GRAND CANYON VISIBILITY TRANSPORT COMMISSION INTEGRATED ASSESSMENT SYSTEM DOCUMENTATION SUMMARY

TASK 2.1
FINAL REPORT

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FOREWORD

This report was written by The Pechan-Avanti Group (Pechan-Avanti) for the Western Governors' Association (WGA summarize the Integrated Assessment System (IAS). The IAS was developed by Argonne National Laboratory (ANL) un subcontract to Decision Focus, Inc., during the Grand Canyon Visibility Transport Commission (GCVTC) study. The inf in this report is taken from the reports and data bases that were provided by the WGA for the performance of this contract the report text is taken directly from the contractor reports from the GCVTC study. In other cases, the information in the reports has been completely re-organized and re-written to meet the requirements of this contract. While efforts have bee verify the written information with IAS model data bases, a complete verification of all information was not possible. Th is possible that some of the information in this report may be incorrect.

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TABLES

ACRONYMS AND ABBREVIATIONS

acfm	actual cubic feet per minute
ANL	Argonne National Laboratory
ARGUS	Argonne Utility Simulation
ASC	Area Source Category
BACT	Best Available Control Technology
BFS	Baseline Forecast Scenario
CAA	Clean Air Act
CADM	Control Action Determination Module
CARB	California Air Resources Board
cc	cubic centimeters
CD-ROM	compact disk-read only memory
CI	compression ignition
CO	carbon monoxide
CRT	Cell Retirement Table
DOT	U.S. Department of Transportation
dscf	dry standard cubic foot
DSM	demand-side management
EIA	Energy Information Administration
EMSs	emissions management scenarios
EPA	U.S. Environmental Protection Agency
ESP	electrostatic precipitator
FCCU	fluid catalytic cracking units
FCU	fluid coking units
FERC	Federal Energy Regulatory Commission
FF	fabric filters
FGD	flue gas desulfurization
FIP	Federal Implementation Plan
ft^3	cubic feet
g/hr	grams per hour
g/kWh	grams per kilowatt hour
g/bhp-hr	grams per brake horsepower-hour
GCVTC	Grand Canyon Visibility Transport Commission
GNP	gross national product
GRP	gross regional product
H_2S	hydrogen sulfide
HC	hydrocarbon
hp	horsepower
I/M	inspection and maintenance
IAS	Integrated Assessment System
ICE	Industrial Combustion Emissions
IGCC	integrated coal gasification combined cycle
kW	kilowatts
lbs/MMBtu	pounds per million British thermal units
LEV	low-emission vehicle

ACRONYMS AND ABBREVIATIONS (continued)

MAPP	Mid-Continent Area Power Pool
MB	megabytes
MMA	Maximum Management Alternative
MSW	municipal solid waste
MW	megawatts
NAPAP	National Acid Precipitation Assessment Program
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Council
NGCC	natural gas combined cycle
NH_3	ammonia
NMOC	non-methane organic compounds
NO	nitrogen oxide
NO_x	oxides of nitrogen
NPS	National Park Service
NSPS	New Source Performance Standards
O&M	operating and maintenance
OAA	organic acid additives
OMS	Office of Mobile Sources
Pechan-Avanti	The Pechan-Avanti Group
PFS	pave, flush, and sweep adjacent unpaved areas
ppm	parts per million
PS	pave then sweep
REMI	Regional Economics Model, Inc.
RFG	reformulated gasoline
RH	relative humidity
ROG	reactive organic gases
RVP	Reid vapor pressure
RWC	residential wood combustion
SCA	Selected Control Actions
SCAQMD	South Coast Air Quality Management District
SCC	Source Classification Code
scf	standard cubic feet
scfm	standard cubic feet per minute
SCL	Source Cell List
SCR	selective catalytic reduction
SI	Spark Ignition
SIC	Standard Industrial Classification
SIPs	State Implementation Plans
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
SO_x	sulfur oxides
tpd	tons per day
tpy	tons per year
TSP	total suspended particulate
ULEV	ultra-low emission vehicle

ACRONYMS AND ABBREVIATIONS (continued)

USFS	U.S. Forest Service
VAQ	visual air quality
VMT	vehicle miles traveled
VOC	volatile organic compound
WGA	Western Governors' Association
WRAP	Western Regional Air Partnership
WTM	working transfer matrix
ZEVs	zero-emission vehicles

CHAPTER I
OVERVIEW OF MODELING APPROACH AND KEY ASSUMPTIONS

The first major section of this chapter discusses all of the key IAS input data. IAS data base table names are provide second major section of this chapter documents all of the key formulas of the IAS computations that make use of the inpu The third section of this chapter provides a discussion of the various ways that emissions management scenarios (EMSs) specified and simulated with the IAS, via its Control Action Determination Module (CADM) logic. Finally, a sample cal provided that demonstrates how future sulfur dioxide (SO_2) emissions are estimated in IAS, using an example region and category.

The fundamental unit of analysis in the IAS, and therefore a key aspect of all the data structures, is the IAS *cell*. A c unique combination of geographical location, type of emissions source, and facility size. When all of the cells are aggreg has accounted for all of the sources of emissions in the modeled region, which includes the eleven western States, Texas, southwestern Canada, and Mexico. Control actions are selected for each cell in each year of a scenario by the user and/or CADM, and then emissions of each pollutant are projected from each individual cell, providing the basis for the receptor impacts calculations of that scenario.

Altogether, there are 2,466 individual cells in the IAS, and each cell may have its own unique set of baseline assump and its own set of potential control options. This means that the IAS data sets are very large and complex. In actuality, a of the cells are treated as "uncontrollable" either because they are in geographical locations that are not being considered controls by the GCVTC, or because they are inherently uncontrollable types of sources, such as windblown dust, or area s that are difficult to control, or because they were given low priority by the Assessment Subcommittee in the IAS develop process. Low priority was defined as a source category that did not *as a group* contribute to more than one percent of tot emissions of any of the pollutants.

A. KEY INPUT DATA BASES

1. Emissions Inventory

The IAS contains information about current (1990) emissions within twelve States. This information, known as the " Inventory," was the product of a coordinated effort between the GCVTC, the States, the U.S. Environmental Protection A (EPA), industry representatives, and contractors (Radian, 1995). The base year emission inventory used in the IAS has th following attributes:

(1) The information is representative of 1990.

(2) The domain of the inventory focuses on the 11 western States, Texas, and Southwestern Canada. Mexican emis are represented by very rough "placeholder" estimates.

(3) Sources include anthropogenic point sources (e.g., smelters, power plants, and refineries), area sources (e.g., res fuel combustion, and agricultural-related activities including fertilizing and tilling operations); mobile sources (road motor vehicles including cars and trucks, and off-road motorized vehicles including trains, aircraft, and construction equipment); biogenic (e.g., commercial and natural vegetation); forest fires, forest management, a waste burning; and fugitive sources, such as reentrained and windblown dust.

(4) Pollutant compounds included in the data base are: SO_2, reactive organic gases (ROG), fine particulates, report separately as organic carbon, elemental carbon, and other ($OC_{2.5}$, $EC_{2.5}$, $PM_{2.5}$), coarse fraction particulates (PM oxides of nitrogen (NO_x), and ammonia (NH_3). There are also estimates of isoprene, terpene, and other volatile compound (VOC) emissions in the data base, but only for biogenic sources. (Although the IAS retains these lat compounds in its data base, they are not linked to visibility impacts via the transfer coefficients.)

(5) The information is at the county level for mobile and area sources, and at the facility level for point sources.

(6) Using seasonal adjustment factors, the annual average inventory was temporally allocated to produce emission estimates inventories for each of the four seasons.

Two separate inventories exist: a point source inventory and an area source inventory. Each inventory consists of mo 150,000 separate records, each identifying a source of emissions. The total amount of computer disk storage occupied by inventory is about 100 megabytes (MB).

The base year (1990) inventory is utilized in the IAS without modifications except for the aggregations described nex produce a more computationally efficient file containing only information necessary for the IAS CADM process, the emis inventory was aggregated into groups called *cells*, and unnecessary information was removed. To obtain the IAS *cells* fro emission inventory, the following steps were performed.

I. Each county in the emission inventory was assigned to an IAS Source Region. Appendix A indicates the 62 IAS regions, the county assignments to IAS regions, and the linkages of the IAS regions to specific pollutant transfer information. Because of the high density of transfer coefficients available in the areas around the receptors, the in those locations tend to be much smaller than regions farther from national parks.

   A. IAS source regions were defined to be consistent with State boundaries and the modeled transfer points. E the transfer points was mapped, then each county was linked to one of the transfer points. Each county's proximity to each transfer point along with relevant topological and meteorological information was consi in this mapping process.

   B. SO_2 transfer information was available for some of the major point sources within the emission inventory. county that contains a major point source with specific transfer information was assigned to its own IAS So Region, and the SO_2 emissions within that county were linked to that source's specific transfer matrix entri Emissions of other pollutants were linked to the most appropriate area source transfer information. All pollutants considered by the IAS that are emitted from IAS Source Regions that do not contain a defined p source are linked to the appropriate area source transfer matrix. This is necessitated by the fact that only S transfer elements are available for the point sources, while the area sources contain transfer elements for ot pollutants in addition to SO_2.

II. The Source Classification Code (SCC) and Area Source Category (ASC) identifier numbers for each inventory r were used to group records into IAS Source Groups. IAS Source Groups were defined according to similar emi rates and available control actions, as determined appropriate by ANL, which was responsible for developing th control options data. For a listing of the 90 IAS Source Groups, and the SCC and ASC numbers that compose e IAS Source Group, see Appendix A.

III. The size of each facility was determined.

   A. The 1990 point source emissions in the emissions inventory were summed at the facility level. A single va for each facility was determined by summing the total emissions of sulfur oxides (SO_x), NO_x, ROG, $EC_{2.5}$, $OC_{2.5}$, and $PM_{2.5}$.

   B. The size of each facility was determined according to the sum of its emissions (summing all of the pollutan concern) and categorized into three groups:

      i. less than 25,000 tons per year (tpy)
      ii. 25,000 to 100,000 tpy
      iii. more than 100,000 tpy

   C. Size categories are not used for area sources.

The pollutants for each record in the 1990 emissions inventory were then aggregated by IAS source region, IAS Sour Group, and facility size. The result of the summing process was the IAS base emissions data, structured according to the I definitions. This information is in the IAS data base table called Cell Baseline Emissions, or CBE0.

2. Control Options Data

Emission forecasts are based on a combination of the 1990 base year emissions in a cell, and a forecast of the control efficiency of specific control options that will be in place in any given forecast year, from 1990 through 2040 (at ten year Since each control option is characterized by how much it can reduce emissions of each pollutant relative to uncontrolled within that source group, once the control options in each year are defined, it is possible to understand the trend in emissio cell *in the absence of any economic growth.* Complications to this are that over time, existing sources will be retired, and will be replaced by new or modified sources, which usually entail a higher level of control due to regulations such as New Performance Standards (NSPS). Thus, the cell-level information also includes the expected retirements over time of all th capacity in each cell, and identification of the control options that will be associated with new, replacement capacity.

Each retrofit control option is also characterized by its cost. Thus, in the same way that emissions can be forecast onc control options have been specified, so too can the control costs for sources in each cell.

The control options input assumptions reside in a number of different data tables that were created by ANL as part of development process.[1] The following section describes the main features of the control options data, while the actual data are documented by ANL in the Task 4.6.5 Data Documentation Report.

Baseline Control Options Specification - A reference point for emissions and visibility trends is necessary before con scenarios can be considered. This reference point is generated by the IAS using a set of baseline control options that ANL for each forecast year and each cell of the IAS. These specifications were developed from a review of existing regulatory requirements, and committed plans of some existing sources. These are provided in the IAS data base tables called the Lo Baseline File LBF0 (for existing source control options over time) and NTS0 (for new source control options). The contro efficiencies implied by these assumptions (for both the existing and new source baseline assumptions) reside in the contro efficiencies data table called Control Option Effectiveness COE0, along with control efficiencies of all other control optio IAS. ANL's report under Task 4.6.5 provides the basis for these assumptions (Argonne, 1995).

As existing source capacity is retired, either temporarily or permanently, new sources are constructed to meet whatev residual demand can no longer be met by existing source capacity. To the extent that there is growth in a cell's demand, th met by new source capacity growth in the same region (unless other siting decisions are specified, which is not the case in baseline.) Thus, also affecting the baseline forecast of emissions is the set of assumptions about how rapidly the existing will be retired (and possibly replaced by new capacity, if demand warrants it). The retirement assumptions are provided i Retirement table called CRT. A temporary form of retirement is possible in the form of reductions in the usage rate of ex capacity, which in turn can be offset by increased usage of new forms of capacity, if warranted by demand levels. This is particularly relevant consideration in the case of older forms of electric utility capacity. ANL utility sector models were u identify the time trend in the capacity utilization of various key power units, and the results were summarized as a capacit input, which is also found in the data table called CRT as inter_ANL. This too is considered in the baseline emissions for

Another component of the baseline assumptions is whether the existing capacity was fully utilized in 1990, when the year emissions were estimated. In situations where underutilization was significant in 1990, there may be room for substa growth in that cell's demand before new capacity will be built. Again, this utilization consideration was determined to be for the utility sector, particularly in cases where utilization of the existing type of capacity was likely to increase between 2010. The 1990 percent utilization assumptions (which are less than 1.0 only for utility cells) can be found in the IAS dat master source cell list, abbreviated as SCL.

There are also costs associated with the baseline control options, and these estimates are provided in the Control Opti data table called COC0, along with the control costs of all other control options in the IAS. Cost inputs are provided as a of the amount of capacity that must be controlled. Thus, the control option cost inputs also require an indicator of the amo capacity (or other control cost driver variables) for each cell. This is provided in a variable called "num_src" that is also p IAS master Source Cell List (SCL). Information on the amount of 1990 existing capacity in a cell was generated from the emission inventory at the same time that the cell base emissions were developed, as described under *Emissions Inventory* above. Since existing capacity may dwindle over time because of retirements or capacity utilization reductions, the cost e for a cell in each forecast year are also adjusted by the information in the cell retirement table. *New source controls are n costed in the IAS. For the most part, significant controls on these sources are already required under existing regulations.*

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[1]The reason that the control options are not all in a unified data table is space management. For example, emissions data for contro require information by pollutant, while the associated cost data for control options does not require that dimension in the data. Thus, t types of data exist in separate data tables, using the minimum level of detail necessary in each case. They can be cross-referenced by t control option identifiers.

EMS Specification - The control options identified for the baseline are the *minimum* level of control possible in any E and the starting point for considering retrofit options. Retrofits are the main policy lever available in EMSs, and the emiss forecast associated with an EMS is generated in the same way as it is for the baseline, but with a different set of specified options in each cell and each year. The first forecast year in which the IAS will allow a user to specify additional levels o 2010, because new control programs could not be initiated by 2000. Thus, in every IAS scenario, the controls are identica of the baseline in 1990 and 2000, and then diverge thereafter.

The key to selecting additional levels of control is a list of what the possible choices are, *given the baseline starting point in the previous forecast year for each cell*. This is an important list, and is available in the IAS data base as the table called the Control Option Exclusivity table, COX0. It simply lists for every possible control option that might be in each cell, what other control options are possible to select in the next forecast year. ANL provided this list and the associa for each of the control options on the list, and they are documented in the report for Task 4.6.5. The current list of control that are considered has 3,589 different control options that can be retrofit onto the baseline levels of control.[2] These contr cover 613 of the IAS cells.

The retrofit control option selections can be made by the user, as in the case of a command-and-control scenario, or b CADM logic of the IAS, which is designed to achieve specific emissions caps or visual air quality (VAQ) goals on an opti least-cost basis. That optimization is performed by considering the costs and incremental improvements associated with e additional level of control. The CADM logic estimates the cost-effectiveness of the available control options by looking the remaining control options in all the cells (from the COX0 list) in the cost and efficiency data tables (the same COC0 a data sets), and computing their costs and emissions impacts. The details of the cost and emissions equations are provided next major section of this chapter, and the details of the CADM computations using these results is described in the last se this chapter.

3. Sector Demand Indices

The sector demand indices are multipliers which, when applied to a 1990 measure of economic output activity, will r output levels for the year to which that index applies. These indices are derived from the basic economic forecast that wa by the GCVTC for use in the visibility scenario development. They were developed by Decision Focus Incorporated usin region version of the Regional Economics Model, Inc.'s (REMI's) EDFS-53 economic model. When combined with the 1 emissions inventory and assumptions about emission control actions over time, an emissions forecast is generated by the I

The REMI model is a dynamic, demographic-economic model which takes as input demand assumptions and change cost structure of various industries due to the economic effects of various control actions. The REMI model predicts chan economic indicators for 15 regions within the IAS domain. The IAS Source Regions were selected so that each IAS Sour was fully contained within one REMI region. This makes linkages of economic growth projections from REMI-based reg IAS Source Regions a straightforward task.

For each IAS Source Sector, the linkage with the REMI sectors required more judgment. Each Source Sector's growt is based on a weighted average of REMI model output projections for its 53 economic sectors, and/or the population or re personal income. The weights used were tailored to each IAS Source Group to reflect the mix of economic/demographic conditions expected to be associated with the type of emissions-generating activity represented by the Source Group. The weights are listed in Appendix A (Table A-2).

Because the IAS is not directly linked with the REMI model, a limited number of scenarios were run with the REMI and the pre-processed sector driver indices based on the REMI results are stored in the IAS data base. These scenarios are "keystone" scenarios. The default keystone scenario is the GCVTC's approved baseline economic forecast. Currently, the other keystone scenario in the IAS data base is the "lower population" scenario that is based on a REMI run that does not any of the trends in labor demand that cannot be explained by any of REMI's many economic or demographic consideratio has generally lower forecasts of population growth than the approved baseline economic forecast.

The IAS's sector demand indices are found in the IAS table called SDI0. The IAS data base has unused fields for up other alternative economic forecasts. Other keystone scenarios may vary according to assumptions about final demand, a

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[2]Note, however, that the COX0 table has about 20,000 entries, because many of the 3589 options that are possible from the baseline assumption could in turn be retrofit by another of the options. This would allow for increasingly stringent caps to be applied in succes forecast years.

prices. Users may create and use alternative REMI-based indices. If the user creates a new REMI run and wishes to inco
results into the IAS, the pre-processing steps and programs documented in Appendix G of the IAS Users Guide should be

4. Transfer Matrices

Given the projection of emissions for each source region in the Southwestern United States that the IAS generates wi inputs described above, the IAS computes the resulting concentrations of aerosols at each of the sixteen National Parks in Golden Circle. The Modeling Committee for the GCVTC has evaluated several atmospheric models that represent the ch and meteorological processes by which emissions are transported and chemically converted. A reduced form of those mo efforts, called a transfer matrix, is used within the IAS. As generally defined, a transfer matrix is a matrix that represents concentration of a pollutant that would occur at a receptor location for a unit of emissions per time period at a source regi transfer matrix contains a single number for each combination or pollutant associated aerosol, transfer region, receptor, a period.

The IAS can theoretically accept transfer matrices that are provided for every combination of county and IAS Recept Location (i.e., national parks), for each 12-hour period of the year, and for each pollutant/aerosol combination. This coul potentially be an enormous amount of data even though the transport matrix concept is itself a simplification of the compl modeling on which the matrix elements are based. For example, a transport matrix with the full complexity described ab have approximately 30 million values and occupy well over one hundred MB of disk storage. Making this problem even complex, however, is the reality that each of the atmospheric modeling efforts uses a different aggregation of sources and time periods (e.g., daily versus seasonal). For this reason, the IAS uses aggregated source regions as its basic unit of anal the "cell") and then associates them with a specific element of the transfer matrix to create a more limited set of source/re pairs. This general capability allows the user to apply transfer matrices produced by different atmospheric transport mod with different averaging times.

The IAS was developed with a fixed regional aggregation of sources and linkages to the transfer coefficient data that currently approved by the Modeling Subcommittee. The regional aggregation of the IAS and the associated transfer matr linkages are documented in Appendix A. Details of the development and calibration of the IAS transfer matrix are availa "Reconciliation of Version 3 Transfer Coefficients for Use in the Integrated Assessment System" (P. Ryan, and S. Kenda Dodge Corp., August 19, 1995). The IAS was delivered with "Version 3.1" transfer coefficients, but the GCVTC may ch use different versions at a later date. The transfer matrix data that work with the IAS system are in the data files that begi letters "WTM."

5. Extinction Efficiencies

The concentration of each aerosol at each of the sixteen National Parks in the Golden Circle determines the light exti The Aerosols and Visibility Subcommittee has provided extinction efficiencies for translating concentrations of each of th into light extinction measures.

Generally, aerosol concentrations by compositional species are converted to light extinction measures by multiplying concentrations by an extinction efficiency and, for hygroscopic components, also by a water growth factor that is a functi relative humidity (RH). Light extinction due to a given aerosol is equal to the concentration of that aerosol multiplied by extinction efficiency of that aerosol multiplied by the water growth factor for that aerosol and humidity level. The sum o extinction from each of the aerosols is the total predicted extinction at the receptor.

As recommended by the Aerosol and Visibility Subcommittee, the IAS has the capability to use the following level o to generate light extinction estimates:

(1) 12 hour model-predicted concentrations of each aerosol that change with each emissions scenario.

(2) Dry extinction efficiencies for each aerosol (time and location invariant).

(3) Water growth factors as a function of RH for each hygroscopic aerosol and 12-hour period.

(4) 12-hour averaged values for RH at each of the receptors.

The Version 3.1 transfer coefficients that have been approved by the Modeling Subcommittee, and which are being d with the IAS (November 1995), have been generated using a simple time-constant RH value, rather than the 12-hour valu is due to the lack of available RH daily data. The default RH assumption is 50 percent. The IAS data files also allow the

alter this assumption to either 25 percent or 75 percent using the IAS run options. This will allow sensitivity analysis to th
assumption without the user having to completely re-generate the detailed transfer matrix data files.

The specific extinction efficiency values used in the Version 3.1 IAS working transfer matrix are documented in "Reconciliation of Version 3 Transfer Coefficients for Use in the Integrated Assessment System" (P. Ryan, and S. Kendal Dodge Corp., August 19, 1995, p.7) as:

$$B_{ext} = 10 + 3\ NHSO\ f_{rh} + 4\ OC\ (0.5 + 0.5\ f_{rh})\ ^{+}\ 10\ EC + 2\ Soil + 0.6\ CM$$

where:

NHSO	=	ammonium sulfate (ug/m^3)
NHNO	=	ammonium nitrate (ug/m^3)
OC	=	organic carbon (ug/m^3)
EC	=	light absorbing carbon (ug/m^3)
Soil	=	soil (ug/m^3)
CM	=	coarse mass (ug/m^3)
f_{rh}	=	0.7/(1.0 - 0.01 RH), {note that f_{rh} $^{=}$ 1.0 when RH < 30%}
RH	=	% relative humidity

Because RH does not vary with time or receptor in the Version 3.1 IAS working transfer matrix, extinction efficienci constant. The extinction efficiencies that result for each aerosol and each of the three generic RH levels are provided in th data base table called EXT0. However, the actual IAS computations of extinction efficiency are *pre-processed* with the ra transfer coefficient information when creating the IAS's working transfer matrix data files (the working transfer matrix [W files). This permits the IAS computations that are performed with each scenario run to go straight from emissions to beta in a single step. As a result, the actual extinction efficiency assumptions used in IAS computations are not readily observa their raw form in any of the data files used during IAS computations. This also means that IAS extinction efficiency assu changes require regenerating the full WTM data files. However, the user can perform sensitivity analysis to the degree th three sets of RH levels provided as IAS run options.

The IAS run options also could allow for visibility impacts to be computed at the "12-hourly" level and/or for the full distribution of the 365 daytime or 730 day-plus-night extinction values to be computed from the 365 transfer coefficients. cases can then be run using specific 12-hour values to understand the details behind specific points along the full distribut However, the Modeling Subcommittee decided to distribute only annual and seasonal *average* transfer coefficients, so this option is not possible with the distributed version of the IAS. The run options functioning with the currently distributed I transfer coefficient data are annual and seasonal averages and annual averages for the 20 percent worst and best days.

B. KEY CALCULATIONS AND RESULTS

Given the number of sources in each cell and information about unit costs and emission control efficiencies due to ea selected control actions, emissions and costs corresponding to each of the cells can be calculated. Expected visibility can calculated from projected emissions. The preceding section provided an overview of the key data inputs to each of these computations of the IAS, and information about the data sources. This section details the actual IAS equations that are ap when an IAS case is "run."

1. Emissions Equations

In the IAS, the relationship between emissions, selected control actions, and sectoral demand is modeled using an em equation summarized in this section. For each IAS source category, existing and new capacities are represented by separa capture control option and emissions rate differences for existing and new sources. Each existing cell will have one assoc "new" cell, the capacity of which will be estimated to grow in sufficient quantity to supply all of the associated sectoral de cannot be met by the capacity of sources that were in place in 1990 and which have not yet been retired as of the time peri question. Sectoral demand is met by existing (i.e., in place as of 1990) capacities first, then if the existing sources (after a for cumulative retirements) cannot meet all of the sectoral demand, new source capacity is added. Unless otherwise speci user, new demand for a cell is met by new capacity in the same IAS Source Region as the existing capacity.

The following emission equation is used to estimate emissions from that part of demand that can be met from sources were existing at the start of the simulation period (i.e., 1990). For each cell, c, and each pollutant, p, within that cell, emis estimated for each year, t, are:

Existing Source Emission$_{c.p.t.}$ =

1990 Emission$_{c.p}$/(fraction emissions remaining given 1990 existing controls$_{c.p}$) *
(fraction emission remaining with assumed control option$_{c.p.t}$) *
intensity index$_{c.t}$, *
MIN {growth index $_{c.t,}$, or
(1,/1990 utilization fraction$_{c}$)*(1-cumulative fraction retired$_{c.t}$)*(capacity factor$_{c.t}$)

where:

1990 Emission is the 1990 emission for that cell and that pollutant in the 1990 emission inventory. This value is stor the CBE0 table of the IAS.

fraction emission remaining given existing controls indicates the degree to which emissions in 1990 have already been reduced by existing controls in place, compared with the case where the same cell might have had no co the base year. If no controls are in place in a given cell as of 1990, then the value of this parameter will be 1. If the c in place in 1990 remove 40 percent of the emissions of a particular pollutant, then the value for that cell and that poll be 0.6. These fractions are taken from the COE0 data for the control option assumed to be in place in 1990, as specif the LBF0 table.

fraction emission remaining with assumed control option is the control efficiency (relative to no controls at all, *not* relative to 1990 control levels) that is associated with the specific control option assumed to be in place in each fo year, t. The control options assumptions are stored in the Selected Control Actions (SCA) results table that is an outp CADM computations (Step I of the IAS scenario computations). The fraction emissions remaining for each control o found in the COE0 file.

intensity index is a variable representing any change in emission or sectoral demand not predicted by the economic m or technological change. For example, the index may incorporate shifts in energy use behavior that are not motivated economic conditions, but rather the result of a voluntary program. These values appear in the SDI0 data file, but unle user adjusts them, they are always 1.0.

growth index is the REMI-based sectoral activity level in any year relative to that activity measured in 1990. Thus, i 1990, this will be 1.0, and will be greater than 1.0 in years where economic activity levels are forecasted to be higher the initial year; and less than 1.0 in years where economic activity levels are forecasted to be lower than in the initial These assumptions are in the SDI0 data.

1990 utilization fraction is an input reflecting capacity utilization conditions for technologies in that cell in the 1990 base year. (New capacity will not be built until demand and/or retirements grow enough to consume any underutilize existing capacity.) These values will be equal to 1.0, except for source sectors for which 1990 is deemed to be a year substantial underutilization. These values are found in the SCL data.

cumulative fraction retired is the fraction of the existing capacity in place in 1990 that continues to emit air pollutant at the base year (1990) emission rate. These inputs are found in the CRT data.

capacity factor is a constraint to be applied to note whether certain types of capacity-in-place in a cell are fully utilize The net effect of reducing the capacity factor is to shift utilization from existing to new sources within the cell where occurs. These inputs are found in the CRT data.

Once the existing capacity is fully utilized, new sources are needed to meet expected activity levels. A new capacity added when the growth index for the corresponding existing source cell is greater than:

(1/1990 utilization fraction$_{c}$)*(1-cumulative fraction retired$_{c.t}$).

Using the subscript c to denote the same cell definition as in the associated existing source case, the emissions from t associated new capacity cell will be:

New Source Emission$_{c.p.t}$ =

1990 Emission$_{c.p}$/(fraction emissions remaining given 1990 existing controls$_{c.p}$) *
MIN (fraction emissions remaining with assumed new source control option$_{c.p}$),

(fraction emissions remaining with assumed existing source control option$_{c.p.t}$) *
intensity index$_{c.t)}$ * {growth index$_{c.t}$ –
[(1/1990 utilization fraction$_{c}$) *(1-cumulative fraction retired$_{c.t}$)*
(capacity factor$_{c.t}$)$_{]}$ }

Note that the MIN operator in the new source emissions equation ensures that the new sources will always be at least controlled as its existing capacity counterpart. In the baseline, new sources are always at least as highly controlled as exis sources. However, as more and more stringent control options are selected, new source requirements may become less str than what is being assumed for the existing source. When this happens, the IAS also applies that level of control to the ne assumption when estimating emissions, effectively ensuring that new sources are always controlled *first*. This operation i performed on a pollutant by pollutant basis, so that if the new source is still more controlled with respect to a different pol that higher level of control is not *undone*. Overrides of the new source control assumptions are not reflected in a scenario' estimate.

The total emissions from a given IAS source category will be the sum of new and existing source emissions for that s category, based on the two equations above.

2. Control Costs

The IAS displays three separate projected cost results for each cell in each year. They are the levelized capital cost, t operating cost and the total levelized cost associated with the control(s) in place in a given year. Note that all of these cos are viewable through the Projected Cost screen in the IAS, represent the levelized *annual* costs that are associated with ea discrete forecast year. This section explains how measures of cost are calculated for each source cell within the IAS.

(1) The capital cost for a cell measures the cost of installing any control which is installed after 1990.[3] Capital cost levelized over the years in which the control will be effective (and accounting for the levelization factor assume This levelized cost is the value reported by the IAS as the capital cost incurred by a cell. The factor used to leve capital costs may be changed by the user.[4]

(2) The operating cost measures the additional ongoing expenses incurred because of the control action. This inclu costs of maintaining and servicing a control technology, in addition to any change in operating efficiency which arise because of the control action. Operating costs may be negative if there are substantial efficiencies or fuel savings.

(3) The combined cost within the IAS is the sum of the levelized capital cost and the operating cost. It is an annual for the modeled year in question, not a total over the entire decade represented by the modeled year.

Levelized Capital Costs. To update the capital cost for the modeled year in which a control is put in place, the IAS adds the "incremental" levelized capital cost of the control action to any levelized capital costs which are already in place (The "incremental" capital cost that is applied to the costs reported by the IAS is calculated by subtracting the capital cost control action(s) in place in the preceding modeled year from the capital costs of the new (combined) control action being a retrofit in the current modeled year). The incremental capital cost of a retrofit action is then adjusted by the number of s the cell and the percentage of sources that have retired:

Adjusted Capital Cost =
Capital Cost * Number of sources in the cell *(1 - % retired at date of installation)

---

[3]Base year $ = 1990. (Note that the fact that REMI forecasts are in $1987 is not problematic to the IAS because all REMI results u calculations have first been converted to an index of economic activity relative to 1990, and hence are unitless.)

[4]The levelization factor used to *assess* capital costs on an annual basis over the useful life of a given control option can be set by th the Financial Assumptions Button in the Control Scenario Screen in the IAS user interface. By default, this discount rate is currently s percent, which is intended to reflect a 7 percent real discount rate plus account for added variable capital costs (e.g., interest, insurance that would increase direct capital *expenditures* by almost 100 percent.

Using this adjusted value, the cost is then levelized across the remaining useful life of the production source that is be retrofit[5], using the levelization factor specified for the case.

Levelized Capital Cost = Adjusted Capital Cost * (L / 1+L) / (1 - 1 / (1+L)")

where:
L = levelization factor assumed
n = remaining useful life of the facility being controlled

The resulting levelized capital cost is applied to each forecast year from the first year the retrofit option is put in plac the end of the useful life assumed in the levelization formula. If there are already levelized capital costs in that cell for tha (e.g., due to a control action taken in a previous period, but still being amortized in this forecast period), these incremental *added* to them.

Annual Operating Costs. The annual operating cost associated with the control action selected for a cell for each forecast year is directly calculated from the unit cost input table for the control action in question, since there is no need to for a legacy of costs of preceding years' decisions, as is the case with the capital costs. Also, operating costs are expressed cost terms. However, the annual cost is adjusted based on the number of sources in the cell, the percentage of sources tha retired, and the capacity factor specific to that cell:

Levelized Operating Cost = Operating Cost * Number of sources in the cell *
(1 - % retired in that year) * capacity factor

The resulting operating cost is applied to each forecast year that a control option remains in place.

Numerical Example. The cost reported by the IAS considers the cost of maintaining any control which is in place in given year, as well as the cost of installing any control technology not in place as of 1990. For example, if the IAS baselin *control option A*, which is then retrofit in an EMS with additional control option to achieve a *control A and B* option in 2010, the costs are calculated as follows:

The baseline specifies control A in each year for a particular cell:

Year	Baseline Control
1990	control A
2000	control A
2010	control A
2020	control A
2030	control A
2040	control A

And the IAS retrofits control A with control B in the year 2010:

Year	EMS Control
1990	control A
2000	control A
2010	control A and B
2020	control A and B
2030	control A and B
2040	control A and B

The cost data for that cell (in the COC0 file) might indicate, for example, that control A has a one-time capital cost of per capacity unit and an annual operating cost of $100 per capacity unit, while control (A and B) has a one-time capital co $1,500 per capacity unit and an annual operating cost of $130 per capacity unit. If there are 10 units of unretired capacity megawatts [MW]) in the cell in question, then the capital costs for applying the controls in this cell would be $100,000 an $150,000.

[5]The average remaining useful life of the facility is found in the master source cell list (SCL) data that was provided by ANL.

The only costs assigned to the baseline scenario are the annual operating cost of $10,000. No capital cost is assigned baseline in this example, because control A has been in place as of 1990. (Cells that have controls installed after 1990 do capital costs of those controls, so there are some capital costs associated with the baseline, which need to be netted out of costs after the runs are completed.) Thus, the baseline costs for this cell would be:

Year	Baseline Control	Capital Cost	Operating Cost
1990	control A	$0	$10,000
2000	control A	0	10,000
2010	control A	0	10,000
2020	control A	0	10,000
2030	control A	0	10,000
2040	control A	0	10,000

For the EMS costs, the annual operating cost shifts from $10,000 in the baseline to $13,000 starting in 2010. (Costs r decline over time with retirements of the cell's capacity.)

However, the computation of the capital costs for the control scenario is more complex. When the IAS shifts to Cont and B), it keeps track of what control level it begins with (i.e., from Control A), and nets that part of the control costs out c capital cost for the combined option. The *incremental capital cost* in the year where a control action is changed (i.e., that which is *actually incurred in 2010)* is the *difference* between the capital cost for Control A and B ($150,000) and the capital cost for Control A ($100,000), or $50,000. The assumption is that the $100,000 capital cost for the Control A port Control (A and B) option was already paid for when the control was first installed prior to 1990.

This incremental capital cost of $50,000 is then levelized according to the formula above, perhaps resulting in an ann of $8,000. The remaining useful life of the existing facilities being retrofit may be 20 years, in which case, the IAS will re $8,000 in 2010 and again in 2020. (Note that the total capital cost is not simply the sum of the costs shown in the two fore years, but also includes another 18 years in between the forecast years, where the $8,000 cost would also be incurred. The presented for a forecast year in the IAS are an annual cost, just presenting costs at a single point in time.) Thus, the EMS' this cell would be:

Year	EMS Control	Capital Cost	Operating Cost
1990	control A	$0	$10,000
2000	control A	0	10,000
2010	control A and B	8,000	13,000
2020	control A and B	8,000	13,000
2030	control A and B	0	13,000
2040	control A and B	0	13,000

C. SCENARIO ANALYSIS AND THE CADM

The IAS is designed around the concept of examining five types of EMSs, and the control actions that would result fr each. Two of the scenarios represent bounding scenarios. The Baseline Forecast Scenario (BFS) represents the control ac would be undertaken under current regulations for each of the cells in each of the years considered by the IAS, and the Ma Management Alternative (MMA) scenario represents the highest emission reductions achievable in each cell by retrofit co options available in the IAS data set. For other EMSs, which are intermediate between the BFS and MMA, the IAS starts Baseline control actions in place, then adds additional controls to each *controllable* cell as specified by the Control Scenar regions except for Canada, Mexico, Washington, Montana, and Texas contain controllable cells.

Between the two bounding scenarios lie three possible types of EMSs: a Technology Specification Scenario, an Emis Cap Scenario, and a Visibility Standard Scenario. The IAS is designed to permit the user to select control actions using th different strategies, or a combination of the strategies.

(1) The user may specify control levels beyond the assumed minimum control level of the baseline for any of the controllable cells in any of the post-2000 forecast years. If a cap is not also specified, then the IAS will treat thi full control scenario specification, and will produce an emissions, visibility and cost projection consistent with c specified by the user.

(2) The IAS can select those control actions to meet an emission cap at the lowest cost. A Regional Cap definition includes the *Market Region* that must meet the cap, the pollutant measure to be capped, the allowable level of emission of that pollutant measure, and the year in which the cap is to be achieved. Using the least-cost algorith the CADM, the IAS simulates the idealized outcome of a market-permit system under a regional cap. Although terminology implies that emissions permit trading would be involved, this is not the only way that the results co interpreted. They could also be thought of as an indication of what the least-cost method would be for specifyin controls to achieve emissions levels consistent with those of a cap.

(3) The IAS's CADM can identify and select those control actions that would meet a VAQ standard at a given recep the lowest cost. Standards for a visibility goal are expressed in units of annual average light extinction. It is pos for the user to identify specific IAS Source Regions that would be required to take control actions as well as tho would be exempted from action.

By applying combinations of the Technology Specification, Regional Cap, and VAQ Goal, one can create many diffe control scenarios that are intermediate between the Baseline and the Maximum Management scenarios using the IAS. Eac scenario can be saved as a new matrix of control actions independent of the EMS from which the control actions were gen That new scenario can then be used as a starting point for further modifications.

The IAS computations used in each of the three types of scenario specification are documented in more detail in the r this section. However, it is worth noting here that the IAS has a range of other parameters that can be used to set up more forms of scenarios. For example, clean air corridors, exemptions of particular source groups from cap requirements, etc., options.

1. Specifying Minimum Control Actions

Since the output of the CADM is a list of specific control actions, a list of minimum control actions entered as input t CADM (e.g., in command-and-control format) will result in the same list being returned as output, unless other run optior caps are simultaneously specified.

When defining control technologies in place, their efficiencies, and their costs must be cell-specific, meaning that wit source sector, these assumptions can be different for different facility sizes or regions. This accommodates the need to all region-specific baseline assumptions, and allows for different treatments of regions in EMSs. This, in turn, implies that re options need to be considered on a cell by cell basis. To ensure data integrity in the specification of a command-and-contr strategy, the IAS user interface allows the user to select only from those retrofit options that are available *given what is al in place*.

2. Regional Caps

The result of a regional cap simulation is a list of control actions that meet the cap with least cost. The first step in de such a cap is to determine the set of IAS Source Regions that would be included in the cap calculations. This is termed a " Region," since the cap logic produces the least-cost method of achieving a cap, which simulates a system of tradable perm generate the list of selected control actions, the emissions in the Market Region to which the cap will be applied are comp the starting point of the minimum specified control actions that will be assumed to be in place. (If there is no direct user specification, the starting point for controls is the set of baseline control actions.) If a region's emission level exceeds the most cost-effective control option available within the Market Region is added. ("Effectiveness" is measured with respect pollutant measure being capped.) This process of calculating expected emissions, then comparing it to the cap, continues cap is met {or the most stringent control actions are in place in all the cells of that Market Region. Control actions that ca selected are only those retrofits that will reduce *emissions further* than those associated with the minimum control actions specified. (The COX0 table assures this restriction.)

There is no change in the rate of retirements and introduction of new sources, nor reassignment of new sources to alte source regions assumed in achieving a regional cap. However, it is possible for the user to exclude specific source sectors cap logic, and to limit the locations for new source capacity.

If there are multiple caps to be processed (e.g., several independent Market Regions with their own caps, or caps appl multiple years for the same Market Region), these caps are processed individually and sequentially. The first caps simula those in 2010, then those in 2020. It does not matter what order the different Market Regions are processed in within a fo year, since their control decisions are independent. However, the IAS processes the Market Regions in a given forecast ye order in which they are specified on the PC screen by the user. The specific steps of the Regional Cap processing by the C each cap are listed below:

For each time period (working from 2010 to 2040), and for each trading region that has an emission cap defined in th

(1) Generate a list of IAS source regions that are associated with the defined regional cap Market Region.

(2) Calculate the total emissions of the relevant pollutant measure in the Market Region that would be generated in year by all source categories in the relevant source regions, given the "current" control actions. (The current co actions are the minimum control actions specified for that year, or superseded by the control action chosen for t preceding time period, if processing for a year later than 2010.)

(3) If the total emissions in step 2 are greater than the specified emission cap for the Market Region, generate a list retrofit control actions available for all the cells in the Market Region, given their list of the current control leve by reference to the COX0 data).

(4) Compute a ratio for each control action identified in step 3 by dividing the emission reduction due to the contro by the incremental cost of the control action. Sort the list of control actions by emission-over-cost ratios.

(5) As long as the regional cap is less than the projected emissions for the Market Region and the list of available c actions is not empty, perform the following steps:

    (i) Add the next control technology from the list.
    (ii) Update the expected emissions for the region.
    (iii) Determine if the cap has been met.

(6) When the regional cap is met, the control actions selected for this time period are defined by the list of control a generated in step 5 to reach the cap. If the list of available control actions has been exhausted but the regional e cap is still less than the projected emissions, the list contains the maximum available control actions for the spe cells.

(7) Perform steps 1 to 6 for the rest of the Market Regions defined in this forecast year.

(8) Move to the next forecast year and start with the first Market Region listed for that year. Use as the minimum c actions, the results for that Market Region from the previous year's cap simulation.

3. VAQ Goals

The CADM for attaining VAQ goals follows a similar set of steps to those described for regional caps except that a V can only be set for a single receptor in each IAS case. (This is because the actions taken for one receptor are interdepende the actions that might be taken at a different receptor. Thus, VAQ caps for multiple receptors are not possible in the way multiple Market Regions are.)

To calculate a list of control actions needed to meet a VAQ goal in a specific receptor location, the CADM first calc difference between visibility and the visibility goal for the receptor. If estimated visibility does not meet the goal, the mo effective control action available will be added. The expected light extinction is then recalculated, and further control act in least-cost order, as necessary. This continues until the VAQ goal has been met, or the most stringent controls have bee

For a receptor with a VAQ goal, the CADM does the following:

(1) Calculate the expected light extinction at the receptor, given the control actions in place.

(2) Generate a list of available control actions sorted according to the ratio of light extinction improvement at that r to the change in cost.

(3) Add the next control technology in the order to the list of selected control actions.

(4) Calculate the projected visibility for the receptor with the new control action in place.

(5) Return to step 1, unless the visibility goal has been met, or all control actions have been applied.

4. General Summary of CADM

Thus, the IAS CADM will preferentially assign the cheapest technologies (in the sense of most cost-effective) to achi
or goal. The general approach is that the CADM rank-orders all of the options feasible as retrofits to the starting set of co
options (e.g., from the baseline controls, or alternative technology specification) according to each option's ratio of increm
levelized cost of a control option to incremental improvement towards the cap or goal. It always selects the most cost effe
options cost first, until the objective is met. If an alternative control option for a cell is reached where a more cost-effecti
has already been selected via this process, it determines whether the less cost-effective option would actually reduce emis
light extinction) further than the option already selected. If it would, then the less cost-effective option is selected, and th
cost-effective option is deleted.

As long as the specified regional cap or VAQ objective is not met and options exist which provide greater total emiss
reductions, the CADM will continue choosing ever more costly controls until there are no remaining control options. Thu
MMA can be simulated simply by setting a VAQ goal at any of the receptors that is impossible to achieve. The backgrou
Rayleigh extinction level of 10 Mm^{-1} would be an infeasible goal, and is used to produce the GCVTC's MMA. Maximum
alternatives with respect to individual pollutants, e.g., with respect to SO_x, could be created by setting a Regional Cap of 0
that pollutant.

There are a number of limitations in the use of the CADM. First, the caps are not simulated dynamically. In other w
there is no foresight in how a cap is attained. This might be a limitation if there are dramatically different types of caps be
applied to a given Market Region in different forecast years (e.g., very stringent caps on different pollutants in different ye
there were significant changes in the available control options over time. This is probably not a significant limitation, giv
control options in the present data set.

Another limitation is that one cannot apply caps to more than one pollutant in the same year. That is, one cannot spec
percent reduction in SO_x, *and* a 25 percent reduction in PM simultaneously in the same Market Region. However, it *is* po
set a cap on multiple pollutants if inter-pollutant trading is allowed. For example, one could specify that the *combined* ton
SO_x and PM must be reduced by 25 percent, and indicate the ratio by which each pollutant could be offset against the othe
the CADM would determine the least-cost way to achieve the overall weighted average reduction, but not constraining an
individual pollutant to any specific caps.

The final limitation to note is that VAQ goals cannot be specified with respect to multiple receptors. This is for the s
reason (interdependence of control actions) that one cannot specify caps on more than one pollutant in a Market Region.
one *can* run a VAQ goal for the receptor that appears to be farthest from its goal, and after the simulation determine wheth
control actions selected are also sufficient to achieve the goals at other receptors.

The user should also be aware that the CADM may sometimes "overshoot" the specified target. This is because it co
of the capacity in each cell, if that control action appears to be the next most cost-effective option. In some cases, the nex
cost-effective action may involve a very large incremental reduction in emissions. If this is case, and the CADM is very c
already achieving the cap, the last control action may more than achieve it, and by a significant amount. In practice, overs
of targets and caps is common, and is usually attributable to taking control actions on road dust (particularly unpaved road
actions). This is not an error in the CADM calculations, but only an artifact of the discrete nature of the IAS cell-based ar

D. SAMPLE CALCULATION

This section contains a sample calculation that shows how the existing and new source SO_2 emissions are computed f
IAS Baseline for a single source category in one IAS region. The sample calculation is for a coal-fired utility with *other* c
(meaning other than SO_x control) in Western Washington.

Table I-1 provides the equation and sample data values for the existing source emissions equation. This table is orga
with the existing source equation across the top row. The second row in Table I-1 lists the IAS data base name where the
reside for each term in the equation. Variable names are listed in the third row. Finally, the bottom row contains the actu
for the example source cell, which is IAS Region 1, scc_id = utcoaloc, and size_id = 3. This source cell represents large (
tpy) coal-fired utility units with controls other than SO_x controls in Western Washington.

The first term in the Table I-1 existing source emissions equation is 1990 emissions (cell, pollutant). For SO_2, the po
used in this sample calculation, the 1990 emissions are 69,461 tpy.

For the six different analysis years, the fraction of emissions remaining given existing controls is determined by look both the LBF0 (Loeb Baseline File) and COE0 (Control Option Efficiencies) files. The Loeb Baseline File shows that the technique tech_id is 0 in 1990 (meaning no NO_x or SO_2 control), and 151 in 2000, and thereafter. Tech_id 151 provides 5 percent NO_x control, but no SO_2 control. So, for the sample calculation, both the *fraction emission remaining given existing control*, and the *fraction emission remaining with assumed control* option are 1.00.

The intensity index value is found in the sector demand indicators file, or SDI0. These values are always 1.0 in the c IAS files. (This index is designed to be used to include the effects of pollution prevention, or energy efficiency improvem future air pollution emissions.)

The growth index is also found in the SDI0 file. While the SDI0 file provides alternative growth indexes, the one nor used in the IAS, and listed here is hhl_sd_indx.

The value to be compared with the growth index for each forecast year is the product of 1/1990 utilization fraction, 1 the cumulative fraction retired, and the capacity factor adjustment. The 1990 utilization fraction is found in the SCL unde variable name pct_utilized. For this cell, the 1990 utilization fraction is 1.0. (For large, coal-fired utility units, the 1990 values range from 0.56 to 1.0.)

The 1 minus cumulative fraction retired term is always 1 until 2040, when it goes to zero, as all existing capacity in t retired. The pct_retired values are found in the Cell Retirement Table (CRT). The capacity factor adjustment values are a in the CRT file. This variable reflects the potential lower utilization of existing units as they age. Values for inten_ANL cell range from 0.99 to 1.00 through 2030, then go to zero as existing capacity is retired.

The New Source emissions sample calculation shown in Table I-2 is similar to that for existing sources, but somewha simpler. This table just shows the 2000 to 2040 data values for the source cell of interest. The new source control option (technology) for utilities has a 98 percent SO_2 reduction from uncontrolled levels. With this 98 percent control, the fracti emissions remaining with the assumed new source control option is 0.02. For this example, 0.02 is always lower than the of emissions remaining with the assumed existing source control option (1.0) times the intensity index (1.0).

Table I-1
Sample Calculation
Existing Source Emissions

	[illegible] /	[illegible]				* [illegible]				* [illegible]	* (1) [illegible]	or (2) [illegible]	* [illegible]		* [illegible]
File Source	CBE0	COE0				COE0			SDI0		SDI0	SCL		CRT	CRT
Variable Name	emiss	LBF0 tech_id nom_cntl_eff				tech_id nom_cntl_eff			inten_indx		hhl_sd_indx	pct_utilized		pct_retired	inten_ANL
Sample Data Values															
IAS Region 1	utcoaloc	Year	tech_id	NO_x	SO_2	tech_id	NO_x	SO_x				pct_utilized=1.0	Year	pct_retired	inten_ANL
	size_id=3	1990	0	0	0	151	0.5	0		Year			1990	0	1.
	SO_2=69,461 tpy	2000	151						1.0	2000	1.118496		2000	0	1.
		2010	151						1.0	2010	1.262207		2010	0	.99
		2020	151						1.0	2020	1.441801		2020	0	.99
		2030	151						1.0	2030	1.634258		2030	0	1.
		2040	151						1.0	2040	1.788273		2040	1.0	0

Table I-2
Sample Calculation
New Source Emissions

	Year								
69,461	2000	1.0	0.02	1.0	1.0	1.118496	1.0	0	1.0
SO_2	2010	1.0	0.02	1.0	1.0	1.262207	1.0	0	0.99
tpy	2020	1.0	0.02	1.0	1.0	1.441801	1.0	0	0.99
	2030	1.0	0.02	1.0	1.0	1.634258	1.0	0	1.0
	2040	1.0	0.02	1.0	1.0	1.788273	1.0	1.0	0.0

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The final term of the new source emissions equation (the part in brackets) reduces to the growth index minus 1.0 for
through 2030. Then, in 2040, the right-hand side of the term in brackets is zero, so the entire growth index (1.788273) is
estimating new source emissions.

The results of the SO_2 emissions sample calculation are shown in Table I-3. For this IAS region, existing source SO_2
emissions remain fairly constant from 1990 to 2030. The slight drop in existing source SO_2 emissions in 2010 and 2020 is
attributed to the change in the intensity index in those two years. Existing source SO_2 emissions go to zero in 2040 as 100
of the existing capacity in this cell retires in 2040. New source SO_2 emissions are in proportion to the growth index minus
years 2000 through 2030. The 2040 new source SO_2 emissions are a product of growth index times the existing source SO
emissions with 98 percent control applied. The combination of existing source retirements and the high level of new sour
control produce a dramatic drop in SO_2 emissions between 2030 and 2040.

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Table I-3
Emission Projection Example
scc_id = utcoaloc
size_id = 3

IAS Region 1	Existing Source SO_2	New Source SO_2	Total SO_2 (tpy)
Year			
1990	69,461	0	69,461
2000	69,461	165	69,626
2010	68,766	378	69,144
2020	68,766	627	69,393
2030	69,461	881	70,342
2040	0	2,484	2,484

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CHAPTER II
ELECTRIC UTILITIES

IAS modeling methods have been examined that have the greatest effect on the utility emission forecasts. Key utility modeling assumptions that are of interest to the Western Regional Air Partnership (WRAP) are: (1) unit lifetimes; (2) new emission rates (Best Available Control Technology, or BACT); (3) capacity utilization trends; and (4) electricity demand rates. Evaluation of these modeling assumptions was made by reviewing the IAS Users Guide and the compact disk-read memory (CD-ROM) with IAS files.

A. UNIT LIFETIMES

Table II-1 lists the general electric unit lifetime assumptions that are used in the IAS. This information is critical in determining utility emissions for long-term future year forecasts (for 2030 and 2040) because by 2040, every utility unit t operating in 1980 is assumed, via the advent of new source review, to have its present emission limitation retired (i.e., rep 21 a new source emission limit). New source utility emission rates are much lower than those for existing units, so replacem existing capacity, especially large coal units, dramatically lowers emission forecasts.

Table II-1
Electric Utility Unit Lifetimes
Used in Retiring Baseload Generation Capacity

Fuel and Unit Type	Unit Size < 100 MW	Unit Size ≥ 100 MW
Coal	45 years	60 years
Nuclear	N/A	40
Natural Gas Combined Cycle	60	60
Oil/Gas Combustion Turbines	30	30
Oil/Gas Steam	30	30
Geothermal, Fuel Cell, Solar/Thermal Biomass, and Other	40	40
Solar/Photovoltaic	30	30

SOURCE: Tables 3.2.5 and 3.2.8 of the IAS Users Guide.

Verification of how Table II-1 unit lifetime assumptions are included in the IAS model data bases is performed by re the Cell Retirement Table (CRT). This is not a straightforward verification to perform because of the number of utility re this file. There are separate records for utilities for each of the 62 IAS source regions (where utilities are located) and for applicable scc_id and sz_id. For any source region that has utilities, there are typically three or four scc_id and sz_id com present in the CRT. Selected variables from the CRT are included in Table II-2 to illustrate how this information is organ to demonstrate the emissions effect.

The first set of records shown in Table II-2 is for utility coal combustors in western Washington State (IAS Region = size ID of 3 indicates that this is a source cell with more than 100,000 tpy of criteria pollutant emissions. The percentage column (pct_retired) indicates that for this region, scc_id, and sz_id, most of the emissions are at the current rate through then are all at the new source emission rate by 2040. If these are units larger than 100 MW, this implies that they began o pre-1980, because their unit lifetime is estimated to be 60 years.

The other important variable in the CRT that affects future utility emissions is inter_ANL. This is a value between ze 1, inclusive, that is used to adjust the projected output from an existing cell to account for capacity factor effects in the uti namely reductions in the usage rate of existing capacity, which in turn, can be offset by increased usage of new forms of c warranted by demand levels. (This applies mainly in the case of older forms of electric utility capacity.) ANL utility sect were used to identify the time trend in the capacity utilization of various key power units. Results were summarized as a c factor input.

B. NEW SOURCE EMISSION RATES

For all IAS regions, a single composite new technology was defined using the new facility attributes shown in Table (Teague, 1998). The composite was based on the relative shares of new capacity added to each region by the Argonne Uti Simulation (ARGUS). The state of new capacity used as input to ARGUS consisted of integrated coal gasification combi (IGCC), natural gas combined cycle (NGCC), and coal-fired boilers with flue gas desulfurization (FGD) for all regions.

Table II-3
Composite New Technology Components

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New Unit Mix	Technology	Fuel
20%	Coal-Fired with FGD	Bituminous Coal
25	Natural Gas Combined Cycle	Natural Gas
55	IGCC	Bituminous Coal

The above composite technology is represented in IAS as having 98 percent SO_2 control and 97 percent NO_x control compared with uncontrolled emission rates.

Table II-2
Cell Retirement Table Excerpts

region_id	scc_id	sz_id	fcst_year	pct_retired	state_id	region_descriptio
1	utcoaloc	3	1990	0	53	Washington-W
		3	2000	0	53	Washington-W
		3	2010	0	53	Washington-W
		3	2020	0	53	Washington-W
		3	2030	0	53	Washington-W
		3	2040	1	53	Washington-W

NOTES: A region_id of 1 indicates that the region is western Washington. Utcoaloc represents utility coal combustion with other control (where other control). A sz_id of 3 indicates that cell emissions are more than 100,000 tpy. The pct_retired column indicates that all units in the cell that operating through 2030, then were all retired in 2040.

C. CAPACITY UTILIZATION TRENDS

Another component of the baseline assumptions is whether existing utility capacity was being fully utilized in the 19 year. In situations where capacity was underutilized in the base year, there is room for substantial growth in the cell's den before new capacity is added in the simulation. The 1990 percentage utilization assumptions (which are less than one onl utility cells) are in the SCL file as pct_utilized.

Pct_utilized is the percentage of capacity within the cell that is used in the 1990 base year (a fraction between 0 and 1 value can also be referred to as a capacity factor. If this value is less than 1.0, the IAS will use the excess capacity to mee increasing electricity demand before adding new source capacity.

Table II-4 excerpts some SCL data for the same IAS region presented earlier in this chapter. This table shows the 19 capacity utilization in this region to be 100 percent for coal units, 81.5 percent for oil, 45.9 percent for natural gas, and 10 for renewables.

Because coal-fired utility unit operation has the most influence on SO_2 emission trends in the region, Table II-5 sumr the large, coal-fired utility 1990 capacity utilization values used in IAS. In IAS, coal-fired utility units are represented in categories – those with SO_2 control, and those with pollutants controlled other than SO_2. These two source categories are separately in Table II-5. For the most part, 1990 capacity utilization values for large, coal-fired units are between 75 and percent. The only exception is the 56 percent capacity utilization value for New Mexico-North East. With these high bas capacity utilization values, the IAS model will have to bring on new source capacity to meet the increasing electricity dem cannot be met by existing units.

D. GROWTH

Electricity demand growth is the primary driver of new electric utility capacity construction. Because of the cost of n capital construction, the expansion of life-extension activities, environmental permitting difficulties, and uncertainty regar electricity market restructuring, new construction to compensate for the retirement of existing baseload facilities is relativ across the nation. In preliminary ANL utility analysis for the IAS economic regions, significant coal-fired unit retirement occur until the 2030-2040 time frame. Because of the lack of baseload retirement (with the exception of nuclear capacity 2020-2030 time frame), new capacity growth will be driven primarily by electricity demand.

REMI does not provide a direct output link to electricity demand. The most useful REMI output related to electricity is the public utility expenditures sector (Standard Industrial Classification [SIC] 30). ANL conducted an econometric ana comparing the relationship between gross national product (GNP) and electricity demand from the Energy Information Administration (EIA) estimates, and gross regional product (GRP) and public utility expenditures from REMI. We found coefficient relating GNP and GRP to electricity demand and public utility expenditures are similar. Given

Table II-4
Source Cell List Excerpts

region_id	scc_id	sz_id	num_src	state_id	region_description	pct_utilized
1	utcoaloc	3	1357600	53	Washington-W	1
	utliqune	99	175000	53	Washington-W	0.815
	utugasoc	3	686000	53	Washington-W	0.459
	utrenwnc	99	68200	53	Washington-W	1

NOTES: A region_id of 1 indicates that the region is western Washington. There are four utility source types represented in this table as follows: utcoaloc (utility coal combustion with other control), utliqune (utility liquid fuels with no control), utugasoc (utility gas combustion with other control), and utrenwnc (utility renewables with no control). The num_src variable is the utility capacity in the cell expressed in kilowatts. The pct_utilized is capacity utilization in 1990.

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Table II-5
Large, Coal-Fired Utilities
1990 Capacity Utilization*

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IAS Region	Region Name	Utility-Coal Other Control	Utility-Coal with SO_x Control
4	Montana	1.00	0.99
9	Wyoming	--	0.94
20	NV-Northern	--	0.87
22	NV-Clark Co.	--	0.91
34	UT-Central	0.88	--
36	UT-Emery Co.	--	0.91
43	AZ-Navajo	0.98	--
44	AZ-Apache Co.	0.79	0.90
50	CO-Moffat Co.	--	0.93
52	CO-Larimer Co.	--	0.99
54	CO-Denver Co.	0.94	--
56	CO-Montrose Co.	--	0.77
58	CO-Southeastern	0.99	--
60	NM-San Juan Co.	--	0.85
61	NM-North Western	--	0.78
63	NM-North East	0.56	--
72	TX-North	0.88	--
73	TX-Central West	0.85	--
90	TX-Eastern	--	0.96
	All Others	1.00	1.00

NOTE: *Utilizations listed are relative to the theoretical maximum utilizations for the facility.

SOURCE: Data resident in the Source Cell List file in the IAS Data Bases (December 1998).

the similarity to REMI-derived output, it was deemed appropriate to use the REMI public utility expenditure results to dri electricity demand in the IAS.

Based on the State-level GRP growth rates derived from REMI, Table II-6 lists the annual growth in electricity dema implied in that region. The IAS uses public utility expenditures by State to grow electricity demand, except in those cases States serve California electricity demand. ANL adjusted electricity demand in those States to reflect the power generatio meet historic California electricity imports.

Within each IAS region, the new capacity requirement is defined as the portion of sectoral demand not met by existin capacities. For most sectors, the default assumption is to add new capacity to where the old capacity is currently located. siting of new point sources takes into consideration compliance with all existing regulatory programs with respect to new location. When certain restrictions are binding, sector demand in an IAS region can be satisfied by new capacity growth i region. For example, new power plants may be constructed in a different IAS region from that of the existing capacity.

For the most part, new capacity additions that are driven by electricity demand growth are co-located at existing gene stations. Additional peaking capacity is also located at existing baseload generation facilities. Siting of certain types of g facilities is restricted from specific areas of concern. Based on the Alternatives Assessment Subcommittee's concerns reg siting of new coal-fired units near the Grand Canyon, new units in these areas are sited at coal-fired plants in other IAS re farther from the Grand Canyon, yet within a reasonable transmission distance. These are explicit assumptions provided fo setup of the IAS baseline, but which IAS users are able to alter.

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Certain fuel/technology combinations are also restricted from being sited in California. No new coal-fired units are p to be located in the State. New gas-fired facilities will be allowed to be sited in California, although these will be assume the strictest possible emission controls. Given that no new nuclear or hydroelectric capacity will be added and that renew gas-fired generation resources are unlikely to be able to meet all of the new baseload requirements cost-effectively, some baseload resources for California will be met by new coal-fired capacity located outside the State. As observed over the p decades, the coal-fired baseload generation serving California has been located in Nevada, Arizona, New Mexico, and oth States. The coal-fired stations, Navajo, Reid Gardner, Valmy, Mojave, and Four Corners are all located outside of Califor are partly-owned by California-based private and public utilities.

To reflect the siting of new coal-fired units outside of California (that serve California energy needs), some percentag California-electricity demand is assumed in the Argonne utility model to occur outside of California. This assumption is to reflect the siting of new coal-fired capacity, not to inflate the demand growth of other States in the IAS. In 1990, rough percent of California's generation needs were met by in-State sources, 15 percent from sources in Oregon, Washington, Id British Columbia, and 20 percent from sources in Nevada, Arizona, New Mexico, and Utah. Currently, there is an ongoin transmission line project to improve and expand electricity transmission from Oregon to California, southern Nevada to C and Arizona to

Table II-6
REMI-Derived Annual Electricity Demand
Growth in the States in the IAS (1990-2040)

State(s) in IAS Region	Average Annual Electricity Demand Growth (%)
Arizona	1.46
California	1.29
Colorado	1.28
Idaho & Wyoming	1.1
Montana	(1.1)*
New Mexico	1.3
Nevada	1.47
Utah	1.27
West Texas	1.07
Average annual growth in IAS	1.26

29 NOTE: *growth not defined in IAS, assumed identical to Idaho.

California. The Mid-Continent Area Power Pool (MAPP) also provides electricity generation resources for California ele demand.

Based on the North American Electric Reliability Council (NERC) projections of electricity demand, generation, and into the California-Southern Nevada power pool, imported generation accounts for roughly 21 percent of total generation California. Historically, 62 percent of the imported generation is from the Arizona-New Mexico power pool, 35 percent o imported generation is from the Northwest Power Pool, and 2 percent is from the MAPP power pool. Based on these data estimated that 21 percent of new generation resources comes from outside the California-Southern Nevada power pool, an resources are apportioned among power pools based on historic generation information. To reflect the large amount of pu capacity in the California-Southern Nevada pool, electricity demand will be increased in other power pools based on the p of imported generation and historical sources of imported electricity. The revised electricity demand for modeling purpos presented in Table II-7.

Table II-7
Revised Electricity Demand

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Power Pool	Average Electricity Demand Growth Per Year (%)
California-Southern Nevada	1.02
Arizona-New Mexico	Increased by .17
Northwest	Increased by .09
MAPP	Increased by .005

New capacity driven by California electricity demand is apportioned and located in Southern Nevada, the Arizona-Ne Mexico Power Pool, the Northwest Power Pool, and the MAPP power pool based on the historic shares of generation.

In addition to imposing pre-determined new capacity restrictions in the baseline emissions forecast, the IAS has the c to allow the user to relocate emission generating capacities to a different region. The relocated sources will generate the s amount of emissions; however, the impact on visibility can be different because different IAS regions can have different t coefficients. The distance of new capacity reallocation is estimated to be as short as possible, given that regulatory requir met. This minimum cost principle implies that most relocated capacity will remain within the same REMI region, which i larger than a typical IAS region, so it is unnecessary to change the economic scenario runs because of changes in new cap location.

Another adjustment to the REMI economic forecast for utility sources is with regard to fuel prices. The REMI model not predict future prices of electric utility fuels. Historical fuel price data are used for the base economic forecast, with fu price data from the EIA Annual Energy Outlook series.

1. Coal

For the base economic forecasts, historic 1993 coal price and type data are used for the year 2000 and after. Coal dat 1993 was chosen since it reflects price changes due to the impact of Phase I SO_2 requirements (Title IV Acid Deposition C The 1993 coal data are presented in Table II-8.

The price of steam coal delivered to electric utility facilities is projected to increase 1.3 percent per year (EIA, 1993).

2. Other Fossil Fuels

Federal Energy Regulatory Commission (FERC) 423 data from 1993 is used as a starting point for projecting the pric other fossil fuels into the future. The base (starting) prices of natural gas and fuel oil by State are presented in Table II-9.

The reference case fossil fuel price estimates are derived from EIA (1993). All prices reflect projected price increase
delivered to the electric utility industry. Distillate oil prices are assumed to increase at 0.7 percent per year. Residual oil
assumed to increase at 2.1 percent per year. Natural gas prices are assumed to increase at 3.2 percent per year.

E. RETROFIT CONTROLS AND COSTS

Electric utility emission control applications and costs in IAS are based on applying four different control techniques
can be applied singly, or in combination. These four utility emission control techniques are: selective catalytic reduction
selective non-catalytic reduction (SNCR), FGD, and organic acid additives (OAA). The first two technologies provide NO
emission reductions. FGD and OAA reduce SO_2 emissions. OAAs are a technology that can be retrofit on existing FGD
to enhance SO_2 removal efficiency.

The retrofit control techniques for existing utility sources apply to three IAS source categories (or scc_ids): utcoaloc
utcoalsx, and utngasoc. These control techniques can only be applied for the period 2001-2040, because a different set of
compliance activities cover the 1990-2000 period.

Control techniques for particulate were omitted because most existing coal-fired units in the region have PM controls
efficiencies as high as 99.9 percent. PM control for new sources is inherent in the technology design, and is not expected
significantly different from existing control levels.

31 Capital and operating cost estimates for the four NO_x and SO_2 control techniques available as retrofit control options
are summarized in Table II-10. IAS also includes all of the possible combinations of the control technologies in Table II-
the costs of applying multiple controls being additive in most situations.

Table II-8
Coal Price and Type Data

State	Average British Thermal Unit (Btu) (per pound)	Average Sulfur Content (% by weight)	Average Ash Content (% by weight)	Average Delivered Cost (cents per million Btu)
Arizona	10,271	.49	12.08	135.2
California	NA	NA	NA	NA
Colorado	9,888	.38	6.97	109.2
Idaho	10,539	1.78	8.23	126.8
Montana	8,490	.65	8.99	69.3
New Mexico	8,991	.81	22.77	136.8
Nevada	11,012	.4	9.73	146.8
Oregon	8,801	.38	4.98	112.2
Texas	7,284	.75	11.95	143.5
Utah	11,489	.48	10.47	119.0
Washington	8,125	.72	14.90	136.0
Wyoming	8,779	.51	7.78	138.5

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Table II-9
1990 Natural Gas and Fuel Oil Prices for Base Economic Forecast

State	Distillate Fuel Oil (cents per million Btu)	Natural Gas (cents per million Btu)
Arizona	511.4	280.7
California	234.7	296.3
Colorado	480.6	250.1
Idaho	Not available	Not available
Montana	525.5	268.1
Nevada	358.3	237.7
New Mexico	505.8	219.3
Oregon	382.8	225.2
Utah	539.1	217.6
Washington	473.0	329.7
Wyoming	473.0	329.7

Table II-10
Utility Retrofit Control Options
Cost Coefficients

Technology	Nominal Capital Cost ($/kW)	Nominal Operating and Maintenance (O&M) Cost ($/kW)	Control Efficiency (%)	
			NO_x*	SO_2
FGD	357	19.64	0	90
SNCR	14	9.35	56	0
SCR	106	18.09	80	0
Organic Acid	0	5.89	50	85

NOTE: *Includes NO_x emission reductions associated with existing low NO_x burners.

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CHAPTER III
INDUSTRIAL SOURCES

This chapter covers IAS modeling methods for point sources that are in the 1990 GCVTC Inventory that are not incl electric utilities. While all non-utility point sources are included in IAS, current and future air pollution emission control and their costs are only evaluated for a subset of these sources – those that contribute emissions that are more than one pe the total inventory. Industrial source types that are the primary focus in IAS included industrial boilers, copper smelters, a petroleum refineries. Table III-1 lists all of the source categories (scc_ids) which have control technique and cost informa IAS. All point sources for which control techniques were not identified are grouped into a source category (ptothrnc) labe point sources with no control.

All of the control cost equations for industrial sources use the stack gas flow rate (cubic feet [ft^3] per minute) to estim capital and O&M cost components. Gas flow rates of these sources vary depending on source size. Unit capital and opera in dollars per standard cubic feet per minute (scfm) are computed using an average flow rate of the cell, and total costs are
35 by multiplying unit costs times the gas flow rate.

In cases where there are multiple units in an IAS cell, Argonne computed unit-level control costs for each technology summed them, and then computed the appropriate stack gas flow rates and dollars per scfm flow rates to insert in the IAS to yield the same capital and operating costs that were calculated using the unit-level information.

For industrial sources, the total gas flow rate from the 1990 base year GCVTC inventory is stored in the SCL file und variable name num_src.

Within industrial sources, the exception to the cost calculation is for storage tanks. For organic chemical and gasolin storage tanks, the number of tanks in a cell is used to estimate control costs.

A. COPPER SMELTERS

Emissions from copper smelters are categorized either as captured or fugitive. Captured emissions are from processe confined or readily collected for treatment. The major pollutants from these smelters are PM and SO_2. If the SO_2 concent greater than 3 percent weight, then the gases can be economically treated in single or double stage acid plants after being t an electrostatic precipitator (ESP) for particulate control. Process gases with low SO_2 concentrations are just treated by ar then vented through a stack. These low sulfur concentration gases contribute significant SO_2 emissions and can be treatec In addition, FGD can be added to an acid plant to further reduce SO_2 emissions.

Table III-1
Industrial Source Categories (SCC_IDs) and Descriptions Used in IAS

Scc_id	Source Category Description
inagpepm	Industrial All Gasoline Processes With PM Control
inagpeuc	Industrial All Gasoline Processes With Unknown Control
inchemnx	Industrial Chemicals and Allied Products With NO_x Control
inchemuc	industrial Chemicals and Allied Products With Unknown Control
incobonx	Industrial Coal Boilers With NO_x Control
incobopm	Industrial Coal Boilers With PM Control
incobouc	Industrial Coal Boilers With Unknown Control
incop2pm	Industrial Copper Smelters - Fugitive With PM Control
incop2uc	Industrial Copper Smelters - Fugitive With Unknown Control
incoppnx	Industrial Copper Smelters - Captured With NO_x Control
incopppm	Industrial Copper Smelters - Captured With PM Control
incoppuc	Industrial Copper Smelters - Captured With Unknown Control
ingspruc	Industrial Natural Gas Production Other With Unknown Control
inngbouc	Industrial Natural Gas Boilers With Unknown Control
inngcmnx	Industrial Natural Gas Production, Compressors With NO_x Control
inngcmpm	Industrial Natural Gas Production, Compressors With PM Control
inngcmuc	Industrial Natural Gas Production, Compressors With Unknown Control
inngflnx	Industrial Natural Gas Production, Flares With NO_x Control
inngflpm	Industrial Natural Gas Production, Flares With PM Control
inngfluc	Industrial Natural Gas Production, Flares With Unknown Control
inngrenx	Industrial Natural Gas Reciprocating With NO_x Control
inngrepm	Industrial Natural Gas Reciprocating With PM Control
inngreuc	Industrial Natural Gas Reciprocating With Unknown Control
inngswpm	Industrial Natural Gas Production, Gas Sweetening With PM Control
inngswuc	Industrial Natural Gas Production, Gas Sweetening With Unknown Control
inoibonx	Industrial Oil Boilers With NO_x Control
inoibopm	Industrial Oil Boilers With PM Control
inoibouc	Industrial Oil Boilers With Unknown Control
inoipruc	Industrial Oil Production With Unknown Control
inorchpm	Industrial Other Miscellaneous, Organic Chemical With PM Control
inorchuc	Industrial Other Miscellaneous, Organic Chemical With Unknown Control
inothrnc	Industrial Other Combustion With No Control
inpeprnx	Industrial Petroleum Process Fuel Use With NO_x Control
inpeprpm	Industrial Petroleum Process Fuel Use With PM Control
inpepruc	Industrial Petroleum Process Fuel Use With Unknown Control
inperenx	Industrial Petroleum Refineries With NO_x Control
inperepm	Industrial Petroleum Refineries With PM Control
inpereuc	Industrial Petroleum Refineries With Unknown Control
insolvnx	Industrial Solvent Use With NO_x Control
insolvpm	Industrial Solvent Use With PM Control
insolvuc	Industrial Solvent Use With Unknown Control
inwobonx	Industrial Wood Boilers With NO_x Control
inwobopm	Industrial Wood Boilers With PM Control
inwobouc	Industrial Wood Boilers With Unknown Control
ptothrnc	Other Point Sources With No Control

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Fugitive emissions from copper smelters are those escaping from equipment through leaks and during material transf one process stage to another. Fugitive emissions can be controlled by first capturing gases by installing hoods, and then tr gases by FGD.

1. Year 2000 Adjustments

Kennecott Utah Copper Corporation provided information about its modernization plans. Based on this information, specific adjustment was made for the Kennecott smelter: a special technology code was assigned to scc_id = incop2uc in 49. This technology adjustment was incorporated into the baseline, and precludes further emission controls being added b this source. No control cost information for this modernization was provided by Kennecott. It was agreed by the Commit no costs are required for the 2000 baseline simulation, only for retrofits. The SO_2 control efficiency for this special techn code is 96 percent, with total suspended particulate (TSP) and PM_{10} control efficiencies set to 50 percent.

2. Growth and Control Assumptions

Copper smelters are estimated to retire their capacity at a rate of 1.2 percent per year. This retirement rate was taken National Energy Modeling System (NEMS) model. This retirement rate is applied in IAS through the CRT file. Values i for copper smelters, expressed as a fraction of 1990 capacity retired, are listed in Table III-2.

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Table III-2
Copper Smelter Retirement Rates by Projection Year

Year	Fraction of 1990 Capacity Retired
1990	0.00
2000	0.13
2010	0.26
2020	0.39
2030	0.52
2040	0.65

No growth in copper smelter activity is estimated through the forecast horizon.

The IAS pollution control technology options available to be applied to the copper smelters emission sources are sho Table III-3. Each control technology has associated SO_2 and PM control efficiencies. For each source category, a baselin control technology and a new source control technology are indicated. Note that the baseline control technologies can cha IAS region, according to the observed controls in place in each area. The control efficiency differences between the base source technologies are an important factor in the projected IAS Baseline emission trends, as

Table III-3
Copper Smelter Source Types, Control Techniques and Control Efficiencies

Scc_id	SCC Description	Tech_id	Technology Description	Nom S
incop2pm	Fugitive with PM Control	233	Hoods with FGD	
		260	ESP	
		261	Kennecott Process Change	
		262	California NO_x Controls	
		263	Secondary Hoods + ESP ✓	
		265	Secondary Hoods + ESP + FGD	
		511	Process Change - Hydrometallurgical Production ✓✓	
incop2uc	Fugitive with Unknown Control	261	Kennecott Process Change ✓	
		262	Secondary Hoods ✓	
		263	Secondary Hoods + ESP	
		264	Secondary Hoods + FF ✓	
		265	Secondary Hoods + ESP + FGD	
		266	Secondary Hoods + FF + FGD	
		511	Process Change - Hydrometallurgical Production ✓✓	
		694	Hoods with FGD + ESP	
incoppnx	Captured with NO_x Control	228	Double Stage Sulfuric Acid Plant ✓	
		511	Process Change - Hydrometallurgical Production ✓✓	
		691	FGD	
incopppm	Captured with PM Control	228	Double Stage Sulfuric Acid Plant ✓	
		229	FGD	
		231	ESP	
		232	Fabric Filter	
		261	Kennecott Process Change	
		511	Process Change - Hydrometallurgical Production ✓✓	
		691	FGD	
incoppuc	Captured with Unknown Control	228	Double Stage Sulfuric Acid Plant ✓	
		511	Process Change - Hydrometallurgical Production ✓✓	
		691	FGD	

NOTES: *Values listed are 1 minus the control efficiency expressed as a fraction.
✓ = Baseline Technology (the baseline technology for a source category can differ depending on IAS region).
✓✓ = New Source Technology

retired existing capacity is replaced with sources emitting at new source rates. Control technologies not indicated as basel
source, technologies are available as retrofit control options that can be selected by IAS to meet emission or visibility targ

B. INDUSTRIAL BOILERS

The industrial sector source categories are very diverse in terms of pollutants and the processes generating them. The either confined to ducts or are fugitive. The industrial sector also contains area sources. This is an artifact in the Radian i when specific sources do not account for all emissions, an area source category is created with the remaining emissions. T several regulations applicable to each source category, which vary depending upon the size of the source. The Federal reg mostly implemented through State Implementation Plans (SIPs) and State regulations.

Regulations typically specify either control technology or performance standards. The development of inputs to the I if the regulation specifies a control technology. It is more complicated if the regulation specifies performance standards, a expressed in various units such as pounds per million British thermal units (lbs/MMBtu), parts per million (ppm), grains/c cubic foot (dscf), opacity, and percent removal required. Also, there may be more than one control technology that can sa regulations. In order to identify the control technology required to meet the regulation, the emission limit and the uncontr emissions are converted to a common basis by making certain assumptions regarding fuel, equipment, and process charact generate the pollutants. Then any needed reduction is estimated and this reduction is compared with the capability of con

Coal Boilers. Many States have regulations in place to limit particulate, SO_2, and NO_x emissions from coal boilers. industrial coal boilers under this study are located in the western United States and, hence, are assumed to use western coa the uncontrolled emission rate for coal boilers, boiler and fuel characteristics have been assumed. The emission rates calc these assumptions are taken to be representative. The higher heating value, percentage ash, and percentage sulfur are ass 10,000 Btu/lb, 10 percent, and 0.6 percent, respectively. The average size, efficiency of the boiler, and the excess air used to be 100 MMBtu/hr, 10,000 Btu/kWh, and 33 percent, respectively. Also, it is assumed that 20 percent of the ash is retai ash, and 5 percent of the sulfur remains with bottom ash. The flue gas flow rate is estimated using the equation:

$$F \quad g \quad a \quad , \; fn = (0.4 \quad + \; 0.2 \; \frac{c \qquad a}{0} * M \qquad /h \; * 0$$

The flue gas flow rate from the assumed boiler size is estimated as 34,320 actual cubic feet per minute (acfm) at 300° scfm. The uncontrolled emission factors are 8 lbs/MMBtu for particulates and 1.14 lbs/MMBtu for SO_2. According to EP (EPA, 1985), the uncontrolled NO_x emission factor for pulverized coal, dry bottom boilers is 21 lbs per ton of coal, which to 1.05 lbs/MMBtu, for the assumed coal.

The regulations for particulates, SO_2, and NO_x typically depend on the size of the boiler. However, boiler size is not the 1990 inventory. Regulations also vary by State. The emission limit for particulates in most States is 0.2 grains per ac Hence, all coal boilers require particulate controls. Both ESP and fabric filters (FF) can meet the emission limit, but ESP assumed because of its widespread use for coal boilers. The SO_2 emission limit is in the range of 1.2 lbs/MMBtu, which i the uncontrolled emission factor. Hence, no SO_2 controls are required. The regulation for SO_2 varies from no regulation i to around 0.75 lbs/MMBtu in others. Combustion modification is sufficient to bring the boiler into compliance with regul with NO_x emission limits.

Wood Boilers. The major pollutant of concern for wood boilers is particulates. The emissions are determined by fue composition, boiler design, ash re-injection, and other factors. The uncontrolled emission factor for particulates from woo lbs per ton. The various regulations for particulates include: opacity not to exceed 20 percent, 0.36 lbs/MMBtu, and 0.1 g standard cubic feet (scf). If we assume 5,000 Btu/lbs as the heating value of wood waste, then the uncontrolled emission f lbs/MMBtu. Hence, wood boilers generally need a control technology for particulates, and ESP has been assumed to be a baseline.

Oil Boilers. The primary emissions from oil boilers are particulates, NO_x, and SO_2. Regulations vary by State, size o and date the boiler came on line. The emission limits are usually in the range of 0.1 to 0.2 grains per scf for particulates, 0 lbs/MMBtu for NO_x, and 0.8 lbs/MMBtu for SO_2. The uncontrolled emissions depend on fuel oil composition and boiler d

The particulate emission factor for an industrial boiler burning distillate oil is 2 pounds per 1,000 gallons. This is eq 0.008 grains per scf, well below typical regulatory limits. The SO_2 emission factor is 142*S pounds per 1,000 gallons. Th corresponds to 0.3 lbs/MMBtu for an average distillate oil (0.3 percent sulfur), which is also well below the regulatory lim emission factor for distillate oil is 20 pounds per 1,000 gallons, corresponding to 0.14 lbs/MMBtu. Since this is also belov regulatory limit, no control technology is required by current regulations for industrial boilers firing distillate oil.

For a fuel sulfur content of S weight percent sulfur, the particulate emission factor for an industrial boiler burning res (10*S + 3) pounds per 1,000 gallons. This is equivalent to 0.113 grains per scf, well above typical regulatory limits, sugg residual oil-fired boilers are likely to employ an ESP in the baseline. The SO_2 emission factor is 157*S pounds per 1,000 corresponds to 2.46 lbs/MMBtu for an average residual oil (2.3 percent sulfur), also well above the regulatory limit. The factor for distillate oil is 55 pounds per 1,000 gallons. This is equivalent to 0.37 lbs/MMBtu, which is below the regulator no control technology is required for NO_x by current regulations for industrial boilers firing residual oil.

In the present analysis, boilers burning distillate and residual oil are aggregated into a single source category. The he boilers burning distillate oil is approximately three times the heat input to boilers burning residual oil. Hence, we have tre as though they are burning distillate oil and are not required to have control equipment. This does not affect the baseline which are taken from the Radian inventory, but it could affect EMS results, since sulfur controls cannot be put on residual without also being put on distillate oil boilers. This is a consequence of the need to aggregate industrial emission sources IAS model.

Natural Gas Boilers. The primary pollutant from natural gas boilers is NO_x. The regulations generally specify perf standards rather than control technology. Again, the emission limits depend on the size of the boiler. According to AP-42 uncontrolled emission factor for natural gas boilers is 140 lbs per million cubic feet, which is equivalent to 0.14 lbs/MMB 1,000 Btu per cubic feet as the heating value of natural gas). State regulations specify around 0.2 lbs/MMBtu. Hence, ind gas boilers generally require no control.

Natural Gas Reciprocating Engines. The primary pollutant is NO_x. The uncontrolled emission factor for SO_2 is 3, lbs per million cubic feet. If we assume 1,000 Btu per ft^3 as the heating value of natural gas then the uncontrolled emissio be 3.4 lbs/MMBtu. Regulations for NO_x emissions are in the range of 0.2 lbs/MMBtu. Hence, natural gas reciprocating e NO_x control equipment with high removal capability. SCR is assumed to be the control technology of choice.

There are three types of industrial boilers (for each identified fuel type): (1) boilers with PM control; (2) boilers with control; and (3) boilers with unknown control. The level of control assumed for these categories is based on a review of r regulation, rather than on reported control efficiency.

Because the control techniques for industrial boiler applications for the variety of fuel types and technology types are voluminous to be presented succinctly in this report, Table III-4 illustrates the control technologies and associated pollutio efficiencies for Industrial Coal Boilers with PM Control. For most IAS regions, the baseline control technology for this s is an ESP. The new source technology is FGD plus ESP plus low NO_x burners, so new coal-fired industrial boiler capacit percent lower NO_x, and 90 percent lower SO_2 than existing sources.

The annual retirement rates that are assumed for the industrial fuel combustors are derived from an energy model of t economy – the Industrial Combustion Emissions (ICE) model. This model was developed and applied as part of the Natio Precipitation Assessment Program (NAPAP) emission and control techniques evaluation process.

Linking REMI sectoral output with industrial fuel combustion activity is complicated by the fact that fuel combustors wide range of industries. Most other sectors could be directly linked to a single REMI sector. To construct the SIC weigh industrial fuel combustion sources, data from the emission inventory were used. Because NO_x emissions are (in 1990) rel uncontrolled in this sector, and are ubiquitous across fuel types, the weights were based on NO_x emissions. The industrial driver weights are shown in Table III-5. As this table shows, the weighting for oil-fired boilers is dominated by the pulp a industry (SIC = 26), while the other industrial combustion category is dominated by primary metal production.

Table III-4
Industrial Boiler - Coal-Fired

Scc_id	Description	Tech_id	Technology Description	Nominal Control Efficiencies		
				NO_x	SO_2	PM
incobopm	Industrial Coal Boilers with PM Control	201	Switch to Natural Gas	72.0%	100%	100%
		203	Electrostatic Precipitator ✓	0	0	99.8
		502	FGD + ESP + Low NO_x Burners ✓✓	50	90	99.8
		601	FGD + ESP	0	90	99.8
		602	FGD + FF	0	90	99.9
		606	ESP + CM	50	0	99.8
		607	ESP + SCR	75	0	99.8
		608	ESP + SNCR	60	0	99.8
		609	FF + CM	50	0	99.9
		610	FF + SCR	75	0	99.9
		611	FF + SNCR	60	0	99.9
		612	ESP + FGD + CM	50	90	99.8
		613	ESP + FGD + SCR	75	90	99.8
		614	ESP + FGD + SNCR	60	90	99.8
		615	FF + FGD + CM	50	90	99.9
		616	FF + FGD + SCR	75	90	99.9
		617	FF + FGD + SNCR	60	90	99.9
		705	ESP + CM + SCR	87.5	0	99.8
		706	ESP + CM + SNCR	80	0	99.8
		707	FF + CM + SCR	87.5	0	99.9
		708	FF + CM + SNCR	80	0	99.9
		709	FGD + ESP + CM + SCR	87.5	90	99.8
		710	FGD + ESP + CM + SNCR	80	90	99.8
		711	FGD + FF + CM + SCR	87.5	90	99.9
		712	FGD + FF + CM + SNCR	80	90	99.9

NOTES: ✓ = Baseline Technology
✓✓ = New Source Technology

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Table III-5
REMI-IAS Source Group Mapping for Industrial Combustion

SIC	Coal-Fired Boilers incobo (%)	Natural Gas Boilers + IC Engines inngbo & inngre (%)	Oil-Fired Boilers inoibo (%)	Other inothr (%)	Wood-Fired Bo[...] inwobo (%)
All Mining (10-13)	63.8	11.9	1.2	1.1	0.0
20	11.2	3.3	3.3	0.1	1.4
24	3.7	0.1	0.6	0.4	59.7
26	7.3	3.8	70.7	0.0	25.1
28	0.2	28.6	2.2	12.7	0.0
29	0.0	23.4	17.3	7.1	0.0
32	0.0	0.2	0.2	78.6	0.0
33	0.4	5.6	0.0	0.0	0.0
49	12.2	20.9	3.1	0.1	13.6
Other	1.3	2.3	1.5	0.0	0.2
Total	100.0	100.0	100.0	100.0	100.0
REMI Link:	61	62	63	64	65

C. OIL AND GAS PRODUCTION

Natural Gas Production - Gas Sweetening. Sulfur is present in natural gas in the form of hydrogen sulfide (H_2S). If H_2S concentration is more than 0.25 grains per 100 scf, then the natural gas is considered to be sour and requires treatment (sweetening) in amine plants to remove hydrogen sulfide. The recovered H_2S is usually incinerated to SO_2 and vented to the atmosphere via a stack. Therefore, the major pollutant from amine sweetening plants is SO_2. Instead of inci the H_2S, sulfur can be recovered in a sulfur plant. The emission factor depends on the concentration of H_2S in natural gas, efficiency of the amine process. Depending upon the concentration of H_2S in the natural gas, a sulfur plant may be more economical due to the production of byproduct sulfur. Hence, a sulfur plant is chosen as a control option for SO_2 from ga sweetening plants.

The IAS retirement rate for gas production-sweetening plants is 1.9 percent per year.

Natural Gas Production - Compressors. Compressors are used for transporting natural gas through pipelines. Compressors are either powered by gas turbines or reciprocating engines. In this study we assumed the use of gas turbine trend is towards the use of large gas turbines. The emission factor for NO_x from gas turbines is 300 pounds per million cu which is equal to 0.3 lbs/MMBtu (assuming 1,000 Btu per cubic feet as the heating value of natural gas). The regulations emissions are in the range of 0.23 lbs/MMBtu. Hence, *combustion modification* is assumed to be sufficient to control NO from gas turbine driven compressors.

Natural Gas Production - Flares. The natural gas produced during well drilling, testing, and closing will be flared to decrease the emissions of hydrocarbons (HC) and H_2S. Also, the gas has to be flared during process upsets. The major from these flares would be SO_2, as HCs are converted to carbon dioxide and water if complete combustion is achieved. F intermittent operation it is difficult to define an emission factor. Also, generally there are no regulations for flares used d up and shut-down processes. Flares are subjected to general provisions such as opacity and smokeless burning and are as comply with these provisions. Hence, *flares are assumed not to require any controls*.

The IAS retirement rate for oil and gas production is 2.3 percent per year.

D. PETROLEUM REFINERIES

Petroleum Refineries. Fluid catalytic cracking units (FCCU), fluid coking units (FCU), and fugitive emissions are t major sources of pollutants in the petroleum refinery. The emissions from FCCU and FCU are SO_2 and NO_x. FGD can be for SO_2 control. Combustion modification, SCR, and SNCR can be applied for NO_x control. The major sources for fugiti emissions are valves, flanges, drains, blow-down systems, and cooling towers. The emissions from these sources can be r by better management practice.

Petroleum Process Fuel Use. Process heaters are used in refineries to heat the feed materials to the reaction or distillation level. The fuel burned is usually refinery gas. They may also burn natural gas, and fuel oil. SO_2 and NO_x are from the process heaters. SO_2 can be controlled by FGD and NO_x can be controlled by combustion modification, SCR, or

The IAS retirement rate for refinery sources is 1.9 percent per year.

E. OTHER INDUSTRIAL SOURCE EMITTERS

Chemicals and Allied Products - Pre 1970 Nitric Acid Plants. NO_x is the major pollutant from manufacturing nitric acid and the major source is the tail gas from the acid absorption tower. Uncontrolled NO_x emissions the range of 14-86 pounds per ton of acid produced. The regulations for the emission of NO_x from nitric acid plants are in range of 3.0-5.5 pounds per ton of acid produced. Clearly, NO_x controls are required in States where regulations exist. Ex absorption and catalytic reduction are commonly applied control technologies for NO_x control. The emissions after apply controls are in the range of 0.05-1.2 pounds per ton of acid for catalytic reduction and 0.8-2.7 pounds per ton of acid for e absorption. Due to the increased cost of natural gas, extended absorption is preferred over catalytic reduction. Hence, ext absorption is the likely control technology for nitric acid plants.

Other Miscellaneous - Organic Chemical Storage Tanks and Gasoline Process Storage Tanks. Generally, the regulations for gasoline and organic chemical storage tanks specify the control technology based on the siz storage tank and the vapor pressure of the liquid being stored. Information regarding the size of the tank and the vapor pr the liquid stored is not available in the Radian inventory. Hence, an average size storage tank of 50 feet diameter is assum it is assumed that the vapor pressure of stored liquid warrants a control technology. Fixed roof, external floating roofs, int floating roofs, and pressure tanks are some of the commonly used control techniques for storage tanks to control emission Of these, fixed roof tanks correspond to the minimum acceptable control technology, and many States require floating roo

For refrigerated vapor recovery system the flow rate of gases to the condenser is assumed to be 269.32 acfm at 72^{o} F. Thi average flow rate reported in the Radian inventory.

<u>Solvent Use</u>. This source category contains several emission sources, such as dry cleaning, solvent degreasing, and surface coatings for automobiles, metals, buildings, wood furniture, plastics, etc. For this diverse category, it is not possib explore the regulations and to identify the required control options. Hence, we have assumed that, in general, all these so employ "Process Modification" in response to ROG regulations.

The IAS retirement rate for nitric acid plants, organic chemical storage, and gasoline storage is 1.9 percent per year.

CHAPTER IV
MOBILE SOURCES

In the GCVTC study, mobile sources include highway vehicles (represented by four vehicle types), commercial and g aviation aircraft, commercial marine vessels, and railroad locomotives. As with the other sectors, future year emission est made by evaluating the potential effects of current regulations and emission standards on emission rates, and forecasting f changes in pollution-generating activity. EPA's mobile source emission factor model (MOBILE5) is used to estimate how vehicle emission rates will change by area in future years. Changes in emission rates for the other three source categories by translating regulation changes into control factors. Growth in activity for these source types to the forecast years is est using weighted averages of expected population and income growth, or weighted averages of selected REMI sectors depe the source category.

A. HIGHWAY VEHICLE BASELINE

There are seven source categories specified for mobile sources. Most are individual SCCs, but diesel powered mediu heavy-duty vehicles were combined and gasoline powered light-duty cars and trucks were combined, due to similarity of c characteristics and control. As of 1990, all categories except aircraft and railroad locomotives were covered under explici standards for one or more pollutants; in a few cases, standards also governed the fuels used by these sources. The Clean A Amendments of 1990 significantly tightened many of these standards.

The turnover of model-year vehicles in in-use fleets each year is the basis for mobile source emission inventory adjus in the baseline. That is, net decrements in emission loadings, where achieved, result from vehicular sources controlled to more stringent emission levels replacing those which are not. Thus, there is no measurable reduction achieved through re existing vehicles in the period after 1990.

1. Computation of Emissions Change Indices

Both the baseline and control technology projections for emission indices (relative to Radian's base year inventory) w computed using:

a. EPA's MOBILE5a model (for on-highway ROG, carbon monoxide [CO], and NO_x) with detailed input streams specific to conditions for each GCVTC State and year;

b. EPA's PART5 model (for on-highway SO_2, $PM_{2.5}$, $OC_{2.5}$, and $EC_{2.5}$) with similar State-specific input streams; an

c. National-weighted *AP-42 Supplement 8* emission rates for all off-highway modes.

Rates for off-highway modes were adjusted to reflect either increased future fleet energy efficiencies, explicit new en controls (such as regulations governing propulsion engines > 50 horsepower [hp]), or both. In a few instances, it was not appropriate to use the Statewide indices for small (1 to 5-county) sub-State IAS regions, especially if these regions contain Interstate Highway System mileage or mainline railroads. In these instances, the appropriate activity adjustments were in into the composite emission rates carried forward to the regional multipliers for each level of technology implementation forecast year) in the baseline, and are also reflected in the indices for the control technology set. The highway vehicle em control programs included in the IAS baseline are summarized in Table IV-1 and in the text below.

Under provisions of Title II of the Clean Air Act (CAA) and subsequent regulation, there are five control technologie common to all GCVTC States (except California) in the baseline:

1. *Reduction of volatility (Reid vapor pressure [RVP]) of gasolines sold during summer months to a maximum of 9 psia, with a maximum as low as 7 psia in some States.*

This change affects light- and heavy-duty gasoline-powered cars and trucks. Summertime volatility controls were fir required by EPA rulemaking to begin in 1989 and to be strengthened from 1992 onward. This control has the effect of significantly curtailing evaporative and modestly reducing exhaust emissions from gasoline-powered vehicles during both

(storage) and operation. The exact magnitude of the reduction and resulting inventory adjustment is calculated on a State-
basis in the MOBILE5a model. This measure is very important, as the evaporative component of uncontrolled emissions from in-use gasoline vehicles can exceed 50 percent of the total.

2. *Incorporation of Federal Tier 1 exhaust standards in all new highway vehicles sold outside of California beginning with the 1994 model year.*

This change affects both gasoline- and diesel-powered light-duty highway vehicles. These standards were explicitly place by Title II; they have the effect of lowering average emission rates per new light-duty vehicle by about 40 percent fo (gasoline-fueled only) and 50 percent for NO_x (all fuels).

3. *Exclusive use of low-sulfur-weight diesel fuel in all States beginning in 1993, as required by a 1990 EPA rulemaking.*

This change affects all regulated on-highway and off-highway diesel-powered trucks, railroad locomotives, and diese powered watercraft. This has the effect of lowering sulfur dioxide emissions by 75 percent (unadjusted for changes in fue economy), and also has the effect of reducing total PM and $PM_{2.5}$ exhaust emissions due to lower sulfates.

Table IV-1
Applicability of Highway Vehicle Control Programs in the IAS Baseline

Control Measure	Applicability
Vehicle Emission Standards	
Tier 1 Tailpipe Standards (Light-Duty Vehicles and Light-Duty Trucks)	National
New Evaporative Emission Test Procedure	National
Onboard Refueling Emission Control	National
Lead Ban	National
Fuel Volatility Rules	National (standard varies by region)
Low Sulfur Diesel	49 States
Oxygenated Fuel	All CO nonattainment areas (all States except Wyoming, Idaho, and Montana)
Federal Reformulated Gasoline	Nine areas required to adopt this program under the CAA plus areas which have opted in to this program (Arizona program)
Clean Fuel Fleet Program	None modeled
California LEV	California
California Reformulated Gasoline	California
Stage II (Service Stations)	Ozone nonattainment areas of Arizona, California, Nevada, Oregon, Washington, and Utah
Basic I/M	Nonattainment areas of all States except Wyoming, Idaho, and Montana
Enhanced I/M	Beginning in 1996 in nonattainment areas of Arizona, Colorado, California, and Nevada to replace basic I/M

4. *On-board control of evaporative refueling emissions on all gasoline-powered light-duty vehicles beginning in 1998 model year.*

This change affects gasoline-powered cars and light trucks. Based on a rule that had been tabled for several years du safety concerns, but was finally promulgated in 1994, this has the effect of virtually eliminating the refueling ROG emissi (which can be 10 to 15 percent of the total) and also obviates the required Stage II at-the-pump control. However, Stage I in the baseline, where it has already been implemented by SIPs as required by Title I.

5. *All States except Wyoming, Idaho, and Montana have winter oxygen content requirements for gasoline from 1992 onward, due to SIP compliance requirements for wintertime CO concentrations.*

This change affects all gasoline-powered cars and trucks. This has the effect of reducing CO (which is emitted at hig from uncontrolled sources during cold months) but may slightly increase ROG, which is not a problem in winter.

In the special case of California, the baseline incorporates the low-emission vehicle (LEV) program promulgated pur the California Clean Air Act of 1988. New highway vehicles begin complying with these more-stringent-than-Federal sta a phased-in basis beginning in 1994. In addition, gasoline sold in southern California from 1996 on is assumed to be 100 California Phase 2 reformulated gasoline (RFG), a more stringently-formulated fuel than Federal RFG. All other Statewic source control strategies adopted by the California Air Resources Board (CARB) through January 1995 have also been incorporated.

Federal RFG is available only in Arizona, under the Federal Implementation Plan (FIP) and succeeding SIP for that S among the eleven remaining GCVTC States. Availability (100 percent of sales) of RFG in Arizona begins in 1995.

2. Changes Due to Nonattainment

Because of ozone nonattainment requirements in various States, the following additional controls are included. In ea MOBILE5a determined the State-specific effects on emission intensity that were incorporated into the baseline inventory adjustments.

1. *Stage II at-the-pump control of refueling evaporative ROGs.*

This change affects all gasoline-fueled highway vehicles. Assumed in place throughout the projection period (beginn mid-1990s) in nonattainment areas of Arizona, California, Nevada, Oregon, Washington, and Utah.

2. *Basic idle-test inspection and maintenance (I/M) program (not necessarily centralized).*

This change affects all automobiles and light trucks. The basic I/M is implemented in nonattainment areas of all Stat Wyoming, Idaho, and Montana, beginning 1992.

3. *Enhanced (240-second transient test) centralized I/M program.*

This change affects all automobiles and light trucks. Beginning in 1996 in nonattainment areas of Arizona, Colorado California, and Nevada, in each case of I/M adoption, full emission reduction credit is assigned per the data blocks of the MOBILE5a model; however, it is recognized based on recent evidence that the magnitude of these credits is exaggerated is coupled with some sort of follow-up program, such as remote sensing, designed to identify and eliminate gross emitters

3. Other "Trends" Without Inventory Changes

It is recognized that public fleets and fuel provider fleets (and probably some private fleets) in all GCVTC States are converting and will in the future continue to convert some of their vehicles to operate at least part-time on alternative (non petroleum) fuels. These actions were not credited as explicit adjustments to the baseline emissions inventory for the follo reasons:

- "Bi-fuel," "dual-fuel," and "flexible-fuel" vehicles are not uniformly less polluting than the conventionally-fuele vehicles they replace — indeed, because they are not optimized for operation on either of the fuels they can use, t emission rates can even be higher.

- The share of vehicles being converted or purchased new to operate on dedicated non-petroleum fuels is insuffici great to affect average emission rates and likely to remain so without more stringent rulemakings under the Ene Policy Act of 1992. This is because EPA's definition of "clean fuels" embraces RFG and reformulated (low-sul low-aromatic) diesel as well as non-petroleum substitutes.

- Under "clean air" (as opposed to petroleum displacement) goals, conversion/ replacement by AFVs is not neces and the effect of RFG and clean diesel penetration into the non-retrofitted fleet is already accounted for. Howev penetration of zero-emission vehicles (ZEVs) in California according to targets set by CARB is explicitly incluc that State. By currently-accepted definition, these ZEVs are dedicated electricity-powered vehicles only, and ar the only vehicles specifically designated as AFVs in the baseline (although other vehicles meeting "Clean Fuel" standards may be AFVs).

It is also recognized that the air quality management plan specific to the South Coast Air Basin of California has supplemented controls adopted by CARB to include additional restrictions on certain modes of vehicle use (e.g., curb idli reduction of high emitters through emission credit trading, congestion pricing, PM_{10} control retrofitting of some diesel bus However, the legal commitment to implementing most of these strategies is still lacking, while their overall impact is sign in doubt. For example, it is premature to take emission reduction credit for a 50 percent share by electric (zero-emission) of new vehicle sales by 2010. Some of the more effective of these measures have been explicitly included in the new sour set for mobile sources used by the IAS but, on balance, we believe that their impact on the overall emissions profile for So California as it affects Class I visibility areas will be marginal at best. Thus, within the tolerances of the IAS, they may be considered already to be subsumed.

B. CONTROLS BEYOND THE BASELINE

The IAS permits only one set of incremental controls to be imposed on new sources in each SCC for purposes of achi greater emissions reduction than provided under baseline conditions and requirements. The set that was applied to mobile in the IAS includes:

- Tier 2 emission standards in place in all States (except California) from 2004 onward; gasoline specification(s) to achieve these standards assumed to be available. These standards would be required if a study mandated by t 1990 Amendments to be completed by the end of 1996 establishes that Tier 1 standards are inadequate to achiev compliance with ambient air standards for ozone. They would affect gasoline-powered cars and light trucks and heavy-duty diesel trucks, and may require the use of pre-heated or close-coupled catalytic converters or a specia trapping device to reduce the emission burst at vehicle start-up. Because these are Federal standards, their distri cost would vary by State according to each State's vehicle sales figures after 2003. Pollutants affected are CO, and NO_x. Magnitude of reduction is computed State by State by MOBILE5a as configured by the American Automobile Manufacturers Association to test the effectiveness of alternatives to broader adoption of the Califo LEV program.

- Stage II (at-the-pump) refueling control removed in 2009 (obviated by Tier 2 and on-board refueling emissions control); this would represent an actual cost saving that would affect gasoline-powered cars and trucks. Magnit reduction is computed State by State by MOBILE5a without the input prompt for Stage II credits.

- RFG used in all States from 2005. This would affect gasoline-powered cars and trucks and control CO, ROG, a NO_x.

- Penetration of alternative-fueled vehicles meeting California ultra-low emission vehicle (ULEV) (not ZEV) star − vehicles which, under CAA definition, could be powered by RFG or clean diesel − reaches 15 percent per yea 2005 onward in all States except California, where it reaches 30 percent. This accelerates the rate at which aver emission factors for criteria pollutants (CO, ROG, NO_x) from all light-duty vehicles decrease from model year t year.

The new Federal controls applicable to off-road engines rated at 50 hp (37 kW) and greater are also explicitly incorpo into this control set from 2002 onward; source categories affected are marine diesels and locomotives. Due to the net con uncertainties for these nonroad engine source categories, especially the crucial tradeoff between controlling for NO_x and c for particulates, only a NO_x reduction is credited to the new standards. Table IV-2 summarizes the control set by IAS SC identifier.

Table IV-2
New Technologies in Transportation
Controls Beyond the Baseline

SCC ID	Technology Code 350 Description
trgpld (2201001000, 2201060000)	Tier 2 emission control implemented in all States but California, beginning 2004; ULEV penetration of new light-duty vehicle fleet begins 2001 at 5 percent, phasing to 15 percent in 2005 and later except in California, where new vehicle share is 30 percent from 2004. Thus, in 2005 and later years, 7-State new vehicle share is 85 percent Tier 2, 15 percent ULEV; for California, 60 percent LEV, 30 percent ULEV, 10 percent ZEV. For those States with I/M, whether basic or enhanced (I/M 240) in the baseline, stringency is increased (cut points lowered) after 2001.
trgpmt (2201070000)	Subject to I/M (all States except Wyoming) from 2001.
trdpld (2230001000, 2230060000)	Tier 2 emission control implemented in all States but California, beginning 2004; ULEV penetration of new light-duty vehicle fleet begins 2001 at 5 percent, phasing to 15 percent in 2005 and later except in California, where new vehicle share is 30 percent from 2004. Thus, in 2005 and later years, 7-State new vehicle share is 85 percent Tier 2, 15 percent ULEV; for California, 60 percent LEV, 30 percent ULEV, 10 percent ZEV. For those States with I/M, whether basic or enhanced (I/M 240) in the baseline, stringency is increased (cut points lowered) after 2001.
trdpmv (2230070000)	Shift to units with lower average power rating, due to change in vehicular activity pattern (i.e., more pickup/delivery missions).
trrail (2285002000)	Shift to higher-efficiency locomotives; full implementation of new source control on 37- kW and higher rated off-road engines on accelerated schedule beginning in 2002.
trmari (2280002000)	Full implementation of (proposed) diesel marine standards for new U.S.-registry crafts, resulting in 37 percent NO_x reduction per fuel unit.
travia (22750120000, 2275050000)	No incremental control on general and commercial aviation; gradual shift to more fuel-efficient commercial aircraft.

IAS applies mobile source emission controls by forecast year using the information in the Control Options Effectiver
(COEO) file. Emission reductions for the different forecast years are applied by using different technology identifiers (tec
each forecast year. So for mobile sources, a tech_id of 301 represents the emission reductions associated with transportati
composite technology controls for 2000, a tech_id of 302 represents emission reductions in 2010, while a tech_id of 303 r
emission reductions in 2020-2040. The latter assumption means that mobile source emission rates in the baseline scenario
decline after 2020. Thus, the mobile source emission forecasts all show an upward trend in emissions after 2020 as vehicl
continues to grow, and emission rates remain constant.

C. ACTIVITY GROWTH

Table IV-3 summarizes the source category groupings used in IAS for mobile sources as well as the associated REMI
used to estimate changes in future year emission producing activity. As Table IV-3 shows, there is not a one-to-one corre
between mobile source categories and REMI sectors. The growth indicators applied in IAS for mobile sources are weight
averages of REMI sector activity indicators. For the important gasoline-powered light-duty vehicles and trucks category,
year growth indicator is a weighted average of population (67 percent) and income per capita (33 percent) indexes.

Table IV-3
Mobile Source Growth Indicators

Scc_id	SCC Description	REMI Sector	Sector Description
travianc	Commercial and General Aviation Aircraft	71	Weighted average of population and income (50/50)
trdplduc	Diesel Powered Light-Duty Cars/Trucks	66	Weighted average of population and income per capita indexes (67/33)
trdpmvuc	Diesel Powered Medium/Heavy Vehicles	68	Weighted average of all REMI sectors except 13, 17, 24-8, 30-5, 38, 40, 44, 45, 48, 50-3
trgplduc	Gasoline-Powered Light-Duty Cars/Trucks	66	Weighted average of population and income per capita indexes (67/33)
trgpmtuc	Gasoline-Powered Medium Trucks	67	Weighted average of all REMI sectors except 13, 17, 24-8, 30-5, 38, 40, 44, 45, 48, 50-3
trmariuc	Commercial Marine Vessels	70	Weighted average of REMI sectors 3, 4, 12, 18, 19, 22, and 49
trmariuc	Railroad Locomotives	69	Weighted average of all REMI sectors, except 13, 17, 23-38, 40, 44, 45, 48, 50-3

CHAPTER V
NONROAD ENGINES/VEHICLES

Nonroad sources are mobile (non-highway) emission sources including lawn and garden equipment, construction equ agricultural equipment, industrial equipment, logging equipment, and recreational vehicles. Nonroad engines are significa emitters of NO_x, PM_{10}, and VOC. Diesel engines account for most of the NO_x and PM_{10} emissions, while gasoline engines most of the VOC. This chapter summarizes the IAS baseline and retrofit control options and costs for nonroad engines. engine/vehicle sources are represented in IAS via four source categories:

1. Large off-highway vehicle diesel (arnrdluc)
2. Small off-highway vehicle diesel (arnrdsuc)
3. Large off-highway vehicle gasoline (arnrgluc)
4. Small off-highway vehicle gasoline (arnrgsuc)

New Nonroad Spark Ignition (SI) Engines of 19kW or Less. In May 1994, EPA issued a Notice of Proposed Rulemaking on new nonroad SI engines of 19 kW (25 hp) or less. The emission standards proposed by EPA are expected to produce a 32 percent reduction in HC emissions by 2020, when full fleet turnover is expected. EPA expects approximately 16,525,000 new engines to be subject to this regulation in the first year of its implementation. This numbe represents about 19.4 percent of the in-use fleet of small SI engines.

CARB has adopted standards for lawn and garden and nonroad utility SI and compression ignition (CI) engines of 0- (0-25 hp). There is potential for other States to adopt the California standards, which are scheduled to become effective in EPA decides to approve a California "waiver" request under CAA §209(e). Although such adoptions would yield certain benefits, the probability of other States adopting the California standards is currently unclear.

California's regulations for small SI engines are much more stringent than the Federal standards. California's HC reg in 1995-1998 are 55 percent more stringent (8.9 g/kWh versus 16.1 g/kWh) than the national standard for engines less tha cubic centimeters (cc), 6.6 percent more stringent (7.5 versus 113.4 g/kWh) than the national standard for engines greater cc, and an average of about 60 percent less than the national standards for hand held equipment. Based on this data, ANL that California's regulations will reduce emissions from 1995-1998 approximately 60 percent compared to the rest of the n

According to EPA estimates, the Federal regulations will reduce HC emissions from this engine class by 20 percent i the year before California's Phase II regulations are scheduled to take effect. Since the HC standards are 60 percent more in California, it follows that HC emissions will be reduced by about 32 percent in California in 1998 (60 percent more tha rest of the nation).

Phase II of California's small nonroad engine regulations takes effect in 1999. Although the regulations vary accordi engine type, the HC emission standards overall are about 85 percent less than the national HC emission standards for this engines. As a result, in 2020, when full fleet turnover is expected, HC emissions from this class should be reduced in Cal around 59 percent from the baseline, instead of the national average of 32 percent.

Phase II of the Federal regulations for small SI engines is scheduled to be finalized in 1997 and the new emission sta should begin with the 1999 model year engines (which coincides with Phase II of California's standards discussed above). these regulations have not been proposed, there is no way to accurately project what the emissions standards will be. It w assumed that Phase II of the Federal regulations will again be 60 percent less stringent than Phase II of the California stan a result, the Phase II standards will reduce HC emissions about 43 percent from baseline in 2020.

Recreational Vehicles. The HC emission standards for recreational vehicles in California are the same as California standards for other small (< 25 hp) SI engines. As a result, it is assumed that the emission reduction percentage for recrea vehicles will be the same as the other small SI equipment standards.

EPA has proposed regulations for new SI (gasoline) and CI (diesel) marine engines. The marine gasoline engine reg propose to control emissions of nitrogen oxide (NO) and CO; those for diesels propose to control emissions of HC, CO, N and smoke. The schedule for promulgation is unclear. While these regulations will likely take effect before 2000, ANL e their effect to be minimal before the year 2000. Therefore, for the purposes of the IAS, ANL assumes that these regulatio begin to affect ambient air quality in the GCVTC region beginning in the year 2000.

CI (Diesel) Engines. Currently, the Federal emission standards for all nonroad CI engines of > 50 hp are identical to those established by the State of California. According to EPA, the per-engine NO_x reductions (from baseline) expected f standards are 27 percent by 2010 and 37 percent by 2025. However, in 2001, California's NO_x and PM_{10} standards for non engines of ^{3}175 hp are reduced by 16 percent and 60 percent, respectively.

In 1994, EPA issued a final rule on emissions of CO, HC, PM_{10}, NO_x, and smoke from large CI (diesel) engines. The standards take effect in four phases, the first beginning January 1, 1996, and the last beginning January 1, 2000, according engine size (the full range of engine sizes affected by this rule is 50-750 hp).

EPA has also proposed a second phase of large (> 50 hp) nonroad engine standards for California beginning in 2002 (California is preempted by Federal regulations from regulating nonroad engines between 50 and 175 hp). The new stand include a 4.0 grams per brake horsepower-hour (g/bhp-hr) NO_x standard for all nonroad CI and SI engines > 50 hp, a 42 p reduction from current standards. EPA is also expected to implement a second phase of CI engine regulations nationwide end of 1996. Because these regulations have not yet been proposed, it is impossible to estimate the level of emission redu expected from this program; however, ANL assumed in the spreadsheet calculations that the NO_x standard will be identica 4.0 g/bhp-hr standard that EPA proposed for California. Since the Phase II NO_x standard is 42 percent less (4.0 versus 6.9 hr) than the Phase I NO_x standard, ANL assumes 42 percent greater NO_x reductions nationwide (beginning in 2002) than w estimated by EPA in its > 50 hp CI engine rule.

PM_{10} Reductions. CARB has estimated that California's > 175 hp CI engine regulations will reduce PM_{10} emissions 40 percent from baseline by 2010 (5.5 tons per day [tpd] reduction out of 13.7 tpd baseline). The Federal regulations for t engine class have the same particulate matter standard. However, EPA did not claim any PM_{10} reductions in its CI engine because it does not feel that the certification test cycle is adequate to predict reductions in PM_{10} from this class of engines spreadsheet calculation of PM_{10} emissions, ANL assumed that PM_{10} emissions will be reduced by 40 percent from this eng nationally.

IAS Baseline Controls. In the base year, EPA's Office of Mobile Sources (OMS) (which has primary regulatory authority for nonroad engines) did not regulate any type of nonroad engine. The first nonroad emissions regulation ever is that for large nonroad diesel engines, promulgated June 17, 1994. Although some prior controls were in place in Californ these sources, no controls for these engines are assumed in the base year.

EPA has proposed regulations for new SI (gasoline) and CI (diesel) marine engines. The marine gasoline engine reg propose to control emissions of NO_x and CO; those for diesels propose to control emissions of HC, CO, NO_x, PM, and sm EPA issued its notice at 59 Fed. Reg. 55930 (Nov. 9, 1994); the schedule for promulgation is unclear. While these regulat likely take effect before 2000, their effect is expected to be minimal before the year 2000. Therefore, these regulations are to take effect beginning in the year 2001.

In 1994, EPA issued a final rule on emissions of CO, HC, PM, NO_x, and smoke from large CI (diesel) engines. The n standards take effect in four phases, the first beginning January 1, 1996, and the last beginning January 1, 2000, according engine size (the full range of engine sizes affected by this rule is 50-750 hp). EPA estimates that the NO_x requirements of standard will reduce average per-unit NO_x emissions from affected engines by 27 percent by 2010, and by 37 percent by 2 Fed. Reg. 31306).

Development of a rule on small nonroad diesel engine emissions is on EPA's regulatory agenda, but no timetable is c set for that rulemaking.

EPA has proposed regulations for new SI (gasoline) engines of 19 kW (25 hp) or less, which would control HC and C emissions from such engines. EPA issued its notice at 59 Fed. Reg. 25399 (May 16, 1994) and is under a court order to pr a final rule by May 30, 1995.

Retrofit. There are four area source categories for off-highway vehicles in the IAS: large and small off-highway die engines, and large and small off-highway gasoline engines. Initial research identified "reformulated fuel" as a potential re control option. Since fuels are already being reformulated for on-highway vehicles, this option had the benefit of little or beyond the incremental refining costs. ANL, however, was unable to obtain satisfactory emission control data for the wid of engines used off-highway. There are too many different types of engines being operated under considerably different p speed ranges to be able to estimate the net control effectiveness of reformulated fuels. Another problem is the lack of a re inventory of engines by engine type, and of operating activity by engine type. Without such an inventory, it is very diffic accurately gauge the impact of reformulated fuels on emissions from these engines and activities. For these and other reas retrofit technologies are applied to off-highway vehicles.

New Source. Unlike all other area source categories, these four share new and retrofit technologies. For each of thes source categories, the new technology was identified as advanced engine technology. Cost data were derived from EPA g documents.

Table V-1 lists the IAS nonroad engine control technologies available to be applied to the four source categories for r engines/vehicles. Controls reduce NO_x emissions for diesel-fueled engines, and ROG emissions for gasoline-fueled engin three of the nonroad source categories, the baseline control technology applied in 2000 and beyond produces lower emissi than occur with the 1990 baseline technology.

Table V-2 lists nonroad engine/vehicle retirement rates. While there are no modeled retirements in 2000, significant retirements of these engines occur beginning in 2010, and continue through the rest of the forecast horizon.

Table V-1
Nonroad Engine/Vehicle Control Technologies

scc_id	tech_id	Pollutant	Nominal CE*
arnrdluc	401 ✓	NO_x	0.6
Large Diesel	402	NO_x	0.6
	499 ✓✓	NO_x	0.47
arnrdsuc	401 ✓	NO_x	0.6
Small Diesel	499 ✓✓	NO_x	0.47
arnrgluc	401 ✓	ROG	0.95
Large Gasoline	402	ROG	0.81
	499 ✓✓	ROG	0.25
arnrgsuc	400 ✓	ROG	1.00
Small Gasoline	401	ROG	0.46
	402	ROG	0.39
	499 ✓✓	ROG	0.32

NOTES: *Values listed are 1 minus the control efficiency expressed as a fraction.
✓ = Baseline Controls (in 2000-2040)
✓✓ = New Source Technology

Table V-2
Nonroad Engine/Vehicle Retirement Rates

	Projection Years					
scc_id	1990	2000	2010	2020	2030	2040
arnrdluc	0	0	0.45	0.75	0.98	1.00
arnrdsuc	0	0	0.45	0.75	0.98	1.00
arnrgluc	0	0	0.40	0.70	0.95	1.00
arnrgsuc	0	0	0.69	0.89	0.98	1.00

CHAPTER VI
AREA SOURCES

The area source sector contains a disparate group of source categories. Area sources vary widely in the nature of thei emissions (some originating from manufactured equipment and others from geogenic conditions), and the degree to which emissions are controllable. The nature and extent of the regulations affecting area source emissions are correspondingly indigenous.

While a few area source categories are regulated at the Federal level, most are regulated by State and local air polluti control agencies, and a few are not directly regulated at all. Also, some area source regulations include specific quantitati requirements for emission levels and equipment types, while others prescribe only qualitative control measures.

This section describes the regulatory requirements that apply to each of the area source categories included in the IAS pollutant for the years 1990-2000. This section also addresses the correspondence between the regulatory requirements ar controls prescribed for area source categories.

A. PAVED AND UNPAVED ROADS

EPA does not regulate fugitive particulate emissions from paved or unpaved roads. States and local agencies exercis regulatory authority over such sources, and the regulations that they have developed vary greatly. Emission limits for this type are typically only found in PM_{10} nonattainment areas. EPA has provided guidance to State and local agencies on recommended ("best available") control measures for particulates from paved and unpaved roads (EPA, 1992). However, emissions-based regulatory requirements have been identified in any jurisdiction in the study region. The following discu characterizes the road regulations that do apply in this area.

State and local regulations for fugitive dust emissions from roads typically apply to commercial/industrial roads, and the control measures to be employed rather than the control rates to be achieved. Road dust regulations very rarely contai quantitative requirements, other than opacity limits, which are generally set at 20 percent opacity. Even EPA's guidance t which provides "example SIP language for reduction of public paved road surface contaminants," contains primarily *qual* prohibitions and control action requirements under given dust-promoting conditions (EPA, 1988). Future changes in the l nature of road dust regulations are uncertain.

ANL identified several strategies for controlling fugitive road dust that are in current practice in the western States. C control strategies commonly used, sweeping is most widely and regularly used by States and municipalities for paved roa control. For unpaved roads, asphalt paving appears to be most common, although the cost of paving generally restricts th of road miles that are paved each year. Unpaved road dust is also controlled with chemical suppressants, although intervi public works staffs at several western municipalities indicate relatively modest use of this control strategy in the study reg

1. Paved Road Controls

Controls for paved roads apply primarily to PM_{10} and $PM_{2.5}$, which are the major pollutants of concern for this catego Due to the difficulty in finding comprehensive cost and effectiveness data, only two options were developed, although oth options could be added when more resources become available. These are mechanical broom sweeping and pave, flush ar 30 meters adjacent to unpaved roads.

The mechanical broom sweeping option is a program to sweep all rural and urban local roads and urban minor roads weekly basis. Currently, only streets in metropolitan areas are swept with any frequency, but this option both extends swe programs to rural areas and increases sweeping frequency.

The second control option considered is to pave a 30 meter "apron" where unpaved roads intersect paved roads. The apron reduces the quantity of dust carried onto the paved road, where it is subsequently reentrained by passing vehicles. T option also assumes that these intersections are watered down and swept once a day to remove accumulated dust. This da watering and sweeping provision contributes significantly to this option's high cost; however, this option was originally de be applied to industrial and/or construction sites.

2. Unpaved Road Controls

As with paved roads, PM_{10} and $PM_{2.5}$ are the dominant pollutants of concern. The primary control measure considere applying hot asphalt paving to all unpaved roads. Chemical dust suppressants were considered as an alternative to paving insufficient data prevented the option from being included in the system. The paving option assumes that the road will be coarse and fine graded prior to paving, and that a 2 inch binder course will be laid down under a 1 inch wearing course. T was assumed to last 20 years, rather than the usual 5 years, due to a more favorable climate.

Once the roads are paved, of course, additional particulate control may be achieved through a sweeping program. Th a paving and sweeping option was developed as a second control option for unpaved roads.

It is difficult to identify upcoming regulations, or other factors, affecting emissions from paved and unpaved roads. C requirements for roads are imposed by State and local agencies through the permitting process, and only for roads (typical unpaved) at commercial operations. In such cases, as well as in implementing controls for public roads, permitting agenci broad discretion in requiring/exercising control measures: thus, road dust controls are extremely variable and site specific addition, the permit provisions for commercial roads generally contain qualitative requirements for control measures and specify levels of particulate reductions required (other than opacity limits, which generally prohibit exceedances of 20 per opacity). No controls are assumed in the base year and no additional regulatory requirements beyond 2000.

3. Retrofit Controls

Paved Road Dust. Two retrofit control options are available to be applied to reduce paved road dust in the IAS: paving, sweeping, and flushing adjacent unpaved areas; and using sweepers. The selection of these controls was driven by information obtained from interviews with public works staff at several Western municipalities, and EPA guidance docum Cost information was also obtained from these sources. No regulations have been identified that require controls on road paved or unpaved roads. All road dust regulations currently in effect impose only opacity limits on road-originating emis

Sweepers (Mechanical Broom)

The sweeper cost data were taken from a report titled "Strategic Street Sweeping Study," which was prepared for the Coachella Valley Association of Government and supplied to ANL by an analyst with the California South Coast Air Qua Management District (SCAQMD). This document provides annual average costs per curb-mile for street sweeping in 8 so California cities, but the year is not known. Costs are assumed to be 1990 dollars. It is assumed that these costs include b and O&M, and that only one pass is made. The nominal cost was assumed to be the average of all values presented. The is the minimum cost presented, and the high cost is the maximum. It was assumed that sweepers would make 2 passes per mile, one for each side of the road, and it was assumed that an annual program would require sweeping 45 times per year a control efficiency of 25 percent. Furthermore, it is also assumed that low and high efficiencies are 80 percent and 120 p the nominal values, respectively.

Average sweeper cost ($/mile): 21.05
Nominal annual sweeper cost ($/mile): 2*45*21.05 = 1894.32
Low annual sweeper cost ($/mile) = 2*45*16.50 = 1485.00
High annual sweeper cost ($/mile) = 2*45*37.90 = 3411.00

Pave, Flush, and Sweep Adjacent Unpaved Areas

The "pave, flush, and sweep adjacent unpaved areas" (PFS) control measure was originally intended to be applied at construction sites, especially where trucks and heavy equipment would regularly carry dirt and silt onto adjacent paved ro the PFS control measure, a 30 meter apron is applied to an unpaved road where it intersects a paved road. It was assumed aprons are applied for every 10 miles of paved road. It was further assumed that dust from these intersections account for percent of all PM and $PM_{2.5}$ emissions from paved roads, so the 71 percent control efficiency figure was adjusted downwa reflect the lesser coverage. The apron costs presented below were taken from EPA (1992). The EPA document provides in $1991, so these were converted to $1990.

Conversion factor from $1991 to $1990: 0.96
Nominal PFS capital cost ($1991 each): 1550.00
Nominal PFS capital cost ($1990/mile): 0.96*1550.00*2/10 = 297.58

Since the PFS technology will only be applied after the sweeping technology, costs for the two technologies must be
It is assumed that the sweeping component of the PFS technology is negligible, so that the PFS and sweeping O&M costs
added. Thus, PFS capital, PFS O&M, and sweeping costs are summed to get total PFS costs. Furthermore, it is assumed
low and high PFS costs are 80 percent and 120 percent of the nominal PFS value, respectively.

Nominal PFS O&M cost ($1991 each): 5351.00
Nominal PFS O&M cost ($1990/mile): 0.96*5351.00*2/10 = 1027.32
Adjusted nominal PFS O&M costs ($1990/mile): 1027.32 + 1894.32 = 2921.64
Adjusted low PFS O&M costs ($1990/mile): 0.80*2921.64 = 2337.31
Adjusted nominal PFS O&M costs ($1990/mile): 1.20*2921.64 = 3505.97

PFS Efficiency Calculation

The reported PFS control efficiency is 71 percent. But the control, as it is applied in the IAS, comes after a sweeping
program has already been implemented. This means that the control efficiency must be adjusted for (1) the assumed 5 per
penetration of road dust from intersections and (2) the 25 percent reduction in dust due to the sweeping program already i

Control efficiency: 71 percent
Nominal control efficiency: 5 percent * 71 percent = 4 percent
Nominal PFS efficiency: 25 percent + 4 percent - (25 percent * 4 percent) = 28 percent
Low PFS efficiency: 0.80*28 percent = 22 percent
High PFS efficiency: 1.20*28 percent = 33 percent

Unpaved Road Dust. Two retrofit controls were developed for unpaved road dust emissions: hot asphalt paving, an
paving followed by sweeping. These are described below. A third option, chemical suppressants, was assessed, but reliab
application rate and cost data could not be obtained and the option was dropped from consideration. The control selection
for unpaved roads utilized the same information sources as did paved road dust. As with paved road dust, no regulatory
requirements exist to drive the selection of these controls.

Hot Asphalt Paving

The hot asphalt paving cost data were taken from the 1993 *Means Heavy Construction Costs* report. This report is
used by contractors to estimate the costs for various construction projects, so it requires some knowledge of construction
techniques. The capital costs arise from building the road, whereas the O&M costs arise from maintaining it. A mile of r
assumed to be 24 feet across for paved lanes (1 each way). Capital costs include the costs to grade subgrade, fine grade g
base, pave 2 inch binder course, pave 1 inch wearing course, and paint 4 inch centerline and side strips. The O&M costs i
only resealing 1/2 inch cracks (i.e., no resurfacing or pothole repair). A survey of the literature suggests that roads have a
lifetime. Due to more favorable weather conditions in the southwest, and fewer vehicle miles traveled (VMT) over these
roads, these roads are assumed to last 20 years. The cost to replace roads built before 2020 have not been estimated, so th
provided are likely to underestimate the true "lifetime" paving costs. All costs include capital, operating, overhead, and p
are in 1993 dollars. The costs are then adjusted to 1990 dollars.

Paving capital cost ($1993/mile): 91361.60
Conversion for $1993 to $1990: 0.91
Nominal paving capital cost ($1990/mile): 0.91*91361.60 = 83056.00
Low paving capital cost ($1990/mile): 0.80*83056.00 = 66444.80
High paving capital cost ($1990/mile): 1.20*83056.00 = 99667.20

Seal cracks ($1993/mile) = 2500.00
Nominal paving O&M ($1990/mile) = 0.91*2500.00 = 2272.73
Low paving O&M ($1990/mile) = 0.80*2272.73 = 1818.18
High paving O&M ($1990/mile) = 1.20*2272.73 = 2727.27

Pave Then Sweep

The "pave then sweep" (PS) control technology combines costs from the sweeping technology in the paved roads sec
the hot asphalt paving control technology presented above. The sweeping technology has no capital costs, so the PS techn
has the same capital costs as hot asphalt paving. The O&M costs were simply added together. The PS control efficiencie
multiplicatively combined to account for the reductions due to paving.

Mileage Estimates

Control strategies for paved and unpaved roads were applied to mileage estimates for the region obtained from U.S. Department of Transportation (DOT) highway statistics (DOT, 1990). Table VI-1 identifies mileage of unpaved roads in t States of the region. These are predominantly rural local roads, but include significant contributions from rural collector a roads. These mileage estimates were disaggregated to IAS regions using regional totals of particulate matter emissions fr unpaved roads in the 1990 emissions inventory. Table VI-2 identifies mileage of paved roads in the twelve States of the r For sweeping programs, it was assumed that rural local roads and urban minor and local roads would be candidates for en sweeping programs. Mileages for these roadway functional classes were used in the analysis. Again, regional estimates w obtained by disaggregating on the basis of regional totals of particulate emissions from paved roads. For both paved and roads, the resulting mileage estimates were used as the num_src variable for the appropriate arpvrduc and arupvduc sourc categories.

4. New Source Controls

Paved Road Dust. No new source control options were identified for paved roads, as new paved road emissions are generally extremely low. Sweeping as a retrofit option is expected to be used after the establishment of new roads. No re have been identified that require controls on road dust from new paved roads. All road dust regulations currently in effect only opacity limits on road-originating emissions. The selection of retrofit controls, and the decision not to select new so controls for paved roads, was driven by information obtained from interviews with public works staff at several Western municipalities, and EPA guidance documents.

Table VI-1
Mileages of Unpaved Roads in the Region

State	Unpaved Roads (miles)				Total Paved Roads (miles)	Total Roads (miles)
	Rural Local	Rural Collector	Urban	Total Unpaved		
Arizona	18,412	2,044	873	21,329	30,283	51,612
California	27,821	1,767	2,622	32,210	131,364	163,574
Colorado	38,860	8,861	544	48,265	29,415	77,680
Idaho	40,868	3,516	113	44,497	17,938	62,435
Montana	43,256	11,377	253	54,886	16,501	71,387
Nevada	32,999	1,325	594	34,918	10,606	45,524
New Mexico	36,609	489	1,125	38,223	16,513	54,736
Oregon	54,795	3,951	713	59,459	35,510	94,969
Texas	114,115	63	12,191	126,369	179,582	305,951
Utah	23,481	3,336	165	26,982	16,262	43,244
Washington	35,912	1,666	721	38,299	43,00	81,299
Wyoming	21,705	6,026	315	28,046	11,167	39,213

SOURCE: Highway Statistics 1990, FHWA-PL-91-003, DOT, Federal Highway Administration, Tables HM-20, HM-51, and HM-67.

Table VI-2
Mileages of Paved Roads in the Region

State	Paved Roads (miles)						
	Major Highways[a]	Rural Minor Roads[b]	Urban Minor Roads[b]	Rural Local Roads	Urban Local Roads	Total Paved Roads (miles)	Total Roads (miles)
Arizona	3,238	6,959	2,572	7,464	10,060	30,283	51,612
California	12,535	27,641	16,028	28,075	47,085	131,364	163,574
Colorado	3,936	12,453	2,215	3,540	7,271	29,415	77,680
Idaho	2,437	6,201	778	7,243	1,279	17,938	62,435
Montana	3,464	7,867	429	3,370	1,371	16,501	71,387
Nevada	1,362	4,636	773	2,372	1,463	10,606	45,524
New Mexico	2,838	8,378	610	1,480	3,207	16,513	54,736
Oregon	3,603	15,486	1,988	9,476	4,957	35,510	94,969
Texas	15,902	63,313	12,412	29,499	58,456	179,582	305,951
Utah	1,880	5,857	903	3,522	4,100	16,262	43,244
Washington	4,006	14,940	3,470	10,206	10,378	43,000	81,299
Wyoming	2,106	6,010	511	1,634	906	11,167	39,213

NOTES: [a]Interstates, freeways, expressways, and other principal arterial roads. Not amenable to frequent sweeping.
[b]Minor arterial roads and collector roads. Possibly amenable to frequent sweeping.

SOURCE: Highway Statistics 1990, FHWA-PL-91-003, DOT, Federal Highway Administration, Tables HM-20, HM-51, and HM-67.

Unpaved Road Dust. ANL determined that new unpaved road sources are extremely rare. In cases where unpaved roads are newly created, the most effective control option would be to immediately pave the roads, which would cause suc to be categorized not as unpaved roads, but paved ones. In IAS, unpaved road mileage/travel remains constant from 1990 2040 (no growth factor is applied).

B. LIVESTOCK

Although some particulate controls were in place for feedlots in the 1990 base year, little or no data exist that indicate types of control, level of control, or control costs. Also, any controls that were in place were required by individual sourc under State and local law, and thus were site-specific. No Federal emissions control requirements are currently in place o for livestock operations, although ANL expects some increase in level of control in this category through permitting or ch State or local regulations by the year 2000. However, because any increases in control are expected to be site-specific and pervasive throughout the region, ANL assumed changes in control for this source category to be insignificant between 19 2000.

The SCAQMD of California has established a three-phase regulatory program for air emissions from livestock operat Other State and regulatory agencies may adopt these requirements after 2000, but the data from southern California proba not apply. Therefore, this program was used as the control option for southern California, but not elsewhere.

C. RESIDENTIAL WOOD COMBUSTION (RWC)

Emissions from RWC were controlled for the first time around 1986 when some western State and local environment agencies began to impose grams per hour (g/hr) PM limits on new stoves.[6] In February 1988, EPA promulgated a two-pha NSPS for RWC,[7] which limited PM emissions from stoves manufactured beginning July 1988, or sold beginning July 199 second, more stringent phase began in 1990 and 1992, respectively, for stove manufacture and sale. It is estimated that th of stoves that were sold subject to State regulation, but prior to the EPA standards (between 1986 and July 1988), was rela small. For purposes of the IAS, ANL assumed that the EPA regulations affected the wood stove market immediately follo (but not in) the base year.

An additional regulatory phase (Phase III) has been established by the State of Washington at a level of 2.5 g/hr PM f catalyst-equipped units and 4.5 g/hr PM for non-catalyst-equipped units.[9] The standard applies to all RWC units sold in th of Washington after January 1, 1995. Phase III is unique to Washington, and before 2000, it is not expected to have a maj on air quality in the GCVTC region. However, ANL has assumed in the IAS that other western State and local agencies (particularly those with nonattainment concerns) will adopt Phase III in the next five years and, therefore, that Phase III w air quality in the years 2000-2040.

RWC is one of the few area source categories for which EPA has issued NSPS. However, in contrast with most other EPA has delegated very little implementation of the RWC standard to the States. Table VI-3 summarizes the requirement implementation schedule of the RWC NSPS.

ANL identified control options for the IAS that correspond to the advanced-technology stoves that are required in EP the State of Washington's regulations. These control options involve replacement and retirement of existing stoves, and in three main types of residential wood-burning technologies: conventional units, "Phase II" units, and pellet stoves.

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[6]Between 1986 and 1988, additional western State and local agencies adopted the emissions requirements for new stoves. The new drove the majority of manufacturers out of business; prior to 1986, there were over 500 wood stove manufacturers; after implementatio standards, only 40 remained. The standards also caused a rise in residential wood combustion unit prices, creating a disincentive for s owners to replace their stoves; sales declined briefly as a result.

[7]53 Fed. Reg. 5873 (Feb. 26, 1988), *codified at 40* C.F.R. 60 Subpart AAA.

[8]EPA has found RWC devices to be one of the largest sources of anthropogenic PM_{10} emissions in the country, and estimated that i wood heaters emitted 2.7 million tons of PM_{10}. U.S. EPA, *Guidance Document for Residential Wood Combustion Emission Measures* (EPA-450/2-89-015)(1989).

[9]Washington Clean Air Act, § 70.94.457(1)(a).

Emissions from RWC were controlled for the first time around 1986, when some western State and local agencies be impose g/hr PM limits on new stoves. In February 1988, EPA promulgated a two-phase NSPS for RWC (53 Fed. Reg. 58 which limited PM emissions from stoves manufactured beginning July 1988, or sold beginning July 1990. A second, mor stringent phase began in 1990 and 1992, respectively, for stove manufacture and sale. It is estimated that the number of st were sold subject to State regulation but prior to the EPA standards (between 1986 and July 1988) was relatively small. B we are uncertain of the assumptions used in the Radian data base, we will assume that the EPA regulations affected the wo market immediately following the base year. The largest growth in the industry in recent years has been in gas-fired stove however (Crouch, 1995). The regulations did not address retrofits of existing units. Existing units are regulated only by S local programs for RWC emissions curtailment and for accelerated phase-outs of conventional stoves.

Retrofit. No retrofit controls were identified for RWC units, for two reasons: first, discussions with wood stove ind officials and retailers indicated that retrofits to existing units are extremely rare; second, more cost-effective controls can achieved through retirement and replacement, which is not only more common, but is required under EPA's recent NSPS

New Source. In February 1988, EPA promulgated a two-phase NSPS for RWC, which limited PM emissions from st manufactured beginning July 1988, or sold beginning July 1990. A second, more stringent phase began in 1990 and 1992 respectively, for stove manufacture and sale. ANL's selected control options for RWC units reflects the technology requir the NSPS: the new source control is replacement of conventional stoves with certified stoves. Certified stoves are the lov technology stoves that have been certified by EPA to meet the lower standards.

Table VI-3
Summary of NSPS Particulate Emission Limits for Residential Wood Stoves[a]

Date of Manufacture/Sale	Control Equipment[b]	Emissions Must not Exceed a Weighted Average of...
Phase I: Manufactured after June 30, 1988 (or sold at retail after June 30, 1990)	Catalytic combustor	5.5 g/hr PM
	No catalytic combustor	8.5 g/hr PM
Phase II: Manufactured after June 30, 1990 (or sold at retail after June 30, 1992)	Catalytic combustor	4.1 g/hr PM
	No catalytic combustor	7.5 g/hr PM

NOTES: [a]SOURCE: 53 Fed. Reg 5873 (Feb. 26, 1988), codified at 40 C.F.R. 60, Subpart AAA.
[b]The lower emission rate for stoves equipped with catalytic combustors is driven by the fact that emissions from combustors increase over time and then level off. That is, with use of combustor-equipped stoves, their emission rates will more closely approximate those of non-combustor equipped stoves. It is estimated that the "leveling-off period" takes 2-5 years, depending both on equipment and use. RWC units have an average lifetime of 7-15 years, again depending on equipment and use.

(Two additional clean-technology stoves, Phase II stoves and pellet stoves, could achieve even greater reductions than rep
with certified stoves. However, ANL did not include these options in IAS because cost information was unavailable.)

D. OPEN BURNING

Open burning of waste is generally defined as combustion of material whose emissions are not directed through a flu
stack or chimney). Most State and local regulations prohibit such burning, but allow exemptions from the general prohibi
Exemptions typically include burning for recreational, ceremonial, and educational purposes, burning of household waste
of low population density, and certain types of agricultural burning. There are currently no Federal regulations restricting
burning.

Estimates of 1990 emissions for the IAS are developed from the GCVTC inventory. However, it is not clear which o
burning activities are represented. In the absence of information about the inventory, ANL assumed the majority of open
emissions to be from residential sources. ANL has assumed land filling and replacement with gas barbecues to be control
for open burning emissions. It is unclear to what extent land filling of waste is required, particularly in rural areas. ANL
determined that disposal service is available in many rural areas, although it is used to a much lesser extent than in urban a
only regulatory jurisdiction that regulates barbecue emissions is the SCAQMD. This is not expected to change in the 199
period.

1990-2000 Modeling. Open burning is regulated at the State and local level; permitting agencies have broad discreti
in selecting open burning activities they allow. Open burning regulations typically contain a generic prohibition, but prov
exemptions for certain specific activities (such as recreational or ceremonial burning). The site-specific nature of open bu
regulation has constrained the ability of this study to identify changes in all State and local burning programs between 19
2000. As a result, *no controls are assumed in that period*.

Retrofit. No retrofit controls were identified for open burning for which cost information could also be developed.
retrofit option that was investigated was the landfilling of waste that is currently burned. After extensive interviews with
waste companies and regulatory agencies, ANL could not derive a reliable cost estimate for this control option, particularl
net-tons-of-emissions-reduced basis.

New Source. New source controls were considered to be inappropriate for the open burning source category, as ope
burning is typically unregulated, and new sources of open burning are typically not identified.

E. WILDFIRES

Although wildfire emissions are anthropogenic to some degree, they are driven by natural conditions to a greater exte
are the emissions of any other area source category, with the exceptions of geogenic and biogenic sources. As such, conv
control measures are largely inappropriate. Nonetheless, preventive controls (such as fuel removal) and mitigative contro
immediate fire suppression) are explicitly addressed in the wildfire policies of the National Park Service (NPS) and U.S. F
Service (USFS).

Any changes in USFS or NPS wildfire/prescribed burning policies after the base year would be assumed to affect em
in the period 1990-2000. That information has been unavailable to date.

Retrofit. The only retrofit control used for wildfire emissions was prescribed burning. This control option was sele
based on discussions with Peter Lahm and Albion Carlson. No cost or control efficiency data were developed for this opt

F. LANDFILLS

Federal Regulation. Prior to the Clean Air Act Amendments of 1990, air emissions from landfills were not regulated
Federal level. In May, 1991, the EPA issued a proposed rule for limiting organic emissions from new and existing munic
waste (MSW) landfills.[10] In it, EPA proposed to establish both NSPS for certain new landfills, and guidelines for controll
emissions from existing MSW landfills. EPA has not issued a final rule, but expects to do so in August 1995. No informa
available from EPA on the likely content of the final rule. Thus, ANL has relied on EPA's May 1991 proposal to estimate

[10]Fed. Reg. 24468 (May 30, 1991). EPA's proposal served to implement § 111(b) of the Clean Air Act and was based on a determ
the Administrator that emissions from MSW landfills "causes or significantly contributes to air pollution which may reasonably be ant
endanger public health or welfare." The Clean Air Act § 111(b)(l)(A), 42 U.S.C. § 741 l(b)(1)(A).

of landfill controls beyond the base year. In the future, it will be valuable to confirm and/or revise these regulatory assum increase confidence in the data generated by the IAS.

The major provisions of EPA's proposals for new and existing landfills were identical. Both programs would require landfills emitting greater than 167 tpy of non-methane organic compounds (NMOC) to be equipped with gas collection sy and to combust the captured gases, with or without energy recovery. Requirements for existing landfills would apply rega whether the landfill was active (still accepting waste or having remaining capacity) or closed (neither accepting waste nor remaining capacity). This aspect of EPA's regulation reflects a unique characteristic of landfill as a source category: they to emit even *after* they are retired from use. Recognizing this fact, ANL has assumed in the IAS that existing landfills wil subject to retirement.

For MSW landfills emitting less than 167 tpy, the rule would not require collection and control equipment to be in pl However, States have the discretion to impose more stringent requirements, including controls on Federally exempted lan they find such controls necessary to their ozone attainment demonstrations.

Controls Required. EPA's May 1991 proposal relied on the use of active collection systems and open flares for contr landfill gas emissions. These technologies are commonly used at landfills nationwide and have been designated by EPA a *demonstrated technology*. EPA allowed alternative control technologies to be employed, but only if they could be demonstrated to achieve 98 percent destruction of all captured landfill gas.

In 1991, EPA proposed three regulatory alternatives, which differed in applicability according to the annual NMOC e rates of MSW landfills. The number of MSW landfills affected by the rule, therefore, depends on which of the three regu alternatives is adopted in the final rule. In its 1991 proposal, EPA estimated the impact of each of its three alternatives on and existing MSW landfills; this information is summarized in Tables VI-4 and VI-5.[11] Based on EPA's proposed rule, A used off gas capture and treatment as a control strategy for new and retrofit landfill applications.

Retrofit and New Source. As discussed above, EPA has proposed regulations for emissions from MSW landfills. F *existing* and *new* landfills that emit over 167 tpy of NMOC, the rule would require installation of offgas capture and treatm systems of at least 98 percent efficiency for NMOC.

Based on EPA's proposal and interviews with EPA staff, ANL has used "offgas capture and treatment" as both a new retrofit control for landfill emissions. Such systems are assumed to achieve 98 percent control of NMOC (ROG) emission data were obtained principally from EPA guidance documents.

G. CONSUMER AND COMMERCIAL SOLVENTS

Area source VOC emissions from solvent use, and their future growth and control are simulated in IAS through three categories, or scc_ids. These three area source categories are listed below.

1. Miscellaneous commercial solvent use with unknown control (arcsoluc)
2. Miscellaneous consumer solvent use with unknown control (arrsoluc)
3. Architectural surface coating with unknown control (arsarcuc)

Retrofit and New Source. There are three area source categories for solvents in the IAS: miscellaneous commercia solvents, miscellaneous consumer solvents, and architectural surface coatings. EPA has proposed regulations for these su to be phased in beginning 1997, with additional phases to be implemented in 1999, 2001, and 2003. The proposed regulat would require newly manufactured solvents and coatings to have VOC levels reduced by 25 percent.

According to EPA's proposal, ANL has used *reformulated products* as a generic control option for these source categories. Because solvents cannot be retrofitted in a traditional sense, and will be replaced in any case due to the new re ANL has not assigned retrofit controls for these source categories. However, the attrition rate for existing (pre-regulated) products has been specified in the LBF file, based on EPA's proposed requirements and ANL interviews with EPA staff.

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[11]The information in these tables was derived wholly from 56 Fed. Reg. 24468. Elaboration on these numbers, as well as cost effec estimates can be found in that document.

Table VI-4
Effect of Proposed Federal Regulatory Alternatives on Existing MSW Landfills

Regulatory Alternative	Emission Rate Cutoff NMOC/year	Landfills Affected	Million Megagrams (Mg) NMOC Emission Reduction	Percent NMOC Reduction
1	25 Mg (28 tpy)	1,884	13	92
2	150 Mg (167 tpy)	621	10.6	79
3	250 Mg (278 tpy)	386	9.6	71

Table VI-5
Effect of Proposed Federal Regulatory Alternatives on New MSW Landfills[a]

Regulatory Alternative	Emission Rate Cutoff NMOC/year	Landfills Affected	Million Mg NMOC Emission Reduction	Percent NMOC Reduction
1	25 Mg (28 tpy)	247	0.99	90
2	150 Mg (167 tpy)	87	0.76	69
3	250 Mg (278 tpy)	41	0.63	57

NOTE: [a]New landfills were considered to be those constructed and opened within five years of issuance of the NSPS (estimated as 1992-1997); these new landfills were assumed to replace existing landfills in that period.

The SCAQMD in 1991 established a general requirement that architectural coatings sold and applied in the District n no greater than 250 grams of VOCs per liter (2.08 lbs per gallon) of coating; some exemptions were provided (Rules and Regulations of the South Coast Management District, Rule 1113). This regulation will generate measurable VOC emissio reductions in the South Coast area after the base year; however, it is unclear to what extent other western air quality agenc adopt regulations that resemble, or are identical to, those of South Coast. For lack of information about regulation by add agencies, it has been assumed that the South Coast regulations will not be adopted by other States in the 1990-2000 perioc future refinements to the IAS, it will be useful to incorporate such regulatory developments.

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APPENDIX A
LIST OF IAS REGIONS

Table A-1
IAS Regions

Region_id	Region Description	Region_id	Region Description
1	Washington W	43	AZ - Navajo Co
2	Washington E	44	AZ - Apache Co
3	Idaho NW	45	AZ - South Eastern
4	Montana	46	AZ - Southern
5	Oregon W	47	AZ - Cochise Co
6	Oregon E	50	CO - Moffat Co
7	Idaho SE	51	CO - North Central
8	WY - Lincoln Co.	52	CO - Larimer Co
9	Wyoming	53	CO - North Eastern
10	CA - Northern	54	CO - Denver Co
11	CA - Bay	55	CO - Mesa Co
12	CA - Central	56	CO - Montrose Co
13	CA - Bakersfield	57	CO - South Western
14	CA - LA	58	CO - South Eastern
15	CA - South East	59	CO - Las Animas Co
16	CA - San Diego	60	NM - San Juan Co
20	NV - Northern	61	NM - North Western
21	NV - Central	62	NM - Central West
22	NV - Clark Co	63	NM - North East
30	UT - ID Border	64	NM - South West
31	UT - Northern	65	NM - South East
32	UT - Salt Lake Co	70	TX - El Paso
33	UT - Utah Co	71	TX - West
34	UT - Central	72	TX - North
35	UT - Millard Co	73	TX - Central West
36	UT - Emery Co	90	TX - Eastern
37	UT - South Western	91	Canada
38	UT - South Eastern	92	Mexico
40	AZ - North Western	93	Mexico-Cananea
41	AZ - South Western	94	Mexico-Nacozari
42	AZ - Cococino Co	95	Mexico-Carbone

Table A-2
IAS Source Group Matchings to REMI Sectors

Scc_id	Scc_desc	REMI Sector	REMI Sector Name
aicobouc	Bituminous & Pulverized Coal Boilers	61	See footnotes
aigaspuc	All Gasoline Processes	29	Communication
aingbouc	Natural Gas, Total: Boilers & IC Engine	62	See footnotes
ainrdluc	Off-Highway Vehicle Diesel, Ind. Equip.	54	Weighted average sectors 1-30
aiogp2uc	Oil & Gas Production, Petroleum	22	Mining
aiogpruc	Oil & Gas Production, Petroleum	22	Mining
aioibouc	Distillate Oil, Total: Boilers & IC	63	See footnotes
aipetruc	Petroleum Refineries: General	19	Petroleum and coal products
aisolvuc	Industrial Solvents	54	Weighted average sectors 1-30
aragpruc	Agricultural Production - Livestock	53	Farm
arbioguc	Natural Sources Biogenic	58	Constant over time
arcsoluc	Misc. Commercial Solvent Use	55	Weighted average sectors 31-48
argeoguc	Natural Sources Geogenic	58	Constant over time
arlfiluc	Landfills	56	Population index adjusted for income
armisanc	Miscellaneous Area Source	58	Constant over time
arnrdluc	Large Off-HWY Vehicle Diesel	55	Weighted average sectors 31-48
arnrdsuc	Small Off-HWY Vehicle Diesel	55	Weighted average sectors 31-48
arnrgluc	Large Off-HWY Vehicle Gasoline	56	Population index adjusted for income
arnrgsuc	Small Off-HWY Vehicle Gasoline	56	Population index adjusted for income
arobrnuc	Open Burning	59	Population index
arothrnc	Other Area Sources	58	Constant over time
arpvrduc	Paved Road Dust	57	Based on VMT, population index
arrsoluc	Misc. Consumer Solvent Use	56	Population index adjusted for income
arrwoduc	Residential Wood Combustion	56	Population index adjusted for income
arsarcuc	Architectural Surface Coating	56	Population index adjusted for income
arupvduc	Unpaved Road Dust	57	Based on VMT, population index
arwfiruc	Wildfires	58	Constant over time
inagpepm	Industrial All Gasoline Processes	19	Petroleum and coal products
inagpeuc	Industrial All Gasoline Processes	19	Petroleum and coal products
inchemnx	Industrial Chemicals and Allied Products	18	Chemical and allied products
inchemuc	Industrial Chemicals and Allied Products	18	Chemical and allied products
incobonx	Industrial Coal Boilers	61	See footnotes
incobopm	Industrial Coal Boilers	61	See footnotes
incobouc	Industrial Coal Boilers	61	See footnotes
incop2pm	Industrial Copper Smelters - Fugitive	4	Primary metal industries
incop2uc	Industrial Copper Smelters - Fugitive	4	Primary metal industries
incoppnx	Industrial Copper Smelters - Captured	4	Primary metal industries
incopppm	Industrial Copper Smelters - Captured	4	Primary metal industries
incoppuc	Industrial Copper Smelters - Captured	4	Primary metal industries
ingsprpm	Industrial Gas Production	22	Mining
ingspruc	Industrial Gas Production	22	Mining
inngbonx	Industrial Natural Gas Boilers	62	See footnotes
inngbopm	Industrial Natural Gas Boilers	62	See footnotes
inngbouc	Industrial Natural Gas Boilers	62	See footnotes
inngcmnx	Industrial Natural Gas Production, Compressors	22	Mining
inngcmpm	Industrial Natural Gas Production, Compressors	22	Mining
inngcmuc	Industrial Natural Gas Production, Compressors	22	Mining
inngflpm	Industrial Natural Gas Production, Flare	22	Mining
inngfluc	Industrial Natural Gas Production, Flares	22	Mining
inngrenx	Industrial Natural Gas Reciprocating	62	See footnotes
inngrepm	Industrial Natural Gas Reciprocating	62	See footnotes
inngreuc	Industrial Natural Gas Reciprocating	62	See footnotes
inngswpm	Industrial Natural Gas Production, Gas Sweeting	22	Mining
inngswuc	Industrial Natural Gas Production, Gas Sweeting	22	Mining
inoibopm	Industrial Oil Boilers	63	See footnotes
inoibouc	Industrial Oil Boilers	63	See footnotes
inoipruc	Industrial Oil Production	22	Mining
inorchpm	Industrial Other Miscellaneous, Organic Chemical	18	Chemical and allied products
inorchuc	Industrial Other Miscellaneous, Organic Chemical	18	Chemical and allied products
inothrnc	Industrial Other	64	See footnotes
inpeprnx	Industrial Petroleum Process Fuel Use	19	Petroleum and coal products
inpeprpm	Industrial Petroleum Process Fuel Use	19	Petroleum and coal products
inpepruc	Industrial Petroleum Process Fuel Use	19	Petroleum and coal products
inperenx	Industrial Petroleum Refineries	19	Petroleum and coal products
inperepm	Industrial Petroleum Refineries	19	Petroleum and coal products
inpereuc	Industrial Petroleum Refineries	19	Petroleum and coal products

Table A-2 (continued)

Scc_id	Scc_desc	REMI Sector	REMI Sector Name
insolvnx	Industrial Solvent Use	54	Weighted average sectors 1-30
insolvpm	Industrial Solvent Use	54	Weighted average sectors 1-30
insolvuc	Industrial Solvent Use	54	Weighted average sectors 1-30
inwobonx	Industrial Wood Boilers	65	See footnotes
inwobopm	Industrial Wood Boilers	65	See footnotes
inwobouc	Industrial Wood Boilers	65	See footnotes
ptothrnc	Other Point Sources	54	Weighted average sectors 1-30
traviauc	Commercial and General Aviation Aircraft	71	Weighted average of population and income
trdplduc	Diesel Powered Light-Duty Cars/Trucks	66	See footnotes
trdpmvuc	Diesel Powered Medium/Heavy Vehicles	68	See footnotes
trgplduc	Gasoline Powered Light-Duty Cars/Trucks	66	See footnotes
trgpmtuc	Gasoline Powered Medium Trucks	67	See footnotes
trmariuc	Commercial Marine Vessels	70	See footnotes
trrailuc	Railroad Locomotives	69	See footnotes
utcoaloc	Utility Coal Combustion	30	Electric, gas, and sanitary services
utcoalsx	Utility Coal Combustion	30	Electric, gas, and sanitary services
utcognnc	Utility Cogeneration	30	Electric, gas, and sanitary services
utliqunc	Utility Liquid Fuels	30	Electric, gas, and sanitary services
utngasnx	Utility Gas Combustion	30	Electric, gas, and sanitary services
utngasoc	Utility Gas Combustion	30	Electric, gas, and sanitary services
utrenwnc	Utility Renewables	30	Electric, gas, and sanitary services
utnchync	Utility Nuclear/Hydro	30	Electric, gas, and sanitary services

Legend for REMI Links

1-53: Direct mapping to REMI sector of same number
54: Weighted average across sectors 1-30
55: Weighted average across sectors 31-48
56: Based on the population index adjusted for income
57: Based on VMT, population index, and a time adjustment (see text)
58: Constant over time
59: Based on population index
61-65: See Table III-5 of this document
66: Weighted average of population and income per capita indexes (.67 and .33)
67-68: Weighted average of all REMI sectors except 13, 17, 24-8, 30-5, 38, 40, 44, 45, 48, 50-3
69: Weighted average of all REMI sectors except 13, 17, 23-38, 40, 44, 45, 48, 50-3
70: Weighted average of REMI sectors 3, 4, 12, 18, 19, 22, 49
71: Weighted average of population and income (.5 and .5)