 70 percent. Methane emissions are also reduced.

Several directed I/M programs have been implemented. The programs typically require a facility to inspect all accessible components once every three months and all inaccessible components once every year. The inspection frequency of pumps, compressors, and pressure relief valves varies among programs from once every 8 hours to daily or weekly inspections. To inspect components for leaks, a hydrocarbon analyzer such as an Organic Vapor Analyzer (OVA) is used to measure the concentration of hydrocarbons close to the component. A reading greater than a specified threshold value, usually 10,000 ppm, indicates that the component is leaking.

Leaking components must be repaired or replaced within a specified time period (typically 1 day to 3 weeks) which varies among districts and by component type and rate of emissions. After a component is repaired, it is reinspected to verify that the component is no longer leaking. Reinspection typically is required within of 1 week to 3 months. In addition, directed I/M programs typically require facilities to physically identify all components and tag leaking components. Records of components, inspections, leaks, and repairs must also be maintained (ARB 1991).

To further reduce fugitive ROG emissions, the California Air Resources Board (ARB) has developed a more stringent I/M program proposal. If the ARB I/M recommendations were adopted by all districts in the state,

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(k) The OPS regulations specify the minimum requirements for the materials and design of pipeline, pipeline components, transmission lines and mains, customer meters, service regulators and service lines. General construction requirements for welding include the use of qualified personnel and the testing of weld with destructive and non-destructive tests. Preventive and maintenance measures include corrosion control and regular leak surveys and strength tests. Operating procedures include damage prevention plans, emergency plans and the investigation of failures. See 49 CFR Part 192.

the more stringent I/M program could reduce fugitive ROG emissions from oil and gas production facilities by an additional 25 percent from current emissions levels (ARB 1991).

The reporting required under the I/M programs designed to date appears to include the information needed to satisfy the reporting requirements of the Natural Gas STAR Program as well as the voluntary reporting guidelines.

C.3.2.3 Glycol Dehydrator Emissions Controls

Glycol dehydrator vents are an important source of methane emissions from the production stage of the natural gas system. Several new permitting requirements and state programs are being initiated to control air toxic emissions from glycol dehydration vents, which include emissions of benzene, toluene, ethyl benzene, and xylene isomers, collectively referred to as BTEX.

Several states have initiated local programs to control BTEX emissions, including Oklahoma and Louisiana (Pees and Cook 1992; Starrett 1992). The Clean Air Act (CAA) Amendments of 1990 will significantly impact many glycol dehydration units in the next few years. Under Title III of the Amendments, a glycol dehydration unit, or a group of glycol dehydration units located within a contiguous area and under common control, which emits 10 tons per year of any one of 189 listed hazardous air pollutants (HAPs) or 25 tons per year of any combination of HAPs is considered a major source of air contamination. Such a source will be subject to regulation under the CAA which will include implementation of maximum achievable control technology to control emissions of HAPs. All new and existing major sources will be required to obtain a permit to operate. An operating permit will be valid for a limited period and will include specific limits and conditions that assure compliance with all applicable requirements and standards (Falzone 1992).

These requirements are expected to lead to the collection and combustion of emissions from many of the largest glycol dehydrators. As a consequence, the methane emitted will also be burned. The BTEX requirements will likely be implemented through permit programs. The information developed to comply with the BTEX requirements is expected to be adequate for the reporting guidelines under EPAct Section 1605(b).

C.4 References

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Appendix 3.D

Methane Emissions and Emissions Reductions in Landfills

Methane Emissions and Emissions Reductions in Landfills

This appendix presents background information on the landfill industry, an overview of its emissions, information on promising emissions reduction options, and a description of related regulations and programs.

D.1 Industry Background

Landfills are the largest anthropogenic source of methane emissions in the United States. In 1990 landfills emitted an estimated 8.1 to 11.8 Tg(l) to the atmosphere. In the absence of efforts to reduce emissions, landfill methane emissions are expected to grow to between 9.5 and 13.4 Tg per year by 2010 (USEPA 1993a).

It is technically feasible to recover up to 85 percent of the methane produced by landfills by drilling wells into the landfills and withdrawing the landfill gas. The estimate of 85 percent is higher than the average landfill gas collection efficiency estimated for existing recovery projects (75 percent) but is achievable with current technology. The extent of reduction that is technically feasible varies among landfills and depends on site-specific design and waste factors.

The potential profitability of the recovery of the gas is very sensitive to the price at which landfills can sell electricity produced from the gas. At an electricity price of \$0.05 per kWh, it is potentially profitable to recover only about 50 to 60 percent of landfill methane emissions. At a price of \$0.04 per kWh it is potentially profitable to recover only about 10 to 15 percent of emissions, and at a price of \$0.06 it is potentially profitable to recover about 65 to 75 percent of emissions (USEPA 1993b).

The main barriers to recovering landfill gas are economic, informational, and institutional barriers. These include low electricity prices, perception of high risk, and siting and permitting concerns.

D.1.1 Industry Structure

Sanitary landfills have been used widely since the early 1970s, and today landfills receive over 70 percent of the solid waste generated in the United States (USEPA 1990). Although an estimated 6,000 landfills emit methane in the United States, about 1,300 account for nearly all the methane emitted. The amount of methane generated per quantity of refuse disposed depends primarily on the amount of refuse in place in the landfill, refuse characteristics, and moisture. Consequently, of these 1,300 landfills, about 900 landfills account for 85 percent of the waste in landfills and 75 percent of the methane emitted. The 19 largest landfills account for about 25 percent of the waste in landfills and 20 percent of the total methane generated.

D.1.2 Methane Emissions

(l) Tg = Teragram = 1 million metric tons

Because about 70 percent of the waste placed in landfills is organic material, the potential for methane production is great. As shown in Table D.1, U.S. landfill methane emissions in 1990 are estimated to range from about 8.1 to 11.8 Tg/yr, or about 37 percent of total U.S. methane emissions.

Despite the efforts underway to divert waste from landfills, changes in waste disposal practices will not significantly reduce U.S. methane emissions over the next 20 years. Based on the analyses in USEPA (1993a), although the rate of waste disposal in landfills is expected to remain fairly constant over the next 20 years, the amount of waste in landfills that can produce methane is expected to increase from about 4,700 million megagrams (10^6 Mg) in 1990 to 5,300 million Mg by 2000 and 5,700 million Mg in 2010. Consequently, even after considering changes in waste disposal practices, methane emissions from landfills may increase from current levels over the next 20 years. Emissions in the years 2000 and 2010 are estimated to be about 9 to 13 Tg/yr (USEPA 1993a).

D.2 Technologies Available for Reducing Emissions

D.2.1 Currently Available Technologies

There are two general approaches for reducing methane emissions from landfills. One approach involves modifying waste management practices to reduce the amount of waste landfilled. By diverting waste away from landfill disposal and toward other waste disposal methods such as recycling, less waste will be in landfills to produce methane in the future. Another approach is to recover the methane and to use it as an energy source or to flare it. Utilizing or flaring the methane is the only method currently available for reducing emissions from existing landfills and from landfills that will contain degradable waste in the future.

It is technically feasible to recover up to 85 percent of the methane produced by landfills by drilling wells into the landfills and withdrawing the landfill gas. Most gas collection systems have the following design. After the landfill is capped, vertical wells consisting of perforated pipe casing are drilled into the landfill. These wells are back filled with permeable material such as gravel around the casing and are sealed at the surface with an impermeable material to prevent the inflow of air. The wells are connected by horizontal piping to a central point where a motor/blower provides a vacuum to remove the gas from the landfill. Once collected, the gas can be used to generate electricity or to sell as a medium-BTU fuel to fire industrial boilers, chillers, or similar equipment. In cases where it may not be economical to use the gas, the best alternative is to flare it.

Table D.1 - National Methane Emission Estimates for 1990(a)

Landfill Size Distribution by Waste in Place						National Emissions (Tg/Yr)	
Size Class	Range Low (Mg)	Range High (Mg)	Number Landfills	Waste in Place (10^6 Mg)	Percent of Total Waste	Low	High
1 (Closed)	0	500,000	3,000	negligible	<0.5%		
2	0	500,000	4,744	494	10.5%	1.01	1.66
3	500,000	1,000,000	425	312	6.6%	0.63	1.05
4	1,000,000	5,000,000	712	1,581	33.6%	3.59	6.15
5	5,000,000	10,000,000	106	709	15.1%	1.35	1.85
6	10,000,000	20,000,000	27	411	8.8%	0.69	0.98
7	20,000,000	200,000,000	19	1,194	25.4%	1.78	2.73
Total(b)			6,034	4,700	Methane Generation	9.80	13.60
					Minus Recovery	1.50	1.50
					Plus Industrial	0.69	0.95
					Minus Oxidation	0.90	1.31
					Net Emissions for 1990	8.09	11.75

(a) Emission estimates from USEPA (1993a); landfill size distribution information based on USEPA (1987).

(b) Totals do not include size class 1.

Source: USEPA (1993b).

Electric power generation is the most common gas utilization method for landfill gas recovery projects. According to the *Methane Recovery From Landfill Yearbook, 1990-91*, compiled by Government Advisory Associates (GAA), Inc., over two-thirds of the gas-to-energy projects generate or plan to generate electricity. The most common options for producing electricity are the use of internal combustion engines and turbines.

Sale of gas as a medium-BTU fuel(m) is possible if the landfill is located close to suitable industrial facilities to which the gas can be transported via pipeline. An ideal medium-BTU gas customer would be located near the landfill and would have a nearly continuous demand for gaseous fuel. Landfill gas customers may use the gas to fuel a cogeneration system, to fire boilers or chillers, or to provide space heating.

Flaring is the simplest way to eliminate landfill gas. The advantage of flaring is that the capital cost is small compared to energy recovery systems. The disadvantage is that flaring produces no income for the landfill.

In 1990, approximately 100 landfill gas recovery projects recovered approximately 1.5 Tg of methane, or about 10 to 15 percent of the methane generated by landfills. At that time, about 50 additional projects were in the planning stages. In 1991, of the just over 100 landfill gas recovery and utilization projects, 71 generated electricity and 25 sold the gas as a medium-BTU fuel. Three landfills both produced electricity and sold the gas as a medium-BTU fuel. Of the 74 landfills that produced electricity, most have an electrical generating capacity between 0.5 and 4 megawatts (GAA 1991).

D.2.2 Emerging Technologies for Reducing Emissions

A number of new or improved technologies for utilizing landfill gas are being developed. In many cases, these technologies are already being field tested or are in limited use, and they are expected to be used more extensively in the near future. The technologies identified in USEPA (1993b) include production of liquid fuels and industrial chemicals from landfill gas and fuel cells.

Fuel cells in particular may be an attractive option for utilizing landfill gas because they have very low NO_x emissions, which is important in many areas where landfills are located.

D.3 Related Regulations and Programs

D.3.1 Landfill Rule

The USEPA has recently proposed a rule that would indirectly control methane emissions by regulating air pollution emissions from landfills. This proposed rule is the Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste (MSW) (USEPA 1991). The purpose of the rule is to limit air pollution from new and modified MSW landfills by requiring them to

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(m) The energy content of a medium-BTU fuel is about 400-600 BTU/ft^3. The energy content of a high-BTU fuel, such as natural gas, is about 1,000 BTU/ft^3.

install gas collection systems and combust the captured landfill gas (with or without energy utilization) if their air pollution emissions exceed a specified cutoff level.

The proposed rule requires any facility with maximum design capacity of 100,000 Mg (111,000 tons) or more to calculate periodically its annual non-methane organic compound (NMOC) emission rate. Each facility where the calculated emission rate is found to exceed the proposed cutoff will be required to install a "well designed gas collection system and one of several effective control devices to either recover or destroy the collected landfill emissions." The control device will have to be capable of reducing NMOCs in the collected gas by 98 percent by weight, thereby meeting EPA's Best Demonstrated Technology (BDT) standards. When finalized, this rulemaking should have a significant impact on landfill gas emissions.

The steps undertaken to comply with this rule will reduce methane emissions. The emissions reductions may be reported as described above. If the landfill flares the gas to comply with the rule, it would need to measure the amount of methane flared in order to have the information needed to report the emissions reductions.

D.3.2 Landfill Outreach Program

Under the Climate Change Action Plan,(n) the U.S. EPA is developing the Landfill Outreach Program to promote the use of cost-competitive techniques for reducing methane emissions from landfills. In addition to addressing landfills affected by the proposed rule limiting air pollution from MSW landfills, the Program is focusing on landfills that will not likely be affected by the rule. As a result of the Program, additional landfills are expected to recover and utilize landfill gas. Activities taken in response to this program may be reported under Section 1605(b).

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Appendix 3.E

Methane Emissions and Emissions Reductions in Coal Mining

Methane Emissions and Emissions Reductions in Coal Mining

This appendix presents background information on the coal mining industry, an overview of its emissions, information on promising emissions reduction options, and a description of related regulations and programs.

E.1 Industry Background

Methane (CH_4) and coal are formed together during coalification, a process in which biomass is converted by biological and geological forces into coal. Methane is stored within coal seams and also within the rock strata surrounding the seams. Deep coal seams have a substantially higher methane content than shallow coal seams, in part because geological pressure intensifies with depth and prevents increasingly larger amounts of methane from escaping. Methane is released when pressure within a coalbed is reduced, through natural erosion, faulting, or mining. Per ton of coal extracted, underground mines release substantially more methane than surface mines.

In 1990, U.S coal mines accounted for about 17 percent of U.S. methane emissions, or about 3.6 to 5.7 Tg(o) per year (USEPA 1993a). In the absence of efforts to reduce emissions, methane emissions from coal mining are expected to increase to 5.0 to 8.7 Tg over the next 20 years primarily due to the projected increased in total U.S. coal production (USEPA 1993a).

Based on an array of available technologies, it is technically feasible to reduce methane emissions from coal mining by about 40 percent (USEPA 1993b). Some of these technologies are estimated to be profitable: the value of the methane recovered exceeds the costs of implementing the technology. Using the profitable technologies, methane emissions from natural coal mining can be reduced by about 30 percent (USEPA 1993b).

The main barriers to realizing these emission reductions are legal and informational. Unresolved legal issues concerning the ownership of coalbed methane resources have constituted one of the most significant barriers to coalbed methane recovery. Ambiguity in certain state legal systems provides a disincentive for investment in coalbed methane projects because of the uncertainties as to which parties may demand compensation for development of resources. This barrier may be partially alleviated as a result of provisions in the Energy Policy Act of 1992, mandating that states must adopt provisions to address coalbed methane ownership issues. In addition to ownership concerns, certain conditions and characteristics of the coal mining industry, including market uncertainty, preferences for investments in coal mine productivity and the relative newness of the concept of utilizing methane from coal mines, may deter methane recovery. Dissemination of information regarding the profitability of the options for reducing emissions would assist in alleviating this barrier.

E.1.1 Industry Structure

(o) Tg = Teragram = 1 million metric tons.

In 1991, of the just over 3,000 operating coal mines in the United States, about 1,500 were underground mines and 1,500 were surface mines. Of these mines, only 210 produced more than one million tons of coal per year. These large mines accounted for about 65 percent of all coal mined in the United States (DOE/EIA 1992).

Based on 1988 data, analysts estimate that in 1990, there were roughly equal numbers of surface and underground mines, and surface mines accounted for 60 percent of total coal produced in the United States. While underground mines accounted for 40 percent of production, they accounted for over 70 percent of methane emissions. Moreover, 200 large and gassy underground mines accounted for over 95 percent of all methane emissions from underground mines (DOE/EIA 1993).

While coal companies vary significantly in size, a relatively small number of large firms own a majority of the large mines, and, thus, account for a large portion of U.S. coal production. In 1991, the top 12 firms (each of which produced more than 20 million tons per year) accounted for over 40 percent of all U.S. production (DOE/EIA 1993).

E.1.2 Methane Emissions

In 1990, an estimated 3.6 to 5.7 Tg of methane was emitted as a result of coal mining activities in the U.S. (Table E.1). The emissions can be divided into three main types: (1) emissions from underground mines, (2) emissions from surface mines, and (3) post-mining emissions.

Underground mining

Underground mines accounted for more than 70 percent of total methane emissions from coal mining in 1988. They will also contribute significantly to emissions in the future. About 55 to 80 percent of the methane liberated by underground coal mines in the U.S. in 1988 was emitted to the atmosphere from ventilation air shafts. Because this methane is contained in air at very low concentrations (less than 1 percent), there are few uses for it. Ventilation air streams will continue to represent a significant portion of methane emissions from underground coal mines in the future.

In 1988, an estimated 0.7 to 1.8 Tg of methane was recovered by degasification systems at U.S. coal mines. These systems, which are used as a supplement to ventilation systems at gassy mines, are in use at about 30 U.S. coal mines. Degasification systems, which recover methane before, during, or after mining, recover methane in concentrations ranging from 30 to over 95 percent. In 1988, six U.S. mines sold the methane produced by degasification systems to local pipeline companies, and as a result about 0.25 Tg of this methane was not emitted into the atmosphere. Currently, 11 mines are recovering methane for pipeline sales.

Table E.1. Annual Methane Emissions from Coal Mining

Key Source	Estimated Range of Emissions (Tg)
Underground Coal Mines:	
Ventilation Systems	2.1
Degasification Systems[(a)]	0.5 - 1.6
Surface Coal Mines	0.2 - 0.7
Post-Mining	0.5 - 0.8
TOTAL (1988)	3.3 - 5.2
TOTAL (1990)[(b)]	3.6 - 5.7

(a) Does not include an additional 0.25 Tg recovered from coal mines in Alabama and Utah that is currently sold to pipelines instead of being vented to the atmosphere.
(b) The 1990 emissions estimate was extrapolated from the 1988 estimate; 1988 is the latest year for which complete data is available.

Source: USEPA 1993a

Annual emissions from degasification systems at underground mines could increase significantly in the future, possibly reaching 0.6 to 2.1 Tg in 2000 and 0.9 to 2.9 Tg in 2010. If key barriers to methane recovery are removed, much of this gas could potentially be recovered profitably instead of being emitted to the atmosphere.

Surface mining

Methane emissions per ton of coal mined are low for surface mined coals. Given the large coal production at U.S. surface mines, however, this emissions source is significant. In 1988, surface mining emissions were an estimated 0.2 to 0.7 Tg.

Post-mining

Some methane remains in the coal after it has been mined and can be emitted during transportation, storage, and handling of the coal. Post-mining emissions in the United States are estimated to be approximately 25 to 40 percent of the in-situ methane content of the coal, or about 0.5 to 0.8 Tg in 1988.

As shown in Table E.1, considerable uncertainty remains regarding current estimates of emissions. While a great deal of progress has been made in quantifying emissions, more work is warranted in some areas.

E.2 Technologies Available for Reducing Emissions

E.2.1 Currently Available Technologies

Through the more widespread use of a variety of technologies and practices, which are currently available and which have been shown to be cost effective in a number of settings, annual methane emissions from U.S. coal mines can be reduced profitably by about 1.0 to 2.2 Tg in 2000 and 1.7 to 3.1 Tg in 2010 (USEPA 1993b). These emission reductions are equivalent to about 20 to 40 million metric tons of carbon dioxide.(p) Furthermore, reducing emissions saves gas that would otherwise be wasted, thus producing annual energy savings equivalent to 1 to 2.2 Tg of natural gas.(q)

Coal mine methane emissions may be mitigated by the implementation of methane recovery projects. Several well-established methods may be used to recover methane. These methods have been developed primarily in order to supplement mine ventilation systems, which ensure that methane concentrations in underground mines remain within safe tolerances (methane is explosive at concentrations of 5 to 15 percent in air). While these degasification systems are currently used for safety reasons, they can also recover methane that may be utilized as an energy source. The purity of the gas that is recovered partially depends on the recovery method and has important implications for the utilization method that can be employed.

To understand how to report emissions reductions achieved by recovering coal mine methane, some background on the recovery techniques themselves is required. In brief, the following are the major approaches for recovering and utilizing coal mine methane.

- **Advance (pre-mining) degasification**. With this method, vertical wells are drilled into the coal seams several years in advance of mining. Depending on the length of time that the wells are in place, the majority of the methane that would otherwise be emitted to the atmosphere when the coal was extracted can be recovered before mining begins. For example, from 50 to over 70 percent of the methane that would otherwise be emitted during mining is likely to be recovered when vertical degasification wells are drilled more than 10 years in advance of mining. One important advantage of this recovery method is that a nearly pure methane can be recovered, because pre-mining drainage ensures that the recovered methane will not be contaminated with ventilation air from mine working areas. Another advantage is that pre-mining drainage greatly improves safety conditions for miners, because the risks of explosion from unsafe methane levels are greatly reduced. A disadvantage of this method is that it may be difficult for some mines to plan where they will mine many years in advance of the actual mining.

(p) This estimate of equivalent carbon dioxide emissions assumes a global warming potential (GWP) of 22 for methane which is consistent with IPCC (1992). However, significant uncertainty remains in methane's GWP, and if a different value is chosen, the estimate of the carbon dioxide-equivalent emissions would need to be modified accordingly.

(q) 1 Tg of methane is approximately 52 billion cubic feet of gas (one cubic foot of gas has about 19.2 grams of methane at 1 atmosphere and 60°F).

- **Gob wells**. The fractured zone caused by the collapse of the strata surrounding the mined coal seam in an underground mine is known as a "gob" area; this area is a significant source of methane. Gob wells are drilled from the surface to a point just above the coal seam. As mining advances under the well, the methane-charged coal and strata around the well fractures. The methane emitted from this fractured area flows into the gob well and up to the surface. Initially, gob wells produce nearly pure methane. Over time, however, ventilation air from mine working areas may flow into the gob area and dilute the methane. It is possible to recover from 30 to over 50 percent of the methane that would otherwise be emitted is possible with this approach.

- **In-mine horizontal boreholes**. In-mine boreholes are drilled inside the mine (as opposed to from the surface), and they operate to drain methane from unmined areas of the coal seam shortly before mining. The recovery efficiency of this technique is low—approximately 10 to 20 percent of methane that would otherwise be emitted. However, the methane produced is typically over 95 percent pure.

Options for utilizing recovered methane include the following:

- **Injecting methane into a pipeline**. This option currently requires that a nearly pure methane be recovered. Gathering lines must be built from the mine to a commercial pipeline.

- **Utilizing methane as a fuel in a turbine or engine**. Under this option, recovered methane is fed into an on-site generator. The electricity generated may be used to meet the potentially significant electricity requirements of the mine. Electricity generated in excess of the mine's on-site needs may be sold to a utility. As opposed to pipeline injection, methane that has been mixed with mine ventilation air may be used for power generation. Power generation is a technically viable option for methane concentrations as low as 30 percent.

- **Co-firing methane in a boiler**. Here, methane is utilized in conjunction with another fuel source in a nearby boiler, such as one used on-site for coal drying.

- **Selling low Btu gas to industrial users**. This option involves selling recovered methane that has been mixed with mine air (gob gas) to a nearby industrial user.

For many mines, development of recovery projects can be a profitable undertaking, due to the energy value of the recovered gas. Currently, 11 U.S. mines have developed projects in which they are selling recovered methane to pipeline companies. A large portion of these cost-effective emissions reductions could be achieved at the large and gassy underground mines located in the Appalachian basins. The extent to which these emissions reductions can be achieved is dependent, in part, on the removal of several existing informational, legal, institutional, and regulatory barriers.

E.2.2 Emerging Technologies

In addition to the methods described above, a number of new or improved technologies and practices for reducing methane emissions are being developed.

One technology currently under development is to enrich gob gas to pipeline quality by using technologies that separate methane molecules from carbon dioxide, oxygen, and/or nitrogen. Several technologies for separating methane are under development and may prove to be economically attractive and technically feasible with additional research.

In addition to the highly concentrated methane produced by degasification systems, the methane emitted in low concentrations in ventilation air also could be utilized. Ventilation air may be used as the combustion air in an on-site turbine or mine-mouth coal fired boiler. However, at the current time, utilization of ventilation air has not been technically demonstrated.

Finally, in cases where it is not possible to utilize methane as an energy source, the gas could be flared, which involves burning the methane so that primarily carbon dioxide, rather than methane, is emitted. Currently, flaring is not considered to be a feasible option for coal mines because of safety considerations, although research on this topic is being conducted. (The Energy Policy Act of 1992 includes a provision for further study of this approach.)

E.3 Related Regulations and Programs

E.3.1 EPA's Coalbed Methane Outreach Program

Under the Climate Change Action Plan,(r) the U.S. EPA is developing the Coalbed Methane Outreach Program to promote the use of cost-effective techniques for reducing methane emissions from coal mining. The program is focusing on large gassy coal mines that are likely candidates for profitable methane recovery and utilization. As a result of the program, additional coal mines are expected to recover and utilize coalbed methane. Activities taken in response to this program may be reported under Section 1605(b).

E.3.2 Other Existing Regulations and Programs

State and federal regulations concerning the release of coal mine methane have been developed solely as a result of safety, rather than environmental, concerns. The principal regulatory body responsible for ensuring the safety of mining operations is the U.S. Mining Safety and Health Administration (MSHA). All underground coal mines in the United States are required to have an MSHA approved mine ventilation plan that can reliably maintain methane concentrations of less than 1 percent in air. To the extent that a mine plans to use mine degasification to control some of its methane liberations, these approaches must be incorporated into the mine ventilation plans approved by MSHA. MSHA is also responsible for measuring

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(r) The Climate Change Action Plan, put forward by the Federal Government in October 1993, aims to address the challenge of global warming with cost-effective emission reduction initiatives. The goal of the Plan is to return U.S. greenhouse gas emissions to 1990 levels by the year 2000.

methane levels in ventilation air streams in underground coal mines. MSHA records of methane concentrations could be used to validate reported emissions reductions. Thus, it would not be necessary to set up a separate methane measurement program as part of the 1605(b) reporting requirements.

Once the methane is recovered, few regulations or programs govern its use. In fact, as mentioned previously, in some key states (such as West Virginia and Pennsylvania) uncertain coalbed methane ownership currently poses a major barrier to the development of methane utilization projects.

E.4 References

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Appendix 3.F

Nitrous Oxide Emissions and Emissions Reductions in the Adipic Acid Production Industry

Nitrous Oxide Emissions and Emissions Reductions in the Adipic Acid Production Industry

This appendix presents background information on the adipic acid production industry, a brief summary of promising emissions reduction options, and a description of related regulations and programs.

F.1 Industry Background

A recent investigation by Thiemens and Trogler suggested that the production of adipic acid may be a small but significant source of anthropogenic nitrous oxide (N_2O) emissions into the atmosphere (Thiemens and Trogler 1991). Adipic acid, principally used in the manufacture of nylon (nylon-6,6), is formed by the oxidation of nitric acid with ketone-alcohol (cyclohexanol). During the adipic acid production process, N_2O is produced as a waste gas. Adipic acid is also used in the production of plasticizers, low temperature lubricants, polyurethanes, and food products (Radian 1992).

In the United States, adipic acid is produced by three companies in four locations: Allied Chemicals in Hopewell, Virginia; DuPont in Orange and Victoria, Texas; and Monsanto in Pensacola, Florida. These four plants have a 1990 combined production capacity of about 800 million kilograms (1.77 billion pounds). U.S adipic acid demand in 1989 and 1990 was estimated at 714 to 744 million kg (1.57 to 1.64 billion pounds) per year. The bulk price of adipic acid in 1990 was estimated at about $1.32 per kg ($0.60 per pound). About 90 percent of the current U.S. adipic acid demand is used for nylon production.

Air emissions of N_2O in the United States are not regulated, and very little emissions data have been made public. However, based on the available overall reaction stoichiometry for adipic acid production, it is estimated that about one mole of nitrous oxide is generated per mole of acid produced, or approximately 0.3 kg of nitrous oxide for every kilogram of adipic acid produced.

Nitrous oxide emissions from adipic acid production can be reduced by collecting or destroying the gas. Efforts are underway by U.S. manufacturers to develop and implement the most cost effective techniques for reducing the emissions. The Monsanto and DuPont Victoria, Texas plants currently thermally decompose the N_2O created in the production process, with a reported control efficiency of 98 percent.

Although thermal decomposition of N_2O is effective, its energy requirements are substantial. In addition, it produces NO_x emissions, which are also undesirable. Other promising alternatives being investigated by adipic acid manufacturers include conversion of N_2O to NO for recovery/reuse in the nitric acid production process; and catalytic decomposition of N_2O to N_2, O_2, and a small amount of residual NO_x.

The conversion of N_2O to NO for recovery/reuse offers substantial energy savings over the thermal decomposition process. However, to take advantage of the NO that is produced, the adipic acid production facility must be co-located with a nitric acid production facility. The capital cost for this option is estimated to be about $20 million for a plant similar in capacity to DuPont's Victoria, Texas, plant, which is the largest such plant in the United States.

Catalytic decomposition of N_2O has lower capital costs and does not need to be located near a nitric acid production facility. However, NO_x emissions would need to be controlled, which would add to the cost. A catalyst-based system, for use in conjunction with NO_x controls, is estimated to have a $5 to $10 million capital cost for a plant similar to DuPont's Victoria, Texas, plant. The NO_x controls would add an estimated $10 million in capital costs. This NO_x control cost may be less if the controls were designed as an integrated part of a new facility.

The production of nitric acid, an input to the adipic acid production process, also produces N_2O emissions. However, less information is currently available on these emissions, and additional research is warranted. At this time, the guidance for reporting emissions reductions from adipic acid production is believed to be applicable for emissions reductions from nitric acid production as well.

Finally, it has been reported that an alternative production process for nylon used by at least one manufacturer in the U.S. also produces a small amount of N_2O emissions. While it appears possible to reduce these emissions as well, additional research is needed to address this source.

F.2 Related Regulations and Programs

There are no N_2O emissions regulations in the U.S. However, over the past several years, U.S. adipic acid producers have committed to voluntarily controlling emissions. The voluntary reporting guidelines allow reporting of emissions reductions with information that is expected to be generated as part of currently planned efforts.

For example, DuPont has set a company goal of eliminating N_2O emissions from its adipic acid production facilities by 1996. It is investigating recovery/reuse at its Victoria, Texas, plant, and catalytic decomposition options for the Orange, Texas plant. DuPont is also holding discussions with other key manufacturers of adipic acid world-wide on technologies that can achieve emissions reduction goals, and has offered to share its technologies. European companies that have participated in the technology discussions include ICI, BASF, and Rhône-Poulenc. The *European Chemical News* reported that a commitment to cut emissions within five years has been agreed upon by the discussion participants (ECN 1991).

In addition to DuPont's efforts, Monsanto is currently thermally decomposing N_2O at its Pensacola, Florida plant. A recent report for the U.S. EPA estimated U.S. 1990 N_2O emissions from all four U.S. adipic acid manufacturing plants to be about 62 million kilograms (Radian 1992). The effects of the existing DuPont and Monsanto control programs are therefore substantial in that uncontrolled emissions are estimated at over 200 million kilograms based on the stoichiometric balance of the production process.

F.3 References

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