

**EMISSIONS INFORMATION  
ACQUISITION AND  
VERIFICATION**

**TASK 2.2 - OTHER POINT  
SOURCE COSTING**

**DRAFT REPORT**

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# ACRONYMS AND ABBREVIATIONS

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\$/kW	dollars per kilowatt
acfm	actual cubic feet per minute
BACT	Best Available Control Technology
BEA	Bureau of Economic Analysis
Btu	British thermal units
CO	carbon monoxide
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
FGD	flue gas desulfurization
GCVTC	Grand Canyon Visibility Transport Commission
H <sub>2</sub> S	hydrogen sulfide
IAS	Integrated Assessment System
ICI	Industrial, Commercial, and Institutional
MW	megawatts
NAPAP	National Acid Precipitation Assessment Program
NEMS	National Energy Modeling System
NPI	National Particulates Inventory
NSPS	New Source Performance Standards
O&M	operation and maintenance
PSD	prevention of significant deterioration
REMI	Regional Economics Model, Inc.
SCCs	Source Classification Codes
scfm	standard cubic feet per minute
SO <sub>2</sub>	sulfur dioxide
SO <sub>3</sub>	sulfur trioxide
tpy	tons per year



This short report provides the information needed to add source cells to the Integrated Assessment System (IAS) for source sectors lumped together into the Other Point Source category during the Grand Canyon Visibility Transport Commission (GCVTC) analysis. Other Point Sources comprise about 100,000 tons per year (tpy) of sulfur dioxide (SO<sub>2</sub>) in 1990, with the total stationary source SO<sub>2</sub> emissions being about 800,000 tpy.

Table 1 lists the proposed classification of other point source categories into IAS source categories, or scc\_ids. For sulfuric acid plants and sulfur recovery plants, there is a one-to-one match between scc\_ids and Source Classification Codes (SCCs). This assignment was made to reflect the different control efficiencies that would be observed by applying SO<sub>2</sub> controls, which themselves have different initial SO<sub>2</sub> control efficiencies. Other source categories are defined by sources with source emission characteristics, common control methods, similar control cost relationships, and new source control technology requirements.

The other point source SO<sub>2</sub> emitters to be evaluated in this study were defined by a computer file received from Pat Ryan with the facility-level and SCC-level emission values. This file was partitioned into three parts: (1) SCCs with all facility-level SO<sub>2</sub> emissions below 100 tpy (not studied further); (2) SCCs that could be linked to existing source categories (scc\_ids) in IAS; and (3) the SCCs for which retrofit control options, new source technologies, and control cost information was developed to include the remaining other point sources in IAS. For (2) there were three copper smelter SCCs that were incorporated in IAS by Pat Ryan. These SCCs are:

1. 30300514 Reverberatory Furnace: Fugitive Emissions
2. 30300522 Slag Cleaning Furnace
3. 30300534 Flash Furnace after Concentrate Dryer

For (3), the assignments of SCCs to scc\_ids is shown in Table 1.

## **A. COST ESTIMATES FOR RETROFIT CONTROL TECHNOLOGIES**

Retrofit control options by source category (scc\_id) are listed in Table 2. This table lists the source category (scc\_id and description), the applicable SO<sub>2</sub> control technology, and the expected control efficiency. These are the control techniques for which control cost information is to be included in the IAS.

Flue gas desulfurization (FGD) is a control option for most of the source categories that were evaluated. The use of FGD scrubbers for controlling SO<sub>2</sub> emissions has been applied to utility and industrial boilers for 25 years, and is now considered a mature technology that can be designed for controlling SO<sub>2</sub> emissions from most industrial sources. FGD scrubbers can be either wet or dry systems. In wet systems, a liquid sorbent is sprayed into the flue gas in an absorber vessel. Limestone and lime-based reagents are most frequently used in scrubbers in the United States. Dry FGD systems include spray dryers, circulating dry scrubbers, and dry injection (ICAC, 1995).

Costs for FGD scrubbers were developed using the 1990 Grand Canyon emission inventory and a computer spreadsheet model provided by the U.S. Environmental Protection Agency (EPA). The model is based on a wet FGD system and was developed

**Table 1  
Other Point Source Category Groupings**

IAS Scc_id	Source Classification Code	Source Category/Process	1990 SO <sub>2</sub> Emissions (tpy)	Number of Emission Sources	Controls Applicable
<b>Sulfuric Acid Plants</b>					
ptsap1uc	30102301	Contact Absorber (99.9% Conversion)	23,913	10	Increase Acid Conversion Rate or FGD
ptsap2uc	30102306	Contact Absorber (99% Conversion)			
ptsap3uc	30102308	Contact Absorber (98% Conversion)			
ptsap4uc	30102310	Contact Absorber (97% Conversion)			
ptsap5uc	30102318	Contact Absorber (93% Conversion)			
<b>Sulfur Recovery Plants</b>					
ptesc1uc	30103201	Elemental Sulfur Production (Claus: 2 Stage w/o Control (92-95% Removal))	4,336	8	Increase Acid Conversion Rate or FGD
ptesc2uc	30103202	Elemental Sulfur Production (Claus: 3 Stage w/o Control (95-96% Removal))			
ptesc3uc	30103203	Elemental Sulfur Production (Claus: 3 Stage w/o Control (96-97% Removal))			
ptsrmpuc	30103204	Sulfur Removal Process (99.9% Removal)			
ptesnuc	30103299	Elemental Sulfur Production (Not Classified)			
<b>Inorganic Chemical Manufacture</b>					
plincmuc	30199999	Elemental Phosphorous (Stack Emissions)	7,543	1	FGD
	30100509	Carbon Black Production (Furnace Process: Fugitive Emissions)	1,606	1	Capture Hood + FGD
<b>Coke Oven Plants</b>					
ptcokenc	30300315	By-product Coke Manufacturing (Gas By-product Plant)	9,043	2	Vacuum Carbonate
	30300401	Coke Manufacture: Beehive Process			
<b>Process Heaters</b>					
ptprhtuc	31000402	Residual Oil	6,909	15	FGD
	31000403	Crude Oil			
	31000404	Natural Gas			
	31000405	Process Gas			
	31000412	Residual Oil: Steam Generators			
	31000413	Crude Oil: Steam Generators			
<b>Industrial, Commercial, &amp; Institutional Boilers</b>					
ptficubc	10200217	Atmospheric Fluidized Bed Combustion: Bubbling Bed (Bituminous Coal)			
	10200224	Spreader Stoker (Subbituminous Coal)			
	10200225	Traveling Grate (Overfeed) Stoker (Subbituminous Coal)			
	10200229	Cogeneration (Subbituminous Coal)			
	10200303	Cyclone Furnace (Lignite Coal)			
	10200402	10-100 Million British thermal units (Btu)/hour (Residual Oil)			

**Table 1 (continued)**

IAS Scc.id	Source Classification Code	Source Category/Process	1990 SO <sub>2</sub> Emissions (tpy)	Number of Emission Sources	Controls Applicable
	10200403	< 10 Million Btu/hour (Residual Oil)			
	10200404	Grade 5 Residual Oil			
	10200502	10-100 Million Btu/hour (Distillate Oil)			
	10201402	Carbon Monoxide (CO) Boiler (Process Gas)			
	10300206	Pulverized Coal: Dry Bottom (Bituminous Coal)			
	10300207	Bituminous Coal/Overfeed Stoker			
	10300209	Spreader Stoker (Bituminous Coal)			
	10300401	Grade 6 Oil (Residual Oil)			
	10300602	10-100 Million Btu/hour (Natural Gas)	4,114	7	FGD
<b>Primary Metal Production</b>					
ptpmtpic	30300901	Steel Manufacturing (Open Hearth Furnace (Stack))			
	30300908	Steel Manufacturing (Electric Arc Furnace: Carbon Steel (Stack))			
	30301101	Molybdenum (Mining: General)			
	30301199	Molybdenum (Other Not Classified)			
	30301201	Titanium (Chlorination)			
	30399999	Aluminum Ore (Electro-reduction): Prebaked Reduction Cell	3,333	1	Capture Hood with gas stream sent to FGD
<b>Secondary Metal Production</b>					
ptsmtpic	30499999	Other Not Classified	600	1	FGD
	30500606	Cement Manufacturing: Kilns (Dry Process)			
	30500612	Cement Manufacturing: Raw Material Transfer (Dry Process)			
	30500622	Cement Manufacturing: Preheater Kilns (Dry Process)			
	30500706	Cement Manufacturing: Kilns (Wet Process)			
	30500801	Ceramic Clay/Tile Manufacture (Drying)			
	30501037	Coal Mining, Cleaning, and Material Handling (Truck Loading: Overburden)			
	30501401	Glass Manufacture (Furnace/General)			
	30501402	Glass Manufacture (Container Glass: Melting Furnace)			
	30501403	Glass Manufacture (Flat Glass: Melting Furnace)			
	30501410	Glass Manufacture (Raw Material Handling (All Types of Glass))			
	30501602	Lime Manufacture (Secondary Crushing/Screening)			
	30501604	Lime Manufacture (Calcining: Rotary Kiln)			
	30501905	Phosphate Rock (Calcining)			
	30502201	Potash Production (Mine: Grinding/Drying)			
	30502509	Construction Sand and Gravel (Cooler)			
	30599999	Cement Plant (Other Not Defined)	4,602	8	FGD
<b>Sulfate (Kraft) Pulping</b>					

**Table 1 (continued)**

IAS Scc_id	Source Classification Code	Source Category/Process	1990 SO <sub>2</sub> Emissions (tpy)	Number of Emission Sources	Controls Applicable
ptkrftuc	30700104	Recovery Furnace/Direct Contact Evaporator			
	30700106	Lime Kiln			
<b>Refinery Sources</b>					
ptrfnruc	30600101	Process Heaters (Oil-Fired)	2,651	7	FGD
	30600105	Process Heaters (Natural Gas-Fired)			
	30600301	Thermal Catalytic Cracking Units			
	30600402	Blowdown Systems (Without Controls)			
	30600903	Flares (Natural Gas)			
	30601401	Petroleum Coke Calciner			
	30609904	Incinerators (Process Gas)			
<b>Totals for All Source Categories</b>			93,969	119	

**Table 2  
Retrofit Control Options**

<b>scc_id</b>	<b>Description</b>	<b>Control Technology Description</b>	<b>Expected SO<sub>2</sub> Control Efficiency (%)</b>
ptsap1uc	Sulfuric Acid Plants - Contact Absorber (99.9% Conversion)	FGD	90
ptsap2uc	Sulfuric Acid Plants - Contact Absorber (99% Conversion)	Dual adsorption Dual adsorption + FGD	90 99
ptsap3uc	Sulfuric Acid Plants - Contact Absorber (98% Conversion)	Dual adsorption Dual adsorption + FGD	95 99.5
ptsap4uc	Sulfuric Acid Plants - Contact Absorber (97% Conversion)	Dual adsorption Dual adsorption + FGD	96.7 99.67
ptsap5uc	Sulfuric Acid Plants - Contact Absorber (93% Conversion)	Dual adsorption Dual adsorption + FGD	98.6 99.86
ptesc1uc	Sulfur Recovery Plants - Elemental Sulfur (Claus: 2 Stage)	Amine scrubbing Amine scrubbing + FGD	98.4 99.84
ptesc2uc	Sulfur Recovery Plants - Elemental Sulfur (Claus: 3 Stage)	Amine scrubbing Amine scrubbing + FGD	97.8 99.78
ptesc3uc	Sulfur Recovery Plants - Elemental Sulfur (Claus: 3 Stage)	Amine scrubbing Amine scrubbing + FGD	97.1 99.71
ptsrmpuc	Sulfur Recovery Plants - Sulfur Removal Process	FGD	90
ptesncuc	Sulfur Recovery Plants - Elemental Sulfur Production n.c.	FGD	90
ptincmuc	Inorganic Chemical Manufacture	FGD	90
ptcokeuc	Coke Oven Plants	Vacuum carbonate	82
ptprhtuc	Process Heaters (Oil and Gas Production Industry)	FGD	90
ptcibuc	Industrial, Commercial, and Institutional (ICI) Boilers	FGD	90
ptpmtuc	Primary Metal Production	FGD	90
ptsmtuc	Secondary Metal Production	FGD	90
ptnmpuc	Nonmetallic Minerals Processing	FGD	90
ptkrftuc	Sulfate (Kraft) Pulping	FGD	90
ptrfnruc	Refinery Sources	FGD	90

from data presented in a report that analyzed the impacts of SO<sub>2</sub> controls on the electric power generation sector (EPA, 1996). To develop a method for estimating costs for emission sources in the 1990 emission inventory, the spreadsheet model was used to develop capital and operating cost components using the stack gas flow rate and stack gas temperature for emission points in the 1990 emission inventory as the independent variable. The following describes the spreadsheet model and then describes the equations used to estimate costs for emission sources.

In this report, all costs are expressed in 1990 dollars unless otherwise indicated. Capital costs were updated from these base years by means of the Chemical Engineering Cost Index. Operating costs were updated using the Producer Price Index.

## **1. FGD Scrubber Spreadsheet Cost Model**

Table 3 presents an illustration of the spreadsheet model. The key input parameters used as variables in the model include stack gas flow rate and temperature entering the scrubber, and annual operating time. SO<sub>2</sub> emission reductions are estimated as 95 percent of the uncontrolled emissions reported for each emission source (EPA, 1996).

The inputs for capital, fixed operation and maintenance (O&M), and variable O&M costs are used as constants in the model. These constants are based on data for FGD scrubber cost assumptions for utility boilers with a 3 percent coal sulfur content (EPA, 1996). The assumptions apply to capacities at or above 500 megawatts (MW) [approximately 1,000,000 actual cubic feet per minute (acfm)]. For smaller sizes, the costs are scaled down using the standard 0.6 power law. Thus, at lower capacities, capital costs [in dollars per kilowatt (\$/kW) or \$/acfm] are proportionately higher. In the spreadsheet model, costs are scaled down using the 0.6 power law if the gas flow rate is less than 1,028,000 acfm. A gas flow rate factor of 0.486 is used to convert costs from \$/kW to \$/acfm. This factor was derived from data in the Integrated Air Pollution Control System (IAPCS) model (version 5). For existing emission sources, a retrofit factor of 1.1 is applied to the capital costs. The FGD scrubber cost assumptions are in 1995 dollars. Capital and annual costs are de-escalated to 1990 dollars using the ratio of Chemical Engineering Annual Plant Cost Indexes for 1990 and 1995.

## **2. Sulfuric Acid Plants**

Technology for SO<sub>2</sub> emissions control from sulfuric acid plants is well established. The dual absorption process is operating successfully at many U.S. facilities. In addition, several desulfurization processes apply to tail gases from a sulfuric acid plant. Using a dual absorption process, a plant can convert 99.7 to 99.8 percent of the SO<sub>2</sub> produced to sulfur trioxide (SO<sub>3</sub>). The dual absorption process has proved to be the SO<sub>2</sub> control system of choice for the sulfuric acid industry since the promulgation of the New Source Performance Standards (NSPS).

**Table 3**  
**Illustration of FGD Scrubber Cost Spreadsheet Model**

<b>Model Inputs</b>		
-- Gas flow rate at FGD scrubber inlet [standard cubic feet per minute (scfm)] <sup>1</sup>	500,000	Variable
-- Gas temperature at FGD scrubber inlet (°F) <sup>1</sup>	400	Variable
-- SO <sub>2</sub> concentration at FGD scrubber inlet (vol. %)	1.0	Variable
-- Capital cost (1995 \$/kW) <sup>2</sup>	192	Constant
-- Fixed O&M cost (1995 \$/kW-year) <sup>2</sup>	6.9	Constant
-- Variable O&M cost (1995 \$/kWh) <sup>2</sup>	0.0015	Constant
-- Flow Rate factor (kW/acfm) <sup>3</sup>	0.486	Constant
-- FGD scrubber operating time (hour/year) <sup>1</sup>	8,736	Variable
-- FGD scrubber control efficiency (%) <sup>2</sup>	90	Constant
-- FGD scrubber useful life (year)	15	Constant
-- Interest (discount) rate (fraction)	0.07	Constant
-- Retrofit factor <sup>2</sup>	1.10	Constant
-- De-escalation factor <sup>4</sup>	0.9383	Constant
<b>Model Outputs</b>		
-- Gas flow rate at FGD inlet (acfm)	811,321	
-- SO <sub>2</sub> inlet rate (tons/year)	124,063	
-- Capital cost (1995 \$/acfm) <sup>5</sup>	107.6	
-- Fixed O&M cost (1995 \$/acfm-year)	3.35	
-- Variable O&M cost (1995 \$/acfm-hour)	0.000729	
-- Capital cost-retrofit (1995 \$) <sup>6</sup>	96,028,000	
-- Capital cost-retrofit (1990 \$) <sup>6</sup>	90,103,000	
-- Fixed O&M cost (1995 \$/year) <sup>6</sup>	2,718,000	
-- Variable O&M cost (1995 \$/year) <sup>6</sup>	2,957,000	
-- Capital recovery factor	0.1098	
-- Capital recovery cost (1995 \$/year) <sup>6</sup>	10,544,000	
-- Total annual cost (1995 \$/year) <sup>6</sup>	16,219,000	
-- Total annual cost (1990 \$/year) <sup>6</sup>	15,218,000	
-- Cost effectiveness (1995 \$/ton)	140	
-- Cost effectiveness (1990 \$/ton)	130	

NOTES: <sup>1</sup>Emission point-specific input value obtained from the National Particulates Inventory (NPI). Note that the gas flow rate in the NPI is reported in units of acfm. The NPI values were converted to scfm for the model.

<sup>2</sup>These costs are for the high sulfur (3 percent) case in the report. They apply to capacities at or above 500 MW (approximately 1,000,000 acfm). For smaller sizes, report suggests scaling down costs via the standard 0.6 power law. Thus, at lower capacities the capital cost (in \$/kW or \$/acfm) will be higher (EPA, 1996).

<sup>3</sup>Factor derived from data in IAPCS model (version 5).

<sup>4</sup>Ratio of Chemical Engineering Plant Indexes (annual) for 1990 and 1995, respectively (357.6/381.1). Ratio used for both capital and annual costs.

<sup>5</sup>If flow rate < 1,028,000 acfm, cost is scaled down via 0.6 power law.

<sup>6</sup>Values are rounded to \$1,000.

Cost equations for dual absorption (EPA, 1985):

$$\bar{P} \quad \text{lb} = \$9,000 + \$9.8 * \bar{W} \quad \text{lb} \quad (i \quad f^3 / \text{in}^3)$$

$$\bar{P} \quad \text{lb} = \$5,000 + \$2.8 * \bar{W} \quad \text{lb} \quad (i \quad f^3 / \text{in}^3)$$

### 3. Coke Ovens

The coke-oven gases produced by the controlled pyrolysis of coal contain reduced sulfur compounds, in addition to numerous hydrocarbons. About 25 to 30 percent of the sulfur in the coal is emitted in gaseous form as a constituent of the coke oven gas. Almost all of this sulfur is present as hydrogen sulfide (H<sub>2</sub>S), with minor amounts of mercaptans. Using the coke oven gas to heat or underfire the coke ovens, or as fuel for other combustion operations, results in SO<sub>2</sub> emissions unless the H<sub>2</sub>S is removed.

Several processes are suitable for removing H<sub>2</sub>S from coke oven gases. In the vacuum carbonate process, H<sub>2</sub>S is absorbed into a 3.0 to 3.5 percent solution of sodium carbonate. The H<sub>2</sub>S is then stripped by steam from the absorbent in a reactivating tower. The reactivation is performed under vacuum to reduce the quantity of steam required. Conventional systems achieve about 90 percent removal.

Cost equations for vacuum carbonate (EPA, 1986):

$$\bar{P} \quad \text{lb} = \$3,400 + \$5.8 * \bar{W} \quad \text{lb} \quad (f^3 \quad \text{p} \quad \text{in}^3)$$

$$\bar{P} \quad \text{lb} = \$9,000 + \$8.5 * \bar{W} \quad \text{lb} \quad (f^3 \quad \text{p} \quad \text{in}^3)$$

### 4. Sulfur Recovery Plants

Refinery sour gas streams are generally fed to a regenerative type of H<sub>2</sub>S removal process. The concentrated acid gas is then sent to the sulfur recovery unit. The Claus process is the most widely used method of producing sulfur from refinery H<sub>2</sub>S. The modified Claus process is based on producing elemental sulfur by first converting one-third of the H<sub>2</sub>S feed by precise combustion with air. The combustion products are then allowed to react thermally with the remaining two-thirds of the H<sub>2</sub>S feed in the presence of a suitable catalyst to form sulfur vapor.

Cost equations for amine scrubbing:

$$\bar{P} \quad \text{lb} = \$2,800 + \$4.7 * \bar{W} \quad \text{lb} \quad (f^3 \quad \text{p} \quad \text{in}^3)$$

$$\bar{P} \quad \text{lb} = \$9,000 + \$8.0 * \bar{W} \quad \text{lb} \quad (f^3 \quad \text{p} \quad \text{in}^3)$$

### 5. Fuel Switching

One of the potential control strategies investigated was fuel switching to either a lower sulfur content fuel of the same type, or to natural gas. The most important of these options is the switch to natural gas, because natural gas essentially has no associated sulfur emissions. While fuel price projections are available that can be used to estimate the operating cost difference associated with a fuel change, the capital costs of

constructing a natural gas pipeline to a site where one currently does not exist, depend on the distance to the nearest existing pipeline. The present IAS data bases do not include fuel switching as a potential control technique for utilities and other industrial sources because of the difficulty in quantifying pipeline costs.

For this analysis of other point source SO<sub>2</sub> emitters, it was hypothesized that plant sites in urban areas would be able to access natural gas pipelines with modest capital investment. There are a limited number of IAS Regions that only include urban counties. A review of the correspondence between IAS Regions that are predominantly urban, and other point source SO<sub>2</sub> emitters found that most facilities were not in urban areas. Therefore, fuel switching was not included in the analysis as a viable control option.

A current example of the potential significance of gas pipeline costs is the situation in Coos Bay, Oregon. Nucor Steel is proposing to build a steel plant at an industrial site in the area, but the firm has said that it will not locate in Coos Bay unless the area pays for a gas pipeline to be constructed to the site.

## **B. NEW SOURCE CONTROL TECHNOLOGIES**

Table 4 lists the proposed new technology control techniques and control effectiveness estimates for the source categories (scc\_ids) in this study. This table was developed by examining NSPS as well as Best Available Control Technology (BACT) determinations. In all cases, the listed control technologies and expected control efficiencies are at least as stringent as current NSPS. Expected SO<sub>2</sub> control efficiencies are reductions from uncontrolled emission levels. Technologies listed in this table are those that would be expected to be required by NSPS or BACT analysis in the absence of any new requirements, or regional agreements.

### **1. Sulfuric Acid Plants**

EPA NSPS for new and modified plants is 2 kg/mg (4 pounds per ton) of 100 percent acid produced, maximum 2 hour average. Achieving this standard requires a conversion efficiency of 99.7 percent in an uncontrolled plant, or the equivalent SO<sub>2</sub> collection mechanism in a controlled facility (EPA, 1995). Dual absorption has generally been accepted as the BACT for meeting NSPS emission limits. There are no byproducts or waste scrubbing materials created, only additional sulfuric acid. Conversion efficiencies of 99.7 percent and higher are achievable, whereas most single absorption plants have SO<sub>2</sub> conversion efficiencies ranging only from 95 to 98 percent.

### **2. Sulfur Recovery**

Existing NSPSs limit sulfur emissions from Claus sulfur recovery plants of greater than 22.40 tons per day capacity to 0.025 percent by volume (250 parts per million volume). This limit is effective at zero percent oxygen on a dry basis if emissions are controlled by an oxidation control system, or a reduction control system, followed by incineration. This is comparable to the 99.8 to 99.9 percent control level for reduced sulfur.

**Table 4  
New Technology Specification**

scc_id	Description	Control Technology Description	Expected SO <sub>2</sub> Control Efficiency	Notes
ptsap1uc	Sulfuric Acid Plants - Contact Absorber (99.9% Conversion)	None	0	New plants with acid adsorption of less than 99.7% will not meet the existing NSPS.
ptsap2uc	Sulfuric Acid Plants - Contact Absorber (99% Conversion)	Dual adsorption	70	New plants with acid adsorption of less than 99.7% will not meet the existing NSPS.
ptsap3uc	Sulfuric Acid Plants - Contact Absorber (98% Conversion)	Dual adsorption	85	New plants with acid adsorption of less than 99.7% will not meet the existing NSPS.
ptsap4uc	Sulfuric Acid Plants - Contact Absorber (97% Conversion)	Dual adsorption	90	New plants with acid adsorption of less than 99.7% will not meet the existing NSPS.
ptsap5uc	Sulfuric Acid Plants - Contact Absorber (93% Conversion)	Dual adsorption	98.5	New plants with acid adsorption of less than 99.7% will not meet the existing NSPS.
ptesc1uc	Sulfur Recovery Plants - Elemental Sulfur (Claus: 2 Stage)	Amine scrubbing	98.4	New plants must have SO <sub>2</sub> removal efficiencies of 99% to meet standards.
ptesc2uc	Sulfur Recovery Plants - Elemental Sulfur (Claus: 3 Stage)	Amine scrubbing	97.8	New plants must have SO <sub>2</sub> removal efficiencies of 99% to meet standards.
ptesc3uc	Sulfur Recovery Plants - Elemental Sulfur (Claus: 3 Stage)	Amine scrubbing	97.1	New plants must have SO <sub>2</sub> removal efficiencies of 99% to meet standards.
ptsrmpuc	Sulfur Recovery Plants - Sulfur Removal Process	None	0	New plants must have SO <sub>2</sub> removal efficiencies of 99% to meet standards.
ptescncuc	Sulfur Recovery Plants - Elemental Sulfur Production n.c.	None	0	Although it seems unlikely that new plants like these will be built again, any BACT review will probably require FGD or equivalent removal.
ptincmuc	Inorganic Chemical Manufacture	FGD	90	Coke oven gas desulfurization is a likely candidate for BACT.
ptcokeuc	Coke Oven Plants	Gas desulfurization	82	FGD applicability is based on the probability that a BACT review under prevention of significant deterioration (PSD) will consider control of process heaters to be similar to that for boilers and require technology which will reduce SO <sub>2</sub> emissions by about 90%.
ptprhtuc	Process Heaters (Oil and Gas Production Industry)	FGD	90	Control of boilers will be FGD for both NSPS as well as BACT.
pticibuc	ICI Boilers	FGD	90	Both control of sulfur before or after combustion is feasible and will be required assuming that new operations like these are built.
ptipmtuc	Primary Metal Production	FGD	90	--
ptsmtpuc	Secondary Metal Production	None	0	--
ptinmmpuc	Nonmetallic Minerals Processing	None	0	--
ptkfrtuc	Sulfate (Kraft) Pulping	FGD	90	Process heaters in the refineries will be judged in the same manner as boilers and other process heaters and control by FGD will be BACT.
ptifrnuc	Refinery Sources	FGD	90	Other refinery sources like blowdown systems, petroleum coke, incinerators, and flares will probably not be required to be controlled.

Emissions from the Claus process may be reduced by: (1) extending the Claus reaction into a lower temperature liquid phase; (2) adding a scrubbing process to the Claus exhaust stream; or (3) incinerating the H<sub>2</sub>S gases to form SO<sub>2</sub>.

### 3. Boilers and Process Heaters

Table 4 lists FGD as the expected new source technology requirement for SO<sub>2</sub> control for ICI boilers, refinery process heaters, and other general process heaters. For boilers, this assumption is consistent with what is being applied to the new coal-fired industrial boilers that are already included in an IAS source category (scc\_id). Because the scc\_ids that were developed for other point sources for boilers and heaters include all fuel types, assuming FGD at a 90 percent SO<sub>2</sub> reduction as the new source technology may over estimate the SO<sub>2</sub> reduction associated with new source technology for these source categories. *California addresses boiler and process heater control by limiting the fuel sulfur to a value that essentially restricts sources to using natural gas, or removing the sulfur from the fuel before combustion. For instance, the South Coast Air Quality Management Division Rule 431.1 limits the sulfur in refinery gas to 40 parts per million by volume. Liquid fuel is limited to a sulfur content of 0.05 percent, and solid fossil fuels are limited to no more than 0.56 pounds of SO<sub>2</sub> per million Btu.* There are two options for examining the sensitivity of the IAS baseline forecast to these new source technology assumptions:

1. Change the new source technology control for ICI boilers, and the two categories of process heaters to no control and run an IAS baseline simulation to 2040.
2. Break each of the applicable assigned scc\_ids into two scc\_ids, with the fuel types, such as coal and oil, where FGD is most likely to be required in one scc\_id, and the gaseous fuels in another. Then, FGD would be an appropriate new source control technology for the coal- and oil-fired units (and perhaps process gas-fired units), while the gaseous fuels would have their new source technology be the same as the existing source technology.

## C. GROWTH AND RETIREMENT RATES

### 1. Retirement Rates

Because technologies continue to evolve, it is important to reflect the potential for reductions in future emissions from the adoption of lower-emitting processes/equipment. There are two available sources of information that can be used in estimating the rate of the adoption of new technologies. These sources have estimated and applied annual equipment turnover rates in projecting fuel consumption (U.S. Department of Energy [DOE]) and in estimating historical capital stocks data (Bureau of Economic Analysis [BEA]). DOE has estimated annual retirement rates in estimating the amount of future industry output that will be produced using new equipment (*Industrial Sector Demand Module of the National Energy Modeling System*, January 1998). BEA has estimated service lives of plant and equipment in developing its capital stock series ("Improved Estimates of Fixed Reproducible Tangible Wealth, 1929-95," *Survey of Current Business*, May 1997).

The emission projections developed for the GCVTC employed an earlier set of DOE annual retirement rates in estimating reduced emissions in future years ("Development of Emission Control and New Technology Options for the Grand Canyon Visibility Transport Region, Volume I, Technology Costs, Performance, and Applicability," Argonne National Laboratory, October 1995). In addition, the GCVTC analysis employed an average turnover rate for fuel combustion sources based on estimates developed for industrial boilers for the National Acid Precipitation Assessment Program (NAPAP). While the new National Energy Modeling System (NEMS) retirement rate estimates are available, it was decided to use the retirement rates developed for the original IAS model in order to employ a consistent approach for simulating source retirement. Table 5 displays the annual retirement rate allocation to source categories.

## 2. Growth Rates

Appropriate growth rates for each new source category (scc\_id) being added to IAS were determined by matching the new scc\_ids with a Regional Economics Model, Inc. (REMI) growth sector (or set of growth sectors). This allocation is shown in Table 5.

### D. DATA BASE ISSUES

There were a number of situations where the information in the 1990 emission inventory to be used in the cost analysis had to be further evaluated where information was incomplete, or included questionable information. These investigations are summarized below for each facility where additional information was gathered.

1. Plant Name: Monsanto  
Facility Identifier: 160290001  
Source Classification Code: 30199999  
SO<sub>2</sub> emissions: 7,543 tons per year

This facility is now owned by P-4 Production, which is a joint venture of Monsanto and Solutia, Inc. The Idaho Department of Health and Welfare, Division of Environmental Quality was contacted by Pechan-Avanti to obtain more information about the SO<sub>2</sub> emitting processes at this facility (because the SCC listed in the 1990 emission inventory was too general to identify the process). This facility produces elemental phosphorus (one of two facilities in the U.S. that does). The air permit for P-4 Production was requested from the Idaho Division of Environmental Quality (and received January 22, 1999) (Casile, 1999). This revealed that the sulfur emitting process is a calcining type process (not fuel sulfur), and that FGD is an appropriate control technique.

2. Plant Name: Unknown Oregon source  
Facility Identifier: 41511851  
Source Classification Code: 30399999  
SO<sub>2</sub> emissions: 3,333 tons per year

Brian Fields of the Oregon DEQ indicated that this facility is Reynolds Metals. He suggested that the most appropriate SCC for this facility/process is 30300101. The process was indicated to be a primary collection system for an aluminum reduction process. There is residual sulfur in the reduction cells from the baking process.

**Table 5**  
**Other Point Source Retirement and Growth Factor Assignments**

<b>scc_id</b>	<b>Description</b>	<b>Retirement Rate (%)</b>	<b>REMI Sector Growth Indicator</b>
ptsap1uc	Sulfuric Acid Plants - Contact Absorber (99.9% Conversion)	1.9	18
ptsap2uc	Sulfuric Acid Plants - Contact Absorber (99% Conversion)	1.9	18
ptsap3uc	Sulfuric Acid Plants - Contact Absorber (98% Conversion)	1.9	18
ptsap4uc	Sulfuric Acid Plants - Contact Absorber (97% Conversion)	1.9	18
ptsap5uc	Sulfuric Acid Plants - Contact Absorber (93% Conversion)	1.9	18
ptesc1uc	Sulfur Recovery Plants - Elemental Sulfur (Claus: 2 Stage)	1.9	18
ptesc2uc	Sulfur Recovery Plants - Elemental Sulfur (Claus: 3 Stage)	1.9	18
ptesc3uc	Sulfur Recovery Plants - Elemental Sulfur (Claus: 3 Stage)	1.9	18
ptsrmpuc	Sulfur Recovery Plants - Sulfur Removal Process	1.9	18
ptesncuc	Sulfur Recovery Plants - Elemental Sulfur Production n.c.	1.9	18
ptincmuc	Inorganic Chemical Manufacture	1.9	18
ptcokeuc	Coke Oven Plants	1.9	4
ptprhtuc	Process Heaters (Oil and Gas Production Industry)	2.3	22
pticibuc	ICI Boilers	0.62	54
ptpmpuc	Primary Metal Production	1.2	4
ptsmpuc	Secondary Metal Production	1.2	4
ptnmmpuc	Nonmetallic Minerals Processing	1.2	3
ptkrftuc	Sulfate (Kraft) Pulping	1.9	16
ptrfnruc	Refinery Sources	1.9	19

3. Plant Name: Unknown Oregon Source  
Facility Identifier: 413992125  
Source Classification Code: 30499999  
SO<sub>2</sub> emissions: 600 tons per year

Brian Fields of the Oregon DEQ indicated that this facility is Globe Metallurgical. Tom Freeman at the Lane Regional Air Pollution Authority indicated that Globe Metallurgical is a primary silicon smelter. The sulfur is from coal that is used in this process. Actual SO<sub>2</sub> emissions are about 20 tons per month. They have one furnace now, and have recently received a PSD permit to construct another furnace. The PSD source has no planned SO<sub>2</sub> control, just particulate matter (but it has not been built yet).

4. Plant Name: Chemical Lime Company–Nelson Plant  
Facility Identifier: 04250011  
Source Classification Code: 30500601  
SO<sub>2</sub> emissions: 141 tons per year

Wayne Hunt of the Northern regional office of Arizona AQD, Compliance indicated that there are no control devices explicitly for SO<sub>2</sub> at CLC Nelson. The 1990 data base was changed to reflect this.

## **E. UNCERTAINTIES**

Control cost estimates provided to the WRAP via this Task 2.2 analysis are probably the most uncertain part of the analysis. For the retrofit control techniques that are applicable to the other point source category SO<sub>2</sub> sources, the cost modeling uses the stack gas flow rate (and sometimes the gas temperature) as the primary indicator of the expected control cost. Therefore, the accuracy of the control cost estimates are directly related to the accuracy of the flow rate values in the 1990 GCVTC inventory. Some of the flow rates in the 1990 GCVTC inventory appear to be default values designed to satisfy the minimum requirements for a plume rise calculation. In these situations, where flow rates were outside the reasonable range for a source type, default flow rates and temperatures were developed and used in the cost calculations. As a result, there is considerable uncertainty in the control cost estimates for individual IAS cells.

There are some SCCs in the other point source data base that are indicated as SO<sub>2</sub> emitters in the 1990 inventory, but represent processes that do not normally emit SO<sub>2</sub>. These sources have been included in IAS as controllable SO<sub>2</sub> sources with the understanding that the SO<sub>2</sub> is being emitted, but by another similar process at this facility. Source misclassifications make both the baseline forecast and management scenarios uncertain.

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