

CHAPTER III

AIR IMPACT

In the past few years, Maryland's power plants (Figure III-1) have been affected by changes in the economic environment, as evidenced by an increased use of coal as a fuel source. The air quality impact of coal, as well as changes in the regulatory environment, advances in pollution control, and other relevant matters are discussed in this chapter. Trends shown by emissions and air quality data are presented, as is a discussion of the predictive value of modeling in assessing air quality impact. Finally, the possible relationship between power plants and "acid rain" is discussed, as well as research in this and other key areas.

A. Emissions

The 1977 Clean Air Act Amendments required "comprehensive, current, and accurate" inventories of actual emissions in order to quantify progress in the emissions reductions needed to reach the National Ambient Air Quality Standards (NAAQS) before deadline dates(1). This requirement stressed the importance of using accurate emissions data in the assessment of the effects of specific sources on total air quality.

Thus, the study of reported emissions data is an important component in an assessment of the impact of power plants on total air quality. The total statewide emissions inventories for the years 1975-1981 (the most recent data available) are presented in Table III-1. The inventory includes data for the following major sources: power generation, industrial processes, domestic and space heating, refuse incineration and mobile sources (where available). Of total 1979 (1979 is the most recent year for which this data is available in final form) statewide emissions (excluding mobile sources) power plants contributed 62 percent of the sulfur oxides, 39 percent of the particulates, 50 percent of the nitrogen oxides, and 3 and 4 percent of total hydrocarbon and carbon monoxide emissions, respectively. Of total 1979 statewide emissions including mobile sources, power plants contributed 56 percent of the sulfur oxides, 30 percent of the particulates, 23 percent of the nitrogen oxides, and less than 1 percent of both total hydrocarbon and carbon monoxide emissions.

Sulfur oxide emissions depend on the sulfur content of the fuel that is burned. During combustion, sulfur in coal and oil is almost completely converted to sulfur oxides and emitted through the stack. The nitrogen oxide emissions depend mainly on detailed factors relating to the combustion equipment, such as flame temperature, amount of excess oxygen, and gas residence time in the flame area. The amount of particulates emitted

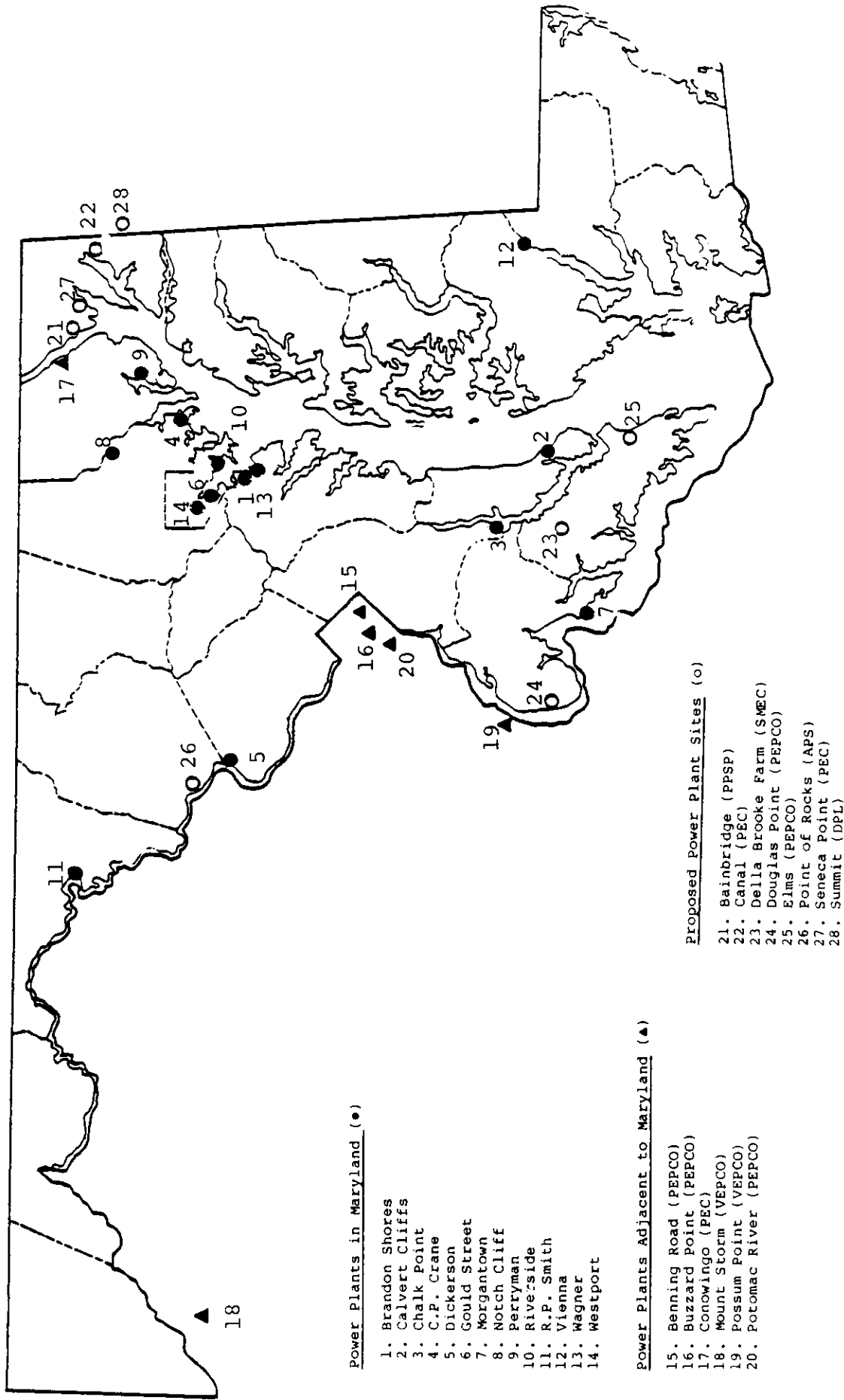


Figure III-1. Locations and generating capacities of major power plants within or adjacent to Maryland

Gross Summer Megawatt Generating Capacity of Public
Utility Power Plants in Maryland

Plant Name	Utility	Steam	Gas Turbine	Fuel of Steam Unit
1. Brandon Shores ^(a)	BG&E	(under construction)		coal
2. Calvert Cliffs	BG&E	1650	--	nuclear
3. Chalk Point ^(b)	PEPCO	1990	48	coal/oil
4. C.P. Crane ^(c)	BG&E	384	14	coal/RDF
5. Dickerson ^(d)	PEPCO	547	13	coal
6. Gould Street	BG&E	103		oil
7. Morgantown	PEPCO	1112	248	coal
8. Notch Cliff	BG&E		128	
9. Perryman ^(e)	BG&E		204	
10. Riverside	BG&E	321	172	oil
11. R.P. Smith ^(f)	PE	127		coal
12. Vienna ^(g)	DP&L	150	17	oil
13. Wagner ^(h)	BG&E	988	14	coal/oil
14. Westport ⁽ⁱ⁾	BG&E	177	118	oil

- (a) Unit 1 (620MW) is scheduled to begin operation in mid-1984. Unit 2 (620MW) is scheduled to begin operation in late-1988.
- (b) Unit 1 (355 MW) and Unit 2 (355 MW) are coal fired. Unit 3 (640MW) and Unit 4 (640MW) are oil fired.
- (c) Conversion from oil to coal completed in 1983. Unit 1 is also burning Refuse Derived Fuel (RDF).
- (d) Proposed addition of Unit 4 (300MW, coal) in 1995.
- (e) Site being considered for a 600-800MW coal fired plant in late 1990's.
- (f) Capability is 129 MW, however, plant is presently operating with a 12 MW derating for air quality compliance.
- (g) Only unit 8 is presently operating. 500 MW coal plant planned for 1995.
- (h) Units 1, 2 and 4 are oil fired. Unit 3 (319 MW) is coal fired.
- (i) Units 1 (19MW), 13 (16MW) and 14 (16MW) are scheduled to be retired in 1984. Unit 3 (58MW) is scheduled to be retired in 1987. Unit 4 (68MW) is scheduled to be retired in 1992.

Figure III-I (continued)

Table III-1. Statewide Total Emissions Inventory for the Five Major Source Categories for 1975-1981(a)

	Total Emissions Reported (tons/year) (b)						
	1975	1976	1977(c)	1978(c)	1979	1980(c)	1981(c)
<u>Particulates</u>							
Including mobile sources(d)	85,000	73,500	—(e)	—	107,300	—	83,800
Excluding mobile sources	66,400	55,400	76,100	67,200	83,000	57,500	60,000
Power Plant % of total (excluding mobile sources)	41	38	53	47	39	45	15
<u>Sulfur Oxides</u>							
Including mobile sources	409,800	318,700	—	—	341,800	—	405,100
Excluding mobile sources	383,300	274,100	390,200	308,300	312,400	344,200	375,100
Power Plant % of total (excluding mobile sources)	74	66	81	74	62	87	75
<u>Hydrocarbons</u>							
Including mobile sources(f)	311,600	263,300	—	—	280,900	—	294,800
Excluding mobile sources	76,200	56,100	52,700	74,300	42,400	58,600	74,700
Power Plant % of total (excluding mobile sources)	4	3	3	3	3	2	2
<u>Nitrogen Oxides</u>							
Including mobile sources	359,000	288,200	—	—	328,100	—	358,400
Excluding mobile sources	169,700	138,900	273,700	177,700	150,500	258,000	196,600
Power Plant % of total (excluding mobile sources)	62	54	84	76	50	55	61
<u>Carbon Monoxide</u>							
Including mobile sources	1,910,200	1,577,000	—	—	1,603,900	—	1,307,200
Excluding mobile sources	107,400	130,700	99,300	100,400	125,300	74,500	63,200
Power Plant % of total (excluding mobile sources)	4	3	6	8	4	6	8

(a) Emissions data obtained from estimates of indicators such as fuel consumption, production rates, control efficiency and vehicle miles traveled. Average emission factors, which relate these indicators to emission rates for specific source categories, are used to derive total emissions. (From Refs. 3-8)

(b) Does not include miscellaneous source categories.

(c) Preliminary data.

(d) These are "man-made" particulate emissions. Particulate "emissions" due to natural causes, e.g., wind-blown dust and pollen, vary widely with place and time and can exceed man-made emissions by an order of magnitude.

(e) Data for mobile sources not available.

(f) In addition, about 150,000 tons per year is released from asphalt roads in the State. This quantity can be reduced to 20,000 to 25,000 tons per year by current use of a different type of road tar. Emission from an asphalt-surfaced road decreases significantly over a period of 1 to 2 years.

depends mostly on the ash content of the fuel. Of various fossil fuels used to fire power plants, gas is the cleanest, producing very small particulate emissions relative to oil or coal. The amount of particulates resulting from oil-fired power generation depends on the type of oil burned, e.g., #6 heavy residual oil produces greater particulate emissions than #2 diesel oil. Coal combustion produces very large amounts of particulate emissions. However, at most major installations, electrostatic precipitators and other pollution control equipment reduce particulate emissions from coal firing to a level comparable to those from oil. All major utility generating facilities in Maryland use such pollution control equipment.

For the period 1975 to 1981 (the most recent data available), reported emissions of these major power plant pollutants fluctuated, showing no clear trend. (Table III-1, Figure III-2).

B. Air Quality

Trends in ambient air quality are determined from analyses of ground-level concentrations measured at air quality monitoring stations distributed throughout the State. However, the data must be used with care. Because station distribution is not uniform, the reported ground-level concentrations may not be representative of the general air quality for all communities in the State. Furthermore, many stations have been moved and the measurement methods have changed over the years. Therefore, selecting stations with sufficient continuous data records to establish long-term trends is sometimes difficult and annual data may not be directly comparable.

With these limitations in mind, air quality data for predominant power plant pollutants, i.e., particulates, sulfur dioxide, and nitrogen oxides, are presented.

Total Suspended Particulates (TSP)

All areas of Maryland¹ are currently in compliance with the National Ambient Air Quality Standards (NAAQS) for TSP presented in Table III-2, ($75\mu\text{g}/\text{m}^3$) except for portions of the Metropolitan Baltimore Intrastate Air Quality Control Region (AQCR), which are designated nonattainment areas in Figure III-3(10). However, the EPA has recently listed the Baltimore AQCR with those that will probably be able to demonstrate that they had met the standards by 31 December 1982(12).

¹An area around Luke in Western Maryland has been designated as "cannot be classified" by EPA. This means that additional data must be obtained before compliance can be determined.

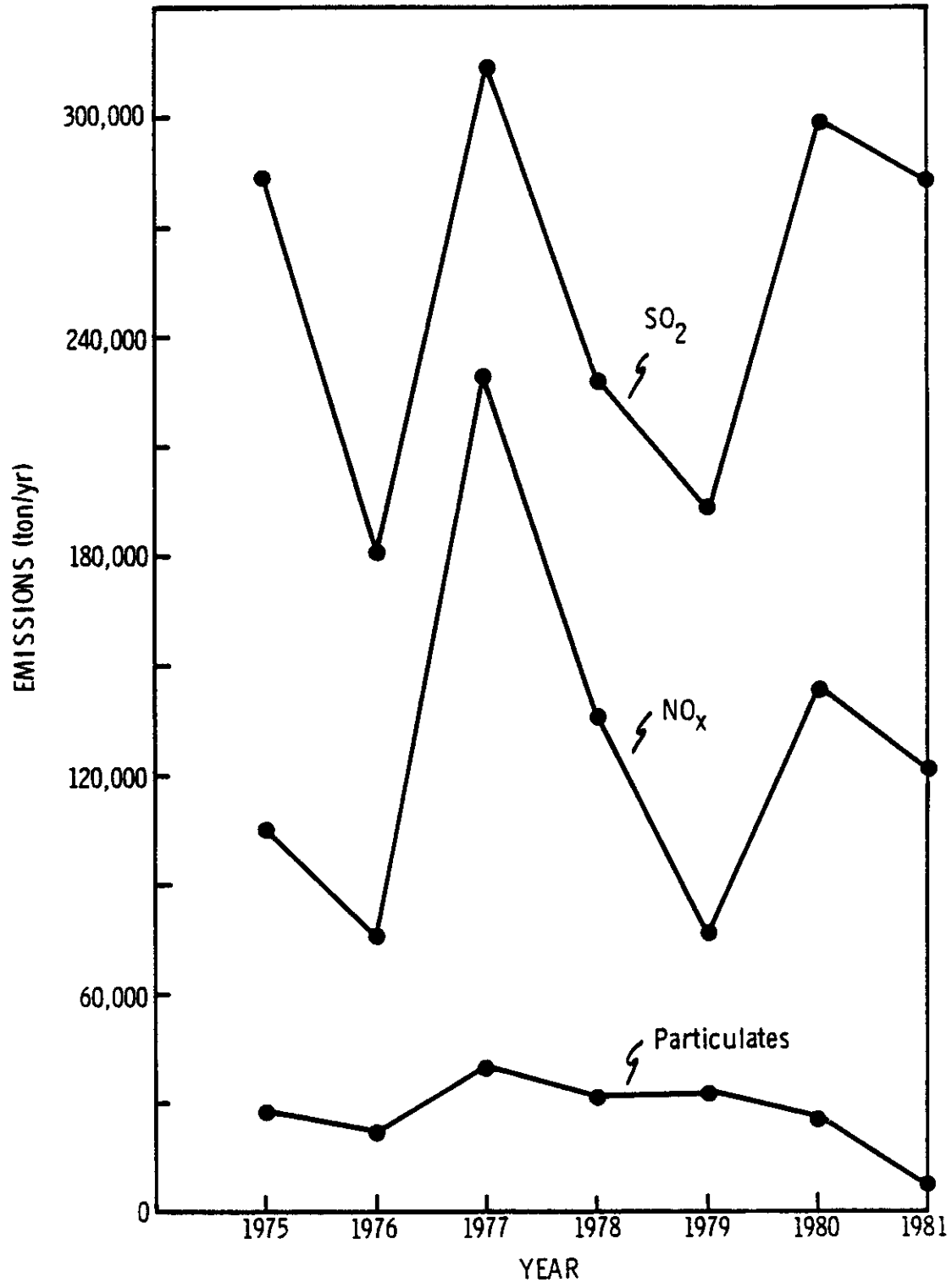


Figure III-2. Reported emissions of major power plant pollutants (data from Ref. 2). Date for 1977, 1978, 1980 and 1981 are preliminary.

Table III-2. Ambient Air Quality Standards

	Primary	Secondary
<u>Sulfur Oxides</u>		
Annual arithmetic mean, $\mu\text{g}/\text{m}^3$	80 (0.03 ppm)	
24-hour average ^(a) , $\mu\text{g}/\text{m}^3$	365 (0.14 ppm)	
3-hour average ^(a) , $\mu\text{g}/\text{m}^3$		1,300
<u>Suspended Particulate Matter</u>		
Annual geometric mean, $\mu\text{g}/\text{m}^3$	75	60 ^(b)
24-hour average ^(a) , $\mu\text{g}/\text{m}^3$	260	150
<u>Lead</u>		
Three-month average, $\mu\text{g}/\text{m}^3$	1.5	(c)
<u>Carbon Monoxide</u>		
8-hour average ^(a) , mg/m^3	10 (9 ppm)	(c)
1-hour average ^(a) , mg/m^3	40 (35 ppm)	(c)
<u>Nitrogen Dioxide</u>		
Annual arithmetic mean, $\mu\text{g}/\text{m}^3$	100 (0.05 ppm)	(c)
<u>Ozone</u>		
1-hour average ^(d) , $\mu\text{g}/\text{m}^3$	235 (0.12 ppm)	(c)

Data from Reference 9.

(a) Not to be exceeded more than once per year

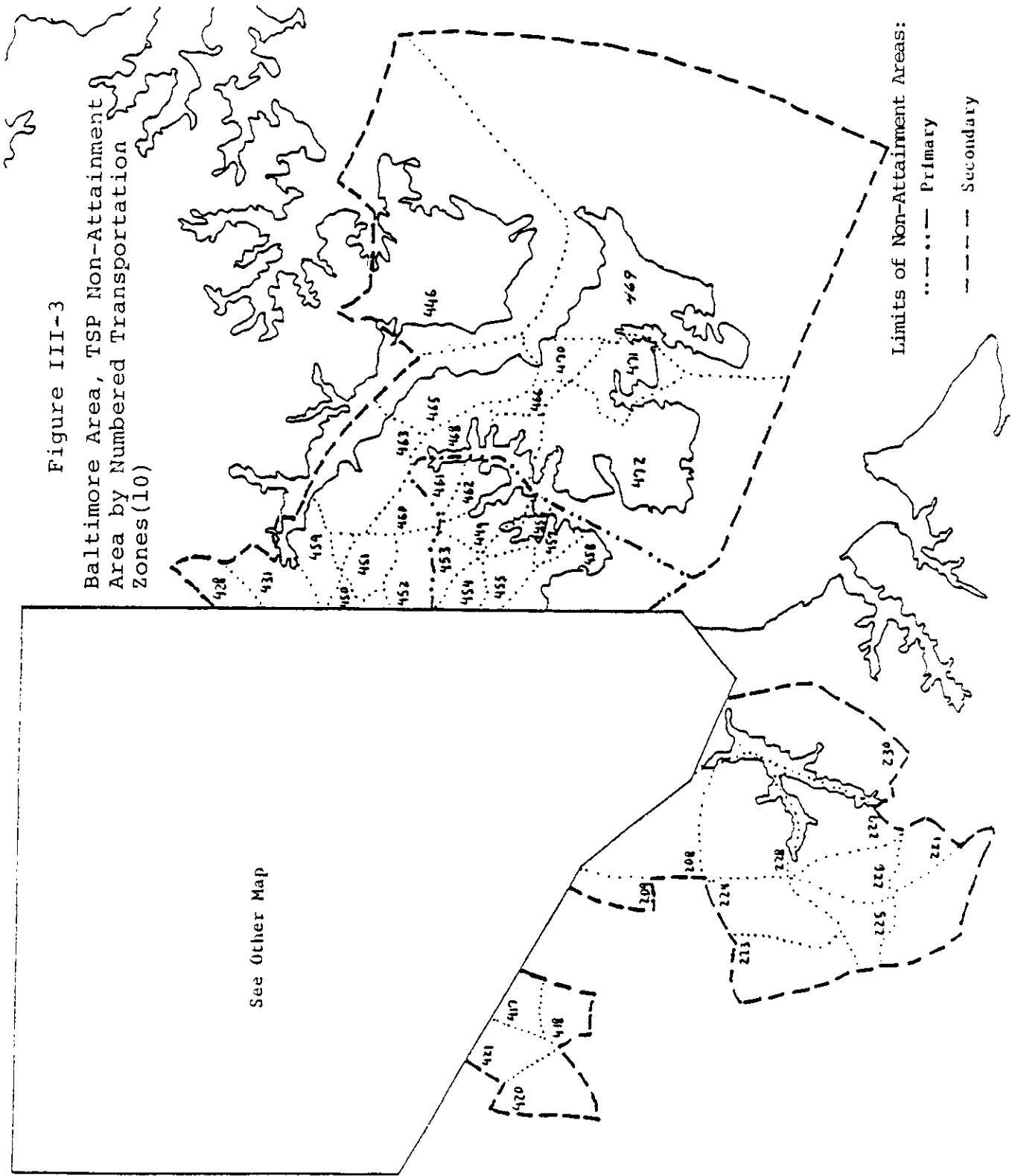
(b) Guideline

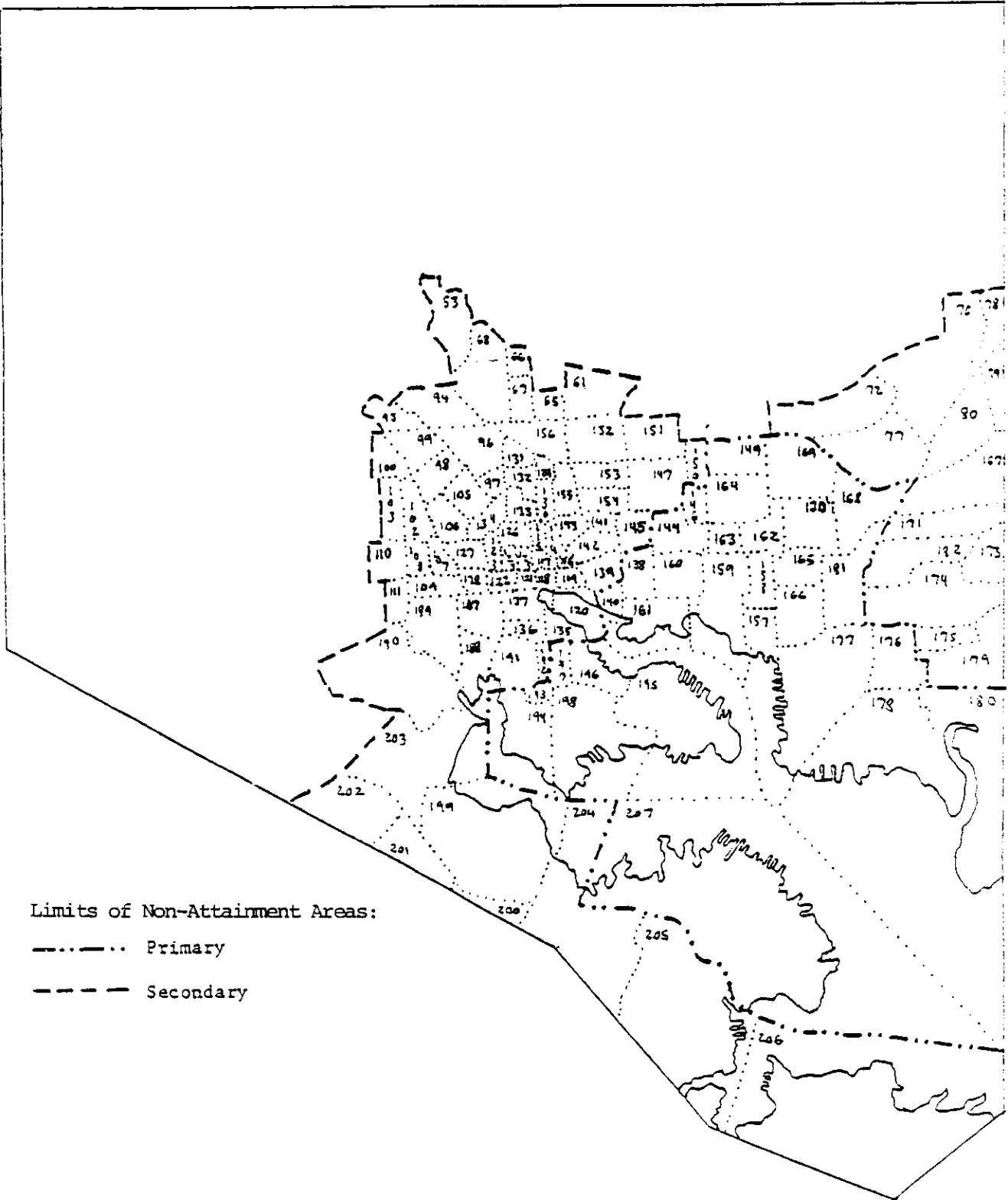
(c) Not established or same as primary

(d) Number of exceedances must not be greater than one per year, as averaged over the most current three years

Figure III-3

Baltimore Area, TSP Non-Attainment Area by Numbered Transportation Zones (10)





Limits of Non-Attainment Areas:

- Primary
- Secondary

Figure III-3. Continued

Mean annual average TSP ground-level concentrations for stations in Maryland with sufficient data to report have remained below the $60\mu\text{g}/\text{m}^3$ guideline (an aid toward achievement of the 24 hour secondary standard) for the past 10 years (see Figure III-4). To identify possible trends, stations from which data were available for the entire period were segregated (see Figure III-5 for station locations). The mean annual average TSP ground-level concentrations for these 15 stations have fluctuated about the $60\mu\text{g}/\text{m}^3$ guideline. However, the average concentration for the entire 10-year period, $56.2\mu\text{g}/\text{m}^3$, is below the guideline (see Figure III-6).

Sulfur Dioxide (SO_2)

The entire State of Maryland is in compliance with the NAAQS for sulfur dioxide(11). Observed annual average ground-level concentrations show a recent increase, but for the past 10 years have consistently been under the $80\mu\text{g}/\text{m}^3$ standard (see Figure III-7).¹

Nitrogen Oxides

All of Maryland is in compliance with the NAAQS for nitrogen oxides.(11) Figure III-8 shows that for the eight-year period, 1974-1981, the observed annual average ground-level concentration remained relatively constant at approximately $40\mu\text{g}/\text{m}^3$.

C. Modeling

For existing sources, monitoring of actual ground-level concentrations generally is the preferred method for estimating air quality impacts. However, due to inherent limitations in the spatial coverage of air quality measurements as well as the high cost involved, observed data alone normally cannot be used to estimate the maximum impact. Air quality models provide another indication of the impact of the existing sources, and can be used to identify maximally impacted areas as an aid in siting monitors. Models are also necessary to predict the air quality impact from sources which do not yet exist (e.g., proposed power plants) or from modifications to existing plants (e.g., fuel switching from oil to coal, plant expansions).

¹It is possible that the increased annual average ground-level concentrations in 1980-1981 may be due to one or more of the following: a) a change in measurement techniques (from flame photometry to continuous or pulsed fluorescence); b) changes in the number of stations contributing to the average; c) changes in the locations of these stations (i.e., from outlying areas to Baltimore City and Anne Arundel County).

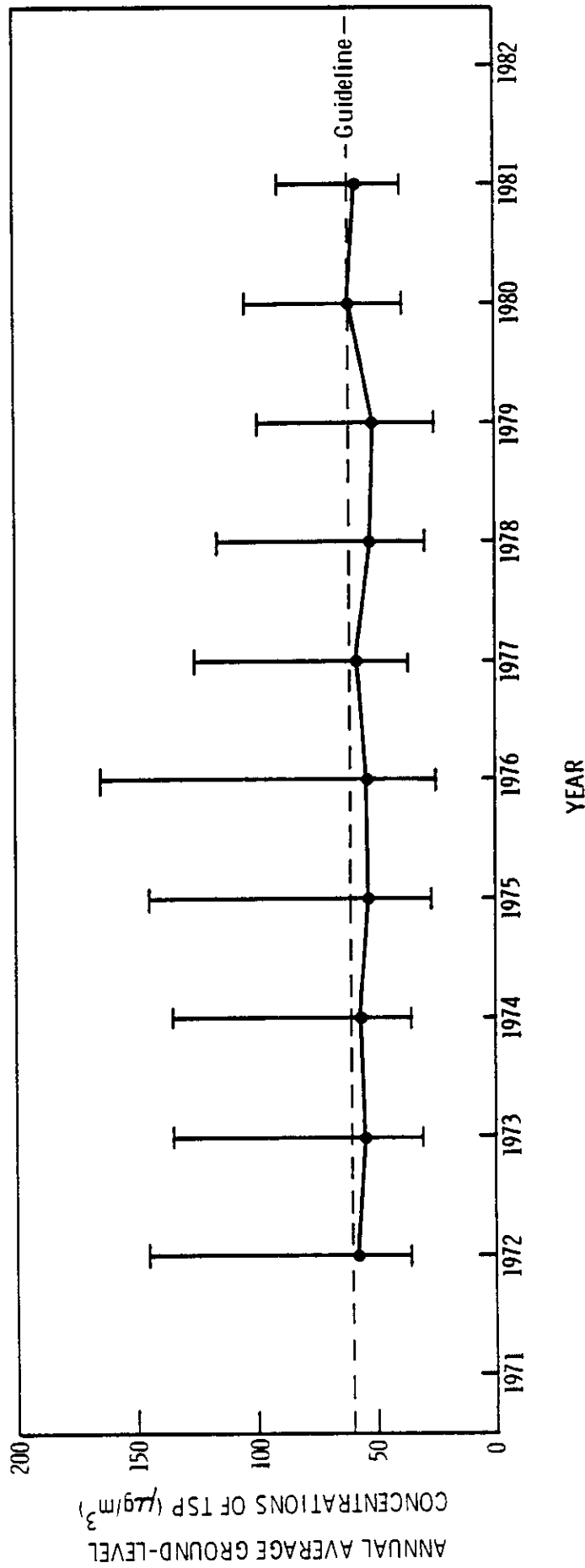


Figure III-4. Composite mean of the annual average TSP ground-level concentration for all Maryland stations with adequate data (at least 75% of the prescribed number of readings). The bars indicate the range of values (data from Ref. 2).

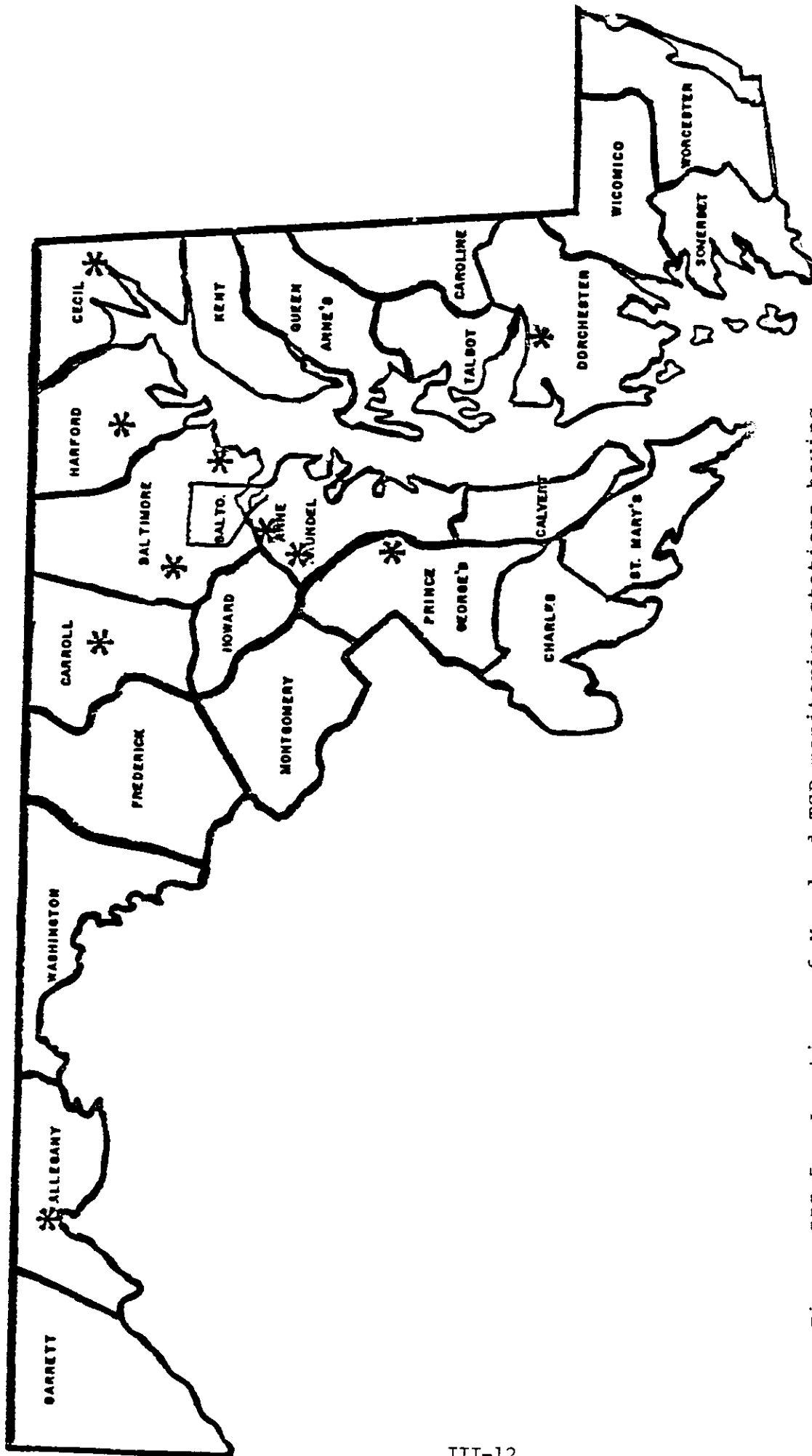


Figure III-5. Locations of Maryland TSP monitoring stations having continuous records, 1972-1981 (from Ref. 2).
 For insert of Baltimore City stations, see next page.

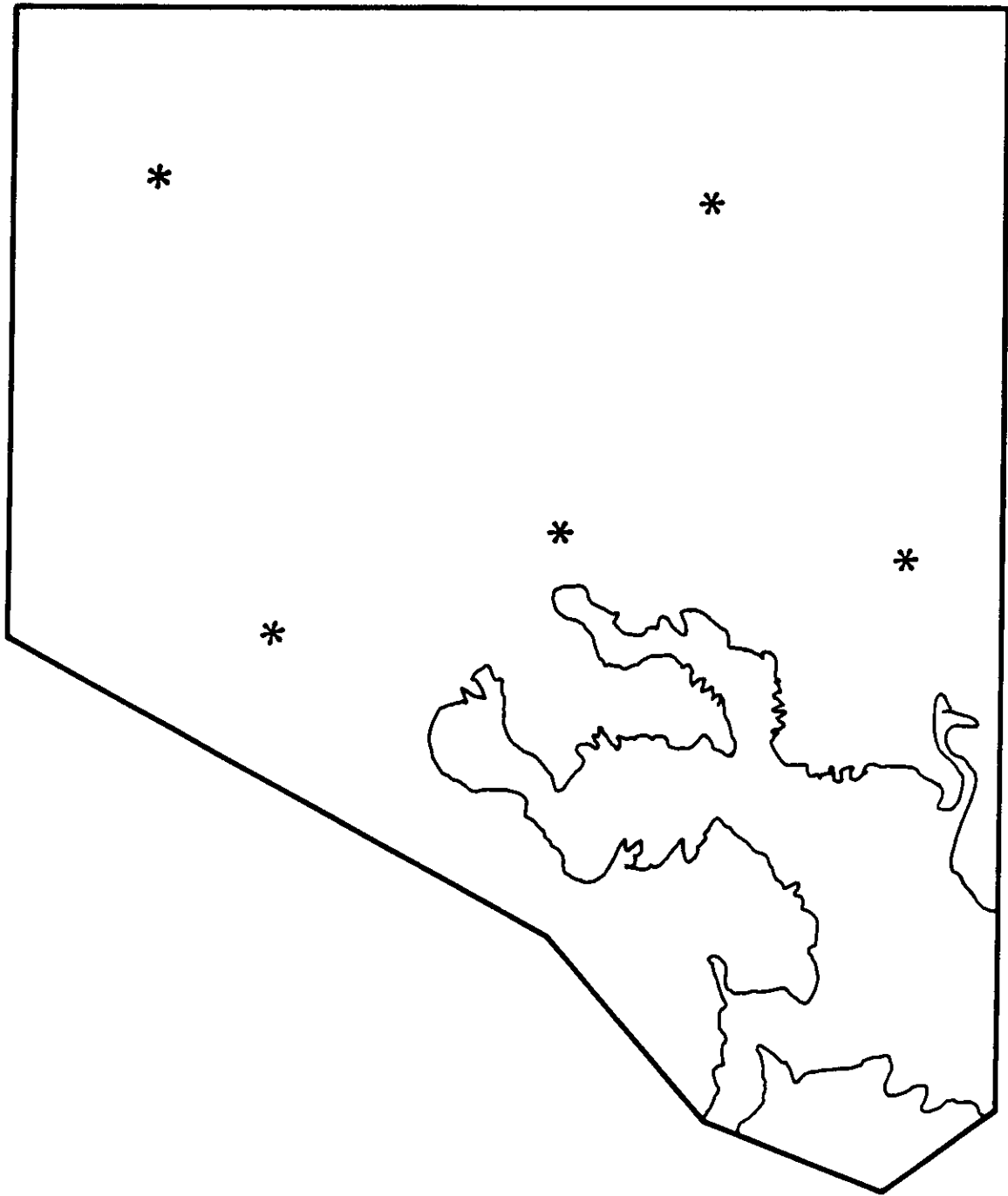


Figure III-5. Continued

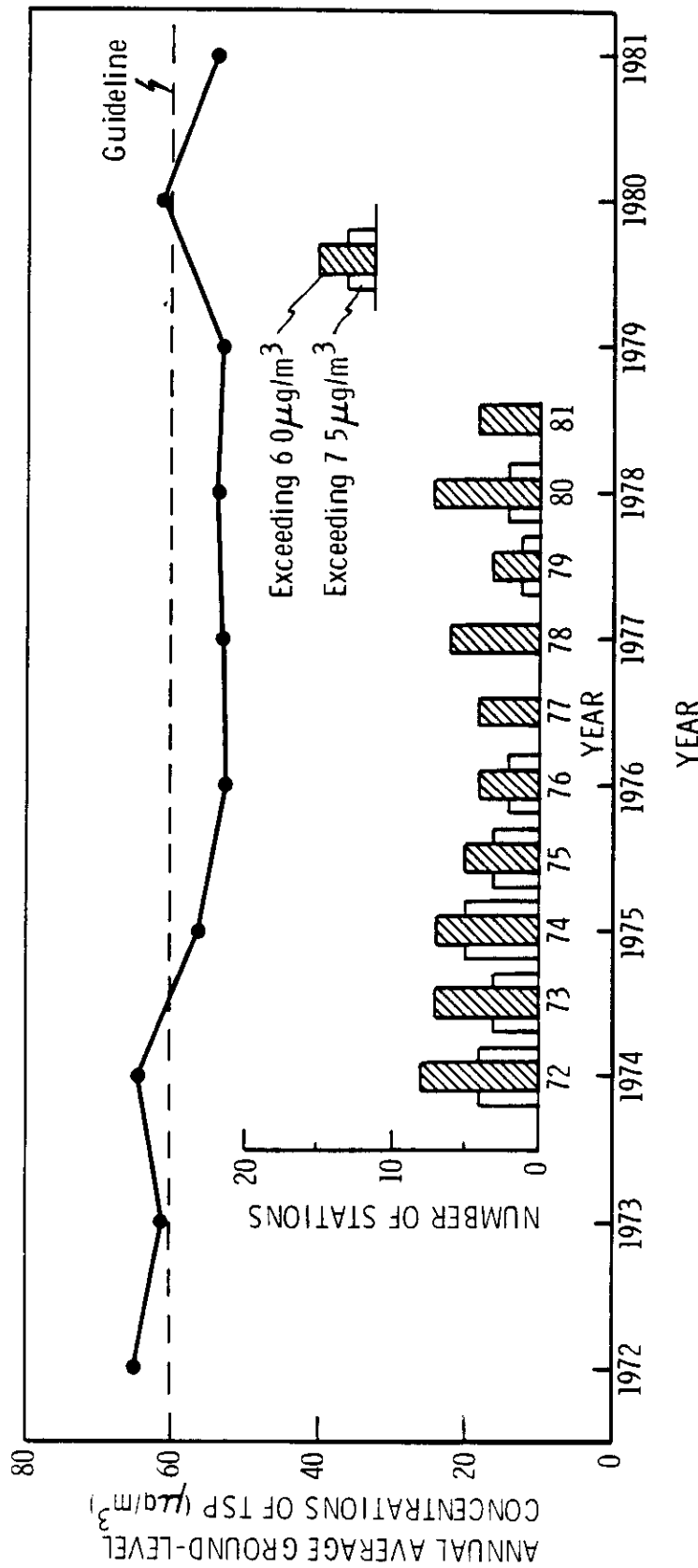


Figure III-6. Composite means of annual average TSP ground-level concentration at 15 stations throughout Maryland which have a continuous record since 1972. Violations of primary and secondary annual average TSP NAAQS for the same 15 stations (data from Ref. 2).

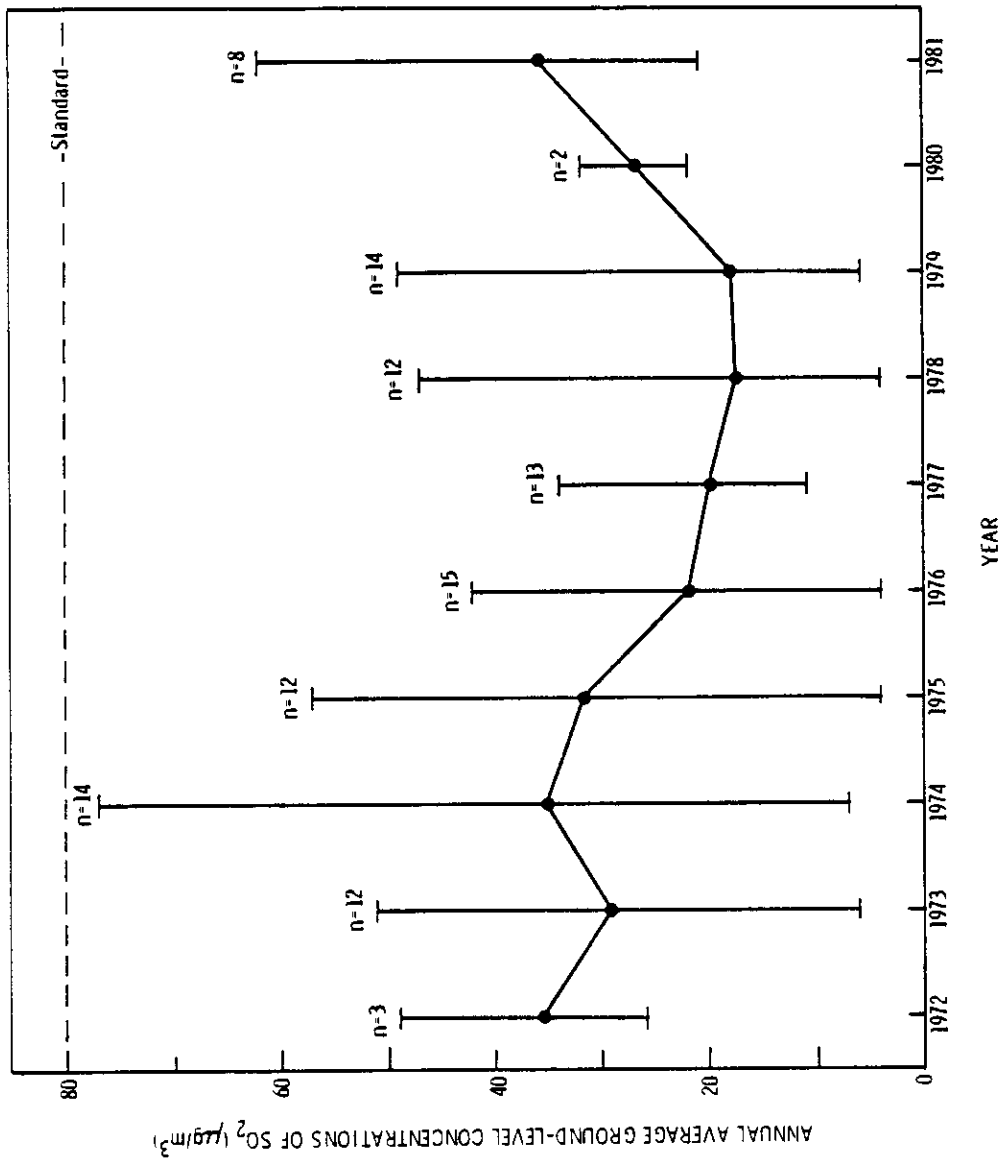


Figure III-7. Composite mean of annual SO₂ ground-level concentration averages for Maryland stations having data for the entire year. For informational purposes only; many stations have less than 75% of the prescribed number of readings. Measurements are by the flame photometric method (1972-1979) and by continuous/pulse fluorescence (1980-1981). Range of values is indicated by the bars (data from Ref. 2).

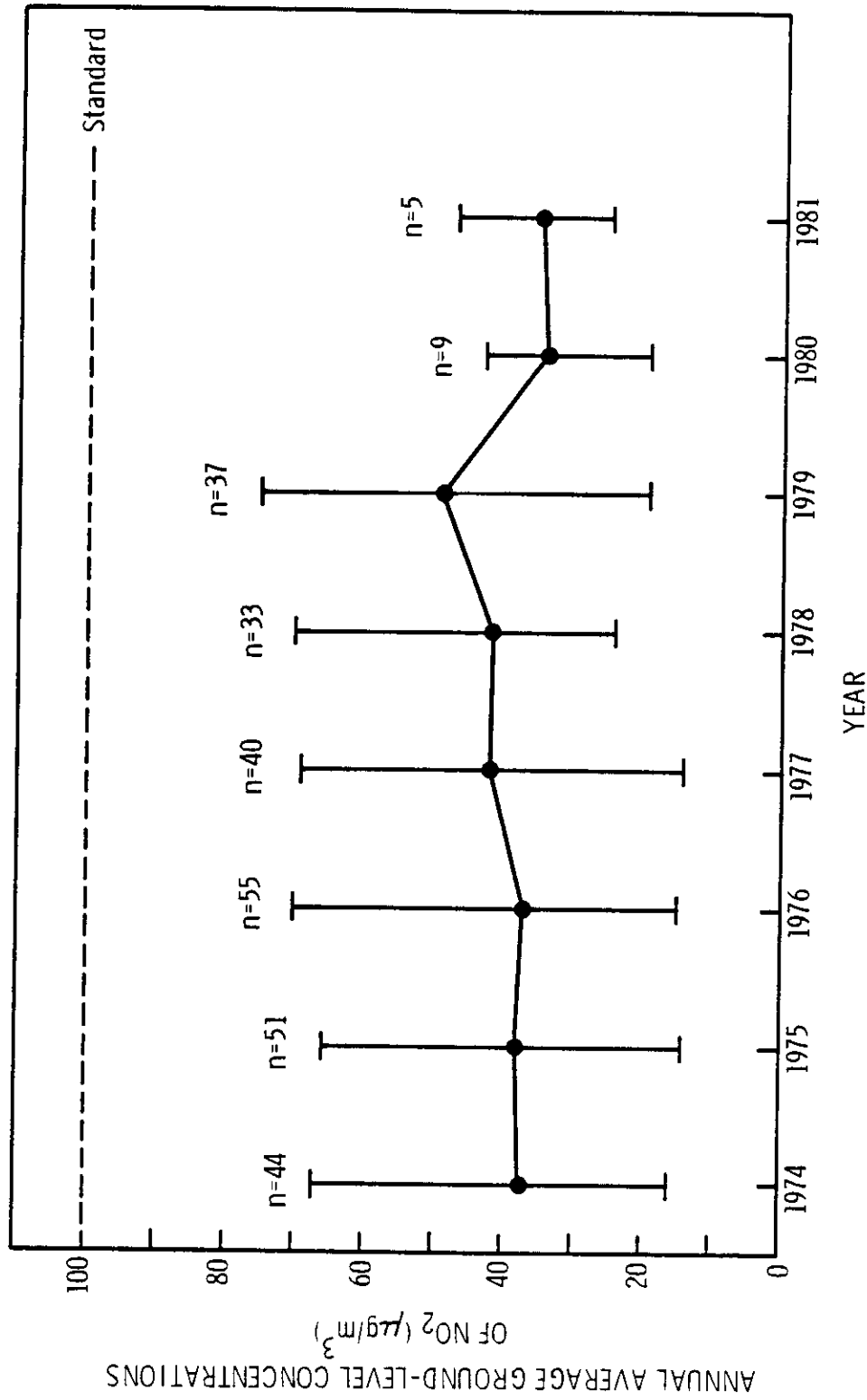


Figure III-8. Composite mean of annual average NO₂ ground-level concentrations (measured by 24-hr gas bubbler) for all Maryland stations with adequate data (at least 75% of the readings). Range of values is indicated by bar (data from Ref. 2).

The primary purpose of air quality models is to make predictions, which are generally used as inputs to decision-making processes. Thus, models are necessary tools to ascertain both present and future compliance with applicable State and Federal air quality regulations of existing, modified, or proposed sources of pollutants.

The primary impetus for model development has been the Clean Air Act. Because of the predictive capability of air quality models, they have been widely used to identify potential violations of National Ambient Air Quality Standards or allowable Prevention of Significant Deterioration (PSD) increments. In addition, the ability of air quality models to assess the adequacy of various emission control strategies has made them an integral part of the development and subsequent revisions of State Implementation Plans (SIPs). The use of air quality models is specifically mentioned in the 1977 Amendments to the Clean Air Act which primarily pertain to the prevention of significant deterioration of air quality (13). In response to the enacted amendments, EPA promulgated regulations [June 19, 1978(14); revised August 7, 1980(15)] that required the use of air quality models as part of the PSD air quality review.

The models themselves are mathematical formulations which attempt to simulate real, usually complex, processes. Specifically, models consist of mathematical equations which represent atmospheric dispersion, chemical transformation, and deposition of effluents from various sources during different meteorological conditions and over varied topography. Most air quality models provide probable estimates of the spatial and temporal distribution of pollutant concentration in the ambient air from estimates of pollutant emissions at the source. Therefore, pollutant dispersion models can be used to estimate the impact that various sources of pollutants have on the air quality within the area near the sources.

Air quality models attempt to reflect current scientific understanding of relevant physical and chemical processes involved in pollutant dispersion in the real atmosphere. However, because of the complex processes involved (e.g., stochastic properties inherent in atmospheric turbulence, the primary mechanism by which pollutants are dispersed in the atmosphere) and uncertainties in model inputs (e.g., lack of accurate on-site ground-level and upper air meteorology as well as an absence of verified long-term site-specific meteorological data) a "perfect model" may never be obtained.

Hundreds of air quality models have been developed over the past twenty years. Most of them assume that the profile of pollutant concentration along a cross-section of a time-averaged effluent plume is Gaussian in shape. The Gaussian plume, which results from atmospheric dispersion processes, was originally described by O.G. Sutton in the 1940's. Unfortunately, even though fundamental knowledge of pollutant transport and diffu-

sion greatly increased during the 1970's and through the present, most air quality models are based primarily on basic knowledge gained before 1970.

Greater accuracy and consistency in air quality modeling is necessary to provide air pollution control agencies, industry, and the public with a common basis for estimating air quality, assessing emission control strategies, and determining specific emission limitations. The EPA Office of Air Quality Planning and Standards (OAQPS) recognized this need and began developing an air quality modeling guideline in late 1976. Based on opinions from EPA Regional Offices, the OAQPS prepared a draft guide which underwent scientific and public review and comment in mid-1977. As the oral and written comments and recommendations concerning the draft guideline were being considered, the Clean Air Act Amendments were signed into law on August 7, 1977.

These amendments require that EPA "...shall specify with reasonable particularity each air quality model or models to be used under specified sets of conditions for purposes of this part..." and that "...at least every three years thereafter, the Administrator shall conduct a conference on air quality modeling..."(13). Therefore, the 1977 amendments have made the EPA modeling guidelines a requirement of law. The first guideline on Air Quality Models was published in final form in April 1978.

Input for future revisions to this guideline may come from several sources. For example, advice on the development and technical evaluation of air quality models was provided by the American Meteorological Society (AMS) through a cooperative agreement with EPA. In addition, EPA has instituted a series of internal Regional Workshops on Air Quality Modeling to foster consistency within the Agency, provide interim guidance, and identify any possible need for change or improvement with respect to modeling. The EPA also conducts research projects concerning atmospheric transport, diffusion, and transformation of pollutants, as further input to possible guideline revisions.

In response to criticisms that the 1978 Model Guidelines officially sanctioned air quality models developed by or for EPA, the Agency (with the strong encouragement of the AMS) solicited new ones. As a result, 28 new models were submitted for their consideration by April 1981.

EPA published proposed revisions to the Guideline on Air Quality Models in October 1980. Because of technical group and user criticism expressed at public hearings concerning the revisions, the guideline has not yet been finalized. The next revised EPA Guideline on Air Quality Models is expected to be available for public review and comment in 1984.

In addition to EPA evaluation of model performance, private concerns, including the electricity utilities, are also actively involved in assessing model accuracy because of the important role that models play in regulatory decisions concerning industry. More accurate air quality prediction may lead to

better and less costly site selection for utilities, and may help to minimize financial risks involved in the relatively expensive, and possibly unnecessary, installation and operation of pollution control devices. Therefore, the Electric Power Research Institute (EPRI) began (in 1978) a rigorous and comprehensive air quality model validation study, the EPRI Plume Model Validation Project. As part of this study, an extensive field measurement program was conducted near the Kincaid power plant located on the relatively smooth and level terrain of central Illinois. The resulting data base is very complete and is an excellent choice for evaluating air quality models used to predict impacts of pollutants emitted from tall stacks in a region of flat or rolling terrain. As part of this study, EPRI also conducted a survey (published in 1982) of plume models available for evaluation and validation. Model evaluations were subsequently performed and results were recently published(16). EPRI also plans to evaluate additional models in both moderate and complex terrains. EPA intends to use the Kincaid data base for their future model evaluations as well.

Many air quality models now in use do not reflect the current scientific understanding of the dispersion process. Specifically, these models: 1) continue to employ Pasquill-Gifford dispersion coefficients, which are inappropriate for buoyant effluent releases from tall stacks such as those which may occur at central generation stations; 2) do not incorporate updated plume rise expressions, including the effects of convection; 3) disregard recent developments from field and laboratory experiments concerning convective scaling of the unstable boundary layer; 4) continue to treat plume penetration of the elevated inversion as an "all-or-none" situation.

These concerns were considered in the development of an air quality model for tall stack releases produced for the Power Plant Siting Program (PPSP) of the Maryland Department of Natural Resources(17). The PPSP model specifically applies to tall stack plumes during convective (or unstable) atmospheric conditions, situations during which such plumes usually yield their highest ground-level concentrations. Significant improvement over the corresponding EPA-approved benchmark CRSTER model is obtained by the inclusion of state-of-the-art methods for estimating atmospheric stability and dispersion, for predicting buoyant plume rise, and for treating plume penetration (including partial penetration) of the elevated stable layer. A comparison between the PPSP model and the CRSTER model was performed by comparing their predicted ground level concentrations at points around several Maryland and Midwest power plants (18). This comparison showed that the PPSP model predictions were superior to those produced by the CRSTER model. The PPSP model, submitted to EPA in April 1982, is awaiting their review.

Table III-3. Sources Subject to Prevention of Significant Deterioration Regulation if their Potential to Emit Equals or Exceeds 100 Ton/yr

Fossil fuel-fired steam electric plants of more than 250 million Btu/hr heat input
Coal cleaning plants (with thermal dryers)
Kraft pulp mills
Portland cement plants
Primary zinc smelters
Iron and steel mill plants
Primary aluminum ore reduction plants
Primary copper smelters
Municipal incinerators capable of charging more than 250 tons of refuse per day
Hydrofluoric, sulfuric, and nitric acid plants
Petroleum refineries
Lime plants
Phosphate rock processing plants
Coke oven batteries
Sulfur recovery plants
Carbon black plants(furnace process)
Primary lead smelters
Fuel conversion plants
Sintering plants
Secondary metal production plants
Chemical process plants
Fossil fuel boilers (or combinations thereof) totaling more than 250 million Btu/hr heat input
Petroleum storage and transfer units with total storage capacity exceeding 300,000 barrels
Taconite ore processing plants
Glass fiber processing plants
Charcoal production plants

D. Regulatory Considerations

The Clean Air Act Amendments of 1977 are of major importance in the regulation of air quality in two critical areas: 1) they specify acceptable approaches in controlling atmospheric emissions from industry; and 2) they give specific legislative direction to "prevention of significant deterioration," one of the most controversial concepts of air pollution controls.

One of the most significant target dates within the Clean Air Act was December 31, 1982. This was the date by which primary ambient air quality standards for particulate matter, sulfur dioxide, nitrogen dioxide, carbon monoxide, and ozone were to have been attained. Pertinent events leading to attainment of the standards by this deadline, as well as regulatory consequences which follow it, are presented below.

Changes and/or advances in the regulatory environment which may affect power plant siting and operations, such as, the EPA's publication of an Emissions Trading Policy Statement and the State's acquisition of PSD authority, are also presented below.

Prevention of Significant Deterioration (PSD)

The basic goals of the Prevention of Significant Deterioration (PSD) regulations are to: 1) ensure that economic growth will occur in harmony with the preservation of existing clean air resources to prevent the development of any new nonattainment problems; 2) protect the public from any adverse effect on their healths and welfare; and 3) preserve, protect, and enhance the air quality in areas of special natural recreational, scenic, or historic value such as national parks and wilderness areas(15). Sources subject to the PSD regulations are major stationary sources and major modifications located in attainment areas and unclassifiable areas for National Ambient Air Quality Standards (NAAQS). A major source is any source listed in Table III-3 with the potential to emit 100 ton/yr or more of any pollutant regulated under the Clean Air Act. Other sources not on this list, which have the potential to emit 250 ton/yr or more of any Clean Air Act (CAA) pollutant, are also considered major.

In August 1980, the PSD regulations were extensively revised as a response (in part) to the court decision in the case of Alabama Power et al. vs Costle. Changes were made both in the definition of major sources and in some monitoring and other permitting requirements. Some of the main features of these revised regulations are outlined below.

A principal change is in the definition of potential to emit. Under the old regulations, "potential to emit" meant uncontrolled emissions at design operating rates. Under the new regulations, the "potential to emit" is defined as the "maximum capacity to emit [a] pollutant under applicable emission standards and permit conditions excluding secondary emissions

(those not directly from the source)." Thus, a source can now avoid PSD review if it binds itself through a federally enforceable permit to certain restrictions on source operations, e.g., sufficiently limited hours of operation or sufficiently effective emissions control equipment which would reduce actual emissions below specified de minimis levels.

A major modification is defined as a physical or operational change to a source which results in a significant net increase in emissions of any pollutant regulated under the CAA. A net emissions increase is the sum of a planned increase and all other contemporaneous emissions increases and decreases at the source, i.e., those which occurred within five years of the date when the particular increase takes place. Such an increase is significant if it exceeds the corresponding de minimis value listed for each pollutant in Table III-4. Increases which are less than de minimis may still be subject to PSD review if they would have an impact on nearby Class I areas. Certain changes, however, including routine maintenance, repair, or replacement, fuel switching required by federal legislation, changes in ownership, and increases in hours of operation unless prohibited by permit, are not considered major modifications, and are thus not subject to PSD review.

In areas designated Class I, Class II (moderate industrial growth permitted), or Class III (less restricted, allowing fuller industrial growth) increases in pollutant concentrations over the baseline concentrations are limited to those listed in Table III-5.

Emissions Trading Policy Statement

On April 7, 1982, EPA published its Emissions Trading Policy Statement which was designed to encourage states to use emissions trades to facilitate more rapid attainment of National Ambient Air Quality Standards (NAAQS) at less cost than would otherwise be possible(19). Emissions trading includes several alternatives to traditional regulation: bubbles, netting, and offsets, as well as banking (storage) of emission reduction credits for future use. These alternatives involve the creation of surplus reductions (i.e., reductions beyond what is need to reach the standards) at certain emission sources and use of these reductions to meet requirements applicable to addition of other emission sources.

EPA's bubble policy lets existing plants (or groups of plants) decrease or be excused from pollution controls at one or more emissions sources in exchange for compensating decreases (or increases in control) at other emission sources. Bubbles give plant managers flexibility to develop less costly ways of meeting air quality requirements. For example, emission increases may be allowed from one group of sources that are more costly to control in return for emission decreases from another group of sources that are less costly to control.

Table III-4. De Minimis Values for Significant Net Emissions Increase. If these Values are Exceeded the Increase is Considered Significant

Pollutant	Ton/yr
CO	100
NOx (as NO ₂)	40
SO ₂	40
Particulate matter	25
Ozone	40 of volatile organic compounds
Lead	0.6
Asbestos	0.007
Beryllium	0.0004
Mercury	0.1
Vinyl Chloride	1
Fluorides	3
Sulfuric acid mist	7
Hydrogen sulfide	10
Total reduced sulfur	10
Reduced sulfur compounds	10
Other CAA pollutants	>0

Table III-5. Prevention of Significant Deterioration Concentrations Increments(a)

Pollutant	(ug/m ³)
<u>Class I Areas</u>	
<u>Particulate Matter</u>	
Annual geometric mean	5
24-hour maximum	10
<u>Sulfur Dioxide</u>	
Annual arithmetic mean	2
24-hour maximum	5
3-hour maximum	25
<u>Class II Areas</u>	
<u>Particulate Matter</u>	
Annual geometric mean	19
24-hour maximum	37
<u>Sulfur Dioxide</u>	
Annual arithmetic mean	20
24-hour maximum	91
3-hour maximum	512
<u>Class III Areas</u>	
<u>Particulate Matter</u>	
Annual geometric mean	37
24-hour maximum	75
<u>Sulfur Dioxide</u>	
Annual arithmetic mean	40
24-hour maximum	182
3-hour maximum	700

(a) For any period other than the annual, the applicable maximum allowable increase may be exceeded during only one such period per year at any one location.

Netting is another way in which a source can use the Emissions Trading Policy. Through netting, a modification at an existing facility is exempt from preconstruction permits, Best Available Control Technology (BACT) and Lowest Achievable Emission Rate (LAER) requirements, and other new source review requirements, if the increased emissions from the modification are offset by decreased emissions from existing emissions at the plant so that the net increase in emissions will no longer leave the new source to be considered a major modification in accordance with the PSD regulation and Emission Offset Interpretive ruling.

In nonattainment areas, new major stationary sources and modifications may be required to secure sufficient surplus emission reductions to more than offset their increased emissions. This requirement is designed to permit industrial growth in nonattainment areas while improving air quality.

Banking lets firms store qualified emission reductions for later use in bubble, netting, or offset transactions. Banked emission reduction credits (ERCs) can also be sold to firms seeking alternate ways to meet regulatory requirements more quickly and flexibly.

At this time, regulations to implement these policies within Maryland are under discussion in the Air Management Administration.

National Ambient Air Quality Standards (NAAQS)

As previously mentioned, December 31, 1982 was an important milestone in the Nation's effort to improve the quality of its air in accordance with the Clean Air Act. This was the date by which primary ambient air quality standards for particulate matter, sulfur dioxide, nitrogen dioxide, carbon monoxide, and ozone, were to have been attained nationwide. Extensions to December 31, 1987 were authorized under statutorily prescribed conditions for attainment of the carbon monoxide and ozone standards.

If an area fails to attain the primary ambient air quality standards, the Clean Air Act imposes certain statutory consequences:

- The area is subject to a ban on the construction or modification of major stationary sources emitting the pollutant for which the area is in nonattainment
- The area may be subject to a suspension of certain Federal grant funds for failing to "submit" a satisfactory plan [Section 176(a)] or failing to "implement" the plan the State submitted [Section 176(b)].

All areas of Maryland are in attainment with the NAAQS for sulfur dioxide and nitrogen dioxide. The TSP nonattainment area in the Metropolitan Baltimore AQCR has been listed by EPA as a region that will probably be able to demonstrate that it had met the standards by 31 December 1982; and the necessary requests for extension dates for ozone and carbon monoxide areas in Maryland have been submitted to EPA. Pending approval of the extension requests for ozone and carbon monoxide, the State should not be subject to any sanctions.

State Acquires PSD Authority

The EPA has approved a revision to Maryland's State Implementation Plan (SIP) which includes a plan for the Prevention of Significant Deterioration(20). Under the revised plan, Maryland now has authority to issue or deny PSD permits. All PSD permit applications are processed by the Department of Health and Mental Hygiene except for those pertaining to electric power generating station facilities, which are reviewed by the State Public Service Commission. However, once a permit for such an energy facility has been issued, the Department of Health and Mental Hygiene has the authority to enforce it (under COMAR 10.18.06.14). The Department also has the authority to prohibit the construction of generating stations that do not comply with these regulations.

E. Pollution Control

The pollutants of concern that are emitted in significant quantities by fossil fuel-fired power plants are particulates, sulfur dioxide, and nitrogen oxides. All coal-fired power plants in Maryland employ some form of particulate control. The majority of the plants (Wagner, Morgantown, Chalk Point, Dickerson, and R.P. Smith) use electrostatic precipitators (ESP) whereas Crane employs a baghouse, and Dickerson employs a venturi scrubber in addition to its ESP. Particulate emissions from power plants in general have in the past been controlled primarily by electrostatic precipitators having some form of mechanical precleaners, e.g., cyclones or settling chambers. For coal-fired boiler applications, the use of fabric filters is increasing.

Sulfur dioxide emissions from power plants can be controlled either by limiting the amount of sulfur in the fuel or by using add-on controls. In Maryland, utilities have chosen to limit the sulfur content of the fuel burned to such an extent that the use of add-on controls becomes unnecessary.¹ Specifically, Maryland power plants burn fuels with sulfur contents below the regulated limits. In Air Quality Control Regions (AQCR) I, II, V, and VI (see Figure III-9), the following sulfur

¹Vienna Unit #9, however, is licensed with a scrubber.

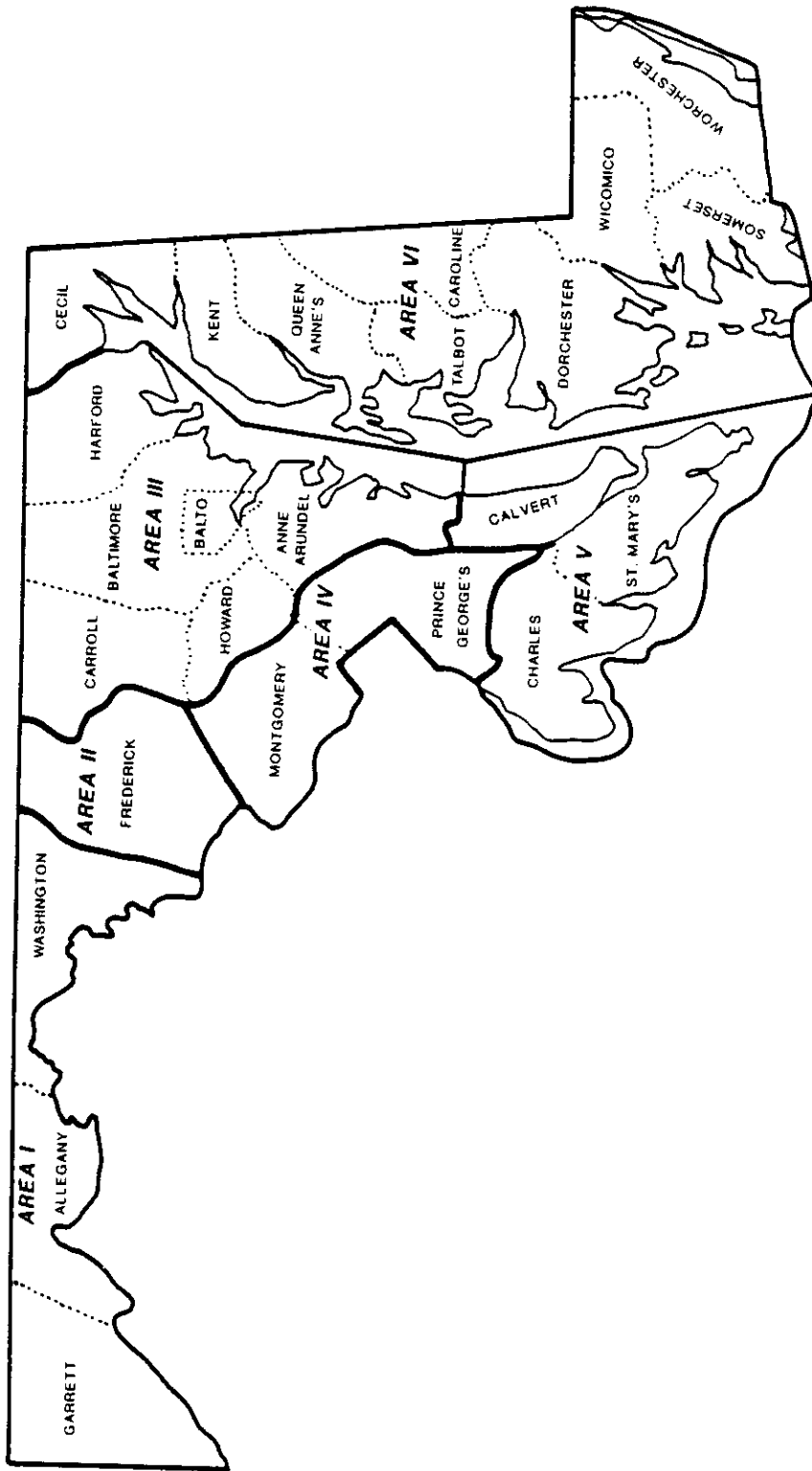


Figure III-9. Maryland state air quality control areas (AQCR's).

content limitations are in effect: 3.5 lbs per million Btu (2.2%S) for solid fuels; 2 percent for residual fuel oils; 0.3 percent for distillate fuel oils; and, 0.3 percent for process gas used as fuel. In areas III and IV, the following sulfur content limitations are in effect: 1 percent for solid fuels¹; 0.3 percent for distillate fuel oils; and, 1 percent for residual fuel oils. Fuel sulfur content can be controlled by a variety of means, including coal washing and blending of high sulfur and low sulfur coals.

Add-on systems, i.e., Flue Gas Desulfurization (FGD) systems remove sulfur dioxide from the exhaust gases. Such systems can be either wet or dry. The most common ones employ lime/limestone scrubbers. In these FGD systems, a waste sludge containing gypsum is produced, and no saleable product is recovered. The double alkali process reduces some of the sludge problems of the conventional lime/limestone process and is easier to operate but the operating costs are slightly higher. Some SO₂ recovering processes have been commercialized, e.g., the Wellman-Lord or the MgO processes, but these have generally not been employed at power plants. In recent years, there has been an increasing trend toward the use of dry FGD systems. In dry systems, flue gas is treated with an alkaline slurry in a spray dryer-type reactor. The water in the slurry evaporates while the SO₂ is removed by chemical reaction. The resulting solid particulates are removed by fabric filters before the gases are exhausted.

Nitrogen oxide controls are a relatively new development. Newer plants, built after the promulgation of the New Source Performance Standards (NSPS) for NO_x, often have some form of control. In general, the NSPS are the benchmark for emission limitations with which new power plants must comply, and the pollution controls employed generally reflect the applicability or non-applicability of the NSPS. Of course, other regulations, e.g., PSD and nonattainment new source regulations, can be more stringent, which would require correspondingly better controls (such as BACT or LAER).

Nitrogen oxide emissions are primarily controlled by proper boiler design and suitable process conditions. Boiler design features that have been effective in reducing NO_x formation are staged combustion, low excess air requirements, and combustion chambers with reduced heat temperatures. Add-on controls for

¹On 28 January 1980, the State approved BG&E's requested relaxation of allowable sulfur dioxide emissions from the coal-fired Crane power plant. The SO₂ emission limit was increased to 3.5 lb. SO₂/MBtu (<2.2%S). This new emission rate became Maryland law on 31 March 1980, and was submitted as a State Implementation Plan revision that was subsequently approved by EPA. These SO₂ emissions limitations are now also in effect at Chalk Point and Dickerson.

NOx removal from flue gases have been applied to combustion sources in Japan, but operating experience is limited and this technique has not been applied at power plants in the U.S.

In recent years, interest has been growing in another method of burning coal, i.e., fluidized bed combustion, which results in lower combustion temperatures (and therefore, lower NOx formation). In some cases, some of the sulfur is also retained in the residue. The process advantages are higher heat transfer rates and less scaling and/or corrosion of heat transfer equipment. The injection of fine limestone into the fluidized bed may be used to reduce SO₂ emissions.

F. Coal Conversion

At one time, especially during the 1960's, virtually all of Maryland's power plants were coal-fired. Because of stringent pollution control requirements and the generally lower cost of oil, many of these plants, e.g., Benning and Buzzard Point in D.C., Riverside, Westport, Gould Street, Crane, and Vienna, were converted to oil in the 1970's. With the reduction in the supply of oil and the corresponding increase in price during the mid 70's, Maryland utilities tried to reduce their oil dependence by the construction of new coal-fired units, conversions of oil units to coal, and the retirement of older oil-fired generating units.

Maryland's current (1983) base-load electrical generating capacity is 7,692 MW (see Table III-6). Of this capacity, 21 percent (1,650 MW) is produced using nuclear fuel, 35 percent (2,700 MW) is produced using #6 oil, 43 percent (3,312 MW) is produced using coal and less than 1 percent (30 MW) is produced using RDF. In addition, 976 MW is available from peak-load gas turbines fueled with #2 oil.

The following changes in fuel consumption at Maryland power plants planned for the next 15 years illustrate a clear trend toward a reduction in oil capacity and a substantial increase in coal capacity:

- The three-phase retirement of the Westport station in 1984, 1987, and 1992 will decrease the total #6 oil-fueled generating capacity to 2,483 MW.
- The two-phase startup of the Brandon Shores station in 1984 and 1988 will increase the total coal-fueled generating capacity to 4,906 MW.
- The planned construction of a coal-fired unit at the Vienna station in 1995 will increase the total coalfired generating capacity to 5,406 MW.

Table III-6. Electrical Generating Capacity of Maryland Power Plants

1983 Plant Operations	Capacity in MW				
	-----Baseload-----				-Peak-
	Coal	#6 Oil	Nuclear	RDF	#2 Oil
Calvert Cliffs			1,650		
Chalk Point	710	1,280			48
C.P. Crane	384			30	14
Dickerson	570				13
Gould Street		103			
Morgantown	1,200				248
Notch Cliff					128
Perryman					204
Riverside		321			172
R.P. Smith	129				
Vienna		150			17
Wagner	319	669			14
Westport		177			118
	<u>3,312</u>	<u>2,700</u>	<u>1,650</u>	<u>30</u>	<u>976</u>