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Best Available Control Technology (BACT) Guidance

Air Pollution Control Requirements for Construction, Substantial Reconstruction or Alteration of Facilities that Emit Air Contaminants

June 2011

This guidance document is intended for general reference only and does not represent a full and complete statement of the technical or legal requirements associated with applicable regulations.

Introduction

This document includes:

- Background on the definition and regulatory context of best available (air pollution) control technology (BACT).
- An overview of the process for determining BACT and information to aid you in complying with it.
- Descriptions of and links to a compilation of Top-Case BACT Guidelines that you may propose in lieu of performing a Top-Down BACT analysis.
- Information on how you may be able to cap volatile organic compounds (VOC) or hazardous air
 pollutants (HAP) emissions from the facility and avoid having to evaluate add-on air pollution control
 equipment. Note: You will still need to employ pollution prevention, best management practices or
 other methods to minimize emissions such as low-VOC coatings and cleanup solutions, or high
 transfer efficiency coating techniques.

Background

As a condition of issuing a written Plan Approval to you for your Non-Major or Major Comprehensive Plan Application (CPA) under <u>310 CMR 7.02</u>(5) or Limited Plan Application (LPA) under <u>310 CMR 7.02</u>(4), the Department of Environmental Protection (MassDEP) must determine BACT for your proposal¹. To achieve this, your plan application must include:

- Top-Down or case-by-case analysis of BACT; or
- Top-Case BACT (BACT as defined by MassDEP in previous relevant decisions or guidelines); or
- A proposed cap on emissions less than 18 tons Volatile Organic Compounds (VOC)/ Halogenated Organic Compounds (HOC) and total Hazardous Air Pollutants (HAPs) and 10 tons of a single HAP – with the use of pollution prevention, best management practices and/or a limit on hours of operation or raw material use.

For equipment/operations that are eligible to comply with performance standards as an alternative to Plan Approval (<u>310 CMR 7.03</u> or <u>310 CMR 7.26</u>), MassDEP has already made BACT determinations and adopted them as performance standards.

BACT Definition & Regulatory Context

The Massachusetts Air Pollution Control Regulations (310 CMR 7.00 et seq.) define BACT as:

An emission limitation based on the maximum degree of reduction of any regulated air contaminant² emitted from or which results from any regulated facility which the Department (MassDEP), on a case-by-case basis taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems and techniques for control of each such contaminant. The best available control technology determination shall not allow emissions in excess of any emissions standard established under the New Source Performance Standards, National Emissions Standards for Hazardous Air Pollutants or under any other applicable section of 310 CMR 7.00, and may include a design feature, equipment specification, work practice, operating standard or combination thereof.

¹ See the MassDEP Plan Approval Overview & Applicability Tables document for a description of how BACT fits into the plan approval process. ² The term are proved by the set of the set

² The term air contaminant and pollutant are used throughout this document. Air contaminant is the term used in MassDEP regulations and is more inclusive than the term "pollutant" which is used by EPA in its regulations. Noise and other air contaminants that may result in a condition of air pollution (e.g. nuisance) are not regulated under the federal Clean Air Act, but are included in the Massachusetts NSR Program.

BACT was first incorporated into the Massachusetts regulations in 1982. As specified in the definition, it is determined on a case-by-case basis and must be at least as stringent as any applicable emission limitation contained in either MassDEP Air Pollution Control Regulations (<u>310 CMR 7.00</u>) or U.S. Environmental Protection Agency (EPA) New Source Performance Standards (<u>40 CFR 60</u>) or National Emissions Standards for Hazardous Air Pollutants (<u>40 CFR 61 or 63</u>).

In 1984, EPA approved the Massachusetts State Implementation Plan (SIP) to include BACT as a key component of the state's Minor New Source Review (NSR) Program.³ As EPA explains:

Minor NSR is for pollutants from stationary sources that do not require Prevention of Significant Deterioration (PSD) or nonattainment NSR permits. The purpose of minor NSR permits is to prevent the construction of sources that would interfere with attainment or maintenance of a National Ambient Air Quality Standard (NAAQS) or violate the control strategy [to restore or make "reasonable further progress" towards attainment] in nonattainment areas. Also, minor NSR permits often contain permit conditions to limit the sources emissions to avoid PSD or nonattainment NSR.

States are able to customize the requirements of the minor NSR program as long as their program meets minimum requirements. The permit agency's minor NSR program is part of the State Implementation Plan (SIP).

In reviewing and approving a plan application, MassDEP needs to ensure that your facility and its air contaminant emissions will not cause violation(s) of <u>National Ambient Air Quality Standards (NAAQS)</u> for carbon monoxide (CO), lead (Pb), nitrogen dioxide (NO₂), particulate matter (PM10), fine particles (PM2.5) or sulfur dioxide (SO₂), or hinder the state's progress in attaining the <u>NAAQS</u> for ozone.

Presumptive BACT by Regulation

For some categories of commonly installed equipment, MassDEP has established performance standards at <u>310 CMR 7.03</u> (Permits-by-Rule) and <u>310 CMR 7.26</u> (Environmental Results Program or ERP) that a facility may comply with in lieu of obtaining a 310 CMR 7.02 Plan Approval. These performance standards provide a presumptive determination of BACT and MassDEP may revise them from time to time by amending its regulations.

Regardless of these alternative pathways to compliance, you are required to apply for a Plan Approval if your facility's emissions would make it subject to PSD or NA NSR, your facility holds or requires an Air Quality Operating Permit, or it falls within a category for which no exemption is available.

As discussed in more detail below under Top-Case BACT, MassDEP has compiled emission limits that you may propose in lieu of performing a Top-Down analysis. In general, these are limits that we have approved previously and represent BACT.

Note: You should contact the appropriate <u>MassDEP Regional Office</u> early in the process of preparing a plan application. A pre-application conference can save you time, spare you frustration, and often result in faster processing of your application by the agency. If you submit your application without scheduling such a meeting, MassDEP may require one, anyway, before it can determine whether your application is administratively complete.

³ In addition to the Massachusetts Minor NSR program, EPA has NSR regulations for larger sources. These regulations are divided into two programs: (1) Prevention of Significant Deterioration (PSD) for criteria pollutants (pollutants or their precursors for which EPA has adopted <u>National Ambient Air Quality Standards (NAAQS</u>) for an area classified as attainment or unclassified and other pollutants regulated under the federal Clean Air Act. MassDEP implements the federal PSD program under <u>40 CFR Part 52</u>, <u>Section 52.21</u>, pursuant to a delegation agreement with EPA. (2) Nonattainment NSR (NA NSR) for criteria pollutants and their precursors for an area that is nonattainment. MassDEP adopted its own regulations to implement the NA NSR program (see <u>310 CMR 7.00</u> Appendix A).

Top-Down BACT

MassDEP needs to balance the many impacts of a project while reviewing its proposed emission limits. You must use a top-down procedure to determine BACT. This requires you to identify the best methodology, technique, technology or other means for delivering the cleanest air quality outcome for one or more specific contaminants, while factoring environmental, energy and economic considerations into the analysis.

In brief, the Top-Down process is a ranking of all available control technologies in descending order of control effectiveness. You must first examine the most stringent ("Top-Case") alternative. MassDEP will presume this represents BACT unless you can demonstrate – and we agree – that it is not feasible for technical, energy, environmental or economic reasons. If you eliminate the most stringent control alternative in this fashion, then you must consider the second best, and so on. This procedure is modeled after the EPA December 1987 <u>Top-Down BACT Policy</u>. It was further described in the June 1991 <u>NESCAUM BACT Guideline</u> and October 1990 draft <u>EPA New Source Review Workshop Manual</u>.

Using Top-Down BACT gives MassDEP flexibility to be responsive to new advances in air pollution control, fosters technology transfer, encourages pollution prevention and entrepreneurship, and rewards innovation by creating an "incubator" for new air quality control strategies. It would also be difficult for MassDEP to set emissions limits for all the various types of sources that have been, or will be, proposed in Massachusetts without using Top-Down BACT.

In preparing your plan application and BACT analysis, you will need to identify all demonstrated and potentially applicable control technology alternatives. You can learn more about these from the following resources:

- EPA BACT/LAER Clearinghouse & Control Technology Center
- State and Other Permitting Agency Control Technology References: <u>MassDEP BACT Web Page</u> <u>California Air Resources Board</u> <u>South Coast Air Quality Management District</u> <u>Texas Commission on Environmental Quality</u>
- <u>Control Technology Vendors</u>
- <u>Federal</u> and <u>state/local new source review permits</u> and associated inspection/performance test reports
- Environmental Consultants
- Technical Journals, Reports (e.g., <u>Air & Waste Management Association</u> and <u>McIlvaine</u> reports), Newsletters and Seminars
- EPA New Source Review (NSR) Bulletin Board

Environmental Impacts

You should give preference to a technology or technique that achieves the required reduction in air contaminant emissions with the greatest degree of pollution prevention. For example, if both using either a low VOC coating and a high VOC coating along with an end-of-pipe air pollution control device would yield the same emissions, it is still better for the environment to use the low VOC coating.

With regard to environmental impacts, the cleanest outcome is required unless it can be eliminated based on technological or economic infeasibility. You cannot "model out of BACT" by simply showing that the modeled results of an inferior-to-Top Case air quality control technique will not result in a NAAQS violation.

Your environmental impacts analysis should also consider the effect of a particular air pollution control technology or technique on other environmental media. For example, if a water-based air pollution control device would be the Top Case to deliver BACT for a given process, but the water supply serving your facility is stressed, then a "dry" control alternative – if technically feasible – might be determined to be the preferable means of delivering BACT.

Energy Impacts

You must also weigh the energy impacts of a given control technique or technology by estimating its direct energy consumption compared with that of alternatives. As a matter of course, energy impacts and costs are considered in the economic impacts assessment of Top-Down BACT.

Economic Impacts

The economic impacts portion of your Top-Down BACT analysis begins with the establishment of "baseline emissions" of a given proposal. The EPA <u>New Source Review Workshop Manual</u> defines baseline emissions as "...essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions."

For example, to calculate baseline emissions for VOC-emitting processes, typically surface coating or similar processes, take the worst-case (highest) VOC-containing coating's hourly emissions rate and multiply it by the maximum number of hours the process will operate. Federally enforceable limits on hours of operation can be used to lower projected emissions below a baseline predicated on 8,760 hours per year of operation.

The baseline emissions rate is an important variable in calculating the economic cost effectiveness of a particular control technology. MassDEP may require you to calculate cost effectiveness based on different baseline emissions rate values to determine whether or not the selection of a particular baseline emissions rate is a deciding factor in the BACT determination.

EPA's <u>New Source Review Workshop Manual</u> instructs that primary consideration should be given to quantifying the cost of control and not the financial standing of an individual facility owner/operator. This simple precept goes a long way toward ensuring a level playing field for similar types of processes. In other words, if similar processes have been built and are operating with an established level of BACT, you may not argue that you cannot afford to provide the same level of air pollution control that they do.

Economic feasibility is measured in terms of the annualized cost of a particular control technology or technique divided by the annual emissions reduction achieved by using it relative to baseline emissions. The annualized cost includes the capital cost of the control technology or technique amortized over its expected lifetime, plus annual operating and maintenance costs.

In preparing your economic impacts analysis, you must use appropriate cost assumptions. Some sources of cost data include:

- <u>Control Technology Vendors</u>
- EPA's Cost Control Manual
- Trade Literature
- Actual Costs from Case Studies
- Input from Independent Experts

Particularly when your economic analysis concludes that a particular control technology would cost too much to be economically feasible, the burden is on you to prove that your analysis and conclusion are reasonable. MassDEP will scrutinize (and may request justification) of each line item, as well as your assumptions relative to:

- Equipment and system design and sizing consistent with good ventilation and air pollution control engineering practices
- Fuel and electricity costs in line with current and forecast pricing at the particular location
- Maintenance, tax and overhead factors
- Life expectancy of equipment and media
- Interest rates
- Costs of expendable supplies and reagents

Incremental control cost differences can be used in some special cases (e.g., when comparing two control techniques or technologies with very similar levels of reduction for the same air contaminant). The Case Study below illustrates this concept and others (such "technology forcing," "pollution prevention" and "other environmental impacts") discussed in this document.

Case Study: In the recent past, boiler manufacturers have developed "ultra-low NOx burners" (ULNBs) which can achieve an oxides of nitrogen emission rate of 9 parts per million (ppm⁴). Before the advent of ULNBs, BACT for NOx for boilers with capacity above approximately 50 million British thermal units per hour was achieved by the use of Selective Catalytic Reduction (SCR) to reduce NOx emissions to 5 ppm, accompanied by a 5 ppm ammonia (NH₃) slip. When analyzing the incremental cost of using SCR to reduce the 9 ppm NOx emission rate attained by ULNB to reach a 5 ppm NOx emission limit, it became readily apparent that requiring SCR with added NH₃ emissions would be economically infeasible, on a dollar-per-ton-of-pollutant-removed basis. Therefore, NOx BACT for this category of emission units is now 9 ppm, with no NH₃ emissions.

Since 1990, MassDEP has used two ranges of annualized dollars per ton of pollutant controlled. For "attainment" pollutants, such as CO and SO₂, we have used an upper bound range of \$4,000 to \$6,000 per ton of pollutant controlled. For "nonattainment" precursor pollutants, such as NOx and VOC, the range is \$11,000 to \$13,000 per ton.

While these ranges are helpful in putting the economics of BACT into context, MassDEP's experience has shown that submitting a detailed, exhaustive Top-Down BACT analysis – which is necessary to justify less-than-Top-Case control on the basis of excessive cost – is the exception rather than the rule. Most applicants choose to employ Top-Case BACT and a typical upper bound, nonattainment pollutant BACT economic assessment seldom exceeds \$4,500 per ton of pollutant removed.

Top-Case BACT

Given MassDEP's history of determining BACT, it may not be necessary for you to "reinvent the wheel." Under <u>310 CMR 7.02</u>(8)(a)2.a., you may consider our past BACT determinations for similar emission units/processes and potentially use them to define BACT for your own proposal. See <u>http://www.mass.gov/dep/air/approvals/bact.htm</u> for additional information.

MassDEP will update our past BACT determinations to reflect advances in technology that result in lower emissions than shown and represent BACT, but we may still opt to require you perform a complete BACT analysis for your proposed project if our determinations for similar emission units/processes have not been updated recently. This underscores the importance of scheduling a pre-application conference with MassDEP as early in the process as possible.

⁴ These concentrations for boilers are all corrected to 3% oxygen.

Emissions Caps

It has been MassDEP's experience that for VOC or organic HAP emissions, add-on air pollution control equipment has not proven to be cost effective if aggregate emissions are less than 18 tons per year. You are not required to evaluate add-on controls for these processes. Instead, under <u>310 CMR 7.02</u>(8)(a)2.b., you may propose a combination of best management practices, pollution prevention, and limitations on hours of operation or materials usage.

Given your facility's circumstances, however, you may decide to propose add-on controls for this sort of activity on your own initiative, or if you become aware of a particular air pollution control technology or technique that is economically feasible for the level of emissions you are proposing. However, you must still employ pollution prevention measures, such as low-VOC and low-HAP coatings, surface preparation compounds, and high transfer efficiency application methods.

This guidance document is intended for general reference only and does not represent a full and complete statement of the technical or legal requirements associated with regulations.

DRAFT OCTOBER 1990

New Source Review Workshop Manual

Prevention of Significant Deterioration and Nonattainment Area Permitting

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PREFACE

This document was developed for use in conjunction with new source review workshops and training, and to guide permitting officials in the implementation of the new source review (NSR) program. It is not intended to be an official statement of policy and standards and does not establish binding regulatory requirements; such requirements are contained in the regulations and approved state implementation plans. Rather, the manual is designed to (1) describe in general terms and examples the requirements of the new source regulations and pre-existing policy; and (2) provide suggested methods of meeting these requirements, which are illustrated by examples. Should there be any apparent inconsistency between this manual and the regulations (including any policy decisions made pursuant to those regulations), such regulations and policy shall govern. This document can be used to assist those people who may be unfamiliar with the NSR program (and its implementation) to gain a working understanding of the program.

The focus of this manual is the prevention of significant deterioration (PSD) portion of the NSR program found in the <u>Federal Regulations</u> at 40 CFR 52.21. It does not necessarily describe the specific requirements in those areas where the PSD program is conducted under a state implementation plan (SIP) which has been developed and approved in accordance with 40 CFR 51.166. The reader is cautioned to keep this in mind when using this manual for general program guidance. In most cases, portions of an approved SIP that are different from those described in this manual will be more restrictive. Consequently, it is suggested that the reader also obtain program information from a State or local agency to determine all requirements that may apply in a area.

The examples presented in this manual are presented for illustration purposes only. They are fictitious and are designed to impart a basic understanding of the NSR regulations and requirements.

A number of terms and acronyms used in this manual have specific meanings within the context of the NSR program. Since this manual is intended for use by those persons generally familiar with NSR these terms are used throughout this document, often without definition. To aid users of the document who are unfamiliar with these terms, general definitions of these terms can be found in Appendix A. The specific regulatory definitions for most of the terms can be found in 40 CFR 52.21. Should there be any apparent inconsistency between the definitions contained in Appendix A and the regulatory definitions or requirements found in Part 40 of the Code of Federal Regulations (including any policy decisions made pursuant to those regulations), the regulations and policy decisions shall govern.

MANUAL ORGANIZATION

The manual is organized into three parts. Part I contains five chapters (Chapters A - E) covering the PSD program requirements. Chapter A describes the PSD applicability criteria and process used to determine if a proposed new or modified stationary source is required to obtain a PSD permit. Chapter B discusses the process by which best available control technology (BACT) is determined for new or modified emissions units. Chapter C discusses the PSD air quality analysis used to demonstrate that the proposed construction will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard or PSD increment. Chapter D discusses the PSD additional impacts analyses which assess the impact of air, ground, and water pollution on soils, vegetation, and visibility caused by an increase in emissions at the subject source. Chapter E identifies class I areas, describes the procedures involved in preparing and reviewing a permit application for a proposed source with potential class I area air quality impacts.

Part II of the manual (Chapters F and G) covers the nonattainment area (NAA) permit program requirements for new major sources and major modifications. Chapter F describes the NAA applicability criteria for new or modified stationary sources locating in a nonattainment area. Chapter G provides a basic overview of the NAA preconstruction review requirements.

Part III (Chapters H and I) covers the major source permit itself. Chapter H discusses the elements of an effective and enforceable permit. Chapter I discusses permit drafting.

INTRODUCTION AND OVERVIEW

Major stationary sources of air pollution and major modifications to major stationary sources are required by the Clean Air Act to a obtain an air pollution permit before commencing construction. The process is called new source review (NSR) and is required whether the major source or modification is planned for an area where the national ambient air quality standards (NAAQS) are exceeded (nonattainment areas) or an area where air quality is acceptable (attainment and unclassifiable areas). Permits for sources in attainment areas are referred to as prevention of significant air quality deterioration (PSD) permits; while permits for sources located in nonattainment areas are referred to as NAA permits. The entire program, including both PSD and NAA permit reviews, is referred to as the NSR program

The PSD and NAA requirements are pollutant specific. For example, a facility may emit many air pollutants, however, depending on the magnitude of the emissions of each pollutant, only one or a few may be subject to the PSD or NAA permit requirements. Also, a source may have to obtain both PSD and NAA permits if the source is in an area where one or more of the pollutants is designated nonattainment.

On August 7, 1977, Congress substantially amended the Clean Air Act and outlined a rather detailed PSD program. On June 19, 1978, EPA revised the PSD regulations to comply with the 1977 Amendments. The June 1978 regulations were challenged in a lengthy judicial review process. As a result of the judicial process on August 7, 1980, EPA extensively revised both the PSD and NAA regulations. Five sets of regulations resulted from those revisions. These regulations and subsequent modifications represent the current NSR regulatory requirements.

The first set of regulations, 40 CFR 51.166, specifies the minimum requirements that a PSD air quality permit program under Part C of the Act must contain in order to warrant approval by EPA as a revision to a State implementation plan (SIP). The second set, 40 CFR 52.21, delineates the federal PSD permit program, which currently applies as part of the SIP, in approximately one third of States that have not submitted a PSD program meeting the requirements of 40 CFR 51.166. In other words, roughly two thirds of the States are implementing their own PSD program which has been approved by EPA as meeting the minimal requirements for such a program, while the remaining States have been delegated the authority to implement the federal PSD program.

The basic goals of the PSD regulations are: (1) to ensure that economic growth will occur in harmony with the preservation of existing clean air resources to prevent the development of any new nonattainment problems; (2) to protect the public health and welfare from any adverse effect which might occur even at air pollution levels better than the national ambient air quality standards (NAAQS); and (3) to preserve, protect, and enhance the air quality in areas of special natural recreational, scenic, or historic value, such as national parks and wilderness areas. The primary provisions of the PSD regulations require that new major stationary sources and major modifications be carefully reviewed prior to construction to ensure compliance with the NAAQS, the applicable PSD air quality increments, and the requirement to apply the BACT on the project's emissions of air pollutants.

The third set, 40 CFR 51.165(a) and (b), specifies the elements of an approvable State permit program for preconstruction review for nonattainment purposes under Part D of the Act. A major new source or major modification which would locate in an area designated as nonattainment and subject to a NAA permit must meet stringent conditions designed to ensure that the new source's emissions will be controlled to the greatest degree possible; that more than equivalent offsetting emissions reductions ("emission offsets") will be obtained from existing sources; and that there will be progress toward achievement of the NAAQS.

The forth and fifth sets, 40 CFR Part 51, Appendix S (Offset Ruling) and 40 CFR 52.24 (construction moratorium) respectively, can apply in certain circumstances where a nonattainment area SIP has not been fully approved by EPA as meeting the requirements of Part D of the Act.

Briefly, the requirements of the PSD regulations apply to new major stationary sources and major modifications. A "major stationary source" is any source type belonging to a list of 28 source categories which emits or has the potential to emit 100 tons per year or more of any pollutant subject to regulation under the Act, or any other source type which emits or has the potential to emit such pollutants in amounts equal to or greater than 250 tons per year. A stationary source generally includes all pollutant-emitting activities which belong to the same industrial grouping, are located on contiguous or adjacent properties, and are under common control.

A "major modification" is generally a physical change or a change in the method of operation of a major stationary source which would result in a contemporaneous significant net emissions increase in the emissions of any regulated pollutant. In determining if a proposed increase would cause a significant net increase to occur, several detailed calculations must be performed.

If a source or modification thus qualifies as major, its prospective location or existing location must also qualify as a PSD area, in order for PSD review to apply. A PSD area is one formally designated by the state as "attainment" or "unclassifiable" for any pollutant for which a national ambient air quality standard exists.

No source or modification subject to PSD review may be constructed without a permit. To obtain a PSD permit an applicant must:

1. apply the best available control technology (BACT);

A BACT analysis is done on a case-by-case basis, and considers energy, environmental, and economic impacts in determining the maximum degree of reduction achievable for the proposed source or modification. In no event can the determination of BACT result in an emission limitation which would not meet any applicable standard of performance under 40 CFR Parts 60 and 61.

2. conduct an ambient air quality analysis;

Each PSD source or modification must perform an air quality analysis to demonstrate that its new pollutant emissions would not violate either the applicable NAAQS or the applicable PSD increment.

3. analyze impacts to soils, vegetation, and visibility;

An applicant is required to analyze whether its proposed emissions increases would impair visibility, or impact on soils or vegetation. Not only must the applicant look at the direct effect of source emissions on these resources, but it also must consider the impacts from general commercial, residential, industrial, and other growth associated with the proposed source or modification.

4. not adversely impact a Class I area; and

If the reviewing authority receives a PSD permit application for a source that could impact a Class I area, it notifies the Federal Land Manager and the federal official charged with direct responsibility for managing these lands. These officials are responsible for protecting the air quality-related values in Class I areas and for consulting with the reviewing authority to determine whether any proposed construction will adversely affect such values. If the Federal Land Manager demonstrates that emissions from a proposed source or modification would impair air quality-related values, even though the emissions levels would not cause a violation of the allowable air quality increment, the Federal Land Manager may recommend that the reviewing authority deny the permit.

5. undergo adequate public participation by applicant.

Specific public notice requirements and a public comment period are required before the PSD review agency takes final action on a PSD application.

CHAPTER A PSD APPLICABILITY

I. INTRODUCTION

An applicability determination, as discussed in this section, is the process of determining whether a preconstruction review should be conducted by, and a permit issued to, a proposed new source or a modification of an existing source by the reviewing authority, pursuant to prevention of significant deterioration (PSD) requirements.

There are three basic criteria in determining PSD applicability. The first and primary criterion is whether the proposed project is sufficiently large (in terms of its emissions) to be a "major" stationary source or "major" modification. Source size is defined in terms of "potential to emit," which is its capability at maximum design capacity to emit a pollutant, except as constrained by federally-enforceable conditions (which include the effect of installed air pollution control equipment and restrictions on the hours of operation, or the type or amount of material combusted, stored or processed).

A new source is major if it has the potential to emit any pollutant regulated under the Act in amounts equal to or exceeding specified major source thresholds [100 or 250 tons per year (tpy)] which are predicated on the source's industrial category. A major modification is a physical change or change in the method of operation at an existing major source that causes a significant "net emissions increase" at that source of any pollutant regulated under the Act.

The second criterion for PSD applicability is that a new major source would locate, or the modified source is located, in a PSD area. A PSD area is one formally designated, pursuant to section 107 of the ACT and 40 CFR 81, by a State as "attainment" or "unclassifiable" for any criteria pollutant, i.e., an air pollutant for which a national ambient air quality standard exists.

The third criterion is that the pollutants emitted in, or increased by, "significant" amounts by the project are subject to PSD. A source's location can be attainment or unclassified for some pollutants and simultaneously nonattainment for others. If the project would emit only pollutants for which the area has been designated nonattainment, PSD would not apply.

The purposes of a PSD applicability determination are therefore:

- (1) to determine whether a proposed new source is a "major stationary source," or if a proposed modification to an existing source is a "major modification;"
- (2) to determine if proposed conditions and restrictions, which will limit emissions from a new source or an existing source that is proposing modification to a level that avoids preconstruction review requirements, are legitimate and federally-enforceable; and

(3) to determine for a major new source or a major modification to an existing source which pollutants are subject to preconstruction review.

In order to perform a satisfactory applicability determination, numerous pieces of information must be compiled and evaluated. Certain information and analyses are common to applicability determinations for both new sources and modified sources; however, there are several major differences. Consequently, two detailed discussions follow in this section: PSD applicability determinations for major new sources and PSD applicability determinations for modifications of existing sources. The common elements will be covered in the discussion of new source applicability. They are the following:

- * defining the source;
- * determining the source's potential to emit;
- * determining which major source threshold the source is subject to; and
- * assessing the impact on applicability of the local air quality, i.e., the attainment designation, in conjunction with the pollutants emitted by the source.

II. NEW SOURCE PSD APPLICABILITY DETERMINATIONS

II. A. DEFINITION OF SOURCE

For the purposes of PSD a <u>stationary source</u> is any building, structure, facility, or installation which emits or may emit any air pollutant subject to regulation under the Clean Air Act (the Act). "Building, structure, facility, or installation" means all the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties and are under common ownership or control. An <u>emissions</u> <u>unit</u> is any part of a stationary source that emits or has the potential to emit any pollutant subject to regulation under the Act.

The term "same industrial grouping" refers to the "major groups" identified by two-digit codes in the Standard Industrial Classification (SIC) Manual, which is published by the Office of Management and Budget. The 1972 edition of the SIC Manual, as amended in 1977, is cited in the current PSD regulations as the basis for classifying sources. Sources not found in that edition or the 1977 supplement may be classified according to the most current edition.

complex under For example a chemical common ownership manufactures polyethylene, ethylene di chl ori de, vinyl chloride, and numerous other chlorinated organi c compounds. Each product is made in separate processing equipment with each piece of equi pment containing several emission units. All of the operations fall under "Chemicals and Allied Products;" SIC Major Group 28, therefore. the complex and all its associated emi ssi ons uni ts constitute one source.

In most cases, the property boundary and ownership are easily determined. A frequent question, however, particularly at large industrial complexes, is how to deal with multiple emissions units at a single location that do not fall under the same two-digit SIC code. In this situation the source is classified according to the primary activity at the site, which is determined by its principal product (or group of products) produced or distributed, or by the services it renders. Facilities that convey, store, or otherwise assist in the production of the principal product are called <u>support</u> <u>facilities</u>.

cleaning For example. a coal mining operation may include a coal plant, which is located at the mine. If the sole purpose of the cleaning plant is to process the coal produced by the mine, then it is considered to be a support facility for the mining operation. If. cleaning plant is collocated with a mine, however. the but accepts more than half of its feedstock from other mines (indicating that the activities of the collocated mine are incidental) then coal would be the primary activity the cleaning and basis for the classification.

Another common situation is the collocation of power plants with manufacturing operations. An example would be a silicon wafer and semiconductor manufacturing plant that generates its own steam and electricity with fossil fuel-fired boilers. The boilers would be considered part of the source because the power plant supports the primary activity of the facility. An emissions unit serving as a support facility for two or more primary activities (sources) is to be considered part of the primary activity that relies most heavily on its support.

For example, a steam boiler jointly owned and operated by two sources would be included with the source that consumes the most steam

As a corollary to the examples immediately above, suppose a power by the semiconductor plant. is co-owned plant and а chemi cal manufacturing plant. The power plant provides 70 percent of its total output (in Btu's per hour) as steam and electricity to the It sells only steam to the chemical plant. semiconductor plant. In the case of co-generation, the support facility should be assigned to a primary activity based on pro rata fuel consumption that is required to produce the energy bought by each of the support facility's customers, since the emission rates in pounds per Btu are different for steam and electricity. In this example then, the power plant would be considered part of the semiconductor plant.

It is important to note that if a new support facility would by itself be a major source based on its source category classification and potential to emit, it would be subject to PSD review even though the primary source, of which it is a part, is not major and therefore exempt from review. The conditions surrounding such a determination is discussed further in the section on major source thresholds (see Section II.C.).

II. B. POTENTIAL TO EMIT

II. B. 1. BASIC REQUIREMENTS

The potential to emit of a stationary source is of primary importance in establishing whether a new or modified source is major. Potential to emit is the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, provided the limitation or its effect on emissions is federally-enforceable, shall be treated as part of its design. Example limitations include:

- (1) Requirements to install and operate air pollution control equipment at prescribed efficiencies;
- (2) Restrictions on design capacity utilization [note that these types of limitations are not explicitly mentioned in the regulations, but in certain instances do meet the criteria for limiting potential to emit];
- (3) Restrictions on hours of operation; and
- (4) Restrictions on the types or amount of material processed, combusted or stored.

II. B. 2. ENFORCEABILITY OF LIMITS

For any limit or condition to be a legitimate restriction on potential to emit, that limit or condition must be federally-enforceable, which in turn requires practical enforceability (see Appendix A) [see <u>U.S. v. Louisiana-</u> <u>Pacific Corporation</u>, 682 F. Supp. 1122, Civil Action No. 86-A-1880 (D. Colorado, March 22, 1988). Practical enforceability means the source and/or enforcement authority must be able to show continual compliance (or noncompliance) with each limitation or requirement. In other words, adequate testing, monitoring, and record-keeping procedures must be included either in an applicable federally issued permit, or in the applicable federally approved SIP or the permit issued under same.

For example, a permit that limits actual source emissions on an annual basis only (e.g., the facility is limited solely to 249 tpy) cannot be considered in determining potential to emit. It contains none of the basic requirements and is therefore not capable of ensuring continual compliance, i.e., it is not enforceable as a practical matter.

The term "federally-enforceable" refers to all limitations and conditions which are enforceable by the Administrator, including:

! requirements developed pursuant to any new source performance standards (NSPS) or national emission standards for hazardous air pollutants (NESHAP),

- ! requirements within any applicable federally-approved State implementation plan, and
- ! any requirements contained in a permit issued pursuant to federal PSD regulations (40 CFR 52.21), or pursuant to PSD or operating permit provisions in a SIP which has been federally approved in accordance with 40 CFR 51 Subpart I.

Federally-enforceable permit conditions that may be used to limit potential to emit can be expressed in a variety of terms and usually include a combination of two or more of the following four requirements in conjunction with appropriate record-keeping requirements for verification of compliance:

(1) Installation and continuous operation and maintenance of air pollution controls, usually expressed as both a required abatement efficiency of the maximum uncontrolled emission rate and a maximum outlet concentration or hourly emission rate (flow rate x concentration);

A typical example might be a 255 tpy limit on a stone crushing operation. The enforceable permit condi ti ons could be a maximum emission rate of 58 lbs/hr, a maximum concentration of 0.1 grains per dry standard cubic foot (gr/dSCF) and a maximum flow rate of 67,000 dSCFM based on nameplate capacity and 8760 hours per year. the permit should also stipulate a minimum 90 percent In addition, overall reduction of particulate matter (PM) emissions on an hourly basis via capture hoods and a baghouse.

(2) Capacity limitations;

The stone crusher decides to limit its potential to emit to tpy by limiting the feed rate to 70 percent of the 180 nameplate capacity. One of the enforceable limits becomes a stone feed rate (tons/hr.) based on 70 percent of nameplate capacity with a federally-enforceable requirement for a method or device for measuring the feed rate on an hourly basis. Another approach is to limit PM emissions rate the to 41 lbs/hr. A third alternative is to retain maxi mum а concentration of 0.1 gr./dSCF, but limit the maximum exhaust rate to 47,000 dSCFM due to the decrease in feed rate. In all these cases. the 90 percent overall reduction of particulate matter (PM) emissions on an hourly basis via capture hoods and baghouse would also be maintained.

In another example, the potential to emit of a boiler with a design input capacity of 200 million Btu/hour is limited to a 100-million-Btu/hr fuel input rate by the permit, which

requires that the boiler's heat input not exceed 50 percent of its rated capacity. The permit would further require that compliance be demonstrated with a continuously recording fuel meter and concurrent monitoring and recording of fuel heating value to show that the fuel input does not exceed 100-million-Btu/hr.

(3) Restrictions on hours of operation, including seasonal operation; and

In the stone crusher example, the operator may choose to limit the hours of operation per year to keep the potential to emit below the major source threshold of 250 tpy. For example. using the same maximum concentration and flow rate and minimum overall control efficiency limitations as in (1) above. а restriction on the number of 8-hour shifts to two. i.e.. 16 hours per day would reduce the potential uncontrolled emissions by 33 percent to 170 tpy.

In another example, a citrus dryer that only operates during the growing season could have its potential to emit limited by a permit restriction on the hours of operation, and further, by prohibiting the dryer from operating between March and November.

(4) Limitations on raw materials used (including fuel combusted) and stored.

An example of this type of limit would be a maximum 1 percent sulfur content in the coal feed for a power plant. Another would be a condition that a surface coater only use waterbased or higher solids coatings with a maximum VOC content of 2.0 pounds VOC per gallon solids deposited on the substrate with requisite limits on coating usage (gallons/hr or gallons/yr on a 12-month rolling time period).

In addition to limits in major source construction permits or federally approved SIP limits for major sources, terms and conditions contained in State operating permits will be considered federally-enforceable under the following conditions:

- (1) the State's operating permit program is approved by EPA and incorporated into the applicable SIP under section 110 of the Act;
- (2) the operating permits are legally binding on the source under the SIP and the SIP specifically provides that permits that

are not legally binding may be deemed not "federallyenforceable;"

- (3) emissions limitations. all controls. and other requirements imposed by such permits are no less stringent than any counterpart limitations and requirements in the SIP, or in standards established under sections 111 and 112 of the ACT;
- (4) the limitations, controls and requirements in the operating permits are permanent, quantifiable, and otherwise enforceable as a practical matter; and
- (5) the permits are issued subject to public participation, i.e., timely notice, opportunity for public comment, etc.

(See also, 54 FR 27281, June 28, 1989.)

A minor (i.e., a non-major) source construction permit issued to a source by a State may be used to determine the potential to emit if:

! the State program under which the permit was issued has been approved by EPA as meeting the requirements of 40 C.F.R. Parts 51.160 through 51.164, and ! the provisions of the permit are federally-enforceable and enforceable as a practical matter.

Note, however, that a permit condition that temporarily restricts production to a level at which the source does not intend to operate for any extensive time is not valid if it appears to be intended to circumvent the preconstruction review requirements for major source by making the source temporarily minor. Such permit limits cannot be used in the determination of potential to emit. Another situation that should receive careful scrutiny is the construction of a manufacturing facility with a physical capacity far greater than the limits specified in a permit condition. See also 54 FR 27280, which specifically discusses "sham" minor source permits.

An example is construction of an electric power generating unit, which is proposed to be operated as a peaking unit but which by its nature can only be economical if it is used as a base-load facility.

Remember, if the permit or SIP requirements, conditions or limits on a source are not federally-enforceable (which includes enforceable as a practical matter), potential to emit is based on full capacity and year-round operation. For additional information on federally enforceability and limiting potential to emit see Appendix A.

II. B. 3. FUGITIVE EMISSIONS

As defined in the federal PSD regulations, fugitive emissions are those "...which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening." To the extent they are quantifiable, fugitive emissions are included in the potential to emit (and increases in same due to modification), if they occur at one of the following stationary sources:

- ! Any belonging to one of the 28 named PSD source categories listed in Table A-1, which were explicitly identified in Section 169 of the Act as being subject to a 100-tpy emissions threshold for classification of major sources;
- ! Any belonging to a stationary source category that as of August 7, 1980, is regulated (effective date of proposal) by New Source Performance Standards (NSPS) pursuant to Section 111 of the Act (listed in Table A-2); and
- ! Any belonging to a stationary source category that as of August 7, 1980, is regulated (effective date of promulgation) by National Emissions Standards for Hazardous Air Pollutants (NESHAP) pursuant to Section 112 of the Act (listed in Table A-2).

Note also that, if a source has been determined to be major, fugitive emissions, to the extent they are quantifiable, are considered in any subsequent analyses (e.g., air quality impact).

Fugitive emissions may vary widely from source to source. Examples of common sources of fugitive emission include:

- ! coal piles particulate matter (PM);
- ! road dust PM;
- ! quarries PM; and
- ! leaking valves and flanges at refineries and organic chemical processing equipment volatile organic compounds (VOC).
TABLE A-1.PSD SOURCE CATEGORIES WITH

100 tpy MAJOR SOURCE THRESHOLDS

- 1. Fossil fuel-fired steam electric plants of more than 250 million Btu/hr heat input
- 2. Coal cleaning plants (with thermal dryers)
- 3. Kraft pulp mills
- 4. Portland cement plants
- 5. Primary zinc smelters
- 6. Iron and steel mill plants
- 7. Primary aluminum ore reduction plants
- 8. Primary copper smelters
- 9. Municipal incinerators capable of charging more than 250 tons of refuse per day
- 10. Hydrofluoric acid plants
- 11. Sulfuric acid plants
- 12. Nitric acid plants
- 13. Petroleum refineries
- 14. Lime plants
- 15. Phosphate rock processing plants
- 16. Coke oven batteries
- 17. Sulfur recovery plants
- 18. Carbon black plants (furnace plants)
- 19. Primary lead smelters
- 20. Fuel conversion plants
- 21. Sintering plants
- 22. Secondary metal production plants
- 23. Chemical process plants
- 24. Fossil fuel boilers (or combinations thereof) totaling more than 250 million Btu/hr heat input
- 25. Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels
- 26. Taconite ore processing plants
- 27. Glass fiber processing plants
- 28. Charcoal production plants

TABLE A-2. NEW SOURCE PERFORMANCE STANDARDS PROPOSED AND
NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS
PROMULGATED PRIOR TO August 7, 1980

<u>New Source Performance Standards 40 CFR 60</u>

Source	Subpart	Affected Facility	Proposed Date
Phosphate rock plants	NN	Grinding, drying and calcining facilities	09/21/79
Ammonium sulfate manufacture	Рр	Ammonium sulfate dryer	02/04/80

National Emission Standards for Hazardous Air Pollutants 40 CFR 61

Pollutant	Subpart	Affected Facility	Promul gated Date
Beryllium	С	Extraction plants, ceramic plants, foundries, incinerators, propellant plants, machining operations	04/06/73
Beryllium, rocket motor firing	D	Rocket motor firing	04/06/73
Mercury	Е	0re processing, 04/06/ chloralkali manufacturing, sludge incinerators	
Vinyl chloride	F	Ethylene dichloride 10/21/7 manufacture via 02 HC1, vinyl chloride manufacture, polyvinyl chloride manufacture	
Asbestos	М	Asbestos mills; roadway surfacing (asbestos tailings); demolition; spraying, fabri cation, waste disposal and insulting	04/06/73
		Manufacture of shotgun shells, renovation, fabrication, asphalt concrete, products containing asbestos	06/19/78

TABLE A-2.NEW SOURCE PERFORMANCE STANDARDS PROPOSED AND
NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR
POLLUTANTS PROMULGATED PRIOR TO August 7, 1980

<u>New Source Performanc</u>	e Standards 40	<u>CFR 60</u>	
))))))))))))))))))) Source Sub)))))))))))))))) part	Affected Facility))))))))))))) Proposed Date
))))))))))))))))))))))))))))))))))))))))))))))))))))) D))))))))))))))))))))))))))))))))))))))))))))))) 08/17/71
Elect. utility steam generating units for which construction is commenced after 09/18/78	Da	Utility boilers (solid, liquid, and gaseous fuels)	09/19/78
Municipal incinerator (≥50 tons/day)	sE	Incinerators	08/17/71
Portland cement plant	sF	Kiln, clinker cooler	08/17/71
Nitric acid plants	G	Process equipment	08/17/71
Sulfuric acid plants	Н	Process equipment	08/17/71
Asphalt concrete plants	I	Process equipment	06/11/73
Petroleum refineries	J	Fuel gas combustion devices Claus sulfur recovery	06/11/73
Storage vessels for petroleum liquids construction after 06/11/73 and prior to 05/19/78	K	Gasoline, crude oil, and distillate storage tanks ≥40,000 gallons capacity	06/11/73
Storage vessels for petroleum liquids construction after 05/18/78	Ка	Gasoline, crude oil, and distillate storage tanks ≥40,000 gallons capacity, vapor pressure ≥1.5	05/18/78
Secondary lead smelters and refineries	L	Blast and reverberatory furnaces, pot furnaces	06/11/73

TABLE A-2.NEW SOURCE PERFORMANCE STANDARDS PROPOSED AND
NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR
POLLUTANTS PROMULGATED PRIOR TO August 7, 1980

<u>New Source Performance Standards 40 CFR 60</u>			
)))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))) Proposed
	-	-	Date
)))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))))
Secondary brass	Μ	Reverberatory and electric	06/11/73
and bronze ingot		furnaces and blast furnaces	
production plants			
Iron and steel mills	5 N	Basic oxygen process furnaces (BOPF)	06/11/73
		Primary emission sources	
Sewage treatment plants	0	Sludge incinerators	06/11/73
Primary copper	Р	Roaster, smelting furnace,	10/16/74
smelters		converter dryers	
Primary zinc smelters	Q	Roaster sintering machine	10/16/74
Primary lead	R	Sintering machine, electric	10/16/74
smelters		smelting furnace, converter	
		Blast or reverberatory furnace	2,
		sintering machine discharge en	nd
Primary aluminum reduction plants	S	Pot lines and anode bake plants	10/23/74
Primary aluminum		Pot lines and anode bake	04/11/79
reduction plants 111(d)		plants	
Phosphate fertilizer	r T	Wet process phosphoric	10/22/74
i ndustry	U	Superphosphoric acid	
	V	Di ammoni um phosphate	
	W	Triple superphosphate products	
	X	Granular triple superphosphate products	9
Coal preparation plants	Y	Air tables and thermal dryers	10/24/74
Ferroalloy production facilitie	Zes	Specific furnaces	10/21/74

TABLE A-2.NEW SOURCE PERFORMANCE STANDARDS PROPOSED AND
NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR
POLLUTANTS PROMULGATED PRIOR TO August 7, 1980

New Source Performance Standards 40 CFR 60 Subpart Affected Facility Proposed Source Date Steel plants: Electric arc furnaces 10/21/74 AA electric arc furnaces Digesters, lime kiln Kraft pulp mills BB 09/24/76 recovery furnace, washer, evaporator, strippers, smelt and BLO tanks Recovery furnace, lime, kiln, smelt tank Glass manufacturing CC Glass melting furnace 06/15/79 pl ants Grain elevators DD Truck loading and unloading 01/13/77 stations, barge or ship loading and unloading stations railcar loading and unloading stations, and grain handling operations 10/03/77 Stationary gas GG Each gas turbine turbi nes Lime manufacturing HH Rotary kiln, hydrator 05/03/77 pl ants Degreasers (organic JJ Cold cleaner, vapor 06/11/80 solvent cleaners) degreaser, conveyorized degreaser Lead oxide production grid Lead acid battery KK 01/14/80 manufacturing plants casting, paste mixing, threeprocess operation and lead reclamation Automobile and MM Prime, guide coat, and 10/05/79 light-duty truck top coat operations at surface coating assembly plants operations

Due to the variability even among similar sources, fugitive emissions should be quantified through a source-specific engineering analysis. Suggested (but by no means all of the useful) references for fugitive emissions data and associated analytic techniques are listed in Table A-3.

Remember, if emissions can be "reasonably" captured and vented through a stack they are not considered "fugitive" under EPA regulations. In such cases, these emissions, to the extent they are quantifiable, would count toward the potential to emit regardless of source or facility type.

For example, the emissions from a rock crushing operation that could reasonably be equipped with a capture hood are not considered fugitive and would be included in the source's potential to emit.

As another example, VOC emissions, even if in relatively small quantities, coming from leaking valves inside a large furniture finishing plant, are typically captured and exhausted through the building ventilation system They are, therefore, measurable and should be included in the potential to emit.

As a counter example, however, it may be unreasonable to expect that relatively small quantities of VOC emissions, caused by leaking valves at outside storage tanks of the large furniture finishing operation, could be captured and vented to a stack.

II. B. 4. SECONDARY EMISSIONS

Secondary emissions are not considered in the potential emissions accounting procedure. Secondary emissions are those emissions which, although associated with a source, <u>are not emitted from the source itself</u>. Secondary emissions occur from any facility that is not a part of the source being reviewed, but which would not be constructed or increase its emissions except as a result of the construction or operation of the major stationary source or major modification. Secondary emissions do not include any emissions from any off-site facility which would be constructed or increase its emissions for some reason other than the construction or operation of the major stationary source or major modification.

TABLE A-3. SUGGESTED REFERENCES FOR ESTIMATING FUGITIVE EMISSIONS

- 1. Emission Factors and Frequency of Leak Occurrence for Fittings in Refinery Process Units. Radian Corporation. EPA-600/2-79-044. February 1979.
- 2. Protocols for Generating Unit Specific Emission Estimates for Equipment Leaks of VOC and VHAP. U.S. Environmental Protection Agency. EPA-450/3-88-0100.
- 3. Improving Air Quality: Guidance for Estimating Fugitive Emissions From Equipment. Chemical Manufacturers Association. January 1989.
- Compilation of Air Pollutant Emission Factors, 3rd ed. U.S. Environmental Protection Agency. AP-42 (including Supplements 1-8). May 1978.
- 5. Technical Guidance for Control of Industrial Process Fugitive Particulate Emissions. Pedco Environmental, Inc. EPA-450/3-77-010. March 1977.
- 6. Fugitive Emissions From Integrated Iron and Steel Plants. Midwest Research Institute, Inc. EPA-600/2-78-050. March 1978.
- 7. Survey of Fugitive Dust from Coal Mines. Pedco Environmental, Inc. EPA-908/1-78-003. February 1978.
- 8. Workbook on Estimation of Emissions and Dispersion Modeling for Fugitive Particulate Sources. Utility Air Regulatory Group. September 1981.
- 9. Improved Emission factors for Fugitive Dust from Weston Surface Coal Mining Sources, Volumes I and II. U.S. Environmental Protection Agency. EPA-600/7-84-048.
- 10. Control of Open Fugitive Dust Sources. Midwest Research Institute. EPA-450/3-88-008. September 1988.

An example is the emissions from an existing quarry owned by one company that doubles its production to supply aggregate to a cement plant proposed for construction as a major source on adjacent property by another company. The quarry's increase in emissions would be secondary emissions which the cement plant's anbient impacts analysis must consider.

Secondary emissions do not include any emissions which come directly from a mobile source, such as emissions from the tailpipe of a motor vehicle or from the propulsion unit of a train or a vessel. This exclusion is limited, however, to only those mobile sources that are regulated under Title II of the Act (see 43 FR 26403 - note #9). Most off-road vehicles are not regulated under Title II and are usually treated as area sources. [As a result of a court decision in <u>NRDC v. EPA</u>, 725 F. 2d 761 (D. C. Circuit 1984), emissions from vessels at berth ("dockside") not to be included in the determination of secondary emissions but <u>are</u> considered primary emissions for applicability purposes.]

Although secondary emissions are excluded from the potential emissions estimates used for applicability determinations, they must be considered in PSD analyses if PSD review is required. In order to be considered, however, secondary emissions must be specific, well-defined, quantifiable, and impact the same general area as the stationary source or modification undergoing review.

II. B. 5. REGULATED POLLUTANTS

The potential to emit must be determined separately for each pollutant regulated by the Act and emitted by the new or modified source. Twenty-six compounds, 6 criteria and 20 noncriteria, are regulated as air pollutants by the Act as of December 31, 1989. They are listed in Table A-4. Note that EPA has designated PM-10 (particulate matter with an aerodynamic diameter less than 10 microns) as a criteria pollutant by promulgating NAAQS for this

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pollutant as a replacement for total PM Thus, the determination of potential to emit for PM-10 emissions as well as total PM emissions (which are still regulated by many NSPS) is required in applicability determinations. Several halons and chlorofluorocarbon (CFC) compounds have been added to the list of regulated pollutants as a result of the ratification of the Montreal Protocol by the United States in January 1989.

II. B. 6. METHODS FOR DETERMINING POTENTIAL TO EMIT

In determining a source's potential to emit, two parameters must be measured, calculated, or estimated in some way. They are:

- ! the worst case uncontrolled emissions rate, which is based on the dirtiest fuels, and/or the highest emitting materials and operating conditions that the source is or will be permitted to use under federally-enforceable requirements, and
- ! the efficiency of the air pollution control system, if any, in use or contemplated for the worst case conditions, where the use of such equipment is federally-enforceable.

TABLE A-4.SIGNIFICANT EMISSION RATES OF POLLUTANTSREGULATED UNDER THE CLEAN AIR ACT

Pollutant

Emissions rate (tons/year)

Pollutants listed at 40 CFR 52.21(b)(23)

*	Carbon monoxide	100
*	Nitrogen oxides ^a	40
*	Sul fur di oxi de ^b	40
*	Particulate matter (PM/PM-10)	25/15
*	Ozone (VOC)	40 (of VOC's)
*	Lead	0.6
	Asbestos	0.007
	Beryllium	0.0004
	Mercury	0. 1
	Vinyl chloride	1
	Fl uori des	3
	Sulfuric acid mist	7
	Hydrogen sulfide (H_2S)	10
	Total Reduced sulfur compounds (including H ₂ S)	10
	-	

- * Criteria Pollutants
- ^a Nitrogen dioxide is the compound regulated as a criteria pollutant; however, significant emissions are based on the sum of all oxides of nitrogen.
- ^b Sulfur dioxide is the measured surrogate for the criteria pollutant sulfur oxides. Sulfur oxides have been made subject to regulation
- explicitly through the proposal of 40 CFR 60 Subpart J as of August 17, 1989.

TABLE A-4.(Concluded) SIGNIFICANT EMISSION RATES OF POLLUTANTS
REGULATED UNDER THE CLEAN AIR ACT

Pollutant

Emissions rate (tons/year)

Other pollutants regulated by the Clean Air Act:^{cd}

Benzene	I	
Arseni c	I	
Radi onucl i des	I	Any emission rate
Radon- 222		
Pol oni um- 210	I	
CFC's 11, 12, 112, 114, 115	I	
Halons 1211, 1301, 2402	I	

^c Significant emission rates have not been promulgated for these pollutants, and until such time, any emissions by a new major sources or any increase in emissions at an existing major source due to modification, are "significant."

^d Regulations covering several pollutants such as cadmium, coke oven emissions, and municipal waste incinerator emissions have recently been proposed. Applicants should, therefore, verify what pollutants have been regulated under the Act at the time of application. Sources of the worst-case uncontrolled emissions and applicable control system efficiencies could be any of the following:

- ! Emissions data from compliance tests or other source tests,
- ! Equipment vendor emissions data and guarantees;
- ! Emission limits and test data from EPA documents, including background information documents for new source performance standards, national emissions standards for hazardous air pollutants, and Section 111d standards for designated pollutants;
- ! AP-42 emission factors (see Table A-3, Reference 2);
- ! Emission factors from technical literature; and
- ! State emission inventory questionnaires for comparable sources.

The effect of other restrictions (federally-enforceable and practicallyenforceable) should also be factored into the results. The potential to emit of each pollutant, including fugitive emissions if applicable, is estimated for each individual emissions unit. The individual estimates are then summed by pollutant over all the emissions units at the stationary source.

II. C. EMISSIONS THRESHOLDS FOR PSD APPLICABILITY

II. C. 1. MAJOR SOURCES

A source is a "major stationary source" or "major emitting facility" if:

- (1) It can be classified in one of the 28 named source categories listed in Section 169 of the CAA (see Table A-1) and it emits or has the potential to emit 100 tpy or more of any pollutant regulated by the Act, or
- (2) it is any other stationary source that emits or has the potential to emit 250 tons per year or more of any pollutant regulated by the CAA.

For example, one of the 28 PSD source categories subject to the 100-tpy threshold is fossil fuel-fired steam generators with a heat input greater than 250 million Btu/hr. Consequently, a 300 million Btu/hr boiler that is designed and permitted to burn any fossil fuel, i.e., coal, oil, natural gas or lignite, that emits 100 tpy or more of any regulated pollutant, e.g., SO_2 , is a major stationary source. If, however, the boiler were designed and permitted to burn wood only, it would not be classified as one of the 28 PSD sources and would instead be subject to the 250 tpy threshold.

A single, fossil fuel-fired boiler with a maximum heat input capacity of 300 million Btu/hr takes a federally-enforceable design limitation that restricts heat input to 240 million Btu/hr. Consequently, this source would not be classified within one of the 28 categories and would therefore be subject to the 250-tpy, rather than the 100-tpy, emissions threshold.

A situation frequently occurs in which an emissions unit that is included in the 28 listed source categories (and so is subject to a 100 tpy threshold), is located within a parent source whose primary activity is not on the list (and is therefore subject to a 250 tpy threshold). A source which, when considered alone, would be major (and hence subject to PSD) cannot "hide" within a different and less restrictive source category in order to escape applicability.

As an example, a proposed coal mining operation will use an on-site coal cleaning plant with a thermal dryer. The source will be defined as a coal mine because the cleaning plant will only treat coal from the mine. The mine's potential to emit (including emissions from the thermal dryer) is less than 250 tpy for every regulated pollutant; therefore. it is a "minor" source. The estimated emissions from the thermal dryer, however, will be 150 tpy particulate matter. Thermal dryers are included in the list of 28 source categories that are subject to the 100 tpy major source threshold. Consequently. the thermal dryer would be considered an emissions unit that by itself is a major source and therefore is subject to PSD review, even though the primary activity is not.

Furthermore, when a "minor" source, i.e., one that does not meet the definition of "major," makes a physical change or change in the method of operation that is by itself a major source, that physical or operational change constitutes a major stationary source that is subject to PSD review.

To illustrate, consider the following scenarios at an existing glass fiber processing plant, which proposes to add new equipment to increase production. Glass fiber processing plants are included in the list of 28 source categories that are subject to the 100-tpy major source threshold. The existing plant emits 40 tpy particulate, which is both its potential to emit and permitted allowable rate. It also has a potential to emit all other pollutants in less than major quantities; therefore it is a minor source.

<u>Scenario 1</u> - The physical change will increase the source's potential to emit particulate matter by 50 tpy. Since the plant is a minor source and the increase is not major by itself, the change is not subject to PSD review.

Scenario 2 The physi cal change will increase the source's potential to emit particulate matter by 65 tpy. Since the plant is a minor source and the increase is not major by itself, neither is subject to PSD review. However, the source's potential to emit after the change will exceed the 100-tpy major source threshold, so modifications will be under future scrutinized the netting provisions (see section A.3.2).

Scenario 3 -The physi cal change will increase the source's potential to emit particulate matter by 110 tpy. Since the existing plant is a minor source and the change by itself results in an emissions increase greater than the major source threshold, that change is subject to PSD review. the physical change Furthermore, makes the entire plant a major source, so future physical changes or changes in the method of operation will be scrutinized against the criteria for major modifications (see section II.A.3.2).

II. C. 2. SIGNIFICANT EMISSIONS

A PSD review is triggered in certain instances when emissions associated with a new major source or emissions increases resulting from a major modification are "significant." "Significant" emissions thresholds are defined two ways. The first is in terms of emission rates (tons/year). Table A-4 listed the pollutants for which significant emissions rates have been established.

Significant increases in emission rates are subject to PSD review in two circumstances:

(1) For a new source which is major for at least one regulated attainment or noncriteria pollutant, i.e., is subject to PSD review, all pollutants for which the area is not classified as nonattainment and which are emitted in amounts equal to or greater than those specified in Table A-4 are also subject to PSD review for its VOC emissions.

For example, an automotive assembly plant is planned for an attainment area for all criteria pollutants. The plant has a potential to emit 350 tpy VOC, 50 tpy NO_x , 60 tpy SO_2 , and 10 tpy PM including 5 tpy PM-10. The 350 tpy VOC exceeds the major source threshold, and therefore subjects the plant to PSD review. The "significant" emissions thresholds for NO_x and SO_2 are 40 tpy; therefore, the NO_x and SO_2 emissions, also, will be subject to PSD review. The PM and PM-10 emissions will not exceed their significant emissions thresholds; therefore they are not subject to review.

(2) For a modification to an existing major stationary source, if both the potential increase in emissions due to the modification itself, and the resulting net emissions increase of any regulated, attainment or noncriteria pollutants are equal to or greater than the respective pollutants' significant emissions rates listed in Table A-4, the modification is "major," and subject to PSD review. Modifications are discussed in detail in Section II.D.

The second type of "significant" emissions threshold is defined as any emissions rate at a new major stationary source (or any net emissions increase associated with a modification to an existing major stationary source) that is constructed within 10 kilometers of a Class I area, and which would increase the 24-hour average concentration of any regulated pollutant in that area by 1 μ g/m³ or greater. Exceedence of this threshold triggers PSD review.

II. D. LOCAL AIR QUALITY CONSIDERATIONS FOR CRITERIA POLLUTANTS

The air quality, i.e., attainment status, of the area of a proposed new source or modified existing source will impact the applicability determination in regard to the pollutants that are subject to PSD review. As previously stated, if a new source locates in an area designated attainment or unclassifiable for any criteria pollutant, PSD review will apply to any pollutant for which the potential to emit is major (or significant, if the source is major) so long as the area is not nonattainment for that pollutant.

For example, a kraft pulp mill is proposed for an attainment area for SO_2 , and its potential to emit SO_2 equals 55 tpy. Its potential to emit total reduced sulfur (TRS) a noncriteria pollutant, equals 295 tpy. Its potential to emit VOC will be 45 tpy and PM/PM-10, 30/5 tpy; however, the area is designated nonattainment for ozone and PM Applicability would be assessed as follows:

The source would be major and subject to PSD review due to the noncriteria TRS emissions.

The SO_2 emissions would therefore be subject to PSD because they are significant and the area is attainment for SO_2 .

The VOC emission and PM emissions would not be subject to PSD, even though their emissions are significant, because the area is designated nonattainment for those pollutants.

The PM-10 emissions are neither major nor significant and would therefore not be subject to review.

Similarly, if the modification of an existing major source, which is located in an attainment area for any criteria pollutant, results in a significant increase in potential to emit and a significant net emissions increase, the modification is subject to PSD, unless the location is designated as nonattainment for that pollutant.

Note that if the source is major for a pollutant for which an area is designated nonattainment, all significant emissions or significant emissions increases of pollutants for which the area is attainment or unclassifiable are still subject to PSD review.

II. E. SUMMARY OF MAJOR NEW SOURCE APPLICABILITY

The elements and associated information necessary for determining PSD applicability to **new** sources are outlined as follows:

Element 1 - Define the source

- ! includes all related activities classified under the same 2-digit SIC Code number
- ! must have the same owner or operator
- ! must be located on contiguous or adjacent properties
- ! includes all support facilities

Element 2 - Define applicability thresholds for major source as a whole (primary activity)

- ! 100 tpy for individual emissions units or groups of units that are included in the list of 28 source categories identified in Section 169 of the CAA
- ! 250 tpy for all other sources

Element 3 - Define project emissions (potential to emit)

- ! Reflects federally-enforceable air pollution control efficiency, operating conditions, and permit limitations
- ! Determined for each pollutant by each emissions unit
- ! Summed by pollutant over all emissions units
- ! Includes fugitive emissions for 28 listed source categories and sources subject to NSPS or NESHAPS as of August 7, 1980

Element 4 - Assess local area attainment status

! Area must be attainment or unclassifiable for at least one criteria pollutant for PSD to apply

Element 5 - Determine if source is major by comparing its potential emissions to appropriate major source threshold

- ! Major if <u>any</u> pollutant emitted by defined source exceeds thresholds, regardless of area designation, i.e., attainment, nonattainment, or noncriteria pollutants
- ! Individual unit is major if classified as a source in one of the 28 regulated source categories and emissions exceed an applicable 100-tpy threshold

Element 6 - Determine pollutants subject to PSD review

- ! Each attainment area and noncriteria pollutant emitted in "significant" quantities
- ! Any emissions or emissions increase from a major source that results in an increase of 1 μ g/m³ (24 hour average) or more in a Class I area if the major source is located or constructed within 10 kilometers of that Class I area.

II. F. NEW SOURCE APPLICABILITY EXAMPLE

The following example provided is for illustration only. The example source is fictitious and has been created to highlight many of the aspects of the PSD applicability process for a new source.

In this example the proposed project is a new coal-fired electric plant. The plant will have two 600-MW lignite-fired boilers. The proposed location is near a separately-owned surface lignite mine, which will supply the fuel requirements of the power plant, and will therefore, have to increase its mining capacity with new equipment. The lignite coal will be mined and then transported to the power plant to be crushed, screened, stored, pulverized and fed to the boilers. The power plant has informed the lignite coal mine that the coal will not have to be cleaned, so the mine will not expand its coal cleaning capacity. The power plant will have on-site coal and limestone storage and handling facilities. In addition, a comparatively small auxiliary boiler will be installed to provide steam for the facility when the main boilers are inoperable. The area is designated attainment for all criteria pollutants.

The applicant proposes pollution control devices for the two 600-MW boilers which include:

- an electrostatic precipitator (ESP) for PM/PM-10 emissions control,
- a limestone scrubber flue gas desulfurization (FGD) system for $SO_{\rm 2}$ emissions control;
- low-nitrogen oxide (NO_x) burners and low-excess-air firing for NO_x emissions control; and
- controlled combustion for CO emissions control.

The first step is to determine what constitutes the source (or sources). A source is defined as all pollutant-emitting activities associated with the same industrial grouping, located on contiguous or adjacent sites, and under common control or ownership. Industrial groupings are generally defined by two-digit SIC codes. The power plant is classified as SIC major group 49; the nearby mine is SIC major group 12. They are neither under the same SIC major group number nor have the same owners, so they constitute separate sources.

The second step is to establish which major source thresholds are applicable in this case. The proposed power plant is a fossil fuel-fired steam electric plant with more than 250 million Btu/hr of heat input, making it a source included in one of the 28 PSD-listed categories. It is therefore subject to both the 100 ton per year criterion for any regulated pollutant used to determine whether a source is major and to the requirement that quantifiable fugitive emissions be included in determining potential to emit. The emissions units at the mine are neither classified within one of the 28 PSD source categories nor regulated under Sections 111 or 112 of the Act. Therefore, the mine is compared against the 250 tpy major source threshold and fugitive emissions from the mining operations are exempt from consideration in determining whether the mine is a major stationary source.

The third step is to define the project emissions. To arrive at the potential to emit of the proposed power plant, the applicant must consider all quantifiable stack and fugitive emissions of each regulated pollutant (i.e., SO_2 , NO_x , PM, PM-10, CO, VOC, lead, and the noncriteria pollutants). Therefore, fugitive PM/PM-10 emissions from haul roads, disturbed areas, coal piles, and other sources must be included in calculating the power plant's potential to emit.

All stack and fugitive emissions estimates have been obtained through detailed engineering analysis of each emissions unit using the best available data or estimating technique. Fugitive emissions are added to the emissions from the two main boilers and the auxiliary boiler in order to arrive at the total potential to emit of each regulated pollutant. The auxiliary boiler in this case is restricted by enforceable limits on operating hours proposed to be included in the source's PSD permit. If the auxiliary boiler were not limited in hours of operation, its contribution would be based on full, continuous operation, and the resulting potential emissions estimates would be higher.

The potential to emit SO_2 , NO_x , PM, CO, and sulfuric acid mist each exceeds 100 tons per year. From data collected at other lignite fired power plants it is known that emissions of lead, beryllium, mercury, fluorides, sulfuric acid mist and arsenic should also be quantified. It is known that fluoride compounds are contained in the coal in significant quantities; however, engineering analyses show fluoride removal in the proposed limestone scrubber will result in insignificant stack emissions. Similarly, liquid absorption, absorption of fly ash removed in the ESP, and removal of bottom

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ash have been shown to maintain emissions of lead and the other regulated noncriteria pollutants below significance levels.

The only emissions at the existing mine, and consequently the only emissions increase that will occur from the expansion to serve the power plant, are fugitive PM/PM-10 emissions from mining operations. The mine's potential to emit, for PSD applicability purposes, is zero and the mine is not subject to a PSD review. The increase in fugitive emissions from the mine, however, will be classified as secondary emissions with respect to the power plant and, therefore, must be considered in the air quality analysis and additional impacts analysis for the proposed power plant if the power plant is subject to PSD review.

The next step is to compare the potential emissions of the power plant to the 100 ton per year major source threshold. If the potential to emit of any regulated pollutant is 100 tons per year or more, the power plant is classified as a major stationary source for PSD purposes. In this case, the plant is classified as a major source because SO_2 , NO_x , PM, CO, and sulfuric acid mist emissions each exceed 100 tons per year. (Note that emissions of any one of these pollutants classifies the source as major.)

Once it has been determined that the proposed source is major, any regulated pollutant (for which the location of the source is not classified as nonattainment) with significant emissions is subject to a PSD review. The applicant quantified, through coal and captured fly ash analyses and through performance test results from existing sources burning equivalent coals, emissions of fluorides, beryllium, lead, mercury, and the other regulated noncriteria pollutants to determine if their emissions exceed the significance levels (see Table A-4.). Pollutants with less than significant emissions are not subject to PSD review requirements (assuming the proposed controls are accepted as BACT for SO_2 , or the application of BACT for SO_2 results in equivalent or lower noncriteria pollutant emissions). Note that, because the proposed construction site is not within 10 kilometers of a Class I area, the source's emissions are not subject to the Class I area significance criteria.

III. MAJOR MODIFICATION APPLICABILITY

A modification is subject to PSD review only if (1) the existing source that is modified is "major," and (2) the net emissions increase of any pollutant emitted by the source, as a result of the modification, is "significant," i.e., equal to or greater than the emissions rates given on Table A-4 (unless the source is located in a nonattainment area for that pollutant). Note also that <u>any</u> net emissions increase in a regulated pollutant at a major stationary source that is located within 10 kilometers of a Class I area, and which will cause an increase of $1 \mu g/m^3$ (24 hour average) or more in the ambient concentration of that pollutant within that Class I area, is "significant".

Typical examples of modifications include (but are not limited to) replacing a boiler at a chemical plant, construction of a new surface coating line at an assembly plant, and a switch from coal to gas requiring a physical change to the plant, e.g., new piping, etc.

As discussed earlier, when a "minor" source, i.e., one that does not meet the definition of "major," makes a physical change or change in the method of operation that is by itself a major source, that physical or operational change constitutes a <u>major stationary source</u> that is subject to PSD review. Also, if an existing minor source becomes a major source as a result of a SIP relaxation, then it becomes subject to PSD requirements just as if construction had not yet commenced on the source or the modification.

III. A. ACTIVITIES THAT ARE NOT MODIFICATIONS

The regulations do not define "physical change" or "change in the method of operation" precisely; however, they exclude from those activities certain specific types of events described below.

(1) Routine maintenance, repair and replacement.

[Sources shoul d discuss any project that wi 11 *significantly* increase actual emissions the to with atmosphere their *respective* permitting *authority*, to whether that project consi dered routine as is maintenance, repair or replacement.]

- (2) A fuel switch due to an order under the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation) or due to a natural gas curtailment plan under the Federal Power Act.
- (3) A fuel switch due to an order or rule under section 125 of the CAA.
- (4) A switch at a steam generating unit to a fuel derived in whole or in part from municipal solid waste.
- (5) A switch to a fuel or raw material which (a) the source was capable of accommodating before January 6, 1975, so long as the switch would not be prohibited by any federallyenforceable permit condition established after that date under a federally approved SIP (including any PSD permit condition) or a federal PSD permit, or (b) the source is approved to make under a PSD permit.
- (6) Any increase in the hours or rate of operation of a source, so long as the increase would not be prohibited by any federally-enforceable permit condition established after January 6, 1975 under a federally approved SIP (including any PSD permit condition) or a federal PSD permit.
- (7) A change in the ownership of a stationary source.

For more details see 40 CFR 52.21(b)(2)(iii).

Notwithstanding the above, if a significant increase in actual emissions of a regulated pollutant occurs at an existing major source as a result of a physical change or change in the method of operation of that source, the "<u>net</u> emissions increase" of that pollutant must be determined.

III. B. EMISSIONS NETTING

Emissions netting is a term that refers to the process of considering certain previous and prospective emissions changes at an existing major source to determine if a "net emissions increase" of a pollutant will result from a

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proposed physical change or change in method of operation. If a net emissions increase is shown to result, PSD applies to each pollutant's emissions for which the net increase is "significant", as shown in Table A-4.

The process used to determine whether there will be a net emissions increase will result uses the following equation:

Net Enissions Change EQUALS Enissions <u>increases</u> associated with the proposed modification MINUS Source-wide creditable contemporaneous emissions <u>decreases</u> PLUS Source-wide creditable contemporaneous emissions increases

Consideration of contemporaneous emissions changes is allowed <u>only</u> in cases involving <u>existing major sources</u>. In other words, minor sources are not eligible to net emissions changes. As discussed earlier, existing minor sources are subject to PSD review only when proposing to increase emissions by "major" (e.g., 100 or 250 tpy, as applicable) amounts, which, for PSD purposes, are considered and reviewed as a major new source.

For example, an existing minor source (subject to the 100 tpy major source a modification which involves the shutdown cutoff) is proposing and an old emissions unit (providing actual contemporaneous removal of an reduction in NOx emissions of 75 tpy) and the construction of two new units with total potential NOx emissions of 110 tpy. Since the existing minor, the tpy reduction consi dered source is 75 is not for PSD applicability purposes. Consequently. PSD applies to the new units because the emissions increase of 110 tpy is itself "major". The new units are then subject to a PSD review for NOx and for any other regulated pollutant with a "significant" potential to emit.

The consideration of contemporaneous emissions changes is also source specific. Netting must take place at the same stationary source; emissions reductions cannot be traded between stationary sources.

III. B. 1. ACCUMULATION OF EMISSIONS

If the proposed emissions increase at a major source is by itself (without considering any decreases) less than "significant", EPA policy does not require consideration of previous contemporaneous small (i.e., less than significant) emissions increases at the source. In other words, the netting equation (the summation of contemporaneous emissions increases and decreases) is not triggered unless there will be a significant emissions increase from the proposed modification.

For example, a major source experienced less than significant increases of NO_x (30 tpy) and SO_2 (15 tpy) 2 years ago, and a decrease of SO_2 (50 tpy) 3 years ago. The source now proposes to add a new process unit with an associated emissions increase of 35 tpy NO_x and 80 tpy SO_2 . For SO₂, the proposed 80 tpy increase from the modification by itself (before netting) is significant. The contemporaneous net emissions change is determined, by taking the algebraic sum of (-50) and (+15) and (+80), which equals +45 Therefore, the proposed modification is a major modification and a tpy. PSD review for SO₂ is required. However. the NO_{y} increase from the proposed modification is by itself less than significant. Consequently, netting for PSD applicability purposes is not performed for NO_x (even though the modification is major for SO_2) and a PSD review is not needed for NO_x.

It is important to note that when <u>any</u> emissions decrease is claimed (including those associated with the proposed modification), <u>all</u> source-wide creditable and contemporaneous emissions increases and decreases of the pollutant subject to netting must be included in the PSD applicability determination.

A deliberate decision to split an otherwise "significant" project into two or more smaller projects to avoid PSD review would be viewed as circumvention and would subject the entire project to enforcement action if construction on any of the small projects commences without a valid PSD permit.

For example, an automobile and truck tire manufacturing plant, an existing major source, plans to increase its production of both types of tires by

"debottlenecking" its production processes. For its passenger tire line, the source applies for and is granted a "minor" modification permit for a new extruder that will increase VOC emissions by 39 tons/yr. A few months "minor" modification permit to construct later. the source applies for a new tread-end cementer on the same line whi ch wi 11 increase VOC а emissions by 12 tons/yr. The EPA would likely consider these proposals as an attempt to circumvent the regulations because the two proposals are related in terms of an overall project to increase source-wide production capacity. The important point in this example is that the two proposals are sufficiently related that the PSD regulations would consider them a single project.

Usually, at least two basic questions should be asked when evaluating the construction of multiple minor projects to determine if they should have been considered a single project. First, were the projects proposed over a relatively short period of time? Second, could the changes be considered as part of a single project?

III. B. 2. CONTEMPORANEOUS EMISSIONS CHANGES

The PSD definition of a net emissions increase $[40 \ \text{CFR} 52.21(b)(3)(i)]$ consists of two <u>additive</u> components as follows:

- (a) Any <u>increases</u> in actual emissions <u>from</u> a particular physical change or change in method of operation at a stationary source; and
- (b) Any other <u>increase and decreases in actual emissions</u> at the source that are contemporaneous with the particular change and are otherwise creditable.

The first component narrowly includes only the emissions increases associated with a particular change at the source. The second component more broadly includes all contemporaneous, source-wide (occurring anywhere at the entire source), creditable emission increases and decreases.

To be <u>contemporaneous</u>, changes in <u>actual</u> emissions must have occurred after January 6, 1975. The changes must also occur within a period beginning 5 years before the date construction is expected to commence on the proposed modification (reviewing agencies may use the date construction is scheduled to commence provided that it is reasonable considering the time needed to issue a final permit) and ending when the emissions increase from the modification An increase resulting from a physical change at a source occurs when occurs. the new emissions unit becomes operational and begins to emit a pollutant. Α replacement that requires a shakedown period becomes operational only after a reasonable shakedown period, not to exceed 180 days. Since the date construction actually will commence is unknown at the time the applicability determination takes place and is simply a scheduled date projected by the source, the contemporaneous period may shift if construction does not commence as scheduled. Many States have developed PSD regulations that allow different time frames for definitions of contemporaneous. Where approved by EPA, the time periods specified in these regulations govern the contemporaneous timeframe.

III. B. 3. CREDITABLE CONTEMPORANEOUS EMISSIONS CHANGES

There are further restrictions on the contemporaneous emissions changes that can be credited in determining net increases. To be creditable, a contemporaneous reduction must be federally-enforceable on and after the date construction on the proposed modification begins. The actual reduction must take place before the date that the emissions increase from any of the new or modified emissions units occurs. In addition, the reviewing agency must ensure that the source has maintained any contemporaneous decrease which the source claims has occurred in the past. The source must either demonstrate that the decrease was federally-enforceable at the time the source claims it occurred, or it must otherwise demonstrate that the decrease was maintained until the present time and will continue until it becomes federallyenforceable. An emissions decrease cannot occur at, and therefore, cannot be credited from an emissions unit which was never constructed or operated, including units that received a PSD permit.

Reductions must be of the same pollutant as the emissions increase from the proposed modification and must be qualitatively equivalent in their

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effects on public health and welfare to the effects attributable to the proposed increase. Current EPA policy is to assume that an emissions decrease will have approximately the same qualitative significance for public health and welfare as that attributed to an increase, unless the reviewing agency has reason to believe that the reduction in ambient concentrations from the emissions decrease will not be sufficient to prevent the proposed emissions increase from causing or contributing to a violation of any NAAQS or PSD increment. In such cases, the applicant must demonstrate that the proposed netting transaction will not cause or contribute to an air quality violation before the emissions reduction may be credited. Also, in situations where a State is implementing an air toxics program, proposed netting transactions may be subject to additional tests regarding the health and welfare equivalency For example, a State may prohibit netting between certain demonstration. groups of toxic subspecies or apply netting ratios greater than the normally required 1:1 between certain groups of toxic pollutants.

A contemporaneous emissions increase occurs as the result of a physical change or change in the method of operation at the source and is creditable to the extent that the new emissions level exceeds the old emissions level. The "old" emissions level for an emissions unit equals the average rate (in tons per year) at which the unit actually emitted the pollutant during the 2-year period just prior to the physical or operational change which resulted in the emissions increase. In certain limited situations where the applicant adequately demonstrates that the prior 2 years is not representative of normal source operation, a different (2 year) time period may be used upon a determination by the reviewing agency that it is more representative of normal source operation. Normal source operations may be affected by strikes, retooling, major industrial accidents and other catastrophic occurrences. The "new" emissions levels for a new or modified emissions unit which has not begun normal operation is its potential to emit.

An emissions increase or decrease is creditable only if the relevant reviewing authority has <u>not</u> relied on it in issuing a PSD permit for the source, and the permit is still in effect when the increase in actual

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emissions from the proposed modification occurs. A reviewing authority relies on an increase or decrease when, after taking the increase or decrease into account, it concludes that a proposed project would not cause or contribute to a violation of an increment or ambient standard. In other words, an emissions change at an emissions point which was considered in the issuance of a previous PSD permit for the source is <u>not</u> included in the source's "net emissions increase" calculation. This is done to avoid "double counting" of emissions changes.

For example, emissions increase decrease al ready considered in an or а source's PSD permit (state or *federal*) can not be consi dered а contemporaneous increase or decrease since the increases or decrease was obviously relied upon for the purpose of issuing the permit. Otherwise the increase or decrease would not have been specified in the permit. In another example, a decrease in emissions from having previously switched to a less polluting fuel (e.g., oil to gas) at an existing emissions unit would not be creditable if the source had, in obtaining a PSD permit (which is still in effect) for a new emissions unit, modeled the source's ambient impact using the less polluting fuel.

Changes in PM (PM/PM-10), SO_2 and NO_x emissions are a subset of creditable contemporaneous changes that also affect the available increment. For these pollutants, emissions changes which do not affect allowable PSD increment consumption are not creditable.

III. B. 4. CREDITABLE AMOUNT

As mentioned above, only contemporaneous and creditable emissions changes are considered in determining the source-wide net emissions change. All contemporaneous and creditable emissions increases and decreases at the source must, however, be considered. The amount of each contemporaneous and creditable emissions increase or decrease involves determining old and new actual annual emissions levels for each affected emission unit.

The following basic criteria should be used when quantifying the increase or decrease:

- For proposed new or modified units which have not begun normal operations, the potential to emit must be used to determine the <u>increase</u> from the units.
- For an existing unit, actual emissions just prior to either a physical or operational change are based on the lower of the actual or allowable emissions levels. This "old" emissions level equals the average rate (in tons per year) at which the unit actually emitted the pollutant during the 2-year period just prior to the change which resulted in the emissions increase. These emissions are calculated using the actual hours of operation, capacity, fuel combusted and other parameters which affected the unit's emissions over the 2-year averaging period. In certain limited circumstances, where sufficient representative operating data do not exist to determine historic actual emissions and the reviewing agency has reason to believe that the source is operating at or near its allowable emissions level, the reviewing agency may presume that source-specific allowable emissions [or a fraction thereof] are equivalent to (and therefore are used in place of) actual emissions at the unit. For determining the difference in emissions from the change at the unit, emissions after the change are the potential to emit from the units.
- A source cannot receive emission reduction credit for reducing any portion of actual emissions which resulted because the source was operating out of compliance.
- An emissions decrease cannot be credited from a unit that has not been constructed or operated.

of how creditability for Examples to apply these criteria prospective emissions reductions is shown in Figure A-1. As shown in Case I of Figure A-1, the potential to emit for an existing emissions unit (which is based on the existing allowable emissi on which are based rate) is greater than the actual emissions, on actual operating data (e.g., type and amount of fuel combusted at the unit) for the past 2 years. The source proposes to switch to a lower sulfur fuel. The amount of the reduction in this case is the emissions and *difference* between the actual the revi sed allowable emissions. (Recall that

for reductions to be creditable, the revised allowable emission rate must be ensured with federally-enforceable limits.)

Figure A-1 also illustrates in Case II that the previous allowable emissions were much higher than the potential to emit. Common examples are PM sources permitted according to process weight tables contained in most SIPs. Since process weight tables apply to a range of source types, they often overpredict actual emission rates for individual sources. In such cases, as in the previous case, the <u>only</u> creditable contemporaneous reduction is the difference between the actual emissions and the revised allowable emission rate for the existing emissions unit.

Case III in Figure A-1 illustrates a potential violation situation where the actual emissions level exceeds allowable limit. The creditable reduction in this case is the difference between what the emissions would have been from the unit had the source been in compliance with its old allowable limits (considering its actual operations) and its revised allowable emissions level.

Consider a more specific example, where a source has an emissions unit with an annual allowable emissions rate of 200 tpy based on *capacity* vear-round operation and hourly unit-specific full an allowable emission rate. The source is, however, out of compliance allowable hourly emission rate by a factor of with the two. Consequently, if the unit were to be operated year-round at full capacity it would emit 400 tpy. However, in this case, although the unit operated at full capacity, it was operated on the average 75 percent of the time for the past 2 years. Consequently, for the past 2 years average actual emissions were 300 tpy. The unit is now to be shutdown. Assumi ng the reduction is otherwise creditable, the reduction from the shutdown is its allowable emissions prorated (200 tpy x . 75 = 150 tpy).by its operating factor

Case I: Normal Existing Source







Case III: Existing Source in Violation of Permit



Figure A-1. Creditable Reductions in Actual Emissions

III. B. 5. SUGGESTED EMISSIONS NETTING PROCEDURE

Through its review of many emissions netting transactions, EPA has found that, either because of confusion or misunderstanding, sources have used various netting procedures, some of which result in cases where projects should have been subjected to PSD but were not. Some of the most common errors include:

- Not including contemporaneous emissions increases when considering decreases;
- Improperly using <u>allowable</u> emissions instead of <u>actual</u> emissions level for the "old" emissions level for existing units;
- Using prospective (proposed) unrelated emissions decreases to counterbalance proposed emission increases without also examining all previous contemporaneous emissions changes;
- Not considering a contemporaneous increase creditable because the increase previously netted out of review by relying on a past decrease which was, <u>but is no longer</u>, contemporaneous. If contemporaneous and otherwise creditable, the increase must be considered in the netting calculus.
- Not properly documenting all contemporaneous emissions changes; and
- Not ensuring that emissions decreases are covered by federallyenforceable restrictions, which is a requirement for creditability.

For the purpose of minimizing confusion and improper applicability determinations, the six-step procedure shown in Table A-5 and described below is recommended in applying the emissions netting equation. Already assumed in this procedure is that the existing source has been defined, its major source status has been confirmed and the air quality status in the area is attainment for at least one criteria pollutant.

TABLE A-5. Procedures for Determiningthe Net Emissions Change at a Source

Determine the emissions increases (but not any decreases) from the proposed project. If increases are significant, proceed; if not, the sources is not subject to review.

Determine the beginning and ending dates of the contemporaneous period as it relates to the proposed modification.

Determine which emissions units at the source experienced (or will experience, including any proposed decreases resulting from the proposed project) a creditable increase or decrease in emissions during the contemporaneous period.

Determine which emissions changes are creditable.

Determine, on a pollutant-by-pollutant basis, the amount of each contemporaneous and creditable emissions increase and decrease.

Sum all contemporaneous and creditable increases and decreases with the increase from the proposed modification to determine if a significant net emissions increase will occur.

Step 1. Determine the emissions increases from the proposed project.

First, only the emissions increases expected to result from the proposed project are examined. This includes emissions increases from the new and modified emissions units and any other plant-wide emissions increases (e.g., debottlenecking increases) that will occur as a result of the proposed modification. [Proposed emissions decreases occurring elsewhere at the source are not considered at this point. Emission decreases associated with a proposed project (such as a boiler replacement) are contemporaneous and may be considered along with other contemporaneous emissions changes at the source. However, they are <u>not</u> considered at this point in the analysis.]

A PSD review applies only to those regulated pollutants with a significant emissions increase from the proposed modification. If the proposed project will not result in a significant emissions increase of any regulated pollutant, the project is exempt from PSD review and the PSD applicability process is completed. However, if this is not the case, each regulated pollutant to be emitted in a significant amount is subject to a PSD review unless the source can demonstrate (using steps 2-6) that the sum of all other source-wide contemporaneous and creditable emissions increases and decreases would be less than significant.

Step 2 Determine the beginning and ending dates of the contemporaneous period as it relates to the proposed modification.

The period begins on the date 5 years (some States may have a different time period) before construction commences on the proposed modification. It ends on the date the emissions increase from the proposed modification occurs.

Step 3 Determine which emissions units at the source have experienced an increase or decrease in emissions during the contemporaneous period.

Usually, creditable emissions increases are associated with a physical change or change in the method of operation at a source which did not require a PSD permit. For example, creditable emissions increases may come from the construction of a new unit, a fuel switch or an increase in operation that (a) would have otherwise been subject to PSD but instead netted out of review (per steps 1-6) or (b) resulted in a less than significant emissions increase (per step 1).

Decreases are creditable reductions in actual emissions from an emissions unit that are, or can be made, federally-enforceable. A
physical change or change in the method of operation is also associated with the types of decreases that are creditable. Specifically, in the case of an emissions decrease, once the decrease has been made federally-enforceable, any proposed increase above the federallyenforceable level must constitute a physical change or change in the method of operation at the source or the reduction is not considered For example, a source could only receive an emissions creditable. decrease for netting purposes from a unit that has been taken out of operation if, due to the imposition of federally-enforceable restrictions preventing the use of the unit, a proposal to reactivate the unit would constitute a physical change or change in the method of operation at the source. If operating the unit was not considered a physical or operational change, the unit could go back to its prior level of operation at any time, thereby producing only a "paper" reduction. which is not creditable.

Step 4 Determine which emissions changes are creditable.

The following basic rules apply:

1) A increase or decrease is creditable only if the relevant reviewing authority has not relied upon it in previously issuing a PSD permit and the permit is in effect when the increase from the proposed modification occurs. As stated earlier, a reviewing authority "relies" on an increase or decrease when, after taking the increase or decrease into account, it concludes in issuing a PSD permit that a project would not cause or contribute to a violation of a PSD increment or ambient standard.

2) For pollutants with PSD increments (i.e., SO2, particulate matter and NOx), an increase or decrease in actual emissions which occurs before the baseline date in an area is creditable only if it would be considered in calculating how much of an increment remains available for the pollutant in question. An example of this situation is a 39 tpy NO. emissions increase resulting from a new heater at a major source in 1987, prior to the NO, increment baseline date. Because these emissions do not affect the allowable PSD increment, they need not be considered in 1990 when the source proposes another unrelated project. The new emissions level for the heater (up to 39 tpy) would be adjusted downward to the old level (zero) in the accounting exercise. Likewise, decreases which occurred before the baseline date was triggered cannot be credited after the baseline date. Such reductions are included in the baseline concentration and are not considered in calculating PSD increment consumption.

3) A decrease is creditable only to the extent that it is "federallyenforceable" from the moment that the actual construction begins on the proposed modification to the source. The decrease must occur before the proposed emissions increase occurs. An increase occurs when the emissions unit on which construction occurred becomes operational and begins to emit a particular pollutant. Any replacement unit that requires shakedown becomes operational only after a reasonable shakedown period not to exceed 180 days.

4) A decrease is creditable only to the extent that it has the same health and welfare significance as the proposed increase from the source.

5) A source cannot take credit for a decrease that it has had to make, or will have to make, in order to bring an emissions unit into compliance.

6) A source cannot take credit for an emissions reduction from potential emissions from an emissions unit which was permitted but never built or operated.

Step 5 Determine, on a pollutant-by-pollutant basis, the amount of each contemporaneous and creditable emissions increase and decrease.

An emissions increase is the amount by which the new level of "actual emissions" at the emissions unit exceeds the old level. The old level of "actual emissions" is that which prevailed just prior (i.e., prior 2 year average) to the physical or operational change at that unit which The new level is that which prevails just after caused the increase. In most cases, the old level is calculated from the unit's the change. actual operating data from a 2 year period which directly preceded the physical change. The new "actual emissions" level us the lower of the unit's "potential" or "allowable" emissions after the change. In other words, a contemporaneous emission increase is calculated as the positive difference between an emissions unit's potential to emit just after a physical or operation change at that unit (not the unit's current actual emissions) and the unit's actual emissions just prior to the change.

An emissions decrease is the amount by which the old level of actual emissions or the old level of allowable emissions, whichever is lower, exceeds the new level of "actual" emissions. Like emissions increases, the old level is calculated from the unit's actual operating data from a 2 year period which preceded the decrease, and the new emissions level will be the lower of the unit's "potential" or "allowable" emissions after the change. Figure A-2 shows a example of how old and new actual SO2 emissions levels are established for an existing emissions unit at a source. The applicant met with the reviewing agency in January 1988, proposing to commence construction on a new emissions unit in mid-1988. The contemporaneous time frame in this case is from mid-1983 (using EPA's 5-year definition) to the expected date of the new boiler start-up, about January 1990.

In mid-1984 an existing boiler switched to a low sulfur fuel oil. The applicant wishes to use the fuel switch as a netting credit. The time period for establishing the old SO2 emissions level for the fuel switch is 2 year period preceding the change [mid-1982] mi d-1984, when the to emissions were 600 tpy (mid-1982 through mid-1983) and 500 tpy (mid-1982 The new SO2 emissions level, through mid-1983)]. 300 tpy, is established by the new allowable emi ssi ons level (which will be made federally-The old level of emissions is 550 tpy (the average of 600 enforceable). tpy and 500 tpy). Thus, if this is the only existing SO2 emissions unit at the source, a decrease of 250 tpy SO2 emissions (550 tpy minus 300 tpv) is creditable towards the emissions proposed for the new boiler. This example assumes that the reduction meets all other applicable criteria for a creditable emissions decrease.

Step 6 Sum all contemporaneous and creditable increases and decreases with the increase from the proposed modification to determine if a significant net emissions increase will occur.

The proposed project is subject to PSD review for each regulated pollutant for which the sum of all creditable emissions increases and decreases results in a significant net emissions increase.

If available, the applicant may consider proposing additional prospective and creditable emissions reductions sufficient to provide for a less than significant net emissions increase at the source and thus avoid PSD review. These reductions can be achieved through either application of emissions controls or placing restrictions on the operation of existing emissions units. These additional reductions would be added to the sum of all other creditable increases and decreases. As with all contemporaneous emissions reductions, these additional decreases must be based on actual emissions changes, federally-enforceable prior to the commencement of construction and occur before the new unit begins operation. They must also affect the allowable PSD increment, where applicable.



Figure A-2. Establishing "Old" and "New" Representative Actual SO $_2$ Emissions

III. B. 6. NETTING EXAMPLE

An existing source has informed the local air pollution control agency that they are planning to construct a new emissions unit "G". The existing source is a major source and the construction of unit G will constitute a modification to the source. Unit G will be capable of emitting 80 tons per year (tpy) of the pollutant after installation of controls. The PSD significant emissions level for the pollutant in question is 40 tpy. Existing emissions units "A" and "B" at the source are presently permitted at 150 tpy The applicant has proposed to limit the operation of units A and B, in each. order to net out of PSD review, to 7056 hours per year (42 weeks) by accepting federally-enforceable conditions. The applicant has calculated that there will be an emissions reduction of -29.2 tpy [150 - 150x(7056/8760)] per unit for a total reduction of 58.4 tpy. Thus, the net emissions increase, as calculated by the applicant, will be +21.6 tpy (80-58.36). The applicant proposes to net out of PSD review citing the +21.6 tpy increase as less than the applicable 40 tpy PSD significance level for the pollutant.

The reviewing agency informed the source that 1) the emissions reductions being claimed from units A and B must be based on the prior actual emissions, not their allowable emissions and (2) because the increase from the modification will be greater than significant, <u>all</u> contemporaneous changes must be accounted for (not just proposed decreases) in order to determine the net emission change at the source.

To verify if, indeed, the source will be able to net out of PSD review, the reviewing agency requested information on the other emissions points at the source, including their actual monthly emissions. For illustrative purposes, the actual annual emissions of the pollutant in question from the existing emissions points (in this example all emissions points are associated with an emissions unit) are given as follows:

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Actual Emissions (tpy)								
Year	Unit A	Unit B	Unit C	Unit D	Unit E	Unit F		
1983	70	130	60	85	50	0		
1984	75	130	75	75	60	0		
1985	80	150	65	80	65	0		
1986	110	90	0	0	70	0		
1987	115	85	0	0	75	75		
1988	105	75	0	0	65	70		
1989	90	90	0	0	60	65		

The applicant's response indicates that units A and B will not be physically modified. However, the information does show that the modification will result in the removal of a bottleneck at the plant and that the proposed modification will result in an increase in the operation of these units.

The PSD baseline for the pollutant was triggered in 1978. The history of the emissions units at the source is as follows:

Emissions Unit(s)	<u>History</u>	
A and B	Built in 1972 and still operational	
C and D	Built in 1972 and retired from operation 01/86	
E	Built in 1972 and still operational	
F	PSD permitted unit; construction commenced $01/86$ and the unit became operational on $01/87$	
G	New modification; construction scheduled to commence 01/90 a the unit is expected to be operational on 01/92	ınd

The contemporaneous period extends from 01/85 (5 years prior to 01/90, the projected construction date of the modification) until 01/92 (the date the emissions increase from the modification). The net emissions change at the source can be formulated in terms of the sum of the unit-by-unit emissions changes which are creditable and contemporaneous with the planned

modification. Emission changes that are not associated with physical/ operational changes are not considered.

In assessing the creditable contemporaneous changes the permit agency considered the following (all numbers are in tpy):

- Potential to emit is used for a new unit. The new unit will receive a federally-enforceable permit restricting allowable emissions to 80 tpy, which then becomes its potential to emit. Therefore, the new unit represents an increase of +80.
- Even though units A and B will not be modified, their emissions are expected to increase as a result of the modification and the anticipated increase must be included as part of the increase from the proposed modification. The emissions change for these units is based on their allowable emissions after the change minus their current actual emissions. Current actual emissions are based on the average emissions over the last 2 years. [Note that only the operations of exiting units A and B are expected to be affected by the modification.] The emissions changes at A and B are calculated as follows:

Unit A's change = +23.3
{new allowable [150x(7056/8760)] - old actual [(105+90)/2]}
Unit B's change = +38.3
{new allowable [150x(7056/8760)] - old actual [(75+90)/2]}

The federally-enforceable restriction on the hours of operation for units A and B act to reduce the amount of the emissions increase at the units due to the modification. However, contrary to the applicant's analysis, the restrictions did not restrict the units' emissions sufficiently to prevent an actual emissions increase.

- The emissions increase from unit F was permitted under PSD. Therefore, having been "relied upon" in the issuance of a PSD permit which is still in effect, the permitted emissions increase is not creditable and cannot be used in the netting equation.
- The operation of unit E is not projected to be affected by the proposed modification. It has not undergone any physical or operational change during the contemporaneous period which would otherwise trigger a creditable emissions change at the unit. Consequently, unit E's emissions are not considered for netting purposes by the reviewing agency.

► The retirement (a physical/operational change) of units C and D occurred within the contemporaneous period and may provide creditable decreases for the applicant. However, if the retirement of the units was relied upon in the issuance of the PSD permit for unit F (e.g, if the emissions of units C or D were modeled at zero in the PSD application) then the reductions would not be creditable. If they were not modeled as retired (zero emissions), then the reduction would be available as an emissions The reduction credit would be based on the last 2 reduction. years of actual data prior to retirement. As with all reductions, to be creditable the retirement of the units must be made federally-enforceable prior to construction of the modification to and start-up of the source. Upon checking the PSD permit application for unit F, the reviewing agency determined that units C and D were not considered retired and their emissions were included in the ambient impact analysis for unit F. Consequently, the emissions reduction from the retirement of unit C and D (should the reductions be made federally-enforceable) was determined as followed:

Unit C's change = -70

{its new allowable [0] - its old actual [(75+65)/2]}

Unit D's change = -77.5

{its new allowable [0] - its old actual [(75+80)/2]}

 The netting transaction would not cause or contribute to a violation of the applicable PSD increment or ambient standards.

The applicant, however, is only willing to accept federally-enforceable conditions on the retirement of unit C. Unit D is to be kept as a standby unit and the applicant is unwilling to have its potential operation limited. Consequently, the reduction in emissions at unit D is not creditable.

The net contemporaneous emissions change at the source is calculated by the reviewing agency as follows:

Emissions Change (tpy)

+80.0 increase from unit G.
+23.3 increase at A from modification at source.
+38.8 increase at B from modification at source.
-70.0 creditable decrease from retirement of unit C
+72.1 total contemporaneous net emissions increase at the source.

The +72.1 tpy net increase is greater than the +40 tpy PSD significance level; consequently the proposed modification is subject to PSD review for that pollutant.

If the applicant is willing to agree to federally-enforceable conditions limiting the allowable emissions from unit D (but not necessarily requiring the unit's permanent retirement), a sufficient reduction may be available to net unit G out of a PSD review. For example, the applicant could agree to accept federally-enforceable conditions limiting the operation of unit D to 672 hours a year (4 weeks), which (for illustrative purposes) equates to an allowable emissions of 15 tpy. The creditable reduction from the unit D would then amount to -62.5 tpy (-77.5 + 15). This brings the total contemporaneous net emissions change for the proposed modification to +9.6 tpy (+72.1 - 62.5). The construction of Unit G would then not be considered a major modification subject to PSD review. It is important to note, however, that if unit D is permanently taken out of service after January 1991 and had not operated in the interim, the source would not be allowed an emissions reduction credit because there would have been no actual emissions decrease during the contemporaneous period. In addition, if the source later requests removal of restrictions on units which allowed unit G to net out of review, unit G then becomes subject to PSD review as though construction had not yet commenced.

IV. GENERAL EXEMPTIONS

IV. A. SOURCES AND MODIFICATIONS AFTER AUGUST 7, 1980

Certain sources may be exempted from PSD review or certain PSD requirements. Nonprofit health or educational sources that would otherwise be subject to PSD review can be exempted if requested by the Governor of the State in which they are located. A portable, major stationary source that has previously received a PSD permit and is to be relocated is exempt from a second PSD review if (1) emissions at the new location will not exceed previously allowed emission rates, (2) the emissions at the new location are temporary, and (3) the source will not, because of its new location, adversely affect a Class I area or contribute to any known increment or national ambient air quality standard (NAAQS) violation. However, the source must provide reasonable advance notice to the reviewing authority.

IV. B. SOURCES CONSTRUCTED PRIOR TO AUGUST 7, 1980

The 1980 PSD regulations do not apply to certain sources affected by previous PSD regulations. For example, sources for which construction began before August 7, 1977 are exempt from the 1980 PSD regulations and are instead reviewed for applicability under the PSD regulations as they existed before August 7, 1977. Several exemptions also exist for sources for which construction began after August 7, 1977, but before the August 7, 1980 promulgation of the PSD regulations (45 FR 52676). These exemptions and the criteria associated nonapplicability are detailed in paragraph (i) of 40 CFR 52.21.

CHAPTER B

BEST AVAILABLE CONTROL TECHNOLOGY

I. INTRODUCTION

Any major stationary source or major modification subject to PSD must conduct an analysis to ensure the application of best available control technology (BACT). The requirement to conduct a BACT analysis and determination is set forth in section 165(a)(4) of the Clean Air Act (Act), in federal regulations at 40 CFR 52.21(j), in regulations setting forth the requirements for State implementation plan approval of a State PSD program at 40 CFR 51.166(j), and in the SIP's of the various States at 40 CFR Part 52, Subpart A - Subpart FFF. The BACT requirement is defined as:

"an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results."

During each BACT analysis, which is done on a case-by-case basis, the reviewing authority evaluates the energy, environmental, economic and other

costs associated with each alternative technology, and the benefit of reduced emissions that the technology would bring. The reviewing authority then specifies an emissions limitation for the source that reflects the maximum degree of reduction achievable for each pollutant regulated under the Act. In no event can a technology be recommended which would not meet any applicable standard of performance under 40 CFR Parts 60 (New Source Performance Standards) and 61 (National Emission Standards for Hazardous Air Pollutants).

In addition, if the reviewing authority determines that there is no economically reasonable or technologically feasible way to accurately measure the emissions, and hence to impose an enforceable emissions standard, it may require the source to use design, alternative equipment, work practices or operational standards to reduce emissions of the pollutant to the maximum extent.

On December 1, 1987, the EPA Assistant Administrator for Air and Radiation issued a memorandum that implemented certain program initiatives designed to improve the effectiveness of the NSR programs within the confines of existing regulations and state implementation plans. Among these was the "top-down" method for determining best available control technology (BACT).

In brief, the top-down process provides that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent--or "top"--alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.

The purpose of this chapter is to provide a detailed description of the top-down method in order to assist permitting authorities and PSD applicants in conducting BACT analyses.

II. BACT APPLICABILITY

The BACT requirement applies to each individual new or modified affected emissions unit and pollutant emitting activity at which a net emissions increase would occur. Individual BACT determinations are performed for each pollutant subject to a PSD review emitted from the same emission unit. Consequently, the BACT determination must separately address, for each regulated pollutant with a significant emissions increase at the source, air pollution controls for each emissions unit or pollutant emitting activity subject to review.

III. A STEP BY STEP SUMMARY OF THE TOP-DOWN PROCESS

Table B-1 shows the five basic steps of the top-down procedure, including some of the key elements associated with each of the individual steps. A brief description of each step follows.

III. A. STEP 1-- IDENTIFY ALL CONTROL TECHNOLOGIES

The first step in a "top-down" analysis is to identify, for the emissions unit in question (the term "emissions unit" should be read to mean emissions unit, process or activity), all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Air pollution control technologies and techniques include the application of production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected This includes technologies employed outside of the United States. pollutant. As discussed later, in some circumstances inherently lower-polluting processes are appropriate for consideration as available control alternatives. The control alternatives should include not only existing controls for the source category in question, but also (through technology transfer) controls applied to similar source categories and gas streams, and innovative control technol ogi es. Technologies required under lowest achievable emission rate (LAER) determinations are available for BACT purposes and must also be included as control alternatives and usually represent the top alternative.

In the course of the BACT analysis, one or more of the options may be eliminated from consideration because they are demonstrated to be technically infeasible or have unacceptable energy, economic, and environmental impacts on a case-by-case (or site-specific) basis. However, at the outset, applicants

TABLE B-1. - KEY STEPS IN THE "TOP-DOWN" BACT PROCESS

STEP 1: IDENTIFY ALL CONTROL TECHNOLOGIES.

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LIST is comprehensive (LAER included).

STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS.

A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review.

STEP 3: RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS. Should include:

- control effectiveness (percent pollutant removed);
- expected emission rate (tons per year);
- expected emission reduction (tons per year);
- energy impacts (BTU, kWh);
- environmental impacts (other media and the emissions of toxic and hazardous air emissions); and
- economic impacts (total cost effectiveness, incremental cost effectiveness).

STEP 4: EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS.

- Case-by-case consideration of energy, environmental, and economic impacts.
- If top option is not selected as BACT, evaluate next most effective control option.

STEP 5: SELECT BACT

- Most effective option not rejected is BACT.

should initially identify all control options with potential application to the emissions unit under review.

III. B. STEP 2-- ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

In the second step, the technical feasibility of the control options identified in step one is evaluated with respect to the source-specific (or emissions unit-specific) factors. A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

For example, in cases where the level of control in a permit is not expected to be achieved in practice (e.g., a source has received a permit but the project was cancelled, or every operating source at that permitted level has been physically unable to achieve compliance with the limit), and supporting documentation showing why such limits are not technically feasible is provided, the level of control (but not necessarily the technology) may be eliminated from further consideration. However, a permit requiring the application of a certain technology or emission limit to be achieved for such technology usually is sufficient justification to assume the technical feasibility of that technology or emission limit.

III. C. STEP 3--RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

In step 3, all remaining control alternatives not eliminated in step 2 are ranked and then listed in order of over all control effectiveness for the pollutant under review, with the most effective control alternative at the top. A list should be prepared for each pollutant and for each emissions unit (or grouping of similar units) subject to a BACT analysis. The list should present the array of control technology alternatives and should include the following types of information:

- ! control efficiencies (percent pollutant removed);
- ! expected emission rate (tons per year, pounds per hour);
- ! expected emissions reduction (tons per year);
- ! economic impacts (cost effectiveness);
- ! environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and, at a minimum, the impact of each control alternative on emissions of toxic or hazardous air contaminants);
- ! energy impacts.

However, an applicant proposing the top control alternative need not provide cost and other detailed information in regard to other control options. In such cases the applicant should document that the control option chosen is, indeed, the top, and review for collateral environmental impacts.

III. D. STEP 4- - EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

After the identification of available and technically feasible control technology options, the energy, environmental, and economic impacts are considered to arrive at the final level of control. At this point the analysis presents the associated impacts of the control option in the listing. For each option the applicant is responsible for presenting an objective evaluation of each impact. Both beneficial and adverse impacts should be discussed and, where possible, quantified. In general, the BACT analysis should focus on the direct impact of the control alternative.

If the applicant accepts the top alternative in the listing as BACT, the applicant proceeds to consider whether impacts of unregulated air pollutants or impacts in other media would justify selection of an alternative control option. If there are no outstanding issues regarding collateral environmental impacts, the analysis is ended and the results proposed as BACT. In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding should be

documented for the public record. Then the next most stringent alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until the technology under consideration cannot be eliminated by any source-specific environmental, energy, or economic impacts which demonstrate that alternative to be inappropriate as BACT.

III. E. STEP 5--SELECT BACT

The most effective control option not eliminated in step 4 is proposed as BACT for the pollutant and emission unit under review.

IV. TOP-DOWN ANALYSIS DETAILED PROCEDURE

IV. A. IDENTIFY ALTERNATIVE EMISSION CONTROL TECHNIQUES (STEP 1)

The objective in step 1 is to identify all control options with potential application to the source and pollutant under evaluation. Later, one or more of these options may be eliminated from consideration because they are determined to be technically infeasible or to have unacceptable energy, environmental or economic impacts.

Each new or modified emission unit (or logical grouping of new or modified emission units) subject to PSD is required to undergo BACT review. BACT decisions should be made on the information presented in the BACT analysis, including the degree to which effective control alternatives were identified and evaluated. Potentially applicable control alternatives can be categorized in three ways.

- ! **Inherently Lower-Emitting Processes/Practices**, including the use of materials and production processes and work practices that prevent emissions and result in lower "production-specific" emissions; and
- ! Add-on Controls, such as scrubbers, fabric filters, thermal oxidizers and other devices that control and reduce emissions after they are produced.
- ! Conbinations of Inherently Lower Emitting Processes and Add-on Controls. For example, the application of combustion and post-combustion controls to reduce NOx emissions at a gas-fired turbine.

The top-down BACT analysis should consider potentially applicable control techniques from all three categories. Lower-polluting processes should be considered based on demonstrations made on the basis of manufacturing identical or similar products from identical or similar raw materials or fuels. Add-on controls, on the other hand, should be considered based on the physical and chemical characteristics of the pollutant-bearing emission stream. Thus, candidate add-on controls may have been applied to a broad range of emission unit types that are similar, insofar as emissions characteristics, to the emissions unit undergoing BACT review.

IV. A. 1. DEMONSTRATED AND TRANSFERABLE TECHNOLOGIES

Applicants are expected to identify all demonstrated and potentially applicable control technology alternatives. Information sources to consider include:

- ! EPA's BACT/LAER Clearinghouse and Control Technology Center;
- ! Best Available Control Technology Guideline South Coast Air Quality Management District;
- ! control technology vendors;
- ! Federal/State/Local new source review permits and associated inspection/performance test reports;
- ! environmental consultants;
- ! technical journals, reports and newsletters (e.g., JAPCA and the McIvaine reports), air pollution control seminars; and
- ! EPA's New Source Review (NSR) bulletin board.

The applicant should make a good faith effort to compile appropriate information from available information sources, including any sources specified as necessary by the permit agency. The permit agency should review the background search and resulting list of control alternatives presented by the applicant to check that it is complete and comprehensive.

In identifying control technologies, the applicant needs to survey the range of potentially available control options. Opportunities for technology transfer lie where a control technology has been applied at source categories other than the source under consideration. Such opportunities should be identified. Also, technologies in application outside the United States to the extent that the technologies have been successfully demonstrated in practice on full scale operations. Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice. To satisfy the legislative requirements of BACT, EPA believes that the applicant must focus on technologies with a demonstrated potential to achieve the highest levels of control. For example, control options incapable of meeting an applicable New Source Performance Standard (NSPS) or State Implementation Plan (SIP) limit would not meet the definition of BACT under any circumstances. The applicant does not need to consider them in the BACT analysis.

The fact that a NSPS for a source category does not require a certain level of control or particular control technology does not preclude its consideration in the top-down BACT analysis. For example, post combustion NOx controls are not required under the Subpart GG of the NSPS for Stationary Gas Turbines. However, such controls must still be considered available technologies for the BACT selection process and be considered in the BACT analysis. An NSPS simply defines the minimal level of control to be considered in the BACT analysis. The fact that a more stringent technology was not selected for a NSPS (or that a pollutant is not regulated by an NSPS) does not exclude that control alternative or technology as a BACT candidate. When developing a list of possible BACT alternatives, the only reason for comparing control options to an NSPS is to determine whether the control option would result in an emissions level less stringent than the NSPS. If so, the option is unacceptable.

IV. A. 2. INNOVATIVE TECHNOLOGIES

Although <u>not required</u> in step 1, the applicant <u>may</u> also evaluate and propose innovative technologies as BACT. To be considered innovative, a control technique must meet the provisions of 40 CFR 52.21(b)(19) or, where appropriate, the applicable SIP definition. In essence, if a developing technology has the potential to achieve a more stringent emissions level than otherwise would constitute BACT or the same level at a lower cost, it may be proposed as an innovative control technology. Innovative technologies are distinguished from technology transfer BACT candidates in that an innovative technology is still under development and has not been demonstrated in a commercial application on identical or similar emission units. In certain instances, the distinction between innovative and transferable technology may not be straightforward. In these cases, it is recommended that the permit agency consult with EPA prior to proceeding with the issuance of an innovative control technology waiver.

In the past only a limited number of innovative control technology waivers for a specific control technology have been approved. As a practical matter, if a waiver has been granted to a similar source for the same technology, granting of additional waivers to similar sources is highly unlikely since the subsequent applicants are no longer "innovative".

IV. A. 3. CONSIDERATION OF INHERENTLY LOWER POLLUTING PROCESSES/PRACTICES

Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives. For example, applicants proposing to construct a coal-fired electric generator, have not been required by EPA as part of a BACT analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting per unit product (in this case electricity). However, this is an aspect of the PSD permitting process in which states have the discretion to engage in a broader analysis if they so desire. Thus, a gas turbine normally would not be included in the list of control alternatives for a coal-fired boiler. However, there may be instances where, in the permit authority's judgment, the consideration of alternative production processes is warranted and appropriate for consideration in the BACT analysis. A production process is defined in terms of its physical and chemical unit operations used to produce the desired product from a specified

set of raw materials. In such cases, the permit agency may require the applicant to include the inherently lower-polluting process in the list of BACT candidates.

In many cases, a given production process or emissions unit can be made to be inherently less polluting (e.g; the use of water-based versus solvent based paints in a coating operation or a coal-fired boiler designed to have a low emission factor for NOx). In such cases the ability of design considerations to make the process inherently less polluting must be considered as a control alternative for the source. Inherently lowerpolluting processes/practice are usually more environmentally effective because of lower amounts of solid wastes and waste water than are generated with add-on controls. These factors are considered in the cost, energy and environmental impacts analyses in step 4 to determine the appropriateness of the additional add-on option.

Combinations of inherently lower-polluting processes/practices (or a process made to be inherently less polluting) and add-on controls are likely to yield more effective means of emissions control than either approach alone. Therefore, the option to utilize a inherently lower-polluting process does not, in and of itself, mean that no additional add-on controls need be included in the BACT analysis. These combinations should be identified in step 1 of the top down process for evaluation in subsequent steps.

IV. A. 4. EXAMPLE

The process of identifying control technology alternatives (step 1 in the top-down BACT process) is illustrated in the following hypothetical example.

Description of Source

A PSD applicant proposes to install automated surface coating process equipment consisting of a dip-tank priming stage followed by a two-step spray application and bake-on enamel finish coat. The product is a specialized electronics component (resistor) with strict resistance property specifications that restrict the types of coatings that may be employed.

List of Control Options

The source is not covered by an applicable NSPS. A review of the BACT/LAER Clearinghouse and other appropriate references indicates the following control options may be applicable:

Option #1: water-based primer and finish coat;

[The water-based coatings have never been used in applications similar to this.]

<u>Option #2</u>: low VOC solvent/high solids coating for primer and finish coat;

[The high solids/low VOC solvent coatings have recently been applied with success with similar products (e.g., other types of electrical components).]

<u>Option #3</u>: electrostatic spray application to enhance coating transfer efficiency; and

[Electrostatically enhanced coating application has been applied elsewhere on a clearly similar operation.]

<u>Option #4</u>: emissions capture with add-on control via incineration or carbon adsorber equipment.

[The VOC capture and control option (incineration or carbon adsorber) has been used in many cases involving the coating of different products and the emission stream characteristics are similar to the proposed resistor coating process and is identified as an option available through technology transfer.] Since the low-solvent coating, electrostatically enhanced application, and ventilation with add-on control options may reasonably be considered for use in combination to achieve greater emissions reduction efficiency, a total of eight control options are eligible for further consideration. The options include each of the four options listed above and the following four combinations of techniques:

<u>Option #5</u>: low-solvent coating with electrostatic applications without ventilation and add-on controls;

<u>Option #6</u>: low-solvent coating without electrostatic applications with ventilation and add-on controls;

Option #7: electrostatic application with add-on control; and

Option #8: a combination of all three technologies.

A "no control" option also was identified but eliminated because the applicant's State regulations require at least a 75 percent reduction in VOC emissions for a source of this size. Because "no control" would not meet the State regulations it could not be BACT and, therefore, was not listed for consideration in the BACT analysis.

Summary of Key Points

The example illustrates several key guidelines for identifying control options. These include:

- ! All available control techniques must be considered in the BACT analysis.
- ! Technology transfer must be considered in identifying control options. The fact that a control option has never been applied to process emission units similar or identical to that proposed does not mean it can be ignored in the BACT analysis if the potential for its application exists.
- ! Combinations of techniques should be considered to the extent they result in more effective means of achieving stringent emissions levels represented by the "top" alternative, particularly if the "top" alternative is eliminated.

IV. B. TECHNICAL FEASIBILITY ANALYSIS (STEP 2)

In step 2, the technical feasibility of the control options identified in step 1 is evaluated. This step should be straightforward for control technologies that are demonstrated--if the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and it is technically feasible. For control technologies that are not demonstrated in the sense indicated above, the analysis is somewhat more involved.

Two key concepts are important in determining whether an undemonstrated technology is feasible: "availability" and "applicability." As explained in more detail below, a technology is considered "available" if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.

Availability in this context is further explained using the following process commonly used for bringing a control technology concept to reality as a commercial product:

- ! concept stage;
- ! research and patenting;
- ! bench scale or laboratory testing;
- ! pilot scale testing;
- ! licensing and commercial demonstration; and
- ! commercial sales.

A control technique is considered available, within the context presented above, if it has reached the licensing and commercial sales stage of development. A source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, technologies in the pilot scale testing stages of development would not be considered available for BACT review. An exception would be if the technology were proposed and permitted under the qualifications of an innovative control device consistent with the provisions of 40 CFR 52.21(v) or, where appropriate, the applicable SIP.

Commercial availability by itself, however, is not necessarily sufficient basis for concluding a technology to be applicable and therefore technically feasible. Technical feasibility, as determined in Step 2, also means a control option may reasonably be deployed on or "applicable" to the source type under consideration.

Technical judgment on the part of the applicant and the review authority is to be exercised in determining whether a control alternative is applicable to the source type under consideration. In general, a commercially available control option will be presumed applicable if it has been or is soon to be deployed (e.g., is specified in a permit) on the same or a similar source type. Absent a showing of this type, technical feasibility would be based on examination of the physical and chemical characteristics of the pollutantbearing gas stream and comparison to the gas stream characteristics of the source types to which the technology had been applied previously. Deployment of the control technology on an existing source with similar gas stream characteristics is generally sufficient basis for concluding technical feasibility barring a demonstration to the contrary.

For process-type control alternatives the decision of whether or not it is applicable to the source in question would have to be based on an assessment of the similarities and differences between the proposed source and other sources to which the process technique had been applied previously. Absent an explanation of unusual circumstances by the applicant showing why a particular process cannot be used on the proposed source the review authority may presume it is technically feasible.

In practice, decisions about technical feasibility are within the purview of the review authority. Further, a presumption of technical feasibility may be made by the review authority based solely on technology transfer. For example, in the case of add-on controls, decisions of this type would be made by comparing the physical and chemical characteristics of the exhaust gas stream from the unit under review to those of the unit from which the technology is to be transferred. Unless significant differences between source types exist that are pertinent to the successful operation of the control device, the control option is presumed to be technically feasible unless the source can present information to the contrary.

Within the context of the top-down procedure, an applicant addresses the issue of technical feasibility in asserting that a control option identified in Step 1 is technically infeasible. In this instance, the applicant should make a factual demonstration of infeasibility based on commercial unavailability and/or unusual circumstances which exist with application of the control to the applicant's emission units. Generally, such a demonstration would involve an evaluation of the pollutant-bearing gas stream characteristics and the capabilities of the technology. Also a showing of unresolvable technical difficulty with applying the control would constitute a showing of technical infeasibility (e.g., size of the unit, location of the proposed site, and operating problems related to specific circumstances of the Where the resolution of technical difficulties is a matter of cost. source). the applicant should consider the technology as technically feasible. The economic feasibility of a control alternative is reviewed in the economic impacts portion of the BACT selection process.

A demonstration of technical infeasibility is based on a technical assessment considering physical, chemical and engineering principles and/or empirical data showing that the technology would not work on the emissions unit under review, or that unresolvable technical difficulties would preclude the successful deployment of the technique. Physical modifications needed to resolve technical obstacles do not in and of themselves provide a justification for eliminating the control technique on the basis of technical infeasibility. However, the cost of such modifications can be considered in estimating cost and economic impacts which, in turn, may form the basis for eliminating a control technology (see later discussion at V. D. 2).

Vendor guarantees may provide an indication of commercial availability and the technical feasibility of a control technique and could contribute to a determination of technical feasibility or technical infeasibility, depending on circumstances. However, EPA does not consider a vendor guarantee alone to be sufficient justification that a control option will work. Conversely, lack of a vendor guarantee by itself does not present sufficient justification that a control option or an emissions limit is technically infeasible. Generally, decisions about technical feasibility will be based on chemical, and engineering analyses (as discussed above) in conjunction with information about vendor guarantees.

A possible outcome of the top-down BACT procedures discussed in this document is the evaluation of multiple control technology alternatives which result in essentially equivalent emissions. It is not EPA's intent to encourage evaluation of unnecessarily large numbers of control alternatives for every emissions unit. Consequently, judgment should be used in deciding what alternatives will be evaluated in detail in the impacts analysis (Step 4) of the top-down procedure discussed in a later section. For example, if two or more control techniques result in control levels that are essentially identical considering the uncertainties of emissions factors and other parameters pertinent to estimating performance, the source may wish to point this out and make a case for evaluation and use only of the less costly of these options. The scope of the BACT analysis should be narrowed in this way

only if there is a negligible difference in emissions and collateral environmental impacts between control alternatives. Such cases should be discussed with the reviewing agency before a control alternative is dismissed at this point in the BACT analysis due to such considerations.

It is encouraged that judgments of this type be discussed during a preapplication meeting between the applicant and the review authority. In this way, the applicant can be better assured that the analysis to be conducted will meet BACT requirements. The appropriate time to hold such a meeting during the analysis is following the completion of the control hierarchy discussed in the next section.

Summary of Key Points

In summary, important points to remember in assessing technical feasibility of control alternatives include:

- ! A control technology that is "demonstrated" for a given type or class of sources is assumed to be technically feasible unless source-specific factors exist and are documented to justify technical infeasibility.
- ! Technical feasibility of technology transfer control candidates generally is assessed based on an evaluation of pollutant-bearing gas stream characteristics for the proposed source and other source types to which the control had been applied previously.
- ! Innovative controls that have not been demonstrated on any source type similar to the proposed source need not be considered in the BACT analysis.
- ! The applicant is responsible for providing a basis for assessing technical feasibility or infeasibility and the review authority is responsible for the decision on what is and is not technically feasible.

IV. C. RANKING THE TECHNICALLY FEASIBLE ALTERNATIVES TO ESTABLISH A CONTROL HIERARCHY (STEP 3)

Step 3 involves ranking all the technically feasible control alternatives

which have been previously identified in Step 2. For the regulated pollutant and emissions unit under review, the control alternatives are ranked-ordered from the most to the least effective in terms of emission reduction potential. Later, once the control technology is determined, the focus shifts to the specific limits to be met by the source.

Two key issues that must be addressed in this process include:

- ! What common units should be used to compare emissions performance levels among options?
- ! How should control techniques that can operate over a wide range of emission performance levels (e.g., scrubbers, etc.) be considered in the analysis?

IV. C. 1. CHOICE OF UNITS OF EMISSIONS PERFORMANCE TO COMPARE LEVELS AMONGST CONTROL OPTIONS

In general, this issue arises when comparing inherently lower-polluting processes to one another or to add-on controls. For example, direct comparison of powdered (and low-VOC) coatings and vapor recovery and control systems at a metal furniture finishing operation is difficult because of the different units of measure for their effectiveness. In such cases, it is generally most effective to express emissions performance as an average steady state emissions level per unit of product produced or processed. Examples are:

- ! pounds VOC emission per gallons of solids applied,
- ! pounds PM emission per ton of cement produced,
- ! pounds SO2 emissions per million Btu heat input, and
- ! pounds SO2 emission per kilowatt of electric power produced,

Calculating annual emissions levels (tons/yr) using these units becomes straightforward once the projected annual production or processing rates are known. The result is an estimate of the annual pollutant emissions that the source or emissions unit will emit. Annual "potential" emission projections are calculated using the source's maximum design capacity and full year round operation (8760 hours), unless the final permit is to include federally enforceable conditions restricting the source's capacity or hours of operation. However, emissions estimates used for the purpose of calculating and comparing the cost effectiveness of a control option are based on a different approach (see section V. D. 2. b. COST EFFECTIVENESS).

IV. C. 2. CONTROL TECHNIQUES WITH A WIDE RANGE OF EMISSIONS PERFORMANCE LEVELS

The objective of the top-down BACT analysis is to not only identify the best control technology, but also a corresponding performance level (or in some cases performance range) for that technology considering source-specific factors. Many control techniques, including both add-on controls and inherently lower polluting processes can perform at a wide range of levels. Scrubbers, high and low efficiency electrostatic precipitators (ESPs), and low-VOC coatings are examples of just a few. It is not the EPA's intention to require analysis of each possible level of efficiency for a control technique, as such an analysis would result in a large number of options. Rather, the applicant should use the most recent regulatory decisions and performance data for identifying the emissions performance level(s) to be evaluated in all cases.

The EPA does not expect an applicant to necessarily accept an emission limit as BACT solely because it was required previously of a similar source type. While the most effective level of control must be considered in the

BACT analysis, different levels of control for a given control alternative can be considered.¹ For example, the consideration of a lower level of control for a given technology may be warranted in cases where past decisions involved different source types. The evaluation of an alternative control level can also be considered where the applicant can demonstrate to the satisfaction of the permit agency demonstrate that other considerations show the need to evaluate the control alternative at a lower level of effectiveness.

Manufacturer's data, engineering estimates and the experience of other sources provide the basis for determining achievable limits. Consequently, in assessing the capability of the control alternative, latitude exists to consider any special circumstances pertinent to the specific source under review, or regarding the prior application of the control alternative. However, the basis for choosing the alternate level (or range) of control in the BACT analysis must be documented in the application. In the absence of a showing of differences between the proposed source and previously permitted sources achieving lower emissions limits, the permit agency should conclude that the lower emissions limit is representative for that control alternative.

In summary, when reviewing a control technology with a wide range of emission performance levels, it is presumed that the source can achieve the same emission reduction level as another source unless the applicant demonstrates that there are source-specific factors or other relevant information that provide a technical, economic, energy or environmental justification to do otherwise. Also, a control technology that has been eliminated as having an adverse economic impact at its highest level of performance, may be acceptable at a lesser level of performance. For example, this can occur when the cost effectiveness of a control technology at its

¹ In reviewing the BACT submittal by a source the permit agency may determine that an applicant should consider a control technology alternative otherwise eliminated by the applicant, if the operation of that control technology at a lower level of control (but still higher than the next control alternative. For example, while scrubber operating at 98% efficiency may be eliminated as BACT by the applicant due to source specific economic considerations, the scrubber operating in the 90% to 95% efficiency range may not have an adverse economic impact.

highest level of performance greatly exceeds the cost of that control technology at a somewhat lower level (or range) of performance.

IV. C. 3. ESTABLISHMENT OF THE CONTROL OPTIONS HIERARCHY

After determining the emissions performance levels (in common units) of each control technology option identified in Step 2, a hierarchy is established that places at the "top" the control technology option that achieves the lowest emissions level. Each other control option is then placed after the "top" in the hierarchy by its respective emissions performance level, ranked from lowest emissions to highest emissions (most effective to least stringent effective emissions control alternative).

From the hierarchy of control alternatives the applicant should develop a chart (or charts) displaying the control hierarchy and, where applicable,:

- ! expected emission rate (tons per year, pounds per hour);
- ! emissions performance level (e.g., percent pollutant removed, emissions per unit product, lb/MMbtu, ppm);
- ! expected emissions reduction (tons per year);
- ! economic impacts (total annualized costs, cost effectiveness, incremental cost effectiveness);
- ! environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and the relative ability of each control alternative to control emissions of toxic or hazardous air contaminants);
- ! energy impacts (indicate any significant energy benefits or disadvantages).

This should be done for each pollutant and for each emissions unit (or grouping of similar units) subject to a BACT analysis. The chart is used in comparing the control alternatives during step 4 of the BACT selection process. Some sample charts are displayed in Table B-2 and Table B-3. Completed sample charts accompany the example BACT analyses provided in section VI.

At this point, it is recommended that the applicant contact the reviewing agency to determine whether the agency feels that any other applicable control alternative should be evaluated or if any issues require special attention in the BACT selection process.

IV. D. THE BACT SELECTION PROCESS (STEP 4)

After identifying and listing the available control options the next step is the determination of the energy, environmental, and economic impacts of each option and the selection of the final level of control. The applicant is responsible for presenting an evaluation of each impact along with appropriate supporting information. Consequently, both beneficial and adverse impacts should be discussed and, where possible, quantified. In general, the BACT analysis should focus on the direct impact of the control alternative.

Step 4 validates the suitability of the top control option in the listing for selection as BACT, or provides clear justification why the top candidate is inappropriate as BACT. If the applicant accepts the top alternative in the listing as BACT from an economic and energy standpoint, the applicant proceeds to consider whether collateral environmental impacts (e.g., emissions of unregulated air pollutants or impacts in other media) would justify selection of an alternative control option. If there are no outstanding issues regarding collateral environmental impacts, the analysis is ended and the results proposed as BACT. In the event that the top candidate
TABLE B-2. SAMPLE BACT CONTROL HIERARCHY

Pollutant	Technol ogy	Range of control (%)	Control level for BACT analysis (%)	Emissions limit
S0 ₂	First Alternative	80-95	95	15 ppm
	Second Alternative	80-95	90	30 ppm
	Third Alternative	70-85	85	45 ppm
	Fourth Alternative	40-80	75	75 ppm
	Fifth Alternative	50-85	70	90 ppm
	Baseline Alternative	-	-	-

TABLE B-3. SAMPLE SUMMARY OF TOP-DOWN BACT IMPACT ANALYSIS RESULTS.

	Control alternative	Emissions (lb/hr,tpy)	Emissions reduction(a) (tpy)	Economic Impacts			Environmental Impacts		Energy Impacts
Pollutant/ Emissions Unit				Total annualized cost(b) (\$/yr)	Average Cost effectiveness(c) (\$/ton)	Incremental cost effectiveness(d) (\$/ton)	Toxi <i>c</i> s impact(e) (Yes/No)	Adverse environmental impacts(f) (Yes/No)	incremental increase over baseline(g) (NHBtu/yr)
NOx/Unit A	Top Alternative Other Alternative(s) Baseline								
NOx/Unit B	Top Alternative Other Alternative(s) Baseline								
SO2/Unit A	Top Alternative Other Alternative(s) Baseline								
SO2/Unit B	Top Alternative Other Alternative(s) Baseline								

(a) Emissions reduction over baseline level.

(b) Total annualized cost (capital, direct, and indirect) of purchasing, installing, and operating the proposed control alternative. A capital recovery factor approach using a real interest rate (i.e., absent inflation) is used to express capital costs in present-day annual costs.

(c) Average Cost Effectiveness is total annualized cost for the control option divided by the emissions reductions resulting from the option.

D R A (d) The incremental cost effectiveness is the difference in annualized cost for the control option and the next most effective control option divided by the difference in emissions reduction resulting from the respective alternatives. 1990 F

(e) Toxics impact means there is a toxics impact consideration for the control alternative.

(f) Adverse environmental impact means there is an adverse environmental impact consideration with the control alternative.

(q) Energy impacts are the difference in total project energy requirements with the control alternative and the baseline expressed in equivalent millions of Btus per year.

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is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding needs to be fully documented for the public record. Then, the next most effective alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until the control technology under consideration cannot be eliminated by any source-specific environmental, energy, or economic impacts which demonstrate that the alternative is inappropriate as BACT.

The determination that a control alternative to be inappropriate involves a demonstration that circumstances exist at the source which distinguish it from other sources where the control alternative may have been required previously, or that argue against the transfer of technology or application of new technology. Alternately, where a control technique has been applied to only one or a very limited number of sources, the applicant can identify those characteristic(s) unique to those sources that may have made the application of the control appropriate in those case(s) but not for the source under consideration. In showing unusual circumstances, objective factors dealing with the control technology and its application should be the focus of the consideration. The specifics of the situation will determine to what extent an appropriate demonstration has been made regarding the elimination of the more effective alternative(s) as BACT. In the absence of unusual circumstance, the presumption is that sources within the same category are similar in nature, and that cost and other impacts that have been borne by one source of a given source category may be borne by another source of the same source category.

IV. D. 1. ENERGY IMPACTS ANALYSIS

Applicants should examine the energy requirements of the control technology and determine whether the use of that technology results in any significant or unusual energy penalties or benefits. A source may, for example, benefit from the combustion of a concentrated gas stream rich in volatile organic compounds; on the other hand, more often extra fuel or electricity is required to power a control device or incinerate a dilute gas stream. If such benefits or penalties exist, they should be quantified. Because energy penalties or benefits can usually be quantified in terms of

additional cost or income to the source, the energy impacts analysis can, in most cases, simply be factored into the economic impacts analysis. However, certain types of control technologies have inherent energy penalties associated with their use. While these penalties should be quantified, so long as they are within the normal range for the technology in question, such penalties should not, in general, be considered adequate justification for nonuse of that technology.

Energy impacts should consider only direct energy consumption and not indirect energy impacts. For example, the applicant could estimate the direct energy impacts of the control alternative in units of energy consumption at the source (e.g., Btu, kWh, barrels of oil, tons of coal). The energy requirements of the control options should be shown in terms of total (and in certain cases also incremental) energy costs per ton of pollutant removed. These units can then be converted into dollar costs and, where appropriate, factored into the economic analysis.

As noted earlier, indirect energy impacts (such as energy to produce raw materials for construction of control equipment) generally are not considered. However, if the permit authority determines, either independently or based on a showing by the applicant, that the indirect energy impact is unusual or significant and that the impact can be well quantified, the indirect impact may be considered. The energy impact should still focus on the application of the control alternative and not a concern over general energy impacts associated with the project under review as compared to alternative projects for which a permit is not being sought, or as compared to a pollution source which the project under review would replace (e.g., it would be inappropriate to argue that a cogeneration project is more efficient in the production of electricity than the powerplant production capacity it would displace and, therefore, should not be required to spend equivalent costs for the control of the same pollutant).

The energy impact analysis may also address concerns over the use of locally scarce fuels. The designation of a scarce fuel may vary from region to region, but in general a scarce fuel is one which is in short supply locally and can be better used for alternative purposes, or one which may not be reasonably available to the source either at the present time or in the near future.

IV. D. 2. COST/ECONOMIC IMPACTS ANALYSIS

Average and incremental cost effectiveness are the two economic criteria that are considered in the BACT analysis. Cost effectiveness, is the dollars per ton of pollutant emissions reduced. Incremental cost is the cost per ton reduced and should be considered in conjunction with total average effectiveness.

In the economical impacts analysis, primary consideration should be given to quantifying the cost of control and not the economic situation of the individual source. Consequently, applicants generally should not propose elimination of control alternatives on the basis of economic parameters that provide an indication of the affordability of a control alternative relative to the source. BACT is required by law. Its costs are integral to the overall cost of doing business and are not to be considered an afterthought. Consequently, for control alternatives that have been effectively employed in the same source category, the economic impact of such alternatives on the particular source under review should be not nearly as pertinent to the BACT decision making process as the average and, where appropriate, incremental cost effectiveness of the control alternative. Thus, where a control technology has been successfully applied to similar sources in a source category, an applicant should concentrate on documenting significant cost differences, if any, between the application of the control technology on those other sources and the particular source under review.

Cost effectiveness (dollars per ton of pollutant reduced) values above the levels experienced by other sources of the same type and pollutant, are taken as an indication that unusual and persuasive differences exist with respect to the source under review. In addition, where the cost of a control alternative for the specific source reviewed is within the range of normal costs for that control alternative, the alternative, in certain limited circumstances, may still be eligible for elimination. To justify elimination of an alternative on these grounds, the applicant should demonstrate to the satisfaction of the permitting agency that costs of pollutant removal for the control alternative are disproportionately high when compared to the cost of control for that particular pollutant and source in recent BACT determinations. If the circumstances of the differences are adequately documented and explained in the application and are acceptable to the reviewing agency they may provide a basis for eliminating the control alternative.

In all cases, economic impacts need to be considered in conjunction with energy and environmental impacts (e.g., toxics and hazardous pollutant considerations) in selecting BACT. It is possible that the environmental impacts analysis or other considerations (as described elsewhere) would override the economic elimination criteria as described in this section. However, absent overriding environmental impacts concerns or other considerations, an acceptable demonstration of a adverse economic impact can be adequate basis for eliminating the control alternative.

IV. D. 2. a. ESTIMATING THE COSTS OF CONTROL

Before costs can be estimated, the control system design parameters must be specified. The most important item here is to ensure that the design parameters used in costing are consistent with emissions estimates used in other portions of the PSD application (e.g., dispersion modeling inputs and permit emission limits). In general, the BACT analysis should present vendorsupplied design parameters. Potential sources of other data on design parameters are BID documents used to support NSPS development, control technique guidelines documents, cost manuals developed by EPA, or control data in trade publications. Table B-4 presents some example design parameters which are important in determining system costs. To begin, the limits of the area or process segment to be costed specified. This well defined area or process segment is referred to as the control system battery limits. The second step is to list and cost each major piece of equipment within the battery limits. The top-down BACT analysis should provide this list of costed equipment. The basis for equipment cost estimates also should be documented, either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source [such as the OAQPS Control Cost Manual (Fourth Edition), EPA 450/3-90-006, January 1990, Table B-4]. Inadequate documentation of battery limits is one of the most common reasons for confusion in comparison of costs of the same controls applied to similar sources. For control options that are defined as inherently lower-polluting processes (and not add-on controls), the battery limits may be the entire process or project.

Design parameters should correspond to the specified emission level. The equipment vendors will usually supply the design parameters to the applicant, who in turn should provide them to the reviewing agency. In order to determine if the design is reasonable, the design parameters can be compared with those shown in documents such as the <u>OAQPS Control Cost Manual</u>, <u>Control Technology for Hazardous Air Pollutants (HAPS) Manual</u> (EPA 625/6-86-014, September 1986), and background information documents for NSPS and NESHAP regulations. If the design specified does not appear reasonable, then the applicant should be requested to supply performance test data for the control technology in question applied to the same source, or a similar source.

TABLE B-4. EXAMPLE CONTROL SYSTEM DESIGN PARAMETERS

Control	Example Design parameters				
Wet Scrubbers	Scrubber liquor (water, chemicals, etc.) Gas pressure drop Liquid/gas ratio				
Carbon Absorbers	Specific chemical species Gas pressure drop lbs carbon/lbs pollutant				
Condensers	Condenser type Outlet temperature				
Incineration	Residence time Temperature				
Electrostatic Precipitator	Specific collection area (ft2/acfm) Voltage density				
Fabric Filter	Air to cloth ratio Pressure drop				
Selective Catalytic Reduction	Space velocity Ammonia to NOx molar ratio Pressure drop Catalyst life				

Once the control technology alternatives and achievable emissions performance levels have been identified, capital and annual costs are developed. These costs form the basis of the cost and economic impacts (discussed later) used to determine and document if a control alternative should be eliminated on grounds of its economic impacts.

Consistency in the approach to decision-making is a primary objective of the top-down BACT approach. In order to maintain and improve the consistency of BACT decisions made on the basis of cost and economic considerations, procedures for estimating control equipment costs are based on EPA's OAQPS Control cost Manual and are set forth in Appendix B of this document. Applicants should closely follow the procedures in the appendix and any deviations should be clearly presented and justified in the documentation of the BACT analysis.

Normally the submittal of very detailed and comprehensive project cost data is not necessary. However, where initial control cost projections on the part of the applicant appear excessive or unreasonable (in light of recent cost data) more detailed and comprehensive cost data may be necessary to document the applicant's projections. An applicant proposing the top alternative usually does not need to provide cost data on the other possible control alternatives.

Total cost estimates of options developed for BACT analyses should be on order of plus or minus 30 percent accuracy. If more accurate cost data are available (such as specific bid estimates), these should be used. However, these types of costs may not be available at the time permit applications are being prepared. Costs should also be site specific. Some site specific factors are costs of raw materials (fuel, water, chemicals) and labor. For example, in some remote areas costs can be unusually high. For example, remote locations in Alaska may experience a 40-50 percent premium on installation costs. The applicant should document any unusual costing assumptions used in the analysis.

IV. D. 2. b. COST EFFECTIVENESS

Cost effectiveness is the economic criterion used to assess the potential for achieving an objective at least cost. Effectiveness is measured in terms of tons of pollutant emissions removed. Cost is measured in terms of annualized control costs.

The Cost effectiveness calculations can be conducted on an average, or incremental basis. The resultant dollar figures are sensitive to the number of alternatives costed as well as the underlying engineering and cost parameters. There are limits to the use of cost-effectiveness analysis. For example, cost-effectiveness analysis should not be used to set the environmental objective. Second, cost-effectiveness should, in and of itself, not be construed as a measure of adverse economic impacts. There are two measures of cost-effectiveness that will be discussed in this section: (1) average cost-effectiveness, and (2) incremental cost-effectiveness.

Average Cost Effectiveness

Average cost effectiveness (total annualized costs of control divided by annual emission reductions, or the difference between the baseline emission rate and the controlled emission rate) is a way to present the costs of control. Average cost effectiveness is calculated as shown by the following formula: Average cost Effectiveness (dollars per ton removed) =

<u>Control option annualized cost</u> Baseline emissions rate - Control option emissions rate

Costs are calculated in (annualized) dollars per year (\$/yr) and emissions rates are calculated in tons per year (tons/yr). The result is a cost

effectiveness number in (annualized) dollars per ton (\$/ton) of pollutant removed.

Calculating Baseline Emissions

The baseline emissions rate represents a realistic scenario of upper boundary uncontrolled emissions for the source. The NSPS/NESHAP requirements or the application of controls, including other controls necessary to comply with State or local air pollution regulations, are not considered in calculating the baseline emissions. In other words, baseline emissions are essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions. When calculating the cost effectiveness of adding post process emissions controls to certain inherently lower polluting processes, baseline emissions may be assumed to be the emissions from the lower polluting process itself. In other words, emission reduction credit can be taken for use of inherently lower polluting processes.

Estimating realistic upper-bound case scenario does not mean that the source operates in an absolute worst case manner all the time. For example, in

developing a realistic upper boundary case, baseline emissions calculations can also consider inherent physical or operational constraints on the source. Such constraints should accurately reflect the true upper boundary of the source's ability to physically operate and the applicant should submit documentation to verify these constraints. If the applicant does not adequately verify these constraints, then the reviewing agency should not be compelled to consider these constraints in calculating baseline emissions. In addition, the reviewing agency may require the applicant to calculate cost

effectiveness based on values exceeding the upper boundary assumptions to determine whether or not the assumptions have a deciding role in the BACT determination. If the assumptions have a deciding role in the BACT determination, the reviewing agency should include enforceable conditions in the permit to assure that the upper bound assumptions are not exceeded.

For example, VOC emissions from a storage tank might vary significantly with temperature, volatility of liquid stored, and throughput. In this case, potential emissions would be overestimated if annual VOC emissions were estimated by extrapolating over the course of a year VOC emissions based solely on the hottest summer day. Instead, the range of expected temperatures should be considered in determining annual baseline emissions. Likewise, potential emissions would be overestimated if one assumed that gasoline would be stored in a storage tank being built to feed an oil-fired power boiler or such a tank will be continually filled and emptied. On the other hand, an upper bound case for a storage tank being constructed to store and transfer liquid fuels at a marine terminal should consider emissions based on the most volatile liquids at a high annual throughput level since it would not be unrealistic for the tank to operate in such a manner.

In addition, historic upper bound operating data, typical for the source or industry, may be used in defining baseline emissions in evaluating the cost effectiveness of a control option for a specific source. For example, if for a source or industry, historical upper bound operations call for two shifts a day, it is not necessary to assume full time (8760 hours) operation on an annual basis in calculating baseline emissions. For comparing cost effectiveness, the same realistic upper boundary assumptions must, however, be used for both the source in question and other sources (or source categories) that will later be compared during the BACT analysis.

For example, suppose (based on verified historic data regarding the industry in question) a given source can be expected to utilize numerous colored inks over the course of a year. Each color ink has a different VOC content ranging from a high VOC content to a relatively low VOC content. The source verifies that its operation will indeed call for the application of numerous color inks. In this case, it is more realistic for the baseline

emission calculation for the source (and other similar sources) to be based on the expected mix of inks that would be expected to result in an upper boundary case annual VOC emissions rather than an assumption that only one color (i.e, the ink with the highest VOC content) will be applied exclusively during the whole year.

In another example, suppose sources in a particular industry historically operate at most at 85 percent capacity. For BACT cost effectiveness purposes (but **mot** for applicability), an applicant may calculate cost effectiveness using 85 percent capacity. However, in comparing costs with similar sources, the applicant must consistently use an 85 percent capacity factor for the cost effectiveness of controls on those other sources.

Although permit conditions are normally used to make operating assumptions enforceable, the use of "standard industry practice" parameters for cost effectiveness calculations (but **mot** applicability determinations) can be acceptable without permit conditions. However, when a source projects operating parameters (e.g., limited hours of operation or capacity utilization, type of fuel, raw materials or product mix or type) that are lower than standard industry practice or which have a deciding role in the BACT determination, then these parameters or assumptions must be made enforceable with permit conditions. If the applicant will not accept enforceable permit conditions, then the reviewing agency should use the absolute worst case uncontrolled emissions in calculating baseline emissions. This is necessary to ensure that the permit reflects the conditions under which the source intends to operate.

For example, the baseline emissions calculation for an emergency standby generator may consider the fact that the source does not intend to operate more than 2 weeks a year. On the other hand, baseline emissions associated with a base-loaded turbine would not consider limited hours of operation. This produces a significantly higher level of baseline emissions than in the case of the emergency/standby unit and results in more cost effective controls. As a consequence of the dissimilar baseline emissions, BACT for the

two cases could be very different. Therefore, it is important that the applicant confirm that the operational assumptions used to define the source's baseline emissions (and BACT) are genuine. As previously mentioned, this is usually done through enforceable permit conditions which reflect limits on the source's operation which were used to calculate baseline emissions.

In certain cases, such explicit permit conditions may not be necessary. For example, a source for which continuous operation would be a physical impossibility (by virtue of its design) may consider this limitation in estimating baseline emissions, without a direct permit limit on operations. However, the permit agency has the responsibility to verify that the source is constructed and operated consistent with the information and design specifications contained in the permit application.

For some sources it may be more difficult to define what emissions level actually represents uncontrolled emissions in calculating baseline emissions. For example, uncontrolled emissions could theoretically be defined for a spray coating operation as the maximum VOC content coating at the highest possible rate of application that the spray equipment could physically process, (even though use of such a coating or application rate would be unrealistic for the source). Assuming use of a coating with a VOC content and application rate greater than expected is unrealistic and would result in an overestimate in the amount of emissions reductions to be achieved by the installation of various control options. Likewise, the cost effectiveness of the options could consequently be greatly underestimated. To avoid these problems, uncontrolled emission factors should be represented by the highest realistic VOC content of

the types of coatings and highest realistic application rates that would be used by the source, rather than by highest VOC based coating materials or rate of application in general.

Conversely, if uncontrolled emissions are underestimated, emissions reductions to be achieved by the various control options would also be underestimated and their cost effectiveness overestimated. For example, this type of situation occurs in the previous example if the baseline for the above

coating operation was based on a VOC content coating or application rate that is too low [when the source had the ability and intent to utilize (even infrequently) a higher VOC content coating or application rate].

Incremental Cost Effectiveness

In addition to the average cost effectiveness of a control option, incremental cost effectiveness between control options should also be calculated. The incremental cost effectiveness should be examined in combination with the total cost effectiveness in order to justify elimination of a control option. The incremental cost effectiveness calculation compares the costs and emissions performance level of a control option to those of the next most stringent option, as shown in the following formula:

Incremental Cost (dollars per incremental ton removed) =

Total costs (annualized) of control option - Total costs (annualized) of next control option Next control option emission rate - Control option emissions rate

Care should be exercised in deriving incremental costs of candidate control options. Incremental cost-effectiveness comparisons should focus on annualized cost and emission reduction differences between **dominant** alternatives. Dominant set of control alternatives are determined by generating what is called the envelope of least-cost alternatives. This is a graphical plot of total annualized costs for a total emissions reductions for all control alternatives identified in the BACT analysis (see Figure B-1).

For example, assume that eight technically available control options for analysis are listed in the BACT hierarchy. These are represented as A through H in Figure B-1. In calculating incremental costs, the analysis should only be conducted for control options that are dominant among all possible options. In Figure B-1, the dominant set of control options, A, B, D, F, G, and H, represent the least-cost envelope depicted by the curvilinear line connecting them. Points C and E are inferior options and should not be considered in the



Figure B-1. LEAST-COST ENVELOPE

derivation of incremental cost effectiveness. Points A, C and E represent inferior controls because B will buy more emissions reduction for less money than A; and similarly, D and F will by more reductions for less money than E, respectively.

Consequently, care should be taken in selecting the dominant set of controls when calculating incremental costs. First, the control options need to be rank ordered in ascending order of annualized total costs. Then, as Figure B-1 illustrates, the most reasonable smooth curve of the control options is plotted. The incremental cost effectiveness is then determined by the difference in total annual costs between two contiguous options divided by the difference in emissions reduction. An example is illustrated in Figure B-1 for the incremental cost effectiveness for control option F. The vertical distance, "delta" Total Costs Annualized, divided by the horizontal distance, "delta" Emissions Reduced (tpy), would be the measure of the incremental cost effectiveness for option F.

A comparison of incremental costs can also be useful in evaluating the economic viability of a specific control option over a range of efficiencies. For example, depending on the capital and operational cost of a control device, total and incremental cost may vary significantly (either increasing or decreasing) over the operation range of a control device.

As a precaution, differences in incremental costs among dominant alternatives cannot be used by itself to argue one dominant alternative is preferred to another. For example, suppose dominant alternatives B, D and F on the least-cost envelope (see Figure B-1) are identified as alternatives for a BACT analysis. We may observe the incremental cost effectiveness between dominant alternative B and D is \$500 per ton whereas between dominant alternative D and F is \$1000 per ton. Alternative D does <u>not</u> dominate alternative F. Both alternatives are dominant and hence on the least cost envelope. Alternative D cannot legitimately be preferred to F on grounds of incremental cost effectiveness.

In addition, when evaluating the total or incremental cost effectiveness of a control alternative, reasonable and supportable assumptions regarding control efficiencies should be made. An unrealistically low assessment of the emission reduction potential of a certain technology could result in inflated cost effectiveness figures.

The final decision regarding the reasonableness of calculated cost effectiveness values will be made by the review authority considering previous regulatory decisions. Study cost estimates used in BACT are typically accurate to \pm 20 to 30 percent. Therefore, control cost options which are within \pm 20 to 30 percent of each other should generally be considered to be indistinguishable when comparing options.

IV. D. 2. c. DETERMINING AN ADVERSE ECONOMIC IMPACT

It is important to keep in mind that BACT is primarily a technologybased standard. In essence, if the cost of reducing emissions with the top control alternative, expressed in dollars per ton, is on the same order as the cost previously borne by other sources of the same type in applying that control alternative, the alternative should initially be considered economically achievable, and therefore acceptable as BACT. However, unusual circumstances may greatly affect the cost of controls in a specific application. If so they should be documented. An example of an unusual circumstance might be the unavailability in an arid region of the large amounts of water needed for a scrubbing system. Acquiring water from a distant location might add unreasonable costs to the alternative, thereby justifying its elimination on economic grounds. Consequently, where unusual factors exist that result in cost/economic impacts beyond the range normally incurred by other sources in that category, the technology can be eliminated provided the applicant has adequately identified the circumstances, including the cost or other analyses, that show what is significantly different about the proposed source.

Where the cost of a control alternative for the specific source being reviewed is within the range of normal costs for that control alternative, the

alternative may also be eligible for elimination in limited circumstances. This may occur, for example, where a control alternative has not been required as BACT (or its application as BACT has been extremely limited) and there is a clear demarcation between recent BACT control costs in that source category and the control costs for sources in that source category which have been driven by other constraining factors (e.g., need to meet a PSD increment or a NAAQS).

To justify elimination of an alternative on these grounds, the applicant should demonstrate to the satisfaction of the permitting agency that costs of pollutant removal (e.g., dollars per total ton removed) for the control alternative are disproportionately high when compared to the cost of control for the pollutant in recent BACT determinations. Specifically, the applicant should document that the cost to the applicant of the control alternative is significantly beyond the range of recent costs normally associated with BACT for the type of facility (or BACT control costs in general) for the pollutant. This type of analysis should demonstrate that a technically and economically feasible control option is nevertheless, by virtue of the magnitude of its associated costs and limited application, unreasonable or otherwise not "achievable" as BACT in the particular case. Total and incremental cost effectiveness numbers are factored into this type of analysis. However, such economic information should be coupled with a comprehensive demonstration, based on objective factors, that the technology is inappropriate in the specific circumstance.

The economic impact portion of the BACT analysis should not focus on inappropriate factors or exclude pertinent factors, as the results may be misleading. For example, the capital cost of a control option may appear excessive when presented by itself or as a percentage of the total project cost. However, this type of information can be misleading. If a large emissions reduction is projected, low or reasonable cost effectiveness numbers may validate the option as an appropriate BACT alternative irrespective of the apparent high capital costs. In another example, undue focus on incremental cost effectiveness can give an impression that the cost of a control

alternative is unreasonably high, when, in fact, the total cost effectiveness, in terms of dollars per total ton removed, is well within the normal range of acceptable BACT costs.

IV. D. 3. ENVIRONMENTAL IMPACTS ANALYSIS

The environmental impacts analysis is not to be confused with the air quality impact analysis (i.e., ambient concentrations), which is an independent statutory and regulatory requirement and is conducted separately from the BACT analysis. The purpose of the air quality analysis is to demonstrate that the source (using the level of control ultimately determined to be BACT) will not cause or contribute to a violation of any applicable national ambient air quality standard or PSD increment. Thus, regardless of the level of control proposed as BACT, a permit cannot be issued to a source that would cause or contribute to such a violation. In contrast, the environmental impacts portion of the BACT

analysis concentrates on impacts other than impacts on air quality (i.e., ambient concentrations) due to emissions of the regulated pollutant in question, such as solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, or emissions of unregulated pollutants.

Thus, the fact that a given control alternative would result in only a slight decrease in ambient concentrations of the pollutant in question when compared to a less stringent control alternative should not be viewed as an adverse **environmental** impact justifying rejection of the more stringent control alternative. However, if the cost effectiveness of the more stringent alternative is exceptionally high, it may (as provided in section V. D. 2.) be considered in determining the existence of an adverse **economic** impact that would justify rejection of the more stringent alternative.

The applicant should identify any significant or unusual environmental impacts associated with a control alternative that have the potential to affect the selection or elimination of a control alternative. Some control technologies may have potentially significant secondary (i.e., collateral) environmental impacts. Scrubber effluent, for example, may affect water Similarly, emissions of water vapor from technologies quality and land use. using cooling towers may affect local visibility. Other examples of secondary environmental impacts could include hazardous waste discharges, such as spent catalysts or contaminated carbon. Generally, these types of environmental concerns become important when sensitive site-specific receptors exist or when the incremental emissions reduction potential of the top control is only marginally greater than the next most effective option. However, the fact that a control device creates liquid and solid waste that must be disposed of does not necessarily argue against selection of that technology as BACT, particularly if the control device has been applied to similar facilities elsewhere and the solid or liquid waste problem under review is similar to those other applications. On the other hand, where the applicant can show that unusual circumstances at the proposed facility create greater problems than experienced elsewhere, this may provide a basis for the elimination of that control alternative as BACT.

The procedure for conducting an analysis of environmental impacts should be made based on a consideration of site-specific circumstances. In general, however, the analysis of environmental impacts starts with the identification and quantification of the solid, liquid, and gaseous discharges from the control device or devices under review. This analysis of environmental impacts should be performed for the entire hierarchy of technologies (even if the applicant proposes to adopt the "top", or most stringent, alternative). However, the analysis need only address those control alternatives with any significant or unusual environmental impacts that have the potential to affect the selection or elimination of a control alternative. Thus, the relative environmental impacts (both positive and negative) of the various alternatives can be compared with each other and the "top" alternative.

Initially, a qualitative or semi-quantitative screening is performed to narrow the analysis to discharges with potential for causing adverse environmental effects. Next, the mass and composition of any such discharges should be assessed and quantified to the extent possible, based on readily available information. Pertinent information about the public or environmental consequences of releasing these materials should also be assembled.

IV. D. 3. a. EXAMPLES (Environmental Impacts)

The following paragraphs discuss some possible factors for considerations in evaluating the potential for an adverse other media impact.

! Water Impact

Relative quantities of water used and water pollutants produced and discharged as a result of use of each alternative emission control system relative to the "top" alternative would be identified. Where possible, the analysis would assess the effect on ground water and such local surface water quality parameters as ph, turbidity, dissolved oxygen, salinity, toxic chemical levels, temperature, and any other important considerations. The analysis should consider whether applicable water quality standards will be met and the availability and effectiveness of various techniques to reduce potential adverse effects.

! Solid Waste Disposal Impact

The quality and quantity of solid waste (e.g., sludges, solids) that must be stored and disposed of or recycled as a result of the application of each alternative emission control system would be compared with the quality and quantity of wastes created with the "top" emission control system. The composition and various other characteristics of the solid waste (such as permeability, water retention, rewatering of dried material, compression strength, leachability of dissolved ions, bulk density, ability to support vegetation growth and hazardous characteristics) which are significant with regard to potential surface water pollution or transport into and contamination of subsurface waters or aquifers would be appropriate for consideration.

! Irreversible or Irretrievable Commitment of Resources

The BACT decision may consider the extent to which the alternative emission control systems may involve a trade-off between short-term environmental gains at the expense of long-term environmental losses and the extent to which the alternative systems may result in irreversible or irretrievable commitment of resources (for example, use of scarce water resources).

! Other Environmental Impacts

Significant differences in noise levels, radiant heat, or dissipated static electrical energy may be considered.

One environmental impact that could be examined is the trade-off between emissions of the various pollutants resulting from the application of a specific control technology. The use of certain control technologies may lead to increases in emissions of pollutants other than those the technology was designed to control. For example, the use of certain volatile organic compound (VOC) control technologies can increase nitrogen oxides (NOx) emissions. In this instance, the reviewing authority may want to give consideration to any relevant local air quality concern relative to the secondary pollutant (in this case NOx) in the region of the proposed source. For example, if the region in the example were nonattainment for NOx, a premium could be placed on the potential NOx impact. This could lead to elimination of the most stringent VOC technology (assuming it generated high quantities of NOx) in favor of one having less of an impact on ambient NOx concentrations. Another example is the potential for higher emissions of toxic and hazardous pollutants from a municipal waste combustor operating at a low flame temperature to reduce the formation of NOx. In this case the real concern to mitigate the emissions of toxic and hazardous emissions (via high

combustion temperatures) may well take precedent over mitigating NOx emissions through the use of a low flame temperature. However, in most cases (unless an overriding concern over the formation and impact of the secondary pollutant is clearly present as in the examples given), it is not expected that this type impact would affect the outcome of the decision.

Other examples of collateral environmental impacts would include hazardous waste discharges such as spent catalysts or contaminated carbon. Generally these types of environmental concerns become important when sitespecific sensitive receptors exist or when the incremental emissions reduction potential of the top control option is only marginally greater than the next most effective option.

IV. D. 3. b. CONSIDERATION OF EMISSIONS OF TOXIC AND HAZARDOUS AIR POLLUTANTS

The generation or reduction of toxic and hazardous emissions, including compounds not regulated under the Clean Air Act, are considered as part of the environmental impacts analysis. Pursuant to the EPA Administrator's decision in <u>North County Resource Recovery Associates</u>, PSD Appeal No. 85-2 (Remand Order, June 3, 1986), a PSD permitting authority should consider the effects of a given control alternative on emissions of toxics or hazardous pollutants not regulated under the Clean Air Act. The ability of a given control alternative to control releases of unregulated toxic or hazardous emissions must be evaluated and may, as appropriate, affect the BACT decision. Conversely, hazardous or toxic emissions resulting from a given control technology should also be considered and may, as appropriate, also affect the BACT decision.

Because of the variety of sources and pollutants that may be considered in this assessment, it is not feasible for the EPA to provide highly detailed national guidance on performing an evaluation of the toxic impacts as part of the BACT determination. Also, detailed information with respect to the type and magnitude of emissions of unregulated pollutants for many source categories is currently limited. For example, a combustion source emits hundreds of substances, but knowledge of the magnitude of some of these

emissions or the hazards they produce is sparse. The EPA believes it is appropriate for agencies to proceed on a case-by-case basis using the best information available. Thus, the determination of whether the pollutants would be emitted in amounts sufficient to be of concern is one that the permitting authority has considerable discretion in making. However, reasonable efforts should be made to address these issues. For example, such efforts might include consultation with the:

- ! EPA Regional Office;
- ! Control Technology Center (CTC);
- ! National Air Toxics Information Clearinghouse;
- ! Air Risk Information Support Center in the Office of Air Quality Planning and Standards (OAQPS); and
- ! Review of the literature, such as; EPA-prepared compilations of emission factors.

Source-specific information supplied by the permit applicant is often the best source of information, and it is important that the applicant be made aware of its responsibility to provide for a reasonable accounting of air toxics emissions.

Similarly, once the pollutants of concern are identified, the permitting authority has flexibility in determining the methods by which it factors air toxics considerations into the BACT determination, subject to the obligation to make reasonable efforts to consider air toxics. Consultation by the review authority with EPA's implementation centers, particularly the CTC, is again advised.

It is important to note that several acceptable methods, including risk assessment, exist to incorporate air toxics concerns into the BACT decision. The depth of the toxics assessment will vary with the circumstances of the particular source under review, the nature and magnitude of the toxic pollutants, and the locality. Emissions of toxic or hazardous pollutant of concern to the permit agency should be identified and, to the extent possible, quantified. In addition, the effectiveness of the various control alternatives in the hierarchy at controlling the toxic pollutant should be estimated and summarized to assist in making judgements about how potential emissions of toxic or hazardous pollutants may be mitigated through the selection of one control option over another. For example, the response to the Administrator made by EPA Region IX in its analysis of the North County permitting decision illustrates one of several approaches (for further information see the September 22, 1987 EPA memorandum from Mr. Gerald Emission titled "Implementation of North County Resource Recover PSD Remand" and July 28, 1988 EPA memorandum from Mr. John Calcagni titled "Supplemental guidance on Implementing the North County Prevention of Significant Deterioration (PSD) Remand").

Under a top-down BACT analysis, the control alternative selected as BACT will most likely reduce toxic emissions as well as the regulated pollutant. An example is the emissions of heavy metals typically associated with coal combustion. The metals generally are a portion of, or adsorbed on, the fine particulate in the exhaust gas stream. Collection of the particulate in a high efficiency fabric filter rather than a low efficiency electrostatic precipitator reduces criteria pollutant particulate matter emissions and toxic heavy metals emissions. Because in most instances the interests of reducing toxics coincide with the interests of reducing the pollutants subject to BACT, consideration of toxics in the BACT analysis generally amounts to quantifying toxic emission levels for the various control options.

In limited other instances, though, control of regulated pollutant emissions may compete with control of toxic compounds, as in the case of certain selective catalytic reduction (SCR) NOx control technologies. The SCR technology itself results in emissions of ammonia, which increase, generally speaking, with increasing levels of NOx control. It is the intent of the toxics screening in the BACT procedure to identify and quantify this type of toxic effect. Generally, toxic effects of this type will not necessarily be overriding concerns and will likely not to affect BACT decisions. Rather, the intent is to require a screening of toxics emissions effects to ensure that a possible overriding toxics issue does not escape notice.

On occasion, consideration of toxics emissions may support the selection of a control technology that yields less than the maximum degree of reduction in emissions of the regulated pollutant in question. An example is the municipal solid waste combustor and resource recovery facility that was the subject of the North County remand. Briefly, BACT for SO2 and PM was selected to be a lime slurry spray drier followed by a fabric filter. The combination yields good SO2 control (approximately 83 percent), good PM control (approximately 99.5 percent) and also removes acid gases (approximately 95 percent), metals, dioxins, and other unregulated pollutants. In this instance, the permitting authority determined that good balanced control of regulated and unregulated pollutants took priority over achieving the maximum degree of emissions reduction for one or more regulated pollutants. Specifically, higher levels (up to 95 percent) of SO2 control could have been obtained by a wet scrubber.

IV. E. SELECTING BACT (STEP 5)

The most effective control alternative not eliminated in Step 4 is selected as BACT.

It is important to note that, regardless of the control level proposed by the applicant as BACT, the ultimate BACT decision is made by the permit issuing agency after public review. The applicant's role is primarily to provide information on the various control options and, when it proposes a less stringent control option, provide a detailed rationale and supporting documentation for eliminating the more stringent options. It is the responsibility of the permit agency to review the documentation and rationale presented and; (1) ensure that the applicant has addressed all of the most effective control options that could be applied and; (2) determine that the applicant has adequately demonstrated that energy, environmental, or economic impacts justify any proposal to eliminate the more effective control options. Where the permit agency does not accept the basis for the proposed elimination of a control option, the agency may inform the applicant of the need for more information regarding the control option. However, the BACT selection essentially should default to the highest level of control for which the

applicant could not adequately justify its elimination based on energy, environmental and economic impacts. If the applicant is unable to provide to the permit agency's satisfaction an adequate demonstration for one or more control alternatives, the permit agency should proceed to establish BACT and prepare a draft permit based on the most effective control option for which an adequate justification for rejection was not provided.

IV. F. OTHER CONSIDERATIONS

Once energy, environmental, and economic impacts have been considered, BACT can only be made more stringent by other considerations outside the normal scope of the BACT analysis as discussed under the above steps. Examples include cases where BACT does not produce a degree of control stringent enough to prevent exceedances of a national ambient air quality standard or PSD increment, or where the State or local agency will not accept the level of control selected as BACT and requires more stringent controls to preserve a greater amount of the available increment. A permit cannot be issued to a source that would cause or contribute to such a violation, regardless of the outcome of the BACT analysis. Also, States which have set ambient air quality standards at levels tighter than the federal standards may demand a more stringent level of control at a source to demonstrate compliance Another consideration which could override the with the State standards. selected BACT are legal constraints outside of the Clean Air Act requiring the application of a more stringent technology (e.g., a consent decree requiring a greater degree of control). In all cases, regardless of the rationale for the permit requiring a more stringent emissions limit than would have otherwise been chosen as a result of the BACT selection process, the emission limit in the final permit (and corresponding control alternative) represents BACT for the permitted source on a case-by-case basis.

The BACT emission limit in a new source permit is not set until the final permit is issued. The final permit is not issued until a draft permit has gone through public comment and the permitting agency has had an opportunity to consider any new information that may have come to light during the comment period. Consequently, in setting a proposed or final BACT limit,

the permit agency can consider new information it learns, including recent permit decisions, subsequent to the submittal of a complete application. This emphasizes the importance of ensuring that prior to the selection of a proposed BACT, all potential sources of information have been reviewed by the source to ensure that the list of potentially applicable control alternatives is complete (most importantly as it relates to any more effective control options than the one chosen) and that all considerations relating to economic, energy and environmental impacts have been addressed.

V. ENFORCEABILITY OF BACT

To complete the BACT process, the reviewing agency must establish an enforceable emission limit for each subject emission unit at the source and for each pollutant subject to review that is emitted from the source. If technological or economic limitations in the application of a measurement methodology to a particular emission unit would make an emissions limit infeasible, a design, equipment, work practice, operation standard, or combination thereof, may be prescribed. Also, the technology upon which the BACT emissions limit is based should be specified in the permit. These requirements should be written in the permit so that they are specific to the individual emission unit(s) subject to PSD review.

The emissions limits must be included in the proposed permit submitted for public comment, as well as the final permit. BACT emission limits or conditions must be met on a continual basis at all levels of operation (e.g., limits written in pounds/MMbtu or percent reduction achieved), demonstrate protection of short term ambient standards (limits written in pounds/hour) and be enforceable as a practical matter (contain appropriate averaging times, compliance verification procedures and recordkeeping requirements). Consequently, the permit must:

- ! be able to show compliance or noncompliance (i.e., through monitoring times of operation, fuel input, or other indices of operating conditions and practices); and
- ! specify a reasonable averaging time consistent with established reference methods, contain reference methods for determining compliance, and provide for adequate reporting and recordkeeping so that the permitting agency can determine the compliance status of the source.

VI. EXAMPLE BACT ANALYSES FOR GAS TURBINES

Note: The following example provided is for illustration only. The example source is fictitious and has been created to highlight many of the aspects of the top-down process. Finally, it must be noted that the cost data and other numbers presented in the example are used only to demonstrate the BACT decision making process. Cost data are used in a relative sense to compare control costs among sources in a source category or for a pollutant. Determination of appropriate costs is made on a case-by-case basis.

In this section a BACT analysis for a stationary gas turbine project is presented and discussed under three alternative operating scenarios:

- ! Example 1--Simple Cycle Gas Turbines Firing Natural Gas
- ! Example 2--Combined Cycle Gas Turbines Firing Natural Gas
- ! Example 3--Combined Cycle Gas Turbines Firing Distillate Oil

The purpose of the examples are to illustrate points to be considered in developing BACT decision criteria for the source under review and selecting BACT. They are intended to illustrate the process rather than provide universal guidance on what constitutes BACT for any particular source category. BACT must be determined on a case-by-case basis.

These examples are not based on any actual analyses performed for the purposes of obtaining a PSD permit. Consequently, the actual emission rates, costs, and design parameters used are neither representative of any actual case nor do they apply to any particular facility.

VI. A. EXAMPLE 1--SIMPLE CYCLE GAS TURBINES FIRING NATURAL GAS

VI.A.1 PROJECT SUMMARY

Table B-5 presents project data, stationary gas design parameters, and uncontrolled emission estimates for the new source in example 1. The gas turbine is designed to provide peaking service to an electric utility. The planned operating hours are less than 1000 hours per year. Natural gas fuel will be fired. The source will be limited through enforceable conditions to the specified hours of operation and fuel type. The area where the source is to be located is in compliance for all criteria pollutants. No other changes are proposed at this facility, and therefore the net emissions change will be equal to the emissions shown on Table B-5. Only NOx emissions are significant (i.e., greater than the 40 tpy significance level for NOx) and a BACT analysis is required for NOx emissions only.

VI. A. 2. BACT ANALYSIS SUMMARY

VII. A. 2. a. CONTROL TECHNOLOGY OPTIONS

The first step in evaluating BACT is identifying all candidate control technology options for the emissions unit under review. Table B-6 presents the list of control technologies selected as potential BACT candidates. The first three control technologies, water or steam injection and selective catalytic reduction, were identified by a review of existing gas turbine facilities in operation. Selective noncatalytic reduction was identified as a potential type of control technology because it is an add-on NOx control which has been applied to other types of combustion sources.

Characteri sti cs		
Number of emissions units	1	
Unit Type	Gas	s Turbines
Cycle Туре	Si	nple-cycle
Output	75	MW
Exhaust temperature,	1,	000 °F
Fuel (s)	Nat	tural Gas
Heat rate, Btu/kw hr	11,	000
Fuel flow, Btu/hr	1, 0	350 million
Fuel flow, lb/hr	83,	300
Service Type	Pea	aki ng
Operating Hours (per year)	1, 0	000
Uncontrolled Emissions, tpy(a)		
NO _x	564 (169	ppm)
SO ₂	<1	
CO	4.	3 (6 ррт)
VOC	1	
РМ	5	(0.0097 gr/dscf)

TABLE B-5. EXAMPLE 1--COMBUSTION TURBINE DESIGN PARAMETERS

(a) Based on 1000 hours per year of operation at full load

TABLE B-6.	EXAMPLE 1SUMMARY	OF	POTENTIAL	NOx	CONTROL
	TECHNOLOGY O	PTI	ONS		

	Typi cal		In Service On:				
	control		Combi ned				
	effi ci ency	Simple cycle		0ther	feasible on		
	range	cycl e	gas	combusti on	simple cycle		
Control technology(a)	(% reduction)	turbines	turbines	sources(c)	turbines		
Selective Catalytic Reductions	40- 90	No	Yes	Yes	Yes(b)		
Water Injection	30- 70	Yes	Yes	Yes	Yes		
Steam Injection	30- 70	No	Yes	Yes	No		
Low NOx Burner	30- 70	Yes	Yes	Yes	Yes		
Selective Noncatalytic Reduction	20- 50	No	Yes	Yes	No		

(a) Ranked in order of highest to lowest stringency.

(b) Exhaust must be diluted with air to reduce its temperature to $600\text{-}750^\circ\text{F}.$

(c) Boiler incinerators, etc.

In this example, the control technologies were identified by the applicant based on a review of the BACT/LAER Clearinghouse, and discussions with State agencies with experience permitting gas turbines in NOx nonattainment areas. A preliminary meeting with the State permit issuing agency was held to determine whether the permitting agency felt that any other applicable control technologies should be evaluated and they agreed on the proposed control hierarchy.

VI. A. 2. b. TECHNICAL FEASIBILITY CONSIDERATIONS

Once potential control technologies have been identified, each technology is evaluated for its technical feasibility based on the characteristics of the source. Because the gas turbines in this example are intended to be used for peaking service, a heat recovery steam generator (HRSG) will not be included. A HRSG recovers heat from the gas turbine exhaust to make steam and increase overall energy efficiency. A portion of the steam produced can be used for steam injection for NOx control, sometimes increasing the effectiveness of the net injection control system However. the electrical demands of the grid dictate that the turbine will be brought on line only for short periods of time to meet peak demands. Due to the lag time required to bring a heat recovery steam generator on line, it is not technically feasible to use a HRSG at the facility. Use of an HRSG in this instance was shown to interfere with the performance of the unit for peaking service, which requires immediate response times for the turbine. Although it was shown that a HRSG was not feasible and therefore not available, water and steam are readily available for NOx control since the turbine will be located near an existing steam generating powerplant.

The turbine type and, therefore, the turbine model selection process, affects the achievability of NOx emissions limits. Factors which the customer considered in selecting the proposed turbine model were outlined in the application as: the peak demand which must be met, efficiency of the gas turbine, reliability requirements, and the experience of the utility with the operation and maintenance service of the particular manufacturer and turbine design. In this example, the proposed turbine is equipped with a combustor

designed to achieve an emission level, at 15 percent 02, of 25 ppm NOx with steam injection or 42 ppm with water injection.²

Selective noncatalytic reduction (SNCR) was eliminated as technically infeasible and therefore not available, because this technology requires a flue gas temperature of 1300 to 2100° F. The exhaust from the gas turbines will be approximately 1000° F, which is below the required temperature range.

Selective catalytic reduction (SCR) was evaluated and no basis was found to eliminate this technology as technically infeasible. However, there are no known examples where SCR technology has been applied to a simple-cycle gas turbine or to a gas turbine in peaking service. In all cases where SCR has been applied, there was an HRSG which served to reduce the exhaust temperature to the optimum range of 600-750oF and the gas turbine was operated continuously. Consequently, application of SCR to a simple cycle turbine involves special circumstances. For this example, it is assumed that dilution air can be added to the gas turbine exhaust to reduce its temperature. However, the dilution air will make the system more costly due to higher gas flows, and may reduce the removal efficiency because the NOx concentration at the inlet will be reduced. Cost considerations are considered later in the analysis.

VI. A. 2. c. CONTROL TECHNOLOGY HIERARCHY

After determining technical feasibility, the applicant selected the control levels for evaluation shown in Table B-7. Although the applicant

 $^{^{\}rm 2}$ For some gas turbine models, 25 ppm is not achievable with either water or steam injection.
	Emi ssi ons	Limits
Control Technology	ppm(a)	ТРҮ
Steam Injection plus SCR	13	44
Steam Injection at maximum ^(b) design rate	25	84
Water Injection at maximum ^(b) design rate	42	140
Steam Injection to meet NSPS	93	312

TABLE B- 7. EXAMPLE 1-- CONTROL TECHNOLOGY HIERARCHY

(a) Corrected to 15 percent oxygen.

(b) Water to fuel ratio.

reported that some sites in California have achieved levels as low as 9 ppm, at this facility a 13 ppm level was determined to be the feasible limit with SCR. This decision is based on the lowest achievable level with steam injection of 25 ppm and an SCR removal efficiency of 50 percent. Even though the reported removal efficiencies for SCR are up to 90 percent at some facilities, at this facility the actual NOx concentration at the inlet to the SCR system will only be approximately 17 ppm (at actual conditions) due to the dilution air required. Also the inlet concentrations, flowrates, and temperatures will vary due to the high frequency of startups. These factors make achieving the optimum 90 percent NOx removal efficiency unrealistic. Based on discussions with SCR vendors, the applicant has established a 50 percent removal efficiency as the highest level achievable, thereby resulting in a 13 ppm level (i.e., 50 percent of 25 ppm).

The next most stringent level achievable would be steam injection at the maximum water-to-fuel ratio achievable by the unit within its design operating range. For this particular gas turbine model, that level is 25 ppm as supported by vendor NOx emissions guarantees and unit test data. The applicant provided documentation obtained from the gas turbine manufacturer³ verifying ability to achieve this range.

After steam injection the next most stringent level of control would be water injection at the maximum water-to-fuel ratio achievable by the unit within its design operating range. For this particular gas turbine model, that level is 42 ppm as supported by vendor NOx emissions guarantees and actual unit test data. The applicant provided documentation obtained from the gas turbine manufacturer verifying ability to achieve this range.

The least stringent level evaluated by the applicant was the current NSPS for utility gas turbines. For this model, that level is 93 ppm at 15 percent 02. By definition, BACT can be no less stringent than NSPS.

 $^{^3}$ It should be noted that achievability of the $\rm NO_x$ limits is dependent on the turbine model, fuel, type of wet injection (water or steam), and system design. Not all gas turbine models or fuels can necessarily achieve these levels.

Therefore, less stringent levels are not evaluated.

VI. A. 2. d. IMPACTS ANALYSIS SUMMARY

The next steps completed by the applicant were the development of the cost, economic, environmental and energy impacts of the different control alternatives. Although the top-down process would allow for the selection of the top alternative without a cost analysis, the applicant felt cost/economic impacts were excessive and that appropriate documentation may justify the elimination of SCR as BACT and therefore chose to quantify cost and economic impacts. Because the technologies in this case are applied in combination, it was necessary to quantify impacts for each of the alternatives. The impact estimates are shown in Table B-8. Adequate documentation of the basis for the impacts was determined to be included in the PSD permit application.

The incremental cost impacts shown are the cost of the alternative compared to the next most stringent control alternative. Figure B-2 is a plot of the least-cost envelope defined by the list of control options.

VI. A. 2. e. TOXICS ASSESSMENT

If SCR were applied, potential toxic emissions of ammonia could occur. Ammonia emissions resulting from application of SCR could be as large as 20 tons per year. Application of SCR would reduce NOx by an additional 20 tpy over steam injection alone (25 ppm) (not including ammonia emissions).

Another environmental impact considered was the spent catalyst which would have to be disposed of at certain operating intervals. The catalyst contains vanadium pentoxide, which is listed as a hazardous waste under RCRA regulations (40 CFR 261.3). Disposal of this waste creates an additional economic and environmental burden. This was considered in the applicant's proposed BACT determination.

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TABLE B-8. EXAMPLE 1--SUMMARY OF TOP-DOWN BACT IMPACT ANALYSIS RESULTS FOR NO_x

Emissi	ons per Turbine			Economi	iomic Impacts En		nergy Impacts	Environm	ironmental Impacts	
Emiss (lb/hr)	ions (tpy)	Emissions reduction(a) (tpy)	Installed capital cost(b) (\$)	Total annualized cost(c) (\$/yr)	Cost effectiveness over baseline(d) (\$/ton)	<pre>Incremental cost effectiveness(e) (\$/ton)</pre>	<pre>Incremental increase over baseline(f) (MMBtu/yr)</pre>	Toxics impact (Yes/No)	Adverse environmental impact (Yes/No)	
44	22	260	11,470,000	1,717,000(g) 6,600	56,200	464,000	Yes	No	
84	42	240	1,790,000	593,000	2,470	8,460	30,000	No	No	
140	70	212	1,304,000	356,000	1,680	800	15,300	No	No	
312	156	126	927,000	288,000	2,285		8,000	No	No	
564	282	-	-	-	-	-	-	-	-	
	Emissi (lb/hr) 44 84 140 312 564	Emissions pe Emissions (lb/hr) (tpy) 44 22 84 42 140 70 312 156 564 282	Emissions per TurbineEmissions (lb/hr)(tpy)Emissions reduction(a) (tpy)4422260844224014070212312156126564282-	Emissions per Turbine Installed capital cost(b) (1b/hr)(tpy) 44 22 260 11,470,000 84 42 240 1,790,000 140 70 212 1,304,000 312 156 126 927,000 564 282 - -	Emissions per Turbine Economic Emissions Emissions Installed Total Emissions reduction(a) cost(b) cost(c) (lb/hr)(tpy) (tpy) (tpy) (\$) 1,717,000(g 84 42 240 1,790,000 593,000 140 70 212 1,304,000 356,000 312 156 126 927,000 288,000 564 282 - - -	Emissions per TurbineEconomic ImpactsEmissions (lb/hr)(tpy)Emissions reduction(a) (tpy)Installed capital cost(b) (\$)Total annualized cost(c) (\$/yr)Cost effectiveness over baseline(d) (\$/ton)442226011,470,0001,717,000(g)6,60084422401,790,000593,0002,470140702121,304,000356,0001,680312156126927,000288,0002,285564282	Emissions per TurbineEconomic ImpactsEEmissions reduction(a) $(1b/hr)(tpy)$ (tpy) (tpy) (tp) $(t$	Emissions per TurbineEconomic ImpactsEnergy Impacts $Emissions$ Installed capital cost(b) (tpy)Total cost(b) (s)Cost effectiveness over baseline(d) (s/yr)Incremental cost effectiveness (s/ton)Incremental increase over baseline(f) (s/ton)442226011,470,0001,717,000(g)6,60056,200464,00084422401,790,000593,0002,4708,46030,000140702121,304,000356,0001,68080015,300312156126927,000288,0002,2858,000564282	Emissions per TurbineEconomic ImpactsEnergy ImpactsEnvironInstalled (lb/hr) (tpy)Installed capital (tpy)Total 	

(a) Emissions reduction over baseline control level.

- (b) Installed capital cost relative to baseline.
- (c) Total annualized cost (capital, direct, and indirect) of purchasing, installing, and operating the proposed control alternative. A capital recovery factor approach using a real interest rate (i.e., absent inflation) is used to express capital costs in present-day annual costs.

(d) Cost Effectiveness over baseline is equal to total annualized cost for the control option divided by the emissions reductions resulting from the uncontrolled baseline.

(e) The optional incremental cost effectiveness criteria is the same as the total cost effectiveness criteria except that the control alternative is considered relative to the next most stringent alternative rather than the baseline control alternative.

(f) Energy impacts are the difference in total project energy requirements with the control alternative and the baseline control alternative expressed in equivalent millions of Btus per year.

(g) Assued 10 year catalyst life since this turbine operates only 1000 hours per year. Assumptions made on catalyst life may have a profound affect upon cost effectiveness.



Figure B-2. Least-Cost Envelope for Example 1

VI. A. 2. f. RATIONALE FOR PROPOSED BACT

Based on these impacts, the applicant proposed eliminating the 13 ppm alternative as economically infeasible. The applicant documented that the cost effectiveness is high at 6,600 \$/ton, and well out of the range of recent BACT NOx control costs for similar sources. The incremental cost effectiveness of \$56,200 also is high compared to the incremental cost effectiveness of the next option.

The applicant documented that the other combustion turbine sources which have applied SCR have much higher operating hours (i.e., all were permitted as base-loaded units). Also, these sources had heat recovery steam generators so that the cost effectiveness of the application of SCR was lower. For this source, dilution air must be added to cool the flue gas to the proper temperature. This increases the cost of the SCR system relative to the same gas turbine with a HRSG. Therefore, the other sources had much lower cost impacts for SCR relative to steam injection alone, and much lower cost effectiveness numbers. Application of SCR would also result in emission of ammonia, a toxic chemical, of possibly 20 tons per year while reducing NOx emissions by 20 tons per year. The applicant asserted that, based on these circumstances, to apply SCR in this case would be an unreasonable burden compared to what has been done at other similar sources.

Consequently, the applicant proposed eliminating the SCR plus steam injection alternative. The applicant then accepted the next control alternative, steam injection to 25 ppmv. The use of steam injection was shown by the applicant to be consistent with recent BACT determinations for similar sources. The review authority concurred with the proposed elimination of SCR and the selection of a 25 ppmv limit as BACT. The use of steam injection was shown by the applicant to be consistent with recent BACT determinations for similar sources. The review authority concurred with the proposed elimination of similar sources. The review authority concurred with the proposed elimination of SCR and the selection of a 25 ppmv limit as BACT.

VI. B. EXAMPLE 2-- COMBINED CYCLE GAS TURBINES FIRING NATURAL GAS

Table B-9 presents the design parameters for an alternative set of circumstances. In this example, two gas turbines are being installed. Also, the operating hours are 5000 per year and the new turbines are being added to meet intermediate loads demands. The source will be limited through enforceable conditions to the specified hours of operation and fuel type. In this case, HRSG units are installed. The applicable control technologies and control technology hierarchy are the same as the previous example except that no dilution is required for the gas turbine exhaust because the HRSG serves to reduce the exhaust temperature to the optimum level for SCR operation. Also, since there is no dilution required and fewer startups, the most stringent control option proposed is 9 ppm based on performance limits for several other natural gas fired baseload combustion turbine facilities.

Table B-10 presents the results of the cost and economic impact analysis for the example and Figure B-3 is a plot of the least-cost envelope defined by the list of control options. The incremental cost impacts shown are the cost of the alternative compared to the next most stringent control alternative. Due to the increased operating hours and design changes, the economic impacts of SCR are much lower for this case. There does not appear to be a persuasive argument for stating that SCR is economically infeasible. Cost effectiveness numbers are within the range typically required of this and other similar source types.

In this case, there would also be emissions of ammonia. However, now the magnitude of ammonia emissions, approximately 40 tons per year, is much lower than the additional NOx reduction achieved, which is 270 tons per year.

Under these alternative circumstances, PM emissions are also now above the significance level (i.e., greater than 25 tpy). The gas turbine

Characteri sti cs	
Number of emission units	2
Emission units	Gas Turbine
Cycle Type	Combi ned- cycl e
Output	
Gas Turbines (2 @ 75 MW each)	150 MW
Steam Turbine (no emissions generated)	70 MW
Fuel (s)	Natural Gas
Gas Turbine Heat Rate, Btu/kw-hr	11, 000 Btu/kw-hr
Fuel Flow per gas turbine, Btu/hr	1,650 million
Fuel Flow per gas turbine, lb/hr	83, 300
Service Type	Intermediate
Hours per year of operation	5000
Uncontrolled Emissions per gas turbine, tpy (a)(b)	
NO _x	1,410 (169 ppm)
S0 ₂	<1
CO	23 (6 ppm)
VOC	5
РМ	25 (0.0097 gr/dscf)

TABLE B-9. EXAMPLE 2--COMBUSTION TURBINE DESIGN PARAMETERS

(a) Based on 5000 hours per year of operation.

(b) Total uncontrolled emissions for the proposed project is equal to the pollutants uncontrolled emission rate multiplied by 2 turbines. For example, total $NO_x = (2 \text{ turbines}) \times 1410$ tpy per turbine) = 2820 tpy.

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TABLE B-10. EXAMPLE 2--SUMMARY OF TOP-DOWN BACT IMPACT ANALYSIS RESULTS FOR NO.

	Emiss	sions pe	er Turbine		Economi	ic Impacts	<u>E</u>	nergy Impacts	Environ	mental Impacts
Control alternative	Emis (lb/h	ssions r) (tpy)	Emissions reduction(a (tpy)	Installed capital h) cost(b) (\$)	Total annualized cost(c) (\$/yr)	Cost effectiveness over baseline(d) (\$/ton)	<pre>Incremental cost effectiveness(e) (\$/ton)</pre>	<pre>incremental increase over baseline(f) (MMBtu/yr)</pre>	Toxics impact (Yes/No)	Adverse environmental impact (Yes/No)
9 ppm Alternative	30	75	1,335	10,980,000	3,380,000(g) 2,531	12,200	160,000	Yes	No
25 ppm Alternative	84	210	1,200	1,791,000	1,730,000	1,440	6,050	105,000	No	No
42 ppm Alternative	140	350	1,060	1,304,000	883,000	833	181	57,200	No	No
NSPS Alternative	312	780	630	927,000	805,000	1,280		27,000	No	No
Uncontrolled Baseline	564	1,410	-	-	-	-	-	-	-	-

(a) Emissions reduction over baseline control level.

(b) Installed capital cost relative to baseline.

(c) Total annualized cost (capital, direct, and indirect) of purchasing, installing, and operating the proposed control alternative. A capital recovery factor approach using a real interest rate (i.e., absent inflation) is used to express capital costs in present-day annual costs.

(d) Cost Effectiveness over baseline is equal to total annualized cost for the control option divided by the emissions reductions resulting from the uncontrolled baseline.

(e) The optional incremental cost effectiveness criteria is the same as the total cost effectiveness criteria except that the control alternative is considered relative to the next most stringent alternative rather than the baseline control alternative.

(f) Energy impacts are the difference in total project energy requirements with the control alternative and the baseline control alternative expressed in equivalent millions of Btus per year.

(g) Assumes a 2 year catalyst life. Assumptions made on catalyst life may have a profound affect upon cost effectiveness.

(h) Since the project calls for two turbines, actual project wide emissions reductions for an alternative will be equal to two times the reduction listed.



Figure B-3. Least-Cost Envelope for Example 2

combustors are designed to combust the fuel as completely as possible and therefore reduce PM to the lowest possible level. Natural gas contains no solids and solids are removed from the injected water. The PM emission rate without add-on controls is on the same order (0.009 gr/dscf) as that for other particulate matter sources controlled with stringent add-on controls (e.g., fabric filter). Since the applicant documented that precombustion or add-on controls for PM have never been required for natural gas fired turbines, the reviewing agency accepted the applicants analysis that natural gas firing was BACT for PM emissions and that no additional analysis of PM controls was required.

VI. C. EXAMPLE 3-- COMBINED CYCLE GAS TURBINE FIRING DISTILLATE OIL

In this example, the same combined cycle gas turbines are proposed except that distillate oil is fired rather than natural gas. The reason is that natural gas is not available on site and there is no pipeline within a reasonable distance. The fuel change raises two issues; the technical feasibility of SCR in gas turbines firing sulfur bearing fuel, and NOx levels achievable with water injection while firing fuel oil.

In this case the applicant proposed to eliminate SCR as technically infeasible because sulfur present in the fuel, even at low levels, will poison the catalyst and quickly render it ineffective. The applicant also noted that there are no cases in the U.S. where SCR has been applied to a gas turbine firing distillate oil as the primary fuel.⁴

A second issue would be the most stringent NOx control level achievable with wet injection. For oil firing the applicant has proposed 42 ppm at 15 percent oxygen. Due to flame characteristics inherent with oil firing, and limits on the amount of water or steam that can be injected, 42 ppm is the lowest NOx emission level achievable with distillate oil firing. Since

 $^{^4}$ Though this argument was considered persuasive in this case, advances in catalyst technology have now made SCR with oil firing technically feasible.

natural gas is not available and SCR is technically infeasible, 42 ppm is the most stringent alternative considered. Based on the cost effectiveness of wet injection, approximately 833 \$/ton, there is no economic basis to eliminate the 42 ppm option since this cost is well within the range of BACT costs for NOx control. Therefore, this option is proposed as BACT.

The switch to oil from gas would also result in SO2, CO, PM, and beryllium emissions above significance levels. Therefore, BACT analyses would also be required for these pollutants. These analyses are not shown in this example, but would be performed in the same manner as the BACT analysis for NOx.

VI. D. OTHER CONSIDERATIONS

The previous judgements concerning economic feasibility were in an area meeting NAAQS for both NOx and ozone. If the natural gas fired simple cycle gas turbine example previously presented were sited adjacent to a Class I area, or where air quality improvement poses a major challenge, such as next to a nonattainment area, the results may differ. In this case, even though the region of the actual site location is achieving the NAAQS, adherence to a local or regional NOx or ozone attainment strategy might result in the determination that higher costs than usual are appropriate. In such situations, higher costs (e.g., 6,600 \$/ton) may not necessarily be persuasive in eliminating SCR as BACT.

While it is not the intention of BACT to prevent construction, it is possible that local or regional air quality management concerns regarding the need to minimize the air quality impacts of new sources would lead the permitting authority to require a source to either achieve stringent emission control levels or, at a minimum, that control cost expenditures meet certain cost levels without consideration of the resultant economic impact to the source.

Besides local or regional air quality concerns, other site constraints may significantly impact costs of particular control technologies. For the

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examples previously presented, two factors of concern are land and water availability.

The cost of the raw water is usually a small part of the cost of wet controls. However, gas turbines are sometimes located in remote locations. Though water can obviously be trucked to any location, the costs may be very high.

Land availability constraints may occur where a new source is being located at an existing plant. In these cases, unusual design and additional structural requirements could make the costs of control technologies which are commonly affordable prohibitively expensive. Such considerations may be pertinent to the calculations of impacts and ultimately the selection of BACT.

CHAPTER C

THE AIR QUALITY ANALYSIS

I. INTRODUCTION

An applicant for a PSD permit is required to conduct an air quality analysis of the ambient impacts associated with the construction and operation of the proposed new source or modification. The main purpose of the air quality analysis is to demonstrate that new emissions emitted from a proposed major stationary source or major modification, in conjunction with other applicable emissions increases and decreases from existing sources (including secondary emissions from growth associated with the new project), will not cause or contribute to a violation of any applicable NAAQS or PSD increment. Ambient impacts of noncriteria pollutants must also be evaluated.

A separate air quality analysis must be submitted for each regulated pollutant if the applicant proposes to emit the pollutant in a significant amount from a new major stationary source, or proposes to cause a significant net emissions increase from a major modification (see *Table I-A-4*, chapter A of this part). [*Note: The air quality analysis requirement also applies to any pollutant whose rate of emissions from a proposed new or modified source is considered to be "significant" because the proposed source would construct within 10 kilometers of a Class I area and would have an ambient impact on such area equal to or greater than 1 µg/må, 24-hour average.]* Regulated pollutants include (1) pollutants for which a NAAQS exists (criteria pollutants) and (2) other pollutants, which are regulated by EPA, for which no NAAQS exist (noncriteria pollutants).

Each air quality analysis will be unique, due to the variety of sources and meteorological and topographical conditions that may be involved. Nevertheless, the air quality analysis must be accomplished in a manner consistent with the requirements set forth in either EPA's PSD regulations under 40 CFR 52.21, or a State or local PSD program approved by EPA pursuant to 40 CFR 51.166. Generally, the analysis will involve (1) an assessment of existing air quality, which may include ambient monitoring data and air

quality dispersion modeling results, and (2) predictions, using dispersion modeling, of ambient concentrations that will result from the applicant's proposed project and future growth associated with the project.

In describing the various concepts and procedures involved with the air quality analysis in this section, it is assumed that the reader has a basic understanding of the principles involved in collecting and analyzing ambient monitoring data and in performing air dispersion modeling. Considerable guidance is contained in EPA's <u>Ambient Monitoring Guidelines for Prevention of Significant Deterioration</u> [Reference 1] and <u>Guideline on Air Quality Models</u> (<u>Revised</u>) [Reference 2]. Numerous times throughout this chapter, the reader will be referred to these guidance documents, hereafter referred to as the <u>PSD</u> <u>Monitoring Guideline</u> and the <u>Modeling Guideline</u>, respectively.

In addition, because of the complex character of the air quality analysis and the site-specific nature of the modeling techniques involved, applicants are advised to review the details of their proposed modeling analysis with the appropriate reviewing agency before a complete PSD application is submitted. This is best done using a modeling protocol. The modeling protocol should be submitted to the reviewing agency for review and approval prior to commencing any extensive analysis. Further description of the modeling protocol is contained in this chapter.

The PSD applicant should also be aware that, while this chapter focuses primarily on compliance with the NAAQS and PSD increments, additional impact analyses are required under separate provisions of the PSD regulations for determining any impairment to visibility, soils and vegetation that might result, as well as any adverse impacts to Class I areas. These provisions are described in the following chapters D and E, respectively.

II. NATIONAL AMBIENT AIR QUALITY STANDARDS AND PSD INCREMENTS

As described in the introduction to this chapter, the air quality analysis is designed to protect the **national ambient air quality standards** (NAAQS) and **PSD increments**. The NAAQS are maximum concentration "ceilings" measured in terms of the total concentration of a pollutant in the atmosphere (See *Table C-1*). For a new or modified source, compliance with any NAAQS is based upon the total estimated air quality, which is the sum of the ambient estimates resulting from existing sources of air pollution (modeled source impacts plus measured background concentrations, as described in this section) and the modeled ambient impact caused by the applicant's proposed emissions increase (or net emissions increase for a modification) and associated growth.

A PSD increment, on the other hand, is the maximum allowable <u>increase</u> in concentration that is allowed to occur above a baseline concentration for a pollutant (see section II.E). The baseline concentration is defined for each pollutant (and relevant averaging time) and, in general, is the ambient concentration existing at the time that the first complete PSD permit application affecting the area is submitted. Significant deterioration is said to occur when the amount of new pollution would exceed the applicable PSD increment. It is important to note, however, that the air quality cannot deteriorate beyond the concentration allowed by the applicable NAAQS, even if not all of the PSD increment is consumed.

II. A CLASS I, II, AND III AREAS AND INCREMENTS.

The PSD requirements provide for a system of area classifications which affords States an opportunity to identify local land use goals. There are three area classifications. Each classification differs in terms of the amount of growth it will permit before significant air quality deterioration would be deemed to occur. Class I areas have the smallest increments and thus allow only a small degree of air quality deterioration. Class II areas can

Pollutant/averaging time	Pri mary Standard	Secondary Standard
0.0		
<u>Particulate Matter</u>		
o PM _{10,} annual ^a	50 μg∕m³	50 μg/m³
o PM_{10} , 24-hour ^b	150 μg/m ³	$150 \ \mu g/m^3$
<u>Sulfur Dioxide</u>		
o SO ₂ , annual ^c	80 μg/m³ (0.03	ppm)
o SO_2 , 24-hour ^d		
365 μg/m ³ (0. 14 ppm)		
o SO_2 , 3-hour ^a		1,300 μg/m³ (0.5 ppm)
<u>Nitrogen Dioxide</u>		
o $NO_{2,}$ annual ^c	0.053 ppm (100	μg/m³0.053 ppm (100 μg/m³)
<u>Ozone</u>		
o 0 ₃ , 1-hour ^b	0.12 ppm (235 µ	ng/m³) 0. 12 ppm (235 μg/m³)
<u>Carbon Monoxi de</u>		
o CO, 8-hour ^d	9 ppm (10 mg/n	n³)
o CO, 1-hour ^d	35 ppm (40 mg/	′ m ³)
Lead		
o Pb, calendar quarter $^{ m c}$ 1.5	µg/m³	

TABLE C-1. National Ambient Air Quality Standards

a Standard is attained when the expected annual arithmetic mean is less than or equal to 50 $\mu g/m^3.$

b Standard is attained when the expected number of exceedances is less than or equal to 1.

c Never to be exceeded.

d Not to be exceeded more than once per year.

accommodate normal well-managed industrial growth. Class III areas have the largest increments and thereby provide for a larger amount of development than either Class I or Class II areas.

Congress established certain areas, e.g., wilderness areas and national parks, as mandatory Class I areas. These areas cannot be redesignated to any other area classification. All other areas of the country were initially designated as Class II. Procedures exist under the PSD regulations to redesignate the Class II areas to either Class I or Class III, depending upon a State's land management objectives.

PSD increments for SO, and particulate matter--measured as total suspended particulate (TSP)--have existed in their present form since 1978. On July 1, 1987, EPA revised the NAAQS for particulate matter and established the new PM-10 indicator by which the NAAQS are to be measured. (Since each State is required to adopt these revised NAAQS and related implementation requirements as part of the approved implementation plan, PSD applicants should check with the appropriate permitting agency to determine whether such State action has already been taken. Where the PM-10 NAAQS are not yet being implemented, compliance with the TSP-based ambient standards is still required in accordance with the currently-approved State implementation plan.) Simultaneously with the promulgation of the PM-10 NAAQS, EPA announced that it would develop PM-10 increments to replace the TSP increments. Such new increments have not yet been promulgated, however. Thus the national PSD increment system for particulate matter is still based on the TSP indicator.

The EPA promulgated PSD increments for NO_2 on October 17, 1988. These new increments become effective under EPA's PSD regulations (40 CFR 52.21) on November 19, 1990, although States may have revised their own PSD programs to incorporate the new increments for NO_2 on some earlier date. Until November 19, 1990, PSD applicants should determine whether the NO_2 increments are being implemented in the area of concern; if so, they must include the necessary analysis, if applicable, as part of a complete permit application. [NOTE: the "trigger date" (described below in section II.B) for the NO_2 increments has been established by regulation as of February 8, 1988. This applies to all State PSD programs as well as EPA's Part 52 PSD program. Thus,

consumption of the NO_2 increments may actually occur before the increments become effective in any particular PSD program.] The PSD increments for SO_2 , TSP and NO_2 are summarized in *Table C-2*.

II. B ESTABLISHING THE BASELINE DATE

As already described, the **baseline concentration is** the reference point for determining air quality deterioration in an area. The baseline concentration is essentially the air quality existing at the time of the first complete PSD permit application submittal affecting that area. In general, then, the submittal date of the first complete PSD application in an area is the "baseline date." On or before the date of the first PSD application, most emissions are considered to be part of the baseline concentration, and emissions changes which occur after that date affect the amount of available PSD increment. However, to fully understand how and when increment is consumed or expanded, three different dates related to baseline must be explained. In chronological order, these dates are as follows:

- ! the major source baseline date;
- ! the **trigger date**; and
- ! the minor source baseline date.

The **mjor source baseline date** is the date after which actual emissions associated with construction (i.e., physical changes or changes in the method of operation) at a major stationary source affect the available PSD increment. Other changes in actual emissions occurring at any source after the major source baseline date do not affect the increment, but instead (until after the minor source baseline date is established) contribute to the baseline concentration. The **trigger date** is the date after which the minor source

TABLE C-2.PSD INCREMENTS

(µg/m³)

	Class I	Class II	Class III	
<u>Sul fur Di oxi de</u>				
o SO_2 , annual ^a	2	20	40	
o SO ₂ , 24-hour ^b	5	91	182	
o SO _{2,} 3-hour ^b	25	512	700	
<u>Particulate Matter</u>				
o TSP, annual ^a	5	19	37	
o TSP, 24-hour ^b	10	37	75	
<u>Nitrogen Dioxide</u>				
o NO_2 , annual ^a	2.5	25	50	

a Never to be exceeded.

b Not to be exceeded more than once per year.

baseline date (described below) may be established. Both the major source baseline date and the trigger date are fixed dates, although different dates apply to (1) SO₂ and particulate matter, and (2) NO₂, as follows:

<u>Pollutant</u>	Major Source Baseli	<u>ine Date</u>
<u>Trigger Date</u>		
PM	January 6, 1975 August 7, 1977	
SO ₂	January 6, 1975 August 7, 1977	
NO ₂	February 8, 1988	February 8, 1988

The **minor source baseline date** is the earliest date after the trigger date on which a complete PSD application is <u>received</u> by the permit reviewing agency. If the application that established the minor source baseline date is ultimately denied or is voluntarily withdrawn by the applicant, the minor source baseline date remains in effect nevertheless. Because the date marks the point in time after which actual emissions changes from <u>all</u> sources affect the available increment (regardless of whether the emissions changes are a result of construction), it is often referred to as the "baseline date."

The minor source baseline date for a particular pollutant is triggered by a PSD applicant only if the proposed increase in emissions of that pollutant is significant. For instance, a PSD application for a major new source or modification that proposes to increase its emissions in a significant amount for SO_2 , but in an insignificant amount for PM, will establish the minor source baseline date for SO_2 but not for PM. Thus, the minor source baseline dates for different pollutants (for which increments exist) need not be the same in a particular area.

II. C ESTABLISHING THE BASELINE AREA

The area in which the minor source baseline date is established by a PSD permit application is known as the **baseline area**. The extent of a baseline area is limited to intrastate areas and may include one or more areas designated as attainment or unclassified under Section 107 of the Act. The baseline area established pursuant to a specific PSD application is to include 1) all portions of the attainment or unclassifiable area in which the PSD applicant would propose to locate, amd 2) any attainment or unclassifiable area in which the proposed emissions would have a significant ambient impact. For this purpose, a significant impact is defined as at least a 1 μ g/m³ annual increase in the average annual concentration of the applicable pollutant. Again, a PSD applicant's establishment of a baseline area in one State does not trigger the minor source baseline date in, or extend the baseline area into, another State.

II. D REDEFINING BASELINE AREAS (AREA REDESIGNATIONS)

It is possible that the boundaries of a baseline area may not reasonably reflect the area affected by the PSD source which established the baseline area. A state may redefine the boundaries of an existing baseline area by redesignating the section 107 areas contained therein. Section 107(d) of the Clean Air Act specifically authorizes states to submit redesignations to the EPA. Consequently, a State may submit redefinitions of the boundaries of attainment or unclassifiable areas at any time, as long as the following criteria are met:

! area redesignations can be no smaller than the 1 μ g/m³ area of impact of the triggering source; and

! the boundaries of any redesignated area cannot intersect the 1 μ g/m³ area of impact of any major stationary source that established or would have established a minor source baseline date for the area proposed for redesignation.

II. E INCREMENT CONSUMPTION AND EXPANSION

The amount of PSD increment that has been consumed in a PSD area is determined from the emissions increases and decreases which have occurred from sources since the applicable baseline date. It is useful to note, however, that in order to determine the amount of PSD increment consumed (or the amount of available increment), no determination of the baseline concentration needs to be made. Instead, increment consumption calculations must reflect only the ambient pollutant concentration <u>change</u> attributable to increment-affecting emissions.

Emissions increases that consume a portion of the applicable increment are, in general, all those <u>not</u> accounted for in the baseline concentration and specifically include:

! actual emissions increases occurring after the **major source baseline date**, which are associated with physical changes or changes in the method of operation (i.e., construction) at a major stationary source; and

! actual emissions increases at any stationary source, area source, or mobile source occurring after the **minor source baseline date**.

The amount of available increment may be added to, or "expanded," in two ways. The primary way is through the reduction of actual emissions from any source after the minor source baseline date. Any such emissions reduction would increase the amount of available increment to the extent that ambient concentrations would be reduced.

Increment expansion may also result from the reduction of actual emissions after the major source baseline date, but <u>before</u> the minor source baseline date, if the reduction results from a physical change or change in the method of operation (i.e., construction) at a major stationary source. Moreover, the reduction will add to the available increment only if the reduction is included in a federally enforceable permit or SIP provision. Thus, for major stationary sources, actual emissions <u>reductions</u> made prior to the minor source baseline date expand the available increment just as <u>increases</u> before the minor source baseline date consume increment. The creditable increase of an existing stack height or the application of any other creditable dispersion technique may affect increment consumption or expansion in the same manner as an actual emissions increase or decrease. That is, the effects that a change in the effective stack height would have on ground level pollutant concentrations generally should be factored into the increment analysis. For example, this would apply to a raised stack height occurring in conjunction with a modification at a major stationary source prior to the minor source baseline date, or to any changed stack height occurring after the minor source baseline date. It should be noted, however, that any increase in a stack height, in order to be creditable, must be consistent with the EPA's stack height regulations; credit cannot be given for that portion of the new height which exceeds the height demonstrated to be the good engineering practice (GEP) stack height.

Increment consumption (and expansion) will generally be based on changes in actual emissions reflected by the normal source operation for a period of 2 years. However, if little or no operating data are available, as in the case of permitted emission units not yet in operation at the time of the increment analysis, the **potential to emit** must be used instead. Emissions data requirements for modeling increment consumption are described in *Section IV. D. 4.* Further guidance for identifying increment-consuming sources (and emissions) is provided in *Section IV. C. 2.*

II. F BASELINE DATE AND BASELINE AREA CONCEPTS -- EXAMPLES

An example of how a baseline area is established is illustrated in Figure C-1. A major new source with the potential to emit significant amounts of SO_2 proposes to locate in County C. The applicant submits a complete PSD application to the appropriate reviewing agency on October 6, 1978. (The trigger date for SO_2 is August 7, 1977.) A review of the State's SO_2 attainment designations reveals that attainment status is listed by individual counties in the state. Since County C is designated attainment for SO_2 , and the source proposes to locate there, October 6, 1978 is established as the minor source baseline date for SO_2 for the entire county.

Dispersion modeling of proposed SO_2 emissions in accordance with approved methods reveals that the proposed source's ambient impact will exceed 1 ug/m³ (annual average) in Counties A and B. Thus, the same minor source baseline date is also established throughout Counties A and B. Once it is triggered, the minor source baseline date for Counties A, B and C establishes the time after which all emissions changes affect the available increments in those three counties.

Although SO₂ impacts due to the proposed emissions are above the significance level of 1 μ g/m³ (annual average) in the adjoining State, the proposed source does not establish the minor source baseline date in that State. This is because, as mentioned in Section II.C of this chapter, baseline areas are <u>intrastate</u> areas only.

The fact that a PSD source's emissions cannot trigger the minor source baseline date across a State's boundary should not be interpreted as precluding the applicant's emissions from consuming increment in another State. Such increment-consuming emissions (e.g., SO_2 emissions increases resulting from a physical change or a change in the method of operation at a



Figure C-1. Establishing the Baseline Area.

major stationary source after January 6, 1975) that affect another State will consume increment there even though the minor source baseline date has not been triggered, but are not considered for increment-consuming purposes until after the minor source baseline date has been independently established in A second example, illustrated in Figure C-2, that State. demonstrates how a baseline area may be redefined. Assume that the State in the first example decides that it does not want the minor source baseline date to be established in the western half of County A where the proposed source will not have a significant annual impact (i.e., $1 \mu g/m^3$, annual average). The State, therefore, proposes to redesignate the boundaries of the existing section 107 attainment area, comprising all of County A, to create two separate attainment areas in that county. If EPA agrees that the available data support the change, the redesignations will be approved. At that time, the October 6, 1978 minor source baseline date will no longer apply to the newly-established attainment area comprising the western portion of County A.

If the minor source baseline date has not been triggered by another PSD application having a significant impact in the redesignated western portion of County A, the SO_2 emissions changes occurring after October 6, 1978 from minor point, area, and mobile sources, and from nonconstruction-related activities at all major stationary sources in this area will be transferred into the baseline concentration. In accordance with the major source baseline date, construction-related emissions changes at major point sources continue to consume or expand increment in the westerm poriton of County A which is no longer part of the original baseline area.



Figure C-2. Redefining the Baseline Area.

III. AMBIENT DATA REQUIREMENTS

An applicant should be aware of the potential need to establish and operate a site-specific monitoring network for the collection of certain ambient data. With respect to **air quality data**, the PSD regulations contain provisions requiring an applicant to provide an ambient air quality analysis which may include pre-application monitoring data, and in some instances postconstruction monitoring data, for any pollutant proposed to be emitted by the new source or modification. In the absence of available monitoring data which is representative of the area of concern, this requirement could involve the operation of a site-specific air quality monitoring network by the applicant. Also, the need for **meteorological data**, for any dispersion modeling that must be performed, could entail the applicant's operation of a site-specific meteorological network.

Pre-application data generally must be gathered over a period of at least 1 year and the data are to represent at least the 12-month period immediately preceding receipt of the PSD application. Consequently, it is important that the applicant ascertain the need to collect any such data and proceed with the required monitoring activities as soon as possible in order to avoid undue delay in submitting a complete PSD application.

III. A PRE-APPLICATION AIR QUALITY MONITORING

For any criteria pollutant that the applicant proposes to emit in significant amounts, continuous ambient monitoring data may be required as part of the air quality analysis. If, however, either (1) the predicted ambient impact, i.e., the highest modeled concentration for the applicable averaging time, caused by the proposed significant emissions increase (or significant net emissions increase), or (2) the existing ambient pollutant concentrations are less than the prescribed significant monitoring value (see *Table C-3*), the permitting agency has discretionary authority to exempt an applicant from this data requirement.

Pollutant	Air Quality Concentrat and Averaging Tim	ion (µg∕m³) me
Carbon monoxide	575	(8-hour)
Nitrogen dioxide	14	(Annual)
Sul fur di oxi de	13	(24-hour)
Particulate Matter, TSP	10	(24- hour)
Particulate Matter, PM-10	10	(24-hour)
0zone	а	
Lead	0.1	(3-month)
Asbestos	b	
Beryllium	0.001	l (24- hour)
Mercury	0. 25	(24- hour)
Vinyl chloride	15	(24- hour)
Fl uori des	0. 25	(24-hour)
Sulfuric acid mist	Ь	
Total reduced sulfur (including H_2S)	Ь	
Reduced sulfur (including H ₂ S)	Ь	
Hydrogen sulfide	0. 2	(1-hour)

TABLE C-3.SIGNIFICANT MONITORING CONCENTRATIONS

a No significant air quality concentration for ozone monitoring has been established. Instead, applicants with a net emissions increase of 100 tons/year or more of VOC's subject to PSD would be required to perform an ambient impact analysis, including pre-application monitoring data.

b Acceptable monitoring techniques may not be available at this time. Monitoring requirements for this pollutant should be discussed with the permitting agency.

The determination of the proposed project's effects on air quality (for comparison with the significant monitoring value) is based on the results of the dispersion modeling used for establishing the impact area (see Section IV. B of this chapter). Modeling by itself or in conjunction with available monitoring data should be used to determine whether the existing ambient concentrations are equal to or greater than the significant monitoring value. The applicant may utilize a screening technique for this purpose, or may elect to use a refined model. Consultation with the permitting agency is advised before any model is selected. Ambient impacts from existing sources are estimated using the same model input data as are used for the NAAQS analysis, as described in section IV. D. 4 of this chapter.

If a potential threat to the NAAQS is identified by the modeling predictions, then continuous ambient monitoring data should be required, even when the predicted impact of the proposed project is less than the significant monitoring value. This is especially important when the modeled impacts of existing sources are uncertain due to factors such as complex terrain and uncertain emissions estimates.

Also, if the location of the proposed source or modification is not affected by other major stationary point sources, the assessment of existing ambient concentrations may be done by evaluating available monitoring data. It is generally preferable to use data collected within the area of concern; however, the possibility of using measured concentrations from representative "regional" sites may be discussed with the permitting agency. The <u>PSD Monitoring Guideline</u> provides additional guidance on the use of such regional sites.

Once a determination is made by the permitting agency that ambient monitoring data must be submitted as part of the PSD application, the requirement can be satisfied in one of two ways. First, under certain conditions, the applicant may use existing ambient data. To be acceptable, such data must be judged by the permitting agency to be representative of the air quality for the area in which the proposed project would construct and operate. Although a State or local agency may have monitored air quality for

several years, the data collected by such efforts may not necessarily be adequate for the preconstruction analysis required under PSD. In determining the representativeness of any existing data, the applicant and the permitting agency must consider the following critical items (described further in the <u>PSD Monitoring Guideline</u>):

- ! monitor location;
- ! quality of the data; and
- ! currentness of the data.

If existing data are not available, or they are judged not to be representative, then the applicant must proceed to establish a site-specific monitoring network. The EPA strongly recommends that the applicant prepare a monitoring plan before any actual monitoring begins. Some permitting agencies may require that such a plan be submitted to them for review and approval. In any case, the applicant will want to avoid any possibility that the resulting data are unacceptable because of such things as improperly located monitors, or an inadequate number of monitors. To assure the accuracy and precision of the data collected, proper quality assurance procedures pursuant to Appendix Bof 40 CFR Part 58 must also be followed. The recommended minimum contents of a monitoring plan, and a discussion of the various considerations to be made in designing a PSD monitoring network, are contained in the PSD Monitoring Guideline.

The PSD regulations generally require that the applicant collect 1 year of ambient data (EPA recommends 80 percent data recovery for PSD purposes). However, the permitting agency has discretion to accept data collected over a shorter period of time (but in no case less than 4 months) if a complete and adequate analysis can be accomplished with the resulting data. Any decision to approve a monitoring period shorter than 1 year should be based on a demonstration by the applicant (through historical data or dispersion modeling) that the required air quality data will be obtained during a time period, or periods, when maximum ambient concentrations can be expected.

For a pollutant for which there is no NAAQS (i.e., a noncriteria pollutant), EPA's general position is not require monitoring data, but to base the air quality analysis on modeled impacts. However, the permitting agency may elect to require the submittal of air quality monitoring data for noncriteria pollutants in certain cases, such as where:

- ! a State has a standard for a non-criteria pollutant;
- ! the reliability of emissions data used as input to modeling existing sources is highly questionable; and
- ! available models or complex terrain make it difficult to estimate air quality or the impact of the proposed or modification.

The applicant will need to confer with the permitting agency to determine whether any ambient monitoring may be required. Before the agency exercises its discretion to require such monitoring, there should be an acceptable measurement method approved by EPA or the appropriate permitting agency.

With regard to particulate matter, where two different indicators of the pollutant are being regulated, EPA considers the PM-10 indicator to represent the criteria form of the pollutant (the NAAQS are now expressed in terms of ambient PM-10 concentrations) and TSP is viewed as the non-criteria form. Consequently, EPA intends to apply the pre-application monitoring requirements to PM-10 primarily, while treating TSP on a discretionary basis in light of its noncriteria status. Although the PSD increments for particulate matter are still based on the TSP indicator, modeling data, not ambient monitoring data, are used for increment analyses.

Ambient air quality data collected by the applicant must be presented in the PSD application as part of the air quality analysis. Monitoring data collected for a criteria pollutant may be used in conjunction with dispersion modeling results to demonstrate NAAQS compliance. Each PSD application involves its own unique set of factors, i.e., the integration of measured ambient data and modeled projections. Consequently, the amount of data to be

used and the manner of presentation are matters that should be discussed with the permitting agency.

III. B POST- CONSTRUCTION AIR QUALITY MONITORING

The <u>PSD Monitoring Guideline</u> recommends that post-construction monitoring be done when there is a valid reason, such as (1) when the NAAQS are threatened, and (2) when there are uncertainties in the data bases for modeling. Any decision to require post-construction monitoring will generally be made after the PSD application has been thoroughly reviewed. It should be noted that the PSD regulations do not require that the significant monitoring concentrations be considered by the permitting agency in determining the need for post-construction monitoring.

Existing monitors can be considered for collecting post-construction ambient data as long as they have been approved for PSD monitoring purposes. However, the location of the monitors should be checked to ascertain their appropriateness if other new sources or modifications have subsequently occurred, because the new emissions from the more recent projects could alter the location of points of maximum ambient concentrations where ambient measurements need to be made.

Generally, post-construction monitoring should not begin until the source is operating near intended capacity. If possible the collection of data should be delayed until the source is operating at a rate equal to or greater than 50 percent of design capacity. The <u>PSD Monitoring Guideline</u> provides, however, that in no case should post-construction monitoring be delayed later than 2 years after the start-up of the new source or modification.

Post-approval ozone monitoring is an alternative to pre-application monitoring for applicants proposing to emit VOC's if they choose to accept nonattainment preconstruction review requirements, including LAER, emissions and air quality offsets, and statewide compliance of other sources under the same ownership. As indicated in Table C-3, pre-application monitoring for ozone is required when the proposed source or modification would emit at least 100 tons per year of volatile organic compounds (VOC). Note that this emissions rate for VOC emissions is a surrogate for the significant monitoring concentration for the pollutant ozone (see *Table C-3*). Under 40 CFR 52.21(m)(1)(vi), post-approval monitoring data for ozone is required (and cannot be waived) in conjunction with the aforementioned nonattainment review requirements when the permitting agency waives the requirement for preapplication ozone monitoring data. The post-approval period may begin any time after the source receives its PSD permit. In no case should the postapproval monitoring be started later than 2 years after the start-up of the new source or modification.

III. C METEOROLOGICAL MONITORING

Meteorological data is generally needed for model input as part of the air quality analysis. It is important that such data be representative of the atmospheric dispersion and climatological conditions at the site of the proposed source or modification, and at locations where the source may have a significant impact on air quality. For this reason, site specific data are preferable to data collected elsewhere. On-site meteorological monitoring may be required, even when on-site air quality monitoring is not.

The <u>PSD Monitoring Guideline</u> should be used to establish locations for any meteorological monitoring network that the applicant may be required to operate and maintain as part of the preconstruction monitoring requirements. That guidance specifies the meteorological instrumentation to be used in measuring meteorological parameters such as wind speed, wind direction, and temperature. The <u>PSD Monitoring Guideline</u> also provides that the retrieval of valid wind/stability data should not fall below 90 percent on an annual basis. The type, quantity, and format of the required data will be influenced by the specific input requirements of the dispersion modeling techniques used in the air quality analysis. Therefore, the applicant will need to consult with the permitting agency prior to establishing the required network.

Additional guidance for the collection and use of on-site data is provided in the <u>PSD Monitoring Guideline</u>. Also, the EPA documents entitled <u>On-Site Meteorological Program Guidance for Regulatory Modeling Applications</u> (Reference 3), and Volume IV of the series of reports entitled <u>Quality</u> <u>Assurance Handbook for Air Pollution Measurement Systems</u> (Reference 4), contain information required to ensure the quality of the meteorological measurements collected.
IV. DISPERSION MODELING ANALYSIS

Dispersion models are the primary tools used in the air quality analysis. These models estimate the ambient concentrations that will result from the PSD applicant's proposed emissions in combination with emissions from existing sources. The estimated total concentrations are used to demonstrate compliance with any applicable NAAQS or PSD increments. The applicant should consult with the permitting agency to determine the particular requirements for the modeling analysis to assure acceptability of any air quality modeling technique(s) used to perform the air quality analysis contained in the PSD application.

IV. A OVERVIEW OF THE DISPERSION MODELING ANALYSIS

The dispersion modeling analysis usually involves two distinct phases: (1) a **preliminary analysis** and (2) a **full impact analysis**. The **preliminary analysis** models only the <u>significant</u> increase in potential emissions of a pollutant from a proposed new source, or the <u>significant</u> net emissions increase of a pollutant from a proposed modification. The results of this preliminary analysis determine whether the applicant must perform a full impact analysis, involving the estimation of background pollutant concentrations resulting from existing sources and growth associated with the proposed source. Specifically, the **preliminary analysis**:

!	determi nes	whether	the	applicant	can	forego	further	air	quality
	analyses for	or a part	ticul	ar polluta	ant;				

- ! may allow the applicant to be exempted from the ambient monitoring data requirements (described in section III of this chapter); and
- ! is used to define the impact area within which a full impact analysis must be carried out.

The EPA does not require a full impact analysis for a particular pollutant when emissions of that pollutant from a proposed source or modification would not increase ambient concentrations by more than prescribed significant ambient impact levels, including special Class I significance

levels. However, the applicant should check any applicable State or local PSD program requirements in order to determine whether such requirements may contain any different procedures which may be more stringent. In addition, the applicant must still address the requirements for additional impacts required under separate PSD requirements, as described in Chapters D and E which follow this chapter.

A **full impact analysis** is required for any pollutant for which the proposed source's estimated ambient pollutant concentrations exceed prescribed significant ambient impact levels. This analysis expands the preliminary analysis in that it considers emissions from:

- ! the proposed source;
- ! existing sources;
- ! residential, commercial, and industrial growth that accompanies the new activity at the new source or modification (i.e., secondary emissions).

For SO_2 , particulate matter, and NO_2 , the full impact analysis actually consists of separate analyses for the NAAQS and PSD increments. As described later in this section, the selection of background sources (and accompanying emissions) to be modeled for the NAAQS and increment components of the overall analysis proceeds under somewhat different sets of criteria. In general, however, the full impact analysis is used to project ambient pollutant concentrations against which the applicable NAAQS and PSD increments are compared, and to assess the ambient impact of non-criteria pollutants.

The reviewer's primary role is to determine whether the applicant select ed the appropriate model(s), used appropriate input data, and followed recommended procedures to complete the air quality analysis. Appendix C in the <u>Modeling Guideline</u> provides an example checklist which recommends a standardized set of data to aid the reviewer in determining the completeness and correctness of an applicant's air quality analysis. *Figure C-3* outlines the basic steps for an applicant to follow for a PSD dispersion modeling analysis to demonstrate compliance with the NAAQS and PSD increments. These steps are described in further detail in the sections which follow.

IV. B DETERMINING THE IMPACT AREA

The proposed project's **impact area** is the geographical area for which the required air quality analyses for the NAAQS and PSD increments are carried out. This area includes all locations where the significant increase in the potential emissions of a pollutant from a new source, or significant net emissions increase from a modification, will cause a significant ambient impact (i.e., equal or exceed the applicable significant ambient impact level, as shown in *Table C-4*). The <u>highest</u> modeled pollutant concentration for each averaging time is used to determine whether the source will have a significant ambient impact for that pollutant.

The **impact area** is a circular area with a radius extending from the source to (1) the most distant point where approved dispersion modeling predicts a significant ambient impact will occur, or (2) a modeling receptor distance of 50 km, whichever is less. Usually the area of modeled significant impact does not have a continuous, smooth border. (It may actually be comprised of pockets of significant impact separated by pockets of insignificant impact.) Nevertheless, the required air quality analysis is carried out within the circle that circumscribes the significant ambient impacts, as shown in *Figure C-4*.

Initially, for each pollutant subject to review an impact area is determined for every averaging time. The impact area used for the air quality analysis of a particular pollutant is the largest of the areas determined for that pollutant. For example, modeling the proposed SO_2 emissions from a new source might show that a significant ambient SO_2 impact occurs out to a distance from the source of 2 kilometers for the annual averaging period;



Figure I-C-3. Basic Steps in the Air Quality Analysis (NAAQS and PSD Increments)

TABLE C-4.

SIGNIFICANCE LEVELS FOR AIR QUALITY IMPACTS IN CLASS II AREAS^a

444444444444444444444444444444444444						
Pollutant	Annual	24-hour	8- hour	3-hour	1-hour	
SO ₂	1	5	-	25	-	
TSP	1	5	-	-	-	
PM 10	1	5	_	_	_	
INF IO	1	5			-	
NO _x	1	-	-	-	-	
CO	-	-	500	-	2,000	
0,3	-	-			<u>b</u>	

^a This table does not apply to Class I areas. If a proposed source is located within 100 kilometers of a Class I area, an impact of 1 μ g/m³ on a 24-hour basis is significant.

 $^{\underline{b}}$ No significant ambient impact concentration has been established. Instead, any net emissions increase of 100 tons per year of VOC subject to PSD would be required to perform an ambient impact analysis.



Figure C-4. Determining the Impact Area.

4.3 kilometers for the 24-hour averaging period; and 3.8 kilometers for the 3-hour period. Therefore, an impact area with a radius of 4.3 kilometers from the proposed source is selected for the SO_2 air quality analysis.

In the event that the maximum ambient impact of a proposed emissions increase is below the appropriate ambient air quality significance level for all locations and averaging times, a full impact analysis for that pollutant is not required by EPA. Consequently, a preliminary analysis which predicts an insignificant ambient impact everywhere is accepted by EPA as the required air quality analysis (NAAQS and PSD increments) for that pollutant. *[NOTE: Vhile it may be shown that no impact area exists for a particular pollutant, the PSD application (assuming it is the first one in the area) still establishes the PSD baseline area and minor source baseline date in the section 107 attainment or unclassifiable area where the source will be located, regardless of its insignificant ambient impact.*]

For each applicable pollutant, the determination of an impact area must include all stack emissions and quantifiable fugitive emissions resulting from the proposed source. For a proposed modification, the determination includes contemporaneous emissions increases and decreases, with emissions decreases input as negative emissions in the model. The EPA allows for the exclusion of <u>temporary</u> emissions (e.g., emissions occurring during the construction phase of a project) when establishing the impact area and conducting the subsequent air quality analysis, if it can be shown that such emissions do not impact a Class I area or an area where a PSD increment for that pollutant is known to be violated. However, where EPA is not the PSD permitting authority, the applicant should confer with the appropriate permitting agency to determine whether it allows for the exclusion of temporary emissions. Once defined for the proposed PSD project, the impact area(s) will determine the scope of the required air quality analysis. That is, the impact area(s) will be used to

- ! set the boundaries within which ambient air quality monitoring data may need to be collected,
- ! define the area over which a full impact analysis (one that considers the contribution of all sources) must be undertaken, and
- ! guide the identification of other sources to be included in the modeling analyses.

Again, if no significant ambient impacts are predicted for a particular pollutant, EPA does not require further NAAQS or PSD increment analysis of that pollutant. However, the applicant must still consider any additional impacts which the proposed source may have concerning impairment on visibility, soils and vegetation, as well as any adverse impacts on air quality related values in Class I areas (see Chapters D and E of this part).

IV. C SELECTING SOURCES FOR THE PSD EMISSIONS INVENTORIES

When a full impact analysis is required for any pollutant, the applicant is responsible for establishing the necessary inventories of existing sources and their emissions, which will be used to carry out the required NAAQS and PSD increment analyses. Such special emissions inventories contain the various source data used as input to an applicable air quality dispersion model to estimate existing ambient pollutant concentrations. Requirements for preparing an emissions inventory to support a modeling analysis are described to a limited extent in the <u>Modeling Guideline</u>. In addition, a number of other EPA documents (e.g., References 5 through 11) contain guidance on the fundamentals of compiling emissions inventories. The discussion which follows pertains primarily to identifying and selecting existing sources to be included in a PSD emissions inventory as needed for a full impact analysis.

The permitting agency may provide the applicant a list of existing sources upon request once the extent of the impact area(s) is known. If the

list includes only sources above a certain emissions threshold, the applicant is responsible for identifying additional sources below that emissions level which could affect the air quality within the impact area(s). The permitting agency should review all required inventories for completeness and accuracy.

IV. C. 1 THE NAAQS INVENTORY

While air quality data may be used to help identify existing background air pollutant concentrations, EPA requires that, at a minimum, all <u>nearby</u> sources be explicitly modeled as part of the NAAQS analysis. The <u>Modeling</u> <u>Guideline</u> defines a "nearby" source as any point source expected to cause a significant concentration gradient in the vicinity of the proposed new source or modification. For PSD purposes, "vicinity" is defined as the impact area. However, the location of such nearby sources could be anywhere within the impact area or an annular area extending 50 kilometers beyond the impact area. (See Figure C-5.)

In determining which existing point sources constitute <u>nearby</u> sources, the <u>Modeling Guideline</u> necessarily provides flexibility and requires judgment to be exercised by the permitting agency. Moreover, the screening method for identifying a <u>nearby</u> source may vary from one permitting agency to another. To identify the appropriate method, the applicant should confer with the permitting agency prior to actually modeling any existing sources.

The <u>Modeling Guideline</u> indicates that the useful distance for guideline models is 50 kilometers. Occasionally, however, when applying the above source identification criteria, existing stationary sources located in the annular area beyond the impact area may be more than 50 kilometers from portions of the impact area. When this occurs, such sources' modeled impacts throughout the entire impact area should be calculated. That is, special steps should not be taken to cut off modeled impacts of existing sources at receptors within the applicants impact area merely because the receptors are



Figure C-5 Defining the Emissions Inventory Screening Area.

located beyond 50 kilometers from such sources. Modeled impacts beyond 50 kilometers should be considered as conservative estimate in that they tend to overestimate the true source impacts. Consequently, if it is found that an existing source's impact include estimates at distances exceeding the normal 50-kilometer range, it may be appropriate to consider other techniques, including long-range transport models. Applicants should consult with the permitting agency prior to the selection of a model in such cases.

It will be necessary to include in the NAAQS inventory those sources which have received PSD permits but have not yet not begun to operate, as well as any complete PSD applications for which a permit has not yet been issued. In the latter case, it is EPA's policy to account for emissions that will occur at sources whose complete PSD application was submitted as of thirty days prior to the date the proposed source files its PSD application. Al so. sources from which secondary emissions will occur as a result of the proposed source should be identified and evaluated for inclusion in the NAAQS inventory. While existing mobile source emissions are considered in the determination of background air quality for the NAAQS analysis (typically using existing air quality data), it should be noted that the applicant need not model estimates of future mobile source emissions growth that could result from the proposed project because the definition of "secondary emissions" specifically excludes any emissions coming directly from mobile sources.

Air quality data may be used to establish background concentrations in the impact area resulting from existing sources that are not considered as <u>nearby</u> sources (e.g., area and mobile sources, natural sources, and distant point sources). If, however, adequate air quality data do not exist (and the applicant was not required to conduct pre-application monitoring), then these "other" background sources are also included in the NAAQS inventory so that their ambient impacts can be estimated by dispersion modeling.

IV. C. 2 THE INCREMENT INVENTORY

An emissions inventory for the analysis of affected PSD increments must also be developed. The increment inventory includes all increment-affecting sources located in the impact area of the proposed new source or modification. Also, all increment-affecting sources located within 50 kilometers of the impact area (see *Figure C-5*) are included in the inventory if they, either individually or collectively, affect the amount of PSD increment consumed. The applicant should contact the permitting agency to determine what particular procedures should be followed to identify sources for the increment inventory.

In general, the stationary sources of concern for the increment inventory are those stationary sources with actual emissions changes occurring since the <u>minor source baseline date</u>. However, it should be remembered that certain actual emissions changes occurring before the minor source baseline date (i.e., at major stationary point sources) also affect the increments. Consequently, the types of stationary point sources that are initially reviewed to determine the need to include them in the increment inventory fall under two specific time frames as follows:

After the major source baseline date-

- ! existing <u>major</u> stationary sources having undergone a physical change or change in their method of operation; and
- ! new <u>major</u> stationary sources.

After the minor source baseline date-

- ! existing stationary sources having undergone a physical change or change in their method of operation;
- ! existing stationary sources having increased hours of operation or capacity utilization (unless such change was considered representative of baseline operating conditions); and
- ! new stationary sources.

If, in the impact area or surrounding screening area, area or mobile source emissions will affect increment consumption, then emissions input data for such minor sources are also included in the increment inventory. The change in such emissions since the minor source baseline date (rather than the absolute magnitude of these emissions) is of concern since this change is what may affect a PSD increment. Specifically, the rate of growth and the amount of elapsed time since the minor source baseline date was established determine the extent of the increase in area and mobile source emissions. For example, in an area where the minor source baseline date was recently established (e.g., within the past year or so of the proposed PSD project), very little area and mobile source emissions growth may have occurred. Also, sufficient data (particularly mobile source data) may not yet be available to reflect the amount of growth that has taken place. As with the NAAQS analysis, applicants are not required to estimate future mobile source emissions growth that could result from the proposed project because they are excluded from the definition of "secondary emissions."

The applicant should initially consult with the permitting agency to determine the availability of data for assessing area and mobile source growth since the minor source baseline date. This information, or the fact that such data is not available, should be thoroughly documented in the application. The permitting agency should verify and approve the basis for actual area source emissions estimates and, especially if these estimates are considered by the applicant to have an insignificant impact, whether it agrees with the applicant's assessment.

When area and mobile sources are determined to affect any PSD increment, their emissions must be reported on a gridded basis. The grid should cover the entire impact area and any areas outside the impact area where area and mobile source emissions are included in the analysis. The exact sizing of an emissions inventory grid cell generally should be based on the emissions density in the area and any computer constraints that may exist. Techniques for assigning area source emissions to grid cells are provided in Reference 11. The grid layout should always be discussed with, and approved by, the permitting agency in advance of its use.

IV. C. 3 NONCRITERIA POLLUTANTS INVENTORY

An inventory of all noncriteria pollutants emitted in significant amounts is required for estimating the resulting ambient concentrations of those pollutants. Significant ambient impact levels have not been established for non-criteria pollutants. Thus, an impact area cannot be defined for noncriteria pollutants in the same way as for criteria pollutants. Therefore, as a general rule of thumb, EPA believes that an emissions inventory for noncriteria pollutants should include sources within 50 kilometers of the proposed source. Some judgment will be exercised in applying this position on a case-by-case basis.

IV. D MODEL SELECTION

Two levels of model sophistication exist: screening and refined dispersion modeling. Screening models may be used to eliminate more extensive modeling for either the preliminary analysis phase or the full impact analysis phase, or both. However, the results must demonstrate to the satisfaction of the permitting agency that all applicable air quality analysis requirements Screening models produce conservative estimates of ambient impact in are met. order to reasonably assure that maximum ambient concentrations will not be underestimated. If the resulting estimates from a screening model indicate a threat to a NAAQS or PSD increment, the applicant uses a refined model to reestimate ambient concentrations (of course, the applicant can select other options, such as reducing emissions, or to decrease impacts). Guidance on the use of screening procedures to estimate the air quality impact of stationary sources is presented in EPA's Screening Procedures for Estimating Air Qaulity Impact of Stationary Sources [Reference 12].

A refined dispersion model provides more accurate estimates of a source's impact and, consequently, requires more detailed and precise input data than does a screening model. The applicant is referred to *Appendix A* of the <u>Modeling Guideline</u> for a list of EPA-preferred models, i.e., guideline models. The guideline model selected for a particular application should be the one which most accurately represents atmospheric transport, dispersion,

and chemical transformations in the area under analysis. For example, models have been developed for both simple and complex terrain situations; some are designed for urban applications, while others are designed for rural applications.

In many circumstances the guideline models known as Industrial Source Complex Model Short- and Long-term (ISCST and ISCLT, respectively) are acceptable for stationary sources and are preferred for use in the dispersion modeling analysis. A brief discussion of options required for regulatory applications of the ISC model is contained in the <u>Modeling Guideline</u>. Other guideline models, such as the Climatological Dispersion Model (CDM), may be needed to estimate the ambient impacts of area and mobile sources.

Under certain circumstances, refined dispersion models that are not listed in the <u>Modeling Guideline</u>, i.e., non-guideline models, may be considered for use in the dispersion modeling analysis. The use of a nonguideline model for a PSD permit application must, however, be pre-approved on a case-by-case basis by EPA. The applicant should refer to the EPA documents entitled <u>Interim Procedures for Evaluating Air Quality Models (Revised)</u> [Reference 13] and <u>Interim Procedures for Evaluating Air Quality Models:</u> <u>Experience with Implementation</u> [Reference 14]. Close coordination with EPA and the appropriate State or local permitting agency is essential if a nonguideline model is to be used successfully.

IV. D. 1 METEOROLOGICAL DATA

Meteorological data used in air quality modeling must be spatially and climatologically (temporally) representative of the area of interest. Therefore, an applicant should consult the permitting authority to determine what data will be most representative of the location of the applicant's proposed facility.

Use of site-specific meteorological data is preferred for air quality modeling analyses if 1 or more years of quality-assured data are available. If at least 1 year of site-specific data is not available, 5 years of meteorological data from the nearest National Weather Service (NWS) station can be used in the modeling analysis. Alternatively, data from universities, the Federal Aviation Administration, military stations, industry, and State or local air pollution control agencies may be used if such data are equivalent in accuracy and detail to the NWS data, and are more representative of the area of concern.

The 5 years of data should be the most recent consecutive 5 years of meteorological data available. This 5-year period is used to ensure that the model results adequately reflect meteorological conditions conducive to the prediction of maximum ambient concentrations. The NWS data may be obtained from the National Climatic Data Center (Asheville, North Carolina), which serves as a clearinghouse to collect and distribute meteorological data collected by the NWS.

IV. D. 2 RECEPTOR NETWORK

Polar and Cartesian networks are two types of receptor networks commonly used in refined air dispersion models. A **polar network** is comprised of concentric rings and radial arms extending outward from a center point (e.g., the modeled source). Receptors are located where the concentric rings and radial arms intersect. Particular care should be exercised in using a polar network to identify maximum estimated pollutant concentrations because of the inherent problem of increased longitudinal spacing of adjacent receptors as

their distance along neighboring radial arms increases. For example, as illustrated in *Figure C-6*, while the receptors on individual radials, e.g., *A1, A2, A3...* and *B1, B2, B3...,* may be uniformly spaced at a distance of 1 kilometer apart, at greater distances from the proposed source, the longitudinal distance between the receptors, e.g., *A4* and *B4*, on neighboring radials may be several kilometers. As a result of the presence of larger and larger "blind spots" between the radials as the distance from the modeled source increases, finding the maximum source impact can be somewhat problematic. For this reason, using a polar network for anything other than initial screening is generally discouraged.

A cartesian network (also referred to as a rectangular network) consists of north-south and east-west oriented lines forming a rectangular grid, as shown in *Figure C-6*, with receptors located at each intersection point. In most refined air quality analyses, a cartesian grid with from 300 to 400 receptors (where the distance from the source to the farthest receptor is 10 kilometers) is usually adequate to identify areas of maximum concentration. However, the total number of receptors will vary based on the specific air quality analysis performed.

In order to locate the maximum modeled impact, perform multiple model runs, starting with a relatively coarse receptor grid (e.g., one or two kilometer spacing) and proceeding to a relatively fine receptor grid (e.g., 100 meters). The fine receptor grid should be used to focus on the area(s) of higher estimated pollutant concentrations identified by the coarse grid model runs. With such multiple runs the maximum modeled concentration can be identified. It is the applicant's responsibility to demonstrate that the final receptor network is sufficiently compact to identify the maximum estimated pollutant concentration for each applicable averaging period. This applies both to the PSD increments and to the NAAQS.



Figure C-6. Examples of Polar and Cartesian Grid Networks.

Some air quality models allow the user to input discrete receptors at user-specified locations. The selection of receptor sites should be a caseby-case determination, taking into consideration the topography, the climatology, the monitor sites, and the results of the preliminary analysis. For example, receptors should be located at:

- ! the fenceline of a proposed facility;
- ! the boundary of the nearest Class I or nonattainment area;
- ! the location(s) of ambient air monitoring sites; and
- ! locations where potentially high ambient air concentrations are expected to occur.

In general, modeling receptors for both the NAAQS and the PSD increment analyses should be placed at ground level points anywhere except on the applicant's plant property if it is inaccessible to the general public. Public access to plant property is to be assumed, however, unless a continuous physical barrier, such as a fence or wall, precludes entrance onto that property. In cases where the public has access, receptors should be located on the applicant's property. It is important to note that ground level points of receptor placement could be over bodies of water, roadways, and property owned by other sources. For NAAQS analyses, modeling receptors may also be placed at elevated locations, such as on building rooftops. However, for PSD increments, receptors are limited to locations at ground level.

IV. D. 3 GOOD ENGINEERING PRACTICE (GEP) STACK HEIGHT

Section 123 of the Clean Air Act limits the use of dispersion techniques, such as merged gas streams, intermittent controls, or stack heights above GEP, to meet the NAAQS or PSD increments. The GEP stack height is defined under Section 123 as "the height necessary to insure that emissions from the stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash, eddies or wakes which may be created by the source itself, nearby structures or nearby terrain obstacles." The EPA has promulgated stack height regulations under 40 CFR Part 51 which help to determine the GEP stack height for any stationary source.

Three methods are available for determining "GEP stack height" as defined in 40 CFR 51.100(ii):

- ! use the 65 meter (213.5 feet) de minimis height as measured from the ground-level elevation at the base of the stack;
- ! calculate the refined formula height using the dimensions of nearby structures (this height equals H + 1.5L, where H is the height of the nearby structure and L is the lesser dimension of the height or projected width of the nearby structure); or
- ! demonstrate by a fluid model or field study the equivalent GEP formula height that is necessary to avoid excessive concentrations caused by atmospheric downwash, wakes, or eddy effects by the source, nearby structures, or nearby terrain features.

That portion of a stack height in excess of the GEP height is generally not creditable when modeling to develop source emissions limitations or to determine source impacts in a PSD air quality analysis. For a stack height less than GEP height, screening procedures should be applied to assess potential air quality impacts associated with building downwash. In some cases, the aerodynamic turbulence induced by surrounding buildings will cause stack emissions to be mixed rapidly toward the ground (downwash), resulting in higher-than-normal ground level concentrations in the vicinity of the source. Reference 12 contain screening procedures to estimate downwash concentrations in the building wake region. The <u>Mbdeling Guideline</u> recommends using the Industrial Source Complex (ISC) air dispersion model to determine building wake effects on maximum estimated pollutant concentrations.

For additional guidance on creditable stack height and plume rise calculations, the applicant should consult with the permitting agency. In addition, several EPA publications [References 15 through 19] are available for the applicant's review.

IV. D. 4 SOURCE DATA

Emissions rates and other source-related data are needed to estimate the ambient concentrations resulting from (1) the proposed new source or modification, and (2) existing sources contributing to background pollutant concentrations (NAAQS and PSD increments). Since the estimated pollutant concentrations can vary widely depending on the accuracy of such data, the most appropriate source data available should always be selected for use in a modeling analysis. Guidance on the identification and selection of existing sources for which source input data must be obtained for a PSD air quality analysis is provided in *section IV.C.* Additional information on the specific source input data requirements is contained in EPA's <u>Modeling Guideline</u> and in the users' guide for each dispersion model.

Source input data that must be obtained will depend upon the categorization of the source(s) to be modeled as either a point, area or line source. Area sources are often collections of numerous small emissions sources that are impractical to consider as separate point or line sources. Line sources most frequently considered are roadways.

For each <u>stationary point source</u> to be modeled, the following minimum information is generally necessary:

- ! pollutant emission rate (see discussion below);
- ! stack height (see discussion on GEP stack height);
- ! stack gas exit temperature, stack exit inside diameter, and stack gas exit velocity;
- ! dimensions of all structures in the vicinity of the stack in question;
- ! the location of topographic features (e.g., large bodies of water, elevated terrain) relative to emissions points; and
- ! stack coordinates.

A source's **emissions rate** as used in a modeling analysis for any pollutant is determined from the following source parameters (where MMBtu means "million Btu's heat input"):

! emissions limit (e.g., lb/MBtu); ! operating level (e.g., MBtu/hour); and ! operating factor (e,g., hours/day, hours/year).

Special procedures, as described below, apply to the way that each of these parameters is used in calculating the emissions rate for either the proposed new source (or modification) or any existing source considered in the NAAQS and PSD increment analyses. *Table C-5* provides a summary of the point source emissions input data requirements for the NAAQS inventory.

For both NAAQS and PSD increment compliance demonstrations, the emissions rate for the proposed new source or modification must reflect the <u>maximum allowable</u> operating conditions as expressed by the federally enforceable emissions limit, operating level, and operating factor for each applicable pollutant and averaging time. The applicant should base the emissions rates on the results of the BACT analysis (see Chapter B, Part I). **Operating levels** less than 100 percent of capacity may also need to be modeled where differences in stack parameters associated with the lower operating levels could result in higher ground level concentrations. A value representing less than continuous operation (8760 hours per year) should be used for the **operating factor** only when a federally enforceable operating limitation is placed upon the proposed source. [NOTE: It is important that the applicant demonstrate that all modeled emission rates are consistent with the applicable permit conditions.]

TABLE C-5 POINT SOURCE MODEL INPUT DATA (EMISSIONS) FOR NAAQS COMPLIANCE DEMONSTRATIONS

Averaging Time	Emission Limit	Operating Level	Operating Factor				
	(#/MMBtu) ¹	X (MMBtu/hr) ¹	X (e.g., hr/yr, hr/day)				
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Z))))))))))))))))))))))))))))))))))))	·····						
Annual and quarterly	Maximum allowable emission limit or Federally enforceabl permit	Design capacity or Federally le enforceable permit condition	Continuous operation (i.e, 8760 hours) ²				
Short termMaximum allowable emissi(24 hours or less)limit or Federally enfor permit limit		Design capacity or Federally le enforceable permit condition	Continuous operation (i.e., all hours of each time period under consideration) (for all hours of the meteorological data base) ²				
,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,	,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,						
Annual and quarterly	Maximum allowable emission limit or Federally enforceabl permit	Actual or design capacity le (whichever is greater), or Federally enforceable permit condition	Actual operating factor averaged over the most recent 2 years ⁵				
Short term	Maximum allowable emission limit or Federally enforceabl permit limit	Actual or design capacity le (whichever is greater), or Federally enforceable permit condition ³	Continuous operation (i.e., all hours of each time period under consideration) (for all hours of the meteorological data base) ²				
Z))))))))))))))))))))))))))))))))))))	,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,						
Annual and quarterly	Maximum allowable emission limit or Federally enforceabl permit limit	Annual level when actually operating, averaged over the most recent 2 years ⁵	Actual operating factor averaged over the most recent 2 years ⁵				
Short term	Maximum allowable emission limit or Federally enforceabl permit limit	Annual level when actually le operating, averaged over the most recent 2 years ⁵	Continuous operation (i.e., all hours of each time period under consideration)				
)))))))))))))))))))))))))))))))))))))))		,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,	(for all hours of the meteorological data base) ²)))))))))))))))))))))))))))))))))))				
¹ Terminology applicable to fuel burning sources; analogous terminology (e.g., #/throughput) may be used for other types of sources. ² If operation does not occur for all hours of the time period of consideration (e.g., 3 or 24 hours) and the source operation is constrained by a Federally enforceable permit condition, an appropriate adjustment to the modeled emission rate may be made (e.g., if operation is only 8:00 a.m. to 4:00 p.m. each day, only these hours will be modeled with emissions from the source. Modeled emissions should not be averaged across non-operating time periods).							

across non-operating time periods). Operating levels such as 50 percent and 75 percent of capacity should also be modeled to determine the load causing the highest concentration. Includes existing facility to which modification is proposed if the emissions from the existing facility will not be affected by the modification. Otherwise use same parameters as for major modification. Unless it is determined that this period is not representative. Generally, the ambient impacts from non-nearby background sources can be represented by air quality data unless adequate data do not exist. 4

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For those existing point sources that must be explicitly modeled, i.e., "nearby" sources (see section IV.C.1 of this chapter), the NAAQS inventory must contain the maximum allowable values for the *emissions limit*, and operating level. The **operating factor** may be adjusted to account for representative, historical operating conditions only when modeling for the annual (or quarterly for lead [Pb]) averaging period. In such cases, the appropriate input is the <u>actual</u> operating factor averaged over the most recent 2 years (unless the permitting agency determines that another period is more representative). For short-term averaging periods (24 hours or less), the applicant generally should assume that nearby sources operate <u>continuously</u>. However, the **operating factor** may be adjusted to take into account any federally enforceable permit condition which limits the allowable hours of operation. In situations where the actual **operating level** exceeds the design capacity (considering any federally enforceable limitations), the actual level should be used to calculate the emissions rate.

If other background sources need to be modeled (i.e., adequate air quality data are not available to represent their impact), the input requirements for the **emissions limit** and **operating factor** are identical to those for "nearby" sources. However, input for the **operating level** may be based on the annual level of actual operation averaged over the last 2 years (unless the permitting agency determines that a more representative period exists).

The applicant must also include any quantifiable **fugitive emissions** from the proposed source or any nearby sources. Fugitive emissions are those emissions that cannot reasonably be expected to pass through a stack, vent, or other equivalent opening, such as a chimney or roof vent. Common quantifiable fugitive emissions sources of particulate matter include coal piles, road dust, quarry emissions, and aggregate stockpiles. Quantifiable fugitive emissions of volatile organic compounds (VOC) often occur at components of process equipment. An applicant should consult with the permitting agency to determine the proper procedures for characterizing and modeling fugitive emissions.

When building **downwash** affects the air quality impact of the proposed source or any existing source which is modeled for the NAAQS analysis, those impacts generally should be considered in the analysis. Consequently, the appropriate dimensions of all structures around the stack(s) in question also should be included in the emissions inventory. Information including building heights and horizontal building dimensions may be available in the permitting agency's files; otherwise, it is usually the responsibility of the applicant to obtain this information from the applicable source(s).

Sources should not automatically be excluded from downwash considerations simply because they are located <u>outside</u> the impact area. Some sources located just outside the impact area may be located close enough to it that the immediate downwashing effects directly impact air quality in the impact area. In addition, the difference in downwind plume concentrations caused by the downwash phenomenon may warrant consideration within the impact area even when the immediate downwash effects do not. Therefore, any decision by the applicant to exclude the effects of downwash for a particular source should be justified in the application, and approved by the permitting agency.

For a PSD increment analysis, an estimate of the amount of increment consumed by existing point sources generally is based on increases in <u>actual</u> emissions occurring since the minor source baseline date. The exception, of course, is for major stationary sources whose <u>actual</u> emissions have increased (as a result of construction) before the minor source baseline date but on or after the major source baseline date. For any increment-consuming (or increment-expanding) emissions unit, the actual **emissions limit**, **operating level**, and **operating factor** may all be determined from source records and other information (e.g., State emissions files), when available, reflecting actual source operation. For the annual averaging period, the change in the actual **emissions rate** should be calculated as the difference between:

- ! the current average actual **emissions rate**, and
 - the average actual **emissions rate** as of the minor source baseline date (or major source baseline date for major stationary sources).

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In each case, the average rate is calculated as the average over previous 2-year period (unless the permitting agency determines that a different time period is more representative of normal source operation).

For each short-term averaging period (24 hours and less), the change in the <u>actual</u> **emissions rate** for the particular averaging period is calculated as the difference between:

- ! the current <u>maximum</u> actual **emissions rate**, and
- ! the <u>maximum</u> actual **emissions rate** as of the minor source baseline date (or major source baseline date for applicable major stationary sources undergoing consturction before the minor source baseline date).

In each case, the maximum rate is the highest occurrence for that averaging period during the previous 2 years of operation.

Where appropriate, air quality impacts from **fugitive emissions** and **building downwash** are also taken into account for the PSD increment analysis. Of course, they would only be considered when applicable to incrementconsuming emissions.

If the change in the actual emissions rate at a particular source involves a change in stack parameters (e.g., stack height, gas exit temperature, etc.) then the stack parameters and emissions rates associated with both the baseline case and the current situation must be used as input to the dispersion model. To determine increment consumption (or expansion) for such a source, the baseline case emissions are input to the model as negative emissions, along with the baseline stack parameters. In the same model run, the current case for the same source is modeled as the total current emissions associated with the current stack parameters. This procedure effectively calculates, for each receptor and for each averaging time, the difference between the baseline concentration and the current concentration (i.e., the amount of increment consumed by the source).

Emissions changes associated with area and mobile source growth occurring since the minor source baseline date are also accounted for in the increment analysis by modeling. In many cases state emission files will contain information on area source emissions or such information may be available from EPA's AIRS-NEDS emissions data base. In the absence of this information, the applicant should use procedures adopted for developing state area source emission inventories. The EPA documents outlining procedures for area source inventory development should be reviewed.

Mobile source emissions are usually calculated by applying mobile source emissions factors to transportation data such as vehicle miles travelled (VMT), trip ends, vehicle fleet characteristics, etc. Data are also required on the spatial arrangement of the VMT within the area being modeled. Mobile source emissions factors are available for various vehicle types and conditions from an EPA emissions factor model entitled MDBILE4. The MDBILE4 users manual [Reference 20] should be used in developing inputs for executing this model. The permitting agency can be of assistance in obtaining the needed mobile source emissions data. Oftentimes, these data are compiled by the permitting agency acting in concert with the local planning agency or transportation department.

For both area source and mobile source emissions, the applicant will need to collect data for the minor source baseline date and the current situation. Data from these two dates will be required to calculate the increment-affecting emission changes since the minor source baseline date.

IV. E THE COMPLIANCE DEMONSTRATION

An applicant for a PSD permit must demonstrate that the proposed source will not cause or contribute to air pollution in violation of any NAAQS or PSD increment. This compliance demonstration, for each affected pollutant, must result in one of the following:

! The proposed new source or modification will not cause a significant ambient impact anywhere.

If the significant net emissions increase from a proposed source would not result in a significant ambient impact anywhere, the applicant is usually not required to go beyond a preliminary analysis in order to make the necessary showing of compliance for a particular pollutant. In determining the ambient impact for a pollutant, the <u>highest</u> estimated ambient concentration of that pollutant for each applicable averaging time is used.

! The proposed new source or modification, in conjunction with existing sources, will not cause or contribute to a violation of any NAAQS or PSD increment.

In general, compliance is determined by comparing the predicted ground level concentrations (based on the full impact analysis and existing air quality data) at each model receptor to the applicable NAAQS and PSD increments. If the predicted pollutant concentration increase over the baseline concentration is below the applicable increment, and the predicted total ground level concentrations are below the NAAQS, then the applicant has successfully demonstrated compliance.

The modeled concentrations which should be used to determine compliance with any NAAQS and PSD increment depend on 1) the type of standard, i.e., deterministic or statistical, 2) the available length of record of meteorological data, and 3) the averaginign time of the standard being analyzed. For example, when the analysis is based on 5 years of National Weather Service meteorological data, the following estimates should be used:

- ! for deterministically based standards (e.g., SO_2), the highest, second-highest short term estimate and the highest annual estimate; and
- ! for statistically based standards (e.g., PM-10), the highest, sixth-highest estimate and highest 5-year average estimate.

Further guidance to determine the appropriate estimates to use for the compliance determination is found in *Chapter 8* of the <u>Modeling Guideline</u> for SO_2 , TSP, lead, NO_2 , and CO; and in EPA's <u>PM 10 SIP Development Guideline</u> [Reference 21] for PM-10.

When a violation of any NAAQS or increment is predicted at one or more receptors in the impact area, the applicant can determine whether the net emissions increase from the proposed source will result in a significant ambient impact at the point (receptor) of each predicted violation, <u>and</u> at the time the violation is predicted to occur. The source will not be considered to cause or contribute to the violation if its own impact is not significant at any violating receptor at the time of each predicted violation. In such a case, the permitting agency, upon verification of the demonstration, may approve the permit. However, the agency must also take remedial action through applicable provisions of the state implementation plan to address the predicted violation(s).

! The proposed new source or modification, in conjunction with existing sources, will cause or contribute to a violation, but will secure sufficient emissions reductions to offset its adverse air quality impact.

If the applicant cannot demonstrate that only <u>insignificant</u> ambient impacts would occur at violating receptors (at the time of the predicted violation), then other measures are needed before a permit can be issued. Somewhat different procedures apply to NAAQS violations than to PSD increment violations. For a **NAAQS violation** to which an applicant contributes significantly, a PSD permit may be granted only if sufficient emissions reductions are obtained to compensate for the adverse ambient impacts caused by the proposed source. Emissions reductions are considered to compensate for the proposed source's adverse impact when, at a minimum, (1) the modeled <u>net</u> concentration, resulting from the proposed emissions increase and the federally enforceable emissions reduction, is less than the applicable significant ambient impact level at each affected receptor, and (2) no new violations will occur. Moreover, such emissions reductions must be made federally enforceable in order to be acceptable for providing the air quality offset. States may adopt procedures pursuant to federal regulations at 40 CFR 51.165(b) to enable the permitting of sources whose emissions would cause or contribute to a NAAQS violation anywhere. The applicant should determine what specific provisions exist within the State program to deal with this type of situation.

In situations where a proposed source would cause or contribute to a **PSD increment violation**, a PSD permit cannot be issued until the increment violation is entirely corrected. Thus, when the proposed source would cause a new increment violation, the applicant must obtain emissions reductions that are sufficient to offset enough of the source's ambient impact to avoid the violation. In an area where an increment violation already exists, and the proposed source would significantly impact that violation, emissions reductions must not only offset the source's adverse ambient impact, but must be sufficient to alleviate the PSD increment violation, as well.

V. AIR QUALITY ANALYSIS -- EXAMPLE

This section presents a hypothetical example of an air quality analysis for a proposed new PSD source. In reality, no two analyses are alike, so an example that covers all modeling scenarios is not possible to present. However, this example illustrates several significant elements of the air quality analysis, using the procedures and information set forth in this chapter.

An applicant is proposing to construct a new coal-fired, steam electric generating station. Coal will be supplied by railroad from a distant mine. The coal-fired plant is a new major source which has the potential to emit significant amounts of SO_{2} PM (particulate matter emissions and PM-10 emissions), NO_x , and CO. Consequently, an air quality analysis must be carried out for each of these pollutants. In this analysis, the applicant is required to demonstrate compliance with respect to -

- ! the **NAAQS** for SO_2 , PM-10, NO_2 , and CO, and
- ! the **PSD increments** for SO_2 , TSP, and NO_2 .

V. A DETERMINING THE IMPACT AREA

The first step in the air quality analysis is to estimate the ambient impacts caused by the proposed new source itself. This preliminary analysis establishes the impact area for each pollutant emitted in significant amounts, and for each averaging period. The largest impact area for each pollutant is then selected as the impact area to be used in the full impact analysis.

To begin, the applicant prepares a modeling protocol describing the modeling techniques and data bases that will be applied in the preliminary analysis. These modeling procedures are reviewed in advance by the permitting agency and are determined to be in accordance with the procedures described in the <u>Modeling Guideline</u> and the stack height regulations.

Several pollutant-emitting activities (i.e., emissions units) at the source will emit pollutants subject to the air quality analysis. The two main boilers emit particulate matter (i.e., particulate matter emissions and PM-10 emissions), SO_2 , NO_x , and CO. A standby auxiliary boiler also emits these pollutants, but will only be permitted to operate when the main boilers are not operating.

Particulate matter emissions and PM-10 emissions will also occur at the coal-handling operations and the limestone preparation process for the flue gas desulfurization (FGD) system. Emissions units associated with coal and limestone handling include:

- Point sources--the coal car dump, the fly ash silos, and the three coal baghouse collectors;
- ! Area sources--the active and the inactive coal storage piles and the limestone storage pile; and
- ! Line sources--the coal and limestone conveying operation.

The emissions from all of the emissions units at the proposed source are then modeled to estimate the source's area of significant impact (impact area) for each pollutant. The results of the preliminary analysis indicate that significant ambient concentrations of NO_2 and SO_2 will occur out to distances of 32 and 50 kilometers, respectively, from the proposed source. No significant concentrations of CO are predicted at any location outside the fenced-in property of the proposed source. Thus, an impact area is not defined for CO, and no further CO analysis is required.

Particulate matter emissions from the coal-handling operations and the limestone preparation process result in significant ambient TSP concentrations out to a distance of 2.2 kilometers. However, particulate matter emissions from the boiler stacks will cause significant TSP concentrations for a distance of up to 10 kilometers. Since the boiler emissions of particulate matter are predominantly PM-10 emissions, the same impact area is used for both TSP and PM-10. This preliminary analysis further indicates that pre-application monitoring data may be required for two of the criteria pollutants, SO_2 and NO_2 , since the proposed new source will cause ambient concentrations exceeding the prescribed significant monitoring concentrations for these two pollutants (see *Table C-3*). Estimated concentrations of PM-10 are below the significant monitoring concentration. The permitting agency informs the applicant that the requirement for pre-application monitoring data will not be imposed with regard to PM-10. However, due to the fact that existing ambient concentrations of both SO_2 and NO_2 are known to exceed their respective significant monitoring concentrations, the applicant must address the preapplication monitoring data requirements for these pollutants.

Before undertaking a site-specific monitoring program, the applicant investigates the availability of existing data that is representative of air quality in the area. The permitting agency indicates that an agency-operated SO_2 network exists which it believes would provide representative data for the applicant's use. It remains for the applicant to demonstrate that the existing air quality data meet the EPA criteria for data sufficiency, representativeness, and quality as provided in the <u>PSD Monitoring Guideline</u>. The applicant proceeds to provide a demonstration which is approved by the permitting agency. For NO_2 , however, adequate data do not exist, and it is necessary for the applicant to take responsibility for collecting such data. The applicant consults with the permitting agency in order to develop a monitoring plan and subsequently undertakes a site-specific monitoring program for NO_2 .

In this example, four intrastate counties are covered by the applicant's impact area. Each of these counties, shown in *Figure C-7*, is designated attainment for all affected pollutants. Consequently, a NAAQS and PSD



Figure I-C-7. Counties Within 100 Kilometers of Proposed Source.

analysis must be completed in each county. With the exception of CO (for which no further analysis is required) the applicant proceeds with the full impact analysis for each affected pollutant.

V. B DEVELOPING THE EMISSIONS INVENTORIES

After the impact area has been determined, the applicant proceeds to develop the required emissions inventories. These inventories contain all of the source input data that will be used to perform the dispersion modeling for the required NAAQS and PSD increment analyses. The applicant contacts the permitting agency and requests a listing of all stationary sources within a 100-kilometer radius of the proposed new source. This takes into account the 50-kilometer impact area for SO_2 (the largest of the defined impact areas) plus the requisite 50-kilometer annular area beyond that impact area. For NO_2 and particulate matter, the applicant needs only to consider the identified sources which fall within the specific screening areas for those two pollutants.

Source input data (e.g., location, building dimensions, stack parameters, emissions factors) for the inventories are extracted from the permitting agency's air permit and emissions inventory files. Sources to consider for these inventories also include any that might have recently been issued a permit to operate, but are not yet in operation. However, in this case no such "existing" sources are identified. The following point sources are found to exist within the applicant's impact area and screening area:

- ! Refinery A;
- ! Chemical Plant B;
- ! Petrochemical Complex C;
- ! Rock Crusher D;
- ! Refinery E;
- ! Gas Turbine Cogeneration Facility F; and
- ! Portland Cement Plant G.

A diagram of the general location of these sources relative to the location proposed source is shown in *Figure C-8*. Because the Portland Cement Plant G is located 70 kilometers away from the proposed source, its impact is not considered in the NAAQS or PSD increment analyses for particulate matter. (The area of concern for particulate matter lies within 60 kilometers of the proposed source.) In this example, the applicant first develops the NAAQS emissions inventory for SO_2 , particulate matter (PM-10), and NO_2 .

V. B. 1 THE NAAQS INVENTORY

For each criteria pollutant undergoing review, the applicant (in conjunction with the permitting agency) determines which of the identified sources will be regarded as "nearby" sources and, therefore, must be explicitly modeled. Accordingly, the applicant classifies the candidate sources in the following way:

	Nearby sources	Other Background Sources
<u>Pollutant</u>	(explicitly model)	(non-modeled background)
S0 ₂	Refinery A	Port. Cement Plant G
_	Chemical Plant B	
	Petro. Complex C	
	Refinery E	
NO ₂	Refinery A,	Refinery E
	Chemical Plant B	
	Petro. Complex C	
	Gas Turbines F	
Parti cul ate	Refinery A	Chemical Plant B
Matter (PM-10)	Petro. Complex C	Refinery E
	Rock Crusher D	Gas Turbines F

For each nearby source, the applicant now must obtain emissions input data for the model to be used. As a conservative approach, emissions input data reflecting the maximum allowable emissions rate of each nearby source could be used in the modeling analysis. However, because of the relatively


Figure C-8. Point Sources Within 100 Kilometers of Proposed Source.

high concentrations anticipated due to the clustering of sources A, B, C and D, the applicant decides to consider the actual operating factor for each of these sources for the annual averaging period, in accordance with *Table C-5*. For example, for SO_2 , the applicant may determine the actual operating factor for sources A, B, and C, because they are classified as nearby sources for SO_2 modeling purposes. On the other hand, the applicant chooses to use the maximum allowable emissions rate for Source E in order to save the time and resources involved with determining the actual operating factors for the 45 individual NO_2 emissions units comprising the source. If a more refined analysis is ultimately warranted, then the actual hours of operation can be obtained from Source E for the purposes of the annual averaging period.

As another example, for particulate matter (**PM 10**), the applicant may determine the actual annual operating factor for sources A, C, and D, because they are nearby sources for PM-10 modeling purposes. Again, the applicant chooses to determine the actual hours of annual operation because of the relatively high concentrations anticipated due to the clustering of these particular sources.

For each pollutant, the applicant must also determine if emissions from the sources that were <u>not</u> classified as nearby sources can be adequately represented by existing air quality data. In the case of SO_2 , for example, data from the existing State monitoring network will adequately measure Source G's ambient impact in the impact area. However, for **PM10**, the monitored impacts of Source B cannot be separated from the impacts of the other sources (A, C, and D) within the proximity of Source B. The applicant therefore must model this source but is allowed to determine both the actual operating factor and the actual operating level to model the source's annual impact, in accordance with *Table C-5*. For the short-term (24-hour) analysis the applicant may use the actual operating level, but <u>continuous</u> operation must be used for the operating factor. The ambient impacts of Source E and Source F will be represented by ambient monitoring data.

For the NO_2 NAAQS inventory, the only source not classified as a nearby source is Refinery E. The applicant would have preferred to use ambient data

to represent the ambient impact of this source; however, adequate ambient NO_2 data is not available for the area. In order to avoid modeling this source with a refined model for NO_2 , the applicant initially agrees to use a screening technique recommended by the permitting agency to estimate the impacts of Source E.

Air quality impacts caused by building downwash must be considered because several nearby sources (A, B, C, and E) have stacks that are less than GEP stack height. In consultation with the permitting agency, the applicant is instructed to consider downwash for all four sources in the SO₂ NAAQS analysis, because the sources are all located in the SO₂ impact area. Also, after consdieration of the expected effect of downwash for other pollutants, the applicant is told that, for NO₂, only Source C must be modeled for its air quality impacts due to downwash, and no modeling for downwash needs to be done with respect to particulate matter.

The applicant gathers the necessary building dimension data for the NAAQS inventory. In this case, these data are available from the permitting agency through its permit files for sources A, B, and E. However, the applicant must contact Source C to obtain the data from that source. Fortunately, the manager of Source C readily provide the applicant this information for each of the 45 individual emission units.

V. B. 2 THE INCREMENT INVENTORY

An increment inventory must be developed for SO_2 , particulate matter (TSP), and NO_2 . This inventory includes all of the applicable emissions input data from:

- ! increment-consuming sources within the impact area; and
- ! increment-consuming sources outside the impact area that affect increment consumption in the impact area.

In considering emissions changes occurring at any of the major stationary sources identified earlier (see *Figure C-8*), the applicant must consider actual emissions changes resulting from a physical change or a change in the

method of operation since the major source baseline date, and any actual emissions changes since the applicable minor source baseline date. To identify those sources (and emissions) that consume PSD increment, the applicant should request information from the permitting agency concerning the baseline area and all baseline dates (including the existence of any prior minor source baseline dates) for each applicable pollutant.

A review of previous PSD applications within the total area of concern reveals that minor source baseline dates for both SO_2 and TSP have already be established in Counties A and B. For NO_2 , the minor source baseline date has already been established in County C. A summary of the relevant baseline dates for each pollutant in these three counties is shown in *Table C-6*. The proposed source will, however, establish the minor source baseline date in Counties C and D for SO_2 and TSP, and in Counties A, B and D for NO_2 .

For **SO**₂, the increment-consuming sources deemed to contribute to increment consumption in the impact area are sources A, B, C and E. Source B underwent a major modification which established the minor source baseline date (April 21, 1984). The actual emissions increase resulting from that physical change is used in the increment analysis. Source A underwent a major modification and Source E increased its hours of operation after the minor source baseline date. The actual emissions increases resulting from both of these changes are used in the increment analysis, as well. Finally, Source C received a permit to add a new unit, but the new unit is not yet operational. Consequently, the applicant must use the potential emissions increase resulting from that new unit to model the amount of increment consumed. The existing units at Source C do not affect the increments because no actual emissions changes have occurred since the April 21, 1984 minor source baseline

TABLE C-6.EXISTING BASELINE DATES FOR SO_2 , TSP,AND NO_2 FOR EXAMPLE PSD INCREMENT ANALYSIS

Pol l utant	Major Source Baseline Date	Minor Source Baseline Date	Affected Counties
Sul fur di oxi de	January 6, 1975	April 21, 1984	A and B
Particulate Matter (TSP)	January 6, 1975	March 14, 1985	A and B
Nitrogen Dioxide	February 8, 1988	June 8, 1988	C

date. Building dimensions data are needed in the increment inventory for nearby sources A, B, and E because each has increment-consuming emissions which are subject to downwash problems. No building dimensions data are needed for Source C, however, because only the emissions from the newlypermitted unit consume increment and the stack built for that unit was designed and constructed at GEP stack height.

For NO_2 , only the gas turbines located at Cogeneration Station F have emissions which affect the increment. The PSD permit application for the construction of these turbines established the minor source baseline date for NO_2 (June 8, 1988). Of course, all construction-based actual emissions changes in NO_x occurring after the major source baseline date for NO_2 (February 8, 1988), at any major stationary source affect increment. However, no such emissions changes were discovered at the other existing sources in the area. Thus, only the actual emissions increase resulting from the gas turbines is included in the NO_2 increment inventory.

For TSP, sources A, B, C, and E are found to have units whose emissions may affect the **TSP increment** in the impact area. Source A established the minor source baseline date with a PSD permit application to modify its existing facility. Source B (which established the minor source baseline date for SO_2 experienced an insignificant increase in particulate matter emissions due to a modification prior to the minor source baseline date for particulate matter (March 14, 1985). Even though the emissions increase did not exceed the significant emissions rate for particulate matter emissions (i.e., 25 tons per year), increment is consumed by the actual increase nonetheless, because the actual emissions increase resulted from construction (i.e., a physical change or a change in the method of operation) at a major stationary source occurring after the major source baseline date for particulate matter. The applicant uses the allowable increase as a conservative estimate of the actual emissions increase. As mentioned previously, Source C received a permit to construct, but the newly-permitted unit is not yet in operation. Therefore, the applicant must use the potential emissions to model the amount of TSP increment consumed by that new unit.

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Finally, Source E's actual emissions increase resulting from an increase in its hours of operation must be considered in the increment analysis. This source is located far enough outside the impact area that its effects on increment consumption in the impact area are estimated with a screening technique. Based on the conservative results, the permitting agency determines that the source's emissions increase will not affect the amount of increment consumed in the impact area.

In compiling the increment inventory, increment-consuming TSP and SO_2 emissions occurring at minor and area sources located in Counties A and B must be considered. Also, increment-consuming NO_x emissions occurring at minor, area, and mobile sources located in County C must be considered. For this example, the applicant proposes that because of the low growth in population and vehicle miles traveled in the affected counties since the applicable minor source baseline dates, emissions from area and mobile sources will not affect increment (SO_2 , TSP, or NO_2) consumed within the impact area and, therefore, do not need to be included in the increment inventory. After reviewing the documentation submitted by the applicant, the permitting agency approves the applicant's proposal not to include area and mobile source emissions in the increment inventory.

V.C The Full Inpact Analysis

Using the source input data contained in the emissions inventories, the next step is to model existing source impacts for both the NAAQS and PSD increment analyses. The applicant's selection of models--ISCST, for shortterm modeling, and ISCLT, for long-term modeling--was made after conferring with the permitting agency and determining that the area within three kilometers of the proposed source is rural, the terrain is simple (noncomplex), and there is a potential for building downwash with some of the nearby sources.

No on-site meteorological data are available. Therefore, the applicant evaluates the meteorological data collected at the National Weather Service station located at the regional airport. The applicant proposes the use of 5 years of hourly observations from 1984 to 1988 for input to the dispersion model, and the permitting agency approves their use for the modeling analyses.

The applicant, in consultation with the permitting agency, determines that terrain in the vicinity is essentially flat, so that it is not necessary to model with receptor elevations. (Consultation with the reviewing agency about receptor elevations is important since significantly different concentration estimates may be obtained between flat terrain and rolling terrain modes.)

A single-source model run for the auxiliary boiler shows that its estimated maximum ground-level concentrations of SO, and NO, will be less than the significant air quality impact levels for these two pollutants (see This boiler is modeled separately from the two main boilers Table C-4). because there will be a permit condition which restricts it from operating at the same time as the main boilers. For particulate matter, the auxiliary boiler's emissions are modeled together with the fugitive emissions from the proposed source to estimate maximum ground-level PM-10 concentrations. In this case, too, the resulting ambient concentrations are less than the significant ambient impact level for PM-10. Thus, operation of the auxiliary boiler would not be considered to contribute to violations of any NAAQS or PSD increment for SO_2 , particulate matter, or NO_2 . The auxiliary boiler is eliminated from further modeling consideration because it will not be permitted to operate when either of the main boilers is in operation.

V. C. 1 NAAQS ANALYSIS

The next step is to estimate total ground-level concentrations. For the SO_2 NAAQS compliance demonstration, the applicant selects a coarse receptor grid of one-kilometer grid spacing to identify the area(s) of high impact caused by the combined impact form the proposed new source and nearby sources. Through the coarse grid run, the applicant finds that the area of highest estimated concentrations will occur in the southwest quadrant. In order to determine the highest total concentrations, the applicant performs a second model run for the southwest quadrant using a 100-meter receptor fine-grid.

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The appropriate concentrations from the fine-grid run is added to the monitored background concentrations (including Source G's impacts) to establish the total estimated SO_2 concentrations for comparison against the NAAQS. The results show maximum SO_2 concentrations of:

- ! 600 $\mu g/m^3$, 3-hour average;
- ! 155 $\mu g/m^3$, 24-hour average; and
- ! 27 μ g/m³, annual average.

Each of the estimated total impacts is within the concentrations allowed by the NAAQS.

For the NO₂ NAAQS analysis, the sources identified as "nearby" for NO₂ are modeled with the proposed new source in two steps, in the same way as for the SO₂ analysis: first, using the coarse (1-kilometer) grid network and, second, using the fine (100-meter) grid network. Appropriate concentration estimates from these two modeling runs are then combined with the earlier screening results for Refinery E and the monitored background concentrations. The highest average annual concentration resulting from this approach is 85 $\mu g/m^3$, which is less than the NO₂ NAAQS of 100 $\mu g/m^3$, annual average.

For the **PM 10 NAAQS** analysis, the same two-step procedure (coarse and fine receptor grid networks) is used to locate the maximum estimated PM 10 concentration. Recognizing that the PM 10 NAAQS is a statistically-based standard, the applicant identifies the sixth highest 24-hour concentration (based on 5 full years of 24-hour concentration estimates) for each receptor in the network. For the annual averaging time, the applicant averages the 5 years of modeled PM 10 concentrations at each receptor to determine the 5year average concentration at each receptor. To these long- and short-term results the applicant then added the monitored background reflecting the impacts of sources E and F, as well as surrounding area and mobile source contributions.

For the receptor network, the highest, sixth-highest 24-hour concentration is 127 μ g/m³, and the highest 5-year average concentration is

38 μ g/m³. These concentrations are sufficient to demonstrate compliance with the PM-10 NAAQS.

V.C.2 PSD Increment Analysis

The applicant starts the increment analysis by modeling the incrementconsuming sources of SO_2 , including the proposed new source. As a conservative first attempt, a model run is made using the maximum allowable SO_2 emissions changes resulting from each of the increment-consuming activities identified in the increment inventory. (Note that this is not the same as modeling the allowable emissions rate for each <u>entire</u> source.) Using a coarse (1-kilometer) receptor grid, the area downwind of the source conglomeration in the southwest quadrant was identified as the area where the maximum concentration increases have occurred. The modeling is repeated for the southwest quadrant using a fine (100-meter) receptor grid network.

The results of the fine-grid model run show that, in the case of peak concentrations downwind of the southwest source conglomeration, the allowable SO_2 increment will be violated at several receptors during the 24-hour averaging period. The violations include significant ambient impacts from the proposed power plant. Further examination reveals that Source A in the southwest quadrant is the large contributor to the receptors where the increment violations are predicted. The applicant therefore decides to refine the analysis by using actual emissions increases rather than allowable emissions increases where needed.

It is learned, and the permitting agency verifies, that the incrementconsuming boiler at Source A has burned refinery gas rather than residual oil since start-up. Consequently, the actual emissions increase at Source A's

boiler, based upon the use of refinery gas during the preceding 2 years, is substantially less than the allowable emissions increase assumed from the use of residual oil. Thus, the applicant models the actual emissions increase at Source A and the allowable emissions increase for the other modeled sources.

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This time the modeling is repeated only for the critical time periods and receptors.

The maximum predicted SO_2 concentration increases over the baseline concentration are as follows:

- ! $302 \mu g/m^3$, 3-hour average;
- ! 72 $\mu g/m^3$, 24-hour average; and
- ! 12 μ g/m³, annual average.

The revised modeling demonstrates compliance with the SO_2 increments. Hence, no further SO_2 modeling is required for the increment analysis.

The full impact analysis for the NO_2 increment is performed by modeling Source F--the sole existing NO_2 increment-consuming source--and the proposed new source. The modeled estimates yield a maximum concentration increase of 21 µg/m³, annual average. This increase will not exceed the maximum allowable increase of 25 µg/m³ for NO_2 .

With the SO_2 and NO_2 increment portions of the analysis complete, the only remaining part is for the **particulate matter (TSP) increments**. The applicant must consider the effects of the four existing increment-consuming sources (A, B, C, and E) in addition to ambient TSP concentrations caused by the proposed source (including the fugitive emissions). The total increase in TSP concentrations resulting from all of these sources is as follows:

- ! 28 μ g/m³, 24-hour average; and
- ! 13 μ g/m³, annual average.

The results demonstrate that the proposed source will not cause any violations of the TSP increments.

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CHAPTER D

ADDITIONAL IMPACTS ANALYSIS

I. INTRODUCTION

All **PSD** permit applicants must prepare an additional impacts analysis for each pollutant subject to regulation under the Act. This analysis assesses the impacts of air, ground and water pollution on soils, vegetation, and visibility caused by any increase in emissions of any regulated pollutant from the source or modification under review, and from associated growth.

Other impact analysis requirements may also be imposed on a permit applicant under local, State or Federal laws which are outside the PSD permitting process. Receipt of a PSD permit does not relieve an applicant from the responsibility to comply fully with such requirements. For example, two Federal laws which may apply on occasion are the **Endangered Species Act** and the **National Historic Preservation Act**. These regulations may require additional analyses (although not as part of the PSD permit) if any federallylisted rare or endangered species, or any site that is included (or is eligible to be included) in the National Register of Historic Sites, are identified in the source's impact area.

Although each applicant for a **PSD** permit must perform an additional impacts analysis, the depth of the analysis generally will depend on existing air quality, the quantity of emissions, and the sensitivity of local soils, vegetation, and visibility in the source's impact area. It is important that the analysis fully document all sources of information, underlying assumptions, and any agreements made as a part of the analysis. Generally, small emissions increases in most areas will not have adverse impacts on soils, vegetation, or visibility. However, an additional impacts analysis still must be performed. Projected emissions from both the new source or modification and emissions from associated residential, commercial, or industrial growth are combined and modeled for the impacts assessment analysis. While this section offers applicants a general approach to an additional impacts analysis, the analysis does not lend itself to a "cookbook" approach.

II. ELEMENTS OF THE ADDITIONAL IMPACTS ANALYSIS

The additional impacts analysis generally has three parts, as follows:

- (1) growth;
- (2) soil and vegetation impacts; and
- (3) visibility impairment.

II. A. GROWTH ANALYSIS

The elements of the growth analysis include:

- a projection of the associated⁵ industrial, commercial, and residential source growth that will occur in the area due to the source; and
- (2) an estimate of the air emissions generated by the above associated industrial, commercial, and residential growth.

First, the applicant needs to assess the availability of residential, commercial, and industrial services existing in the area. The next step is to predict how much new growth is likely to occur to support the source or modification under review. The amount of residential growth will depend on the size of the available work force, the number of new employees, and the availability of housing in the area. Industrial growth is growth in those industries providing goods and services, maintenance facilities, and other large industries necessary for the operation of the source or modification under review. Excluded from consideration as associated sources are mobile sources and temporary sources.

Having completed this portrait of expected growth, the applicant then begins developing an estimate of the secondary air pollutant emissions which would likely result from this permanent residential, commercial, and

⁵ Associated growth is growth that comes about as the result of the construction or modification of a source, but is not a part of that source. It does not include the growth projections addressed by 40 CFR 51.166(n)(3)(ii) and 40 CFR 52.21(n)(2)(ii), which have been called non-associated growth. Emissions attributable to associated growth are classified as secondary emissions.

industrial growth. The applicant should generate emissions estimates by consulting such sources as manufacturers specifications and guidelines, *AP-42*, other *PSD* applications, and comparisons with existing sources.

The applicant next combines the secondary air pollutant emissions estimates for the associated growth with the estimates of emissions that are expected to be produced directly by the proposed source or modification. The combined estimate serves as the input to the air quality modeling analysis, and the result is a prediction of the ground-level concentration of pollutants generated by the source and any associated growth.

II. B. AMBIENT AIR QUALITY ANALYSIS

The ambient air quality analysis projects the air quality which will exist in the area of the proposed source or modification during construction and after it begins operation. The applicant first combines the air pollutant emissions estimates for the associated growth with the estimates of emissions from the proposed source or modification. Next, the projected emissions from other sources in the area which have been permitted (but are not yet in operation) are included as inputs to the modeling analysis. The applicant then models the combined emissions estimate and adds the modeling analysis results to the background air quality to arrive at an estimate of the total ground-level concentrations of pollutants which can be anticipated as a result of the construction and operation of the proposed source.

II. C. SOILS AND VEGETATION ANALYSIS

The analysis of soil and vegetation air pollution impacts should be based on an inventory of the soil and vegetation types found in the impact area. This inventory should include all vegetation with any commercial or recreational value, and may be available from conservation groups, State agencies, and universities.

For most types of soil and vegetation, ambient concentrations of criteria pollutants below the secondary national ambient air quality standards

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(NAAQS) will not result in harmful effects. However, there are sensitive vegetation species (e.g., soybeans and alfalfa) which may be harmed by long-term exposure to low ambient air concentrations of regulated pollutants for which are no NAAQS. For example, exposure of sensitive plant species to 0.5 micrograms per cubic meter of fluorides (a regulated, non-criteria pollutant) for 30 days has resulted in significant foliar necrosis.

Good references for applicants and reviewers alike include the EPA Air Quality Criteria Documents, a U.S. Department of the Interior document entitled Inpacts of Coal-Fired Plants on Fish, Wildlife, and Their Habitats, and the U.S. Forest Service document, A Screening Procedure to Evaluate Air Pollution Effects on Class I Wilderness Areas. Another source of reference material is the National Park Service report, Air Quality in the National Parks, which lists numerous studies on the biological effects of air pollution on vegetation.

II. D. VISIBILITY IMPAIRMENT ANALYSIS

In the visibility impairment analysis, the applicant is especially concerned with impacts that occur within the area affected by applicable emissions. Note that the visibility analysis required here is distinct from the Class I area visibility analysis requirement. The suggested components of a good visibility impairment analysis are:

- ! a determination of the visual quality of the area,
- ! an initial screening of emission sources to assess the possibility of visibility impairment, and
- ! if warranted, a more in-depth analysis involving computer models.

To successfully complete a visibility impairments analysis, the applicant is referred to an EPA document entitled **Workbook for Estimating Visibility Impairment** or its projected replacement, the **Workbook for Plume Visual Impact Screening and Analysis**. In this workbook, EPA outlines a screening procedure designed to expedite the analysis of emissions impacts on the visual quality of an area. The workbook was designed for Class I area impacts, but the outlined procedures are generally applicable to other areas as well. The following sections are a brief synopsis of the screening procedures.

II. D. 1. SCREENING PROCEDURES: LEVEL 1

The Level 1 visibility screening analysis is a series of conservative calculations designed to identify those emission sources that have little potential of adversely affecting visibility. The VISCREEN model is recommended for this first level screen. Calculated values relating source emissions to visibility impacts are compared to a standardized screening value. Those sources with calculated values greater than the screening criteria are judged to have potential visibility impairments. If potential visibility impairments are indicated, then the Level 2 analysis is undertaken.

II. D. 2. SCREENING PROCEDURES: LEVEL 2

The Level 2 screening procedure is similar to the Level 1 analysis in that its purpose is to estimate impacts during worst-case meteorological conditions; however, more specific information regarding the source, topography, regional visual range, and meteorological conditions is assumed to be available. The analysis may be performed with the aid of either hand

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calculations, reference tables, and figures, or a computer-based visibility model called "*PLUVUE II*."

II. D. 3. SCREENING PROCEDURES: LEVEL 3

If the Levels 1 and 2 screening analyses indicated the possibility of visibility impairment, a still more detailed analysis is undertaken in Level 3 with the aid of the plume visibility model and meteorological and other regional data. The purpose of the Level 3 analysis is to provide an accurate description of the magnitude and frequency of occurrence of impact.

The procedures for utilizing the plume visibility model are described in the document **User's Manual for the Plume Visibility Model**, which is available from EPA.

II.E. CONCLUSIONS

The additional impacts analysis consists of a growth analysis, a soil and vegetation analysis, and a visibility impairment analysis. After carefully examining all data on additional impacts, the reviewer must decide whether the analyses performed by a particular applicant are satisfactory. General criteria for determining the completeness and adequacy of the analyses may include the following:

- ! whether the applicant has presented a clear and accurate portrait of the soils, vegetation, and visibility in the proposed impacted area;
- ! whether the applicant has provided adequate documentation of the potential emissions impacts on soils, vegetation, and visibility; and
- ! whether the data and conclusions are presented in a logical manner understandable by the affected community and interested public.

III. ADDITIONAL IMPACTS ANALYSIS EXAMPLE

Sections D.1 and D.2 outlined, in general terms, the elements and considerations found in a successful additional impacts analysis. To demonstrate how this analytic process would be applied to a specific situation, a hypothetical case has been developed for a mine mouth power plant. This section will summarize how an additional impacts analysis would be performed on that facility.

III.A. EXAMPLE BACKGROUND INFORMATION

The mine mouth power plant consists of a power plant and an adjoining lignite mine, which serves as the plant's source of fuel. The plant is capable of generating 1,200 megawatts of power, which is expected to supply a utility grid (little is projected to be consumed locally). This project is located in a sparsely populated agricultural area in the southwestern United The population center closest to the plant is the town of States. Clarksville, population 2,500, which is located 20 kilometers from the plant The next significantly larger town is Milton, which is 130 kilometers site. away and has a population of 20,000. The nearest Class I area is more than 200 kilometers away from the proposed construction. The applicant has determined that within the area under consideration there are no National or State forests, no areas which can be described as scenic vistas, and no points of special historical interest.

The applicant has estimated that construction of the power plant and development of the mine would require an average work force of 450 people over a period of 36 months. After all construction is completed, about 150 workers will be needed to operate the facilities.

III. B. GROWTH ANALYSIS

To perform a growth analysis of this project, the applicant began by projecting the growth associated with the operation of the project.

III. B. 1. WORK FORCE

The applicant consulted the State employment office, local contractors, trade union officers, and other sources for information on labor capability and availability, and made the following determinations.

Most of the 450 construction jobs available will be filled by workers commuting to the site, some from as far away as Milton. Some workers and their families will move to Clarksville for the duration of the construction. Of the permanent jobs associated with the project, about 100 will be filled by local workers. The remaining 50 permanent positions will be filled by nonlocal employees, most of whom are expected to relocate to the vicinity of Clarksville.

III. B. 2. HOUSING

Contacts with local government housing authorities and realtors, and a survey of the classified advertisements in the local newspaper indicated that the predominant housing unit in the area is the single family house or mobile home, and the easy availability of mobile homes and lots provides a local capacity for quick expansion. Although there will be some emissions associated with the construction of new homes, these emissions will be temporary and, because of the limited numbers of new homes expected, are considered to be insignificant.

III. B. 3. INDUSTRY

Although new industrial jobs often lead to new support jobs as well (i.e., grocers, merchants, cleaners, etc.), the small number of new people brought into the community through employment at the plant is not expected to generate commercial growth. For example, the proposed source will not require an increase in small support industries (i.e., small foundries or rock crushing operations).

As a result of the relatively self-contained nature of mine mouth plant operations, no related industrial growth is expected to accompany the operation of the plant. Emergency and full maintenance capacity is contained within the power-generating station. With no associated commercial or industrial growth projected, it then follows that there will be no growthrelated air pollution impacts.

III. C. SOILS AND VEGETATION

In preparing a soils and vegetation analysis, the applicant acquired a list of the soil and vegetation types indigenous to the impact area. The vegetation is dominated by pine and hardwood trees consisting of loblolly pine, blackjack oak, southern red oak, and sweet gum. Smaller vegetation consists of sweetbay and holly. Small farms are found west of the forested area. The principal commercial crops grown in the area are soybeans, corn, okra, and peas. The soils range in texture from loamy sands to sandy clays. The principal soil is sandy loam consisting of 50 percent sand, 15 percent silt, and 35 percent clay.

The applicant, through a literature search and contacts with the local universities and experts on local soil and vegetation, determined the sensitivity of the various soils and vegetation types to each of the applicable pollutants that will be emitted by the facility in significant amounts. The applicant then correlated this information with the estimates of pollutant concentrations calculated previously in the air quality modeling analysis.

After comparing the predicted ambient air concentrations with soils and vegetation in the impact area, only soybeans proved to be potentially sensitive. A more careful examination of soybeans revealed that no adverse effects were expected at the low concentrations of pollutants predicted by the modeling analysis. The predicted sulfur dioxide (SO_2) ambient air concentration is lower than the level at which major SO_2 impacts on soybeans have been demonstrated (greater than 0.1 ppm for a 24-hour period).

Fugitive emissions emitted from the mine and from coal pile storage will be deposited on both the soil and leaves of vegetation in the immediate area of the plant and mine. Minor leaf necrosis and lower photosynthetic activity is expected, and over a period of time the vegetation's community structure may change. However, this impact occurs only in an extremely limited, nonagricultural area very near the emissions site and therefore is not considered to be significant. The potential impact of limestone preparation and storage also must be considered. High relative humidity may produce a crusting effect of the fugitive limestone emissions on nearby vegetation. However, because of BACT on limestone storage piles, this impact is slight and only occurs very near the power plant site. Thus, this impact is judged insignificant.

III. D. VISIBILITY ANALYSIS

Next, the applicant performed a visibility analysis, beginning with a screening procedure similar to that outlined in the EPA document Workbook for Estimating Visibility Impairment. The screening procedure is divided into three levels. Each level represents a screening technique for an increasing possibility of visibility impairment. The applicant executed a Level 1 analysis involving a series of conservative tests that permitted the analyst to eliminate sources having little potential for adverse or significant visibility impairment. The applicant performed these calculations for various distances from the power plant. In all cases, the results of the calculations were numerically below the standardized screening criteria. In preparing the suggested visual and aesthetic description of the area under review, the applicant noted the absence of scenic vistas. Therefore, the applicant concluded that no visibility impairment was expected to occur within the source impact area and that the Level 2 and Level 3 analyses were unnecessary.

III. E. EXAMPLE CONCLUSIONS

The applicant completed the additional impacts analysis by documenting every element of the analysis and preparing the report in straightforward, concise language. This step is important, because a primary intention of the PSD permit process is to generate public information regarding the potential impacts of pollutants emitted by proposed new sources or modifications on their impact areas. NOTE: This example provides only the highlights of an additional impacts analysis for a hypothetical mine mouth power plant. An actual analysis would contain much more detail, and other types of facilities might produce more growth and more, or different, kinds of impacts. For example, the construction of a large mnnufacturing plant could easily generate air qualityrelated growth impacts, such as a large influx of workers into an area and the growth of associated industries. In addition, the existence of particularly sensitive forms of vegetation, the presence of Class I areas, and the existence of particular meteorological conditions would require an analysis of much greater scope.

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CHAPTER E

CLASS I AREA IMPACT ANALYSIS

I. INTRODUCTION

Class I areas are areas of special national or regional natural, scenic, recreational, or historic value for which the PSD regulations provide special protection. This section identifies Class I areas, describes the protection afforded them under the Clean Air Act (CAA), and discusses the procedures involved in preparing and reviewing a permit application for a proposed source with potential Class I area air quality impacts.

II. CLASS I AREAS AND THEIR PROTECTION

Under the CAA, three kinds of Class I areas either have been, or may be, designated. These are:

- ! mandatory Federal Class I areas;
- ! Federal Class I areas; and
- ! non-Federal Class I areas.

Mandatory Federal Class I areas are those specified as Class I by the CAA on August 7, 1977, and include the following areas in existence on that date:

- ! international parks;
- ! national wilderness areas (including certain national wildlife refuges, national monuments and national seashores) which exceed 5,000 acres in size;
- ! national memorial parks which exceed 5,000 acres in size; and
- ! national parks which exceed 6,000 acres in size.

Mandatory Federal Class I areas, which may not be reclassified, are listed by State in Table E-1. They are managed either by the Forest Service (FS), National Park Service (NPS), or Fish and Wildlife Service (FWS).

The States and Indian governing bodies have the authority to designate additional Class I areas. These Class I areas are not "mandatory" and may be reclassified if the State or Indian governing body chooses. States may reclassify either State or Federal lands as Class I, while Indian governing bodies may reclassify only lands within the exterior boundaries of their respective reservations.

State/Type/Area Managing	g Agency	State/Type/Area Managing	Agency
Alabana		California - Continued	
National Wilderness Areas		National Wilderness Areas	
Sipsey	FS	Agua Ti bi a	FS
		Cari bou	FS
Alaska		Cucamonga	FS
National Parks		Desol ati on	FS
Denal i	NPS	Dome Land	FS
		Emi grant	FS
National Wilderness Areas		Hoover	FS
Bering Sea	FWS	John Muir	FS
Simeonof	FWS	Joshua Tree	NPS
Tuxedni	FWS	Kai ser	FS
		Lava Beds	NPS
Ari zona		Marble Mountain	FS
National Parks		Mi narets	FS
Grand Canyon	NPS	Mokel umne	FS
Petrified Forest	NPS	Pi nnacl es	NPS
		Point Reyes	NPS
National Wilderness Areas		San Gabriel	FS
Chiricahua Nat. Monu.	NPS	San Gorgoni o	FS
Chi ri cahua	FS	San Jacinto	FS
Gal i uro	FS	San Rafael	FS
Mazatzal	FS	South Warner	FS
Mt. Baldy	FS	Thousand Lakes	FS
Pine Mountain	FS	Ventana	FS
Saguaro Nat. Monu.	NPS	Yolla Bolly-Middle-Eel	FS
Sierra Ancha	FS		
Superstition	FS	Col orado	
Sycamore Canyon	FS	National Parks	
		Mesa Verde	NPS
Arkansas		Rocky Mountain	NPS
National Wilderness Areas			
Caney Creek	FS	National Wilderness Areas	
Upper Buffalo	FS	Black Canyon of the Gunn.	NPS
		Eagles Nest	FS
Cal i forni a		Flat Tops	FS
National Parks		Great Sand Dunes	NPS
Kings Canyon	NPS	La Garita	FS
Lassen Vol cani c	NPS	Maroon Bells Snowmass	FS
Redwood	NPS	Mount Zirkel	FS
Sequoi a	NPS	Rawah	FS
Yosemi te	NPS	Wemi nuche	FS
		West Elk	FS

TABLE E-1. MANDATORY CLASS I AREAS

State/Type/Area M	fanaging Agency	State/Type/Area Ma	naging Agency
Flori da		Mi chi gan	
National Parks		National Parks	
Evergl ades	NPS	Isle Royale	NPS
National Wilderness A	reas	National Wilderness	Areas
Bradwell Bay	FS	Seney	FWS
Chassahowi tzka	FWS		
Saint Marks	FWS	M innesota	
		National Parks	
Georgi a		Voyageurs	NPS
National Wilderness A	reas		
Cohutta	FS	National Wilderness	Areas
Okefenokee	FWS	Boundary Waters Canoe Ar. H	
Wolf Island	FWS		
		Missouri	
Hawai i		National Wilderness	Areas
National Parks		Hercul es-Gl ades	FS
Hal eakal a	NPS	Mi ngo	FWS
Hawaii Volcanoes	NPS	_	
		Montana	
Idaho		National Parks	
National Parks		Gl aci er	NPS
Yellowstone (See W	lyomi ng)	Yellowstone (See	Wyomi ng)
National Wilderness A	reas	National Wilderness	Areas
Craters of the Moo	n NPS	Anaconda- Pi ntl ar	FS
Hells Canyon (see	Oregon)	Bob Marshall	FS
Sawtooth	FS	Cabinet Mountain	s FS
Sel way-Bitterroot	FS	Gates of the Mou	ntain FS
C C		Medicine Lake	FWS
Kentucky		Mission Mountain	FS
National Parks		Red Rock Lakes	FWS
Mammoth Cave	NPS	Scapegoat	FS
		Sel way-Bitterroo	t (see Idaho)
Loui si ana		U. L. Bend	FWS
National Wilderness A	reas		
Breton	FWS	Nevada	
		National Wilderness	Areas
Mai ne		Jarbri dge	FS
National Parks			
Acadi a	NPS	New Hanpshi re	
		National Wilderness	Areas
National Wilderness A	reas	Great Gulf	FS
Moosehorn	FWS	Presidential Ran	ge-Dry R. FS

TABLE E-1. Continued

State/Type/Area Mana	nging Agency	State/Type/Area Managing	g Agency
New Jersey		Oregon - Continued	
National Wilderness Areas	5	National Wilderness Areas	
Bri ganti ne	FWS	Diamond Peak	FS
-		Eagle Cap	FS
New Mexico		Gearhart Mountain	FS
National Parks		Hells Canyon	FS
Carlsbad Caverns	NPS	Kal mi opsi s	FS
		Mountain Lakes	FS
National Wilderness Areas	5	Mount Hood	FS
Bandel i er	NPS	Mount Jefferson	FS
Bosque del Apache	FWS	Mount Washington	FS
Gila	FS	Strawberry Mountain	FS
Pecos	FS	Three Sisters	FS
Salt Creek	FWS		
San Pedro Parks	FS	South Carolina	
Wheeler Peak	FS	National Wilderness Areas	
White Mountain	FS	Cape Romain	FWS
North Carolina		South Dakota	
National Parks		National Parks	
Great Smoky Mountains (see Tennessee)		Wind Cave	NPS
National Wilderness Areas	5	National Wilderness Areas	
Joyce Kilmer-Slickroo	ck FS	Badl ands	NPS
Linville Gorge	FS		
Shi ni ng Rock	FS	Tennessee	
Swanquarter	FWS	National Parks	
		Great Smoky Mountains	NPS
North Dakota			
National Parks		National Wilderness Areas	
Theodore Roosevelt	NPS	Joyce Kilmer-Slickrock	
		(see North Car	rolina)
National Wilderness Areas	5		
Lostwood	FWS	Texas	
		National Parks	
Okl ahon n		Big Bend	NPS
National Wilderness Areas	5	Guadal upe Mountai n	NPS
Wichita Mountains	FWS		
Oregon			
National Parks			
Crater Lake	NPS		

TABLE E-1. Continued

State/Type/Area M	Managing Agency	State/Type/Area	Managi ng	Agency
litah		West Virginia		
National Parks		National Wilder	rness Areas	
Arches	NPS	Dolly Sods		FS
Brvce Canvon	NPS	Otter Creek		FS
Canvonl ands	NPS			
Capitol Reef	NPS	Wi sconsi n		
		National Wilder	rness Area	
		Rainbow Lake		FWS
Vernont				
National Wilderness A	reas	Wyoni ng		
Lve Brook	FS	National Parks		
0		Grand Teton		NPS
		Yellowstone		NPS
Virgin Islands				
National Parks		National Wilder	rness Areas	
Virgin Islands	NPS	Bri dger		FS
C		Fi tzpatri ck		FS
Vi rgi ni a		North Absaro	ka	FS
National Parks		Teton		FS
Shenandoah	NPS	Washaki e		FS
National Wilderness A	lreas	International	Parks	
James River Face	FS	Roosevel t-Car	mpobello	n/a
Washington				
National Parks				
Mount Rainier	NPS			
North Cascades	NPS			
01 ypmi c	NPS			
National Wilderness A	lreas			
Alpine Lakes	FS			
Glacier Peak	FS			
Goat Rocks	FS			
Mount Adams	FS			
Pasayten	FS			

TABLE E-1. * Continued

Any Federal lands a State so reclassifies are considered *Federal Class I areas.* In so far as these areas are not mandatory Federal Class II areas, these areas may be again reclassified at some later date. (there are as of the date of this manual, no State-designated Federal Class I areas.) However, in accordance with the CAA the following areas may be redesignated only as Class I or II.

> an area which as of August 7, 1977, exceeded 10,000 acres in size and was a national monument, a national primitive area, a national preserve, a national recreation area, a national wild and scenic river, a national wildlife refuge, a national lakeshore or seashore; and

a national park or national wilderness area established after August 7, 1977, which exceeds 10,000 acres in size.

Federal Class I areas are managed by the Forest Service (FS), the National Park Service (NPS), or the Fish and Wildlife Service (FWS).

State or Indian lands reclassified as Class I are considered non-Federal Class I areas. Four Indian Reservations which are non-Federal Class I areas are the Northern Cheyenne, Fort Peck, and Flathead Indian Reservations in Montana, and the Spokane Indian Reservation in Washington.

One way in which air quality degradation is limited in all Class I areas is by stringent limits defined by the Class I increments for sulfur dioxides, particulate matter [measured as total suspended particulate (TSP)], and nitrogen dioxide. As explained previously in Chapter C, Section II. A, PSD increments are the maximum increases in ambient pollutant concentrations allowed over the baseline concentrations. In addition, the FLM of each Class I area is charged with the affirmative responsibility to protect that area's unique attributes, expressed generically as air quality related values (AQRV's). The FLM, including the State or Indian governing body, where applicable, is responsible for defining specific AQRV's for an area and for establishing the criteria to determine an adverse impact on the AQRV's.

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Congress intended the Class I increments to serve a special function in protecting the air quality and other unique attributes in Class I areas. In Class I areas, increments are a means of determining which party, i.e., the permit applicant or the FLM, has the burden of proof for demonstrating whether the proposed source would not cause or contribute to a Class I increment violation, the FLM may demonstrate to EPA, or the appropriate permitting authority, that the emissions from a proposed source would have an adverse impact on any AQRV's established for a particular Class I area.

If, on the other hand, the proposed source would cause or contribute to a Class I increment violation, the burden of proof is on the applicant to demonstrate to the FLM that the emissions from the source would have no adverse impact on the AQRV's. These concepts are further described in Section III.d of this chapter.

II. A. CLASS I INCREMENTS

The Class I increments for total suspended particulate matter (TSP), SO₂, and NO₂ are listed in Table E-2. Increments are the maximum increases in ambient pollutant concentrations allowed over baseline concentrations. Thus, these increments should limit increases in ambient pollutant concentrations caused by new major sources or major modifications near Class I areas. Increment consumption analyses for Class I areas should include not only emissions from the proposed source, but also include increment-consuming emissions from other sources.

Pollutant	Annual	24- hour	3-hour
Sul fur di oxi de	2	5	25
Particulate matter (TSP)	5	10	N/A
Nitrogen dioxide	2.5	N/A	N/A

TABLE E-2. CLASS I INCREMENTS (ug/m³)

II. B. AIR QUALITY- RELATED VALUES (AQRV's)

The AQRV's are those attributes of a Class I area that deterioration of air quality may adversely affect. For example, the Forest Service defines AQRV's as "features or properties of a Class I area that made it worthy of designation as a wilderness and that could be adversely affected by air pollution." Table E-3 presents an extensive (though not exhaustive) list of example AQRV's and the parameters that may be used to detect air pollutioncaused changes in them. Adverse impacts on AQRV's in Class I areas may occur even if pollutant concentrations do not exceed the Class I increments.

Air quality-related values generally are expressed in broad terms. The impacts of increased pollutant levels on some AQRV's are assessed by measuring specific parameters that reflect the AQRV's status. For instance, the projected impact on the presence and vitality of certain species of animals or plants may indicate the impact of pollutants on AQRV's associated with species diversity or with the preservation of certain endangered species. Similarly, an AQRV associated with water quality may be measured by the pH of a water body or by the level of certain nutrients in the water. The AQRV's of various Class I areas differ, depending on the purpose and characteristics of a particular area and on assessments by the area's FLM Also, the concentration at which a pollutant adversely impacts an AQRV can vary between Class I areas because the sensitivity of the same AQRV often varies between areas.

When a proposed major source's or major modification's modeled emissions may affect a Class I area, the applicant analyzes the source's anticipated impact on visibility and provides the information needed to determine its effect on the area's other AQRV's. The FLM's have established criteria for determining what constitutes an "adverse" impact. For example, the NPS

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TABLE E- 3.EXAMPLES OF AIR QUALITY-RELATED VALUES AND POTENTIALAIR POLLUTION-CAUSED CHANGES

Potential Air Pollution-Caused Changes
Growth, Mortality, Reproduction,
Diversity, Visible Injury, Succession,
Productivity, Abundance
Total Alkalinity, Metals Concentration,
Anion and Cation Concentration, pH,
Dissolved Oxygen
Contrast, Visual Range, Coloration
Decomposition Rate
0dor

defines an "adverse impact" as "any impact that: (1) diminishes the area's national significance; (2) impairs the structure or functioning of ecosystems; or (3) impairs the quality of the visitor experience." If an FLM determines, based on any information available, that a source will adversely impact AQRV's in a Class I area, the FLM may recommend that the reviewing agency deny issuance of the permit, even in cases where no applicable increments would be exceeded.

II. C. FEDERAL LAND MANAGER

The FLM of a Class I area has an affirmative responsibility to protect AQRV's for that area which may be adversely affected by cumulative ambient pollutant concentrations. The FLM is responsible for evaluating a source's projected impact on the AQRV's and recommending that the reviewing agency either approve or disapprove the source's permit application based on anticipated impacts. The FLM also may suggest changes or conditions on a permit. However, the reviewing agency makes the final decisions on permit issuance. The FLM also advises reviewing agencies and permit applicants about other FLM concerns, identifies AQRV's and assessment parameters for permit applicants, and makes ambient monitoring recommendations.

The U.S. Departments of Interior (USDI) and Agriculture (USDA) are the FLM's responsible for protecting and enhancing AQRV's in Federal Class I areas. Those areas in which the USDI has authority are managed by the NPS and the FWS, while the USDA Forest Service separately reviews impacts on Federal Class I national wildernesses under its jurisdiction. The PSD regulations specify that the reviewing authority furnish written notice of any permit application for a proposed major stationary source or major modification, the emissions from which may affect a Class I area, to the FLM and the official charged with direct responsibility for management of any lands within the area. Although the Secretaries of Interior and Agriculture are the FLM's for Federal Class I areas, they have delegated permit review to specific elements within each department. In the USDI, the NPS Air Quality Division reviews PSD permits for both the NPS and FWS. Hence, for sources that may affect wildlife

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refuges, applicants and reviewing agencies should contact and send correspondence to both the NPS and the wildlife refuge manager located at the refuge. Table E-4 summarizes the types of Federal Class I areas managed by each FLM In the USDA, the Forest Service has delegated to its regional offices (listed in Table E-5) the responsibility for PSD permit application review.

TABLE E-4.	FEDERAL	LAND	MANAGERS
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Federal Land Manager	Federal Class I Areas Managed	Address
National Park Service (USDI)	National Memorial Parks National Monuments ¹ National Parks National Seashores ¹	Air Quality Division National Park Service - Air P.O. Box 25287 Denver, CO 80225-0287
Fish and Wildlife Service (USDI)	National Wildlife Refuges ¹	Send to NPS, above, and to Wildlife Refuge Manager. ²
Forest Service (USDA)	National Wildernesses	Send to Forest Service Regional Office (See Table E-5)

¹Only those national monuments, seashores, and wildlife refuges which also were designated wilderness areas as of August 7, 1977 are included as mandatory Federal Class I areas.

²The Wildlife Refuge Manager is located at or near each refuge.

TABLE E- 5.USDA FOREST SERVICE REGIONAL OFFICESAND STATES THEY SERVE*

USDA Forest Service Northern Region Federal Building P. 0. Box 7669 Missoula, MT 59807 [ID, ND, SD, MT]

USDA Forest Service Southwestern Region Federal Building 517 Gold Avenue, SW Albuquerque, NM 87102 [AZ, NM]

USDA Forest Service Pacific Southwest Region 630 Sansome Street San Francisco, CA 94111 [CA, HI, GUAM, Trust Terr. of Pacific]

USDA Forest Service Southern Region 1720 Peachtree Road, NW Atlanta, GA 30367 [AL, AR, FL, GA, KY, LA, MS, NC, OK, PR, SC, TN, TX, VI, VA] USDA Forest Service Rocky Mountain Region 11177 West 8th Avenue P. O. Box 25127 Lakewood, CO 80225 [CO, KS, NE, SD, WY]

USDA Forest Service Intermountain Region Federal Building 324 25th Street Ogden, UT 84401 [ID, UT, NV, WY]

USDA Forest Service Pacific Northwest Region P.O. Box 3623 Portland, OR 97208 [WA, OR]

USDA Forest Service Eastern Region 310 W. Wisconsin Avenue, Room 500 Milwaukee, WI 53203 [CT, DE, IL, IN, IA, ME, MD, MA, MI, MN, MD, NH, NY, NJ, OH, PA, RI, VT, W, WI]

USDA Forest Service Alaska Region P.O. Box 21628 Juneau, AK 99802-1628 [AK]

* Some Regions serve only part of a State.

III. CLASS I AREA IMPACT ANALYSIS AND REVIEW

This section presents the procedures an applicant should follow in preparing an analysis of a proposed source's impact on air quality and AQRV's in Class I areas, including recommended informal steps. For each participant in the analysis - the permit applicant, the FLM, and the permit reviewing agency - the section summarizes their role and responsibilities.

III. A. SOURCE APPLICABILITY

If a proposed major source or major modification **may affect** a Class I area, the Federal PSD regulations require the reviewing authority to provide written notification of any such proposed source to the FLM (and the USDI and USDA officials delegated permit review responsibility). The meaning of the term "may affect" is interpreted by EPA policy to include all major sources or major modifications which propose to locate within 100 kilometers (km) of a Class I area. Also, if a major source proposing to locate at a distance greater than 100 km is of such size that the reviewing agency or FLM is concerned about potential emission impacts on a Class I area, the reviewing agency can ask the applicant to perform an analysis of the source's potential emissions impacts on the Class I area. This is because certain meteorological conditions, or the quantity or type of air emissions from large sources locating further than 100 km, may cause adverse impacts on a Class I area's. A reviewing agency should exclude no major new source or major modification from performing an analysis of the proposed source's impact if there is some potential for the source to affect a Class I area's.

The EPA's policy requires, at a minimum, an AQRV impact analysis of any PSD source the emissions from which increase pollutant concentration by more than 1 μ g/m³ (24-hour average) in a Class I area. However, certain AQRV's may be sensitive to pollutant increases less than 1 μ g/m³. Also, some Class I areas may be approaching the threshold for effects by a particular pollutant on certain resources and consequently may be sensitive to even small increases in pollutant concentrations. For example, in some cases increases in sulfate concentration less than 1 μ g/m³ may adversely impact visibility. Thus, an

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increase of 1 μ g/m³ should not absolutely determine whether an AQRV impact analysis is needed. The reviewing agency should consult the FLM to determine whether to require all the information necessary for a complete AQRV impact analysis of a proposed source.

III. B. PRE- APPLICATION STAGE

A pre-application meeting between the applicant, the FLM, and the reviewing agency to discuss the information required of the source is highly recommended. The applicant should contact the appropriate FLM as soon as plans are begun for a major new source or modification near a Class I area (i.e., generally within 100 km of the Class I area). A preapplication meeting, while not required by regulation, helps the permit applicant understand the data and analyses needed by the FLM At this point, given preliminary information such as the source's location and the type and quantity of projected air emissions, the FLM can:

- ! agree on which Class I areas are potentially affected by the source;
- ! discuss AQRV's for each of the areas(s) and the indicators that may be used to measure the source's impact on those AQRV's;
- ! advise the source about the scope of the analysis for determining whether the source potentially impacts the Class I area(s);
- ! discuss which Class I area impact analyses the applicant should include in the permit application; and
- ! discuss all pre-application monitoring in the Class I area that may be necessary to assess the current status of, and effects on, AQRV's (this monitoring usually is done by the applicant).

III. C. PREPARATION OF PERMIT APPLICATION

For each proposed major new source or major modification that may affect a Class I area, the applicant is responsible for:

- ! identifying all Class I areas within 100 km of the proposed source and any other Class I areas potentially affected;
- ! performing all necessary Class I increment analyses (including any necessary cumulative impact analyses);
- ! performing for each Class I area any preliminary analysis required by a reviewing agency to find whether the source may increase the ambient concentration of any pollutant by 1 μ g/m³ (24-hour average) or more;
- ! performing for each Class I area an AQRV impact analysis for visibility;
- ! providing all information necessary to conduct the AQRV impact analyses (including any necessary cumulative impact analyses);
- ! performing any monitoring within the Class I area required by the reviewing agency; and
- ! providing the reviewing agency with any additional relevant information the agency requests to "complete" the Class I area impacts analysis.

By involving the FLM early in preparation of the Class I area analysis, the applicant can identify and address FLM concerns, avoiding delays later during permit review.

The FLM is the AQRV expert for Class I areas. As such, the FLM can recommend to the applicant:

- ! the AQRV's the applicant should address in the PSD permit application's Class I area impact analysis;
- ! techniques for analyzing pollutant effects on AQRV's;
- ! the criteria the FLM will use to determine whether the emissions from the proposed source would have an adverse impact on any AQRV;

- ! the pre-construction and post-construction AQRV monitoring the FLM will request that the reviewing agency require of the applicant; and
- ! the monitoring, analysis, and quality assurance/quality control techniques the permit applicant should use in conducting the AQRV monitoring.

The permit applicant and the FLM also should keep the reviewing agency apprised of all discussions concerning a proposed source.

III. D. PERMIT APPLICATION REVIEW

Where a reviewing agency anticipates that a proposed source may affect a Class I area, the reviewing agency is responsible for:

- ! sending the FLM a copy of any advance notification that an applicant submits within 30 days of receiving such notification;
- ! sending EPA a copy of each permit application and a copy of any action relating to the source;
- ! sending the FLM a complete copy of all information relevant to the permit application, including the Class I visibility impacts analysis, within 30 days of receiving it and at least 60 days before any public hearing on the proposed source (the reviewing agency may wish to request that the applicant furnish 2 copies of the permit application);
- ! providing the FLM a copy of the preliminary determination document; and
- ! making a final determination whether construction should be approved, approved with conditions, or disapproved.

A reviewing agency's policy regarding Class I area impact analyses can ensure FLM involvement as well as aid permit applicants. Some recommended policies for reviewing agencies are:

! not considering a permit application complete until the FLM certifies that it is "complete" in the sense that it contains adequate information to assess adverse impacts on AQRV's;

- ! recommending that the applicant agree with the FLM (usually well before the application is received) on the type and scope of AQRV analyses to be done;
- ! deferring to the FLM's adverse impact determination, i.e., denying permits based on FLM adverse impact certifications; and
- ! where appropriate, incorporating permit conditions (e.g., monitoring program) which will assure protection of AQRV's. Such conditions may be most appropriate when the full extent of the AQRV impacts is uncertain.

In addition, the reviewing agency can serve as an arbitrator and advisor in FLM/applicant agreements, especially at meetings and in drafting any written agreements.

While the FLM's review of a permit application focuses on emissions impacts on visibility and other AQRV's, the FLM may comment on all other aspects of the permit application. The FLM should be given sufficient time (at least 30 days) to thoroughly perform or review a Class I area impact analysis and should receive a copy of the permit application either at the same time as the reviewing agency or as soon after the reviewing agency as possible. The FLM can make one of two decisions on a permit application: (1) no adverse impacts; or (2) adverse impact based on any available information. Where a proposed major source or major modification adversely impacts a Class I area's AQRV's, the FLM can recommend that the reviewing agency deny the permit request based on the source's projected adverse impact on the area's AQRV's. However, rather than recommending denial at this point, the FLM may work with the reviewing agency to identify possible permit conditions that, if agreed to by the applicant, would make the source's effect on AQRV's acceptable. In cases where the permit application contains insufficient information for the FLM to determine AQRV impacts, the FLM should notify the reviewing agency that the application is incomplete.

During the public comment period, the FLM can have two roles: 1) final determination on the source's impact on AQRV's with a formal recommendation to the reviewing agency; and 2) a commenter on other aspects of the permit application (best available control technology, modeling, etc.). Even for PSD permit applications where a proposed source's emissions clearly would not cause or contribute to exceedances of any Class I increment, the FLM may demonstrate to the reviewing agency that emissions from the proposed source or modification would adversely impact AQRV's of a mandatory Federal Class I area and recommend denial. Conversely, a permit applicant may demonstrate to the FLM that a proposed source's emissions do not adversely affect a mandatory Federal Class I area's AQRV's even though the modeled emissions would cause an

exceedance of a Class I increment. Where a Class I increment is exceeded, the burden of proving no adverse impact on AQRV's is on the applicant. If the FLM concurs with this demonstration, the FLM may recommend approval of the permit to the reviewing agency and such a permit may be issued despite projected Class I increment exceedances.

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IV. VISIBILITY IMPACT ANALYSIS AND REVIEW

Visibility is singled out in the regulations for special protection and enhancement in accordance with the national goal of preventing any future, and remedying any existing, impairment of visibility in Class I areas caused by man-made air pollution. The visibility regulations for new source review (40 CFR 51.307 and 52.27) require visibility impact analysis in PSD areas for major new sources or major modifications that have the potential to impair visibility in <u>any</u> Federal Class I area. Information on screening models available for visibility analysis can be found in the manual "Workbook for Plume Visual Impact Screening and Analysis," EPA-450/4-88-015 (9/88).

IV. A VISIBILITY ANALYSIS

An "adverse impact on visibility" means visibility impairment which interferes with the management, protection, preservation, or enjoyment of a visitor's visual experience of the Federal Class I area. The FLM makes the determination of an adverse impact on a case-by-case basis taking into account the geographic extent, duration, intensity, frequency and time of visibility impairment, and how these factors correlate with (1) times of visitor use of the Federal Class I area, and (2) the frequency and timing of natural conditions that reduce visibility. Visibility perception research indicates that the visual effects of a change in air quality requires consideration of the features of the particular vista as well as what is in the air, and that measurement of visibility usually reflects the change in color, texture, and form of a scene. The reviewing agency may require visibility monitoring in any Federal Class I area near a proposed new major source or modification as the agency deems appropriate.

An integral vista is a view perceived from within a mandatory Class I Federal area of a specific landmark or panorama located outside of the mandatory Class I Federal area. A visibility impact analysis is required for the integral vistas identified at 40 CFR 81, Subpart D, and for any other integral vista identified in a SIP.

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IV. B PROCEDURAL REQUIREMENTS

When the reviewing agency receives advance notification (e.g., early consultation with the source prior to submission of the application) of a permit application for a source that may affect visibility in a Federal Class I area, the agency must notify the appropriate FLM within 30 days of receiving the notification. The reviewing agency must, upon receiving a permit application for a source that may affect Federal Class I area visibility, notify the FLM in writing within 30 days of receiving it and at least 60 days prior to the public hearing on the permit application. This written notification must include an analysis of the source's anticipated impact on visibility in any Federal Class I area and all other information relevant to the permit application. The FLM has 30 days after receipt of the visibility impact analysis and other relevant information to submit to the reviewing agency a finding that the source will adversely impact visibility in a Federal Class I area.

If the FLM determines that a proposed source will adversely impact visibility in a Federal Class I area and the reviewing agency concurs, the permit may not be issued. Where the reviewing agency does not agree with the FLM s finding of an adverse impact on visibility the agency must, in the notice of public hearing, either explain its decision or indicate where the explanation can be obtained.

V. BIBLIOGRAPHY

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CHAPTER F

CHAPTER F

NONATTAINMENT AREA APPLICABILITY

I. INTRODUCTION

Many of the elements and procedures for source applicability under the nonattainment area NSR applicability provisions are similar to those of PSD applicability. The reader is therefore encouraged to become familiar with the terms, definitions and procedures from Part I.A., "PSD Applicability," in this manual. Important differences occur, however, in three key elements that are common to applicability determinations for new sources or modifications of existing sources located in attainment (PSD) and nonattainment areas. Those elements are:

- ! Definition of "source,"
- ! Pollutants that must be evaluated (geographic effects); and
- ! Applicability thresholds

Consequently, this section will focus on these three elements in the context of a nonattaiment area NSR program. Note that the two latter elements, pollutants that must be evaluated for nonattainment NSR due to the location of the source in designated nonattainment areas (geographic effects) and applicability thresholds, <u>are not independent</u>. They will, therefore, be discussed in section III.

II. DEFINITION OF SOURCE

The original NSR regulations required that a source be evaluated according to a **dual** source definition. On October 14, 1981, however, the EPA revised the new source review regulations to give a State the option of adopting a **plantwide** definition of stationary source in nonattainment areas, if the State's SIP did not rely on the more stringent "dual" definition in its attainment demonstration. Consequently, there are two stationary source definitions for nonattainment major source permitting: a "plantwide" definition and a "dual" source definition. <u>The permit application must use,</u> <u>and be reviewed according to, whichever of the two definitions is used to</u> <u>define a stationary source in the applicable SIP.</u>

II. A. "PLANTWIDE" STATIONARY SOURCE DEFINITION

The EPA definition of stationary source for nonattainment major source permitting uses the "plantwide" definition, which is the same as that used in PSD. A complete discussion of the concepts associated with the plantwide definition of source are presented in the PSD part of this manual (see section II). In essence, this definition provides that only physical or operation changes that result in a significant net emissions increase **at the entire plant** are considered a major modification to an existing major source (see sections II and III).

For example, if an existing major source proposes to increase emissions by constructing a new emissions unit but plans to reduce actual emissions by the same amount at another emissions unit at the plant (assuming the reduction is federally enforceable and is the only contemporaneous and creditable emissions change at the source), then there would be no net increase in emissions at the plant and therefore no "major" modification to the stationary source.

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II. B. "DUAL SOURCE" DEFINITION OF STATIONARY SOURCE

The "dual" definition of stationary source defines the term stationary source as ". . . any building, structure, facility, or installation which emits or has the potential to emit any air pollutant subject to regulation under the Clean Air Act." Under this definition, the three terms **building**, **structure**, or **facility** are defined as a single term meaning **all** of the pollutant-emitting activities which belong to the same industrial grouping (i.e., same two-digit SIC code), are located on one or more adjacent properties, and are under the control of the same owner or operator. The fourth term, **installation**, means an identifiable piece of process equipment. Therefore, a stationary source is both:

! a building, structure, or facility (plantwide); and

! an installation (individual piece of equipment).

In other words, the "dual source" definition of stationary source treats each emissions unit as (1) a separate, independent stationary source, and (2) a component of the entire stationary source.

For example, in the case of a power plant with three large boilers each emitting major amounts (i.e., >100 tpy) of NO_x , each of the three boilers is an individual stationary source and all three boilers together constitute a stationary source. [Note that the power plant would be seen only as a single stationary source under the plantwide definition (all three boilers together as one stationary source)].

Consequently, under the dual source definition, the emissions from each physical or operational change at a plant are reviewed both with and without regard to reductions elsewhere at the plant.

For example, a power plant is an existing major SO_2 source in an SO_2 nonattainment area. The power plant proposes to 1) install SO_2 scrubbers on an existing boiler and 2) construct a new boiler at the same facility. Under the "plantwide" definition, the SO_2 reductions from the scrubber installation could be considered, along with other contemporaneous emissions changes at the plant and the new emissions increase of the new boiler to arrive at the source's net emission increase. This might result in a net

emissions change which would be below the SO₂ significance level and the new boiler would "net" out of review as mnjor modification. Under the dual source definition, however, the new boiler would be regarded as a individual source and would be subject to nonattainment NSR requirements if its potential emissions exceed the 100 tpy threshold. The emissions reduction from the scrubber could not be used to reduce net source emissions, but would instead be regarded as an SO₂ emissions reduction from a separate source.

The following examples are provided to further clarify the application of the dual source definition to determine if a modification to an existing major source is major and, therefore, subject to major source NSR permitting requirements.

Example 1An existing mjor stationary source is located in a
nonattainment area for NOx where the "dual source"
definition applies, and has the following emissions units:
Unit #1 with a potential to emit of 120 tpy of NOx
Unit #2 with a potential to emit of 80 tpy of NOx
Unit #3 with a potential to emit of 120 tpy of NOx
Unit #4 with a potential to emit of 130 tpy of NOxCase 1A modification planned for Unit #1 will result in an emissions

case 1 A multification planned for Unit #1 will result in an emissions increase of 45 tpy of NO_x. The following emissions changes are contemporaneous with the proposed modification (all case examples assume that increases and decreases are creditable and will be mode federally enforceable by the reviewing authority when the modification is permitted and will occur before construction of the modification):

> Unit #3 had an actual decrease of 10 tpy NO_x Unit #4 had an actual decrease of 10 tpy NO,

Only contemporaneous emissions changes at Unit #1 are considered because Unit #1 is a mnjor source of NO_x by itself (i.e., potential emissions of NO_x are greater than 100 tpy). The proposed increase at unit #1 of 45 tpy is greater than the 40 tpy

 NO_x significant emissions rate since the emissions changes at the other units are not considered. Consequently, the proposed modification to Unit #1 is major under the dual source definition.

Case 2 A modification to unit #2 is planned which will result in an emissions increase of 45 tpy of NO_x. The following emissions changes are contemporaneous with the proposed modification:

Unit #1 had an actual decrease of 10 tpy

Unit #3 had an actual decrease of 10 tpy

Unit #2 is not a major stationary source in and of itself (i.e., its potential to emission of 80 tpy NO_x is less than the 100 tpy major source threshold). Therefore, the major stationary source being modified is the whole plant and the emissions decreases at units #1 and #3 are considered in calculating the net emissions change at the source. The net emissions change of 25 tpy (the sum of +45, -10, and -10) at the source is less than the applicable 40 tpy NO_x significant emissions rate. Consequently, the proposed modification is <u>not</u> major.

Case 3 A brand new unit #5 with a potential to emission of 45 tpy of NO_x (note that potential emissions are less than the 100 tpy mjor source cutoff) is being added to the plant. The following emissions changes are contemporaneous with the proposed modification:

Unit #1 had an actual decrease of 15 tpy

Unit #2 had an actual increase of 25 tpy

Unit #3 had an actual decrease of 20 tpy

The new unit #5 is not a major stationary source in and of itself. Therefore, the major stationary source being modified is the whole plant and the emissions decreases at units #1, #2 and #3 are considered in calculating the net emissions change at the source. The net emissions change of 35 tpy (the sum of + 45, -15, +25, and -20) at the source is less than the applicable 40 tpy NO_x significance level. Therefore, the proposed unit #5 is <u>not</u> a major modification.

Case 4 A brand new unit #6 with a potential to emit of NO_x of 120 tpy is being added to the plant. Because the new unit is, by itself, a new major source (i.e., potential NO_x emissions are greater than the 100 tpy mjor source cutoff), it cannot net out of review (using emissions reductions achieved at other emissions units at the plant) under the dual source definition.

Example 2 An existing plant has only two emissions units. The units have a potential to emit of 25 tpy and 40 tpy. Here, any modification to the plant would have to have a potential to emit greater than 100 tpy before the modification is mnjor and subject to review. This is because neither of the two existing emissions units (at 25 tpy and 40 tpy), nor the total plant (at 65 tpy) are considered to be a mnjor source (i.e., existing potential emissions do not exceed 100 tpy). If, however, a third unit with potential emissions of 110 tpy were added, that unit would be subject to review regardless of any emissions reductions from the two existing units.

III. POLLUTANTS ELIGIBLE FOR REVIEW AND APPLICABILITY THRESHOLDS

III. A. POLLUTANTS ELIGIBLE FOR REVIEW (GEOGRAPHIC CONSIDERATIONS)

A new source will be subject to nonattainment area preconstruction review requirements only if it will emit, or will have the potential to emit, in major amounts any criteria pollutant for which the area has been designated nonattainment. Similarly, only if a modification results in a significant increase (and significant net emissions increase under the plantwide source definition) of a pollutant, for which the source is major and for which the area is designated nonattainment, do nonattainment requirements apply.

III. B. MAJOR SOURCE THRESHOLD

For the purposes of nonattainment NSR, a major stationary source is

- ! any stationary source which emits or has the potential to emit <u>100</u> tpy of any [criteria] pollutant subject to regulation under the CAA, or
- ! any physical change or change in method of operation at an existing non-major source that constitutes a major stationary source by itself.

Note that the 100 tpy threshold applies to all sources. The alternate 250 tpy major source threshold [for PSD sources not classified under one of the 28 regulated source categories identified in Section 169 of the CAA (See Section I.A.2.3 and Table I-A-1) as being subject to a 100 tpy threshold] does not exist for nonattainment area sources.

III. C. MAJOR MODIFICATION THRESHOLDS

Major modification thresholds for nonattainment areas are those same significant emissions values used to determine if a modification is major for PSD. Remember, however, that only criteria pollutants for which the location of the source has been designated nonattainment are eligible for evaluation.

IV. NONATTAINMENT APPLICABILITY EXAMPLE

The following example illustrates the criteria presented in sections II and III above.

Construction of a new plant with potential emissions of 500 tpy SO_2 , 50 tpy VOC and 30 tpy NO_x is proposed for an area designated nonattainment for SO_2 and ozone and attainment for NO_x . (Recall that VOC is the regulated surrogate pollutant for ozone.) The new plant is major for SO_2 and therefore would be subject to nonattainment requirements for SO_2 only. Even though the VOC emissions are significant, the source is minor for VOC, and according to nonattainment regulations, is not subject to major source review. For purposes of PSD, the NO_x emissions are neither major nor significant and are, therefore, not subject to PSD review.

Two years after construction on the new plant commences, a modification of this plant is proposed that will result in an emissions increase of 60 tpy VOC and 35 tpy NO_x without any creditable contemporaneous emissions reductions. Again, the VOC emissions increase would not be subject, because the existing source is not major for VOC. The emissions increase of 35 tpy NO_x is not significant and again, is not subject to PSD review. Note, however, that the plant would be considered a major source of VOC in subsequent applicability determinations.

One year later, the plant proposes another increase in VOC emissions by 75 tpy and NO_x by another 45 tpy, again with no contemporaneous emissions reductions. Because the existing plant is now major for VOC and will experience a significant net emissions increase of that pollutant, it will be subject to nonattainment NSR for VOC. Because the source is major for a regulated pollutant (VOC) and will experience a significant net emissions increase of an attainment pollutant (NO_x), it will also be subject to PSD review.

CHAPTER G

NONATTAINMENT AREA REQUIREMENTS

I. INTRODUCTION

The preconstruction review requirements for major new sources or major modifications locating in designated nonattainment areas differ from prevention of significant deterioration (PSD) requirements. First, the emissions control requirement for nonattainment areas, lowest achievable emission rate (LAER), is defined differently than the best available control technology (BACT) emissions control requirement. Second, before construction of a nonattainment area source can be approved, the source must obtain emissions reductions (offsets) of the nonattainment pollutant from other sources which impact the same area as the proposed source. Third. the applicant must certify that all other sources owned by the applicant in the State are complying with all applicable requirements of the CAA, including all applicable requirements in the State implementation plan (SIP). Fourth, such sources impacting visibility in mandatory class I Federal areas must be reviewed by the appropriate Federal land manager (FLM).

II. LOWEST ACHIEVABLE EMISSION RATE (LAER)

For major new sources and major modifications in nonattainment areas, LAER is the most stringent emission limitation derived from either of the following:

- ! the most stringent emission limitation contained in the implementation plan of any State for such class or category of source; or
- ! the most stringent emission limitation achieved in practice by such class or category of source.

The most stringent emissions limitation contained in a SIP for a class or category of source must be considered LAER, unless (1) a more stringent emissions limitation has been achieved in practice, or (2) the SIP limitation is demonstrated by the applicant to be unachievable. By definition LAER can not be less stringent than any applicable new source performance standard (NSPS).

There is, of course, a range of certainty in such a definition. The greatest certainty for a proposed LAER limit exists when that limit is actually being achieved by a source. However, a SIP limit, even if it has not yet been applied to a source, should be considered initially to be the product of careful investigation and, therefore, achievable. A SIP limit's credibility diminishes if a) no sources exist to which it applies; b) it is generally acknowledged that sources are unable to comply with the limit and the State is in the process of changing the limit; or c) the State has relaxed the original SIP limit. Case-by-case evaluations need to be made in these situations to determine the SIP limit's achievability.

The same logic applies to SIP limits to which sources are subject but with which they are not in compliance. Noncompliance by a source with a SIP limit, even if it is the only source subject to that specific limit, does not automatically constitute a demonstration that the limit is unachievable. The specific reasons for noncompliance must be determined, and the ability of the source to comply assessed. However, such noncompliance may prove to be an indication of nonachievability, so the achievability of such a SIP limitation should be carefully studied before it is used as the basis of a LAER determination. Some recommended sources of information for determining LAER are:

- ! SIP limits for that particular class or category of sources;
- ! preconstruction or operating permits issued in other nonattainment areas; and
- ! the BACT/LAER Clearinghouse.

Several technological considerations are involved in selecting LAER. The LAER is an emissions rate specific to each emissions unit including fugitive emissions sources. The emissions rate may result from a combination of emissions-limiting measures such as (1) a change in the raw material processed, (2) a process modification, and (3) add-on controls. The reviewing agency determines for each new source whether a single control measure is appropriate for LAER or whether a combination of emissions-limiting techniques should be considered.

The reviewing agency also can require consideration of technology transfer. There are two types of potentially transferable control technologies: (1) gas stream controls, and (2) process controls and modifications. For the first type of transfer, classes or categories of sources to consider are those producing similar gas streams that could be controlled by the same or similar technology. For the second type of transfer, process similarity governs the decision.

Unlike BACT, the LAER requirement does not consider economic, energy, or other environmental factors. A LAER is not considered achievable if the cost of control is so great that a major new source could not be built or operated. This applies generically, i.e., if no new plants could be built in that industry if emission limits were based on a particular control technology. If some other plant in the same (or comparable) industry uses that control technology, then such use constitutes evidence that the cost to the industry of that control is not prohibitive. Thus, for a new source, LAER costs are considered only to the degree that they reflect unusual circumstances which in

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some manner differentiate the cost of control for that source from control costs for the rest of the industry. When discussing costs, therefore, applicants should compare control costs for the proposed source to the costs for sources already using that control.

Where technically feasible, LAER generally is specified as both a numerical emissions limit (e.g., lb/MMBtu) and an emissions rate (e.g., lb/hr). Where numerical levels reflect assumptions about the performance of a control technology, the permit should specify both the numerical emissions rate and limitation and the control technology. In some cases where enforcement of a numerical limitation is judged to be technically infeasible, the permit may specify a design, operational, or equipment standard; however, such standards must be clearly enforceable, and the reviewing agency must still make an estimate of the resulting emissions for offset purposes.

III. EMISSIONS REDUCTIONS "OFFSETS"

A major source or major modification planned in a nonattainment area must obtain emissions reductions as a condition for approval. These emissions reductions, generally obtained from existing sources located in the vicinity of a proposed source, must (1) offset the emissions increase from the new source or modification and (2) provide a net air quality benefit. The obvious purpose of acquiring offsetting emissions decreases is to allow an area to move towards attainment of the NAAQS while still allowing some industrial growth. Air quality improvement may not be realized if all emissions increases are not accounted for and if emissions offsets are not real.

In evaluating a nonattainment NSR permit, the reviewing agency ensures that offsets are developed in accordance with the provisions of the applicable State or local nonattainment NSR rules. The following factors are considered in reviewing offsets :

- the pollutants requiring offsets and amount of offset required;
- the location of offsets relative to the proposed source;
- the allowable sources for offsets;
- the "baseline" for calculating emissions reduction credits; and
- the enforceability of proposed offsets.

Each of these factors should be discussed with the reviewing agency to ensure that the specific requirements of that agency are met.

The offset requirement applies to each pollutant which triggered nonattainment NSR applicability. For example, a permit for a proposed petroleum refinery which will emit more than 100 tpy of sulfur dioxide (SO_2) and particulate matter in a SO_2 and particulate matter nonattainment area is required to obtain offsetting emissions reductions of SO_2 and particulate matter.

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III. A. CRITERIA FOR EVALUATING EMISSIONS OFFSETS

Emissions reductions obtained to offset new source emissions in a nonattainment area must meet two important objectives:

- ! ensure reasonable progress toward attainment of the NAAQS; and
- ! provide a positive net air quality benefit in the area affected by the proposed source.

States have latitude in determining what requirements offsets must meet to achieve these NAA program objectives. The EPA has set forth minimum considerations under the Interpretive Ruling (40 CFR 51, Appendix S). Acceptable offsets also must be creditable, quantifiable, federally enforceable, and permanent.

While an emissions offset must always result in reasonable progress toward attainment of the NAAQS, it need not show that the area will attain the NAAQS. Therefore, the ratio of required emissions offset to the proposed source's emissions must be greater than one. The State determines what offset ratio is appropriate for a proposed source, taking into account the location of the offsets, i.e., how close the offsets are to the proposed source.

To satisfy the criterion of a net air quality benefit does not mean that the applicant must show an air quality improvement at every location affected by the proposed source. Sources involved in an offset situation should impact air quality in the same general area as the proposed source, but the net air quality benefit test should be made "on balance" for the area affected by the new source. Generally, offsets for VOC's are acceptable if obtained from within the same air quality control region as the new source or from other nearby areas which may be contributing to an ozone nonattainment problem. For all pollutants, offsets should be located as close to the proposed site as possible. Applicants should always discuss the location of potential offsets with the reviewing agency to determine whether the offsets are acceptable.

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III. B. AVAILABLE SOURCES OF OFFSETS

In general, emissions reductions which have resulted from some other regulatory action are not available as offsets. For example, emissions reductions already required by a SIP cannot be counted as offsets. Also, sources subject to an NSPS in an area with less stringent SIP limits cannot use the difference between the SIP and NSPS limits as an offset. In addition, any emissions reductions already counted in major modification "netting" may not be used as offsets. However, emissions reductions validly "banked" under an approved SIP may be used as offsets.

III. C. CALCULATION OF OFFSET BASELINE

A critical element in the development or review of nonattainment area new source permits is to determine the appropriate baseline of the source from which offsetting emissions reductions are obtained. In most cases the SIP emissions limit in effect at the time that the permit application is filed may be used. This means that offsets will be based on emissions reductions below these SIP limits. Where there is no meaningful or applicable SIP requirement, the applicant be required to use actual emissions as the baseline emissions level.

III. D. ENFORCEABILITY OF PROPOSED OFFSETS

The reviewing agency ensures that all offsets are federally enforceable. Offsets should be specifically stated and appear in the permit, regulation or other document which establishes a Federal enforceability requirement for the emissions reduction. External offsets must be established by conditions in the operating permit of the other plant or in a SIP revision.

IV. OTHER REQUIREMENTS

An applicant proposing a major new source or major modification in a nonattainment area must certify that all major stationary sources owned or operated by the applicant (or by any entity controlling, controlled by, or under common control with the applicant) in that State are in compliance with all applicable emissions limitations and standards under the CAA. This includes all regulations in an EPA-approved SIP, including those more stringent than Federal requirements.

Any major new source or major modification proposed for a nonattainment area that may impact visibility in a mandatory class I Federal area is subject to review by the appropriate Federal land manager (FLM). The reviewing agency for any nonattainment area should ensure that the FLM of such mandatory class I Federal area receives appropriate notification and copies of all documents relating to the permit application received by the agency.

CHAPTER H

ELEMENTS OF AN EFFECTIVE PERMIT

I. INTRODUCTION

An effective permit is the legal tool used to establish all the source limitations deemed necessary by the reviewing agency during review of the permit application, as described in Parts I and II of this manual, and is the primary basis for enforcement of NSR requirements. In essence, the permit may be viewed as an extension of the regulations. It defines as clearly as possible what is expected of the source and reflects the outcome of the permit review process. A permit may limit the emissions rate from various emissions units or limit operating parameters such as hours of operation and amount or type of materials processed, stored, or combusted. Operational limitations frequently are used to establish a new potential to emit or to implement a desired emissions rate. The permit must be a "stand-alone" document that:

! identifies the emissions units to be regulated;

! establishes emissions standards or other operational limits to be met;

! specifies methods for determining compliance and/or excess emissions,

including reporting and recordkeeping requirements; and

! outlines the procedures necessary to maintain continuous compliance with the emission limits.

To achieve these goals, the permit, which is in effect a contract between the source and the regulatory agency, must contain specific, clear, concise, and enforceable conditions.

This part of the manual gives a brief overview of the development of a permit, which ensures that major new sources and modifications will be constructed and operated in compliance with the applicable new source review (NSR) regulations [including prevention of signification deterioration (PSD)
and nonattainment area (NAA) review], new source performance standards (NSPS), national emissions standards for hazardous air pollutants (NESHAP), and applicable state implementation plan (SIP) requirements. In particular, a permit contains the specific conditions and limitations which ensure that:

- ! an otherwise major source will remain minor;
- ! all contemporaneous emissions increases and decreases are creditable and federally-enforceable; and
- ! where appropriate, emissions offset transactions are documented clearly and offsets are real, creditable, quantifiable, permanent and federally-enforceable.

For a more in-depth study, refer to the Air Pollution Training Institute (APTI) course SI 454 (or Workshop course 454 given by APTI) entitled "Effective Permit Writing." This course is highly recommended for all permit writers and reviewers.

II. TYPICAL CONSTRUCTION PERMIT ELEMENTS

While each final permit is unique to a particular source due to varying emission limits and specific special terms and conditions, every permit must also contain certain basic elements:

- ! legal authority;
- ! technical specifications;
- ! emissions compliance demonstration;
- ! definition of excess emissions;
- ! administrative procedures; and
- ! other specific conditions.

Although many of these elements are inherent in the authority to issue permits under the SIP, they must be explicit within the construction of a NSR permit. Table H-1 lists a few typical subelements found in each of the above. Some permit conditions included in each of these elements can be considered standard permit conditions, i.e., they would be included in nearly every permit. Others are more specific and vary depending on the individual source.

II. A. LEGAL AUTHORITY

In general, the first provision of a permit is the specification of the legal authority to issue the permit. This should include a reference to the enabling legislation and to the legal authority to issue and enforce the conditions contained in the permit and should specify that the application is, in essence, a part of the permit. These provisions are common to nearly all permits and usually are expressed in standard language included in every permit issued by an agency. These provisions articulate the contract-like nature of a permit in that the permit allows a source to emit air pollution only if certain conditions are met. A specific citation of any applicable

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<u>Permit Category</u>	<u>Typical Elements</u>
Legal Authority	Basisstatute, regulation, etc. Conditional Provisions Effective and expiration dates
Technical Specifications	Unit operations covered Identification of emission units Control equipment efficiency Design/operation parameters Equipment design Process specifications Operating/maintenance procedures Emission limits
Emission Compliance Demonstration	<pre>Initial performance test and methods Continuous emission monitoring and methods Surrogate compliance measures - process monitoring - equipment design/operations - work practice</pre>
Definition of Excess Emissions	Emission limit and averaging time Surrogate measures Malfunctions and upsets Follow-up requirements
Admi ni strati ve	Recordkeeping and reporting procedures Commence/delay construction Entry and inspections Transfer and severability
Other Conditions	Post construction monitoring Emissions offset

TABLE H.1. SUGGESTED MINIMUM CONTENTS OF AIR EMISSION PERMITS

permit effective date and/or expiration date is usually included under the legal authority as well.

II. B. TECHNICAL SPECIFICATIONS

Overall, the technical specifications may be considered the core of the permit in that they specifically identify the emissions unit(s) covered by the permit and the corresponding emission limits with which the source must comply. Properly identifying each emissions unit is important so that (1) inspectors can easily identify the unit in the field and (2) the permit leaves no question as to which unit the various permit limitations and conditions apply. Identification usually includes a brief description of the source or type of equipment, size or capacity, model number or serial number, and the source's identification of the unit.

Emissions and operational limitations are included in the technical specifications and must be clearly expressed, easily measurable, and allow no subjectivity in their compliance determinations. All limits also must be indicated precisely for each emissions point or operation. For clarity, these limits are often best expressed in tabular rather than textual form In general, it is best to express the emission limits in two different ways, with one value serving as an emissions cap (e.g., lbs/hr.) and the other ensuring continuous compliance at any operating capacity (e.g., lbs/MMBtu). The permit writer should keep in mind that the source must comply with both values to Such limits should be of a short term nature. demonstrate compliance. continuous and enforceable. In addition, the limits should be consistent with the averaging times used for dispersion modeling and the averaging times for compliance testing. Since emissions limitation values incorporated into a permit are based on a regulation (SIP, NSPS, NESHAP) or resulting from new source review, (i.e., BACT or LAER requirements), a reference to the applicable portion of the regulation should be included.

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II. C. EMISSIONS COMPLIANCE DEMONSTRATION

The permit should state how compliance with each limitation will be determined, and include, but is not limited to, the test method(s) approved for demonstrating compliance. These permit compliance conditions must be very clear and enforceable as a practical matter (see Appendix C). The conditions must specify:

- ! when and what tests should be performed;
- ! under what conditions tests should be performed;
- ! the frequency of testing;
- ! the responsibility for performing the test;
- ! that the source be constructed to accommodate such testing;
- ! procedures for establishing exact testing protocol; and
- ! requirements for regulatory personnel to witness the testing.

Where continuous, quantitative measurements are infeasible, surrogate parameters must be expressed in the permit. Examples of surrogate parameters include: mass emissions/opacity correlations, maintaining pressure drop across a control (e.g., venturi throat of a scrubber), raw material input/mass emissions output ratios, and engineering correlations associated with specific work practices. These alternate compliance parameters may be used in conjunction with measured test data to monitor continuous compliance or may be independent compliance measures where source testing is not an option and work practice or equipment parameters are specified. Only those parameters that exhibit a correlation with source emissions should be used. Identifying and quantifying surrogate process or control equipment parameters (such as pressure drop) may require initial source testing or may be extracted from confirmed design characteristics contained in the permit application.

Parameters that must be monitored either continuously or periodically should be specified in the permit, including averaging time for continuously monitored data, and data recording frequency for periodically (continually) monitored data. The averaging times should be of a short term nature

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consistent with the time periods for which dispersion modeling of the respective emissions rate demonstrated compliance with air quality standards, and consistent with averaging times used in compliance testing. This requirement also applies to surrogate parameters where compliance may be timebased, such as weekly or monthly leak detection and repair programs (also see Appendix C). Whenever possible, "never to be exceeded" values should be specified for surrogate compliance parameters. Also, operating and maintenance (0&M) procedures should be specified for the monitoring instruments (such as zero, span, and other periodic checks) to ensure that valid data are obtained. Parameters which must be monitored continuously or continually are those used by inspectors to determine compliance on a realtime basis and by source personnel to maintain process operations in compliance with source emissions limits.

II. D. DEFINITION OF EXCESS EMISSIONS

The purpose of defining excess emissions is to prevent a malfunction condition from becoming a standard operating condition by requiring the source to report and remedy the malfunction. Conditions in this part of the permit:

- ! precisely define excess emissions;
- ! outline reporting requirements;
- ! specify actions the source must take; and
- ! indicate time limits for correction by the source.

Permit conditions defining excess emissions may include alternate conditions for startup, shutdown, and malfunctions such as maximum emission limits and operational practices and limits. These must be as specific as possible since such exemptions can be misused. Every effort should be made to include adequate definitions of both preventable and nonpreventable malfunctions. Preventable malfunctions usually are those which cause excess emissions due to negligent maintenance practices. Examples of preventable malfunctions may include: leakage or breakage of fabric filter bags; baghouse seal ruptures; fires in electrostatic precipitators due to excessive build up of oils or other flammable materials; and failure to monitor and replace spent activated carbon beds in carbon absorption units. These examples reinforce the need for good O&M plans and keeping records of all repairs. Permit requirements concerning malfunctions may include: timely reporting of the malfunction duration, severity, and cause; taking interim and corrective actions; and taking actions to prevent recurrence.

II. E. ADMINISTRATIVE PROCEDURES

The administrative elements of permits are usually standard conditions informing the source of certain responsibilities. These administrative procedures may include:

!	recordkeeping and reporting requirements, including all continuous monitoring data, excess emission reports, malfunctions, and
	surrogate compliance data;
ļ	notification requirements for performance tests, malfunctions,
	commencing or delay of construction;
ļ	entry and inspection procedures;
!	the need to obtain a permit to operate; and
!	specification of procedures to revoke, suspend, or modify the permit.
	-

Though many of these conditions will be entered into the permit via standard permit conditions, the reviewer must ensure the language is adequate to establish precisely what is expected or needed from the source, particularly the recordkeeping requirements.

II.F. OTHER CONDITIONS

In some cases, specific permit conditions which do not fit into the above elements may need to be outlined. Examples of these are conditions requiring: the permanent shutdown of (or reduced emissions rates for) other emissions units to create offsets or netting credits; post-construction monitoring; continued Statewide compliance; and a water truck to be dedicated solely to a haul road. In the case of a portable source, a condition may be included to require a copy of the effective permit to be on-site at all times. Some 0&M procedures, such as requiring a 10 minute warmup for an incinerator, would be included in this category, as well as conditions requiring that replacement fabric filters and baghouse seals be kept available at all times. Any source-specific condition which needs to be included in the permit to ensure compliance should be listed here.

III. SUMARY

Assuming a comprehensive review, a permit is only as clear, specific, and effective as the conditions it contains. As such, Table H-2 on the following page lists guidelines for drafting actual permit conditions. The listing specifies how typical permit elements should be written. For further discussion on drafting "federally enforceable" permit conditions as a practical matter, please refer to Appendix C - "Potential to Emit."

TABLE H. 2. GUIDELINES FOR WRITING EFFECTIVE SPECIFIC CONDITIONS IN NSR PERMITS

- 1. Make each permit condition *simple, clear*, and *specific* such that it "stands alone."
- 2. Make certain *legal authority* exists to specify conditions.
- 3. Permit conditions should be **objective** and **meaningful**.
- 4. Provide description of *processes, emissions units* and *control equipment* covered by the permit, including operating rates and periods.
- 5. Clearly *identify each permitted emissions unit* such that it can be located in the field.
- 6. Specify allowable emissions (or concentration, etc.) rates for **each pollutant and emissions unit** permitted, and specify each applicable emissions standard by name in the permit.
- 7. Allowable emissions rates should reflect the conditions of **BACT/LAER** and **Air Quality Analyses** (e.g., specify limits two ways: maximum mass/unit of process **and** maximum mass/unit time)
- 8. Specify for all emissions units (especially fugitive sources) permit conditions that require *continuous application of BACT/LAER* to achieve maximum degree of emissions reduction.
- 9. Initial and subsequent performance tests should be conducted at worst case operating (non-malfunction) conditions for all emissions units. Performance tests should determine **both emissions and control equipment efficiency**.
- 10. Continual and continuous **emissions performance monitoring** and recordkeeping (direct and/or surrogate) should be specified where feasible.
- 11. Specify **test method** (citation) and **averaging period** by which all compliance demonstrations (initial and continuous) are to be made.
- 12. Specify what *conditions* constitute "*excess emissions,*" and what is to be done in those cases.

CHAPTER I PERMIT DRAFTING

I. RECOMMENDED PERMIT DRAFTING STEPS

This section outlines a recommended five-step permit drafting process (see Table I-1). These steps can assist the writer in the orderly preparation of air emissions permits following technical review.

Step 1 concerns the emissions units and requires the listing and specification of three things. First, list each new or modified emissions unit. Second, specify each associated emissions point. This includes fugitive emissions points (e.g., seals, open containers, inefficient capture areas, etc.) and fugitive emissions units (e.g., storage piles, materials handling, etc.). Be sure also to note emissions units with more than one ultimate exhaust and units sharing common exhausts. Third, the writer must describe each emissions unit as it may appear in the permit and identify, as well as describe, each emissions control unit. Each new or modified emissions unit identified in Step 1 that will emit or increase emissions of any pollutant is considered in Step 2.

Step 2 requires the writer to specify each pollutant that will be emitted from the new or modified source. Some pollutants may not be subject to regulation or are of de minimis amounts such that they do not require major source review. All pollutants should be identified in this step and reviewed for applicability. Federally enforceable conditions must be identified for de minimis pollutants to ensure they do not become significant (see Appendix C - Potential to Emit). An understanding of "potential to emit" is pertinent to permit review and especially to the drafting process.

I.1

TABLE I-1. FIVE STEPS TO PERMIT DRAFTING

- ! Identify each new (or modified) emissions unit that will emit (or increase) any pollutant.
- ! Identify any pollutant and emissions units involved in a netting or emissions reduction proposal (i.e., all contemporaneous emissions increases and decreases).
- ! Include point and fugitive emissions units.
- ! Identify and describe emissions unit and emissions control equipment.

STEP 2. SPECIFY POLLUTANTS

- ! Pollutants subject to NSR/PSD.
- Pollutants not subject to NSR/PSD but could reasonably be expected to exceed significant emissions levels. Identify conditions that ensure de minimis (e.g., shutdowns, operating modes, etc..).

STEP 3. SPECIFY ALLOWABLE EMISSION RATES AND BACT/LAER REQUIREMENTS

- ! Minimum number of allowable emissions rates specified is equal to at least two limits per pollutant per emissions unit.
- ! One of two allowable limits is unit mass per unit time (lbs/hr) which reflects application of emissions controls at maximum capacity.
- ! Maximum hourly emissions rate must correspond to that used in air quality analysis.
- ! Specify BACT/LAER emissions control requirements for each pollutant/emissions unit pair.

TABLE I-1. - Continued

- ! Continuous, direct emission measurement is preferable.
- ! Specify initial and periodic emissions testing where necessary.
- ! Specify surrogate (indirect) parameter monitoring and recordkeeping where direct monitoring is impractical or in conjunction with tested data.
- ! Equipment and work practice standards should complement other compliance monitoring.

STEP 5. OTHER PERMIT CONDITIONS

! Establish the basis upon which permit is granted (legal authority).

- ! Should be used to minimize "paper" allowable emissions.
- ! Federally enforceable permit conditions limiting potential to emit.

Step 3 pools the data collected in the two previous steps. The writer should specify the pollutants that will be emitted from each emission unit and identify associated emission controls for each pollutant and/or emission unit. (Indicate if the control has been determined to be BACT.) The writer also must assess the minimum number of allowable emissions rates to be specified in the permit. Each emissions unit should have at least two allowable emissions rates for each pollutant to be emitted. This is the most concise manner in which to present permit allowables and should be consistent with the averaging times and emissions ratio used in the air quality analysis. As discussed earlier in Section H, the applicable regulation should also be cited as well as whether BACT, LAER, or other SIP requirements apply to each pollutant to be regulated.

Step 4 essentially mirrors the items discussed in the previous Chapter H, Section IV., Emissions Compliance Demonstration. At this point the writer enters into the permit any performance testing required of the source. The conditions should specify what emissions test is to be performed and the frequency of testing. Any surrogate parameter monitoring must be specified. Recordkeeping requirements and any equipment and work practice standards needed to monitor the source's compliance should be written into the permit in Step 4. Any remaining or additional permit conditions, such as legal authority and conditions limiting potential to emit can be identified in (Other Permit Conditions, see Table I-1.) At this point, the permit Step 5. should be complete. The writer should review the draft to ensure that the resultant permit is an effective tool to monitor and enforce source compliance. Also, the compliance inspector should review the permit to ensure that the permit conditions are enforceable as a practical matter.

II. PERMIT WORKSHEETS AND FILE DOCUMENTATION

Some agencies use permit drafting worksheets to store all the required information that will be incorporated into the permit. The worksheets may be helpful and are available at various agencies and in other EPA guidance documents. The worksheets serve as a summary of the review process, though this summation should appear in the permit file with or without a worksheet. Documenting the permit review process in the file cannot be overemphasized. The decision-making process which leads to the final permit for a source must be clearly traceable through the file. When filing documentation, the reviewer must also be aware of any confidential materials. Many agencies have special procedures for including confidential information in the permit file. The permit reviewer should follow any special procedures and ensure the permit file is documented appropriately.

III. SUMARY

Listed below are summary "helpful hints" for the permit writer, which should be kept in mind when reviewing and drafting the permit. Many of these have been touched on throughout Part III, but are summarized here to help ensure that they are not overlooked:

- ! Document the review process throughout the file.
- ! Be aware of confidentiality items, procedures, and the consequences of the release of such information.
- ! Ensure the application includes all pertinent review information (e.g., has the applicant identified solvents used in some coatings; are solvents used, then later recovered; ultimate disposal of collected wastes identified; and applicable monitoring and modeling results included).
- ! Address secondary pollutant formation.
- ! Ensure that all applicable regulations and concerns have been addressed (e.g., BACT, LAER, NSPS, NESHAP, non-regulated toxics, SIP, and visibility).

- ! Ensure the permit is organized well, e.g., conditions are independent of one another, and conditions are grouped so as not be cover more than one area at a time.
- ! Surrogate parameters listed are clear and obtainable.
- ! Emissions limits are clear. In cases of multiple or common exhaust, limits should specify if per emissions unit or per exhaust.
- <u>Every</u> permit condition is 1) reasonable, 2) meaningful,
 3) monitorable, and 4) always enforceable as a practical matter.

APPENDIX A - DEFINITION OF SELECTED NSR TERMS

BACT

Best Available Control Technology is the control level required for sources subject to PSD. From the regulation (reference 40 CFR 52.21(b)) BACT means "an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results."

- **Emission Units** The individual emitting facilities at a location that together make up the source. From the regulation (reference 40 CFR 52.21(b)), it means "any part of a stationary source which emits or would have the potential to emit any pollutant subject to regulation under the Act."
- **Increments** The maximum permissible level of air quality deterioration that may occur beyond the baseline air quality level. Increments were defined statutorily by Congress for SO₂ and PM. Recently EPA also has promulgated increments for NO_x. Increment is consumed or expanded by actual emissions changes occurring after the baseline date and by construction related actual emissions changes occurring after January 6, 1975, and February 8, 1988 for PM/SO₂ and NO_x, respectively.

APPENDIX A - DEFINITION OF SELECTED NSR TERMS (Continued)

Innovative Control Technology	From the regulation (reference 40 CFR 52.21(b)(19)) "Innovative control technology" means any system of air pollution control that has not been adequately demonstrated in practice, but would have a substantial likelihood of achieving greater continuous emissions reduction than any control system in current practice or of achieving at least comparable reductions at lower cost in terms of energy, economics, or nonair quality environmental impacts. Special delayed compliance provisions exist that may be applied when applicants propose innovative control techniques.
LAER	Lowest Achievable Emissions Rate is the control level required of a source subject to nonattainment review. From the regulations (reference 40 CFR 51.165(a)), it means for any source "the more stringent rate of emissions based on the following:
	(a) The most stringent emissions limitation which is contained in the implementation plan of any State for such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limitations are not achievable; or
	(b) The most stringent emissions limitation which is achieved in practice by such class or category of stationary sources. This limitation, when applied to a modification, means the lowest achievable emissions rate of the new or modified emissions units within a stationary source. In no event shall the application of the term permit a proposed new or modified stationary source to emit any pollutant in excess of the amount allowable under an applicable new source standard of performance."

APPENDIX A - DEFINITION OF SELECTED NSR TERMS (Continued)

Major Modification A major modification is a modification to an existing major stationary source resulting in a significant net emissions increase (defined elsewhere in this table) that, therefore, is subject to PSD review. From the regulation (reference 40 CFR 52.21(b)(2)):

"(i) `Major modification' means any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.

(ii) Any net emissions increase that is significant for volatile organic compounds shall be considered significant for ozone.

(iii) A physical change or change in the method of operation shall not include:

- (a) routine maintenance, repair and replacement;
- (c) use of an alternative fuel by reason of an order or rule under Section 125 of the Act;

(d) Use of an alternative fuel at a steam generating unit to the extent that the fuel is generated from municipal solid waste;

(e) Use of an alternative fuel or raw material by a stationary source which:

(1) The source was capable of accommodating before January 6, 1975, unless such change would be prohibited under any Federally enforceable permit condition which was established after January 6, 1975, pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR Subpart I or 40 CFR 51.166; or

(2) The source is approved to use under any permit issued under 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51.166;

(f) an increase in the hours of operation or in the production rate, unless such change would be prohibited under any federally enforceable permit condition which was established after January 6, 1975, pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR Subpart I or 40 CFR 51.166; or

(g) any change in ownership at a stationary source."

APPENDIX A - DEFINITION OF SELECTED NSR TERMS (Continued)

Major Stationary Source A major stationary source is an emissions source of sufficient size to warrant PSD review. Major modification to major stationary sources are also subject to PSD review. From the regulation (reference 40 CFR 52.21(b)(1)), (i) "Major stationary source" means:

"(a) Any of the following stationary sources of air pollutant which emits, or has the potential to emit, 100 tons per year or more of any pollutant subject to regulation under the Act: Fossil fuelfired steam electric plants of more than 250 million British thermal units per hour heat input, coal cleaning plants (with thermal dryers), Kraft pulp mills, Portland cement plants, primary zinc smelters, iron and steel mill plants, primary aluminum ore reduction plants, primary aluminum ore reduction plants, primary copper smelters, municipal incinerators capable of charging more than 250 tons of refuse per day, hydrofluoric, sulfuric, and nitric acid plants, petroleum refineries, lime plants, phosphate rock processing plants, coke oven batteries, sulfur recovery plants, carbon black plants (furnace process), primary lead smelters, fuel conversion plants, sintering plants, secondary metal production plants, chemical process plants, fossil fuel boilers (or combinations thereof) totaling more than 250 million British thermal units per hour heat input, petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels, taconite ore processing plants, glass fiber processing plants, and charcoal production plants;

(b) Notwithstanding the stationary source size specified in paragraph (b)(1)(i) of this section, any stationary source which emits, or has the potential to emit, 250 tons per year or more of any air pollutant subject to regulation under the Act; or

(c) Any physical change that would occur at a stationary source not otherwise qualifying under paragraph (b)(1) as a major stationary source not otherwise qualifying under paragraph (b)(1) as a major stationary source, if the changes would constitute a major stationary source by itself.

(ii) A major stationary source that is major for volatile organic compounds shall be considered major for ozone."

NAAQS National Ambient Air Quality Standards are Federal standards for the minimum ambient air quality needed to protect public health and welfare. They have been set for six criteria pollutants including SO₂, PM/PM₁₀, NO_x, CO, O₃ (VOC), and Pb.

APPENDIX A - DEFINITION OF SELECTED NSR TERMS (Continued)

- **NESHAP** NESHAP, or National Emission Standard for Hazardous Air Pollutants, is a technology-based standard of performance prescribed for hazardous air pollutants from certain stationary source categories under Section 112 of the Clean Air Act. Where they apply, NESHAP represent absolute minimum requirements for BACT.
- NSPS NSPS, or New Source Performance Standard, is an emission standard prescribed for criteria pollutants from certain stationary source categories under Section 111 of the Clean Air Act. Where they apply, NSPS represent absolute minimum requirements for BACT.
- PSD Prevention of significant deterioration is a construction air pollution permitting program designed to ensure air quality does not degrade beyond the NAAQS levels or beyond specified incremental amounts above a prescribed baseline level. PSD also ensures application of BACT to major stationary sources and major modifications for regulated pollutants and consideration of soils, vegetation, and visibility impacts in the permitting process.
- **Regulated Pollutants**⁶ Refers to pollutants that have been regulated under the authority of the Clean Air Act (NAAQS, NSPS, NESHAP):
 - O_3 (VOC) Ozone, regulated through volatile organic compounds as precursors
 - NO_x Nitrogen oxides
 - SO₂ Sulfur dioxide
 - PM (TSP)- Total suspended particulate matter
 - PM (PM₁₀) Particulate matter with \leq 10 micron aerometric diameter

CO	- Carbon monoxide			
Pb	- Lead	5	TRS	- Total reduced sulfur (including H_2S)
As	- Asbestos	5	RDS	- Reduced Sulfur Compounds (including H_2S)
Ве	- Beryllium	5	Bz	- Benzene
Hg	- Mercury	5	Rd	- Radionuclides
VC	- Vinyl chloride	5	As	- Arsenic
F	- Fluorides	5	CFC's	- Chlorofluorocarbons
H_2SO_4	- Sulfuric acid mist	5	Rn-222	- Radon-222
H_2S	- Hydrogen sulfide	5	Halons	

⁶ The referenced list of regulated pollutants is current as of November 1989. Presently, additional pollutants may also be subject to regulation under the Clean Air Act.

APPENDIX A - DEFINITION OF SELECTED NSR TERMS (Continued)

Significant Emissions Increase For new major stationary sources and major modifications, a significant emissions Review requirements must be met for each pollutant increase triggers PSD review. undergoing a significant net emissions increase. From the regulation (reference 40 CFR 52.21(b)(23)). (i) "Significant" means, in reference to a net emissions increase from a modified major source or the potential of a new major source to emit any of the following pollutants, a rate of emissions that would equal or exceed any of the following rates: Carbon monoxide: 100 tons per year (tpy) Nitrogen oxides: 40 tpy Sulfur dioxide: 40 tpy Particulate matter: 25 tpy PM10: 15 tpy Ozone: 40 tpy of volatile organic compounds Lead: 0.6 tpy Asbestos: 0.007 tpy Beryllium: 0.0004 tpy Mercury: 0.1 tpy Vinyl chloride: 1 tpy Fluorides: 3 tpy Sulfuric acid mist: 7 tpy Hydrogen Sulfide (H_2S) : 10 tpy Total reduced sulfur (including H_2S): 10 tpy Reduced sulfur compounds (including H_2S): 10 tpy (ii) "Significant" means, in reference to a net emissions increase or the potential of a source to emit a pollutant subject to regulation under the Act, that (i) above does not list, any emissions rate. (For example, benzene and radionuclides are pollutants falling into the "any emissions rate" category.) (iii) Notwithstanding, paragraph (b)(23)(i) of this section, "significant means any emissions rate

(iii) Notwithstanding, paragraph (b)(23)(i) of this section, "significant means any emissions rate or any net emissions increase associated with a major stationary source or major modification which would construct within 10 kilometers of a Class I area, and have an impact on such an area equal to or greater than 1 ug/m³, (24-hour average).

APPENDIX A - DEFINITION OF SELECTED NSR TERMS (Continued)

SIP State Implementation Plan is the federally approved State (or local) air quality management authority's statutory plan for attaining and maintaining the NAAQS. Generally, this refers to the State/local air quality rules and permitting requirements that have been accepted by EPA as evidence of an acceptable control strategy.

Stationary Source For PSD purposes, refers to all emissions units at one location under common ownership or control. From the regulation (reference 40 CFR 52.21(b)(5) and 51.166(b)(5)), it means "any building, structure, facility, or installation which emits or may emit any air pollutant subject to regulation under the Act."

> "Building, structure, facility, or installation" means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or person under common control). Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same "Major Group" (i.e., which have the same first two digit code) as described in the Standard Industrial Classification Manual, 1972, as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101-0066 and 003-005-00176-0, respectively).

APPENDIX B

ESTIMATING CONTROL COSTS

APPENDIX B - ESTIMATING CONTROL COSTS

I. CAPITAL COSTS

Capital costs include equipment costs, installation costs, indirect costs, and working capital (if appropriate). Figure B-4 presents the elements of total capital cost and represents a building block approach that focuses on the control device as the basic unit of analysis for estimating total capital investment. The total capital investment has a role in the determination of total annual costs and cost effectiveness.

One of the most common problems which occurs when comparing costs at different facilities is that the battery limits are different. For example, the battery limit of the cost of a electrostatic precipitation might be the precipitator itself (housing, plates, voltage regulators, transformers, etc.), ducting from the source to the precipitator, and the solids handling system. The stack would not be included because a stack will be required regardless of whether or not controls are applied. Therefore, it should be outside the battery limits of the control system.

Direct installation costs are the costs for the labor and materials to install the equipment and includes site preparation, foundations, supports, erection and handling of equipment, electrical work, piping, insulation and painting. The equipment vendor can usually supply direct installation costs.

The equipment vendor should be able to supply direct installation costs estimates or general installation costs factors. In addition, typical installation cost factors for various types of equipment are available in the following references.



(a) These costs are factored from the sum of the control device and auxiliary equipment costs.

- (b) These costs are factored from the purchased control equipment.
- (c) Usually required only at "grass roots" installations.
- (d) Unlike the other direct and indirect costs, costs for these items are not factored from the purchased equipment cost. Rather, they are sized and costed separately.
- (e) Normally not required with add-on control systems.

FIGURE B-4. Elements of Total Capital Costs

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- ! OAQPS Control Cost Manual (Fourth Edition), January 1990, EPA 450/3-90-006
- ! <u>Control Technology for Hazardous Air Pollutants (HAPS) Manual</u>, September 1986, EPA 625/6-86-014
- ! Standards Support Documents
 - Background Information Documents
 - Control Techniques Guidelines Documents
- ! Other EPA sponsored costing studies
- ! Engineering Cost and Economics Textbooks
- ! Other engineering cost publications

These references should also be used to validate any installation cost factors supplied from equipment vendors.

If standard costing factors are used, they may need to be adjusted due to site specific conditions. For example, in Alaska installation costs are on the order of 40-50 percent higher than in the contiguous 48 states due to higher labor prices, shipping costs, and climate.

Indirect installation costs include (but are not limited to) engineering, construction, start-up, performance tests, and contingency. Estimates of these costs may be developed by the applicant for the specific project under evaluation. However, if site-specific values are not available, typical estimates for these costs or cost factors are available in:

- ! OAQPS Control Cost Manual (Fourth Edition), EPA 450/3-90-006
- i
- Cost Analysis Manual for Standards Support Documents, April 1979

These references can be used by applicants if they do not have site-specific estimates already prepared, and should also be used by the reviewing agency to determine if the applicant's estimates are reasonable. Where an applicant uses different procedures or assumptions for estimating control costs than contained in the referenced material or outlined in this document, the nature and reason for the differences are to be documented in the BACT analysis.

Working capital is a fund set aside to cover initial costs of fuel, chemicals, and other materials and other contingencies. Working capital costs for add on control systems are usually relatively small and, therefore, are usually not included in cost estimates.

Table B-11 presents an illustrative example of a capital cost estimate developed for an ESP applied to a spreader-stoker coal-fired boiler. This estimate shows the minimum level of detail required for these types of estimates. If bid costs are available, these can be used rather than study cost estimates.

II. TOTAL ANNUAL COST

The permit applicant should use the levelized annual cost approach for consistency in BACT cost analysis. This approach is also called the "Equivalent Uniform Annual Cost" method, or simply "Total Annual Cost" (TAC). The components of total annual costs are their relationships are shown in Figure B-5. The total annual costs for control systems is comprised of three elements: "direct" costs (DC), "indirect costs" (IC), and "recovery credit" (RC), which are related by the following equation:

$$TAC = DC + IC - RC$$

TABLE B-11.EXAMPLE OF A CAPITAL COST ESTIMATE FOR AN
ELECTROSTATIC PRECIPITATOR

	Capital cost (\$)
Direct Investment	
Equipment cost	
ESP unit	175, 800
Ducting	64, 100
Ash handling system	97, 200
Total equipment cost	337, 100
Installation costs	
ESP unit	175, 800
Ducting	102, 600
Ash handling system	97, 200
Total installation costs	375, 600
Total direct investment (TDI)	712, 700
(equipment + installation)	
Indirect Investment	71, 300
Engineering (10% of TDI)	71, 300
Construction and field expenses (10% of TDI)	71, 300
Construction fees (10% of TDI)	71, 300
Start-up (2% of TDI)	14, 300
Performance tests (minimum \$2000)	3, 000
Total indirect investment (TII)	231, 200
Contingencies (20% of TDI + TII)	188, 800
TOTAL TURNKEY COSTS (TDI + TII)	1, 132, 700
Working Capital (25% of total direct operating costs)a	21, 100
GRAND TOTAL	1, 153, 800

+))))))))))))))))))))))))))))))))))))))	9				
* o Raw Materials	*				
* o Utilities	* S))))))))))),			
* - Electricity	/)))))))) Variable	*			
* - Steam	*	*			
* - Water	*	*	S)))))))))	,	
* - Others	*	*		*	
.))))))))))))))))))))))))))))))))))))))	-	*	Di rect	*	
		/)))	Annual	*	
+))))))))))))))))))))))))))))))))))))))	2	*	Costs	*	
* o Labor	*	*		*	
* - Operating	*	*		*	
* - Supervi sory	/)))))))) Semivariable	*		*	
* - Maintenance	* S)))))))))))-		*	
* o Maintenance materials	*		+	*	
* o Replacement parts	*			*	Total
.))))))))))))))))))))))))))))))))))))))	-			* =	Annual
				*	Costs
	+)))))))))))))))))))))))))))))))),			*	
	* o Overhead *		Indi rect	*	
	* o Property Taxes /)))))))))	Annual	*	
	* o Insurance *		Costs	*	
	* o Capital Recovery *			*	
	.))))))))))))))))))))))))))))))))))		-	*	
	+))))))))))))))))))))))))))))))))))))))			*	
	* o Recovered Product*		Recovery	*	
	* o Recovered Energy /))))))	Credits	*	
	* o Useful byproduct *			*	
	* o Energy Gain *		S))))))))	-	
	.))))))))))))))))))))))))))))))))))				

FIGURE B-5. Elements of Total Annual Costs

Direct costs are those which tend to be proportional or partially proportional to the quantity of exhaust gas processed by the control system or, in the case of inherently lower polluting processes, the amount of material processed or product manufactured per unit time. These include costs for raw materials, utilities (steam, electricity, process and cooling water, etc.), and waste treatment and disposal. Semivariable direct costs are only partly dependent upon the exhaust or material flowrate. These include all associated labor, maintenance materials, and replacement parts. Although these costs are a function of the operating rate, they are not linear functions. Even while the control system is not operating, some of the semivariable costs continue to be incurred.

Indirect, or "fixed", annual costs are those whose values are relatively independent of the exhaust or material flowrate and, in fact, would be incurred even if the control system were shut down. They include such categories as overhead, property taxes, insurance, and capital recovery.

Direct and indirect annual costs are offset by recovery credits, taken for materials or energy recovered by the control system, which may be sold, recycled to the process, or reused elsewhere at the site. These credits, in turn, may be offset by the costs necessary for their purification, storage, transportation, and any associated costs required to make then reusable or resalable. For example, in auto refinishing, a source through the use of certain control technologies can save on raw materials (i.e., paint) in addition to recovered solvents. A common oversight in BACT analyses is the omission of recovery credits where the pollutant itself has some product or process value. Examples of control techniques which may produce recovery credits are equipment leak detection and repair programs, carbon absorption systems, baghouse and electrostatic precipitators for recovery of reusable or saleable solids and many inherently lower polluting processes.

b.7

Table B-12 presents an example of total annual costs for the control system previously discussed. Direct annual costs are estimated based on system design power requirements, energy balances, labor requirements, etc., and raw materials and fuel costs. Raw materials and other consumable costs should be carefully reviewed. The applicant generally should have documented delivered costs for most consumables or will be able to provide documented estimates. The direct costs should be checked to be sure they are based on the same number of hours as the emission estimates and the proposed operating schedule.

Maintenance costs in some cases are estimated as a percentage of the total capital investment. Maintenance costs include actual costs to repair equipment and also other costs potentially incurred due to any increased system downtime which occurs as a result of pollution control system maintenance.

Fixed annual costs include plant overhead, taxes, insurance, and capital recovery charges. In the example shown, total plant overhead is calculated as the sum of 30 percent of direct labor plus 26 percent of all labor and maintenance materials. The OAQPS Control Cost Manual combines payroll and plant overhead into a single indirect cost. Consequently, for "study" estimates, it is sufficiently accurate to combine payroll and plant overhead into a single indirect cost. Total overhead is then calculated as 60 percent of the sum of all labor (operating, supervisory, and maintenance) plus maintenance materials.

Property taxes are a percentage of the fixed capital investment. Note that some jurisdictions exempt pollution control systems from property taxes. Ad valorem tax data are available from local governments. Annual insurance charges can be calculated by multiplying the insurance rate for the facility by the total capital costs. The typical values used to calculate taxes and

b.8

	Annual costs
	(\$/yr)
Direct Costs	
Direct labor at \$12.02/man-hour	26, 300
Supervision at \$15.63/man-hour	0
Maintenance labor at \$14.63/man-hour	16, 000
Replacement parts	5, 200
Electricity at \$0.0258/kWh	3, 700
Water at \$0.18/1000 gal	300
Waste disposal at \$15/ton (dry basis)	33, 000
Total direct costs	84, 500
Indirect Costs	
Overhead	
Payroll (30% of direct labor)	7, 900
Plant (26% of all labor and replacement parts)	12, 400
Total overhead costs	20, 300
Capital charges	
G&A taxes and insurance	45, 300
(4% of total turnkey costs)	
Capital recovery factor	133, 100
(11.75% of total turnkey costs)	
Interest on working capital	2, 100
(10% of working capital)	
Total capital charges	180, 500
TOTAL ANNUALIZED COSTS	285, 300

TABLE B-12. EXAMPLE OF A ANNUAL COST ESTIMATE FOR AN ELECTROSTATIC PRECIPITATOR APPLIED TO A COAL-FIRED BOILER

insurance is four percent of the total capital investment if specific facility data are not readily available.

The annual costs previously discussed do not account for recovery of the capital cost incurred. The capital cost shown in Table B-2 is annualized using a capital recovery factor of 11.75 percent. When the capital recovery factor is multiplied by the total capital investment the resulting product represents the uniform end of year payment necessary to repay the investment in "n" years with an interest rate "i".

The formula for the capital recovery factor is:

$$CRF = \underline{i (1 + i)^n}$$

(1 + i)^n-1

where:

CPF = capital recovery factor n = economic life of equipment i = real interest rate

The economic life of a control system typically varies between 10 to 20 years and longer and should be determined consistent with data from EPA cost support documents and the IRS Class Life Asset Depreciation Range System.

From the example shown in Table B-12 the interest rate is 10 percent and the equipment life is 20 years. The resulting capital recovery factor is 11.75 percent. Also shown is interest on working capital, calculated as the product of interest rate and the working capital.

It is important to insure that the labor and materials costs of parts of the control system (such as catalyst beds, etc.) that must be replaced before the end of the useful life are subtracted from the total capital investment before it is multiplied by the capital recovery factor. Costs of these parts should be accounted for in the maintenance costs. To include the cost of those parts in the capital charges would be double counting. The interest rate used is a real interest rate (i.e., it does not consider inflation). The value used in most control costs analyses is 10 percent in keeping with current EPA guidelines and Office of Management and Budget recommendations for regulatory analyses.

It is also recommended that income tax considerations be excluded from cost analyses. This simplifies the analysis. Income taxes generally represent transfer payments from one segment of society to another and as such are not properly part of economic costs.

III. OTHER COST ITEMS

Lost production costs are not included in the cost estimate for a new or modified source. Other economic parameters (equipment life, cost of capital, etc.) should be consistent with estimates for other parts of the project.

APPENDIX C^7

POTENTIAL TO EMIT

Upon commencing review of a permit application, a reviewer must define the source and then determine how much of each regulated pollutant the source potentially can emit and whether the source is major or minor (nonmajor). A new source is major if its potential to emit exceeds the appropriate major emissions threshold, and a change at an existing major source is a major modification if the source's net emissions increase is "significant." This determination not only quantifies the source's emissions but dictates the level of review and applicability of various regulations and new source review requirements. The federal regulations, 40 CFR 52.21(b)(4), 51.165(a)(1)(iii), and 51.166(b)(4), define the "potential to emit" as:

"the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable."

In the absence of federally enforceable restrictions, the potential to emit calculations should be based on uncontrolled emissions at maximum design or achievable capacity (whichever is higher) and year-round continuous operation (8760 hours per year).

⁷ This Appendix is based largely on an EPA memorandum "Guidance on Limiting Potential to Emit in New Source Permitting," from Terrell E. Hunt, Office of Enforcement and Compliance Monitoring, and John S. Seitz, Office of Air Quality Planning and Standards, June 13, 1989.

When determining the potential to emit for a source, emissions should be estimated for individual emissions units using an engineering approach. These individual values should then be summed to arrive at the potential emissions for the source. For each emissions unit, the estimate should be based on the most representative data available. Methods of estimating potential to emit may include:

- ! Federally enforceable operational limits, including the effect of pollution control equipment;
- ! performance test data on similar units;
- ! equipment vendor emissions data and guarantees;
- ! test data from EPA documents, including background information documents for new source performance standards, national emissions standards for hazardous air pollutants, and Section 111(d) standards for designated pollutants;
- ! AP-42 emission factors;
- ! emission factors from technical literature; and
- ! State emission inventory questionnaires for comparable sources.

NOTE: Potential to emit values reflecting the use of pollution control equipment or operational restrictions are usable only to the extent that the unit/process under review utilizes the same control equipment or operational constraints and makes them federally enforceable in the permit.

Calculated emissions will embrace all potential, not actual, emissions expected to occur from a source on a continuous or regular basis, including fugitive emissions where quantifiable. Where raw materials or fuel vary in their pollutant-generating capacity, the most pollutant-generating substance must be used in the potential-to-emit calculations unless such materials are restricted by federally enforceable operational or usage limits. Historic usage rates alone are not sufficient to establish potential-to-emit.
Permit limitations are significant in determining a source's potential to emit and, therefore, whether the source is "major" and subject to new source review. Permit limitations are the easiest and most common way for a source to restrict its potential to emit. A source considered major, based on emission calculations assuming 8760 hours per year of operation, can often be considered minor simply by accepting a federally enforceable limitation restricting hours of operation to an actual schedule of, for example, 8 hours per day. A permit does not have to be a major source permit to legally restrict potential emissions. Minor source construction permits are often federally enforceable. Any limitation can legally restrict potential to emit if it meets three criteria: 1) it is federally enforceable as defined by 40 CFR 52. 21(b) (17), 52. 24(f) (12), 51. 165(a) (1) (xiv), and 51. 166(b) (17), i.e., contained in a permit issued pursuant to an EPA-approved permitting program or a permit directly issued by EPA, or has been submitted to EPA as a revision to a State Implementation Plan and approved as such by EPA; 2) it is enforceable as a practical matter; and (3) it meets the specific criteria in the definition of "potential to emit," (i.e., any physical or operational limitation on capacity, including control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed). The second criterion is an implied requirement of the first. A requirement may purport to be federally enforceable, but in reality cannot be federally enforceable if it cannot be enforced as a practical matter.

In the absence of dissecting the legal aspects of "federal enforceability," the permit writer should always assess the enforceability of a permit restriction based upon its practicability. Compliance with any limitation must be able to be established at any given time. When drafting permit limitations, the writer must always ensure that restrictions are written in such a manner that an inspector could verify instantly whether the source is or was complying with the permit conditions. Therefore, short-term averaging times on limitations are essential. If the writer does this, he or she can feel comfortable that limitations incorporated into a permit will be federally enforceable, both legally and practically.

The types of limitations that restrict potential to emit are emission limits, production limits, and operational limits. Emissions limits should reflect operation of the control equipment, be short term, and, where feasible, the permit should require a continuous emissions monitor. Blanket emissions limits alone (e.g., tons/yr, lb/hr) are virtually impossible to verify or enforce, and are therefore not enforceable as a practical matter. Production limits restrict the amount of final product which can be manufactured or produced at a source. Operational limits include all restrictions on the manner in which a source is run, e.g., hours of operation, amount of raw material consumed, fuel combusted or stored, or specifications for the installation, maintenance and operation of add-on controls operating at a specific emission rate or efficiency. All production and operational limits except for hours of operation are limits on a source's capacity To appropriately limit potential to emit consistent with a utilization. previous Court decision [United States v. Louisiana-Pacific Corporation, 682 F. Supp. 1122 (D. Colo. Oct. 30, 1987) and 682 F. Supp. 1141 (D. Colo. March 22, 1988)], all permits issued must contain a production or operational limitation in addition to the emissions limitation and emissions averaging time in cases where the emission limitation does not reflect the maximum emissions of the source operating at full design capacity without pollution control equipment. In the permit, these limits must be stated as conditions that can be enforced independently of one another. This emphasizes the idea of good organization when drafting permit conditions and is discussed in more detail in the Part III text. The permit conditions must be clear, concise, and independent of one another such that enforceability is never questionable.

When permits contain production or operational limits, they must also have requirements that allow a permitting agency to verify a source's compliance with its limits. These additional conditions dictate enforceability and usually take the form of recordkeeping requirements. For example, permits that contain limits on hours of operation or amount of final product should require use of an operating log for recording the hours of operation and the amount of final product produced. For organizational

purposes, these limitations would be listed in the permit separately and records should be kept on a frequency consistent with that of the emission limits. It should be specified that these logs be available for inspection should a permitting agency wish to check a source's compliance with the terms of its permit.

When permits require add-on controls operated at a specified efficiency level, the writer should include those operating parameters and assumptions upon which the permitting agency depended to determine that controls would achieve a given efficiency. To be enforceable, the permit must also specify that the controls be equipped with monitors and/or recorders measuring the specific parameters cited in the permit or those which ensure the efficiency of the unit as required in the permit. Only through these monitors could an inspector instantaneously measure whether a control was operating within its permit requirements and thus determine an emissions unit's compliance. It is these types of additional permit conditions that render other permit limitations practically and federally enforceable.

Every permit also should contain emissions limits, but production and operational limits are used to ensure that emissions limits expressed in the permit are not exceeded. Production limits are most appropriately expressed in the shortest time periods as possible and generally should not exceed 1 month (i.e., pounds per hour or tons per day), because compliance with emission limits is most easily established on a short term basis. An inspector, for example, could not verify compliance for an emissions unit with only monthly and annual production, operational or emission limits if the inspection occurred anytime except at the end of a month. In some rare situations a 1-month averaging time may not be reasonable. In these cases, a limit spanning a longer period is appropriate if it is a rolling average However, the limit should not exceed an annual limit rolled on a limit. monthly basis. Note also that production and operational recordkeeping requirements should be written consistent with the emissions limits. Thus. if an emissions unit was limited to a particular tons per day emissions rate,

then production records which monitor compliance with this limit should be kept on a daily basis rather than weekly.

One final matter to be aware of when calculating potential to emit involves identifying "sham" permits. A sham permit is a federally enforceable permit with operating restrictions limiting a source's potential to emit such that potential emissions do not exceed the major or de minimis levels for the purpose of allowing construction to commence prior to applying for a major source permit. Permits with conditions that do not reflect a source's **planned** mode of operation may be considered void and cannot shield the source from the requirement to undergo major source preconstruction review. In other words, if a source accepts operational limits to obtain a minor source construction permit but intends to operate the source in excess of those limitations once the unit is built, the permit is considered a sham. If the source originally intended or planned to operate at a production level that would make it a major source, and if this can be proven, EPA will seek enforcement action and the application of BACT and other requirements of the PSD program. Additionally, a permit may be considered a sham permit if it is issued for a number of pollution-emitting modules that keep the source minor, but within a short period of time an application is submitted for additional modules which will make the total source major. The permit writer must be aware of such sham permits. If an application for a source is suspected to be a sham, EPA enforcement and source personnel should be alerted so details may be worked out in the initial review steps such that a sham permit is not issued. The possibility of sham permits emphasizes the need, as discussed in the Part III text, to organize and document the review process throughout the file. Thi s documentation may later prove to be evidence that a sham permit was issued, or may serve to refute the notion that a source was seeking a sham permit.

Overall, the permit writer should understand the extreme importance of potential to emit calculations. It must be considered in the initial review and continually throughout the review process to ensure accurate emission

limits that are consistent with federally enforceable production and operational restrictions.

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Emissions & Generation Resource Integrated Database (eGRID)

eGRID2018

Released: 1/28/2020 Revised: 3/9/2020

Next Planned Release: eGRID2020 in 1Q2022

- <u>eGRID2018v2 Data File (XLSX)</u> (11 MB)
 - What's new in eGRID2018
 - <u>Revised SRMW output emission rates</u>
- <u>Technical Support Document</u>
- <u>Summary Tables (PDF)</u>
- <u>Summary Tables (XLSX)</u> (791 K)
- <u>Grid Gross Loss Estimates</u>
- <u>Maps</u>
- <u>Release Notes (TXT)</u> (4 K)

<u>Download all eGRID2018 Files (ZIP)</u> (29 MB)

Download all eGRID historical files (1996-2016) (ZIP) (159 MB)

The Emissions & Generation Resource Integrated Database (eGRID) is a comprehensive source of data on the environmental characteristics of almost all electric power generated in the United States. These environmental characteristics include:

- air emissions for nitrogen oxides, sulfur dioxide, carbon dioxide, methane, and nitrous oxide;
- emissions rates;
- net generation;
- resource mix; and
- many other attributes.

eGRID data can be used for the following activities:

• greenhouse gas registries and inventories,

- carbon footprints,
- consumer information disclosure,
- emission inventories and standards,
- power market changes, and
- avoided emission estimates.



LAST UPDATED ON JUNE 30, 2020



2018 ISO New England Electric Generator Air Emissions Report

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Summary of Changes to the 2018 Emissions Report

The primary change to the *2018 Emissions Report* is the addition of a load-weighted approach to calculating the marginal emission rates. This new approach is consistent with the way in which ISO New England's Internal Market Monitor has begun representing the marginal units by fuel type in its quarterly and annual markets reports¹. The *Emissions Report* now includes the marginal emission rates based on both the current method, referred to as the time-weighted approach, and the new load-weighted approach.

The following is a summary of the additional information provided in the *2018 Emissions Report*:

- Figures 4-10 and 4-11 show the percentage of load for which various resource types were marginal
- Figures 4-12 and 4-13 compare the 2018 time-weighted and load-weighted percent marginal for various resource types
- Figures 5-5 and 5-6 include the monthly and annual load-weighted marginal heat rate values
- Section 5.3.2 includes the results of the load-weighted LMU marginal emission rate calculations
- Section 5.3.3 compares the marginal emission rates using the time- and load-weighted approaches
 - Table 5.7 compares the annual rates
 - Figures 5-13, 5-14, and 5-15 illustrate the differences between the time- and load-weighted monthly marginal emission rates for SO₂, NO_x, and CO₂
- Section 5.4 includes the load-weighted HEDD LMU marginal emission rates

In addition, the following changes were made to various figures in the report showing attributes by fuel type:

- The natural gas fuel category was split into combined cycle and simple cycle generator types in the following figures:
 - Figure 4-1, ISO-NE summer capacity by state
 - Figure 4-4, ISO-NE monthly generation by fuel type
 - Figures 4-6, 4-8, 4-10, and 4-11: percentage of time/load that various resource types were marginal
 - Figures 4-6 and 4-10 also reflect pumped storage demand, i.e., pumping load, as separate from the total pumped storage category

Questions regarding the 2018 Emissions Report may be directed to ISO-NE Customer Support:

Email: <u>custserv@iso-ne.com</u> Phone: (413) 540-4220

¹ https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor/

Section 1 Executive Summary

This ISO New England (ISO) *Electric Generator Air Emissions Report (Emissions Report*) provides a comprehensive analysis of New England electric generator air emissions (nitrogen oxides [NO_X], sulfur dioxide [SO₂], and carbon dioxide [CO₂]) and a review of relevant system conditions. The main factors analyzed are as follows:

- System² and marginal emissions (in thousand short tons [ktons])³
- System and marginal emission rates (pounds per megawatt-hour [lbs/MWh] and pounds per million British thermal unit [lbs/MMBtu])
- Marginal heat rate (MMBtu/MWh)

The report presents information for different time periods of interest:

- On-peak compared with off-peak hours
- Ozone season compared with non-ozone season
- Monthly variations
- High electric demand days (HEDDs)

The *Emissions Report*, first developed in 1993, has evolved in response to stakeholder needs. It was initially motivated by the need to determine the reductions of ISO New England's aggregate NO_X, SO₂, and CO₂ generating unit air emissions resulting from demand-side management (DSM) programs. The use of these emission rates was subsequently broadened to reflect the emission-reduction benefits of energy-efficiency programs and renewable resource projects within the region.

During the ten-year period from 2009 through 2018, total system emissions have decreased overall: NO_X by 43%, SO_2 by 94%, and CO_2 by 31%. The decline in emissions during this period reflects shifts in the regional generation mix, with increasing natural gas-fired generation as well as wind generation offsetting decreases in coal- and oil-fired generation (see Figure 1-1).

² For purposes of this report, "System" refers to native generation located within the ISO New England Balancing Authority Area. It does not include imports.

³The mass value of "tons" is equivalent to a US short ton, or 2,000 lbs and "ktons" is equivalent to 2,000,000 lbs.



Figure 1-1: Percentage energy generation by fuel type, 2009 compared with 2018. Note: This chart does not include net imports, which comprised 7% of total ISO New England energy in 2009, and 17% of total energy in 2018. Imports were excluded because they are assumed to have zero emissions in this report.⁴

Compared with the 20-year average for heating and cooling days (i.e., an indicator of weather), 2018 had a 51% warmer summer and an average winter. From 2017 to 2018, the net energy for load⁵ and system generation increased by 1.9% and 1.1%, respectively. The net energy that ISO New England received from neighboring areas in 2018 was approximately 6% higher than the previous year. Generation by hydro, wind, and solar resources increased by 5%, while nuclear generation declined by 0.5%. From 2017 to 2018, coal-fired generation decreased by 34%, but oil-fired generation increased by 57%, and natural gas-fired generation by 3%.

Table 1-1 shows the total 2017 and 2018 ISO New England system emissions (ktons) and average system emission rates (lbs/MWh) of NO_x, SO₂ and CO₂. System emissions increased for NO_x and SO₂ from 2017 to 2018, but decreased for CO₂. The SO₂ emission rate increased in 2018, but there was no change in the NO_x rate, and the CO₂ emission rate decreased.

⁴ Although the generation behind ISO-NE's imports does produce emissions, the Emissions Report has historically reported only the emissions from generators located within the ISO-NE footprint. In the marginal emissions analysis, imports have been marginal only a small percentage of the time (<0.1%), and the ISO has assumed zero emissions from those imports due to the lack of environmental attributes data available from some adjoining control areas sourcing those imports. However, as a result of recent requests to begin reporting the emissions produced by imported generation in both the system and marginal analyses, the ISO is developing a methodology for estimating those emissions.

⁵ Net energy for load (NEL) is calculated by summing the metered output of native generation, price-responsive demand, and net interchange (imports minus exports). It excludes the electric energy required to operate pumped storage plants.

Annual System ^(a) Emissions						
	2017 Emissions (kTons)	2018 Emissions (kTons)	Change in Emissions (%)	2017 Emission Rate (Ibs/MWh)	2018 Emission Rate (Ibs/MWh)	Change in Emission Rate (%)
NOx	15.30	15.61	2.1	0.30	0.30	0.0
SO ₂	4.00	4.96	24.0	0.08	0.10	25.0
CO ₂	34,969	34,096	-2.5	682	658	-3.5

Table 1-1 2017 and 2018 ISO New England System Emissions (ktons) and Emission Rates (lbs/MWh)

(a) The term "system" refers to native generation here and throughout the report.

Table 1-2 shows the 2017 and 2018 annual average marginal emission rates as calculated by the locational marginal unit (LMU) marginal emission analysis. This analysis uses the emission rates from the ISO's identified marginal unit(s) that set the energy market hourly locational marginal price(s) (LMP). The LMP results from economic dispatch, which minimizes total energy costs for the entire ISO New England system, subject to a set of constraints reflecting physical (transmission) limitations of the power system.

In response to stakeholder requests, the ISO calculated additional marginal emission metrics this year. The 2018 LMUs are calculated using two different approaches: a time-weighted approach, which is the method used in previous years, and a load-weighted approach. The time-weighted LMUs are based on the percentage of time that the LMUs are marginal in an hour, and assume that when the system is constrained and more than one unit is marginal, all marginal units contribute equally to meeting load across the system. In contrast, and new this year, the ISO calculated load-weighted LMUs, which reflect the share of load for which the generator is marginal when the system is constrained.

For both the time-weighted and load-weighted LMUs, this report presents the results of two scenarios of emission rates: 1) all LMUs, and 2) emitting LMUs.

LMU Marginal Emission Rates						
		Time-Weighte	Load- Weighted			
	2017 Annual Rate	2018 Annual Rate	Percent Change 2017 to 2018	2018 Annual Rate	2018 Load- Weighted vs. 2018 Time- Weighted	
	(lbs/MWh)	(lbs/MWh)	(%)	(lbs/MWh)	(%)	
All LMUs						
NO _X	0.15	0.17	13.3	0.20	17.6	
SO ₂	0.08	0.11	37.5	0.13	18.2	
CO ₂	654	655	0.2	745	13.7	
Emitting LMUs						
NO _X	0.23	0.28	21.7	0.27	-3.6	
SO ₂	0.12	0.17	41.7	0.16	-5.9	
CO ₂	971	1,005	3.5	971	-3.4	

Table 1-2 2017 and 2018 Annual Time-Weighted and Load-Weighted LMU Marginal Emission Rates (lbs/MWh)

Figure 1-2 summarizes the 2018 ISO New England emission rates. The all-LMU and emitting-LMU marginal emission rates for the top-five high electric demand days (HEDDs) characterize the emissions profiles of the marginal units responding to system demand during these days. On those HEDD days, the percentage of coal and oil units on the margin was higher than on average during the year.



Figure 1-2: Comparison of 2018 ISO New England system and marginal emission rates (Ibs/MWh).

A generator's heat rate (MMBtu/MWh) is a measurement of its efficiency in converting fuel into electricity. Using the time-weighted LMU approach, the 2018 calculated all-LMU marginal heat rate of 5.153 MMBtu/MWh was 5% lower than the 2017 value of 5.428 MMBtu/MWh. When considering the emitting units only, the LMU marginal heat rate decreased 2%, from 8.043 MMBtu/MWh in 2017 to 7.855 MMBtu/MWh in 2018.

The heat rates were also calculated using the load-weighted approach, which resulted in 2018 marginal heat rates of 5.962 MMBtu/MWh and 7.744 MMBtu/MWh for the all-LMU and emitting-LMU scenarios, respectively.

Section 2 Background

In 1994, the New England Power Pool (NEPOOL) Environmental Planning Committee (EPC) analyzed the impact that demand-side management (DSM) programs had on 1992 nitrogen oxide (NO_X) air emissions of NEPOOL generating units. The results were presented in a report, *1992 Marginal NO_X Emission Rate Analysis*. This report was used to support applications to obtain NO_X Emission-Reduction Credits (ERC) in Massachusetts resulting from the impacts of DSM programs.⁶ Such applications were filed under the Massachusetts ERC banking and trading program, which became effective on January 1, 1994. The ERC program allows inventoried sources of NO_X, volatile organic compounds (VOC), and carbon monoxide (CO) in Massachusetts to earn bankable and tradable emission credits by reducing actual power plant emissions below regulatory requirements.

Also in 1994, the *1993 Marginal Emission Rate Analysis* (*1993 MEA Report*) was published, which provided expanded analysis of the impact of DSM programs on power plant NO_X, sulfur dioxide (SO₂), and carbon dioxide (CO₂) air emissions for 1993. MEA reports were published annually from 1994 to 2007 to provide similar annual environmental analyses for these years.⁷ For the 2008 emissions analysis, members of ISO New England's Environmental Advisory Group (EAG) requested that the *MEA Report* be restructured to include calculated system and marginal emissions for the entire ISO New England generation system, rather than focusing primarily on marginal emissions.⁸ In response, the report was revised and renamed the *ISO New England Electric Generator Air Emissions Report* (*Emissions Report*), to reflect the importance of emissions from the entire ISO New England electric generation system.

The *Emissions Report* includes a marginal emissions analysis that is based on the Locational Marginal Unit (LMU) methodology. This methodology, which was begun as a pilot program in 2011, uses marginal units identified by the Locational Marginal Price (LMP) to calculate the marginal emissions for LMUs. The emissions are based on a time-weighted approach, which reflects the percentage of time that a resource was marginal.

The *Emissions Report* continues to evolve. This year, in response to a request by the EAG, the report includes a new, load-weighted approach, which reflects the emissions associated with the amount of load served by the marginal unit when the system is constrained. The load-weighted approach is akin to the approach used by the ISO New England Internal Market Monitor in the reporting of marginal units in their quarterly and annual reports.

Stakeholders can use the calculated marginal emissions to track air emissions from ISO New England's electric generation system and to estimate the impact that DSM programs and nonemitting renewable energy projects (i.e., wind and solar units) have on reducing ISO New England's NO_x, SO₂, and CO₂ power plant air emissions. The *2018 Emissions Report* focuses on analysis and

⁶ Massachusetts Executive Office of Energy and Environmental Affairs, "BWP AQ [Bureau of Waste Prevention—Air Quality] 18—Creation of Emission Reduction Credits," webpage (2019), http://www.mass.gov/eea/agencies/massdep/service/approvals/bwp-aq-18.html.

<u>http://www.inass.gov/eea/agencies/massuep/service/approvals/bwp-aq-16.num</u>. 7 ISO New England emissions analyses and reports from 1999 to the present are available at h

⁷ ISO New England emissions analyses and reports from 1999 to the present are available at <u>http://www.iso-ne.com/system-planning/system-plans-studies/emissions</u>.

⁸ The EAG is a stakeholder working group that assists the ISO's Planning Advisory Committee (PAC), the Reliability Committee (RC), and the associated Power Supply Planning Committee (PSPC); <u>http://www.iso-ne.com/eag.</u>

observations over the past decade (2009 to 2018). The Appendix includes data for years before 2009, as well as the values behind the figures presented.

2.1 History of Marginal Emissions Methodologies

MEA studies performed before 2004 used production simulation models to replicate, as closely as possible, the actual system operations for the study year (reference case). An incremental load scenario was then modeled in which the system load was increased by 500 MW in each hour (marginal case). The calculation for the marginal air emission rates was based on the differences in generator air emissions between the reference and marginal scenarios. However, the reference case simulation could not exactly match the actual unit-specific energy production levels of the study year because the production simulation model had a number of limitations. For example, the model could not accurately represent the historical overall dynamics of the energy dispatch, out-of-merit and reliability-based dispatches, unit-specific outages and deratings, and the effects of the daily volatility of regional (power plant) fuel prices.

From 2004 to 2013, the Fuel Type Assumed (FTA) methodology was used to calculate the average marginal emission rates. This method was based on the assumption that all natural-gas-fired and oil-fired generators responded to changing system load by increasing or decreasing their loading. Units fueled with other sources, such as coal, wood, biomass, refuse, or landfill gas, were excluded from the calculation; historically (in the 2000s), these types of units operated as base load or were non-dispatchable and not typically dispatched to balance supply with demand on the system. Other non-emitting resources, such as hydroelectric, pumped storage, wind, solar, and nuclear units that do not vary in output to follow load were also assumed not to be marginal units and were excluded from the FTA calculation of marginal emission rates.

In 2011, the ISO began developing a methodology for calculating the marginal emission rate based on the locational marginal unit, which stemmed from recommendations of the Environmental Advisory Group (EAG). This methodology identifies marginal units using the LMP, a process that minimizes total cost of energy production for the entire ISO New England system while accounting for transmission and other constraints reflecting physical limitations of the power system. This method identifies the last unit dispatched to balance the system, called the *locational marginal unit (LMU)* (refer to Section 3.3). Results are presented starting in 2009, the earliest year of available data.

The current method for calculating the marginal emission rate, as described above, is based on the assumption that when there are multiple marginal resources within a time interval, they split the load equally. In this report, this is referred to as the time-weighted LMU approach. However, when more than one resource is marginal, the system is typically constrained and marginal resources likely do not contribute equally to meeting load across the system. At the request of regional stakeholders and the EAG, the ISO has added a new method for calculating marginal emission rates, which is based on the percentage of system load a marginal unit can serve. This method, referred to as the load-weighted LMU approach, is based on the assumptions used by the ISO New England Internal Market Monitor (IMM) beginning in 2018 to report the percentage of the total system load that can be served by marginal units of a particular fuel or unit type.⁹ The marginal emission rates

⁹ The IMM began weighting marginal resources by their contribution to load to more clearly show the impact of the marginal resources on the LMP. Renewable-type generation resources with lower marginal costs are located in export-constrained areas of northern New England and frequently set real-time prices in these areas. This is particularly true of

calculated with the load-weighed LMU approach are included in the *2018 Emissions Report* along with the time-weighted LMU marginal emission rates.

2.2 History of Heat Rate Methodologies

A thermal power plant's heat rate is a measure of its efficiency in converting fuel (British thermal units, Btus) to electricity (kWh); the lower the heat rate, the more efficient the facility. A plant's heat rate depends on the individual plant design, its operating conditions, its level of electrical power output, etc.

Before 1999, MEA studies assumed a fixed marginal heat rate of 10.0 million BTUs per megawatthour (MMBtu/MWh), which was used to convert from pounds (lbs)/MWh to lbs/MMBtu.¹⁰ In the 1999 to 2003 MEA studies, the marginal heat rate was calculated using the results of production simulation runs. Beginning with the 2004 MEA study, the marginal heat rate was based on the actual generation of marginal fossil units only.

Beginning with the *2007 MEA Report*, the marginal heat rate has been calculated using a combination of both US Environmental Protection Agency (EPA) heat input data and the heat-rate information collected and maintained by the ISO. For the marginal fossil units with EPA data, the heat inputs reported to EPA were used. For units without EPA data, the heat inputs were calculated by multiplying each unit's monthly generation by the ISO's heat-rate data. The individual heat input values (in MMBtu) using the two methods were then added and the sum divided by the total generation of the marginal fossil units.

As described in Section 3.4, the calculation of the marginal heat rate is based on the heat rates for each individual LMU. In the current methodology, the percentage of time each generator is marginal per year leads to the contribution of that unit's heat rate to the time-weighted LMU marginal heat rate. With the addition of the load-weighted LMU methodology to the *Emissions Report*, a similar marginal heat rate calculation has been performed based on the percentage of load served by each marginal generator.

wind resources, which became marginal much more frequently with the implementation of the Do Not Exceed (DNE) dispatch rules on May 25, 2016. DNE incorporates wind and hydro intermittent units into unit dispatch, making the units eligible to set price. Previously, these units had to self-schedule their output in the real-time market and, therefore, could not set price.

¹⁰ 10 MMBtu/MWh is equivalent to 10,000,000 Btu/kWh.

Section 3 Data Sources and Methodologies

This section discusses the data sources and methodologies used for the emissions analysis. The calculations for total system emission rate, marginal emission rate, and marginal heat rate are shown. The time periods studied are also described.

3.1 Data Sources

The primary source of data for the ISO New England power system emissions and marginal emission rate calculations for NO_x , SO_2 , and CO_2 was the US EPA Clean Air Markets Division (CAMD) database.¹¹ The database contains measured 2018 air emissions (tons) reported by generators under EPA's monitoring and recordkeeping requirements for the Acid Rain Program and NO_x mass emissions and the Regional Greenhouse Gas Initiative (RGGI).¹²

For those units not required to report emissions data to EPA under 40 CFR Part 75 for a federal or state regulation, monthly emission rates (lbs/MWh) from the New England Power Pool Generation Information System (NEPOOL GIS) were used. If this information was not available, annual emission rates (lbs/MWh) from EPA's eGRID2016 were used.¹³ In the case of no other sources of data, emission rates based on eGRID data were obtained for similar type units. These unit-specific emission rates were used in conjunction with the actual megawatt-hours of generation, from the ISO's database used for energy market settlement purposes, to calculate tons of emissions.

All electric generators dispatched by ISO New England are included in the emissions calculations. Emissions from "behind-the-meter" generators or those generators not within the ISO New England balancing authority area are not part of this analysis.

3.2 Total System Emission Rate Calculation

The total annual system emission rate is based on the emissions produced by all ISO New England generators during a calendar year. The rates are calculated by dividing the total air emissions by the total generation from all units. The formula for calculating the total annual system emission rate is:

Annual System Emission Rate (lbs/MWh) = $\frac{\text{Total Annual Emissions (lbs)}_{\text{All Generators}}}{\text{Total Annual Energy (MWh)}_{\text{All Generators}}}$

¹¹ EPA's Clean Air Markets Program data (2019) are available at <u>http://ampd.epa.gov/ampd/</u>, and the Clean Air Markets emissions data (2019) are available at <u>http://www.epa.gov/airmarkets/</u>. Generators report emissions to EPA under the Acid Rain Program, which covers generators 25 MW or larger. Generators subject to RGGI also report CO₂ emissions to EPA. Additional details for the monitoring, recordkeeping, and reporting requirements of SO₂, NO_x, and CO₂ emissions, volumetric flow, and opacity data from affected units under 40 CFR Part 75 are available at <u>https://www.epa.gov/airmarkets/clean-air-markets-emissions-monitoring</u>.

¹² Before 2005, the MEA reports used annual data obtained primarily from the EPA Emissions Scorecard. In the 2005 and 2006 MEA Reports, monthly EPA data, rather than hourly data, were used for calculating marginal rates.

¹³ The U.S. EPA's eGRID2016 database (2019) is available at <u>http://www.epa.gov/cleanenergy/energy-</u> <u>resources/egrid/index.html</u>. The eGRID2018 database, which was released on 1/28/20, was not available in time for this report.

3.3 Marginal Emission Rate Calculation

The Locational Marginal Unit (LMU) is identified by the LMP, which is set by the cost of the generation dispatched to meet the next increment of load at the pricing location. The resource that sets price is called the marginal unit. LMPs minimize total energy costs for the entire ISO New England system, subject to a set of constraints reflecting physical limitations of the power system.

The process to determine the LMP identifies at least one locational marginal unit for each fiveminute period, which is associated with meeting the energy requirements on the system during that pricing interval. When transmission is not constrained, the marginal unit is classified as the unconstrained marginal unit. Each binding transmission constraint adds an additional marginal unit, resulting in n + 1 marginal units (LMUs) for every n binding constraints, in each five-minute period.

The LMU percent marginal in an hour was calculated using two different approaches: the timeweighted and load-weighted approach. The time-weighted approach involves calculating the percentage of time that each unit was marginal in an hour based on the five-minute interval data. With the load-weighted approach, the amount of load served by each unit in a five-minute interval was used to calculate the percentage of total system load served by each unit in an hour.

To calculate the marginal emission rates, the hourly emissions (lbs) for those units in the EPA CAMD database were grouped into on-peak and off-peak periods (defined in Section 3.5) for each month. When only monthly NEPOOL GIS or annual eGRID data were available, these emission rates were multiplied by the associated monthly on-peak and off-peak generation. The amount of monthly emissions (lbs) from each individual marginal fossil generator was then divided by that generator's monthly on-peak or off-peak generation to obtain the corresponding emission rate (lbs/MWh) for that time period. For NO_X emission rates, the monthly totals (lbs) for each generator were grouped into ozone and non-ozone season emissions and divided by the respective ozone and non-ozone season generation.

The percentage of time each generator was marginal in each month (in the case of the timeweighted approach) or the percentage of load served by the generator in each month (in the case of the load-weighted approach) during on- or off-peak hours was calculated and then multiplied by the generator's month-specific on-peak or off-peak average emission rate as described above. That amount was summed for each marginal unit and then divided by the total on-peak or off-peak hours in the year. The LMU marginal emission rate calculations are as follows, where generator k is identified to be marginal during hour h and has a specific monthly emission rate during month m: LMU On-Peak Marginal Emission Rate

$$= \frac{\sum_{k=1}^{LMP \text{ marginal units}} \sum_{h=1}^{on-peak \text{ hours in year}} (\% \text{ of LMP Unit Marginal}_{k,h} \times \text{On-Peak Emission Rate}_{k,m})}{On-Peak Hours in Year}$$

LMU Off-Peak Marginal Emission Rate

$$= \frac{\sum_{k=1}^{LMP \text{ marginal units}} \sum_{h=1}^{off\text{-peak hours in year}} (\% \text{ of LMP Unit Marginal}_{k,h} \times Off\text{-Peak Emission Rate}_{k,m})}{Off\text{-Peak Hours in Year}}$$

The annual LMU marginal emission rate was then calculated by combining the on-peak and off-peak rates in a weighted calculation.

The analysis of time-weighted and load-weighted LMU marginal emission rates was conducted for two different scenarios. Each scenario includes or excludes certain generators depending on their characteristics. The two scenarios are as follows:

- All LMUs—includes all locational marginal units identified by the LMP
- **Emitting LMUs**—excludes all non-emitting units with no associated air emissions, such as pumped storage, hydroelectric, and nuclear generation, as well as and wind and solar renewables. Pumped storage demand, i.e., the energy used to pump water into a pumped-storage unit's storage pond, and external transactions were also assumed to have no emissions.

3.4 Marginal Heat Rate Calculation

The marginal heat rate was calculated by first calculating a heat rate for each individual generator¹⁴. The heat rates for the individual LMUs were then multiplied by the percentage of time each generator was marginal (time-weighted LMU), or by the percentage of load served (load-weighted LMU).

These values were then added together and divided by the total number of hours in the year, resulting in the time-weighted and load-weighted LMU marginal heat rates.

Similar to the marginal emission rate calculation, the analysis was performed for both the all-LMU and the emitting-LMU scenarios.

Since a unit's heat rate is equal to its heat input, or fuel consumption, divided by its generation, the calculated marginal heat rate is defined as follows:

Calculated Marginal Heat Rate = $\frac{\text{Calculated Fuel Consumption of Marginal Fossil Units (MBtu)}}{\text{Actual Generation of Marginal Fossil Units (MWh)}}$

¹⁴ The heat rate for noncombustible renewables, i.e., pumped storage, hydroelectric, wind, and solar resources, was considered to be zero in these calculations since those resources do not burn fuel to produce energy. Pumped storage demand and imports were also assumed to have a zero heat rate.

3.5 Time Periods Analyzed

The 2018 marginal air emission rates for on- and off-peak periods for ISO New England were calculated for this report. Data for the on-peak period are presented so that a typical industrial and commercial user that can provide load response during a traditional weekday can explicitly account for its emissions reductions during the on-peak hours. The marginal emission rates for NO_X were calculated for five time periods:¹⁵

- On-peak ozone season, consisting of all weekdays between 8:00 a.m. and 10:00 p.m. from May 1 to September 30
- Off-peak ozone season, consisting of all weekdays between 10:00 p.m. and 8:00 a.m. and all weekend hours from May 1 to September 30
- On-peak non-ozone season, consisting of all weekdays between 8:00 a.m. and 10:00 p.m. from January 1 to April 30 and from October 1 to December 31
- Off-peak non-ozone season, consisting of all weekdays between 10:00 p.m. and 8:00 a.m. and all weekend hours from January 1 to April 30 and from October 1 to December 31
- Annual average

Because the ozone and non-ozone seasons are only relevant to NO_X emissions, the SO_2 and CO_2 emission rates were only calculated for the following time periods:

- On-peak annual, consisting of all weekdays between 8:00 a.m. and 10:00 p.m.
- Off-peak annual, consisting of all weekdays between 10:00 p.m. and 8:00 a.m. and all weekend hours
- Annual average

¹⁵ The ISO developed a special report, *Analysis of New England Electric Generators' NO_X Emissions on 25 Peak-Load Days in 2005–2009*, released September 23, 2011, which summarized its analysis of NO_X emissions during peak days (https://www.iso-ne.com/static-assets/documents/genrtion resrcs/reports/emission/peak nox analysis.pdf

Section 4 Data and Assumptions

This section highlights the key parameters and assumptions modeled in the *2018 Emissions Report*, including weather, emissions data, installed capacity, and system generation.

4.1 2018 New England Weather

Because the weather significantly affects the demand for energy and peak loads, comparing 2018 temperatures, total energy use and both cooling and heating degree days to previous years can provide some perspective.

New England experienced an extreme cold wave at the beginning of the year that stretched from the end of December 2017 through the first week of January 2018. The average temperature in January was 26°F, which was slightly below the 20-year average of 27°F. Summer 2018 was considerably warmer and more humid than 2017. The average temperature for the summer was 72°F, which was the third hottest summer over the past ten years, and the average Temperature Humidity Index (THI) of 69°F was the hottest of the last ten years.

The 2018 summer peak electricity demand of 25,980 MW was 8.4% higher than the 2017 summer peak of 23,968 MW. There were 499 cooling degree days in 2018, which is 50.8% higher than the 20-year average.¹⁶ The net energy for load was 1.9% higher in 2018 than 2017. With respect to the winter months, there were 6,060 heating degree days, which is 0.9% higher than the 20-year average.

New England's historical cooling and heating degree days for 1999 through 2018 are shown in Appendix Table 1. The difference between the cooling and heating degree days for a particular year and the average is also provided.

4.2 Emissions Data

For calculating total system emissions, approximately 66% of the SO₂ emissions and 73% of the CO₂ emissions were based on EPA's Clean Air Markets data. For NO_x, Clean Air Markets data were used for 34% of total emissions.

The emission rates were multiplied by the 2018 energy generation reported to the ISO to obtain the emissions (tons) by each generator.

4.3 ISO New England System Installed Capacity

The ISO New England power grid operates as a unified system serving all loads in the region. The amount of generation by fuel type and its associated emissions are affected by a number of factors, including the following:

¹⁶ Over the 20-year span from 1999 to 2018, the average number of cooling degree days was 331, and the average number of heating degree days was 6,004.

- Forced and scheduled maintenance outages of resources and transmission system elements
- Fuel prices and emission allowance costs
- Imports from and exports to neighboring regions
- System peak load and energy consumption
- Water availability to hydroelectric facilities and for thermal power plant cooling
- A variety of other factors

Figure 4-1 shows the total 2018 summer capacity for ISO New England generation as obtained from *ISO New England's 2019–2028 Forecast Report of Capacity, Energy, Loads and Transmission* (CELT).¹⁷ Appendix Table 2 and Appendix Table 3 summarize the total summer and winter capacity for ISO New England generation by state and fuel type.¹⁸



Figure 4-1: 2018 ISO New England summer capacity by state (MW).

Figure 4-2 illustrates the new generating capacity added to the ISO New England system from 2009 through 2018. A total of 4,092 MW was added, with combustion turbines and combined-cycle plants capable of burning natural gas or distillate oil making up about 78% of this new capacity. Notably, over half of the total natural gas capacity additions during this period occurred in 2018, with approximately 1,600 MW of new gas-fired capacity. The remaining additions over the prior ten years consist primarily of renewable generation, including 14% of total capacity from wind and solar resources.

¹⁷ The ISO New England *CELT Report* is typically issued in May of each year. The *2019 CELT Report* (using the seasonal claimed capabilities (SCC) as of January 1, 2019) was used to completely capture all the new capacity additions that occurred during the prior calendar year, 2018. The capacity may also include generators that retired in 2018. The CELT reports are available at http://www.iso-ne.com/system-planning/system-plans-studies/celt.

¹⁸ The natural gas capacity in this chart and elsewhere in the report has been broken out into combined cycle (CC) and simple cycle (SC) generators to show the portion of the natural gas capacity that is comprised of peaking plants.



Figure 4-2 : ISO New England generator additions, 2009 to 2018 (MW). Note: The generator additions and uprate values are based on the summer Seasonal Claimed Capabilities, as reported in the 2019 CELT Report.

Several large generators in New England have retired in the past ten years. The retirements, as shown in Figure 4-3, total 1,829 MW of coal, 1,332 MW of residual oil, and 604 MW of nuclear generation since late 2011.



Figure 4-3: Major retirements in ISO New England, 2009 to 2018 (MW).

Note: The retirement date shown is not necessarily the year in which the retirement occurred. In the case of units that retired late in the year, the retirement is included in the following year because that is when the impact would primarily have been observed.

4.4 ISO New England System Energy Production

The ISO relies on generating units of all operating characteristics and fuel types, and a generator's fuel type directly correlates with the magnitude and characteristics of the unit's emissions.

Figure 4-4 shows the 2018 monthly generation by fuel type. The overlaid black line represents the total generation in each month and corresponds with the right axis. Natural-gas-fired generation accounted for 35% to 62% of the total generation in each month.¹⁹. During winter months with higher energy demand and occasional limitations in natural gas availability, other fuel types have increased their energy contribution to support the ISO New England system.²⁰ During the winter months, the use of firmly contracted gas pipeline transportation by the regional gas sector's local distribution company (LDC) customers takes priority over the use of the interruptible and/or secondary pipeline capacity which is primarily used by gas-fired generators to generate electricity.²¹ Almost all gas-fired generating units lack both firm supply and transportation contracts.

Although oil- and coal-fired generation were each only 1% of the annual total in 2018, their contribution to total generation in the month of January was significantly higher than normal (11% and 4%, respectively) due to an extreme cold wave during the first part of the month. The percentage of natural-gas-fired generation was lowest in the winter and spring months and increased to meet the higher demand in the summer months and during fall generator outages.

Hydroelectric, solar, and wind generation accounted for 8% to 18% of the total 2018 generation. These fuel types exhibit seasonal differences in their generation due to fuel availability; typically hydroelectric and wind generation decline over the summer months due to less rainfall replenishing reservoirs and rivers and less favorable onshore wind conditions, while solar generation peaks between March and September.



Figure 4-4: 2018 ISO New England monthly generation by fuel type (% MWh, MWh).

¹⁹ Annual energy production share for natural gas-fired generation was 49% in 2018, compared to 48% in 2017.

²⁰ Annual energy production share by fuel type remained generally consistent between 2017 and 2018.

²¹ Firm customers of regional gas LDCs include residential, commercial, and industrial (RCI) customers.

Figure 4-5 shows the generation (MWh) by fuel type from 2014 to 2018 based on the resource's primary fuel type listed in the *2019 CELT Report*. In 2018, coal-fired generation continued its decline, and was about 570 GWh lower than in 2017. In contrast, oil-fired generation decreased by 460 GWh in 2018. Natural-gas-fired generation in 2018 was about 1,300 GWh higher than in 2017, increasing by about 3%. Nuclear generation was about the same as in 2017, decreasing by less than 1%. Generation by non-emitting renewable resources increased in 2018: hydroelectric generation grew 2%, and solar and wind together increased by 435 GWh, or 10% over 2017. The overall system generation of 103,740 GWh in 2018 was 1% higher than the 2017 level.



Figure 4-5: ISO New England annual generation by fuel type, 2014 to 2018 (million MWh).

4.5 Locational Marginal Unit Scenarios

The data and assumptions applied for the all-LMU and emitting-LMU scenarios for both the timeweighted and load-weighted approaches are presented in this section, including the percentage of time various fuel types were marginal. Because the price of the marginal unit (and thus the price of electricity) is largely determined by the unit's fuel type and heat rate, examining the marginal units by fuel type can explain changes in electricity prices and emissions.

4.5.1 Time-Weighted Approach

4.5.1.1 All LMUs

In this scenario, all identified locational marginal units were used to develop the marginal emission rates. Non-emitting generators were associated with a zero emission rate. Figure 4-6 shows each fuel type's time on the margin and month-to-month variations. Natural gas was marginal 43% to 80% of the time. The months when natural gas units were marginal the most, in the range of 78% to 80% of the time, were June through August. Although oil-fired generation was on the margin an average of only 1% during the year, it was marginal approximately 13% of the time in January when there was a period of extreme cold weather. During the months of April and November, coal-fired generation was on the margin more than other months, about 4% of the time. Other

Renewables, which consist of biomass, refuse, and landfill gas units, were marginal an average of 2% of the time, with a peak of 5% in September. Intermittent resources became eligible to be dispatched and set price beginning in May 2016, when the Do Not Exceed dispatch rules went into effect. In 2018, the time that wind was marginal ranged from 1% in August to a maximum of 30% in October. Note that Figure 4-6 includes a breakdown of the pumped storage category into pumped storage generation and pumped storage demand²², which were marginal an average of 9% and 5% of the time, respectively.



Figure 4-6: 2018 percentage of time various resource types were marginal —all LMUs.

Figure 4-7 shows the historical percentage of time that each fuel type was marginal within a calendar year. Natural gas has been the primary marginal fuel type during the past five years. From 2017 to 2018, the percentage of time that natural gas was marginal decreased by 3%. The amount of time that oil was the marginal fuel remained at 1% in 2018, and coal decreased from 2% in 2017 to 1%. The percentage of time that the Other Renewables category was marginal decreased by 1%. In 2018, as in 2017, wind often displaced gas as the price-setting fuel. However, wind predominantly set price in small, local export-constrained areas of the system, as opposed to setting price for large parts of the system. Though wind was marginal 16% of the time in 2018, it was generally marginal in a very local congested area and did not directly impact system price. At the system level, wind was the marginal fuel type approximately 1% of the time.²³

²² Pumped storage demand refers to the electric energy used to pump water into a pumped-storage unit's storage pond. ²³ Beginning with the 2018 Spring Quarterly Markets Report (July 2018), the ISO-NE Internal Market Monitor (IMM) recalculated the percentage of time marginal units by fuel type by quarter, using a load-weighted analysis for 2016 through the first half of 2018. The IMM switched to the load-weighted marginal resources methodology to better reflect the impact of system constraints since resources within an export-constrained area are not able to fully contribute to meeting the load for the wider system. The IMM reports are available at <u>https://www.iso-ne.com/markets-</u> <u>operations/market-monitoring-mitigation/internal-monitor/.</u>



Figure 4-7: Annual percentage of time various resource types were marginal —all LMUs, 2014 to 2018.

4.5.1.2 Emitting LMUs

Marginal generating resources with no air emissions were excluded in this scenario. Therefore, hydroelectric, pumped storage, external transactions, and other renewables with no air emissions were not taken into account, while all other LMUs were.



Figure 4-8: 2018 percentage of time various resource types were marginal —emitting LMUs.



Figure 4-9: Annual percentage of time various resource types were marginal – emitting LMUs, 2014 to 2018.



4.5.2 Load-Weighted Approach



4.5.2.1 All LMUs



4.5.2.2 Emitting LMUs



Figure 4-11: 2018 percentage of load for which various resource types were marginal —emitting LMUs.

4.5.3 Time-Weighted vs. Load-Weighted Approach



Figure 4-12: Comparison of 2018 annual marginality for various resource types using the time-weighted vs. load-weighted approach —all LMUs.


Figure 4-13: Comparison of 2018 annual marginality for various resource types using the time-weighted vs. load-weighted approach —emitting LMUs.

4.6 High Electric Demand Days

In New England, high electric demand days (HEDDs) are typically characterized by high temperatures leading to elevated cooling (energy) demand. During peak energy demand periods, such as HEDDs, the ISO relies on peaking units, which are utilized less during the rest of the year but respond quickly to meet system demand. These peaking units are often jet (aero-derivative) or combustion turbines with higher emission rates. Therefore, examining the marginal emission rates on HEDDs (see Section 5.4) reveals the emission rates associated with the units responding to higher system demand.

Section 5 Results and Observations

This section presents the results for ISO New England's 2018 system²⁴ emissions representing all generators. It also provides the results for the annual marginal heat rates and the locational marginal unit emission rates for the all-LMU and emitting-LMU scenarios, using both the time-weighted and load-weighted approaches.

5.1 2018 ISO New England System Emissions

Results are presented for the following metrics:

- Aggregate NO_X, SO₂, and CO₂ emissions for each state for 2018
- A comparison of aggregate NO_X, SO₂, and CO₂ emissions for 2009 to 2018
- 2018 annual average NO_x, SO₂, and CO₂ emission rates, by state and for the ISO New England system as a whole
- Monthly variations in the emission rates for 2018
- A comparison of annual average NO_X, SO₂, and CO₂ emission rates for 2009 to 2018

5.1.1 Results

Figure 5-1 shows the 2018 annual aggregate NO_X , SO_2 , and CO_2 air emissions for each state. The ISO New England system total emissions for NO_X , SO_2 , and CO_2 were 15.61 ktons, 4.96 ktons, and 34,096 ktons, respectively. The calculations for these emission levels were based on the actual generation of all generating units in ISO New England's balancing authority area and the actual or assumed unit-specific emission rates.²⁵ The reason for the divergent total emissions for each state is that the total emissions reflect the generation of units physically located in that state (refer to Figure 4-1 showing summer capacity by state) rather than emissions associated with the generation needed to meet that state's energy demand.

²⁴ In this report, "system" refers to native generation within the ISO New England Balancing Authority Area.

²⁵ This does not include northern Maine and the Citizens Block Load (in Northern Vermont), which is typically served by New Brunswick and Quebec. These areas are not electrically connected to the ISO New England Control Area.



Figure 5-1: 2018 ISO New England system annual emissions of NO_x, **SO**₂, **and CO**₂ (ktons). **Note:** System annual emissions based on physical location of the generating resources. Sum may not equal ISO New England system total due to rounding.

Figure 5-2 shows the annual aggregate NO_x , SO_2 , and CO_2 air emissions for 2009 through 2018. Since 2009, NO_x emissions have dropped by 43% and SO_2 by 94%, while CO_2 has decreased by about 31%. Refer to Appendix Table 4 for the values behind this graph.



Figure 5-2: ISO New England system annual generator emissions, 2009 to 2018 (ktons).

Table 5-1 shows the 2018 annual average NO_X , SO_2 , and CO_2 air emission rates (lbs/MWh), by state and for the New England system as a whole. The rate calculations were based on the actual hourly

unit generation of ISO New England generating units located within each state and the actual or assumed unit-specific emission rates.

State	NOx	SO ₂	CO ₂
Connecticut	0.19	0.05	560
Maine	0.35	0.23	568
Massachusetts	0.48	0.12	817
New Hampshire	0.29	0.15	538
Rhode Island	0.14	0.01	916
Vermont	0.31	0.03	591
New England	0.30	0.10	658

Table 5-1 2018 ISO New England System Annual Average Generator Emission Rates (lbs/MWh)

Monthly variations in the emission rates shown in Figure 5-3 reflect the generation by different fuel types shown in Figure 4-4. In 2018, the highest emission rates by far occurred in January. This was due to a cold snap that resulted in oil-fired plants generating a significant portion of the region's electricity. At other times during the year, emission rates rose in April, July, November, and December, when there were slight increases in coal- and oil-fired generation. In addition, higher loads in the summer, as well as a reduction in nuclear generation in the early fall, resulted in higher emissions due to increased gas-fired generation during those months.



Figure 5-3: 2018 ISO New England system monthly average generator emission rates (lbs/MWh).

Figure 5-4 illustrates the annual average NO_x , SO_2 , and CO_2 air emission rates (lbs/MWh) for 2009 to 2018 using the calculation method presented in Section 3.2. Since 2009, the annual average NO_x emission rate has decreased by 35%, SO_2 by 92%, and CO_2 by 21%. Appendix Table 6 shows historical emission rates since 1999.



Figure 5-4: ISO New England system annual average generator emission rates, 2009 to 2018 (lbs/MWh).

5.1.2 Additional Observations

Total energy generation decreased by 1.1% in 2018 from 2017. The amount of energy from coalfired generation continued its decline in 2018, decreasing by 34% to 1.1% of total generation. Energy from oil-fired generators increased by about 57% to 1.2% of total generation, primarily due to the large amount of oil generation in January. Natural gas-fired generation increased by 3% to 48.6% of total generation. In contrast, there was a 1% increase in total energy produced by nonemitting sources, which includes nuclear generation. Although nuclear generation itself decreased by 0.5%, photovoltaic and wind generation grew by 10%, and generation by hydroelectric facilities rose 2%. The impacts on system emissions resulting from these changes in the generation mix can be seen in Table 5-2. The increase in oil-fired generation from 2017 to 2018 contributed to increases of 2.1% and 24.0% in system emissions for NO_X and SO_2 . CO_2 emissions decreased by 2.5%. Similar changes were also observed in the 2018 emission rates: the NO_X rate stayed the same, SO_2 increased by 25.0%, and CO_2 decreased by 3.5%.

2017 ai	and Emission Rates (lbs/MWh)										
	Annı	al System Em	issions								
2017 Emissions	2018 Emissions	Change in Emissions	2017 Emission Rate	2018 Emission Rate	Change in Emission Rate						

(%)

2.1

24.0

-2.5

(lbs/MWh)

0.30

0.08

682

Table 5-2
2017 and 2018 ISO New England System Emissions (ktons)
and Emission Rates (lbs/MWh)

NOx

SO₂

CO₂

(kTons)

15.30

4.00

34,969

(kTons)

15.61

4.96

34,096

(%)

0.0

25.0

-3.5

(lbs/MWh)

0.30

0.10

658

Overall, total system emissions have declined over the last 10 years, which can be attributed to several factors:

- Increased use of highly efficient natural-gas-fired generators
- Decline in the cost of natural gas
- Mandated use of lower-sulfur fuels
- Retirement of oil- and coal-fired generation, and retrofits of NO_X and SO₂ emission controls on some of the remaining oil- and coal-fired generators

5.2 2018 ISO New England Marginal Heat Rate

The calculated annual marginal heat rate reflects the average annual efficiency of all the marginal fossil units dispatched throughout 2018. The 2018 monthly marginal heat rates for both the time-weighted and load-weighted all-LMU and emitting-LMU scenarios are shown in Figure 5-5, and the historical marginal heat rates for 2010 to 2018 are presented in Figure 5-6. The values behind Figure 5-6 are provided in Appendix Table 7.



Figure 5-5: 2018 time- and load-weighted LMU monthly marginal heat rate (MMBtu/MWh).



Figure 5-6: LMU annual marginal heat rate, 2010-2018 (MMBtu/MWh).

There has been an overall trend of declining heat rates from 2010 through 2016, with the exception of a spike in 2014. Beginning in 2017, there has been a steep drop in the heat rate in the all-LMU scenario due to the large amount of wind units on the margin, which was a result of the DNE dispatch rules implemented in May 2016. Figure 5-6 includes the 2018 LMU marginal heat rates that were calculated using the load-weighted approach. In that case, the value for the all-LMU scenario was 16% higher than the value based on the time-weighted approach because a significant portion of the wind plants are located in export-constrained northern New England. For the emitting-LMUs scenario, the marginal heat rate calculated using the load-weighted approach was somewhat lower than the time-weighted results because several biomass plants, which generally have higher heat rates, are also located in export-constrained areas.

5.3 2018 ISO New England Marginal Emission Rates

This section presents the 2018 calculated LMU-based marginal emission rates for the all-LMU and emitting-LMU scenarios, as defined in Section 4.5. The 2018 rates based on both the time-weighted and load-weighted LMU approaches are included; however, only time-weighted LMU results are available for years prior to 2018.

The NO_X data for both these scenarios are provided for each of the five time periods studied. Since the ozone and non-ozone seasons are not relevant to SO_2 and CO_2 , only the on-peak, off-peak, and annual rates are provided for these emissions.

5.3.1 Marginal Emission Rates Using the Time-Weighted Approach

5.3.1.1 All-LMU Scenario

The time-weighted all-LMU marginal emission rates were calculated with all LMUs (units the LMP identified as marginal). Table 5-3 shows the rates in lbs/MWh. Appendix Table 8 shows these rates in lbs/MMBtu, with the associated marginal heat rate of 5.153 MMBtu/MWh used as the conversion factor. It is helpful to compare Figure 5-7, which shows the monthly LMU marginal emission rates,

with Figure 4-6 (showing the 2018 percentage of time various fuel types were marginal for all LMUs) and Figure 5-3 (showing the 2018 ISO New England system monthly average NO_x , SO_2 , and CO_2 emission rates). Appendix Table 9 lists the values behind Figure 5-7.

Ozone / Non-Ozone Season Emissions (NOx)								
Air Emission	Ozone Season		Non-Ozone Season		Annual			
	On-Peak	Off-Peak	On-Peak	Off-Peak	(All Hours)			
NOx	0.20	0.14	0.19	0.17	0.17			
	An	nual Emissio	ons (SO ₂ and	CO ₂)				
Air		Anr	nual		Annual			
Emission		On-Peak	Off-Peak		(All Hours)			
SO ₂		0.14	0.08		0.11			
CO ₂		690	630		655			

Table 5-3
2018 Time-Weighted LMU Marginal Emission Rates—All LMUs (lbs/MWh) ^{(a, b}

(a) The ozone season occurs between May 1 and September 30, while the non-ozone season occurs from January 1 to April 30 and from October 1 to December 31.

(b) On-peak hours consist of all weekdays between 8:00 a.m. and 10:00 p.m. Off-peak hours consist of all weekdays between 10:00 p.m. and 8:00 a.m. and all weekend hours.



Figure 5-7: 2018 time-weighted monthly LMU marginal emission rates—all LMUs (lbs/MWh).

5.3.1.2 Emitting-LMU Scenario

Table 5-4 and Appendix Table 10 present the marginal emission rates for emitting LMUs. The marginal heat rate for this scenario is 7.855 MMBtu/MWh. The values for the monthly rates shown in Figure 5-8 are shown in Appendix Table 11.

Ozone / Non-Ozone Season Emissions (NOx)								
Air Emission	Ozone	Season	Non-Ozor	Annual				
	On-Peak	Off-Peak	On-Peak	Off-Peak	(All Hours)			
NOx	0.27	0.20	0.31	0.31	0.28			
	An	nual Emissio	ons (SO₂ and	CO ₂)				
Air		Anr	nual		Annual			
Emission		On-Peak	Off-Peak		(All Hours)			
SO ₂		0.21	0.14		0.17			
CO ₂		1,028	989		1,005			

Table 5-4 2018 Time-Weighted LMU Marginal Emission Rates—Emitting LMUs (lbs/MWh)





5.3.1.3 2009 to 2018 Time-Weighted LMU Marginal Emission Rates

The LMUs actively exhibit the changes in ISO New England's energy production. Compared with the emitting-LMU scenario, the all-LMU scenario has lower marginal emission rates because it includes zero-air-emission resources that lower the average emission rate. Figure 5-9 and Figure 5-10 summarize the marginal emission rates for the two LMU scenarios based on the time-weighted approach. The values behind the graphs are provided in Appendix Table 12 through Appendix Table 17 in lbs/MWh.



Figure 5-9: Time-weighted LMU marginal emission rates, 2009 to 2018—all LMUs (lbs/MWh).



Figure 5-10: Time-weighted LMU marginal emission rates, 2009 to 2018—emitting LMUs (lbs/MWh).

5.3.2 Marginal Emission Rates Using the Load-Weighted Approach

5.3.2.1 All-LMU Scenario

The 2018 load-weighted, all-LMU marginal emission rates were calculated based on the percentage of load served by all marginal units. Table 5-5 shows the rates in lbs/MWh. Appendix Table 18 shows these rates in lbs/MMBtu, with the associated marginal heat rate of 5.962 MMBtu/MWh used as the conversion factor. Figure 5-11, which shows the monthly load-weighted LMU marginal emission rates, can be compared with Figure 4-6 (showing the 2018 percentage of load for which various fuel types were marginal for all LMUs) and Figure 5-3 (showing the 2018 ISO New England system monthly average NO_X, SO₂, and CO₂ emission rates). Appendix Table 19 lists the values behind Figure 5-11.

Ozone / Non-Ozone Season Emissions (NOx)								
Air Emission	Ozone	Season	Non-Ozone Season		Annual			
	On-Peak	Off-Peak	On-Peak	Off-Peak	(All Hours)			
NOx	0.19	0.14	0.25	0.22	0.20			
	An	nual Emissio	ons (SO₂ and	CO ₂)				
Air		Anr	nual		Annual			
Emission		On-Peak	Off-Peak		(All Hours)			
SO ₂		0.16	0.11		0.13			
CO ₂		779	720		745			

Table 5-5 2018 Load-Weighted LMU Marginal Emission Rates—All LMUs (lbs/MWh)





5.3.2.2 Emitting-LMU Scenario

Table 5-6 and Appendix Table 20 present the load-weighted marginal emission rates for emitting LMUs. The marginal heat rate for this scenario is 7.744 MMBtu/MWh. The values for the monthly rates shown in Figure 5-12 are shown inAppendix Table 21.

Ozone / Non-Ozone Season Emissions (NOx)								
Air	Ozone	Season	Non-Ozor	ie Season	Annual			
Emission	On-Peak	Off-Peak	On-Peak	Off-Peak	(All Hours)			
NOx	0.25	0.18	0.32	0.31	0.27			
	An	nual Emissio	ons (SO ₂ and	CO ₂)				
Air		Anr	nual		Annual			
Emission		On-Peak	Off-Peak		(All Hours)			
SO ₂		0.20	0.14		0.16			
CO ₂		987	960		971			

Table 5-6 2018 Load-Weighted LMU Marginal Emission Rates—Emitting LMUs (lbs/MWh)



Figure 5-12: 2018 load-weighted monthly LMU marginal emission rates—emitting LMUs (lbs/MWh).

5.3.3 Comparison of Marginal Emission Rates Using the Time- and Load-Weighted Approaches

As shown in Table 5-7, the 2018 load-weighted marginal emission rates for the all-LMU scenario are significantly higher than the time-weighted marginal emission rates. This is because the load-

weighted approach takes into consideration the fact that most of the wind units are located in export-constrained areas of northern New England and therefore set price for a small percentage of the system load. This in turn reduces the contribution of wind units to the marginal emission rates, resulting in higher average marginal rates. With the time-weighted approach, these constrained wind resources are given equal weight with other generators that set price for the remainder of the region, resulting in lower marginal emission rates. The contrast between the treatment of the LMUs can be seen in Figure 4-12, which compares the annual marginality for various fuel types based on the time-weighted vs. load-weighted approach for all LMUs.

In the case of the emitting-LMU scenario, the load-weighted marginal emission rates are lower than the time-weighted rates. This is because there are a significant number of emitting LMUs, primarily wood-burning plants, in export-constrained areas. Refer to Figure 4-13 for a comparison of the annual marginality calculated with the time-weighted vs. load-weighted approaches for the emitting-LMU scenario.

LMU Marginal Emissions									
	2018 Time- Weighted Annual Rate	2018 Load- Weighted Annual Rate	2018 Load Weighted vs. 2018 Time- Weighted						
	(lbs/MWh)	(lbs/MWh)	(%)						
All LMUs									
NOx	0.17	0.20	17.6						
SO ₂	0.11	0.13	18.2						
CO ₂	655	745	13.7						
Emitting LMUs									
NOx	0.28	0.27	-3.6						
SO ₂	0.17	0.16	-5.9						
CO ₂	1,005	971	-3.4						

Table 5-7 2018 Time-Weighted and Load-Weighted LMU Marginal Emission Rates (lbs/MWh)

Figure 5-13, Figure 5-14, and Figure 5-15 illustrate the differences between the load-weighted and time-weighted LMU monthly marginal emission rates for the all-LMU and emitting-LMU scenarios. In general, the greatest differences in the monthly rates for the all-LMU scenario occur during the non-summer months, when wind units are on the margin more often. During those months, the load-weighted LMU approach results in higher marginal rates due to the lower impact of wind. For the emitting-LMU scenario, the differences resulting from the two approaches are most apparent in those months that Other Renewables, primarily consisting of wood-burning units, are on the margin more often. In this case, the marginal rates calculated using the load-weighted approach are lower than those using the time-weighted approach.



Figure 5-13: 2018 time- and load-weighted monthly LMU marginal SO₂ emission rates.



Figure 5-14: 2018 time- and load-weighted monthly LMU marginal NO_x emission rates.



Figure 5-15: 2018 time- and load-weighted monthly LMU marginal CO₂ emission rates.

5.4 Marginal Emission Rates for High Electric Demand Days

Using the LMU methodology, the top-five high electric demand days in 2018 were examined. In 2018, the top five HEDDs were July 5, and August 6, 7, 28, and 29. The temperatures in New England during these days ranged from 89° to 93°F. Peak daily loads ranged from 24,512 MW on Thursday, July 5, to a high of 26,024 MW on Wednesday, August 29. Table 5-8 shows the average LMU marginal emission rate during these five days.

HEDD LMU Marginal Emission Rate (Ibs/MWh)								
	Time-W	eighted	Load-Weighted					
	All LMUs	Emitting LMUs	ting Js All LMUs Em					
NOx	0.60	0.82	0.61	0.83				
SO ₂	0.57	0.72	0.59	0.74				
CO ₂	902	1,201	933	1,209				

Table 5-8 High Electric Demand Day LMU Marginal Emission Rates (lbs/MWh)

5.5 Observations

ISO New England's power plant air emissions are directly dependent on the specific units available and dispatched to serve load for each hour of the year. Therefore, seasonal emissions can vary widely, primarily due to changes in economic and reliability dispatch, unit availability, fuel price and consumption, fuel switching, transmission topology, and load levels. The amount of imports, the use of pumped storage, and significant generator outages, such as a nuclear unit outage, also affect emissions. The LMU marginal emission rates reflect the dynamics of the ISO New England power system.

The time-weighted LMU annual marginal rates for SO_2 , NO_x , and CO_2 have exhibited an overall decrease during the past ten years. Compared with 2009, the 2018 LMU SO_2 annual marginal rates have declined by over 90% for both the all-LMU and emitting-LMU scenarios. As illustrated in Figure 5-9 and Figure 5-10, most of this decline took place in 2012, when there was an increase in natural gas units on the margin combined with a significant decrease in marginal coal-fired units. In the case of marginal NO_x emission rates, there have been declines of 55% and 43% for the all-LMU and emitting-LMU scenarios, respectively, since 2009. During that period, the CO_2 rates have declined by 29% for the all-LMU scenario and 13% for the emitting-LMU scenario.

The greatest drop in the time-weighted all-LMU marginal CO_2 rate over the past ten years occurred in 2017, due to wind units being marginal a significant percentage of the time beginning that year. The load-weighted LMU marginal emission rates for the all-LMU scenario, which reflect the fact that wind is marginal for only a small percentage of the total system load, are significantly higher than the time-weighted rates. They range from 14% higher for CO_2 to 18% higher for both NO_X and SO₂. For the emitting LMU-scenario, the load-weighted rates are 3% to 6% lower than the timeweighted rates.

In 2018, the on-peak marginal rates for SO_2 , CO_2 , and NO_X were higher than the off-peak rates. This is likely due to the operation of older, less-efficient peaking units (jets or combustion turbines) dispatched to meet peak load.

Despite declines in the time-weighted LMU marginal emission rates since at least 2014, there was an uptick in all of the rates in 2018. This was most likely due to the significant amount of time that oil units were marginal during the January cold wave, as well as the increased time that emitting generators in the Other Renewables category were marginal (see Figure 4-9). A decrease in the amount of wind on the margin may also have had an impact. The changes in the marginal rates in 2018 were more dramatic than the changes in the system rates. The NO_X annual average marginal rates increased by 13% and 22% for the all-LMU and emitting-LMU scenarios, respectively, while there was no change in the NO_X system rate. The all-LMU and emitting-LMU marginal emission rates for SO₂ increased by around 40% in 2018, but there was only a 25% increase in the system rate. For CO₂, there was no change in the all-LMU marginal rate and the emitting-LMU rate increased by 3.5%. In contrast, the CO₂ system emission rate decreased by 3.5%.

Section 6 Appendix

Year	Total Cooling Degree Days	Difference from Average (%)	Total Heating Degree Days	Difference from Average (%)
1999	360	8.8%	5,774	-3.8%
2000	211	-36.2%	6,380	6.3%
2001	319	-3.6%	5,870	-2.2%
2002	353	6.7%	5,938	-1.1%
2003	350	5.8%	6,628	10.4%
2004	249	-24.7%	6,332	5.5%
2005	417	26.0%	6,331	5.4%
2006	334	1.0%	5,532	-7.9%
2007	287	-13.3%	6,153	2.5%
2008	278	-16.0%	6,027	0.4%
2009	223	-32.6%	6,272	4.5%
2010	403	21.8%	5,636	-6.1%
2011	354	7.0%	5,802	-3.4%
2012	350	5.8%	5,285	-12.0%
2013	398	20.3%	6,137	2.2%
2014	238	-28.1%	6,299	4.9%
2015	334	1.0%	6,080	1.3%
2016	351	6.1%	5,705	-5.0%
2017	309	-6.6%	5,839	-2.7%
2018	499	50.8%	6,060	0.9%
Average	331		6,004	

Appendix Table 1 ISO New England Total Cooling and Heating Degree Days, 1999 to 2018

Appendix Table 2 2018 ISO New England Summer Generating Capacity (MW, %)^(a. b)

	Connec	ticut	Massach	usetts	Mair	ne	New Ham	npshire	Rhode I	sland	Verm	ont
Unit Type	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%
Coal	383.4	4.2	-	-	-	-	530.6	12.8	-	-	-	-
Natural Gas	3,747.0	40.8	6,319.3	55.3	1,574.4	51.3	1,240.7	29.9	1,889.0	97.1	-	-
Nuclear	2,073.1	22.6	-	-	-	-	1,250.4	30.1	-	-	-	-
Oil	2,650.9	28.9	2,537.8	22.2	738.4	24.1	481.4	11.6	-	-	132.4	31.1
Hydro	90.9	1.0	182.9	1.6	452.4	14.8	417.7	10.1	0.7	0.0	194.9	45.7
Pumped Storage	28.7	0.3	1,759.5	15.4	-	-	-	-	-	-	-	-
Solar	13.1	0.1	373.1	3.3	4.9	0.2	1.2	0.0	20.2	1.0	-	-
Wind	-	-	9.6	0.1	97.9	3.2	18.4	0.4	8.8	0.5	17.9	4.2
Other Renewables	187.3	2.0	244.4	2.1	198.9	6.5	213.5	5.1	26.6	1.4	80.8	19.0
Total	9,174.4	100.0	11,426.7	100.0	3,067.0	100.0	4,153.8	100.0	1,945.3	100.0	426.1	100.0

(a) Sum may not equal total due to rounding.

(b) Seasonal Claimed Capability as of January 1, 2019.

Appendix Table 3 2018 ISO New England Winter Generating Capacity (MW, %)^(a. b)

	Connec	ticut	Massach	usetts	Maiı	пе	New Ham	npshire	Rhode I	sland	Verm	ont
Unit Type	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%
Coal	382.5	3.9	-	-	-	-	534.7	12.1	-	-	-	-
Natural Gas	4,133.8	41.9	7,144.5	56.0	1,772.4	47.9	1,370.8	31.1	2,120.9	97.7	-	-
Nuclear	2,092.7	21.2	680.6	5.3	-	-	1,251.4	28.4	-	-	-	-
Oil	2,919.2	29.6	2,690.6	21.1	859.7	23.2	501.7	11.4	-	-	167.8	31.9
Hydro	107.7	1.1	213.5	1.7	573.3	15.5	483.0	11.0	1.9	0.1	230.0	43.7
Pumped Storage	28.4	0.3	1,755.6	13.8	-	-	-	-	-	-	-	-
Solar	3.1	0.0	3.6	0.0	0.1	0.0	-	-	0.3	0.0	-	-
Wind	-	-	20.8	0.2	279.8	7.6	46.8	1.1	21.6	1.0	46.1	8.8
Other Renewables	194.1	2.0	252.4	2.0	217.8	5.9	214.6	4.9	25.4	1.2	82.8	15.7
Total	9,861.4	100.0	12,761.6	100.0	3,703.1	100.0	4,403.0	100.0	2,170.2	100.0	526.6	100.0

(a) Sum may not equal total due to rounding.

(b) Seasonal Claimed Capability as of January 1, 2019.

Appendix Table 4 ISO New England System Annual Generator Emissions, 2001 to 2018 (kilotons)^(a)

	NOx	SO ₂	CO ₂		
Year	kilotons	kilotons	kilotons	kilotons	
	(short)	(short)	(short)	(metric)	
2001	59.73	200.01	52,991	48,073	
2002	56.40	161.10	54,497	49,439	
2003	54.23	159.41	56,278	51,055	
2004	50.64	149.75	56,723	51,458	
2005	58.01	150.00	60,580	54,957	
2006	42.86	101.78	51,649	46,855	
2007	35.00	108.80	59,169	53,677	
2008	32.57	94.18	55,427	50,283	
2009	27.55	76.85	49,380	44,797	
2010	28.79	80.88	52,321	47,465	
2011	25.30	57.01	46,959	42,601	
2012	20.32	16.61	41,975	38,079	
2013	20.32	18.04	40,901	37,105	
2014	20.49	11.67	39,319	35,670	
2015	18.86	9.11	40,312	36,570	
2016	16.27	4.47	37,467	33,990	
2017	15.30	4.00	34,969	31,723	
2018	15.61	4.96	34,096	30,931	
Percent Reduction, 2001-2018	74	98	36	36	

(a) Since greenhouse gas data is often expressed in metric tons, an additional column showing CO₂ emissions in metric kilotons is included in this table. A metric ton is approximately 2,205 lbs.

Monthly System Emission Rates (Ib/MWh)							
Month	NO _x	SO ₂	CO ₂				
1	0.53	0.46	787				
2	0.30	0.07	623				
3	0.28	0.05	621				
4	0.28	0.10	583				
5	0.26	0.04	527				
6	0.28	0.04	631				
7	0.26	0.08	701				
8	0.26	0.05	705				
9	0.28	0.04	678				
10	0.31	0.04	742				
11	0.29	0.08	643				
12	0.27	0.06	596				

Appendix Table 5 2018 ISO New England System Average Monthly Generator Emission Rates (Ibs/MWh)

Appendix Table 6 ISO New England System Annual Average Generator Emission Rates, 1999 to 2018 (Ibs/MWh)

Year	Total Generation (GWh)	NO _x	SO2	CO2
1999	104,409	1.36	4.52	1,009
2000	110,199	1.12	3.88	913
2001	114,626	1.05	3.51	930
2002	120,539	0.94	2.69	909
2003	127,195	0.93	2.75	970
2004	129,459	0.78	2.31	876
2005	131,874	0.88	2.27	919
2006	128,046	0.67	1.59	808
2007	130,723	0.54	1.66	905
2008	124,749	0.52	1.51	890
2009	119,282	0.46	1.29	828
2010	126,383	0.46	1.28	829
2011	120,612	0.42	0.95	780
2012	116,942	0.35	0.28	719
2013	112,040	0.36	0.32	730
2014	108,356	0.38	0.22	726
2015	107,916	0.35	0.17	747
2016	105,570	0.31	0.08	710
2017	102,562	0.30	0.08	682
2018	103,740	0.30	0.10	658
Percent Redu	ction, 1999 - 2018	78	98	35

LMU Marginal Heat Rate (MMBtu/MWh)							
	Time-W	eighted	Load-Weighted				
Year	All Marginal LMUs	Emitting LMUs	All Marginal LMUs	Emitting LMUs			
2009	8.591	8.507					
2010	7.414	8.385					
2011	6.907	8.190					
2012	6.678	7.870					
2013	6.841	8.271					
2014	7.692	9.034					
2015	6.707	8.096					
2016	6.625	7.925					
2017	5.428	8.043					
2018	5.153	7.855	5.962	7.744			

Appendix Table 7
LMU Marginal Heat Rate, 2009 to 2018 (MMBtu/MWh)

2018 Time-Weighted LMU Marginal Emission Rates—All LMUs (lbs/MMBtu)

Ozone / Non-Ozone Season Emissions (NOx)							
Air	Ozone	Season	Non-Ozon	Annual			
Emission	On-Peak	Off-Peak	On-Peak	Off-Peak	Average (All Hours)		
NOx	0.038	0.026	0.036	0.033	0.033		
	Annı	ual Emissio	ns (SO ₂ and	CO ₂)			
Air		Anr	nual		Annual		
Emission		On-Peak	Off-Peak		Average (All Hours)		
SO ₂		0.027	0.016		0.021		
CO ₂		134	122		127		

Appendix Table 9 2018 Monthly Time-Weighted LMU Marginal Emission Rates—All LMUs (lbs/MWh)

LMU	LMU Marginal Emission Rates (lb/MWh)								
Month	NO _X	SO ₂	CO ₂						
1	0.47	0.66	746						
2	0.12	0.05	638						
3	0.11	0.03	603						
4	0.17	0.09	598						
5	0.10	0.01	550						
6	0.14	0.03	727						
7	0.16	0.05	767						
8	0.20	0.14	825						
9	0.21	0.05	761						
10	0.10	0.02	512						
11	0.15	0.08	505						
12	0.12	0.06	629						

Appendix Table 10 2018 Time-Weighted LMU Marginal Emission Rates—Emitting LMUs (lbs/MMBtu)

Ozone / Non-Ozone Season Emissions (NOx)							
Air	Ozone	Season	Non-Ozon	Annual			
Emission	On-Peak	Off-Peak	On-Peak	Off-Peak	Average (All Hours)		
NO _x	0.035	0.025	0.040	0.039	0.035		
	Annı	ual Emission	ns (SO ₂ and	CO ₂)			
Air		Anr	nual		Annual		
Emission		On-Peak	Off-Peak		Average (All Hours)		
SO ₂		0.027	0.018		0.021		
CO2		131	126		128		

Appendix Table 11

2018 Monthly Time-Weighted LMU Marginal Emission Rates—Emitting LMUs (lbs/MWh)

LMUI	LMU Marginal Emission Rates (lb/MWh)							
Month	NO _X	SO ₂	CO ₂					
1	0.83	1.03	1,184					
2	0.20	0.08	1,010					
3	0.18	0.05	959					
4	0.27	0.14	1,019					
5	0.19	0.03	1,003					
6	0.20	0.04	917					
7	0.20	0.06	936					
8	0.26	0.19	1,005					
9	0.30	0.07	1,091					
10	0.19	0.04	924					
11	0.28	0.16	1,034					
12	0.20	0.10	986					

	Ozone Season		Non-Ozone Season			
Year	On-Peak	Off-Peak	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2009	0.36	0.39	0.29	0.45	0.38	-
2010	0.62	0.47	0.33	0.47	0.46	21.7
2011	0.24	0.29	0.14	0.36	0.27	-42.2
2012	0.35	0.21	0.19	0.16	0.22	-18.4
2013	0.32	0.21	0.35	0.43	0.34	56.7
2014	0.21	0.14	0.51	0.56	0.38	13.1
2015	0.34	0.16	0.32	0.32	0.28	-27.2
2016	0.26	0.14	0.25	0.19	0.21	-25.0
2017	0.23	0.11	0.14	0.15	0.15	-28.6
2018	0.20	0.14	0.19	0.17	0.17	13.3
% Chango						
2009 - 2018	-45.1	-65.0	-35.2	-62.0	-55.0	

Appendix Table 12 NO_x Time-Weighted LMU Marginal Emission Rates, 2009 to 2018 —All LMUs (lbs/MWh)

NOx Time-Weighted LMU Marginal Emission Rates, 2009 to 2018—Emitting LMUs (lbs/MWh)

	Ozone Season		Non-Ozone Season			
Year	On-Peak	Off-Peak	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2009	0.45	0.53	0.33	0.61	0.49	-
2010	0.69	0.49	0.40	0.62	0.55	11.8
2011	0.32	0.31	0.17	0.46	0.33	-39.8
2012	0.40	0.26	0.23	0.19	0.26	-22.0
2013	0.37	0.26	0.42	0.56	0.42	62.7
2014	0.26	0.17	0.59	0.72	0.47	12.1
2015	0.44	0.19	0.39	0.41	0.36	-23.5
2016	0.33	0.18	0.30	0.24	0.25	-30.6
2017	0.31	0.14	0.25	0.24	0.23	-8.0
2018	0.27	0.20	0.31	0.31	0.28	21.7
% Change 2009 - 2018	-39.1	-62.9	-6.5	-49.1	-43.1	

Year	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2009	1.12	1.72	1.47	-
2010	1.05	1.45	1.29	-12.2
2011	1.34	1.35	1.35	4.7
2012	0.39	0.32	0.35	-73.9
2013	0.51	0.59	0.55	56.0
2014	0.46	0.45	0.45	-18.0
2015	0.40	0.29	0.33	-26.8
2016	0.22	0.11	0.16	-51.5
2017	0.12	0.05	0.08	-50.0
2018	0.14	0.08	0.11	37.5
% Change 2009 - 2018	-87.4	-95.1	-92.5	

Appendix Table 14 SO₂ Time-Weighted LMU Marginal Emission Rates, 2009 to 2018—All LMUs (lbs/MWh)

SO2 Time-Weighted LMU Marginal Emission Rates, 2009 to 2018—Emitting LMUs (lbs/MWh)

Year	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2009	1.40	2.28	1.90	-
2010	1.19	1.76	1.52	-20.0
2011	1.65	1.60	1.62	6.6
2012	0.45	0.39	0.42	-74.3
2013	0.59	0.76	0.69	65.9
2014	0.53	0.56	0.55	-20.2
2015	0.48	0.36	0.41	-25.5
2016	0.28	0.13	0.19	-53.7
2017	0.18	0.08	0.12	-36.8
2018	0.21	0.14	0.17	41.7
% Change 2009 - 2018	-85.0	-93.9	-91.1	

Year	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2009	882	946	919	-
2010	1,019	1,036	1,029	12.0
2011	943	908	922	-10.4
2012	876	839	854	-7.4
2013	921	937	930	8.9
2014	931	949	941	1.2
2015	891	832	857	-9.0
2016	892	807	842	-1.7
2017	681	635	654	-22.3
2018	690	630	655	0.2
% Change 2009 - 2018	-21.7	-33.4	-28.7	

Appendix Table 16 CO₂ Time-Weighted LMU Marginal Emission Rates, 2009 to 2018—All LMUs (lbs/MWh)

CO2 Time-Weighted LMU Marginal Emission Rates, 2009 to 2018—Emitting LMUs (lbs/MWh)

Year	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2009	1,042	1,242	1,157	-
2010	1,138	1,215	1,183	2.2
2011	1,148	1,061	1,097	-7.3
2012	1,019	1,003	1,010	-7.9
2013	1,079	1,163	1,125	11.4
2014	1,064	1,138	1,107	-1.6
2015	1,053	1,023	1,036	-6.4
2016	1,035	987	1,007	-2.8
2017	981	964	971	-3.6
2018	1,028	989	1,005	3.5
% Change 2009 - 2018	-1.4	-20.3	-13.1	

load-Weigh	ted LMU N	/larginal Ei	mission Ra	tes—All Ll	VIUs (Ibs/N	
	Ozone / Non-Ozone Season Emissions (NOx)					
Air	Ozone Season		Non-Ozone Season		Annual	
Emission	On-Peak	Off-Peak	On-Peak	Off-Peak	Average (All Hours)	
NO _x	0.032	0.023	0.041	0.037	0.034	

Annual Emissions (SO₂ and CO₂)
Annual

On-Peak

0.027

131

Off-Peak

0.018

121

Air

Emission

SO,

CO,

Annual

Average

(All Hours)

0.022

125

Appendix Table 18 2018 Load-Weighted LMU Marginal Emission Rates—All LMUs (lbs/MMBtu)

Appendix Table 19

2018 Monthly Load-Weighted LMU Marginal Emission Rates—All LMUs (lbs/MWh)

LMU Marginal Emission Rates (lb/MWh)						
Month	NO _X SO ₂ CO ₂					
1	0.68	0.81	943			
2	0.14	0.07	749			
3	0.13	0.04	724			
4	0.19	0.10	684			
5	0.10	0.01	630			
6	0.16	0.03	771			
7	0.17	0.05	796			
8	0.19	0.14	793			
9	0.19	0.05	740			
10	0.15	0.03	718			
11	0.18	0.11	676			
12	0.13	0.08	709			

Appendix Table 20 2018 Load-Weighted LMU Marginal Emission Rates—Emitting LMUs (lbs/MMBtu)

Ozone / Non-Ozone Season Emissions (NOx)						
Air	Ozone Season		Non-Ozone Season		Annual	
Emission	On-Peak	Off-Peak	On-Peak	Off-Peak	Average (All Hours)	
NO _x	0.032	0.024	0.041	0.040	0.035	
Annual Emissions (SO ₂ and CO ₂)						
Air		Annual		Annual		
Emission		On-Peak	Off-Peak		Average (All Hours)	
SO ₂		0.026	0.018		0.021	
CO2		127	124		125	

LMU Marginal Emission Rates (lb/MWh)						
Month	onth NO _X SO ₂ CO ₂					
1	0.89	0.98	1,166			
2	0.19	0.08	973			
3	0.17	0.05	933			
4	0.28	0.15	1,005			
5	0.16	0.03	937			
6	0.19	0.04	909			
7	0.20	0.06	934			
8	0.24	0.20	957			
9	0.25	0.06	950			
10	0.20	0.04	931			
11	0.26	0.16	1,000			
12	0.19	0.10	958			

Appendix Table 21 2018 Monthly Load-Weighted LMU Marginal Emission Rates—Emitting LMUs (lbs/MWh)

Section 1

Introduction

Chapter 2

Cost Estimation: Concepts and Methodology

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2.1 Introduction

This chapter presents a methodology that will enable the user, having knowledge of the source being controlled, to produce study-level estimates of the costs incurred by regulated entities for a control system applied to that source. The methodology, which applies to each of the control systems included in this Manual, is general enough to be used with other "add-on" systems as well. Further, the methodology can apply to estimating the costs of fugitive emission controls and other non-stack abatement methods.

There are several types of users for this Manual. Industrial users are the most common, but State, local, other officials, and other environmental stakeholders (e.g., environmental groups) are other users of the Manual. EPA strongly recommends that the methodology in this Manual be followed as part of compliance with various Clean Air Act programs.

The cost estimation methodology can be used in the development of assessing private compliance decisions/strategies or effects of permits as various alternatives are considered. If the regulation or permit prescribes a particular control technology (e.g., installation of a scrubber), then the costs of individual controls can be estimated for affected entities. If the regulation or permit establishes performance standards, with flexibility as to how the standards can be achieved, then the cost estimation methods can be used to estimate the costs of various options for achieving the standards.

We note that these cost estimation procedures are meant to support the calculation of the costs of purchasing and installing pollution control equipment, and then operating and maintaining this equipment, at a facility. Such costs are private costs because they reflect the private choices and decisions of the owners and operators of the facilities. Broader costs associated with the installation and operation of pollution control equipment, such as impacts on society (e.g., changes in prices to consumers due to the impact on a producer from additional pollution control) are analyzed using methods that assess the social costs of regulatory intervention.

Again, the methods provided in this Manual is to aid in assessing private choices that regulated entities may undertake in complying with regulation. Analyzing private decisions and the associated costs are important in and of itself and can be used as inputs to assessing the likely effects of regulations. In other words, the cost estimation methodology in this Manual is meant for private cost estimation, not social cost estimation. Information on social cost estimation can be found in the EPA Economic Guidelines and the U.S. Office of Management and Budget's Circular A-4. This Manual is not intended to assess the likely effects of federal regulations to society, but is intended to provide assessment of private actions which can be inputs to social impacts analysis.

Users with the role of developing or reviewing compliance plans can use this Manual to estimate private costs of installing and operating control equipment. Regulated entities facing regulation can use this Manual to help decide how to comply with the requirements they are facing.

2.2 Private Versus Social Costs

Before delving deeper into a discussion on estimating private costs, identifying the differences between private and social costs is important. The Manual focuses on private cost, which refers to the costs borne by a private entity for an action the private entity decides. For example, if the private entity pays for the cost of installing and operating pollution control equipment, among many options available to the entity, the entirety of these costs would be considered private costs.

The EPA's Guidelines for Preparing Economic Analysis define social cost as follows: "Social cost represents the total burden a regulation will impose on the economy; it can be defined as the sum of all opportunity costs incurred as a result of a regulation. These opportunity costs consist of the value lost to society of all the goods and services that will not be produced and consumed if firms comply with the regulation and reallocate resources away from production activities and towards pollution abatement. To be complete, an estimate of social cost should include both the opportunity costs of current consumption that will be forgone as a result of the regulation, and the losses that may result if the regulation reduces capital investment and thus future consumption."¹

The term social cost refers to the overall cost of an action to society, not just to the private entity that incurs the expense to control pollution. Social cost is based on the concept of opportunity cost, the value associated with production and consumption that are reduced or changed as a result of reallocating resources to reduce pollution.

Assessing private cost is more straightforward because it attempts to tally up expenses that individual entities or facilities incur to purchase, finance, and operate pollution abatement equipment or strategies. Suppose a state government wanted to encourage pollution control for a certain industry and provided grants to pay half of the costs of a scrubber. The private cost for the industry would be 50% of the cost of a scrubber. Using another example, suppose a firm purchases equipment, pays sales tax on the item, and receives an immediate tax rebate. The private cost to the firm is the sum of the equipment price plus the sales tax amount minus the excise tax amount.

The estimation of private costs is the focus of the cost estimation procedures and data in this Manual. Both EPA and OMB have developed guidance on methods appropriate for use in estimating social costs for regulatory impact analysis or economic impact analysis where the social costs of government interventions are assessed. The guidelines presented in this Manual are not suitable in conducting regulatory impact analysis or economic impact analysis where the social costs of government interventions are assessed. Because this Manual focuses on private costs to facilities of installing and operating pollution control equipment, we will not present the

¹ U.S. Environmental Protection Agency, Office of Policy, National Center for Environmental Economics. Guidelines for Preparing Analysis. May 2014. Pp. 8-1 – 8-2.

methodologies for social cost calculations. For more information on social cost estimation methods, please see EPA's Economics Guidelines [5] and OMB Circular A-4 [6].

2.3 Types of Cost Estimates

As mentioned in Chapter 1.1, the costs and estimating methodology in this Manual are directed toward the "study" estimate with a probable error of 30% percent. According to Perry's Chemical Engineer's Handbook, a study estimate is "… used to estimate the economic feasibility of a project before expending significant funds for piloting, marketing, land surveys, and acquisition … [I]t can be prepared at relatively low cost with minimum data." [1] The accuracy of the study-level estimate is consistent with that for a Class 4 cost estimate as defined by the Association for Advancement of Cost Engineering International (AACEI), which AACEI defines as a "study or feasibility"-level estimate. [2]

Specifically, to develop a study estimate, the following must be known:

- Location of the plant;
- Location of the source within the plant;
- Design parameters, such as source size or capacity rating, uncontrolled pollutant concentrations, pollutant removal requirements, etc.
- Rough sketch of the process flow sheet (i.e., the relative locations of the equipment in the system);
- Preliminary sizes of, and material specifications for, the system equipment items;
- Approximate sizes and types of construction of any buildings required to house the control system;
- Rough estimates of utility requirements (e.g. electricity, steam, water, and waste disposal);
- Quantity and cost materials consumed in the process (e.g., water, reagents, and catalyst);
- Preliminary flow sheet and specifications for ducts and piping; Approximate sizes of motors required;
- Economic parameters (e.g. annual interest rate, equipment life, cost year, and taxes.) [1]

Besides the labor requirements for construction and operation of a project, the user will need an estimate of the labor hours required for engineering and drafting activities because the accuracy of an estimate (study or otherwise) depends on the amount of engineering work expended on the project. There are four other types of estimates, three of which are more accurate than the study estimate. Figure 2.1 below displays the relative accuracy of each type of cost estimation process. The other processes are: [1]

• Order-of-magnitude. This estimate provides "a rule-of-thumb procedure applied only to repetitive types of plant installations for which there exists good cost history." Its

probable error bounds are greater than 30%. (However, according to Perry's, "... no limits of accuracy can safely be applied to it.") The sole input required for making this level of estimate is the control system's capacity (often measured by the maximum volumetric flow rate of the gas passing through the system).

- Scope, Budget Authorization, or Preliminary. This estimate, with probable error of 20%, requires more detailed knowledge than the study estimate regarding the site, flow sheet, equipment, buildings, etc. In addition, rough specifications for the insulation and instrumentation are also needed.
- Project Control or Definitive. This estimate, with a probable error of 10%, requires yet more information than the scope estimates, especially concerning the site, equipment, and electrical requirements.
- Firm, Contractor's, or Detailed. This is the most accurate (probable error of 5%) of the estimate types, requiring complete drawings, specifications, and site surveys. Consequently, detailed cost estimates are typically not available until right before construction, since "time seldom permits the preparation of such estimates prior to an approval to proceed with the project."[1]



Figure 2.1: The Continuum of Accuracy for Cost Analyses

These error bands are attempts at assessing the probable errors associated with each estimation method based on past practices of the engineering cost-estimation discipline. However, the error bands do not shed any light on the distribution of the likely errors. The users of this Manual should not draw conclusions about probable errors that this Manual does not intend.

Study-level estimates represent a compromise between the less accurate order-ofmagnitude estimates and the more accurate estimate types. The former is too imprecise to be of much value in the context of pollution control installation and operation, while the latter are very expensive for an entity to prepare, and require detailed site- and process-specific knowledge that some Manual users are unlikely to have. Over time, this Manual has become the standard for air pollution control costing methodologies for many State regulatory agencies. For example, Virginia requires that the Manual be used in making cost estimates for BACT and other permit applications, unless the permit applicant can provide convincing proof that another cost reference should be used.² Texas accepts the Manual methodology "as a sound source for the quantitative cost analysis" for BACT analyses it reviews.³

The industrial user is more likely to have site-specific and detailed information than the average cost and sizing information used in a study estimate. The methodology laid out in this Manual can provide cost estimates that are more accurate when using detailed site-specific information. The anecdotal evidence from most testimonials volunteered by industrial users indicates that much greater accuracy than 30 percent probable error can be attained. However, this Manual does not assume that detailed site-specific information will always be available to estimate costs associated with installing and operating pollution abatement equipment at a much higher accuracy level. This Manual retains the conclusion that the cost methodology laid out in this chapter and information in each control measure chapter with 30% probable error is relevant to be used in air pollution control cost estimation for permitting actions. It is the affected industry source that bears the burden of providing information of sufficient quality that will yield cost estimates of at least a study-level estimate for permitting decisions pertaining to their facilities.

2.4 Cost Categories Defined

The terminology addressing cost categories used in the earlier editions of this Manual was adapted from the AACEI. [2]. However, different disciplines give different names to the same cost components, and the objective of this edition is to reach out to a broader scientific audience. For example, engineers determine a series of equal payments over a long period of time that fully funds a capital project (and its operations and maintenance) by multiplying the present value of those costs by a capital recovery factor, which produces an Equivalent Uniform Annual Cost (EUAC) value. This is identical to the process used by accountants and financial analysts, who adjust the present value of the project's cash flows to derive an annualized cost number.

2.4.1 Elements of Total Capital Investment

In assessing the total capital investment, this Manual takes the viewpoint of an owner, the firms making the investment, or those who have material interest in the project. Total capital investment (TCI) includes all costs required to purchase equipment needed for the control system (purchased equipment costs), the costs of labor and materials for installing that equipment (direct installation costs), costs for site preparation and buildings, and certain other costs (indirect installation costs). TCI also includes costs for land, working capital, and off-site facilities.⁴ Taxes, permitting costs, and other administrative costs are covered in Section 2.6.5.8. Financing costs

² State of Virginia, Department of Environmental Quality. Draft PSD Guidelines, August 4, 2011. Pp. 4-4 to 4-5.

³ Texas Commission on Environmental Quality. Air Permits Division. Air Permit Reviewer Reference Guide, APDG 6110. Appendix G. p. 45. January 2011.

⁴ Estimates of TCI for some control measures may not necessarily be calculated in this way due to availability of public information on capital investment costs and equations for those measures, such as the SNCR and SCR chapters in this Manual.

are covered in Sections 2.5.3 and 2.5.4. Foregone revenue associated with facility shut downs are covered in Section 2.6.4.2.

Direct installation costs include costs for foundations and supports, erecting and handling the equipment, electrical work, piping, insulation, and painting. Indirect installation costs include such costs as engineering costs; construction and field expenses (i.e., costs for construction supervisory personnel, office personnel, rental of temporary offices, etc.); contractor fees (for construction and engineering firms involved in the project); start-up and performance test costs (to get the control system running and to verify that it meets performance guarantees); and contingencies. Another item within owner's costs, technology royalties, is not separately included with the Manual's methodology because technology royalties are assumed to be reflected within the purchased equipment costs. Contingencies is a catch-all category that covers unforeseen costs that may arise, such as "... possible redesign and modification of equipment, escalation increases in cost of equipment, increases in field labor costs, and delays encountered in start-up." [2] Contingencies are discussed in more detail later in this chapter. Contingencies are not the same thing as uncertainty and retrofit factor costs, which are treated separately in this chapter. Escalation is not treated as part of contingencies. Please refer to section 2.6.4 for further discussion.

The elements of TCI are displayed in Figure 2.2. Note that the sum of the purchased equipment cost, direct and indirect installation costs, site preparation, and buildings costs comprises the battery limits estimate. A battery limit is the geographic boundary defining the coverage of a specific project [3]. Usually this encompasses all equipment of interest (in this case, the pollution control equipment), but excluding provision of storage, utilities, administrative buildings, or auxiliary facilities unless so specified [3]. This estimate would mainly apply to control systems installed in existing plants, though it could also apply to those systems installed in new plants when no special facilities for supporting the control system (i.e., off-site facilities) would be required. Off-site facilities include units to produce steam, electricity, and treated water; laboratory buildings; and railroad spurs, roads, and other transportation infrastructure items. Some pollution control systems do not generally have off-site capital units dedicated to them since these pollution control devices rarely consume energy at that level. However, it may be necessary—especially in the case of control systems installed in new or "grass roots" plants—for extra capacity to be built into the site generating plant to service the system. For example, installation of a venturi scrubber, which often requires large amounts of electricity, would require including costs associated with off-site facilities.

Note, however, that the capital cost of a device does not include routine utility costs (which can include the cost of steam, electricity, process and cooling water, compressed air, refrigeration, waste treatment and disposal, and fuel), even if the device were to require an offsite facility. Utility costs are categorized as operating costs that covers both the investment and operating and maintenance costs for the utility. The utility costs associated with start-up operations are included in the "Start-Up" component of the indirect installation costs. Operating costs are discussed in greater detail below. In addition, not every air pollution control system installation will have all of the elements for its TCI that are listed below (e.g., buildings).



^aTypically factored from the sum of the primary control device and auxiliary equipment costs.

^bTypically factored from the purchases equipment cost.

^cUsually required only at "grass roots" installations.

^dUnlike the other direct and indirect costs, costs for these items usually are not factored from the purchased equipment cost. Rather, they are sized and costed separately.

^eNormally not required with add-on control systems.

Figure 2.2: Elements of Total Capital Investment

As Figure 2.2 shows, the installation of pollution control equipment may also require land, but since some add-on control systems take up very little space (often a quarter-acre or less), this cost may be relatively small. Certain control systems, such as those used for flue gas desulfurization (FGD) or selective catalytic reduction (SCR), require larger quantities of land for the equipment, chemicals storage, and waste disposal. In these cases, especially when performing a retrofit installation, space constraints can significantly influence the cost of installation, and the purchase of additional land and remediation of existing land and property may be a significant factor in the development of the project's capital costs.
However, land is not treated the same as other capital investments, since it is not depreciated for accounting purposes. The value of the land may fluctuate depending on the market conditions, but for accounting purposes and assessing private costs, land is not depreciated. The purchase price of new land needed for siting a pollution control device can be added to the TCI, but it must not be depreciated. If the firm plans on dismantling the device at some future time, the value of the land should be included at the disposal point as an "income" to the project to net it out of the cash flow analysis (more on cash flow analysis later, in section 2.5.4).

One might expect initial operational costs (the initial costs of fuel, chemicals, and other materials, as well as labor and maintenance related to start-up) to be included in the operating cost section of the cost analysis instead of in the capital component, but such an allocation would be inappropriate. Routine operation of the control does not begin until the system has been tested, balanced, and adjusted to work within its design parameters. Until then, all utilities consumed, all labor expended, and all maintenance and repairs performed are a part of the construction phase of the project and are included in the TCI in the "Start-Up" component of the indirect installation costs.

In addition, the TCI of controls for sources that affect fan capacity (e.g., FGD scrubbers, SCRs) may be impacted by the unit's elevation with respect to sea level. Cost calculations for the control measures within the Manual have typically been developed for systems located at sea level. For systems located at higher elevations (generally over 500 feet above sea level), the purchased equipment cost and balance of plant cost should be increased based on the ratio of the atmospheric pressure between sea level and the location of the system, i.e., atmospheric pressure at sea level divided by atmospheric pressure at the elevation of the unit.⁵

The method for estimating TCI in this Manual is an "overnight" estimation method. This method estimates capital cost as if no interest was incurred during construction and therefore estimates capital cost as if the project is completed "overnight." An alternate way of describing this method is the present value cost that would have to be paid as a lump sum up front to completely pay for a construction project. Cost items such as Allowance for Funds Used During Construction (AFUDC), which is defined as the costs of debt and equity funds used to finance plant construction, and is an amount credited on the firm's statement of income and charged to construction in progress on the firm's balance sheet, is treated separately in Section 2.5.3 in this Manual. This item is an estimate that is incurred over the timespan of construction. For example, this is considered as a cost item within the electric power industry.⁶ [15] Other cost items similarly treated separately include escalation of costs to a future year due to inflation in Section 2.5.4. We provide more discussion later in this chapter on these cost items that are not included in this section.

⁵ One instance of this is the estimates of costs for the recently revised SNCR and SCR Control Cost Manual chapters, which are available at <u>http://www.epa.gov/ttn/ecas/costmodels.html</u>.

⁶ See the National Energy Technology Laboratory's "Quality Guidelines for Energy System Studies: Cost Estimation Methodology for NETL Assessments of Power Plant Performance."

2.4.2 Elements of Total Cost

Total Cost (TC) refers to costs that are incurred yearly. TC has three elements: direct costs (DC), indirect costs (IC), and recovery credits (RC), which are related by the following equation:

$$TC = DC + IC - RC \tag{2.1}$$

The basis of direct costs and recovery credits is one year, as this period allows for seasonal variations in production (and emissions generation) and is directly usable in financial analyses. (See Section 2.3.) [4] The various annual costs and their interrelationships are displayed in Figure 2.3. Some indirect costs are not incurred on an annual basis. Purchase, installation, and start-up of pollution abatement capital equipment often take multiple years. To incorporate these multiyear costs with other annual costs, the capital costs are amortized and converted into capital recovery. If the timing between direct costs and indirect costs are different, then an alternative approach for estimating total cost is to calculate the present value of these costs before summing them.

Variable costs are those that vary with some measure of productivity - generally the company's productive output. But for our purposes, the proper metric may be the quantity of exhaust gas processed by the control system per unit time. Semi-variable costs also vary with some measure of production, but have a positive cost even when production is zero.

An example would be a boiler producing process steam for only sixteen hours a day. During the time the boiler is idle, it costs less to keep the boiler running at some idle level than to re-heat it at the beginning of the next shift. Consequently, that idle level operation cannot be attributed to production and should be considered the fixed component of the semi-variable fuel cost of the boiler. Direct costs include costs for raw materials (reagents or adsorbers), utilities (steam, electricity, process and cooling water), waste treatment and disposal, maintenance materials (greases and other lubricants, gaskets, and seals), replacement parts, and operating, supervisory, and maintenance labor. Generally, raw materials, utilities, and waste treatment and disposal are variable costs, but there is no hard and fast rule concerning any of the direct cost components. Each situation requires a certain level of insight and expertise on the part of the analyst to present the cost components accurately



Figure 2.3: Elements of Total Annual Cost

Indirect, or "fixed" annual costs are independent of the level of production (or whatever unit of measure serves as the analytical metric) and, in fact, would be incurred even if the control system were shut down. Indirect costs include such categories as administrative charges, property taxes, insurance, administrative charges including permitting costs and capital cost amortized into capital recovery.

Capital is depreciable, indicating that, as the capital is used, it wears out and that lost value cannot be recovered. Economic depreciation, which is the lost value due to wear and tear, is different than accounting depreciation, the declared lost value, that is usually used in a cost analysis. Depreciation costs are a variable or semi-variable cost that is also included in the calculation of tax credits (if any) and depreciation allowances whenever taxes are considered in a cost analysis. However, taxes are not uniformly applied, and subsidies, tax moratoriums, and deferred tax opportunities distort how the direct application of a tax works.

Finally, direct and indirect annual costs can be offset by recovery credits, taken for materials or energy recovered by the control system, which may be sold, recycled to the process, or reused elsewhere at the site. An example of such credits is the by-product of controlling sulfur with a FGD scrubber. As the lime or limestone reagent reacts with the sulfur in the exhaust gas stream, it becomes transformed into $CaSO_4$ - gypsum - which can be landfilled inexpensively (a direct cost) or collected and sold to wallboard manufacturers (a recovery credit). These credits,

must be calculated as net of any associated processing, storage, transportation, and any other costs required to make the recovered materials or energy reusable or resalable. Great care and judgment must be exercised in assigning values to recovery credits, since materials recovered may be of small quantity or of doubtful purity, resulting in their having less value than virgin material. Like direct annual costs, recovery credits are variable, in that their magnitude is directly proportional to level of production.

A more thorough description of these costs and how they may be estimated is provided in Section 2.6

2.5 Financial Concepts

Firms have latitude in developing compliance strategies. For standards that are performance oriented, firms have great latitude. Even for standards that are fairly prescriptive and technical in nature, firms still have to make some choices on how to comply. How do they compare these choices or alternatives?

Alternatives will usually have expenditures at multiple times. Not only may the expenditures be different but the timing of expenditures may also be different. When comparing two different investment opportunities, how do you distill all of these data into one comprehensive and coherent form so that an informed decision can be made? This section deals with a number of the concepts and operations that are needed to make a meaningful comparison. They include: selection of an appropriate timeframe, addressing the time value of money, adjusting for prices over time, and selection of the appropriate measure of cost.

2.5.1 Time Frame

To compare two alternatives in a meaningful way, the comparison is more meaningful when the alternatives are examined over the same time frame or calculate the net present value of the alternatives. For example, if one alternative uses a control device that lasts two years and another alternative uses a device that lasts three years, the alternatives may be difficult to compare directly because of the inconsistent lifetimes of the devices. One approach to developing a more meaningful comparison would be to assume a common time frame by using each type of device for six years, with the two-year alternative being replaced two times and the three-year alternative being replaced once. Another approach is to calculate the net present value of the two alternatives. Amortization or the EUAC method also can be helpful in comparing alternatives with different lifetimes.

2.5.2 Interest Rates

Firms may borrow to finance the expenses associated with their compliance strategies. The interest rate at which a firm borrows is a key component in estimating the total costs of compliance. Financial markets set different interest rates for different activities depending on many factors.

The three factors that are relevant to this Manual are: time value of money, inflation risk, and credit risk of borrowers.

Time value of money reflects the timing aspect of borrowing money—a firm would like to borrow now and pay back later and a financial institution would like to lend now and collect later. The time value of money is also known as the real interest rate. Financial institutions know that the price of goods and services will probably increase in the future, but they don't know by how much. So they hedge against this risk by building in a premium for this risk. The credit risk of borrowers refers to the risk associated with whether the loan will be paid back. The credit risk premium will depend on the credit rating of the borrowing firms.

The interest rates that firms face are nominal interest rates. For the rest of the discussion, this Manual assumes that the credit risk of borrowers is essentially zero. Removing the inflation adjustment from the nominal interest rate yields the real rate of interest - the actual cost of borrowing from a societal perspective. In equation form, the nominal interest rate (*i*) equals the ex ante real interest rate (*i_r*) plus the expected rate of inflation (p^e) plus the product of the expected inflation rate and the real interest rate as seen in Equation 2.3.

$$i = ir + p^{e} + ir p^{e}$$

$$(2.3)$$

This is the well-known Fisher Equation. Since the product of the ex ante real interest rate and expected inflation is small, Equation 2.3 simplifies to:

$$i = ir + p^e$$

When performing cost analysis, it is important to ensure that the correct interest rate is being used. Because this Manual is concerned with estimating private costs, the correct interest rate to use is the nominal interest rate, which is the rate firms actually face. Accounting for inflation should be done separately rather than using the real interest rate.

The determination of appropriate private nominal interest rates is important for analyses of private costs done for permit applications where the costs assessed are for the permitted source. Different firms may structure how they finance their purchases differently. Some may choose to finance their purchases through cash holding or other means of equity; some may choose to borrow to finance their investment. When firms choose to borrow, depending on the size of the investment, borrowing could be structured very differently at very different interest rates given the choices firms have for financing an investment. For permit applications, if firmspecific nominal interest rates are not available, then the bank prime rate can be an appropriate estimate for interest rates given the potential difficulties in eliciting accurate private nominal interest rates since these rates may be regarded as confidential business information or difficult to verify. The bank prime rate is published by the Board of Governors of the Federal Reserve System.⁷ The bank prime rate is the "rate posted by a majority of the top 25 (by assets in domestic offices) insured U.S. chartered commercial banks. The bank prime rate is one of several base rates used by banks to price short-term business loans."⁸ Analysts should use the bank prime rate with caution as these base rates used by banks do not reflect entity and project specific characteristics and risks including the length of the project, and credit risks of the borrowers.

For input to analysis of rulemakings, assessments of private cost should be prepared using firm-specific nominal interest rates if possible, or the bank prime rate if firm-specific interest rates cannot be estimated or verified. If neither of these types of private nominal rates are available, then the cost analysis should use 3% or 7%, rates that are used for social cost estimation as discussed later in this section, as a default. Analysts should be especially cautious using 3% and 7% rates in assessing cost of short term assets or projects. These rates represent long-run, real interest rates as described later in this section. Conflating real and nominal interest rates may lead to different conclusions than using consistent interest rates throughout the analysis. Private interest rates are but one component of the overall cost analysis, which will include social cost estimation to reflect relevant guidance from OMB.

To clarify potential confusion that might arise, this Manual discusses the difference between private interest rate and social discount rate. If capital markets are perfect with no distortions (e.g., no taxes, no risk), then the return to savings (the consumption rate of interest) equals the return on private sector investments. Therefore, when the government needs to convert future costs and benefits into present value terms in the same way as the affected individuals would do so, it should also discount using this single market rate of interest. In other words, in this "first best" world, the private market interest rate would be an unambiguous choice for the social discount rate. However, 'real-world' issues make the issue much more complicated. For example, private sector investment returns are taxed (often at multiple levels), capital markets are not perfect, and capital investments often involve risks reflected in market interest rates (i.e., lenders charge riskier projects higher rates of interest to compensate for lenders' risk). All of these factors drive a wedge between the social rate at which consumption can be traded through time (the pretax rate of return to private investments) and the rate at which individuals can trade consumption over time (the post-tax consumption rate of interest).

As stated earlier, interest rate accounts for the time value of money, inflation, and other premiums, including risks, faced by lenders. The social discount rate is the rate at which society can trade consumption through time (i.e., the time value of money). When assessing the societal effect of regulations, such as for EPA rulemakings that are economically significant according to Executive Order 12866, analysts should use the 3% and 7% real discount rates as specified in the U.S. Office of Management and Budget (OMB)'s Circular A-4 [6]. The 3% discount rate represents the social discount rate when consumption is displaced by regulation and the 7% rate

⁷ Board of Governors of the Federal Reserve System. "Selected Interest Rate (Daily) – H.15." Available at: https://www.federalreserve.gov/releases/h15/ (Accessed August 4, 2017).

⁸ Board of Governors of the Federal Reserve System. "Selected Interest Rate (Daily) – H.15." Available at: https://www.federalreserve.gov/releases/h15/ (Accessed August 4, 2017).

represents the social discount rate when capital investment is displaced. Regardless, these are real social discount rates that are riskless. Therefore, they are not appropriate to use to assess private costs that will be incurred by firms in making their investment decisions. In assessing these private decisions, interest rates that face firms must be used, not social rates.

2.5.3 Prices and Inflation

With changes in prices over time for all relevant goods and services such as capital equipment, engineering services, other materials and reagents used in the construction and operation of control equipment, inflation's impacts on prices and their effect on cost estimates is of concern to Manual users. The prices in the Manual were not standardized. Some chapters had prices for materials and reagents developed in the late 1990s, and other chapters had prices developed from as far back as 1985. Because these differences were not explicitly discussed in these earlier additions, the Agency attempted to standardize all prices into a particular base year's dollar in subsequent editions of the Manual to reduce the chance for analytical error. In the sixth edition of the Manual, EPA updated all the costs to at least 1990. For the seventh edition of the Manual, EPA will update the costs to at least 2012.

Updating costs for this Manual is an effort with a goal of standardizing all costs to one base year for a particular analysis. Each chapter of the Manual fully discloses the limitations of the costing information found in that chapter. This allows the analyst to make any adjustment they deem necessary, provided sufficient basis exists, and assuming the approval of the appropriate regulatory agency.

To develop the costs used in each of the chapters of this Manual, we attempted to survey the largest possible group of vendors and collected information from industry literature and other technical reports to determine an industry average price for each cost component. In many cases, this involved contact with a number of vendors, including trade associations, and the assimilation of large amounts of data. In other cases, the pollution control equipment was supplied by only a few vendors, which limited the robustness of our models. And, in still other cases, the number of existing manufacturers or the highly site-specific nature of their installation made it difficult for us to develop robust prices for some components. While recognizing the difficulties in providing manufacturer-specific or site-specific information, this Manual also knowledges that timeliness of such information is important. If the survey information is not timely, errors to the cost estimation would be introduced in unknown ways. Thus, every effort is made to update the information in as timely a manner as possible.

In collecting and using prices in estimating pollution control costs, one should be cognizant of the effect of inflation. We can define prices in "real" and "nominal" terms. Real and nominal prices act in the same way as real and nominal interest rates. Nominal prices are actual prices (i.e., the sticker or spot price) and represent the value of a particular good at a particular point in time. Real prices remove the effect of inflation. The reason for using real price is that purchases may happen over several years especially for projects that invest heavily in capital. Because purchasing power in any given year may be different than other years, combining nominal prices is like mixing apples and oranges.

This Manual uses real prices for estimation of capital costs (in this case, an older capital cost to a more recent year), and other costs for any given cost analysis, not nominal prices. Using a price of reagent, catalyst, or other cost input to reflect possible price changes over the equipment lifetime is not correct in adjusting for inflation. Hence, the inclusion of price inflation via escalation estimates or having input prices reflect price changes over time as part of capital cost estimation is not allowed under the Control Cost Manual Methodology. The capital cost should be estimated for the time that the cost estimate is prepared, and should not be escalated to some future year, such as an anticipated date that construction will be completed or some other future year unless the analyst has a robust method to forecast future inflation. A linear extrapolation of past inflation is not a robust method of forecasting future inflation.

Adjusting nominal prices to real prices involves establishing a base year for comparison purposes and then creating an adjustment factor for each year's prices relative to those in the base period. This adjustment factor is a price index (PI) that can then be used to adjust nominal prices to an equivalent base year value; derived through the following formula:

For example, if the price of a reagent in 2010 is 100, and we want a reagent price for 2012, then an index value of 1.2 for that reagent price between 2012 and 2010 will yield a 2012 price of 120. The Federal government and industry develop a variety of indexes tailored to the analysis of specific price issues. The most recognizable of these indexes are the Consumer Price Index (CPI), the Producer Price Index (PPI) and Gross Domestic Price (GDP) implicit deflator, which investigate the change in prices across the entire economy. The most relevant price index for private cost estimation is PPI, and PPI is provided at the 6-digit North American Industry Classification System (NAICS) level. However, for some equipment and materials, even a 6-digit NAICS code level PPI may be too general for the specific needs of industry in the course of an analysis and should only be used if other indexes, particularly well-documented indexes for specific industries, materials, or uses, are not available.

The CPI is not recommended because the price change of interest is among consumer goods and services which have little relevance to capital project spending or industrial intermediate goods such as raw materials such as reagents [8]. The Gross Domestic Product (GDP) implicit price deflator measures broad price changes in the economy rather than CPI, which is a measure of only goods bought by consumers. PPI is a measure of inflation faced by

industries.⁹ Other indexes are also available from industry and academic sources through the Internet, industry publications, trade journals, and financial institutions. One index that has been used extensively by EPA for escalation purposes is the Chemical Engineering Plant Cost Index (CEPCI), an index that tracks costs of equipment, construction labor, buildings, and supervision in chemical process industries.¹⁰ Other cost indexes exist, such as Marshall & Swift (M&S), another equipment cost index that is widely used.¹¹

It should be noted that the accuracy associated with escalation (and its reverse, deescalation) declines the longer the time period over which this is done. Escalation with a time horizon of more than five years is typically not considered appropriate as such escalation does not yield a reasonably accurate estimate. [9] Thus, obtaining new price quotes for cost items is advisable beyond five years. If longer escalation periods are unavoidable due to limited recent cost data that is reasonably available, then the analysis should use the principles in this Manual chapter to provide as accurate an escalation as possible consistent with the Manual given the limitations of the cost analysis. The appropriate length of time for escalation can vary as a result of significant changes in the cost of major production inputs (e.g., energy, steel, chemical reagents, etc.) and technological changes in control measures, particularly if these changes occur in an unusually short period of time. Hence, shorter time periods for escalation and de-escalation are clearly preferred over longer ones.

2.5.4 Financial Analysis

Firms make purchase decisions that occur at different times for different durations and schedule paybacks which also occur at different times as well. Because of these reasons, the following financial analysis tools are necessary because they allow firms, state regulators, and other users of the Manual to be able to compare the costs of different compliance strategies.

2.5.4.1 Net Present Value

The process through which future cash flows are translated into current dollars is called present value analysis. When the cash flows involve income and expenses, it is also commonly referred to as net present value (NPV) analysis. In either case, the calculation is the same: adjust the value of future money to values based on the same year (generally year zero of the project), employing an appropriate interest (discount) rate and then add them together, after all income and expenses have been converted into the same year dollar using appropriate price indices.

Derivation of a cash flow's net present value involves the following steps:

⁹ U.S. Bureau of Labor Statistics. "Comparing the Consumer Price Index with the gross domestic product price index and gross domestic product implicit price deflator." Monthly Labor Review. March 2016.

¹⁰ This index is available at http://www.chemengonline.com/pci. It is also available in Chemical Engineering magazine. Mention of this index is not meant to offer commercial endorsement by EPA.

¹¹ More information on this cost index can be found at http://www.corelogic.com/products/marshall-swift-valuation-service.aspx.

- Identification of alternatives. For example, the choice between a fabric filter/baghouse and an electrostatic precipitator (ESP) for removing particulate matter (PM) from a flue gas stream.
- Determination of costs and cash flows over the life of each alternative. Each of the subsequent chapters of this Manual offers detailed costing information on specific air pollution control devices and equipment.
- Determination of an appropriate real interest or discount rate(s). The appropriate interest rate in private cost assessment is the private interest rate for each firm affected. Determining private interest rates may be difficult due to the firm-specific nature of the private nominal interest rates faced by firms. If firm-specific private nominal interest rates are available, then the appropriate rates are simply the difference between the nominal interest rate minus the prevailing inflation in the industry. Industrial and other users of this Manual should consult with their financial officers and/or trade associations for input regarding such rates. More extensive discussion of interest rates can be found earlier in this Manual in Section 2.5.2. If discounting is performed using the same rate across all alternatives, ranking of alternatives by cost will always yield the same order, no matter which rate is used.
- For each alternative: Calculate a discounting factor for each year over the life of the equipment. The discount factor formula is: $DF_t=\{1/(1+i)^t\}$ where i is the discount rate and t is the number of years. For example, using a seven percent discount rate produces discount factors of: 0.9346, 0.8734, 0.8163, 0.7629, and 0.7130 for the 1st, 2nd, 3rd, 4th, and 5th years of a piece of equipment's life, respectively. Table A.1 in Appendix A displays discount factors for interest rates from 5.5 to 15 percent, in half-percent increments for 25 years.
- For each year's cash flows, sum all incomes and expenses to determine the net cash flow for that year in nominal terms.
- Multiply each years' net cash flow by the appropriate discount factor.
- Sum the discounted net cash flows to derive the net present value.

Compare the net present values from each alternative. The net present value of a stream of cash flows over the life of an investment can be calculated using equation 2.6:

$$NPV = \sum NCF_t * [i/(1 - (1 + i)^{-t})]$$
(2.6)

where NCF_t represents the net cash flow for year *t*, and *i* is the interest rate.

•

If discounting is performed using a uniform rate across different mutually exclusive alternatives, ranking of alternatives by cost or net cash flow will always yield the same order, no matter which rate is used or cost approach is employed.

2.5.4.2 Amortization: Equivalent Uniform Annual Cost and Annualization

Net present value (NPV) analysis allows us to evaluate between investments by summing the present value of all future incomes and expenses, but that does not give us an insight into the expected cash flows that will actually occur. NPV allows for comparison of alternatives by compressing the value of cost streams or return on investments over same or different time horizons to a single point in time. It's as though regulated entities are paying up front for all the future costs of installation, maintenance, and operation of a pollution control device. However, firms may want to pay back their expenses in equal sums over the life of the control. A common engineering cost tool for this sort of evaluation is called the equivalent uniform annual cash flow (EUAC) approach. [4] In the finance literature, this approach is called amortization.

EPA uses the EUAC approach as the basis for the Control Cost Methodology for the following reason:

• The methodology is general enough to be used for estimating costs for any pollution control measure applied to any industry. In this respect, the EUAC is different from the levelized cost method (LCM), which is a method specific to the electric power industry and requires relatively extensive information to be applied properly as compared to application of the EUAC. The EUAC thus provides consistency in cost analysis of pollution control measures for sources in all industries as part of actions for which the Control Cost Manual is applicable. [7]

Annualization is a process similar to EUAC but is not limited to constant cash flows. It involves determining the NPV of each alternative equipment investment and then determining the equal payment that would have to be made at the end of each year to attain the same level of expenditure. In essence, annualization involves establishing an annual "payment" sufficient to finance the investment for its entire life, using the formula:

$$PM T = NPV^{*}(i/1 - (1+i)^{-n})$$
(2.7)

where PMT is the equivalent uniform payment amount over the life of the control equipment, n, at an interest rate, *i*. NPV indicates the present value of the investment as defined above in equation 2.6.

This payment is the capital recovery cost (*CRC*), which is calculated by multiplying the *NPV* of the investment by the capital recovery factor (*CRF*):

$$CRC = NPV \times CRF$$
 (2.8)

where *CRF* is defined according to the formula:

$$CRF = i(1+i)^n / ((1+i)^n - 1)$$
(2.8a)

The *CRF* equation is a transformation of the *PMT* form in equation 2.7 and returns the same information. Table A.2 in Appendix A lists the *CRF* for interest rates between 5.5 percent and 15 percent for annualization periods from one to 25 years.

The life of the control is defined in this Manual as the equipment life. This is the expected design or operational life of the control equipment. This is not an estimate of the economic life, for there are many parameters and plant-specific considerations that can yield widely differing estimates for a particular type of control equipment.

The life of the control is appropriate to use when the analytic timeline or the length of the analysis is longer than the useful life of the control equipment. If the analytic timeline is shorter than the useful life of the control equipment, use the analytic timeline to annualize the capital cost.

It is crucial that the analyst use the same interest or discount rate to estimate costs using NPV and when amortizing (i.e., EUAC).

2.6 Estimating Procedure

The estimating procedure used in the Manual consists of five steps: (1) obtaining the facility parameters and compliance options for a given facility; (2) preparing the control system design; (3) sizing the control system components; (4) estimating the costs of these individual components; and (5) estimating the costs (capital and annual) of the entire system.

2.6.1 Facility Parameters and Regulatory Options

Obtaining the facility parameters and regulatory options involves not only assembling the parameters of the air pollution source (i.e., the quantity, temperature, and composition of the emission stream(s)), but also compiling data for the facility's operation. (Table 2.2 lists examples of these.) We identify two facility parameters: intensive (with values independent of quantity or dimensions) and extensive (size-dependent variables, such as the gas volumetric flow rate).

Compliance options are usually specified by others (generally a regulatory authority) and are often technology driven, typically defining allowable ways to achieve a predetermined emission limit. These options range from "no control" to a requirement for the system to reach the maximum control technically achievable. The options allowed will depend, firstly, on whether the emission source is a point source (a stack or other identifiable primary source of pollution), a fugitive source (a process leak or other source of pollution that could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening) or an area fugitive source (an unenclosed or partly enclosed area, such as a storage pile or a construction site). Stacks are normally controlled by "add-on" devices - the primary focus of this Manual. (However, some of these devices can be used to control process fugitive emissions in certain cases, such as a fabric filter used in conjunction with a building evacuation system.) Add-on or end-of-pipe pollution controls are normally used to meet a specified emission limit, although in the case of particulate emissions, they may also be required to meet an opacity level.

Facility Parameters	Compliance Options
Intensive	No control
Facility status (new or existing, location)	
Gas Characteristics (temperature, pressure,	Add-on devices
moisture control)	Emission limits
Pollutant concentration(s) and/or particle size distribution	Opacity limits
Extensive	Process modification
Facility capacity	Raw material changes
Facility life	Fuel substitution
Exhaust gas flow rate	
Pollutant emission rate(s)	Source/Feedstock pretreatment Coal desulfurization Wet dust suppression

 Table 2.2: Facility Parameters and Compliance Options

2.6.2 Control System Design

Preparing the control system design for an end of pipe device at a plant involves deciding what kinds of systems will be priced (a decision that will depend on the pollutants to be controlled, exhaust gas stream conditions, and other factors), and what auxiliary equipment will be needed. When specifying the auxiliary equipment for a typical add-on control device (e.g., a coal fired FGD scrubber), several questions may need to be answered, among others, depending on the specific control device:

• What is the fuel's (in this case, coal's) sulfur content? What is the content of other toxic substances in the fuel (heavy metals, mercury)?

- How many absorber modules will be needed?
- Does the exhaust stream pose any hazard to the materials of the hoods, ducts, fans, and other auxiliary equipment? Is the exhaust caustic or acidic? Is it abrasive? Does the treatment of the exhaust render it caustic or acidic?
- Does the exhaust stream require any pre-treatment (e.g., particulate control equipment, which will likely be in operation at the source) before it enters the control device?
- Will the captured pollutants be disposed of or recycled? How will this be done? Will a salable byproduct be produced (e.g., gypsum for drywall)?
- Can the on-site capacity (e.g., utilities, stockpiling space) accommodate the added requirements of the control system? Is additional wastewater and solid waste disposal capacity needed?

2.6.3 Sizing the Control System

Once the system components have been selected, they must be sized (i.e., the correct size of components must be determined). Sizing is probably the most critical step because the assumptions made in this step will more heavily influence capital investment than any other. Table 2.3 lists examples of these parameters. Also listed in Table 2.3 are general parameters which must be specified before the purchased cost of the system equipment can be estimated. Note that, unlike the control device parameters, these parameters may apply to any kind of control system. They include materials of construction (which may range from carbon steel to various stainless steels to fiberglass-reinforced plastic), presence or absence of insulation, and the equipment or useful life of the system. As indicated in Section 2.4.2, this last parameter is required for estimating the annual capital recovery costs as long as the analytic length exceeds the useful life of the equipment. The lifetime not only varies according to the type of the control system, but with the severity of the environment in which it is installed. Each of the control-specific chapters of this Manual include a comprehensive list of the specific parameters that must be considered for each device.

F • • • F • •	
General	Device-Specific
Material of construction: carbon steel	Gas-to-cloth ratio (critical parameter): 3.0 to 1
Insulated? Yes	Pressure drop: 6.0 in w.c. (inches water column)
Equipment life: 30 years	Construction: standard (vs. custom)

Table 2.3: Examples of Typical Control Device Parameters [3]

Redundancy ^a : none	Duty: continuous (vs. intermittent)
	Filter type: shaker
	Bag material: polyester, 16-oz.

^a Refers to whether there are any extra equipment items installed (e.g., fans) to function in case the basic items become inoperative, so as to avoid shutting down the entire system. Please note that values in this table are shown only for illustrative purposes.

2.6.4 Estimating Total Capital Investment

2.6.4.1 General Considerations

The fourth step is estimating the purchased equipment cost of the control system equipment. As discussed in Section 2.2, total direct cost includes purchased equipment cost, which in turn, is the sum of the base equipment cost (control device plus auxiliaries), freight, instrumentation, and sales tax. The values of these installation factors depend on the type of the control system installed and are, therefore, listed in the individual Manual chapters dedicated to them. These costs are available from this Manual for the most commonly used add-on control devices and auxiliary equipment, with each type of equipment covered in a separate chapter (see Table of Contents and the discussion in Chapter 1). Total Direct Cost also includes Direct Installation Cost, which contains many of the cost categories included in Section 2 of this Manual, Generic Equipment and Devices.¹²

As mentioned previously, most of the costs in each of the subsequent sections of this Manual were derived from data obtained from reputable control equipment vendors. For many control devices there are many vendors, which allowed us to offer robust average costs of components submitted by large samples of vendors in response to Agency survey efforts. [10] For items that are mass produced or "off-the-shelf" equipment, vendors provided a written quotation listing their costs, model designations, date of quotation, estimated shipment date, and other information. For other equipment there are not as many vendors or we did not receive sufficient number of responses to our inquiries, resulting in small samples. Thus, there could be a limited number of observations in the data sets available for estimation of average costs. In these cases, we offer these average costs and the cost discussion in that control's particular chapter offers appropriate caveats to the analyst.

For some controls, no amount of vendor data would have made our cost numbers more accurate because the control in question is either so large or so site-specific in design that suppliers design, fabricate, and construct each control according to the specific needs of the facility. For these kinds of controls, the vendor may still give quotations, but will likely take much longer to do so and may even charge for this service, to recoup the labor and overhead expenses of his estimating department. When performing a cost analysis, the cost of the quotation is a part of the TCI.

¹² Estimates of TCI for some control measures may not necessarily be calculated in this way due to availability of public information on capital investment costs and equations for those measures, such as the SNCR and SCR chapters in this Manual.

Generally, vendor quotes are "F.O.B." (free-on-board) for the vendor, meaning that no taxes, freight, or other charges are included. For these equipment, the analyst must take care to identify and include the cost of transportation, taxes, and other necessary charges in the TCI (see Figure 2.1). The costs of freight, instrumentation, and sales tax are calculated differently from the direct and indirect installation costs. These items are developed by multiplying the base equipment cost (F.O.B. the vendor) by an industry-accepted factor. Unlike other estimating factors that differ from system to system, installation factors are essentially equal for all control systems. [10] Table 2.4, below, displays values for these factors.

	% of Total Equipment Cost, FOB						
Cost	Range	Typical					
Freight Sales Tax	0.01 - 0.10 0 - 0.08	0.05 0.03					
Instrumentation	0.05- 0.30	0.10					

 Table 2.4: Cost Ranges for Freight, Sales Tax, and Instrumentation

To some extent, the application of an appropriate factor requires the subjective application of the analyst's best judgment. For example, the range in freight costs is, in part, a function of the distance between the vendor and the site. The lower end of the factor range represents shorter distance deliveries, while the upper end of the range would reflect freight charges to remote locations such as Alaska and Hawaii. [10] The sales tax factors simply reflect the range of local and state tax rates currently in effect in the United States. [10] In some locations, and for many institutional and governmental purchases, sales taxes do not apply; (hence the zero value at the low end of the sales tax factor range). The range of instrumentation factors is also quite large. For systems requiring only simple continuous or manual control, the lower factor would apply. However, if the control is intermittent and/or requires safety backup instrumentation, the higher end of the range would be applicable. [10] Finally, some "package" control systems (e.g., incinerators covered in Chapter 3) have built-in controls, with instrumentation costs included in the base equipment cost. In those cases, the instrumentation factor to use would, of course, be zero.

Regarding the amount of labor for construction and installation of a control device, EPA has prepared a number of analyses that include estimates for power plants in particular. These analyses are extensive in nature, and we refer readers wanting more information to appendixes in several recent Regulatory Impact Analyses (RIAs) that include employment data for various add-on control devices, including some of the control devices found in the Control Cost Manual.¹³

¹³ One example of this is Appendix 6A in the RIA for the Mercury and Air Toxics Standards (MATS), which provides an estimate of the labor necessary to construct and install an FGD scrubber on a coal-fired power plant

2.6.4.2 Retrofit Cost Considerations

Probably the most subjective part of a cost estimate occurs when the control system is to be installed on an existing facility. Unless the original designers had the foresight to include additional floor space and room between components for new equipment, the installation of retrofitted pollution control devices can impose an additional expense to "shoe-horn" the equipment into the right locations. For example, an SCR reactor can occupy thousands of square feet and may be installed directly behind a boiler's combustion chamber to offer the best environment for NOx removal. Many of the utility boilers currently considering or have installed an SCR reactor to meet Federal or other NOx limits are over thirty years old - designed and constructed before SCR was a proven technology in the United States. For these boilers, there is often little room for the reactor to fit in the existing space and additional ductwork, fans, and flue gas heaters may be needed to make the system work properly.

To quantify the additional costs of installation not directly related to the capital cost of the controls themselves, engineers and cost analysts typically multiply the cost of the system by a retrofit factor. The proper application of a retrofit factor is as much an art as it is a science, in that it requires a good deal of insight, experience, and intuition on the part of the analyst. The key behind a good cost estimate using a retrofit factor is to make the factor no larger than is necessary to cover the occurrence of expected (but reasonable) extra costs for demolition and installation. Such expected but extra costs include - but are certainly not limited to - the unexpected magnitude of anticipated cost elements; the costs of unexpected delays; the cost of re-engineering and refabrication; and the cost of correcting design errors.

The magnitude of the retrofit factor varies across the kinds of estimates made as well as across the spectrum of control devices. The retrofit factor is calculated as a multiplier applied to the TCI. For instance, if a retrofit factor of as much as 50 percent can be justified, then the retrofit factor in the cost estimate is 1.5. For systems installed at the end of the stack, such as flares, retrofit uncertainty is typically a factor. In these cases, an appropriate retrofit factor may be as little as one or two percent of the TCI. In complicated systems requiring many pieces of auxiliary equipment, it is not uncommon to see retrofit factors of much greater magnitude being used.

Since each retrofit installation is unique, no general factors can be developed. Nonetheless, if necessary, some general information can be given concerning the kinds of system modifications one might expect to be considered in developing a retrofit factor:

1. <u>Handling and erection</u>. Because of a "tight fit," special care may need to be taken when unloading, transporting, and placing the equipment. This cost could increase

boiler. This RIA can be found at <u>http://www.epa.gov/ttn/ecas/regdata/RIAs/matsriafinal.pdf</u>. In addition, the RIA for the Cross-State Air Pollution Rule (CSAPR) provides estimates of the labor necessary to construct and install an SCR, dry sorbent injection (DSI) and FGD scrubber on coal-fired power plant boilers. The CSAPR RIA can be found at <u>http://www.epa.gov/airtransport/pdfs/FinalRIA.pdf</u>.

significantly if special means (e.g., helicopters) are needed to get the equipment on roofs or to other inaccessible places.

- 2. <u>Site Preparation.</u> Site preparation includes the surveying, clearing, leveling, grading, and other civil engineering tasks involved in preparing the site for construction. Unlike the other categories, this cost may be zero or decreases, since most of this work would have been done when the original facility was built [11]. However, if the site is crowded and the control device is large, the size of the site may need to be increased and then site preparation may prove to be a major source of retrofit related costs. As mentioned earlier in the chapter, if additional land is purchased to accommodate the installation of the control equipment, this cost needs to be added in as well. If other production related equipment must be relocated to allow for the installation of the control equipment, the cost associated with the relocation needs to be included.
- 3. <u>Off-Site Facilities</u>. Off-site facilities should not be a major source of retrofit costs, since they are typically used for well-planned activities, such as the delivery of utilities, transportation, or storage.
- 4. <u>Limited Space for Staging Equipment</u>. During construction, materials and equipment are transported, received, and stored on site. These commodities are marked, arranged, and placed in a sequence for retrieval by construction crews prior to final installation. In many ways, the storage yard on a construction site represents a depot with shipments being received from vendors and commodities being constantly repositioned to facilitate retrieval to meet a scheduled installation sequence. For large sites, repositioning becomes less of an issue; however, for small limited area sites, repositioning items in the construction queue becomes a major logistical effort, and in some cases, requires JIT (just-in-time) delivery to allow for direct off-loading from carrier and then straight to installation. To allow schedule flexibility (for the unseen), equipment can be stored off-site (for a fee) or at the fabricator's shop (once again, for a space rental fee).
- 5. <u>Transportation</u>. The delivery of equipment is more than the arrival of commodities at plant site. It is the examination of the destination route from shop to plant site with all special aspects taken into consideration, such as: road bearing limitations, bridge overpass height restrictions, permits for oversized shipments (extra wide loads), required special escorts, time-of-day transit limitations (non-traffic hour, weekends only), railway restrictions, waterway provisions (locks, docking, piloting), tunnel limitations. Depending on the site's location in relationship to the origin point, the typical transit route for normal cargo shipments yields to alternate routes and times for large special shop fabricated assemblies.

6. <u>Lost Production</u>. The shut-down for installation of a control device into the system should be a well-planned and anticipated event, and typically occurs during routine, scheduled outages. As such, its cost should be considered a part of the indirect installation cost (start-up). However, unanticipated problems with the installation due to retrofit-related conditions if they happen could impose significant costs on the system. Retrofit factors should be reserved for those items directly related to the demolition, fabrication, and installation of the control system. A contingency factor should be reserved (and applied to) only those items that could incur a reasonable but unanticipated increase but are not directly related to the demolition, fabrication of the system. For example, a hundred year flood may postpone delivery of materials, but their arrival at the job site is not a problem unique to a retrofit situation. If the shut-downs do not occur in a well planned and routine manner, any additional foregone production of goods and products would need to be included as a private cost attributable to the retrofit cost.

It is important to consider the type of contract and its influence on contingency factors. The two types of major contract vehicles that exist for the buyer (owner) to issue to a seller (vendor) are: lump-sum / fixed price and cost-plus. Between these extremes, a myriad of hybrids exists. The lump-sum contract vehicle stipulates a fixed price for delivery of a product performing to specified conditions set by the buyer with all materials, services, engineering/design, installation, and commissioning supplied by the seller. Under this fixed price, the seller is at financial risk for delivering a conforming product at the contracted price; corrections to attain conformance and cost overruns are at the seller's expense; however, realized savings are solely to the seller's benefit. The buyer's risk involves changes to the supplied product outside of contractually agreed upon conditions due to unforeseen events or issues. Under such contracts, the engineering contractor assumes the majority of the risk. A cost-plus vehicle allows the buyer to pay for actual expenses incurred by the vendor (materials, labor, engineering / design, etc.) without mark-up plus an agreed upon surcharge to cover the vendor's overhead and profit. The owner is at risk because this type of contract can become open-ended; however, the buyer has extreme control over the cost process and can terminate the project at any time without penalty. The seller settles for minor risk while forgoing the chance to realize cost efficient savings; however, an assured profit margin exists. This is also known as a "time and materials" contract. In between these two extreme contract vehicles, a multitude of blended hybrids exist to suit both buyer and seller and blend the likenesses of each; for example: lump sum + fee, cost-plus + award with shared savings / overruns, lump sum on materials / cost plus on labor, and many more. Contingency cost placement differs between the two vehicles. For cost-plus contracts, the owner determines the contingency amount set aside; for lump-sum / fixed price contracts, the seller determines contingency allowances, (which is reflected in the price).

Project execution typically follows one of two forms: Design-Build (DB) or Design, Bid, Build (DBB) [12]. A contract issued under Design-Build conditions allows the buyer to have a single entity contact (supplier) which performs the engineering, design, purchasing and installation for the vended product plus retains responsibility for that product. DB project execution operates under shorter time schedule since the single entity can design, procure, and construct

simultaneously from commencement through completion. The owner's main disadvantage becomes losing control over the design process and selection of equipment, which consequently affects cost. While DB is a common term, it is better known as EPC (engineer, procure, construct), EPCM (engineer, procure, construct, manage), and EPM (engineer, procure, manage with construction under separate contract). DBB project execution follows a more deliberate path with each phase completed before the next. The design phase involves hiring an architect/engineering firm (via contract vehicle) create a complete documentation package for a product. This involves specifications, drawings, fabrication drawings, construction drawings, and all documentation necessary for competitive bid to supply materials, commodities, and construction services for installation. General contractors bid on this design package and a bid is selected. This type of project execution distinctly separates the design/engineering phase from the procurement and installation phase, but takes longer to implement. The method's main advantage allows revising design before equipment and services are procured.

Regardless of execution form selected (DB or DBB), the buyer tends to become involved with the vendor's process (to varying degrees) to coordinate activities between the owner's staff and the supplier's personnel. There is one exception to this case, and it is termed the "turnkey" project. In its purest sense, the buyer's involvement on a turnkey project is negligible; the owner meets the supplier on the first day to award the contract and returns on the final day to receive ownership. In reality, the buyer exercises minor involvement to ensure ongoing progress.

Lump-sum or EPC contracts are generally awarded on the basis of a competitive tender and often lead to the lowest direct cost compared to other type of contracts. These contracts are often turnkey in nature. Thus, these contracts will have larger contingencies than engineer, procure, construction, and management (EPCM) contracts. EPCM contractors are paid when their costs are incurred (cost-reimbursable contracts) and the owner assumes more of the risk (though the owner has more flexibility to specify changes during construction). Most contracts awarded to pollution control vendors are EPC or turnkey due to their shorter time schedules.

Contingency also accounts for inadequacies in cost estimating methods and for expected unknowns that may arise during project execution. The contingency funds are born by the owner or by the supplier, depending on contract vehicle issued. In any case, it is reflected in the TCI. Contingency is inversely proportional to the level of accuracy for a cost estimate. A study-level cost estimate, which is the level of analysis accuracy for estimates arrived at using the Control Cost Methodology, will have a higher contingency as compared for a more accurate (20% probable error) cost estimate that was arrived at with a greater amount of data and effort. Contingency can also vary depending primarily on the age of the technology. For mature control technologies, which reflect the control technologies covered in the other chapters of this Manual, the contingency can range from 5 to 15% of the TCI [3] This contingency is quite consistent with

general cost guidance for mature or well-known technologies.¹⁴ Finally, contingency should not account for events such as price escalation, work stoppages, and disasters. [13]

2.6.5 Estimating Annual Costs

Determining the total annual cost is the last step in the estimating procedure. As mentioned in Section 2.3 the total annual cost is comprised of three components—direct and indirect costs and recovery credits. Some cost items are annual; others are multi-year. Unlike the installation costs, which are factored from the purchased equipment cost, annual cost items are usually computed from known data on the system size and operating mode, as well as from the facility and control device parameters.

Following is a more detailed discussion of the items comprising the total cost. (Values/factors for these costs are given in the chapters for individual devices.)

2.6.5.1 Raw Materials

Raw materials may be needed with control systems. Examples would be chemicals used in gas absorbers or venturi scrubbers as absorbents or to neutralize acidic exhaust gases (e.g., hydrochloric acid). Chemicals may also be required to treat wastewater discharged by scrubbers or absorbers before releasing it to surface waters. If the source uses the same raw materials for production, the analyst must be careful to include only are only those costs that are attributable to the raw materials needed by the control device. Quantities of chemicals required are calculated via material balances, with an extra 10 to 20% added for miscellaneous losses on average. Specifying one or several sources for a recent reagent cost should be sufficient for cost estimation that is consistent with the Control Cost Methodology. Costs for chemicals are available from vendors, governmental sources such as the U.S. Geological Survey (USGS), and from ICIS Chemical Business, IHS Chemical Week, and similar well-recognized business publications.¹⁵ A list of well-regarded sources for chemicals used as reagents in pollution control operations and other industrial chemical operations and processes can be found at university library web sites, with one maintained by Texas A&M's University Library being a particularly good example.¹⁶ If the price of these reagents and raw materials become more volatile and deviate significantly from historical price trends, then the analyst is advised to take this into account in assessing the cost of material.

2.6.5.2 Labor

This section discusses the amount of labor required to operate and maintain a pollution control system. The necessary labor depends on the system's size, complexity, level of automation,

¹⁴ Hollman, John K. "Improving Your Contingency Estimates for More Realistic Project Budgets." Chemical Engineering, December 2014. Available at http://www.chemengonline.com/improve-your-contingency-estimates-for-more-realistic-project-budgets/?printmode=1#disqus_thread.

¹⁵ No endorsement by US EPA is made or implied of any publication that is named here, or anywhere else in the Manual.

¹⁶ The link is at <u>http://guides.library.tamu.edu/chemicalengineering</u>. Click on "Chemical Prices" for industrial chemical data sites and publications.

and operating mode (i.e., batch or continuous). The labor is usually estimated on an hours-pershift basis. As a rule, though, data showing explicit correlations between the labor requirement and capacity are often hard to obtain. One non-linear correlation found in the literature is shown below: [3]

$$L_2/L_1 = (V_2/V_1)^y \tag{2.9}$$

where

$L_1, L_2 =$	=	labor requirements for systems 1 and 2
$V_1, V_2 =$	=	capacities of systems 1 and 2 (as measured by the gas flow rate,
		for instance)
у =	=	0.2 to 0.25 (typically)

The exponent in Equation 2.9 can vary considerably. Conversely, in many cases, the amount of operator labor required for a system will be approximately the same regardless of its size.

Maintenance labor is calculated in the same way as operating labor and is influenced by the same variables. The maintenance labor rate, however, is normally higher than the operating labor rate, mainly because more skilled personnel are required. Many cost studies use a flat ten percent premium over the operations labor wage rate for maintenance labor costs. [13] A certain amount must also be added to operating labor to cover supervisory requirements. Generally, cost estimates include supervisory labor as a flat fifteen per cent of the operating labor requirement. [13] To obtain the annual labor cost, multiply the operating and supervisory labor requirements (labor-hr/operating-hr) by the respective wage rates (in \$/labor-hr) and the system operating factor (number of hours per year the system is in operation). Wage rates also vary widely, depending upon the source category, geographical location, etc. These data are tabulated and periodically updated by the U.S. Department of Labor, Bureau of Labor Statistics, in its Monthly Labor Review and in other publications. This Manual uses labor rates that are representative of industries at the national level. For cost assessments, these wages (adjusted for inflation through an appropriate cost index) should be adequate for study level purposes.

Finally, please note that the wage rates used by the Manual and its supplemental programs are base labor rates, which do not include payroll and plant overhead. Wages found in reports from the Bureau of Labor Statistics or some other reliable source may or may not include overhead. The analyst must be careful to apply overhead and other wage adjustment factors uniformly. (See the discussion on Overhead, below.)

2.6.5.3 Maintenance Materials

Maintenance also requires maintenance materials—oil, other lubricants, duct tape, etc., and a host of small tools. The costs for these items can be figured individually, but since they are normally so small, they are usually factored from the maintenance labor. Reference [3] suggests a factor of 100% of the maintenance labor to cover the maintenance materials cost.

2.6.5.4 Utilities

This cost category covers many different items, ranging from electricity to compressed air. Of these, only electricity is common to all control devices, where fuel oil and natural gas are generally used only by incinerators; water and water treatment, by venturi scrubbers, quenchers, and spray chambers; steam, by carbon adsorbers; and compressed air, by pulse-jet fabric filters. Techniques and factors for estimating utility costs for specific devices are presented in their respective sections. However, because nearly every system requires a fan to convey the exhaust gases to and through it, a general expression for computing the fan electricity cost (C_e) is given here: [10]

$$C_e = 0.746 \ Q \ \Delta P \ s \ \Theta p_e/6356\eta \tag{2.10}$$

Where

- P = pressure drop through system (inches of water, column) (Values for P are given in the chapters covering the equipment items.)
- s = specific gravity of gas relative to air (1.000, for all practical purposes)
- Θ = operating factor (hr/yr)
- η = combined fan and motor efficiency (usually 0.60 to 0.70)
- p_e = electricity cost¹⁷ (\$/kw-hr)

A similar expression can be developed for calculating pump motor electricity requirements.

2.6.5.5 Waste Treatment and Disposal

Though often overlooked, there can be a significant cost associated with treating and/or disposing of waste material captured by a control system that neither can be sold nor recycled to the process. Liquid waste streams, such as the effluent from a gas absorber, are usually processed before being released to surface waters. The type and extent of this processing will, of course, depend on the characteristics of the effluent. For example, the waste can first be sent to one (or more) clarifiers, for coagulation and removal of suspended solids. The precipitate from the clarifier is then conveyed to a rotary filter, where most of the liquid is removed. The resulting filter cake is then disposed of, via landfilling, for example. The costs of waste treatment and disposal should be estimated where appropriate and consistent with the Control Cost Methodology. If installation of control equipment is expected to increase the waste generation from the current level, the difference between the expected level and the current level is attributable to the control equipment and should be accounted for in the cost estimate. Estimation of costs is accounted for in the chapters for specific control measures where waste treatment and disposal is a concern (e.g., gas absorbers, carbon adsorbers).

¹⁷ The electricity cost in this equation is the cost to the power plant to generate its electricity, or busbar cost. Data on busbar costs is collected in Form 1 of the Federal Energy Regulatory Commission (FERC). Information on Form 1 can be found at <u>http://www.ferc.gov/docs-filing/forms/form-1/data.asp</u>.

2.6.5.6 Replacement Materials

The cost of maintenance materials is a component of the operations and maintenance function of the system and is not the same thing as the system's replacement materials cost, which is the cost of such items as carbon (for carbon absorbers), bags (for fabric filters) and catalyst (for catalytic incinerators), along with the labor for their installation. Because replacement materials last for more than a year but are consumed by the system, they cannot be included in the general maintenance and operations costs, which are annual in nature. Instead, these the present value of these costs in constant dollar must be calculated before being annualized by taking into account the life of the material (see section 2.5.5.3, above). The annual cost of the replacement materials is a function of the initial parts cost, the parts replacement labor cost, the life of the parts, and the interest rate, as follows:

$$CRC_{p} = \left(C_{p} + C_{pl}\right) CRF_{p}$$

$$(2.11)$$

Where

CRC_p	=	capital recovery cost of replacement parts (\$/yr)
C_p	=	initial cost of replacement parts, including sales taxes and freight
		(\$)
C_{pl}	=	cost of parts-replacement labor (\$)
CRF_p	=	capital recovery factor for replacement parts (defined in Section
_		2.3).

The useful life of replacement materials is generally less than the useful life of the rest of the control system - typically two to five years. Consequently, the analyst can choose to keep the length of the analysis as same as the life of the control system, and input the cost of the replacement materials accordingly before annualizing or annualize the replacement material cost stream separately from the control system. Furthermore, the annualized cost of the pollution control system should be performed net of the cost of the replacement materials needed at the beginning of operations to prevent double counting. Replacement materials labor will vary, depending upon the amount of the material, its workability, accessibility of the control device, and other factors. The cost of replacement materials labor should be included in the cost of the materials before annualization. Either way, this approach is appropriate when only the cost is under consideration in the overall analysis.

2.6.5.7 Overhead

This cost is easy to calculate, but often difficult to comprehend. Much of the confusion surrounding overhead is due to the many different ways it is computed and to the several costs it includes, some of which may appear to be duplicative.

There are, generally, two categories of overhead: payroll and plant. Payroll overhead includes expenses directly associated with operating, supervisory, and maintenance labor, such as: workmen's compensation, Social Security and pension fund contributions, vacations, group insurance, and other fringe benefits. Some of these are fixed costs (i.e., they must be paid regardless of how many hours per year an employee works). Payroll overhead is traditionally computed as a percentage of the total annual labor cost (operating, supervisory, and maintenance).

Conversely, plant (or "factory") overhead accounts for expenses not necessarily tied to the operation and maintenance of the control system, including: plant protection, control laboratories, employee amenities, plant lighting, parking areas, and landscaping. Some estimators compute plant overhead by taking a percentage of all labor plus maintenance materials [3], while others factor it from the total labor costs alone. [3]

For study estimates, it is sufficiently accurate to combine payroll and plant overhead into a single indirect cost. This is done in this Manual. Also, overhead is factored from the sum of all labor (operating, supervisory, and maintenance) plus maintenance materials, the approach recommended in reference [3]. The factors recommended therein range from 50 to 70% [3]. An average value of 60% is used in this Manual.

2.6.5.8 Property Taxes, Insurance, Administrative Charges and Permitting Costs

The first three indirect operating costs are factored from the system total capital investment, at 1, 1, and 2%, respectively. Property taxes and insurance are self-explanatory. Administrative charges cover sales, research and development, accounting, and other home office expenses. (It should not be confused with plant overhead, however.) For simplicity, the three items are usually combined into a single, 4% factor. These estimates can serve for cost estimates if sources do not have any reliable and accurate information on these indirect operating costs. This is the standard approach used in actions for which the cost methodology in this Cost Manual is a basis.

The permitting costs are costs borne by the facilities to get the necessary approval to design and install the control equipment. This is a site-specific cost where the costs borne by one facility may not translate well into another facility. However, because of potentials for delays, re-design and other considerations, permitting costs should be included in the overall cost assessment. While the cost of re-design and lost production are explicitly taken into account, analysts should carefully the effects of permitting process and their associated costs on the overall cost assessment.

2.7 Example

As an illustrative example of applying the cost methodology discussed in this chapter, consider the hypothetical All-American Electrical (AAE) ¹ that operates a single 600 MWe tangentially fired high sulfur bituminous coal-fired boiler to produce steam to power its generators.

It emits an uncontrolled 50,000 tons of sulfur dioxide per year, and because it is planning on a major renovation, it must install devices to reduce its sulfur emissions to less than 1,000 tons per year (98 percent removal efficiency). After careful study of the available technologies, AAE has determined that either a wet limestone flue gas desulfurization (FGD) scrubber or a wet buffered lime FGD would be the most logical choice to achieve such a high removal rate. For simplification purposes we will assume either device would have an operating life of thirty years, after which the scrubbers could be sold as scrap for a salvage value of about \$500,000. We also provide an estimate of annual gypsum sales in the overall calculation given that gypsum can be a by-product of FGD scrubber operation. Table 2.5, below, displays the capital and annual costs associated with each of the alternative devices.

	Wet Limestone FGD	Wet Buffered Lime FGD
Capital Cost	\$200,000,000	\$180,000,000
Annual O&M Costs Fixed O&M Costs ^a	\$2,000,000	\$1,800,000
Reagent	\$1,200,000	\$3.750,000
Auxiliary Power	\$1,300,000	\$1,150,000
Annual Gypsum Sales	\$1,200,000	\$600,000
Parasitic Power ^b	\$950,000	\$375,000

 Table 2.5: Capital, O&M, and Parasitic Energy Costs (Including Revenue Streams) of

 Alternative FGD Controls

^a Estimated at 1% of capital cost

^b In many systems, the insertion of a pollution control device causes the system to lose productive capacity. This can be caused by the device creating obstructions in the flue, temperature losses that create imbalances, or other physical changes that affect performance. These losses are collectively termed "parasitic power" losses.

From the information in Table 2.5, neither device can be shown to be superior to the other. It costs \$20 million less to install a wet buffered lime scrubber, but a buffered lime FGD would cost over three times as much each year for the purchase of the lime, relative to the cost of the reagent in a limestone FGD. Each FGD has similar fixed O&M costs, but because a buffered lime FGD uses much less reagent, it requires less power to run - about half the power demand and about 40 percent of the productive loss of the limestone FGD. While these factors indicate the wet buffered lime FGD may be a better alternative, the use of less reagent also means the production of less gypsum by-product - for about half the expected revenue generating capability of a limestone system. To make our selection, we must rely upon our financial tools.

The exercise does not lend itself to a payback analysis, even though there are revenues to be generated from the sale of the scrubber's byproduct. So long as annual costs exceed annual revenues, payback will not an alternative because there will be no net revenue to help offset the capital costs of the project. Furthermore, even if one were to ignore the cost component of the cash flow, the revenues from most pollution control devices are so low that their payback values are meaningless. For instance, the limestone and buffered lime scrubbers in this exercise have a simple payback (without considering costs) of 167 and 300 years, respectively. Consequently, the analyst must look to the more sophisticated tools available: cash flow analysis and net present value.

Table 2.6 shows the hypothetical cash flows from each alternative control in nominal dollars. You will notice that the cost for O&M and the revenues from selling the gypsum byproduct are constant over time. That is because we have ignored any inflation rate change in prices and have created our cash flow analysis in real dollars. This is the preferred way to approach this kind of analysis, since it relies on the most accurate information available (current prices) and does not try to extrapolate those prices into the future. Because we will perform our cash flow analysis in real dollars, we must use the real interest rate to determine net present values. We will assume AAE can borrow funds at will at a nominal interest rate of nine percent and sources the company consults expect the inflation rate over the relevant range to be, on average, two percent. Consequently, the real rate of interest is (nine percent minus two percent) seven percent. Using real dollars for revenues and costs and then using nominal interest rates for our discounting factors (nine percent) would have led to an understatement of the net present value of the projects, making them appear less beneficial to AAE.

Translating the costs in each future year to year zero values means applying the factors found in Table A.1 from Appendix A. From the 10 percent column, we applied the factors 0.90909, 0.82645, 0.75131, 0.68301, and 062092, respectively, to the net costs of years 1, 2, 3, 4, and 5 to determine the year zero costs, and then sum all of the values to derive the net present value for each control alternative. Based upon the information developed in the cash flow analysis and the NPV calculation, which control device is the best one for AAE to install? The answer is still not evident! Even with a twenty million dollar capital cost savings, the net present value of the wet buffered lime FGD is only about a half million dollars more expensive than the wet limestone FGD! This is a function of the other cash flow components - the higher operating cost of the buffered lime system versus the higher revenue generating capacity of the limestone FGD, both of which work to almost completely eliminate the capital cost advantage of the buffered lime scrubber. Clearly, relying on just the sticker price of the two units could have driven us to a potentially bad decision. So now what? Payback analysis does not offer any help, (nor will internal rate of return (IRR), which also relies upon a positive net cash flow to work). Cash flow analysis tells us that, within our study-level estimation range, the two devices are almost identical. That in and of itself is important information, because the environmental engineer can be fairly certain that whichever device they choose, the effect of that choice on his company will be about the same. That leaves them free to look at other considerations that are not accounted for easily within this cost analysis: Twice as much limestone means twice as much storage and twice as much stockpiling of the gypsum by-product. Is that an important factor? Limestone is more caustic than buffered lime, but it takes less equipment to operate the system. Should the engineer opt for simplicity in design or potentially higher rates of repair? These are the sort of considerations, some

numerical and can be accounted for in the cost analysis, and some not, that can now come into play in making a decision, now that the relative values of each device has been determined.

This does not mean that our process has failed. Far from it. If our input assumptions have been made correctly, then we have determined that from a cost standpoint, there does not seem to be an appreciably different risk to choosing one device over the other. However, other considerations may play a role in making the choice clearer. For instance, the limestone scrubber will produce about twice as much gypsum as the wet buffered lime scrubber. Does the storage, transportation, or marketability of that amount of gypsum create a problem? Likewise, it takes about three times as much limestone to remove the same amount of sulfur, relative to the amount of lime needed, but the lime costs between five and seven times as much as the limestone. Do these considerations clarify the choice? Finally, the power demands for each device differ significantly, both in terms of operation and in lost productive capacity. Perhaps these considerations will make one device more attractive to the firm. The bottom line is that there is no clear-cut "cookbook" process through which the analyst will be able to make the right informed decision each time, and the formalized costing methodology employed by the Manual is only a part of that process. However, if the Manual's methodology is followed rigorously and in an unbiased manner, then the analyst can feel safe about the study-level cost of his alternative projects and can then move on to a more formal cost determination with the help of an engineering or consulting firm.

Years	0	1	2	3	4	5	6	7	8	9	10
Limestone Scrubber Income											
Gypsum Sales	0	1.200	1.200	1.200	1.200	1.200	1.200	1.200	1.200	1.200	1.200
Salvage Value	0	0	0	0	0	0	0	0	0	0	500
Expenses											
Capital Investment	200,000	0	0	0	0	0	0	0	0	0	0
Annual O&M Costs	0	4,500	4,500	4,500	4,500	4,500	4,500	4,500	4,500	4,500	4,500
Parasitic Power	0	950	950	950	950	950	950	950	950	950	950
Net Annual Cost	-200,000	-4,250	-4,250	-4,250	-4,250	-4,250	-4,250	-4,250	-4,250	-4,250	-3,750
Present Value	-200,000	-4,048	-3,855	-3,671	-3,496	-3,330	-3,171	-3,020	-2,877	-2,740	-2,302
NPV	-232,510										
Duffered Lime Complete											
Income											
Gypsum Sales	0	600	600	600	600	600	600	600	600	600	600
Salvage Value	0	0	0	0	0	0	0	0	0	0	500
Expenses											
Capital Investment	180,000	0	0	0	0	0	0	0	0	0	0
Annual O&M Costs	0	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000
Parasitic Power	0	375	375	375	375	375	375	375	375	375	375
Net Annual Cost	-180,000	-6,775	-6,775	-6,775	-6,775	-6,775	-6,775	-6,775	-6,775	-6,775	-6,275
Present Value	-180,000	-6,452	-6,145	-5,852	-5,574	-5,308	-5,056	-4,815	-4,586	-4,367	-3,852
NPV	-232,008										

Table 2.6: Cash Flow Analyses Exercise (in thousands of dollars)

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APPENDIX A

Net Present Value and Capital Recovery Factor Tables

Table A.1 shows an example of present value calculations that includes illustrative discount rates and illustrative investment lifespans.¹⁸ The table displays the amount an individual would be willing to accept today for a dollar promised in the future assuming the illustrative discount rates and investment lifespans. Select the year in which the dollar is supposed to be paid from the leftmost column and the discount rate from the top row. The value where the column and row intersect is the present value of that future dollar. For instance, if you were promised a dollar twelve years from now, and you believed the interest rate over that period would be 9.5 percent, then you would be willing to accept 33.7 cents for that dollar today.

Table A.1: Present Value Factors for a Dollar to Be Paid Now Instead of in a Future Year

	5.50%	6.00%	6.50%	7.00%	7.50%	8.00%	8.50%	9.00%	9.50%	10.00%
1	0.94787	0.9434	0.93897	0.93458	0.93023	0.92593	0.92166	0.91743	0.91324	0.90909
2	0.89845	0.89	0.88166	0.87344	0.86533	0.85734	0.84946	0.84168	0.83401	0.82645
3	0.85161	0.83962	0.82785	0.8163	0.80496	0.79383	0.78291	0.77218	0.76165	0.75131
4	0.80722	0.79209	0.77732	0.7629	0.7488	0.73503	0.72157	0.70843	0.69557	0.68301
5	0.76513	0.74726	0.72988	0.71299	0.69656	0.68058	0.66505	0.64993	0.63523	0.62092
6	0.72525	0.70496	0.68533	0.66634	0.64796	0.63017	0.61295	0.59627	0.58012	0.56447
7	0.68744	0.66506	0.64351	0.62275	0.60275	0.58349	0.56493	0.54703	0.52979	0.51316
8	0.6516	0.62741	0.60423	0.58201	0.5607	0.54027	0.52067	0.50187	0.48382	0.46651
9	0.61763	0.5919	0.56735	0.54393	0.52158	0.50025	0.47988	0.46043	0.44185	0.4241
10	0.58543	0.55839	0.53273	0.50835	0.48519	0.46319	0.44229	0.42241	0.40351	0.38554
11	0.55491	0.52679	0.50021	0.47509	0.45134	0.42888	0.40764	0.38753	0.36851	0.35049
12	0.52598	0.49697	0.46968	0.44401	0.41985	0.39711	0.3757	0.35553	0.33654	0.31863
13	0.49856	0.46884	0.44102	0.41496	0.39056	0.3677	0.34627	0.32618	0.30734	0.28966
14	0.47257	0.4423	0.4141	0.38782	0.36331	0.34046	0.31914	0.29925	0.28067	0.26333
15	0.44793	0.41727	0.38883	0.36245	0.33797	0.31524	0.29414	0.27454	0.25632	0.23939
16	0.42458	0.39365	0.3651	0.33873	0.31439	0.29189	0.2711	0.25187	0.23409	0.21763
17	0.40245	0.37136	0.34281	0.31657	0.29245	0.27027	0.24986	0.23107	0.21378	0.19784
18	0.38147	0.35034	0.32189	0.29586	0.27205	0.25025	0.23028	0.21199	0.19523	0.17986
19	0.36158	0.33051	0.30224	0.27651	0.25307	0.23171	0.21224	0.19449	0.17829	0.16351
20	0.34273	0.3118	0.2838	0.25842	0.23541	0.21455	0.19562	0.17843	0.16282	0.14864
21	0.32486	0.29416	0.26648	0.24151	0.21899	0.19866	0.18029	0.1637	0.1487	0.13513
22	0.30793	0.27751	0.25021	0.22571	0.20371	0.18394	0.16617	0.15018	0.1358	0.12285
23	0.29187	0.2618	0.23494	0.21095	0.1895	0.17032	0.15315	0.13778	0.12402	0.11168
24	0.27666	0.24698	0.2206	0.19715	0.17628	0.1577	0.14115	0.1264	0.11326	0.10153
25	0.26223	0.233	0.20714	0.18425	0.16398	0.14602	0.13009	0.11597	0.10343	0.0923

¹⁸ The example calculations in Table A.1 are all illustrative in nature. Nothing in this example is meant to contradict language earlier in this chapter concerning the appropriate use of interest rates, equipment life, and the EUAC in cost analysis to which the Control Cost Methodology is a basis.

Table A.1: Continued

	10.50%	11.00%	11.50%	12.00%	12.50%	13.00%	13.50%	14.00%	14.50%	15.00%
1	0.90498	0.9009	0.89686	0.89286	0.88889	0.88496	0.88106	0.87719	0.87336	0.86957
2	0.81898	0.81162	0.80436	0.79719	0.79012	0.78315	0.77626	0.76947	0.76276	0.75614
3	0.74116	0.73119	0.7214	0.71178	0.70233	0.69305	0.68393	0.67497	0.66617	0.65752
4	0.67073	0.65873	0.64699	0.63552	0.6243	0.61332	0.60258	0.59208	0.58181	0.57175
5	0.607	0.59345	0.58026	0.56743	0.55493	0.54276	0.53091	0.51937	0.50813	0.49718
6	0.54932	0.53464	0.52042	0.50663	0.49327	0.48032	0.46776	0.45559	0.44378	0.43233
7	0.49712	0.48166	0.46674	0.45235	0.43846	0.42506	0.41213	0.39964	0.38758	0.37594
8	0.44989	0.43393	0.4186	0.40388	0.38974	0.37616	0.36311	0.35056	0.3385	0.3269
9	0.40714	0.39092	0.37543	0.36061	0.34644	0.33288	0.31992	0.30751	0.29563	0.28426
10	0.36845	0.35218	0.33671	0.32197	0.30795	0.29459	0.28187	0.26974	0.25819	0.24718
11	0.33344	0.31728	0.30198	0.28748	0.27373	0.2607	0.24834	0.23662	0.2255	0.21494
12	0.30175	0.28584	0.27083	0.25668	0.24332	0.23071	0.2188	0.20756	0.19694	0.18691
13	0.27308	0.25751	0.2429	0.22917	0.21628	0.20416	0.19278	0.18207	0.172	0.16253
14	0.24713	0.23199	0.21785	0.20462	0.19225	0.18068	0.16985	0.15971	0.15022	0.14133
15	0.22365	0.209	0.19538	0.1827	0.17089	0.15989	0.14964	0.1401	0.1312	0.12289
16	0.2024	0.18829	0.17523	0.16312	0.1519	0.1415	0.13185	0.12289	0.11458	0.10686
17	0.18316	0.16963	0.15715	0.14564	0.13502	0.12522	0.11616	0.1078	0.10007	0.09293
18	0.16576	0.15282	0.14095	0.13004	0.12002	0.11081	0.10235	0.09456	0.0874	0.08081
19	0.15001	0.13768	0.12641	0.11611	0.10668	0.09806	0.09017	0.08295	0.07633	0.07027
20	0.13575	0.12403	0.11337	0.10367	0.09483	0.08678	0.07945	0.07276	0.06666	0.0611
21	0.12285	0.11174	0.10168	0.09256	0.08429	0.0768	0.07	0.06383	0.05822	0.05313
22	0.11118	0.10067	0.09119	0.08264	0.07493	0.06796	0.06167	0.05599	0.05085	0.0462
23	0.10062	0.09069	0.08179	0.07379	0.0666	0.06014	0.05434	0.04911	0.04441	0.04017
24	0.09106	0.0817	0.07335	0.06588	0.0592	0.05323	0.04787	0.04308	0.03879	0.03493
25	0.0824	0.07361	0.06579	0.05882	0.05262	0.0471	0.04218	0.03779	0.03387	0.03038

Table A.2 displays the annual payment you would have to make for a specific number of years to equal the present value of a single dollar borrowed today. Select the number of years you will make payments from the leftmost column and the discount rate from the top row. The value where the column and row intersect is annual payment on that borrowed dollar. For example, if you plan on making equal payments for twelve years at 9.5 percent interest to repay a dollar borrowed today, you would make annual payments of 14.3 cents.

	5.50%	6.00%	6.50%	7.00%	7.50%	8.00%	8.50%	9.00%	9.50%	10.00%
1	1.055	1.06	1.065	1.07	1.075	1.08	1.085	1.09	1.095	1.1
2	0.54162	0.54544	0.54926	0.55309	0.55693	0.56077	0.56462	0.56847	0.57233	0.57619
3	0.37065	0.37411	0.37758	0.38105	0.38454	0.38803	0.39154	0.39505	0.39858	0.40211
4	0.28529	0.28859	0.2919	0.29523	0.29857	0.30192	0.30529	0.30867	0.31206	0.31547
5	0.23418	0.2374	0.24063	0.24389	0.24716	0.25046	0.25377	0.25709	0.26044	0.2638
6	0.20018	0.20336	0.20657	0.2098	0.21304	0.21632	0.21961	0.22292	0.22625	0.22961
7	0.17596	0.17914	0.18233	0.18555	0.1888	0.19207	0.19537	0.19869	0.20204	0.20541
8	0.15786	0.16104	0.16424	0.16747	0.17073	0.17401	0.17733	0.18067	0.18405	0.18744
9	0.14384	0.14702	0.15024	0.15349	0.15677	0.16008	0.16342	0.1668	0.1702	0.17364
10	0.13267	0.13587	0.1391	0.14238	0.14569	0.14903	0.15241	0.15582	0.15927	0.16275
11	0.12357	0.12679	0.13006	0.13336	0.1367	0.14008	0.14349	0.14695	0.15044	0.15396
12	0.11603	0.11928	0.12257	0.1259	0.12928	0.1327	0.13615	0.13965	0.14319	0.14676
13	0.10968	0.11296	0.11628	0.11965	0.12306	0.12652	0.13002	0.13357	0.13715	0.14078
14	0.10428	0.10758	0.11094	0.11434	0.1178	0.1213	0.12484	0.12843	0.13207	0.13575
15	0.09963	0.10296	0.10635	0.10979	0.11329	0.11683	0.12042	0.12406	0.12774	0.13147
16	0.09558	0.09895	0.10238	0.10586	0.10939	0.11298	0.11661	0.1203	0.12403	0.12782
17	0.09204	0.09544	0.09891	0.10243	0.106	0.10963	0.11331	0.11705	0.12083	0.12466
18	0.08892	0.09236	0.09585	0.09941	0.10303	0.1067	0.11043	0.11421	0.11805	0.12193
19	0.08615	0.08962	0.09316	0.09675	0.10041	0.10413	0.1079	0.11173	0.11561	0.11955
20	0.08368	0.08718	0.09076	0.09439	0.09809	0.10185	0.10567	0.10955	0.11348	0.11746
21	0.08146	0.085	0.08861	0.09229	0.09603	0.09983	0.1037	0.10762	0.11159	0.11562
22	0.07947	0.08305	0.08669	0.09041	0.09419	0.09803	0.10194	0.1059	0.10993	0.11401
23	0.07767	0.08128	0.08496	0.08871	0.09254	0.09642	0.10037	0.10438	0.10845	0.11257
24	0.07604	0.07968	0.0834	0.08719	0.09105	0.09498	0.09897	0.10302	0.10713	0.1113
25	0.07455	0.07823	0.08198	0.08581	0.08971	0.09368	0.09771	0.10181	0.10596	0.11017

Table A.2: Capital Recovery Factors for Equal Payments on a Dollar over a Number of Years

Table A.2: Continued

	10.50%	11.00%	11.50%	12.00%	12.50%	13.00%	13.50%	14.00%	14.50%	15.00%
1	1.105	1.11	1.115	1.12	1.125	1.13	1.135	1.14	1.145	1.15
2	0.58006	0.58393	0.58781	0.5917	0.59559	0.59948	0.60338	0.60729	0.6112	0.61512
3	0.40566	0.40921	0.41278	0.41635	0.41993	0.42352	0.42712	0.43073	0.43435	0.43798
4	0.31889	0.32233	0.32577	0.32923	0.33271	0.33619	0.33969	0.3432	0.34673	0.35027
5	0.26718	0.27057	0.27398	0.27741	0.28085	0.28431	0.28779	0.29128	0.29479	0.29832
6	0.23298	0.23638	0.23979	0.24323	0.24668	0.25015	0.25365	0.25716	0.26069	0.26424
7	0.2088	0.21222	0.21566	0.21912	0.2226	0.22611	0.22964	0.23319	0.23677	0.24036
8	0.19087	0.19432	0.1978	0.2013	0.20483	0.20839	0.21197	0.21557	0.2192	0.22285
9	0.17711	0.1806	0.18413	0.18768	0.19126	0.19487	0.19851	0.20217	0.20586	0.20957
10	0.16626	0.1698	0.17338	0.17698	0.18062	0.18429	0.18799	0.19171	0.19547	0.19925
11	0.15752	0.16112	0.16475	0.16842	0.17211	0.17584	0.1796	0.18339	0.18722	0.19107
12	0.15038	0.15403	0.15771	0.16144	0.16519	0.16899	0.17281	0.17667	0.18056	0.18448
13	0.14445	0.14815	0.1519	0.15568	0.1595	0.16335	0.16724	0.17116	0.17512	0.17911
14	0.13947	0.14323	0.14703	0.15087	0.15475	0.15867	0.16262	0.16661	0.17063	0.17469
15	0.13525	0.13907	0.14292	0.14682	0.15076	0.15474	0.15876	0.16281	0.1669	0.17102
16	0.13164	0.13552	0.13943	0.14339	0.14739	0.15143	0.1555	0.15962	0.16376	0.16795
17	0.12854	0.13247	0.13644	0.14046	0.14451	0.14861	0.15274	0.15692	0.16112	0.16537
18	0.12586	0.12984	0.13387	0.13794	0.14205	0.1462	0.15039	0.15462	0.15889	0.16319
19	0.12353	0.12756	0.13164	0.13576	0.13993	0.14413	0.14838	0.15266	0.15698	0.16134
20	0.12149	0.12558	0.1297	0.13388	0.1381	0.14235	0.14665	0.15099	0.15536	0.15976
21	0.11971	0.12384	0.12802	0.13224	0.13651	0.14081	0.14516	0.14954	0.15396	0.15842
22	0.11813	0.12231	0.12654	0.13081	0.13512	0.13948	0.14387	0.1483	0.15277	0.15727
23	0.11675	0.12097	0.12524	0.12956	0.13392	0.13832	0.14276	0.14723	0.15174	0.15628
24	0.11552	0.11979	0.1241	0.12846	0.13287	0.13731	0.14179	0.1463	0.15085	0.15543
25	0.11443	0.11874	0.1231	0.1275	0.13194	0.13643	0.14095	0.1455	0.15008	0.1547

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			16.48	17.12		18.50	18.29	.29			
Industrial					13.38	13.88		14.89	14.37	7	
NM = Not meaningful due to large relative standard error. Show relative standard errors expressed as percent in parenthesis:
Terms and definitions

3.1 Stationary Gas Turbines

3.1.1 General¹

Gas turbines, also called "combustion turbines", are used in a broad scope of applications including electric power generation, cogeneration, natural gas transmission, and various process applications. Gas turbines are available with power outputs ranging in size from 300 horsepower (hp) to over 268,000 hp, with an average size of 40,200 hp.² The primary fuels used in gas turbines are natural gas and distillate (No. 2) fuel oil.³

3.1.2 Process Description^{1,2}

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Gas turbines are essentially composed of three major components: compressor, combustor, and power turbine. In the compressor section, ambient air is drawn in and compressed up to 30 times ambient pressure and directed to the combustor section where fuel is introduced, ignited, and burned. Combustors can either be annular, can-annular, or silo. An annular combustor is a doughnut-shaped, single, continuous chamber that encircles the turbine in a plane perpendicular to the air flow. Can-annular combustors are similar to the annular; however, they incorporate several can-shaped combustion chambers rather than a single continuous chamber. Annular and can-annular combustors are based on aircraft turbine technology and are typically used for smaller scale applications. A silo (frame-type) combustor has one or more combustion chambers mounted external to the gas turbine body. Silo combustors are typically larger than annular or can-annular combustors and are used for larger scale applications.

The combustion process in a gas turbine can be classified as diffusion flame combustion, or leanpremix staged combustion. In the diffusion flame combustion, the fuel/air mixing and combustion take place simultaneously in the primary combustion zone. This generates regions of near-stoichiometric fuel/air mixtures where the temperatures are very high. For lean-premix combustors, fuel and air are thoroughly mixed in an initial stage resulting in a uniform, lean, unburned fuel/air mixture which is delivered to a secondary stage where the combustion reaction takes place. Manufacturers use different types of fuel/air staging, including fuel staging, air staging, or both; however, the same staged, lean-premix principle is applied. Gas turbines using staged combustion are also referred to as Dry Low NO_X combustors. The majority of gas turbines currently manufactured are lean-premix staged combustion turbines.

Hot gases from the combustion section are diluted with additional air from the compressor section and directed to the power turbine section at temperatures up to 2600°F. Energy from the hot exhaust gases, which expand in the power turbine section, are recovered in the form of shaft horsepower. More than 50 percent of the shaft horsepower is needed to drive the internal compressor and the balance of recovered shaft horsepower is available to drive an external load.² Gas turbines may have one, two, or three shafts to transmit power between the inlet air compression turbine, the power turbine, and the exhaust turbine. The heat content of the exhaust gases exiting the turbine can either be discarded without heat recovery (simple cycle); recovered with a heat exchanger to preheat combustion air entering the combustor (regenerative cycle); recovered in a heat recovery steam generator to raise process steam, with or without supplementary firing (cogeneration); or recovered, with or without supplementary firing, to raise steam for a steam turbine Rankine cycle (combined cycle or repowering). The simple cycle is the most basic operating cycle of gas turbines with a thermal efficiency ranging from 15 to 42 percent. The cycle thermal efficiency is defined as the ratio of useful shaft energy to fuel energy input. Simple cycle gas turbines are typically used for shaft horsepower applications without recovery of exhaust heat. For example, simple cycle gas turbines are used by electric utilities for generation of electricity during emergencies or during peak demand periods.

A regenerative cycle is a simple cycle gas turbine with an added heat exchanger. The heat exchanger uses the turbine exhaust gases to heat the combustion air which reduces the amount of fuel required to reach combustor temperatures. The thermal efficiency of a regenerative cycle is approximately 35 percent. However, the amount of fuel efficiency and saving may not be sufficient to justify the capital cost of the heat exchanger, rendering the process unattractive.

A cogeneration cycle consists of a simple cycle gas turbine with a heat recovery steam generator (HRSG). The cycle thermal efficiency can be as high as 84 percent. In a cogeneration cycle, the steam generated by the HRSG can be delivered at a variety of pressures and temperatures to other thermal processes at the site. For situations where additional steam is required, a supplementary burner, or duct burner, can be placed in the exhaust duct stream of the HRSG to meet the site's steam requirements.

A combined cycle gas turbine is a gas turbine with a HRSG applied at electric utility sites. The gas turbine drives an electric generator, and the steam from the HRSG drives a steam turbine which also drives an electric generator. A supplementary-fired boiler can be used to increase the steam production. The thermal efficiency of a combined cycle gas turbine is between 38 percent and 60 percent.

Gas turbine applications include gas and oil industry, emergency power generation facilities, independent electric power producers (IPP), electric utilities, and other industrial applications. The petroleum industry typically uses simple cycle gas turbines with a size range from 300 hp to 20,000 hp. The gas turbine is used to provide shaft horsepower for oil and gas production and transmission. Emergency power generation sites also utilize simple cycle gas turbines. Here the gas turbine is used to provide backup or emergency power to critical networks or equipment. Usually, gas turbines under 5,000 hp are used at emergency power generation sites.

Independent electrical power producers generate electricity for resale to larger electric utilities. Simple, regenerative, or combined cycle gas turbines are used at IPP; however, most installations use combined cycle gas turbines. The gas turbines used at IPP can range from 1,000 hp to over 100,000 hp. The larger electric utilities use gas turbines mostly as peaking units for meeting power demand peaks imposed by large commercial and industrial users on a daily or seasonal basis. Simple cycle gas turbines ranging from 20,000 hp to over 200,000 hp are used at these installations. Other industrial applications for gas turbines include pulp and paper, chemical, and food processing. Here, combined cycle gas turbines are used for cogeneration.

3.1.3 Emissions

The primary pollutants from gas turbine engines are nitrogen oxides (NO_X) , carbon monoxide (CO), and to a lesser extent, volatile organic compounds (VOC). Particulate matter (PM) is also a primary pollutant for gas turbines using liquid fuels. Nitrogen oxide formation is strongly dependent on the high temperatures developed in the combustor. Carbon monoxide, VOC, hazardous air pollutants (HAP), and PM are primarily the result of incomplete combustion. Trace to low amounts of HAP and sulfur dioxide (SO₂) are emitted from gas turbines. Ash and metallic additives in the fuel may also contribute to PM in the exhaust. Oxides of sulfur (SO_X) will only appear in a significant quantity if heavy oils are fired

in the turbine. Emissions of sulfur compounds, mainly SO_2 , are directly related to the sulfur content of the fuel.

Available emissions data indicate that the turbine's operating load has a considerable effect on the resulting emission levels. Gas turbines are typically operated at high loads (greater than or equal to 80 percent of rated capacity) to achieve maximum thermal efficiency and peak combustor zone flame temperatures. With reduced loads (lower than 80 percent), or during periods of frequent load changes, the combustor zone flame temperatures are expected to be lower than the high load temperatures, yielding lower thermal efficiencies and more incomplete combustion. The emission factors for this sections are presented for gas turbines operating under high load conditions. Section 3.1 background information document and emissions database contain additional emissions data for gas turbines operating under various load conditions.

Gas turbines firing distillate oil may emit trace metals carried over from the metals content of the fuel. If the fuel analysis is known, the metals content of the fuel ash should be used for flue gas emission factors assuming all metals pass through the turbine.

If the HRSG is not supplementary fuel fired, the simple cycle input-specific emission factors (pounds per million British thermal units [lb/MMBtu]) will also apply to cogeneration/combined cycle systems. If the HRSG is supplementary fired, the emissions attributable to the supplementary firing must also be considered to estimate total stack emissions.

3.1.3.1 Nitrogen Oxides -

Nitrogen oxides formation occurs by three fundamentally different mechanisms. The principal mechanism with turbines firing gas or distillate fuel is thermal NO_X , which arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most thermal NO_X is formed in high temperature stoichiometric flame pockets downstream of the fuel injectors where combustion air has mixed sufficiently with the fuel to produce the peak temperature fuel/air interface.

The second mechanism, called prompt NO_X , is formed from early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO_X forms within the flame and is usually negligible when compared to the amount of thermal NO_X formed. The third mechanism, fuel NO_X , stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Natural gas has negligible chemically-bound fuel nitrogen (although some molecular nitrogen is present). Essentially all NO_X formed from natural gas combustion is thermal NO_X . Distillate oils have low levels of fuel-bound nitrogen. Fuel NO_X from distillate oil-fired turbines may become significant in turbines equipped with a high degree of thermal NO_X controls. Otherwise, thermal NO_X is the predominant NO_X formation mechanism in distillate oil-fired turbines.

The maximum thermal NO_X formation occurs at a slightly fuel-lean mixture because of excess oxygen available for reaction. The control of stoichiometry is critical in achieving reductions in thermal NO_X . Thermal NO_X formation also decreases rapidly as the temperature drops below the adiabatic flame temperature, for a given stoichiometry. Maximum reduction of thermal NO_X can be achieved by control of both the combustion temperature and the stoichiometry. Gas turbines operate with high overall levels of excess air, because turbines use combustion air dilution as the means to maintain the turbine inlet temperature below design limits. In older gas turbine models, where combustion is in the form of a diffusion flame, most of the dilution takes place downstream of the primary flame, which does not minimize peak temperature in the flame and suppress thermal NO_X formation. Diffusion flames are characterized by regions of near-stoichiometric fuel/air mixtures where temperatures are very high and significant thermal NO_X is formed. Water vapor in the turbine inlet air contributes to the lowering of the peak temperature in the flame, and therefore to thermal NO_X emissions. Thermal NO_X can also be reduced in diffusion type turbines through water or steam injection. The injected water-steam acts as a heat sink lowering the combustion zone temperature, and therefore thermal NO_X . Newer model gas turbines use lean, premixed combustion where the fuel is typically premixed with more than 50 percent theoretical air which results in lower flame temperatures, thus suppressing thermal NO_X formation.

Ambient conditions also affect emissions and power output from turbines more than from external combustion systems. The operation at high excess air levels and at high pressures increases the influence of inlet humidity, temperature, and pressure.⁴ Variations of emissions of 30 percent or greater have been exhibited with changes in ambient humidity and temperature. Humidity acts to absorb heat in the primary flame zone due to the conversion of the water content to steam. As heat energy is used for water to steam conversion, the temperature is the flame zone will decrease resulting in a decrease of thermal NO_X formation. For a given fuel firing rate, lower ambient temperatures lower the peak temperature in the flame, lowering thermal NO_X significantly. Similarly, the gas turbine operating loads affect NO_X emissions. Higher NO_X emissions are expected for high operating loads due to the higher peak temperature in the flame zone resulting in higher thermal NO_X.

3.1.3.2 Carbon Monoxide and Volatile Organic Compounds -

CO and VOC emissions both result from incomplete combustion. CO results when there is insufficient residence time at high temperature or incomplete mixing to complete the final step in fuel carbon oxidation. The oxidation of CO to CO_2 at gas turbine temperatures is a slow reaction compared to most hydrocarbon oxidation reactions. In gas turbines, failure to achieve CO burnout may result from quenching by dilution air. With liquid fuels, this can be aggravated by carryover of larger droplets from the atomizer at the fuel injector. Carbon monoxide emissions are also dependent on the loading of the gas turbine. For example, a gas turbine operating under a full load will experience greater fuel efficiencies which will reduce the formation of carbon monoxide. The opposite is also true, a gas turbine operating under a light to medium load will experience reduced fuel efficiencies (incomplete combustion) which will increase the formation of carbon monoxide.

The pollutants commonly classified as VOC can encompass a wide spectrum of volatile organic compounds some of which are hazardous air pollutants. These compounds are discharged into the atmosphere when some of the fuel remains unburned or is only partially burned during the combustion process. With natural gas, some organics are carried over as unreacted, trace constituents of the gas, while others may be pyrolysis products of the heavier hydrocarbon constituents. With liquid fuels, large droplet carryover to the quench zone accounts for much of the unreacted and partially pyrolized volatile organic emissions.

Similar to CO emissions, VOC emissions are affected by the gas turbine operating load conditions. Volatile organic compounds emissions are higher for gas turbines operating at low loads as compared to similar gas turbines operating at higher loads.

3.1.3.3 Particulate Matter¹³ -

PM emissions from turbines primarily result from carryover of noncombustible trace constituents in the fuel. PM emissions are negligible with natural gas firing and marginally significant with distillate oil firing because of the low ash content. PM emissions can be classified as "filterable" or "condensable" PM. Filterable PM is that portion of the total PM that exists in the stack in either the solid or liquid state and

can be measured on a EPA Method 5 filter. Condensable PM is that portion of the total PM that exists as a gas in the stack but condenses in the cooler ambient air to form particulate matter. Condensable PM exists as a gas in the stack, so it passes through the Method 5 filter and is typically measured by analyzing the impingers, or "back half" of the sampling train. The collection, recovery, and analysis of the impingers is described in EPA Method 202 of Appendix M, Part 51 of the Code of Federal Regulations. Condensable PM is composed of organic and inorganic compounds and is generally considered to be all less than 1.0 micrometers in aerodynamic diameter.

3.1.3.4 Greenhouse Gases⁵⁻¹¹ -

Carbon dioxide (CO_2) and nitrous oxide (N_2O) emissions are all produced during natural gas and distillate oil combustion in gas turbines. Nearly all of the fuel carbon is converted to CO_2 during the combustion process. This conversion is relatively independent of firing configuration. Methane (CH_4) is also present in the exhaust gas and is thought to be unburned fuel in the case of natural gas or a product of combustion in the case of distillate fuel oil.

Although the formation of CO acts to reduce CO_2 emissions, the amount of CO produced is insignificant compared to the amount of CO_2 produced. The majority of the fuel carbon not converted to CO_2 is due to incomplete combustion.

Formation of N_2O during the combustion process is governed by a complex series of reactions and its formation is dependent upon many factors. However, the formation of N_2O is minimized when combustion temperatures are kept high (above 1475°F) and excess air is kept to a minimum (less than 1 percent).

3.1.3.5 HAP Emissions -

Available data indicate that emission levels of HAP are lower for gas turbines than for other combustion sources. This is due to the high combustion temperatures reached during normal operation. The emissions data also indicate that formaldehyde is the most significant HAP emitted from combustion turbines. For natural gas fired turbines, formaldehyde accounts for about two-thirds of the total HAP emissions. Polycyclic aromatic hydrocarbons (PAH), benzene, toluene, xylenes, and others account for the remaining one-third of HAP emissions. For No. 2 distillate oil-fired turbines, small amount of metallic HAP are present in the turbine's exhaust in addition to the gaseous HAP identified under gas fired turbines. These metallic HAP are carried over from the fuel constituents. The formation of carbon monoxide during the combustion process is a good indication of the expected levels of HAP emissions. Similar to CO emissions, HAP emissions increase with reduced operating loads. Typically, combustion turbines operate under full loads for greater fuel efficiency, thereby minimizing the amount of CO and HAP emissions.

3.1.4 Control Technologies¹²

There are three generic types of emission controls in use for gas turbines, wet controls using steam or water injection to reduce combustion temperatures for NO_X control, dry controls using advanced combustor design to suppress NO_X formation and/or promote CO burnout, and post-combustion catalytic control to selectively reduce NO_X and/or oxidize CO emission from the turbine. Other recently developed technologies promise significantly lower levels of NO_X and CO emissions from diffusion combustion type gas turbines. These technologies are currently being demonstrated in several installations.

Emission factors in this section have been determined from gas turbines with no add-on control devices (uncontrolled emissions). For NO_X and CO emission factors for combustion controls, such as water-steam injection, and lean pre-mix units are presented. Additional information for controlled

emissions with various add-on controls can be obtained using the section 3.1 database. Uncontrolled, leanpremix, and water injection emission factors were presented for NO_X and CO to show the effect of combustion modification on emissions.

3.1.4.1 Water Injection -

Water or steam injection is a technology that has been demonstrated to effectively suppress NO_X emissions from gas turbines. The effect of steam and water injection is to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With water injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel weight ratio of less than one.

Depending on the initial NO_X levels, such rates of injection may reduce NO_X by 60 percent or higher. Water or steam injection is usually accompanied by an efficiency penalty (typically 2 to 3 percent) but an increase in power output (typically 5 to 6 percent). The increased power output results from the increased mass flow required to maintain turbine inlet temperature at manufacturer's specifications. Both CO and VOC emissions are increased by water injection, with the level of CO and VOC increases dependent on the amount of water injection.

3.1.4.2 Dry Controls -

Since thermal NO_X is a function of both temperature (exponentially) and time (linearly), the basis of dry controls are to either lower the combustor temperature using lean mixtures of air and/or fuel staging, or decrease the residence time of the combustor. A combination of methods may be used to reduce NO_X emissions such as lean combustion and staged combustion (two stage lean/lean combustion or two stage rich/lean combustion).

Lean combustion involves increasing the air-to-fuel ratio of the mixture so that the peak and average temperatures within the combustor will be less than that of the stoichiometric mixture, thus suppressing thermal NO_X formation. Introducing excess air not only creates a leaner mixture but it also can reduce residence time at peak temperatures.

Two-stage lean/lean combustors are essentially fuel-staged, premixed combustors in which each stage burns lean. The two-stage lean/lean combustor allows the turbine to operate with an extremely lean mixture while ensuring a stable flame. A small stoichiometric pilot flame ignites the premixed gas and provides flame stability. The NO_X emissions associated with the high temperature pilot flame are insignificant. Low NO_X emission levels are achieved by this combustor design through cooler flame temperatures associated with lean combustion and avoidance of localized "hot spots" by premixing the fuel and air.

Two stage rich/lean combustors are essentially air-staged, premixed combustors in which the primary zone is operated fuel rich and the secondary zone is operated fuel lean. The rich mixture produces lower temperatures (compared to stoichiometric) and higher concentrations of CO and H_2 , because of incomplete combustion. The rich mixture also decreases the amount of oxygen available for NO_X generation. Before entering the secondary zone, the exhaust of the primary zone is quenched (to extinguish the flame) by large amounts of air and a lean mixture is created. The lean mixture is pre-ignited and the combustion completed in the secondary zone. NO_X formation in the second stage are minimized through a variety of names, including Dry-Low NOx (DLN), Dry-Low Emissions (DLE), or SoLoNOx.

3.1.4.3 Catalytic Reduction Systems -

Selective catalytic reduction (SCR) systems selectively reduce NO_X emissions by injecting ammonium (NH₃) into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, NH₃, and O₂ react on the surface of the catalyst to form N₂ and H₂O. The exhaust gas must contain a minimum amount of O₂ and be within a particular temperature range (typically 450°F to 850°F) in order for the SCR system to operate properly.

The temperature range is dictated by the catalyst material which is typically made from noble metals, including base metal oxides such as vanadium and titanium, or zeolite-based material. The removal efficiency of an SCR system in good working order is typically from 65 to 90 percent. Exhaust gas temperatures greater than the upper limit (850° F) cause NO_X and NH₃ to pass through the catalyst unreacted. Ammonia emissions, called NH₃ slip, may be a consideration when specifying an SCR system.

Ammonia, either in the form of liquid anhydrous ammonia, or aqueous ammonia hydroxide is stored on site and injected into the exhaust stream upstream of the catalyst. Although an SCR system can operate alone, it is typically used in conjunction with water-steam injection systems or lean-premix system to reduce NO_X emissions to their lowest levels (less than 10 ppm at 15 percent oxygen for SCR and wet injection systems). The SCR system for landfill or digester gas-fired turbines requires a substantial fuel gas pretreatment to remove trace contaminants that can poison the catalyst. Therefore, SCR and other catalytic treatments may be inappropriate control technologies for landfill or digester gas-fired turbines.

The catalyst and catalyst housing used in SCR systems tend to be very large and dense (in terms of surface area to volume ratio) because of the high exhaust flow rates and long residence times required for NO_X , O_2 , and NH_3 , to react on the catalyst. Most catalysts are configured in a parallel-plate, "honeycomb" design to maximize the surface area-to-volume ratio of the catalyst. Some SCR installations incorporate CO catalytic oxidation modules along with the NO_X reduction catalyst for simultaneous CO/NO_X control.

Carbon monoxide oxidation catalysts are typically used on turbines to achieve control of CO emissions, especially turbines that use steam injection, which can increase the concentrations of CO and unburned hydrocarbons in the exhaust. CO catalysts are also being used to reduce VOC and organic HAPs emissions. The catalyst is usually made of a precious metal such as platinum, palladium, or rhodium. Other formulations, such as metal oxides for emission streams containing chlorinated compounds, are also used. The CO catalyst promotes the oxidation of CO and hydrocarbon compounds to carbon dioxide (CO_2) and water (H_2O) as the emission stream passes through the catalyst bed. The oxidation process takes place spontaneously, without the requirement for introducing reactants. The performance of these oxidation catalyst systems on combustion turbines results in 90-plus percent control of CO and about 85 to 90 percent control of formaldehyde. Similar emission reductions are expected on other HAP pollutants.

3.1.4.4 Other Catalytic Systems^{14,15} -

New catalytic reduction technologies have been developed and are currently being commercially demonstrated for gas turbines. Such technologies include, but are not limited to, the SCONOX and the XONON systems, both of which are designed to reduce NO_X and CO emissions. The SCONOX system is applicable to natural gas fired gas turbines. It is based on a unique integration of catalytic oxidation and absorption technology. CO and NO are catalytically oxidized to CO_2 and NO_2 . The NO_2 molecules are subsequently absorbed on the treated surface of the SCONOX catalyst. The system manufacturer guarantees CO emissions of 1 ppm and NO_X emissions of 2 ppm. The SCONOX system does not require the use of ammonia, eliminating the potential of ammonia slip conditions evident in existing SCR systems. Only limited emissions data were available for a gas turbine equipped with a SCONOX system. This data reflected HAP emissions and was not sufficient to verify the manufacturer's claims.

The XONON system is applicable to diffusion and lean-premix combustors and is currently being demonstrated with the assistance of leading gas turbine manufacturers. The system utilizes a flameless combustion system where fuel and air reacts on a catalyst surface, preventing the formation of NO_X while achieving low CO and unburned hydrocarbon emission levels. The overall combustion process consists of the partial combustion of the fuel in the catalyst module followed by completion of the combustion downstream of the catalyst. The partial combustion within the catalyst produces no NO_X , and the combustion downstream of the catalyst occurs in a flameless homogeneous reaction that produces almost no NO_X . The system is totally contained within the combustor of the gas turbine and is not a process for clean-up of the turbine exhaust. Note that this technology has not been fully demonstrated as of the drafting of this section. The catalyst manufacturer claims that gas turbines equipped with the XONON Catalyst emit NO_X levels below 3 ppm and CO and unburned hydrocarbons levels below 10 ppm. Emissions data from gas turbines equipped with a XONON Catalyst were not available as of the drafting of this section.

3.1.5 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the memoranda describing each supplement or the background report for this section. These and other documents can be found on the new EFIG home page (http://www.epa.gov/ttn/chief).

Supplement A, February 1996

- For the PM factors, a footnote was added to clarify that condensables and all PM from oiland gas-fired turbines are considered PM-10.
- In the table for large uncontrolled gas turbines, a sentence was added to footnote "e" to indicate that when sulfur content is not available, 0.6 lb/10⁶ ft³ (0.0006 lb/MMBtu) can be used.

Supplement B, October 1996

- Text was revised and updated for the general section.
- Text was added regarding firing practices and process description.
- Text was revised and updated for emissions and controls.
- All factors for turbines with SCR-water injection control were corrected.
- The CO_2 factor was revised and a new set of N_2O factors were added.

Supplement F, April 2000

- Text was revised and updated for the general section.
- All emission factors were updated except for the SO₂ factor for natural gas and distillate oil turbines.

- Turbines using staged (lean-premix) combustors added to this section.
- Turbines used for natural gas transmission added to this section.
- Details for turbine operating configurations (operating cycles) added to this section.
- Information on new emissions control technologies added to this section (SCONOX and XONON).
- HAP emission factors added to this section based on over 400 data points taken from over 60 source tests.
- PM condensable and filterable emission factors for natural gas and distillate oil fired turbines were developed.
- NOx and CO emission factors for lean-premix turbines were added.
- Emission factors for landfill gas and digester gas were added.

Emission Factors ^a						
Turbine Type	Nitrogen Oxides		Carbor	n Monoxide		
Natural Gas-Fired Turbines ^b	(lb/MMBtu) ^c Emission Factor (Fuel Input) Rating		(lb/MMBtu) ^c (Fuel Input)	Emission Factor Rating		
Uncontrolled	3.2 E-01	А	8.2 E-02 ^d	А		
Water-Steam Injection	1.3 E-01	А	3.0 E-02	А		
Lean-Premix	9.9 E-02	D	1.5 E-02	D		
Distillate Oil-Fired Turbines ^e	(lb/MMBtu) ^f (Fuel Input)	Emission Factor Rating	(lb/MMBtu) ^f (Fuel Input)	Emission Factor Rating		
Uncontrolled	8.8 E-01	С	3.3 E-03	С		
Water-Steam Injection	2.4 E-01	В	7.6 E-02	С		
Landfill Gas-Fired Turbines ^g	(lb/MMBtu) ^h (Fuel Input)	Emission Factor Rating	(lb/MMBtu) ^h (Fuel Input)	Emission Factor Rating		
Uncontrolled	1.4 E-01	А	4.4 E-01	А		
Digester Gas-Fired Turbines ^j	(lb/MMBtu) ^k (Fuel Input)	Emission Factor Rating	(lb/MMBtu) ^k (Fuel Input)	Emission Factor Rating		
Uncontrolled	1.6 E-01	D	1.7 E-02	D		

Table 3.1-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_X) AND CARBON MONOXIDE (CO) FROM STATIONARY GAS TURBINES

^a Factors are derived from units operating at high loads (≥ 80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

^b Source Classification Codes (SCCs) for natural gas-fired turbines include 2-01-002-01, 2-02-002-01, 2-02-002-03, 2-03-002-02, and 2-03-002-03. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value.

- ^c Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10⁶ scf), multiply by 1020.
- ^d It is recognized that the uncontrolled emission factor for CO is higher than the water-steam injection and lean-premix emission factors, which is contrary to expectation. The EPA could not identify the reason for this behavior, except that the data sets used for developing these factors are different.
- ^e SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.
- ^f Emission factors based on an average distillate oil heating value of 139 MMBtu/10³ gallons. To convert from (lb/MMBtu) to (lb/10³ gallons), multiply by 139.
- ^g SCC for landfill gas-fired turbines is 2-03-008-01.
- ^h Emission factors based on an average landfill gas heating value of 400 Btu/scf at 60°F. To convert from (lb/MMBtu), to (lb/10⁶ scf) multiply by 400.
- ^j SCC for digester gas-fired turbine is 2-03-007-01.
- ^k Emission factors based on an average digester gas heating value of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10⁶ scf) multiply by 600.

Emission Factors ^a - Uncontrolled						
	Natural Gas-I	Fired Turbines ^b	Distillate Oil-Fired Turbines ^d			
Pollutant	(lb/MMBtu) ^c (Fuel Input)	Emission Factor Rating	(lb/MMBtu) ^e (Fuel Input)	Emission Factor Rating		
$\rm{CO}_2^{\ f}$	110	А	157	А		
N ₂ O	0.003 ^g	E	ND	NA		
Lead	ND	NA	1.4 E-05	С		
SO ₂	0.94S ^h	В	1.01S ^h	В		
Methane	8.6 E-03	С	ND	NA		
VOC	2.1 E-03	D	4.1 E-04 ^j	Е		
TOC ^k	1.1 E-02	В	4.0 E-03 ¹	С		
PM (condensible)	4.7 E-03 ¹	С	7.2 E-03 ¹	С		
PM (filterable)	1.9 E-03 ¹	С	4.3 E-03 ¹	С		
PM (total)	6.6 E-03 ¹	С	1.2 E-02 ¹	С		

Table 3.1-2a. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSEGASES FROM STATIONARY GAS TURBINES

^a Factors are derived from units operating at high loads (≥ 80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief". ND = No Data, NA = Not Applicable.

^b SCCs for natural gas-fired turbines include 2-01-002-01, 2-02-002-01 & 03, and 2-03-002-02 & 03.

^c Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10⁶ scf), multiply by 1020. Similarly, these emission factors can be converted to other natural gas heating values.

^d SCCs for distillate oil-fired turbines are 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

^e Emission factors based on an average distillate oil heating value of 139 MMBtu/ 10^3 gallons. To convert from (lb/MMBtu) to (lb/ 10^3 gallons), multiply by 139.

- ^f Based on 99.5% conversion of fuel carbon to CO₂ for natural gas and 99% conversion of fuel carbon to CO₂ for distillate oil. CO₂ (Natural Gas) [lb/MMBtu] = (0.0036 scf/Btu)(% CON)(C)(D), where % CON = weight percent conversion of fuel carbon to CO₂, C = carbon content of fuel by weight, and D = density of fuel. For natural gas, C is assumed at 75%, and D is assumed at 4.1 E+04 lb/10⁶ scf. For distillate oil, CO₂ (Distillate Oil) [lb/MMBtu] = (26.4 gal/MMBtu) (%CON)(C)(D), where C is assumed at 87%, and the D is assumed at 6.9 lb/gallon.
- ^g Emission factor is carried over from the previous revision to AP-42 (Supplement B, October 1996) and is based on limited source tests on a single turbine with water-steam injection (Reference 5).
- ^h All sulfur in the fuel is assumed to be converted to SO₂. S = percent sulfur in fuel. Example, if sulfur content in the fuel is 3.4 percent, then S = 3.4. If S is not available, use 3.4 E-03 lb/MMBtu for natural gas turbines, and 3.3 E-02 lb/MMBtu for distillate oil turbines (the equations are more accurate).
- ^j VOC emissions are assumed equal to the sum of organic emissions.
- ^k Pollutant referenced as THC in the gathered emission tests. It is assumed as TOC, because it is based on EPA Test Method 25A.
- ¹ Emission factors are based on combustion turbines using water-steam injection.

Table 3.1-2b. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSEGASES FROM STATIONARY GAS TURBINES

Emission Factors ^a - Uncontrolled						
	Landfill Gas-F	ired Turbines ^b	Digester Gas-Fired Turbines ^d			
Pollutants	(lb/MMBtu) ^c Emission Factor Rating		(lb/MMBtu) ^e	Emission Factor Rating		
CO ₂ ^f	50	D	27	С		
Lead	ND	NA	< 3.4 E-06 ^g	D		
PM-10	2.3 E-02	В	1.2 E-02	С		
SO ₂	4.5 E-02	С	6.5 E-03	D		
VOC ^h	1.3 E-02	В	5.8 E-03	D		

^a Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief". ND = No Data, NA = Not Applicable.

^b SCC for landfill gas-fired turbines is 2-03-008-01.

^c Emission factors based on an average landfill gas heating value (HHV) of 400 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10⁶ scf), multiply by 400.

^d SCC for digester gas-fired turbine include 2-03-007-01.

^e Emission factors based on an average digester gas heating value of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10⁶ scf), multiply by 600.

^f For landfill gas and digester gas, CO₂ is presented in test data as volume percent of the exhaust stream (4.0 percent to 4.5 percent).

^g Compound was not detected. The presented emission value is based on one-half of the detection limit.

^h Based on adding the formaldehyde emissions to the NMHC.

Emission Factors ^b - Uncontrolled					
Pollutant	Emission Factor (lb/MMBtu) ^c	Emission Factor Rating			
1,3-Butadiene ^d	< 4.3 E-07	D			
Acetaldehyde	4.0 E-05	С			
Acrolein	6.4 E-06	С			
Benzene ^e	1.2 E-05	А			
Ethylbenzene	3.2 E-05	С			
Formaldehyde ^f	7.1 E-04	А			
Naphthalene	1.3 E-06	С			
РАН	2.2 E-06	С			
Propylene Oxide ^d	< 2.9 E-05	D			
Toluene	1.3 E-04	С			
Xylenes	6.4 E-05	С			

Table 3.1-3. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM NATURAL GAS-FIRED STATIONARY GAS TURBINES^a

^a SCC for natural gas-fired turbines include 2-01-002-01, 2-02-002-01, 2-02-002-03, 2-03-002-02, and 2-03-002-03. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

^b Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

^c Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60° F. To convert from (lb/MMBtu) to (lb/10⁶ scf), multiply by 1020. These emission factors can be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this heating value.

^d Compound was not detected. The presented emission value is based on one-half of the detection limit.

^e Benzene with SCONOX catalyst is 9.1 E-07, rating of D.

^f Formaldehyde with SCONOX catalyst is 2.0 E-05, rating of D.

Table 3.1-4. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM DISTILLATE OIL-FIRED STATIONARY GAS TURBINES^a

Emission Factors ^b - Uncontrolled					
Pollutant	Emission Factor (lb/MMBtu) ^c	Emission Factor Rating			
1,3-Butadiene ^d	< 1.6 E-05	D			
Benzene	5.5 E-05	С			
Formaldehyde	2.8 E-04	В			
Naphthalene	3.5 E-05	С			
РАН	4.0 E-05	С			

^a SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

^b Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

^c Emission factors based on an average distillate oil heating value (HHV) of 139 MMBtu/10³ gallons. To convert from (lb/MMBtu) to (lb/10³ gallons), multiply by 139.

Table 3.1-5. EMISSION FACTORS FOR METALLIC HAZARDOUS AIR POLLUTANTS FROM DISTILLATE OIL-FIRED STATIONARY GAS TURBINES^a

Emission Factors ^b - Uncontrolled					
Pollutant	Emission Factor	Emission Factor Rating			
	(ID/IVIIVIBLU)				
Arsenic ^d	< 1.1 E-05	D			
Beryllium ^d	< 3.1 E-07	D			
Cadmium	4.8 E-06	D			
Chromium	1.1 E-05	D			
Lead	1.4 E-05	D			
Manganese	7.9 E-04	D			
Mercury	1.2 E-06	D			
Nickel ^d	< 4.6 E-06	D			
Selenium ^d	< 2.5 E-05	D			

^a SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

^b Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

^c Emission factors based on an average distillate oil heating value (HHV) of 139 MMBtu/10³ gallons. To convert from (lb/MMBtu) to (lb/10³ gallons), multiply by 139.

Table 3.1-6. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM LANDFILL GAS-FIRED STATIONARY GAS TURBINES^a

Emission Factors ^b - Uncontrolled					
Pollutant	Emission Factor Rating				
Acetonitrile ^d	< 1.2E-05	D			
Benzene	2.1E-05	В			
Benzyl Chloride ^d	< 1.2 E-05	D			
Carbon Tetrachloride ^d	< 1.8 E-06	D			
Chlorobenzene ^d	< 2.9 E-06	D			
Chloroform ^d	< 1.4 E-06	D			
Methylene Chloride	2.3 E-06	D			
Tetrachloroethylene ^d	< 2.5 E-06	D			
Toluene	1.1 E-04	В			
Trichloroethylene ^d	< 1.9 E-06	D			
Vinyl Chloride ^d	< 1.6 E-06	D			
Xylenes	3.1 E-05	В			

^a SCC for landfill gas-fired turbines is 2-03-008-01. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

^b Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

^c Emission factors based on an average landfill gas heating value (HHV) of 400 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10⁶ scf), multiply by 400.

Table 3.1-7. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTSFROM DIGESTER GAS-FIRED STATIONARY GAS TURBINES^a

Emission Factors ^b - Uncontrolled					
Pollutant	Emission Factor (lb/MMBtu) ^c	Emission Factor Ratings			
1,3-Butadiene ^d	< 9.8 E-06	D			
1,4-Dichlorobenzene ^d	< 2.0 E-05	D			
Acetaldehyde	5.3 E-05	D			
Carbon Tetrachloride ^d	< 2.0 E-05	D			
Chlorobenzene ^d	< 1.6 E-05	D			
Chloroform ^d	< 1.7 E-05	D			
Ethylene Dichloride ^d	< 1.5 E-05	D			
Formaldehyde	1.9 E-04	D			
Methylene Chloride ^d	< 1.3 E-05	D			
Tetrachloroethylene ^d	< 2.1 E-05	D			
Trichloroethylene ^d	< 1.8 E-05	D			
Vinyl Chloride ^d	< 3.6 E-05	D			
Vinylidene Chloride ^d	< 1.5 E-05	D			

^a SCC for digester gas-fired turbines is 2-03-007-01. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

^b Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

^c Emission factors based on an average digester gas heating value (HHV) of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10⁶ scf), multiply by 600.

Table 3.1-8. EMISSION FACTORS FOR METALLIC HAZARDOUS AIR POLLUTANTSFROM DIGESTER GAS-FIRED STATIONARY GAS TURBINES^a

Emission Factors ^b - Uncontrolled						
Pollutant Emission Factor (lb/MMBtu) ^c Emission Factor Rating						
Arsenic ^d	< 2.3 E-06	D				
Cadmium ^d	< 5.8 E-07	D				
Chromium ^d	< 1.2 E-06	D				
Lead ^d	< 3.4 E-06	D				
Nickel	2.0 E-06	D				
Selenium	1.1 E-05	D				

^a SCC for digester gas-fired turbines is 2-03-007-01. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

^b Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

^c Emission factor based on an average digester gas heating value (HHV) of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10⁶ scf), multiply by 600.

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Stationary Gas and Combustion Turbines: New Source Performance Standards (NSPS)



Docket Numbers

- <u>EPA-HQ-OAR-2002-0053</u>
- <u>EPA-HQ-OAR-2004-0490</u>

On this page:

- Rule Summary
- <u>Rule History</u>
- <u>Additional Resources</u>

Rule Summary

Stationary combustion turbines are a type of internal combustion engine that is composed of three main sections. The first section, the compressor, draws air into the engine, pressurizes it, and feeds it to the combustion chamber. Fuel is mixed with the compressed air and the mixture is burned in the combustion chamber. The combustion produces a high temperature, high pressure gas stream that enters and expands through the final section, the turbine section. As hot combustion gas expands through the turbine section, it spins rotating blades which turn a shaft. The rotating blades both drive the compressor to draw more pressurized air into the combustion section and either spin a generator to produce electricity or a mechanical drive (e.g., a compressor).

The turbine exhaust gases are hot enough, several hundred degrees, to produce additional useful output. Combined cycle and combined heat and power units use heat recovery steam generators (HRSG) to produce steam from the thermal energy in the turbine exhaust. This steam can either be used to produce additional electricity or for direct heating applications.

The New Source Performance Standards (NSPS) for stationary combustion turbines are outlined in the Code of Federal Regulations under 40 CFR Part 60 Subparts GG and KKKK. Subpart GG covers turbine engines that commenced constructed after October 3, 1977 and before February 18, 2005. Subpart KKKK covers both the combustion turbine engine and any associated heat recovery steam generator for units that commenced construction after February 18, 2005. The key pollutants EPA regulates from these sources includes nitrogen oxides (NOx) and sulfur dioxide (SO₂).

Rule History

08/29/2012 – <u>Proposed Rule</u> (Stationary Gas Turbines and Stationary Combustion Turbines, subparts GG & KKKK)

03/20/2009 – <u>Direct Final Rule</u> (Stationary Combustion Turbines, subpart KKKK)

07/06/2006 – Final Rule (Stationary Combustion Turbines, subpart KKKK)

02/24/2006 – <u>Proposed Rule</u> & <u>Direct Final Rule</u> (Stationary Gas Turbines, Subpart GG)

Stationary Gas and Combustion Turbines: New Source Performance Standards (NSPS) | Stationary Sources of Air Pollution | US EPA 02/18/2005 – <u>Proposed Rule</u> (Stationary Combustion Turbines, subpart KKKK)

07/08/2004 – Final Rule; amendments (Stationary Gas Turbines, Subpart GG)

05/28/2003 – <u>Withdrawal of Direct Final Rule</u> (Stationary Gas Turbines, Subpart GG)

04/14/2003 – <u>Proposed Rule</u> & <u>Direct Final Rule</u> (Stationary Gas Turbines, Subpart GG)

11/05/1987 – Final Rule; correction (Stationary Gas Turbines, Subpart GG)

01/27/1982 – <u>Final Rule</u> (Stationary Gas Turbines, Subpart GG)

04/15/1981 – Proposed Rule (Stationary Gas Turbines, Subpart GG)

09/10/1979 – <u>Final Rule</u> (Stationary Gas Turbines, subpart GG)

10/03/1977 - Proposed Rule (Stationary Gas Turbines, subpart GG)

Additional Resources

<u>Response to Public Comments on Proposed Standards of Performance for</u> <u>Stationary Combustion Turbines (February 2006)</u>

Economic Impact Analysis of the Stationary Combustion Turbines NSPS: Final Report (February 2006)

Economic Impact Analysis of the Proposed Stationary Combustion Turbines NSPS: Final Report (February 2005)

View the <u>supporting documents in the docket folder</u> to find additional related documents to the rules.

Related Rules

<u>Stationary Combustion Turbines: National Emission Standards for Hazardous Air</u> <u>Pollutants (NESHAP)</u>

<u>Alternative Control Techniques Document: NOx Emissions from Stationary Gas</u> <u>Turbines</u>

LAST UPDATED ON SEPTEMBER 26, 2016

Cost-of-Service Rate Filings

The Natural Gas Act (NGA) requires that rates charged for interstate pipeline services be "just and reasonable." Setting just and reasonable rates requires a balancing of equities between the interests of the pipeline and its ratepayers. The basic methodology we use to establish just and reasonable rates is cost-of-serve ratemaking. Under cost-of-service ratemaking, rates are designed based on a pipeline's cost of providing service including an opportunity for the pipeline to earn a reasonable return on its investment.

The Commission sets rates for interstate pipeline services in a number of proceedings. For example, when a pipeline files to increase its rates, it makes a filing with the Commission under Section 4 of the NGA. These types of filings are referred to as general Section 4 rate cases. In these proceedings, the Commission reviews all of a pipelines rates and services. A pipeline can file a general Section 4 rate case anytime it wishes, provided the pipeline did not agree otherwise in a settlement. A pipeline must demonstrate that the new rates it proposes to charge are just and reasonable. When a rate increase filing is made pursuant to Section 4, the application is typically suspended and set for hearing by the Commission's litigation staff in Office of Administrative Litigation (OAL). The issues in the application can be settled if parties can reach consensus. However, if the issues cannot be resolved, they will proceed to a hearing before an Administrative Law Judge (ALJ). Whether the case is settled or proceeds to hearing, the Commission will eventually need to act upon the settlement, or upon the record in the hearing.

The Commission also has authority under Section 5 of the NGA to require prospective changes in the rates charged by a pipeline when it can be demonstrated that the rates are no longer just and reasonable. The Commission can initiate a Section 5 proceeding on its own motion or upon complaint from an interested party. In a Section 5 proceeding, the Commission has the burden of demonstrating that the currently effective rates of the pipeline are no longer just and reasonable, and of establishing just and reasonable rates.

The Commission also sets rates for pipeline services under Section 7 of the NGA. Under Section 7(c) of the NGA a pipeline files to request a "Certificate of Public Convenience and Necessity" to construct a new pipeline or to expand existing facilities, in order to offer new or additional services. The rates established by the Commission under Section 7 for these services are referred to as "initial rates" and generally remain in effect until such time as the pipeline files a Section 4 rate filing in which all of a pipeline's rates are reviewed.

Additionally, the Commission sets rates for intrastate pipelines under Section 311 of the Natural Gas Policy Act (NGPA). Under Section 311, intrastate pipelines are permitted to

Cost-of-Service Rate Filings | Federal Energy Regulatory Commission

transport gas for interstate pipelines and local distribution companies (LDC) in interstate commerce without becoming subject to jurisdiction under the NGA (intrastate pipelines are regulated by their State Agencies). The rates established under Section 311 must meet a "fair and equitable" standard, as opposed to a "just and reasonable" standard. When this Commission sets the rates for Section 311 service, the rates are computed using the same costof-service methodology used under the NGA. However, an intrastate pipeline may elect to use an approved cost-based rate on file with the State agency that regulates its intrastate business.

Finally, there are "limited" Section 4 filings where pipelines file to add a new service and establish new rates, as well as, complaint proceedings that raises rate issues to be addressed by the Commission.

The <u>Implementation Guide for Electronic Filing</u> contains information for interstate pipelines creating the required Schedules and Statements for a general rate cases, and for the public to understand the content of a general rate cases.

<u>Home</u>

Town of Weymouth Property Viewer

Welcome to the Town of Weymouth on-line Property Records Viewing System. This system provides access to the Town's property records maintained in the Assessor's Office or day a week, 24-hour a day basis. Through this system, you can view property information, pictures, and maps.

The Property Viewer Search Feature does not work with Internet Explorer 8 and other legacy browsers. Upgrading IE, using Firefox, or using Chrome will allow you to search our Property Viewer.

Values are based on FY2020 with an Assessment date of 1/1/2019. *Note some values may reflect work in progress due new construction, building permits, etc. Final values for F Year 2021 will be available after January 1, 2021. If additional information is needed please contact the Assessor's Office. ALSO SEE DISCLAIMER.

SEARCH FOR A: P	roperty	Map Location					
House Number				Parcel ID	Address	Owner	
Street Name			~	No results.			
Owner							
Block Number							
Lot Number							
	Search						
	Show Adv	anced Search					

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Assessor

The Assessor's Office is responsible for the administration of all laws and regulations regarding property tax assessment. The Assessors, as required by Chapters 59, 60A, 61, 121A of the Massachusetts General Laws and various Acts of the Legislature, perform the appraisal of approximately 21,000 parcels of property. This includes residential, commercial, industrial, utilities, and personal property. The Assessor commits to the Collector over 58,000 excise tax bills to be processed on motor vehicles and boats each year. The Assessors establish the assessed value of property each fiscal year.

The Mayor and Town Council determine the budget each year. A tax classification hearing is held each year in the Town Council Chambers at Town Hall. The Town Council votes to distribute the tax burden amongst classes as a result of this hearing. The Assessor then commits to the Collector the amount of taxes to be collected including betterments and water and sewer liens. The Assessors handle requests for abatements and exemptions through the avenues prescribed by the Massachusetts Legislature. The exemptions are for veterans with at least 10% service related disability, income-eligible elderly, surviving spouse, and blind.

< A

Assessor | Weymouth MA

This Division also is responsible for preparing cases for hearing and defending property values before the Massachusetts Appellate Tax Board and for reporting all sales within the Town to the Massachusetts Department of Revenue. The Assessors' Office works daily with the inquiries of taxpayers, planners, developers, builders, real estate professionals and others. The Assessors coordinate the revaluation process to comply with the laws of the Commonwealth and to achieve a sound base for fiscal planning within the Town.

Staff Contacts

Name	Title	Phone
Patricia O'Kane M.A.A.	Principal Assessor	781-682-3853
Boat Declaration - Form of List		
Boat Excise Abatement Application		
Boat Excise Information		
Change of Address Form		
Change of Business Status Form		
FY20 Sales		
FY20 Tax Classification		
Motor Vehicle Excise Abatement App	olication	
Motor Vehicle Excise FAQ		
Norfolk County Registy of Deeds		
Online Property Viewer		
Personal Property Form of List		
Propositon 2 1/2		
Weymouth Tax Rates		
Contact Info		

Hours of Operation:

8:30AM to 4:30PM, Monday through Friday. Closed most holidays Phone: (781) 682-3677 Fax: (781) 682-6142 Address: 75 Middle Street Weymouth, MA 02189 United States See map: Google Maps

Frequently Asked Questions

I am elderly. Does the Town offer any help with payment of taxes?

Why do the assessors want to see the interior and exterior of my property?

Must I apply for an Exemption every year if I have been approved?

I recently purchased my home. When will the tax bill be sent in my name?

I have not made any improvements to my home, how can my value increase? Can my taxes increase more that 2.5%?

View all

News & Announcements

Senior and Veterans Exemption Applications now being accepted for Fiscal Year 2021

Town of Weymouth 75 Middle Street, Weymouth, MA 02189 Phone: (781) 335-2000 Fax: (781) 335-3283 Website Disclaimer | Government Websites by CivicPlus ®

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Massachusetts Department of Environmental Protection (MassDEP) Top Case Best Available Control Technology (BACT) Guidelines

This information is maintained by the MassDEP, Bureau of Air and Waste, Air Pollution Control Program, and is subject to change. These listings present Top Case BACT guidelines for Non-major air contaminants emitting sources.

For a particular air contaminant subject to BACT under a Prevention of Significant Deterioration (PSD) permit, or Lowest Acheivable Emission Rate (LAER) under 310 CMR 7.00 Appendix A, Emission Offsets and Nonattainment Review, collectively termed Major New Source Review, the Top Case Guidelines do not apply. PSD BACT and Appendix A LAER must be analyzed on a case-by-case basis.

This Guidance is published for informational purposes only. Use of the applicable Top Case BACT emissions limitations contained herein may preclude the need for applicants to prepare and submit a "top-down BACT analysis" for MassDEP's review, and will streamline the Air Quality permitting process for both the applicants and MassDEP. Applicants should note that BACT requirements for any new or modified air contaminants source are subject to change through the MassDEP 310 CMR 7.02 Air Quality Plan Approval (permitting) procedures. Please contact the MassDEP Regional Office that regulates your facility should you have any questions related to these Top Case BACT guidelines.

Please be aware that, in addition to BACT requirements, federal NSPS, MACT and/or GACT requirements may also apply pursuant to 40 CFR Parts 60, 61 and 63.

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BOILERS (June, 2011)						
Source Type	Fuel	Air	Emission	Control Technology	BACT Determination	
		Contaminant	Limitations			
Dellere	NI - 4 1	NOx	0.0350 lb/MM Btu	• Low NOx burners, FGR	310 CMR 7.26(33)(b): IPS Regulations	
Boilers	Boilers Natural Gas 10 mmBtu to <40 MMBtu	PM	0.010 lb/MM Btu			
10 mmBtu to < 10		CO	0.080 lb/MM Btu			
MMBtu		VOC	0.030 lb/MM Btu			
Doilors	Ultra Low	NOx	0.150lb/MMBtu	• Low NOx	310 CMR 7.26(33)(b): IPS Regulations	
Doners	Distillate	PM	0.020 lb/MMBtu	burners, FGR		
10 mmRtu to < 40	0.0015 %	CO	0.080 lb/MM Btu			
MMBtu	0.0015 /0	VOC	0.030 lb/MM Btu			
		NOx	0.011 lb/MMBtu	• Ultra Low NOx	US EPA RBLC Database	
Boilers	Natural	PM	0.002 lb/MMBtu	burners, Low		
× 40 MD 4 4	Gas	СО	0.035 lb/MMBtu	NOx burners,		
\geq 40 MMBtu to <100 MMBtu		VOC	0.035 lb/MMBtu	FGR		
	Ultra Low	NOx	0.100 lb/MMBtu	Ultra Low NOx	US EPA RBLC Database	
Boilers	Sulfur	PM	0.015 lb/MMBtu	burners, Low		
	Distillate	CO	0.035 lb/MMBtu	NOx burners,		
≥40 MMBtu to <100 MMBtu	0.0015 %	VOC	0.035 lb/MMBtu	FGR		
Boilers		NOx	0.011 lb/MMBtu	Ultra Low NOx burners, Low NOx burners, FGR, SCR	310 CMR 7.02 Plan Approval, Transmittal Number X229675	
		PM	0.01 lb/MMBtu			
	Natural	CO	0.011 lb/MMBtu			
≥100 mmBtu to <250 MMBtu	Gas	VOC	0.03 lb/MMBtu			

BOILERS (June, 2011)						
Source Type	Fuel	Air	Emission	Control Technology	BACT Determination	
		Contaminant	Limitations			
		NOx	0.100 lb/MMBtu	• Ultra Low NOx		
Boilers	Ultra Low			burners, Low	310 CMR 7.02 Plan	
	Sulfur	PM	0.03 lb/MMBtu	NOx burners,	Approval, Transmittal	
>100 MMBtu to 249	Distillate			FGR, SCR	Number X229675	
MMBtu	0.0015 %					
		VOC NOv	$\frac{0.03 \text{ ID/WIWIBLU}}{0.011 \text{ Ib/MMBtu}}$			
Doilora	Natural			Ultra Low NOx		
Dollets	Gas	PM CO	0.002 ID/IVINIBLU	NOv hymners	US EFA PPLC Databasa	
>250 MMBtu	Gas		$\frac{0.013 \text{ ID/IVIIVIDIU}}{0.015 \text{ Ib}/IVIIVIDIU}$	ECD SCD	RDLC Database	
	Illena Lavy	VOC NOv	$\frac{0.015 \text{ ID/WIWIBIU}}{0.100 \text{ Ib/MMBtu}}$			
Poilara	Sulfur		0.100 ID/IVIIVIDIU	Ultra Low NOX		
Doners	Distillate			NOv burners	RBLC Database	
>250 MMBtu	0.0015 %		0.035 ID/IVIIVIBIU	FGR SCR	RDLC Database	
<u>>230 MiMBtu</u>	0.0015 /0	VOC		TOR, SER		
D - '1		NOX	0.030 lb/MMBtu	• Low NOx		
Boilers		PM	0.0100 lb/MMBtu	burners, FGR	US EPA EIA Database	
>250 MMPtu	Coal	CO	0.050 lb/MMBtu	• SCR		
≥ 230 WIWIDtu	Coal	VOC	0.035 lb/MMBtu	• Oxidization		
		SO_2	0.080 lb/MMBtu	catalyst		
		NH ₃	2 ppmvd at 3% O ₂	• FF/Baghouse		
				• FGD (wet or dry		
				at 98-99 %		
				afficiency)		
				efficiency)		
Key to Abbreviations

lb/MMBtu = pounds per million British thermal units ppmvd = parts per million volume dry % = weight percent NOx = nitrogen oxides $SO_2 = sulfur dioxide$ PM = particulate matter (including condensables) $O_2 = oxygen$ CO = carbon monoxide $NH_3 = ammonia$ VOC = volatile organic compounds FF = fabric filter/baghouse SCR = selective catalytic reduction technology CEMS = continuous emissions monitoring system FGD = flue gas desulfurization FGR = flue gas recirculation RBLC = RACT BACT LAER Clearinghouse

	INCINERATORS (June, 2011)						
Source Type	Fuel	Air Contaminant	Emission Limitations*	Control Technology	BACT Determination		
Municipal Waste	Municipal solid waste (household, commercial, and institutional waste)	ContaininantNOxNH3COVOCCdPbHgSO2**HCI**Dioxin/Furan(CDD/CDF)	2 ppmvd 2 ppmvd 2 ppmvd 2 ppmvd ** ** ** ** ** **	 Gasification of MSW to SynGas Combustion of SynGas via Combustion Turbine Technology (or equivalent combustion methodology). Pollutant emissions may be controlled during syngas production and/or post- combustion. 	 LA County Conversion Technology Evaluation Report – Phase II – Assessment (October 2007) NYC Focused Verification and Validation of Advanced SW Management Conversion Technologies – Phase 2 Study (March 2007) 		
Medical Waste (for all incinerator sizes)	Medical and pathological waste	NOx PM CO SO ₂ Pb Cd Hg	250 ppmvd 0.015 gr/dscf 40 ppmvd 55 ppmvd 0.07 mg/dscm or 98% removal efficiency 0.04 mg/dscm or 90% removal efficiency 0.55 mg/dscm or 85%	 dry scrubber, wet scrubber good combustion control Practices carbon injection 	US EPA 40 CFR Part 60 Subpart Ec		

	INCINERATORS (June, 2011)					
Source Type	Fuel	Air Contaminant	Emission Limitations*	Control Technology	BACT Determination	
			removal efficiency			
		Dioxin/Furan Total	25 ng/dscm			
		Dioxin/Furan TEQ	0.6 ng/dscm			
		PM	0.06 gr/dscf	• Secondary chamber design		
Crematoria		CO	100 ppmvd	retention time and	310 CMR 7.02 Plan	
(Human bodies and body parts)	Natural Gas	Opacity	10 percent	 temperature, 1 second at 1,800 degrees °F Secondary chamber minimum operating temperature, 1,600 °F Opacity Monitor 	Approval, Transmittal Number X227136	

*all emission limitations are corrected to 7 percent O₂

**Emissions of metals (Cd, Hg, Pb, etc.), dioxin/furans (CDD/CDF) and acid gases (HCl and H₂SO₄/SO₂) are to be determined on a case-by-case basis, consistent with the MassDEP BACT Guidelines, NESCAUM BACT Guidelines, and US EPA NSR BACT requirements. Ambient air quality modeling will be required to demonstrate compliance with MassDEP "<u>Ambient Air Exposure</u> <u>Limits for Chemicals in Massachusetts</u>".

Key to Abbreviations

mg = milligram ng = nanogram gr = grainsdscf = dry standard cubic foot dscm = dry standard cubic meter ppmvd = part per million volume dry % = weight percent NOx = nitrogen oxides $SO_2 = sulfur dioxide$ PM = particulate matter (including condensables) $O_2 = oxygen$ Pb = leadCd = cadmiumHg = mercuryCO = carbon monoxideHCl = hydrogen chloride FF = fabric filter ESP = electrostatic precipitator SNCR = selective non catalytic reduction CEMS = continuous emissions monitoring system FGD = flue gas desulfurization TEQ = toxic equivalent

	BIOMASS	FUEL FIRED S	STEAM ELECTRIC GEN	ERATION UNITS (June, 2011)	
Source Type	Fuel	Air	Emission Limitations	Control Technology	BACT Determination
		Contaminant			
DOL		NOx	0.015 lbs/MMBtu		
EGUs		PM	0.012 lbs/MMBtu		MaaDED
> 25 MW	Diamaga	СО	0.01 lbs/MMBtu	• SCR	MassDEP DACT Cuidenee for
≥ 23 IVI VV	DIOIIIASS	VOC	0.01 lbs/MMBtu	• Oxidization Catalyst	Biomass Projects
		SO ₂	0.02 lbs/MMBtu	• FF/Baghouse	April 2007
		NH ₃	2 ppmvd at 3 percent	AERSKCEEN or AERMOD for Tarrier	<u>April 2007</u>
			O_2	Modeling	
		Opacity	5 percent	• Motels testing for C&D	
		HCl	20 ppmvd at 3 percent	• Metals testing for C&D and possibly other	
			O ₂	biomass	
		Toxics*	• 85% Hg RE	 PM testing must also 	
			• 99% Heavy	included condensable PM	
			Metal RE	• FGD	
			• AALs and	102	
			I ELS		
			modeling		
			demonstration		
		NOv	0.015 lbs/MMBtu		
FGUs		NOA	0.013 105/10101010	• SCP	
1005	Biomass	PM	0.012 lbs/MMBtu	 Ovidization Catalyst 	MassDEP
Equal to $or > 10 MW$	Biolilass	CO	0.01 lbs/MMBtu	EE/Paghouse	BACT Guidance for
and $< 25 \text{ MW}$		VOC	0.01 lbs/MMBtu	• AERMOD for Toxica	Biomass Projects.
		SO ₂	0.02 lbs/MMBtu	• ALKWOD IOI TOXICS Modeling	April 2007
		NH ₃	2 ppmvd at 3 percent	 Metals testing for C&D 	_ <u>_</u>
			O ₂	- inicials testing for C&D	
		Opacity	5 percent	and possibly other	

	BIOMASS	FUEL FIRED S	STEAM ELECTRIC GEN	ERATION UNITS (June, 2011)	
Source Type	Fuel	Air	Emission Limitations	Control Technology	BACT Determination
		HCl Toxics*	20 ppmvd at 3 percent O ₂ • 85% Hg RE • 99% Heavy Metal RE • AALs and TELs compliance modeling demonstration	 biomass PM testing must also included condensable PM FGD 	
FGUs		NOx	0.093 lbs/MMBtu		
LUUS	Biomass	PM	0.012 lbs/MMBtu		
Equal to $or > 1 MW$	Diomass	CO	0.25 lbs/MMBtu	• SCP	MassDFP
and $< 10 \text{ MW}$		VOC	0.01 lbs/MMBtu	 Ovidization Catalyst 	BACT Guidance for
		SO_2	0.02 lbs/MMBtu	EE/Paghouso	Biomass Projects
		NH ₃	10 ppmvd at 3 percent O ₂	AERMOD for Toxics	April 2007
		Opacity	5 percent	• Motels testing for C &D	
		HCl	20 ppmvd at 3 percent O ₂	and possibly other	

	BIOMASS FUEL FIRED STEAM ELECTRIC GENERATION UNITS (June, 2011)						
Source Type	Fuel	Air	Emission Limitations	Control Technology	BACT Determination		
		Contaminant					
		Toxics*	• 85% Hg RE	biomass			
			• 99% Heavy	• PM testing must also			
			Metal RE	included condensable PM			
			 AALs and 	• FGD			
			TELs				
			compliance				
			modeling				
			demonstration				

*Ambient air quality modeling will be required to demonstrate compliance with MassDEP "<u>Ambient Air Exposure Limits for</u> <u>Chemicals in Massachusetts</u>". for projects where: 1. construction and demolition wood is burned; 2. boilers that are major source of Criteria Air Contaminants or Hazardous Air Pollutants.

Key to Abbreviations

lb/MMBtu = pounds per million British thermal units % = weight percent ppmvd = parts per million volume dry NOx = nitrogen oxides SO_2 = sulfur dioxide PM = particulate matter (including condensables) O_2 = oxygen CO = carbon monoxide NH₃ = ammonia HCl = hydrogen chloride

- FF = fabric filter/baghouse
- RE = removal efficiency

SCR = selective catalytic reduction technology

CEMS = continuous emissions monitoring system

FGD = flue gas desulfurization

AAL = Allowable Ambient Limit

TEL = Threshold Effects Exposure Limit

RECIPROCATING INTERNAL COMBUSTION ENGINES (June, 2011)						
Fuel Air Emission Limitations		BACT Determination				
	Contaminant					
	NOx	0.3 lbs/MW-hr				
Natural Gas	CO	2 lbs/MW- hr	310 CMR 7.26(43)(b): Table 2 and 4			
	CO_2	1900 lbs/MW-hr	IPS Regulations			
	NOx	0.3 lbs/MW-hr				
Ultra Low Sulfur Distillate 0 0015	PM	0.07 lbs/MW-hr	310 CMR 7.26(43)(b): Table 2 and 4 IPS Regulations			
%	СО	2 lbs/MW- hr	n 5 Regulations			
	CO_2	1900 lbs/MW-hr				
	NOx	0.15 lb/MW-hr				
	PM	0.03 lb/MW-hr	310 CMR 7.26(43)(b): Table 2 and 4			
Natural Gas	СО	1 lb/MW-hr	IPS Regulations			
	CO ₂	1650 lb/MW-hr				
Ultra Low Sulfur	NOx	0.15 lb/MW-hr				
Distillate 0.0015	PM	0.03 lb/MW-hr	310 CMR 7.26(43)(b): Table 2 and 4			
70	СО	1 lb/MW-hr	IFS Regulations			
	CO ₂	1650 lb/MW-hr				
Natural Gas or Ultra Low Sulfur Distillate 0.0015	Must comply with the applicable emission limitations set by US EPA for non-road engines at 40 CFR 89.		310 CMR 7.26(42)(b)1. IPS Regulations			
	RECIPR Fuel Natural Gas Ultra Low Sulfur Distillate 0.0015 % Natural Gas or Ultra Low Sulfur Distillate 0.0015 %	RECIPROCATING INTERFuelAir ContaminantNatural GasNOxNatural GasCOUltra Low Sulfur Distillate 0.0015 %PMCOCO2NoxPMCO2NOxPMCOCO2CO2Natural GasCO%COCO2CO2Ultra Low Sulfur Distillate 0.0015 %NOxPMCOCO2CO2Ultra Low Sulfur Distillate 0.0015 %PMMust comply w limitations set engin %Imitations set engin	FuelAirEmission LimitationsFuelAirEmission LimitationsContaminantNOx0.3 lbs/MW-hrNatural GasCO2 lbs/MW- hrCO21900 lbs/MW-hrUltra Low SulfurPM0.07 lbs/MW-hrDistillate 0.0015CO2 lbs/MW- hr%CO2 lbs/MW-hrCO21900 lbs/MW-hr%CO2 lbs/MW-hrMOx0.15 lb/MW-hr%CO1 lb/MW-hrNatural GasCO1 lb/MW-hr%CO1 lb/MW-hrUltra Low Sulfur Distillate 0.0015NOx0.15 lb/MW-hr%CO1 lb/MW-hr			

Key to Abbreviations:

lbs/MW-hr = pounds per megawatt hour
NOx = nitrogen oxides
PM = particulate matter (including condensables)
CO = carbon monoxide
CO₂ = carbon dioxide
MW = megawatt
kW = kilowatt
% = weight percent
IPS = Industrial Performance Standards

	COMBUSTION TURBINES (June, 2011)						
Source Type	Fuel	Air Contaminant	Emission Limitations	BACT Determination	Control Technology		
Combined Cycle	Natural Gas	NOx	2.0 ppmvd at 15 % O ₂	Plan Approval, Transmittal	• Dry Low NOx		
Turbine				Number W004632	Combustor		
		NH ₃	2.0 ppmvd at 15 % O ₂		• SCR		
> 10 MW/hr		СО	2.0 ppmvd at 15 % O ₂		Oxidation catalyst		
		VOC	1.7 ppmvd at 15 % O ₂		• NOx, CO, NH_3		
		CO_2	Contact Regional Office				
Combined Cycle	Ultra Low	NOx	6.0 ppmvd at 15 % O ₂	Plan Approval, Transmittal	Dry Low NOx		
Turbine	Sulfur Distillate			Number W004896	Combustor		
	Oil	NH ₃	2.0ppmvd at 15 % O ₂		• SCR		
> 10 MW/hr	0.0015 %	СО	7.0 ppmvd at 15 % O ₂		Oxidation catalyst		
		VOC	7.0 ppmvd at 15 % O ₂		$- \bullet \text{ NOX, CO, NH}_3$		
		CO_2	Contact Regional Office		CENIS		
Simple Cycle Turbine	Natural Gas	NOx	2.5 ppmvd @15 % O ₂	Plan Approval, Transmittal Number W120701	Dry Low NOx Combustor		
		NH ₃	5.0 ppmvd @ 15 % O ₂		• SCR		
> 10 MW/hr			with an optimization		Oxidation catalyst		
			program to achieve		• NOX CO NH ₂		
			2.0 ppmvd @15 % O ₂		CEMS		
		СО	5.0 ppmvd @15 % O ₂				
		VOC	2.5 ppmvd @15 % O ₂				
		CO ₂	Contact Regional Office				
Simple Cycle	Ultra Low	NOx	5.0 ppmvd at 15 % O ₂	Plan Approval, Transmittal	Dry Low NOx		
Turbine	Sulfur Distillate			Number W120701			

		CO	MBUSTION TURBINES (June,	, 2011)	
Source Type	Fuel	Air Contaminant	Emission Limitations	BACT Determination	Control Technology
	Oil	NH_3	5.0 ppmvd at 15 % O ₂		Combustor
> 10 MW/hr	0.0015 %	СО	5.0 ppmvd @15 % O ₂		• SCR
		VOC	4.5 ppmvd @15 % O ₂		• Oxidation catalyst
		CO_2	Contact Regional Office		CEMS
Combustion Turbine	Natural Gas	NOx	0.47 lbs/MW-hr	310 CMR 7.26(43) IRP Regulation	
Less than 1 MW		СО	0.47 lbs/MW-hr		
		CO_2	NA		
Combustion	Ultra Low		0.60 lbs/MW-hr	310 CMR 7.26(42)	
Turbine 37 kW to	Sulfur Distillate	NOx		IRP Regulation	
≤1 MW (Emergency Only)	Oil 0.0015 %	CO_2	Contact Regional Office		
Combustion Turbine	Natural Gas	NOx	0.14 lbs/MW-hr	310 CMR 7.26(43) IRP Regulation	SCROxidation catalyst
1 MW to 10 MW		NH ₃	2.0 ppmvd @ 15 % O ₂		• (possible required
		СО	0.09 lbs/MW-hr		technology)
		CO_2	1900 lbs/MW-hr		
Combustion	Ultra Low	NOx	0.34 lbs/MW-hr	310 CMR 7.26(43)	• SCR
Turbine	Sulfur Distillate			IRP Regulation	Oxidation catalyst
1 MW to 10 MW	Oil	NH ₃	2.0 ppmvd @ 15 % O2		• (possible required
	0.0015 %	СО	0.18 lbs/MW-hr		technology)
		CO_2	1900 lbs/MW-hr		
Combined Cycle Combustion		NOx	2.0 ppmvd at 15 % O ₂	See Combined Cycle Turbine Transmittal Numbers above	Gasification of coal with gas cleaning
Turbine Coal	Coal	NH ₃	2.0 ppmvd at 15 % O ₂		technology
Gasification		СО	2.0 ppmvd at 15 % O ₂		Post-combustion GT

COMBUSTION TURBINES (June, 2011)						
Source Type	Fuel	Air Contaminant	Emission Limitations	BACT Determination	Control Technology	
IGCC Technology		VOC	2.0 ppmvd at 15 % O ₂		gas cleaning	
		CO ₂	Contact Regional Office			

Key to Abbreviations:

lbs/MW-hr = pounds per megawatt hour lb/MMBtu = pounds per million British thermal unit ppmvd = part per million volume dry NOx = nitrogen oxidesCO = carbon monoxide $CO_2 = carbon dioxide$ $O_2 = oxygen$ VOC = volatile organic compounds NOx = nitrogen oxides $NH_3 = ammonia$ MW = megawattSCR = selective catalytic reduction CEMS = continuous emissions monitoring system % = weight percent GT = gas turbinekW = kilowattIGCC = integrated gasification combined cycle

*Emission Limitations – Output Based shall incorporate the heat rate component necessary to evaluate energy efficiency. At this time BWP should evaluate only the specific combustion unit or system (simple cycle turbine, combined cycle turbine, etc.), however BWP should request the project proponent to evaluate the proposed project as a "whole" and provide a facility output based emission rate (BACT) for the project to incorporate the use of energy efficient of ancillary equipment.

	PRINTING* (June, 2011)							
Source Type	Air Contaminant	Minimum Requirements	Control Technology	BACT Determination				
Non-heatset Lithographic Printing	VOC	 Fountain solutions: Web-fed - No Alcohol allowed Sheet-fed - unrefrigerated ≤ 5% VOC refrigerated (< 60 °F) and ≤ 8% VOC (by weight, including alcohol) Cleanup Solution ≤ 30% VOC by weight, or VOC composite partial pressure of 10 mmHg at 20 °C or less Adhesive Standard (Midsize and large printers) - ≤300 g VOC per liter of product, less water, as applied Record keeping in accordance with 310 CMR 7.26(28) 	 Fountain solution tanks covered Clean-up Solution in covered containers Shop towels with solvent kept in covered containers 	310 CMR 7.26(24) IPS Regulation				

PRINTING* (June, 2011)							
Graphic Arts Printing Gravure, Letterpress and Flexographic	VOC	 Standards – Midsize and Large Printers Ink – ≤300 g VOC per liter of product, less water, as applied Coating – ≤300 g VOC per liter of product less water, as applied Adhesive – ≤150 g VOC per liter of product, less water, as applied Clean-up solution standard – VOC composite partial pressure of ≤ 25 mm Hg (at 20 °C) Record keeping in accordance with 310 CMR 7.26(28) 	 Clean-up solution in covered containers Shop towels with solvent kept in covered containers 	310 CMR 7.26(25) IPS Regulation			

	PRINTING* (June, 2011)		
Screen Printing	 Standards – Midsize and Large Printers Ink – ≤400 g VOC per liter of product, less water, as applied Coating – ≤400 g VOC per liter of product less water, as applied Adhesive –≤ 400 g VOC per liter of product, less water, as applied Extreme Performance Ink/Coating – ≤800 g VOC per liter of product, less water, as applied Metallic Ink - ≤400 g VOC per liter of product, less water, as applied Conductive Ink - ≤850 g VOC per liter of product, less water, as applied Conductive Ink - ≤850 g VOC per liter of product, less water, as applied Clean-up solution standard – VOC composite partial pressure of ≤ 5 mm Hg (at 20 °C) Record keeping in accordance with 310 CMR 7.26(28) 	 Clean-up Solution in covered containers Shop towels with solvent kept in covered containers 	310 CMR 7.26(26) IPS Regulation
Printers with: Heatset Presses or VOC Non-conforming Operations	See Regulation 310 CMR 7.26(27) for minimum BACT Requirements		310 CMR 7.26(27) IPS Regulation

		PRINTING* (June, 2011)
All Printers	ers HAPs Facilities may obtain a federally enforceable approval to cap HAPs below MACT major source	Facilities may obtain a federally enforceable
		approval to cap HAPs below MACT major source
		thresholds to < 25 tons of total HAPs per rolling 12
		month period and to < 10 tons of any individual
		HAPs per rolling 12 month period

*Printers that **exceed** the facility emissions/usage thresholds contained in Regulation 310 CMR 7.26 are subject to Best Available Control Technology (BACT), The BACT determinations require the installation of PTE and VOC destruction/removal efficiency of 98-99% utilizing regenerative thermal oxidation, thermal oxidation, catalytic oxidation, etc. **See Miscellaneous VOC Source BACT.**

Key to Abbreviations

- VOC = volatile organic compounds HAPs = Hazardous Air Pollutants PTE = Permanent Total Enclosure IPS = Industrial Performance Standards % = weight percent @ = at kPa = kilopascal < = less than ≤ = less than or equal to > = greater than
- \geq = greater than or equal to

CMR = Code of Massachusetts RegulationsCFR = Code of Federal Regulations $ft^2 = square feet$

 $m^3/min =$ cubic meters per minute m/min = meters per minute g = grams $^{\circ}F =$ degrees Fahrenheit $^{\circ}C =$ degrees Celsius mm Hg = millimeters of mercury

Painting – Enclosed Painting (June, 2011)						
Source Type	Air Contamin ant	Minimum Requirements	Control Technology	BACT Determination		
Enclosed Painting < 670 gallons materials containing VOC per month or < 2.5 tons of VOC per month and < 2,000 gallons material containing VOC per 12 month rolling period or <18 tons VOC per 12 month rolling period • Sources having VOC emissions or coating usage greater than the thresholds listed above, must capture and control VOC emissions	VOC	 Painting must be conducted in spray booth Coatings must comply with 310 CMR 7.18 source specific requirements Exempt (See 310 CMR 7.18 source specific requirements) coating cannot exceed 55 gallons per 12 month rolling period Spray guns must be either: electrostatic, high volume low pressure (HVLP), or other having equal or better transfer efficiency than electrostatic or HVLP and approved by MassDEP in writing. Spray gun cleaning activities to minimize evaporation, maximize solvent re-use, collect spent solvent into air tight containers 	 Coating formulations Maximized transfer efficiency TO, RTO, CA or other air pollution control technology to achieve collection/destruction efficiency ≥ 98% for sources ≥ 18 tons of VOC per rolling 12 month period Project proponent must evaluate all P2 opportunities before resorting to "end of pipe" control of VOC 	310 CMR 7.03(16)		

	Painting – Enclosed Painting (J	une, 2011)	
HAPs	 See 40 CFR Part 63 Facilities may obtain a federally enforceable approval to cap HAPs below MACT major source thresholds to < 25 tons of total HAPs per rolling 12 month period and to < 10 tons of any individual HAPs per rolling 12 month period 	 See 40 CFR Part 63 Facilities may obtain a federally enforceable approval to cap HAPs below MACT major source thresholds to < 25 tons of total HAPs per rolling 12 month period and to < 10 tons of any individual HAPs per rolling 12 month period 	40 CFR Part 63
PM	 Particulate control efficiency ≥99% Face velocity ≤200 ft/min 	• Dry filter media ≥97% collection efficiency	310 CMR 7.03(16)
Opacity	 no visible emissions (zero percent opacity) 		
All Pollutants	 stack must discharge vertically stack rain protection which impedes vertical discharge is NOT allowed stack velocity > 40 ft/s minimum stack exit height: 35 ft above ground or 10 ft above roof level No nuisance odors 		

Key to Abbreviations VOC = volatile organic compounds HAPs = hazardous air pollutants PM = particulate matter TO = thermal oxidizer RTO = regenerative thermal oxidizer CA = carbon adsorption % = weight percent > = greater than \geq = greater than or equal to < = less than \leq = less than or equal to CFR = Code of Federal Regulations CMR = Code of Massachusetts Regulations m/hr = meters per hourft = feetft/min = feet per minute ft/s = feet per secondP2 = pollution prevention

Painting – Outdoor Painting (June, 2011)					
Source Type	Air	Minimum Requirements	Control Technology	BACT	
	Contaminant			Determination	
Outdoor Painting Ship Painting VOC \geq 18 tons per 12 month rolling period	Contaminant VOC	 Painting must be conducted in an enclosed/shrouded area, 99% capture efficiency (i.e. APACTS or similar) Coatings must comply with 310 CMR 7.18 source specific requirements Exempt (See 310 CMR 7.18 source specific requirements) coating cannot exceed 55 gallons per 12 month rolling period Spray guns must be either: electrostatic, high volume low pressure (HVLP), or other having equal or better transfer efficiency than electrostatic or HVLP Spray gun cleaning activities to minimize evaporation, maximize solvent re-use, collect spent solvent into air tight 	 Coating formulations Maximized transfer efficiency VOC collection (99% capture efficiency) and control system (98+% control efficiency), i.e. APACTS, or similar Project proponent must evaluate all P2 opportunities before resorting to "end of pipe" control of VOC 	Determination 310 CMR 7.02 Plan Approval Transmittal Number W210062	
		 per 12 month rolling period Spray guns must be either: electrostatic, high volume low pressure (HVLP), or other having equal or better transfer efficiency than electrostatic or HVLP Spray gun cleaning activities to minimize evaporation, maximize solvent re-use, collect spent solvent into air tight containers 	pipe" control of VOC		

 HAPs	See 40 CFR Part 63Facilities may obtain a	•	See 40 CFR Part 63 Facilities may obtain a
	federally enforceable approval to cap HAPs		federally enforceable approval to cap HAPs
	below MACT major source thresholds to < 25		below MACT major source thresholds to <
	tons of total HAPs per rolling 12 month period		25 tons of total HAPs per rolling 12 month
	and to < 10 tons of any individual HAP per rolling		period and to < 10 tons of any individual HAP
	12 month period		period
PM	• Particulate control efficiency >99%	•	Dry filter media >99% collection efficiency
	 Face velocity ≤200 ft/min or APACTS 		(may also utilize an APACTS for PM control)
Opacity	 No visible emissions (zero percent opacity) 		
All Air Contaminant	No nuisance odors		

Key to Abbreviations

VOC = volatile organic compounds PM = particulate matter HAPs = hazardous air pollutants% = weight percent
> = greater than $\ge = \text{greater than or equal to}$ < = less than $\le \text{less than}$ $\le \text{less than or equal to}$ CFR = Code of Federal Regulations CMR = Code of Massachusetts Regulations m/hr = meters per hour ft/min = feet per minute ft/s = feet per second P2 = pollution prevention APACTS = automated paint application, containment and treatment system

VOC COATING SOURCES (June, 2011)					
Source Type	Air Contaminant	Minimum Control Efficiency	Control Technology	BACT Determination	
VOC Coating Sources VOC emissions > 18 tons per 12 month rolling period	VOC	 100% Capture Efficiency (PTE- Method 204)* 99% Destruction Efficiency 	• Regenerative Thermal Oxidizer (RTO)	In general, MassDEP considers proposed VOC coating operations which propose to meet the	
		 100% Capture Efficiency (PTE-Method 204)* 99% Destruction Efficiency 	• Thermal Oxidizer (TO)/Afterburner (AB)	requirements of this Table as complying with Top Case BACT as required by 310 CMR 7 02(8)	
		 100% Capture Efficiency (PTE-Method 204)* 98% Destruction Efficiency 	 Catalytic Oxidizer (CatOx)) – may be utilized only if the effluent exhaust stream contains no substituents which could cause catalyst poisoning 	Cinic 7.02(0)	
		 100% Capture Efficiency (PTE-Method 204)* 98% Collection Efficiency 	 Adsorption Technology or equivalent (including nitrogen blanketing and condensation strategies) Project proponent must evaluate all P2 opportunities before resorting to "end of pipe" control of VOC 		

HAPs • As above, in addition to requirements specified by 40 CFR 63 if facility is a major source for HAPs	 As above, in addition to requirements specified by 40 CFR 63 if facility is a major source for HAPs
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*Capture efficiency determined by US EPA Method 204 for Permanent Total Enclosures (PTE). PTE criteria:

- any natural draft opening (NDO) is at least four equivalent opening diameters from each VOC emitting point;
- the total area of all NDO's shall not exceed 5 percent of the surface area of the enclosure's four walls, floor, and ceiling;
- the average face velocity (FV) of air through all NDOs shall be at least 3600 m/hr (200 fpm). The direction of air flow through all NDOs shall be into the enclosure;
- all access doors and windows whose areas are not included in the method and are not included in the calculation are closed at all times during routine operation of the process;
- all VOC and/or HAPs emissions are captured and contained for discharge through a control device.

Key to Abbreviations

VOC = volatile organic compounds PTE = Permanent Total Enclosure % = weight percent \geq = greater than or equal to NDO = Natural Draft Opening m/hr = meters per hour fpm = feet per minute P2 = pollution prevention CFR = Code of Federal Regulations HAPs = hazardous air pollutants

MISCELLANEOUS VOC EMITTING SOURCES						
Source Type	Air Contaminant	Minimum Control Efficiency	Control Technology	BACT Determination		
Miscellaneous VOC emitting Sources VOC emissions ≥ 18 tons	VOC	 100% Capture Efficiency (PTE- Method 204)* 99% Destruction Efficiency 	Regenerative Thermal Oxidizer (RTO)	In general, MassDEP considers proposed miscellaneous VOC operations which propose to meet the		
per 12 month rolling period		 100% Capture Efficiency (PTE-Method 204)* 99% Destruction Efficiency 	• Thermal Oxidizer (TO)/Afterburner (AB)	requirements of this Table as complying with Top Case BACT as required by 310 CMR 7 02(8)		
		 100% Capture Efficiency (PTE-Method 204)* 98% Destruction Efficiency 	• Catalytic Oxidizer (CatOx)	Cinit (1.02(0))		
		 100% Capture Efficiency (PTE-Method 204)* 98% Collection Efficiency 	 Adsorption Technology (AT) or equivalent (may also include nitrogen blanketing and condensation strategies) Project proponent must 			
			evaluate all P2 opportunities before resorting to "end of pipe" control of VOC			

 strategies) Project proponent must evaluate all P2 opportunities before resorting to "end of 		HAPs	 < 10 tons per year, single HAP < 18 tons per year, total HAPs 	 RTO or TO/AB or CatOx or AT or equivalent (may also include nitrogen blanketing and condensation strategies) Project proponent must evaluate all P2 opportunities before resorting to "end of 	
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*Capture efficiency determined by US EPA Method 204 for Permanent Total Enclosures (PTE). PTE criteria:

- any natural draft opening (NDO) is at least four equivalent opening diameters from each VOC emitting point;
- the total area of all NDO's shall not exceed 5 percent of the surface area of the enclosure's four walls, floor, and ceiling;
- the average face velocity (FV) of air through all NDOs shall be at least 3600 m/hr (200 fpm). The direction of air flow through all NDOs shall be into the enclosure;
- all access doors and windows whose areas are not included in the method and are not included in the calculation are closed at all times during routine operation of the process;
- all VOC and/or HAPs emissions are captured and contained for discharge through a control device.

Key to Abbreviations

VOC = volatile organic compounds HAPs = Hazardous Air Pollutants HAP = Hazardous Air Pollutant PTE = Permanent Total Enclosure

% = weight percent

< = less than

> = greater than or equal to

NDO = Natural Draft Opening m/hr = meters per hour fpm = feet per minute P2 = pollution prevention

Cleaning and Degreasing Operations (June, 2011)					
Source Type	Air	Minimum Requirements	Control Technology	BACT Determination	
	Contaminant				
Hand Wipe Solvent Cleaning Operations	VOC HAPs*	 Use of low vapor pressure solvents (i.e. <15 mm Hg) Minimize use of solvents to employees Use of controlled flow solvent dispensers (squeeze bottles) Use of closed containers for non-active solvent and papers/cloths Cleaning performed in hood, booth or room vented to air pollution control device (if possible) having a capture efficiency >90% 	 Carbon adsorption technology, condensation technology, or thermal oxidation at >95% destruction/collection efficiency for facilities ≥ 10 tons per year Good Housekeeping to address spills and routine operation 	 310 CMR 7.18(8) Solvent Metal Degreasing 310 CMR 7.03(8) Plan Approval Exemptions - Degreasers 	
		• See 40 CFR Fait 05			

Cold Solvent Cleaning Operations	VOC	 Be equipped with a cover Be equipped with an internal drain Cleaned parts are enclosed for 15 seconds or until dripping ceases Designed with a freeboard ratio of ≥0.75 Designed with a water blanket (if solvent insoluble with water and is heavier than water) Covers are closed when parts are not being handled or when unit is not in use Open area drafts are <40 m/min Leaks must be immediately addressed and degreaser shutdown Solvent v.p. ≤4.3 kPa @ 38 degrees Celsius Sink-like work area < 100 cm² 	 Carbon adsorption technology or condensation technology at >95% collection efficiency for facilities ≥ 10 tons per year Good housekeeping to address spills and routine operation (see 310 CMR 7.18(8)(a))
	HAPs [*]	• See 40 CFR Part 63, Subpart T	• See 40 CFR Part 63, Subpart T

IPA Cleaning and Degreasing	VOC	 Be equipped with a cover Be equipped with an internal drain Cleaned parts are enclosed for 15 seconds or until dripping ceases Designed with a freeboard ratio of ≥0.75 Covers are closed when parts are not being handled or when unit is not in use Open area drafts are ≤40 m/min Leaks must be immediately addressed and degreaser shutdown Carbon adsorption technology or condensation technology at >95% collection efficiency for facilities ≥ 10 tons per year Good housekeeping to address spills and routine operation (see 310 CMR 7.18(8)(a))
Vapor Degreasing Operations	VOC	 Equipped with cover that will not disturb vapor zone Degreaser covered at all times except: loading, unloading and degreasing Equipped with safety switches (see 310 CMR 7.18 (8)(b)3) Freeboard ration ≥0.75 if open area >10ft² or refrigerated chiller, or enclosed system vented to carbon adsorption system with outlet VOC concentration <6ppmv Solvent carry-out minimized Carbon adsorption or condensation technology at ≥95% collection efficiency Good Housekeeping Practices (see 310 CMR 7.18(8)(b)) Best Management and Operating Practices (see 310 CMR 7.18(8)(b)) Best Management and Operating Practices (see 310 CMR 7.18(8)(b))

	HAPs [*]	• See 40 CFR Part 63	• See 40 CFR Part 63
Conveyorized Vapor Degreasing Operations	VOC	 Conveyorized degreaser >21.5 ft² must be equipped with either: refrigerated chiller, or vented at a rate ≥15 m³/min to an adsorption system with VOC outlet ≤6 ppm Eliminate solvent carry-out Equipped with safety switches (310 CMR 7.18(8)(c)3 Open areas are minimized 	 Carbon adsorption or condensation technology at ≥95% collection efficiency Good Housekeeping Practices (see 310 CMR 7.18(8)(c)) Best Management and Operating Practices (see 310 CMR 7.18(8)(c))
	HAPs [*]	• See 40 CFR Part 63	• See 40 CFR Part 63
Aqueous Cleaning Operations	VOC	 All organic solvent in cleaning fluid is water soluble Cleaning fluid is <5% by weight organic material 	 Good Housekeeping Practices Best Management and Operating Practices

* Facilities may obtain a federally enforceable approval to cap HAPs below MACT major source thresholds to < 25 tons of total HAPs per rolling 12 month period and to < 10 tons of any individual HAPs per rolling 12 month period.

Key to Abbreviations

VOC = volatile organic compounds HAPs = Hazardous Air Pollutants PTE = Permanent Total Enclosure % = weight percent @ = atv.p. = vapor pressure kPa = kilopascal < = less than < = less than or equal to > = greater than \geq = greater than or equal to CMR = Code of Massachusetts Regulations CFR = Code of Federal Regulations $ft^2 = square feet$ mm Hg = millimeters of mercury ppmv = parts per million volume $m^3/min = cubic meters per minute$ m/min = meters per minute IPA = Isopropyl Alcohol

EXPANDABLE POLYSTYRENE FOAM (June, 2011)

Source Type	Air	Minimum Control Requirements	Control Technology	BACT	
	Contaminant			Determination	
Expandable Polystyrene Foam Manufacturers	VOC (Pentane)	 Pre-expanding activities (including steam expansion and curing/drying/aging with transfer to storage "bags") with off-gassing: 100% capture efficiency* for the auring/dming/aging activities to control 	Thermal Oxidation or Regenerative Thermal Oxidation Technology at 99 % destruction	310 CMR 7.02 Plan Approval Transmittal Number	
Manufacturers		 curing/drying/aging activities to control device 95% capture efficiency for the pre-expanders emissions sent to control device 100% contume officiency* for "coing 	efficiency	W093075 Transmittal Number W052874 Transmittal Number	
		 100% capture efficiency* for "aging bag" storage emissions collected by general ventilation and/or floor sweeps to control device Rotary expanders are prohibited as BACT New vertical batch expanders with 100% capture efficiency may utilize an existing boiler, having a VOC control efficiency of 97%, as a control device if ALL emission points are controlled (specifically targeting the product storage room), including off-gassing during final storage. Best Management Practices (BMP) to include at minimum no wrapping of product, and storing product for long duration to maximize off-gassing to be collected (100%) and controlled (97%-99%). 	Boilers may be utilized as an air pollution control device for VOC emissions at a 97 % destruction/removal efficiency (DRE), for new vertical batch expanders	Transmittal Number W028295	
EXPANDABLE POLYSTYRENE FOAM (June, 2011)					
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Source Type	Air	Minimum Control Requirements	Control Technology	BACT	
	Contaminant			Determination	
		Molding activities emissions controlled under			
		vacuum. 95% of polystyrene molding emissions			
		are collected and delivered to the control			
		device.			
		Molded polystyrene product storage emissions			
		cannot exceed 8-10% of the pentane contained			
		in the original polystyrene beads.			
		Halogenated blowing agents are prohibited.			
		Pentane content of styrene beads is limited to			
		\leq 5% by weight (based on a monthly average)			

*Capture efficiency determined by US EPA Method 204 for Permanent Total Enclosures (PTE). PTE criteria:

- any natural draft opening (NDO) is at least four equivalent opening diameters from each VOC emitting point;
- the total area of all NDO's shall not exceed 5 percent of the surface area of the enclosure's four walls, floor, and ceiling;
- the average face velocity (FV) of air through all NDOs shall be at least 3600 m/hr (200 fpm). The direction of air flow through all NDOs shall be into the enclosure;
- all access doors and windows whose areas are not included in the method and are not included in the calculation are closed at all times during routine operation of the process;
- all VOC emissions are captured and contained for discharge through a control device.

Key to Abbreviations

VOC = volatile organic compounds PTE = Permanent Total Enclosure % = weight percent NDO = Natural Draft Opening m/hr = meters per hour

fpm = feet per minute

BULK GASOLINE TERMINALS (June, 2011)					
Source Type	Air Contamin ant	Emission Limit	Minimum Control Requirements	Control Technology	BACT Determination
Bulk Gasoline Terminals	VOC	2 mg/l of gasoline loaded	Vacuum Assist, negative pressure (VANP) vapor collection system – 100% collection efficiency. Switch loading to occur only under VANP. Continuously monitor and record system vacuum for the vapor collection system (at each loading lane). Submerged filling. Semi-annual tank truck leak testing per 40 CFR 60 Subpart XX – US EPA Method 27	 Activated Carbon Adsorption Technology Combustion Technology is prohibited, since the Department Regulations at 310 CMR 7.24 require vapor "recovery", not vapor destruction technology. 	310 CMR 7.02 Plan Approval, Transmittal Number W080267

	BULK GASOLINE TERMINALS (June, 2011)
	BULK GASOLINE TERMINALS (June, 2011) Installation and operation of electronic interlocks and visible and audible alarms to prevent non-vapor-tight gasoline loading and fugitive emissions at the tank truck loading rack. Interlocks shall be maintained to ensure that vapor collection system under negative pressure continuously and vapor collection hose is connected properly between tank truck and facility during loading operations Installation and operation of CEMS to monitor inlet and
	outlet of ACAT. Subject to 40 CFR 60 Subpart XX
HAPs	As above, in addition to requirements specified by 40 CFR 63 Subpart R if facility is a major source for HAPsAs above, in addition to requirements specified by 40 CFR 63 Subpart R if facility is a major source for HAPs40 CFR 63 Subpart R 40 CFR 63 Subpart R HAPsIf facility is not major for HAPs, the facility may be subject to 40 CFR 63 Subpart BBBBBB.

Key to Abbreviations

VOC = volatile organic compounds HAPs = Hazardous Air Pollutants mg/l = milligrams per liter % = weight percent CEMS = continuous emissions monitoring system

BULK GASOLINE STORAGE TANKS (June, 2011)					
Source Type	Air Contaminant	Minimum Requirements	Control Technology	BACT Determination	
Bulk Gasoline Storage Tanks	VOC	 In addition to requirements specified in Regulations 310 CMR 7.24 and 40 CFR 60 Subpart Kb All tanks shall be equipped with cable suspended full contact floating roofs (leg- supported floating roofs shall not be allowed) Tanks designed such that there will be no standing liquid when emptied Tanks must include a connection for a control device (98% VOC/HAPs control efficiency or 5000 ppmv VOC/HAPs tank concentration) that will control vapors when roofs are not floating (when tanks are emptied, cleaned, during seasonal fuel switching/tank landings, etc.) Utilize 98% overall efficiency VOC/HAPs control device when seasonal fuel switching/tank landing event would cause potential VOC/HAPs emission of one or more tons 	 Cable suspended full contact floating roof Drain dry tank bottom Vapor control device 	 In addition to requirements specified in Regulations 310 CMR 7.24 and 40 CFR 60 Subpart Kb 310 CMR 7.02 Plan Approval, Transmittal Number W152661 	
	HAPs*	• As above, in addition to requirements specified by 40 CFR 63 Subpart R if facility is a major source for HAPs	 As above, in addition to requirements specified by 40 CFR 63 Subpart R if facility is a major source for HAPs 	 As above, in addition to requirements specified by 40 CFR 63 Subpart R if facility is a major source for HAPs 	

<u>Key to Abbreviations</u> VOC = volatile organic compounds HAPs = hazardous air pollutants % = weight percent ppmv = parts per million volume CFR = Code of Federal Regulations CMR = Code of Massachusetts Regulations

*If not major for HAPs, the facility may be subject to 40 CFR 63 Subpart BBBBBB.

BIOTECHNOLOGY SURFACE DISINFECTION PROCESSES (June, 2011)					
Source Type	Air	Minimum Requirements	Control Technology	BACT	
	Contaminant			Determination	
Surface disinfection processes used in drug, medical device, and biologic product production having: ≤ 15 tons per 12 month rolling period VOC or total/combined HAPs	VOC HAPs VOC/HAPs	 ≤ 15 tons of VOC per rolling 12 month period ≤ 2.5 tons of VOC per month ≤ 15 tons of total/combined HAPs per rolling 12 month period ≤ 3 tons of total/combined HAPs per month ≤ 2 tons of individual HAP per month ≤ 9 tons of individual HAPs per rolling 12 month period VOC containing solutions kept in tightly closed containers Spent cleaning 	 Good housekeeping Best Management Practices 	310 CMR 7.03(25)	
		cloths/wipes kept in tightly closed containers			
>15 tons per 12 month rolling period VOC and/or total/combined	VOC/HAPs	 100% Capture Efficiency (PTE-Method 204)* 99% Destruction Efficiency 	• Regenerative Thermal Oxidizer (RTO)	See MISCELLANEOUS VOC EMITTING SOURCES	

	BIOTECHNOLOGY SURFACE DISINFECTI	ON PROCESSES (June, 2011)
HAPs ^{**}	 100% Capture Efficiency (PTE-Method 204)* 99% Destruction Efficiency 	• Thermal Oxidizer (TO)
	 100% Capture Efficiency (PTE-Method 204)* 98% Destruction Efficiency 	Catalytic Oxidizer (CatOx) – may be utilized only if the effluent exhaust stream contains no substituents which could cause catalyst poisoning
	 100% Capture Efficiency (PTE-Method 204)[*] 98% Removal Efficiency 	Adsorption Technology or equivalent (including nitrogen blanketing and condensation strategies)

*Capture efficiency determined by US EPA Method 204 for Permanent Total Enclosures (PTE). PTE criteria:

- any natural draft opening (NDO) is at least four equivalent opening diameters from each VOC emitting point;
- the total area of all NDOs shall not exceed 5 percent of the surface area of the enclosure's four walls, floor, and ceiling;
- the average face velocity (FV) of air through all NDOs shall be at least 3600 m/hr (200 fpm). The direction of air flow through all NDOs shall be into the enclosure;
- all access doors and windows whose areas are not included in the method and are not included in the calculation are closed at all times during routine operation of the process;
- all VOC emissions are captured and contained for discharge through a control device.

^{**}To avoid MACT, a facility may request a federally enforceable cap of < 25 tons per rolling 12 month period for total HAPs and < 10 tons per 12 month rolling period for individual HAP.

Key to Abbreviations

VOC = volatile organic compoundsHAPs = Hazardous Air Pollutants PTE = Permanent Total Enclosure % = weight percent < = less than \leq = less than or equal to > = greater than \geq = greater than or equal to CMR = Code of Massachusetts Regulations CFR = Code of Federal Regulations

CHEMICAL AND COATING MANUFACTURING SOURCES* (June, 2011)					
Source Type	Air Contaminant	Minimum Requirements	Control Technology	BACT Determination	
Storage Tanks	VOC	 Submerged fill pipes Vapor collection system to a control device[*] 	• Vapor collection system must be at all times under negative pressure (100 % capture	In general, MassDEP considers proposed chemical and coating manufacturing sources which propose to emit VOC and which propose to meet the requirements of this Table as complying with Top Case BACT as required by 310 CMR 7.02(8)	
	HAPs	• Compliance with 40 CFR 63 Subpart HHHHH (for major source of HAPs)	 efficiency)* VOC control device must achieve a control efficiency of 		
Process Piping	VOC	• All material transfers to be accomplished by hard piping, not by manual transfers	 ≥ 98 % (flares are Prohibited)* Good housekeeping for cleaning and spill prevention Waste coatings and cleaning solvents kept in closed containers when not in use All covers, ports, hatches, etc. must be kept clean and in a tight fitting manner All material and product loading must be done utilizing submerged fill pipes NOTE: Malodorous compounds may need to install technology that exceeds BACT to eliminate any nuisance odors generated from the process. 		
	HAPs	• Compliance with 40 CFR 63 Subpart HHHHH (for major source of HAPs)			
Mixers, Dispensers	VOC 4	 All units equipped with permanent, tightly fitted covers, minimum shaft clearance, and shaft boot All tanks shall be equipped with a vapor collection system to a control device* All cleaning activities will occur with emissions collected via the vapor collection system Compliance with 40 CFR 63 Subpart HHHHH (for major source of HAPs) 			

	CHEMICAL AND COATING MANUFACTURING SOURCES* (June, 2011)					
Letdown Tanks	VOC	 Tanks must have tightly fitting: covers, hatches and ports kept closed except for sampling and addition of materials Tanks controlled by a vapor collection system to a control device 				
	HAPs	Compliance with 40 CFR 63 Subpart HHHHH (for major source of HAPs)				
Product Packaging	VOC	• Packaging must occur in a PTE** equipped with a vapor collection system to a control device				
	HAPs	• Compliance with 40 CFR 63 Subpart HHHHH (for major source of HAPs)				

*For Chemical and Coating Manufacturing Sources \geq 18 tons per twelve month rolling period, these sources must comply with the BACT Guidelines found in the above Table, for Minimum Requirements including add-on air pollution control technology. While sources < 18 tons per twelve month rolling period may apply for a facility wide VOC emissions cap, these sources must still comply with the Minimum Requirements including Control Technology, however add-on air pollution control technology is not required.

**Capture efficiency determined by US EPA Method 204 for Permanent Total Enclosures (PTE). PTE criteria:

- any natural draft opening (NDO) is at least four equivalent opening diameters from each VOC emitting point;
- the total area of all NDO's shall not exceed 5 percent of the surface area of the enclosure's four walls, floor, and ceiling;

- the average face velocity (FV) of air through all NDOs shall be at least 3600 m/hr (200 fpm). The direction of air flow through all NDOs shall be into the enclosure;
- all access doors and windows whose areas are not included in the method and are not included in the calculation are closed at all times during routine operation of the process;
- all VOC and/or HAPs emissions are captured and contained for discharge through a control device.

Key to Abbreviations

VOC = volatile organic compounds HAPs = Hazardous Air Pollutants PTE = Permanent Total Enclosure % = weight percent NDO = Natural Draft Opening m/hr = meters per hour fpm = feet per minute P2 = pollution prevention CFR = Code of Federal Regulations \geq = greater than or equal to < = less than

	AMMONIA STORAGE AND HANDLING (June, 2011)					
Source Type	Air Contaminant	Minimum Requirements	BACT Determination			
Anhydrous Ammonia Storage and Handling	NH3	 A mitigation plan describing the methods and procedures used to reduce the risk of a catastrophic release of ammonia A contingency plan that describes the corrective actions utilized to notify persons in the immediate area of the release of ammonia Audio, Visual and Olfactory (AVO) inspections twice per day to monitor potential ammonia leaks During transfers of ammonia, all ammonia vapors are vented back to the host storage tank, UNCONTROLLED AMMONIA RELEASES TO ATMOSPHERE ARE PROHIBITED Relieving pressures from hoses and connectors must be bled to adequate volume of water All valves, connectors, and hoses must be maintained in a leak proof condition at all times Upon detection of any leak, the facility must implement immediate leak repair, if not possible, the use of a leak collection/containment system must be utilized until a repair may be implemented (i.e. automated water spray set to operate upon detection of NH₃ fumes.) Reinforced containment constructed around the ammonia storage tank for safety Method of operation and interlocks to prevent unauthorized release and operation of the ammonia storage and transferring system US EPA Level 2 Controls 	• US EPA Prevention Reference Manual: Chemical Specific, Volume 11, Control of Accidental Releases of Ammonia, EPA/600/8- 87/034k			

AMMONIA STORAGE AND HANDLING (June, 2011)				
Aqueous Ammonia Storage and Handling	• Diked containment, release of spherical orbs to reduce surface area, etc.			

Key to Abbreviations

 $NH_3 = ammonia$

	ASPHALT PROCESSING AND ASPHALT ROOFING (June, 2011)				
Source Type	Air Contaminant	Minimum Requirements	BACT Determination		
	THC	 Reduce THC mass emissions by 95% or to a THC emission limit ≤ 20 ppmvd @ 3 volume percent O₂ Control all THC emissions via a TO or RTO having a CE of 100% (PTE-Method 204)* having a DRE of ≥ 99.5% Natural gas firing 			
Saturator/Coater/Sealant Applicator	PM	 Control all PM emissions via a FF/BH having a RE of ≥ 99.9% ≤ 0.005 gr/dscf outlet emission limit 0.04 kg/Mg of asphalt shingle or mineral-surfaces rolled roofing 0.40 kg/Mg of saturated felt or smooth surfaced rolled roofing Natural gas firing 	40 CFR 60 Subpart UU 40 CFR 63 NESHAPS/MACT		
	Opacity	 ≤ 5 percent opacity at all times Natural gas firing 			
Storage Silo and Material Handling	PM	 Control all PM emissions via a FF/BH having a RE of ≥ 99.9% ≤ 0.005 gr/dscf outlet emission limit 			

ASPHALT PROCESSING AND ASPHALT ROOFING (June, 2011)				
Source Type	Source Type Air Minimum Requirements		BACT Determination	
	Contaminant			
	Opacity	• Zero percent opacity – no visible emissions		
	РМ	 0.67 kg/Mg from blow still when catalyst used 0.60 kg/Mg from blow still when catalyst not used Fuel oils are prohibited – natural gas firing only 		
Blow Still	HAPs/THC/V OC	 Reduce THC mass emissions by 95% or to a THC emission limit ≤ 20 ppmvd @ 3% O2 Control all THC emissions via a TO or RTO having a CE of 100% (PTE-Method 204)* DRE of ≥ 99.5% Natural gas firing 		

* Capture efficiency determined by US EPA Method 204 for Permanent Total Enclosures (PTE). PTE criteria:

- any natural draft opening (NDO) is at least four equivalent opening diameters from each THC emitting point;
- the total area of all NDO's shall not exceed 5 percent of the surface area of the enclosure's four walls, floor, and ceiling;
- the average face velocity (FV) of air through all NDOs shall be at least 3600 m/hr (200 fpm). The direction of air flow through all NDOs shall be into the enclosure;
- all access doors and windows whose areas are not included in the method and are not included in the calculation are closed at all times during routine operation of the process;
- all THC emissions are captured and contained for discharge through a control device.

Key to Abbreviations

VOC = volatile organic compounds HAPs = hazardous air pollutants THC = total hydrocarbons PM = particulate matter CE = capture efficiency DRE = destruction/removal efficiency RE = removal efficiency \leq = less than or equal to > = greater than or equal to TO = thermal oxidizerRTO = regenerative thermal oxidizer % = weight percent ppmvd = parts per million volume dry @ = atkg/Mg = kilograms per Megagram gr/dscf = grains per dry standard cubic footFF/BH = fabric filter/baghouse NESHAPS = National Emissions Standards for Hazardous Air Pollutants MACT = maximum achievable control technology

BULK CEMENT SHIP UNLOADING (June, 2011)					
Source Type	Air Contaminant	Minimum Requirements	BACT Determination		
	NOx				
Power Source to	SO_2	• Shore Utility Power – Electric Power [emergency power must comply with Engine & Turbine EPP Regulation at			
system	CO	310 CMR 7.26(42)]			
	PM		_		
		• Enclosed, self-unloading ship with pneumatic conveyor system; receiving shore silos/containers/domes			
	РМ •	• Enclosed processing equipment vented to FF/BH having a PM collection efficiency of 99.99%.	310 CMR 7.02 Plan Approvals,		
		 Emission Limits range between 0.001 and 0.003 gr/acf, process equipment specific 	Transmittal Number W154933,		
Material Handling		• System must be equipped with process flow interlocks, high level sensor interlocks in silos, containers, domes to ensure that over-loading of storage vessels and over- pressurization of delivery lines do not occur	Transmittal Number W158294		
		• Continuous process monitoring must occur during any loading or transferring events, the system shall record all system excursions and be equipped with audible and visual alarms.			

Key to Abbreviations

PM = particulate matter NOx = nitrogen oxides $SO_2 = sulfur dioxide$ CO = carbon monoxide gr/acf = grains per actual cubic foot % = weight percent FF/BH = fabric filter/baghouse CMR = Code of Massachusetts Regulations

CONCRETE BATCH PLANTS (June, 2011)				
Source Type	Air Contaminant	Minimum Requirements	BACT Determination	
Permanent Concrete Batch Plants	РМ	 Emission Limit ≤ 0.0002 gr/dscf Dry material storage controlled with FF/BH ≥ 99.99% collection efficiency All aggregate material handling prewashed achieving ≥ 70% reduction Aggregate stockpiles controlled by continuous water spray systems to achieve ≥ 70% reduction, aggregate storage piles must be maintained at a minimum moisture content of 4% by weight Central mixer and/or truck drop point emissions controlled to ≥ 99% or emission limit of ≤ 0.008 gr/dscf – use of suction shroud with minimum 5000 acfm flow rate Visible emissions ≤ 5 percent opacity except up to 10 percent opacity for no more than 2 minutes during any one hour, not to exceed 10 percent opacity from any process point, internal roads, work areas, material storage areas or stockpiles 	310 CMR 7.02 Plan Approval, Transmittal Number 002964	

CONCRETE BATCH PLANTS (June, 2011)					
Source Type	Air Contaminant	Minimum Requirements	BACT Determination		
Temporary Concrete Batch Plants	PM	 Emission Limit ≤ 0.008[should this also be 0.0002?] gr/dscf Dry material storage controlled with FF/BH ≥ 99.99% collection efficiency All aggregate material handling prewashed achieving > 70% reduction Aggregate stockpiles controlled by continuous water spray systems to achieve ≥ 70% reduction, aggregate storage piles must be maintained at a minimum moisture content of 4% by weight Central mixer and/or truck drop point emissions controlled to ≥ 99% or emission limit of ≤ 0.008 gr/dscf – use of suction shroud with minimum 5000 acfm flow rate Visible emissions ≤ 5 percent at any time from any process point, internal roads, work areas, material storage areas or stockpiles 			

Key to Abbreviations

PM = particulate matter gr/dscf = grains per dry standard cubic foot % = weight percent FF/BH = fabric filter/baghouse > = greater than $\geq = greater than or equal to$ < = less than $\leq = less than or equal to$ acfm = actual cubic feet per minute

DRY BULK MATERIAL HANDLING AND UNLOADING (June, 2011)				
Source Type	Air Contaminant	Minimum Requirements	BACT Determination	
Dry Bulk Material Handling and Unloading Activities	PM	 Pertains to dry, enclosed and open activities. Dry and/or enclosed activities to include dry commodities such as gypsum, lime, soda ash, salt cake, etc. Enclosed systems vented to a FF/BH having a collection efficiency of 99.99% or an emission limit of 0.001 to 0.003 gr/dscf activity specific. Material handling by use of pneumatic transfer, bag unload, box unload, small container unload to achieve total enclosure (100% capture efficiency) Open systems of stockpiles must achieve ≥70% control of emissions, utilizing, water sprays, fogging, chemical suppressants and/or foam. Zero Percent Opacity Comply with MassDEP Noise Policy 	310 CMR 7.02 Plan Approval, Transmittal Number W158294	

Key to Abbreviations

PM = particulate matter FF/BH = fabric filter/baghouse gr/dscf = grains per dry standard cubic foot % = weight percent

	MATERIAL AND COAL HANDLING (June, 2011)						
Source Type	Air	Minimum Requirements	BACT Determination				
	Contaminant						
Material Handling	PM	 Pertains to dry, enclosed and open activities. Dry and/or enclosed activities to include dry commodities such as gypsum, lime, soda ash, salt cake, etc. Enclosed systems vented to a FF/BH having a collection efficiency of ≥99.99% or an emission limit of 0.001 to 0.003 gr/dscf activity specific. Open systems of stockpiles must achieve ≥70% control of emissions, utilizing, water sprays, fogging, chemical suppressants and/or foam. 					

MATERIAL AND COAL HANDLING (June, 2011)				
Source Type	Air Contaminant	Minimum Requirements	BACT Determination	
Coal Handling	РМ	 Enclosed systems, such as domes. In cases where domes or enclosures are not permissible by local ordinances, or equivalent: stockpiles and internal roads must be treated with water sprays; stockpiles must also be treated with encrusting agents. Transfer points must be treated with foam and/or surfactants. Receiving and unloading must be conducted within enclosures and/or shrouding. Foaming sprays during receiving and unloading activities is required. Conveying of coal must be fully enclosed. Screening of coal must be fully enclosed. 		

Key to AbbreviationsPM = particulate matter FF/BH = fabric filter/baghouse gr/dscf = grains per dry standard cubic foot =greater than or equal to % = weight percent

ROCK CRUSHING				
Source Type	Air Contaminant	Minimum Requirements	BACT Determination	
Rock Crushers	PM-10/PM- 2.5	 ≤0.014 gr/dscf (emission limit) use of charges "water fog" sprays of transfer points, conveyors water spray with chemical suppressants for material storage piles enclosure of jaw/cone crushers, screens, and associated material transfer points and vent to baghouse(s) having a PM removal efficiency of ≥99.99% or proper application of water sprays to achieve an equivalent ≥99.99% overall PM control efficiency water sprays for road surfaces visible emissions not to exceed seven percent opacity 	40 CFR 60 Subpart OOO	

Key to Abbreviations

PM-10 = particulate matter 10 microns or less PM-2.5 = particulate matter 2.5 microns or less \leq = less than or equal to \geq = greater than or equal to Gr/dscf = grains per dry standard cubic foot % = weight percent

	HOT MIX ASPHALT - BATCH PLANTS AND DRUM MIX PLANTS (June, 2011)					
Source Type	Fuel	Air Contaminant	Minimum Requirements	BACT Determination		
	Reserved					
	Ultra Low Sulfur Distillate	PM(filterable) PM(condensable)	 ≤ 0.01 gr/dscf 0.0194 lbs/ton 			
Batch Plants	Fuel Oil	NOx	• $\leq 0.113 \text{ lb/MMBtu}$	310 CMR 7.02 Plan Approval		
And	(0.0015 % S)	СО	• $\leq 0.39 \text{ lb/MMBtu}$	Transmittal		
Drum Mix Plants	(0.0015 /0 5)	VOC	• ≤ 0.032 lbs/ton product produced	Number X227251		
		PM	• $\leq 0.01 \text{ gr/dscf}$			
	Natural Cas	NOx	• $\leq 0.044 \text{ lb/MMBtu}$			
Natural Gas	СО	• $\leq 0.30 \text{ lb/MMBtu}$				
		VOC	• ≤ 0.032 lbs/ton product produced			
	All Fuels	Opacity	• \leq 5 percent, except \leq 20% for \leq 2 minutes during any one hour period			

	HOT MIX ASPHALT - BATCH PLANTS AND DRUM MIX PLANTS (June, 2011)					
Source Type	Fuel	Air Contaminant	Minimum Requirements	BACT Determination		
	All Fuels	Other	 Emissions Testing for new facilities Visilite testing of FF/BH – once at start-up of "season", and once per month thereafter during the operating season Ultra Low-NOx Burner(s), FGR as necessary 80% PM reduction – All aggregate must be prewashed Baghouse outlet temperature and pressure differential monitoring system, with instantaneous readings in control room; audible and visual alarms to alert operator to need for corrective actions Top of silo controls to collect and control 90 percent minimum of exhaust gases displaced from filling of silos 			

Key to Abbreviations

VOC = volatile organic compoundsS = sulfurPM = particulate matterNOx = oxides of nitrogen

< = less than $\leq =$ less than or equal to $\geq =$ greater than or equal to

% = weight percent

@ = at
FGR = flue gas recirculation
lbs/ton = pounds per ton
lb/MMBtu = pounds per million British thermal units
gr/dscf = grains per dry standard cubic foot
FF/BH = fabric filter/baghouse
CMR = Code of Massachusetts Regulations

CHROME PLATING AND ANODIZING OPERATIONS USING CHROMIC ACID (June, 2011)				
Source Type	Air	Minimum Requirements	BACT Determination	
	Contaminant			
Hard Chrome Plating Tank	PM and Chrome	 Small Existing Tanks: 100% capture efficiency (PTE-Method 204)* Emission Limit ≤ 0.03 mg/dscm or Wetting agent fume suppressant in plating tank with plating solution surface tension not exceeding 45 dynes/cm (stalagmometer) or 35 dynes/cm (tensiometer), and good housekeeping for spills. All Other Hard Chromium Tanks: 100% capture efficiency (PTE-Method 204)* Emission Limit ≤ 0.015 mg/dscm or Wetting agent fume suppressant in plating tank with plating solution surface tension not exceeding 45 dynes/cm (stalagmometer) or 35 dynes/cm (capture efficiency (PTE-Method 204)* 	40 CFR 63 Subpart N MACT/NESHAPS	
Decorative Chrome Plating Tank	PM and Chrome	 1. 100% capture efficiency (PTE-Method 204)* 2. Emission Limit ≤ 0.01 mg/dscm or 3. Wetting agent fume suppressant in plating tank with plating solution surface tension not exceeding 45 dynes/cm (stalagmometer) or 35 dynes/cm (tensiometer), and good housekeeping for spills. 		

CHROME PLATING AND ANODIZING OPERATIONS USING CHROMIC ACID (June, 2011)					
Source Type	Irce Type Air Minimum Requirements BACT I				
	Contaminant				
Chromic Acid Anodizing	PM and Chrome	 100% capture efficiency (PTE-Method 204)* Emission Limit ≤ 0.01 mg/dscm or Wetting agent fume suppressant in plating tank with plating solution surface tension not exceeding 45 dynes/cm (stalagmometer) or 35 dynes/cm (tensiometer), and good housekeeping for spills. 			

*Capture efficiency determined by US EPA Method 204 for Permanent Total Enclosures (PTE). PTE criteria:

- any natural draft opening (NDO) is at least four equivalent opening diameters from each pollutant emitting point;
- the total area of all NDO's shall not exceed 5 percent of the surface area of the enclosure's four walls, floor, and ceiling;
- the average face velocity (FV) of air through all NDOs shall be at least 3600 m/hr (200 fpm). The direction of air flow through all NDOs shall be into the enclosure;
- all access doors and windows whose areas are not included in the method and are not included in the calculation are closed at all times during routine operation of the process;
- all PM and chrome emissions are captured and contained for discharge through a control device.

Key to Abbreviations

PM = particulate matter gr/dscf = grains per dry standard cubic foot % = weight percent m/hr = meters per hour ft/min = feet per minute FF/BH = fabric filter/baghouse

≤ = less than or equal to
mg/dscm = milligrams per dry standard cubic meter
dynes/cm = dynes per centimeter
CFR = Code of Federal Regulations
MACT = Maximum Achievable Control Technology
NESHAPS = National Emission Standards for Hazardous Air Pollutants

	ETHYLENE OXIDE STERILIZATION (June, 2011)				
Source Type	Air	Minimum Requirements	BACT Determination		
	Contaminant				
Sterilizers and Aerators	ETO (VOC/HAPs)	 Sterilization and/or aeration process vessels or rooms must be constructed to achieve and maintain 100% Capture Efficiency at minimum, per Method 204* All ETO exhaust emissions from the sterilizer and/or aerator must be ducted to a control device (Thermal Oxidizer, Catalytic Oxidizer, or Wet Chemical Scrubber) achieving and maintaining a Destruction Efficiency of ≥ 99.9% or ETO emissions, post control, of < than 0.2 ppm. No by-pass stacks are permitted. 	310 CMR 7.02 Plan Approval Transmittal Number W058285 MACT - 40 CFR 63, Subpart O		

* Capture efficiency determined by US EPA Method 204 for Permanent Total Enclosures (PTE). PTE criteria:

- any natural draft opening (NDO) is at least four equivalent opening diameters from each VOC emitting point;
- the total area of all NDO's shall not exceed 5 percent of the surface area of the enclosure's four walls, floor, and ceiling;
- the average face velocity (FV) of air through all NDOs shall be at least 3600 m/hr (200 fpm). The direction of air flow through all NDOs shall be into the enclosure;
- all access doors and windows whose areas are not included in the method and are not included in the calculation are closed at all times during routine operation of the process;
- all VOC and/or HAPs emissions are captured and contained for discharge through a control device.
Key to Abbreviations

VOC = volatile organic compoundsHAPs = hazardous air pollutants ETO = ethylene oxide \geq = greater than or equal to \leq = less than or equal to ppm = part per million % = weight percent CMR = Code of Massachusetts Regulations CFR = Code of Federal Regulations MACT = Maximum Achievable Control Technology

GALVANIZING OPERATIONS (June, 2011)			
Source Type	Air	Minimum Requirements	BACT Determination
	Contaminant		
Zinc Kettle	PM	• 95% Capture Efficiency (PTE-Method 204)*	MACT 40 CFR 63 Subpart CCC
		• 99.99% collection efficiency, achieved with a FF/BH equipped with lime pre-coated bags.	
		• Emission Limit ≤ 0.003 gr/dscf	
		• No Opacity from stack exhaust (0 percent)	
		• Separate ammonia chloride preflux tank.	
HCl Tanks	HCl	• 98% control efficiency utilizing fume suppressant or equivalent	

*Capture efficiency determined by US EPA Method 204 for Permanent Total Enclosures (PTE). PTE criteria:

- any natural draft opening (NDO) is at least four equivalent opening diameters from each pollutant emitting point;
- the total area of all NDO's shall not exceed 5 percent of the surface area of the enclosure's four walls, floor, and ceiling;
- the average face velocity (FV) of air through all NDOs shall be at least 3600 m/hr (200 fpm). The direction of air flow through all NDOs shall be into the enclosure;
- all access doors and windows whose areas are not included in the method and are not included in the calculation are closed at all times during routine operation of the process;
- all PM and HCl emissions are captured and contained for discharge through a control device.

Key to Abbreviations

PM = particulate matter HCl = hydrochloric acid gr/dscf = grains per dry standard cubic foot % = weight percent m/hr = meters per hour fpm = feet per minute FF/BH = fabric filter/baghouse