In 1977 (Figure III-8), the modeled SO_2 concentrations in the vicinity of the Vienna power plant were even higher than those in the Baltimore area, even though Vienna's emissions were less than a quarter of those from the Baltimore area power plants. This is largely due to Vienna's lower stack heights, which cause greater localized impact. Ground-level concentrations in the vicinity of Vienna decreased considerably when Units 5, 6, and 7, all three with short stacks, were retired in 1979 (see Figure III-9, for 1980).

- Particulates

Modeled particulate levels due to combined Maryland power plant stack emissions in 1984 were extremely low -- below 0.2 ug/m^3, or about two orders of magnitude less than ambient particulate levels measured in the Baltimore area. Considering these results alone, it appears that power plants have very little impact on atmospheric particulate levels in Maryland. However, in general, the coal fired plants' major contributions to ambient levels of particulates are fugitive dust sources rather than stack emissions. Because fugitive sources were not included in these analyses, power plant impacts on local ambient particulate levels are probably somewhat greater than accounted for here; however, these higher impacts occur locally on plant property or near plant property boundaries.

- NO_2

Figures III-11, III-12, and III-13 show projected NO_2 impacts of Maryland power plants for the three years investigated. The greatest ambient NO_2 concentration, 2.5 ug/m^3, occurred in the vicinity of Vienna in 1977 (Figure III-11). The impact in that area decreased after the retirement of three Vienna units in 1979 (see Figures III-12 and III-13). The maximum ground-level concentrations in 1980 and 1984, 2.0 ug/m^3 and 1.5 ug/m^3 respectively, occurred in the vicinity of the Easton power plant. Easton has a number of diesel generators with low stacks, which operated frequently in 1980. Although the diesels produce much less power than oil and coal boilers, their characteristically high NO_x emissions and low stacks result in significant ambient NO_2 levels in the vicinity of the plant.

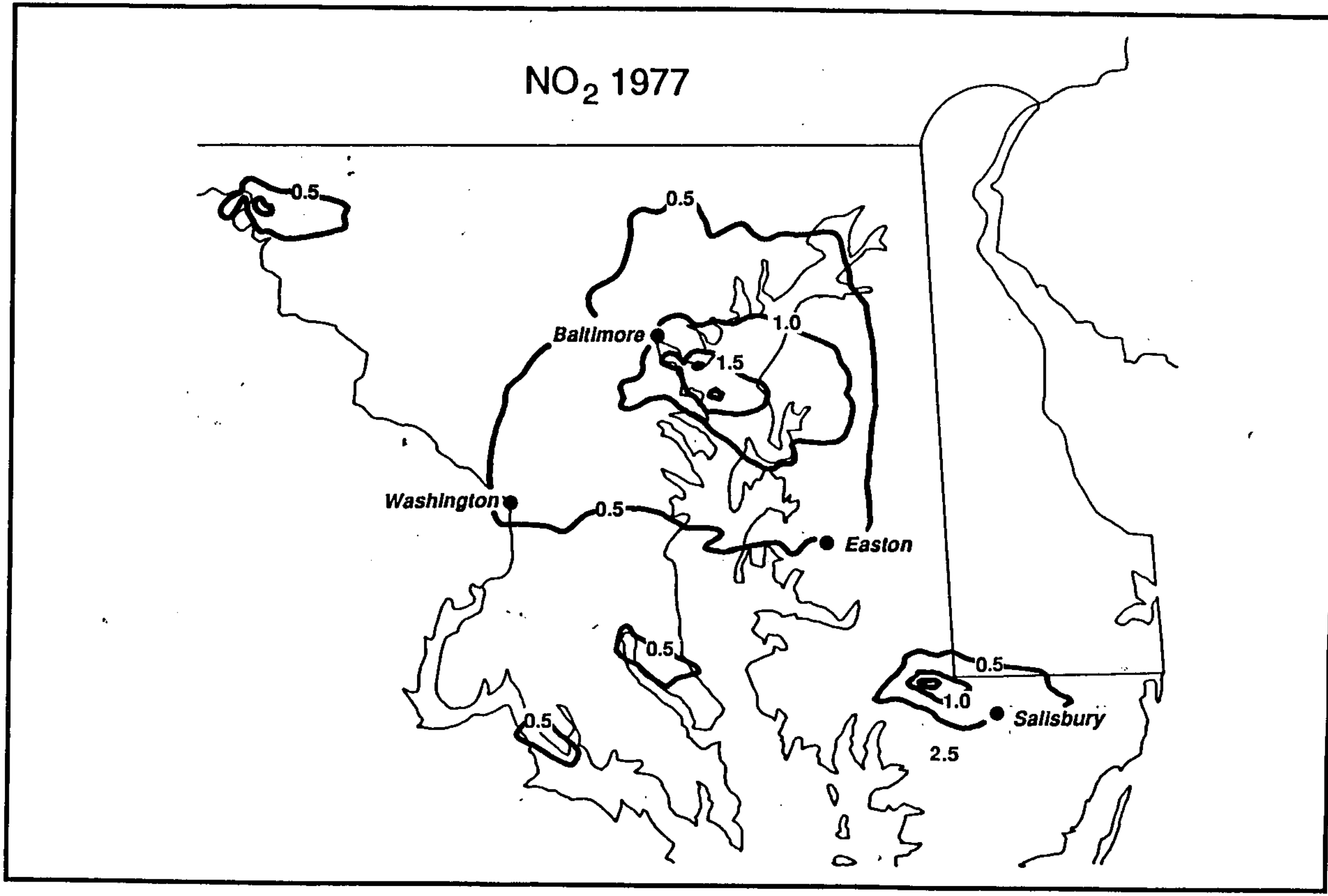

Figure III-11. Contours of model-predicted annual NO_2 ground-level concentrations for 1977 due to Maryland power plants (minimum contour is 0.5 $\mu g/m^3$, contour interval is 0.5 $\mu g/m^3$). Maximum concentration is indicated by an arrow.

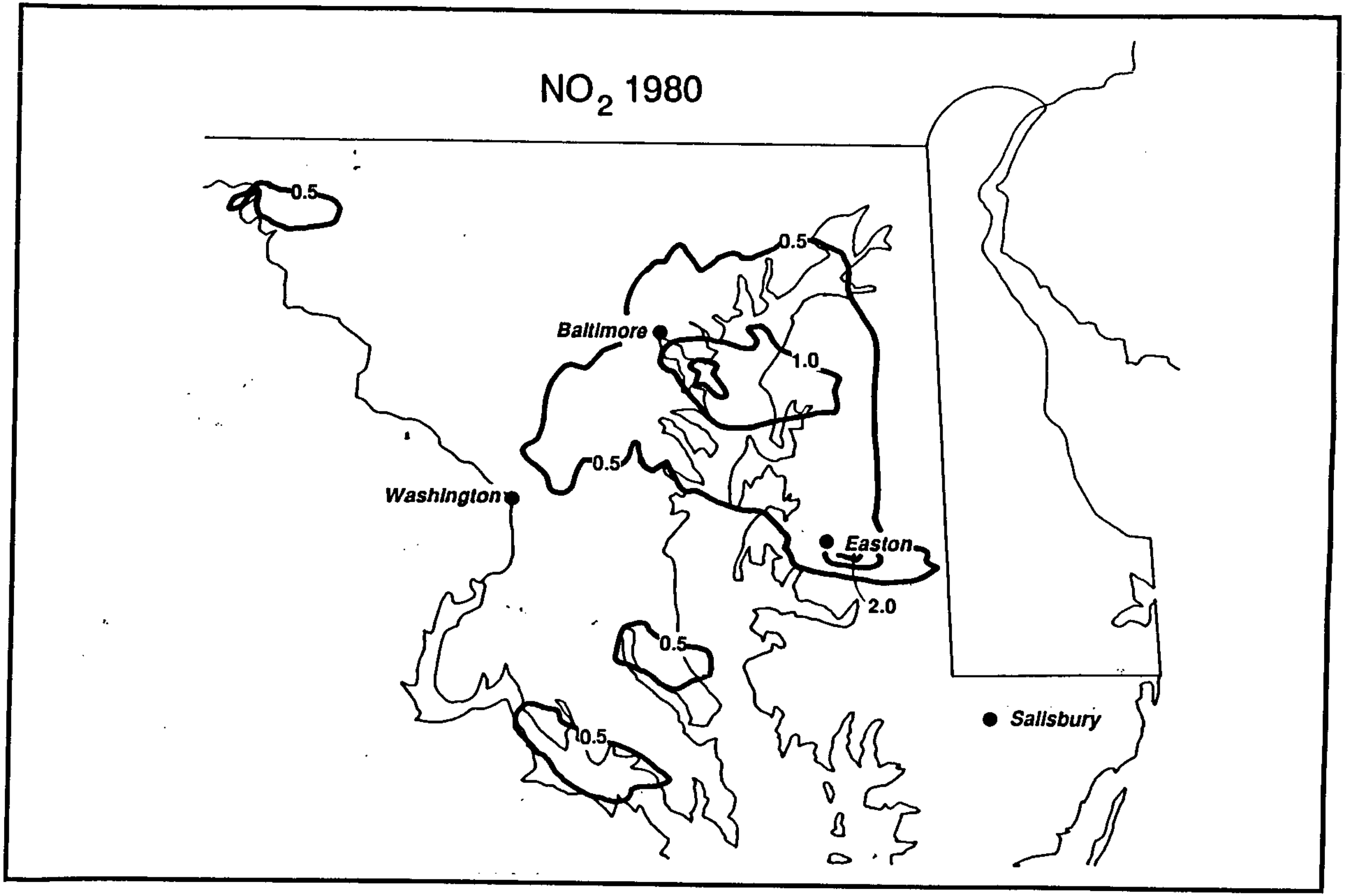

Figure III-12. Contours of model-predicted annual NO_2 ground-level concentrations for 1980 due to Maryland power plants (minimum contour is 0.5 $\mu g/m^3$, contour interval is 0.5 $\mu g/m^3$). Maximum concentration is indicated by an arrow.

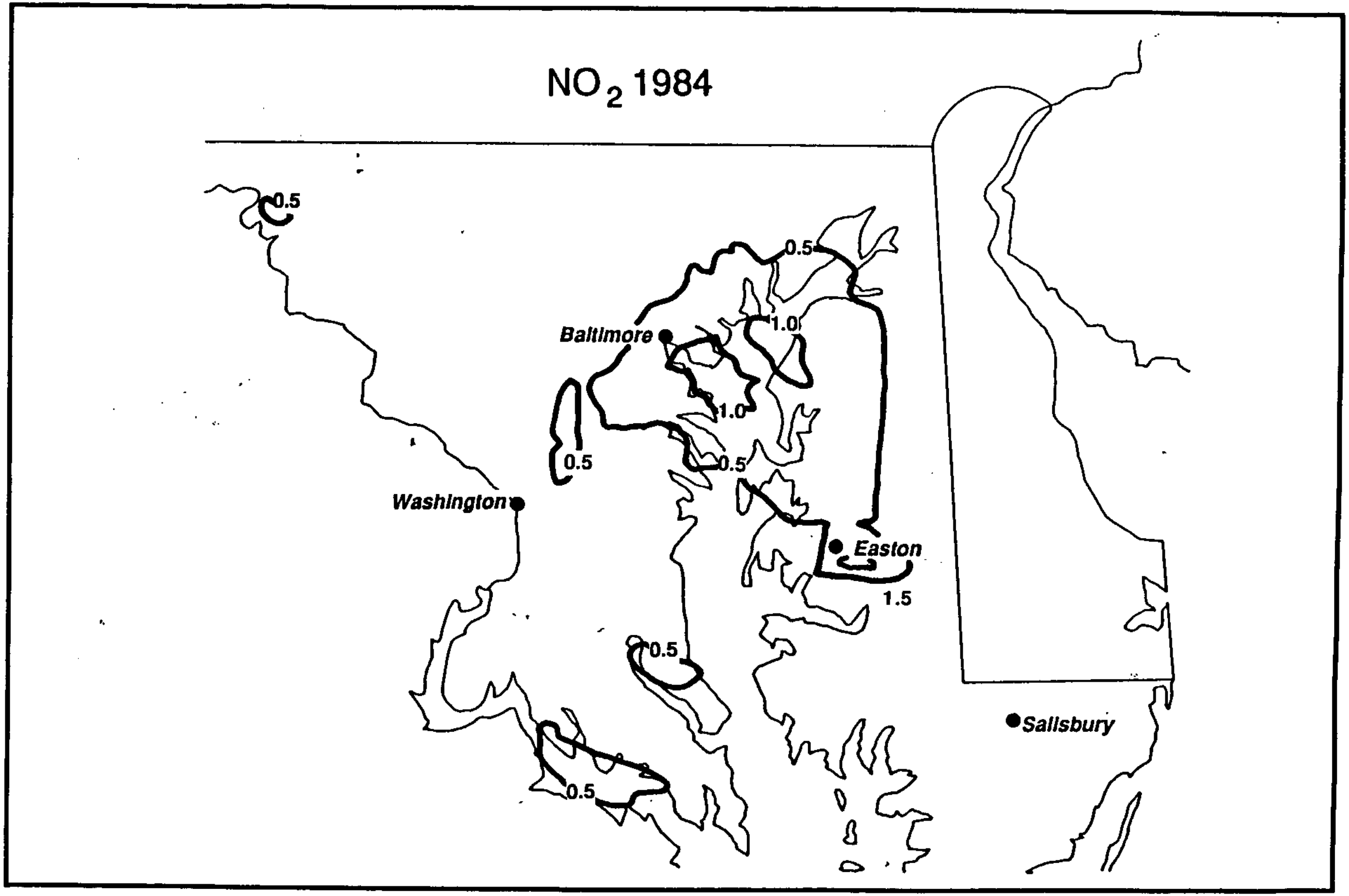

Figure III-13. Contours of model-predicted annual NO_2 ground-level concentrations for 1984 due to Maryland power plants (minimum contour is 0.5 $\mu g/m^3$, contour interval is 0.5 $\mu g/m^3$). Maximum concentration is indicated by an arrow.

The greatest modeled annual average NO_2 concentration attributable to the Baltimore power plants, 2.0 ug/m^3, occurred east of Baltimore in 1977 (Figure III-11). This maximum decreased to 1.5 ug/m^3 in 1984 (Figure III-13), which was only 4 percent of the actual ambient level (39 ug/m^3) measured east of Baltimore. These results suggest that, as with SO_2, power plants have relatively small impacts on ambient NO_2 levels.

<u>Summary</u>

Although total emissions of SO_2 and NO_2 from power plants in Maryland remained fairly constant over the past 10 years, and emissions of particulates decreased, measurements of those pollutants at ground level in recent years have not reflected those trends. Monitored ambient levels of SO_2 have decreased, NO_2 levels have increased and particulates levels have remained about the same. This suggests that there is little correlation between power plant emissions and ambient levels of air quality as measured by state-operated monitors. A possible explanation is that pollutant monitors are intentionally located in areas where high levels of pollution, from all sources, are expected to occur. This is not necessarily in the vicinity of power plants. Thus while the state monitoring system provides a picture of ambient air quality in a given area, it does not specifically measure the impacts of power plant emissions.

Even when rough comparisons can be made, as in the Baltimore area, combined Maryland power plant emissions contribute only a small fraction to the annual average ground-level concentrations of SO_2, NO_2, and particulates. Modeling indicates that the maximum annual average SO_2 concentration due to power plants occurs downwind of Baltimore and is about 5 ug/m^3, less than 17 percent of the concentration measured in that vicinity, which is about 30 ug/m^3. The predicted contribution of NO_2 levels by Baltimore power plant sources was about 4 percent of ambient levels. Baltimore power plant stack sources did not make significant contributions to ambient particulate levels.

C. Laws and Regulations Affecting Power Plant Impact on Air Quality

One of the most important influences on power plant emissions to the air is regulatory control, particularly air quality control laws and regulations. Energy use control legislation, passed in the late 1970's in the response to petroleum shortages, has also considerably affected power plant fuel usage. Fuel switching has had important implications for emissions control strategies, even though overall emissions over the past ten years have not increased dramatically as a result. This section examines the content and the administration of air quality regulations and energy conservation legislation as they apply to power plants in Maryland.

<u>The Regulatory Framework of Air Quality Control</u>

The Clean Air Act of 1963 (CAA) and its Amendments of 1970 and 1977 form the basis for most of the regulations that restrict pollutant emissions from power plants into the atmosphere. The primary goals of this legislation were stated in the form of National Ambient Air Quality Standards (NAAQS), first promulgated as federal regulations in 1971 (Table III-6). Maryland air quality standards are identical to the federal, with the exception of an additional standard for gaseous fluorides. Some additional air quality regulations relevant to power plant emissions concern New Source Performance Standards (NSPS), Prevention of Significant Deterioration (PSD), National Emission Standards for Hazardous Air Pollutants (NESHAPS), new source review and emissions trading policies.

Under the Clean Air Act, state and local governments bear the principal responsibility for enforcing air pollution control, using guidelines set by federal regulations. State and local air quality standards must be at least as stringent as the federal. Maryland, like many other states, has essentially chosen to use the federal air quality standards. Those standards, and other state regulations promulgated to achieve them, are found in Sections 10.18.01-23 of the Code of Maryland Regulations. Those regulations were submitted to the U.S. EPA and approved as the Maryland State Implementation Plan (SIP) under provision of the Clean Air Act. The SIP may be found in 40 CFR 52, Subpart V.

The federal and state air quality regulations that affect Maryland power plants can be considered in two broad categories. The first is associated with limits on pollution levels in the atmosphere: ambient air quality standards that set limits on the ambient concentrations permitted, and allowable PSD increment consumption, that limits the degradation of the air quality in existing clean air areas (that is, areas in attainment of the air quality standards). The second category directly limits the amounts of pollutants that any one source or category of sources can emit to the air -- thus indirectly affecting ambient air quality.

Air Quality Standards

Ambient air quality standards limit the concentration of selected pollutants -- criteria pollutants -- in the air, measured near ground level. Two types of standards are used: (1) primary standards, which are established with a margin of safety to prevent harm to human health; and (2) secondary standards, called "public welfare" standards, which are established with a margin of safety to avoid damage to livestock, vegetation, man-made materials, or the economic value of objects. NAAQS have been established for sulfur dioxide (SO_2), particulate matter (PM_{10}), nitrogen dioxide (NO_2), carbon monoxide (CO), ozone (O_3), and lead (Pb) (Table III-6). The PM_{10} standard, which governs particles less than 10 um in diameter, replaced the older total suspended particulate (TSP) standard in 1987. Maryland has an additional standard for gaseous fluorides; otherwise its standards are identical to the federal.

For administrative purposes, Maryland is divided into six Air Quality Control Regions (Figure III-14). If criteria pollutant levels exceed any standard in any area, it is deemed a "nonattainment area" for that pollutant. All of Maryland is in attainment for SO_2, NO_2 and Pb. The Baltimore metropolitan area (Area III) and the Maryland portion of the Washington, DC metropolitan area (Area IV) are nonattainment areas for ozone, and portions of them are also nonattainment for CO. The Baltimore industrial region has been nonattainment for TSP, but it is not yet known whether it will be declared nonattainment under the new PM_{10} standard.

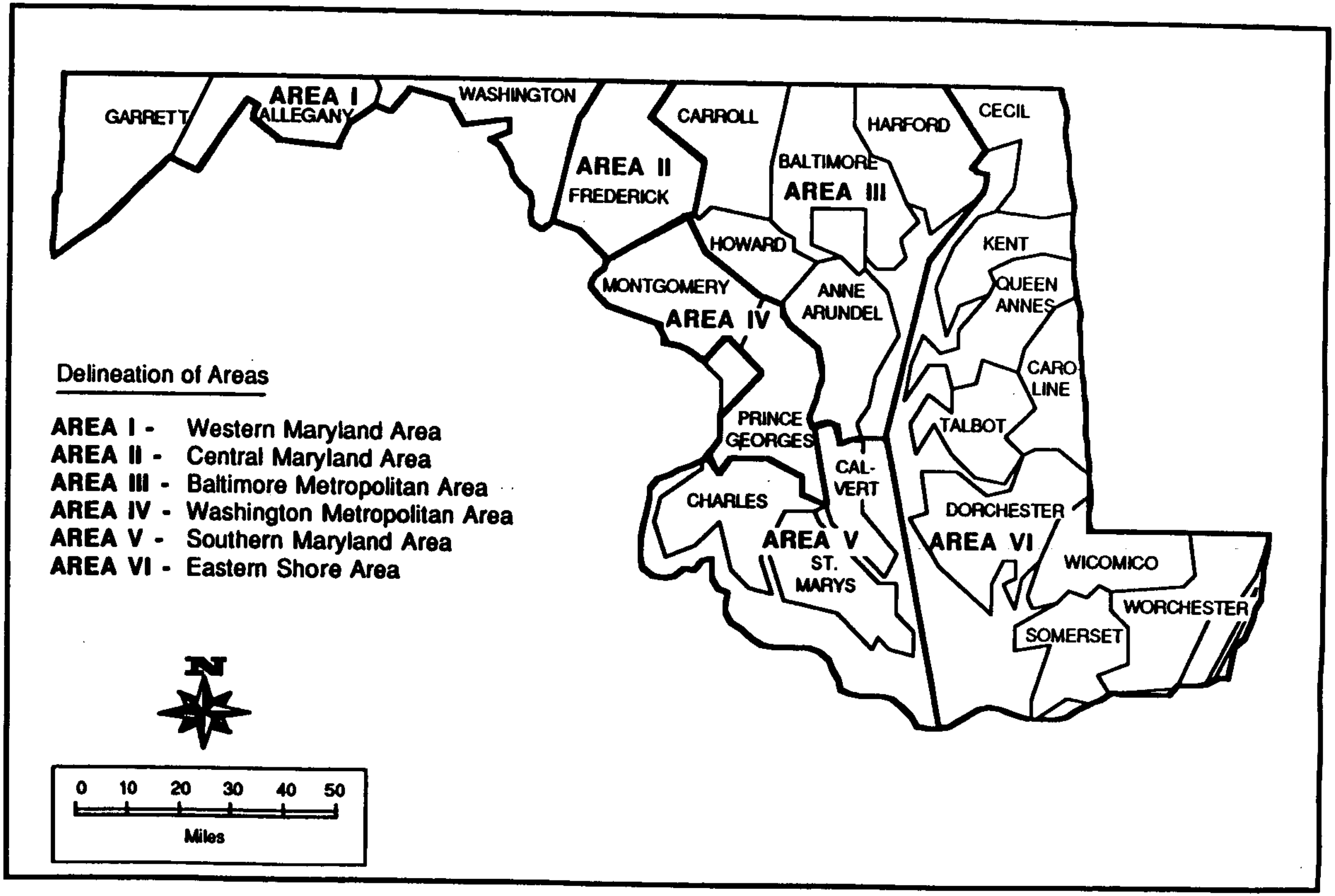

Figure III-14. Maryland State air quality control areas

Emissions Limits and Associated Regulations

While air quality standards form the basis for most air quality control regulations, they cannot be applied directly to pollution sources. They are only enforceable through emissions limits. Emissions are limited so as to enable attainment of NAAQS in the source's area. Hence limits may vary from one source to another. Maryland power plants are subject to emission limits (listed in Table III-5) contained in the SIP for Maryland. Additionally, sources constructed after August 1971 are subject to the New Source Performance Standards (NSPS).

Emissions limits are also established for some toxic air pollutants under National Emissions Standards for Hazardous Air Pollutants (NESHAPS) and Maryland's proposed Air Toxics Regulations. NESHAPS cover asbestos, benzene, beryllium, coke oven emissions, inorganic arsenic, mercury, radionuclides and vinyl chloride. Power plants are not subject directly to NESHAPS. However, since they can emit mercury and beryllium, new plants could be subject to new source review for these pollutants under PSD regulations, which are described below.

Maryland has proposed regulations (COMAR 10.18.15 - Toxic Air Pollutants - Draft) requiring industrial sources to identify and control emissions of certain carcinogens and other pollutants that constitute health hazards. Utility boilers are currently exempt from most of these proposed regulations. Future boilers that burn refuse-derived fuel (RDF), however, will be subject to those regulations. Utilities that come under these regulations would be required to quantify their emissions to demonstrate compliance and determine ambient impacts, and either meet certain screening criteria or demonstrate via risk analysis that public health will not be adversely affected by their emissions.

Regulations Affecting New Sources

New sources of air pollutants must meet different sets of requirements. Those that began construction after August 1971 -- which will include any new Maryland power plants -- must meet federal New Source Performance Standards (NSPS). Table III-7 lists the current NSPS for electric utility steam generators fired by fossil fuels. The State of Maryland also regulates emission limitations for

Table III-7

Revised (1978) new source standards of performance for electric utility steam generators fired by fossils fuels

Pollutant	Emission Limit Applicable to Boilers Constructed after September 18, 1978
Particulate Matter	Solid fuel: 0.03 lb/MMBtu heat input and 99 percent reduction of uncontrolled emissions Liquid fuel: 0.03 lb/MMBtu heat input and 70 percent reduction of uncontrolled emissions Gaseous fuel: 0.03 lb/MMBtu heat input All fuels: opacity of 20 percent; except that 27 percent opacity is permissible for not more than 6 min in any hour
Sulfur Dioxide	Liquid or gaseous fuel: 0.8 lb/MMBtu heat input and 90 percent reduction of uncontrolled emissions OR 0.2 lb/MMBtu heat input[a] Solid fuel: 1.2 lb/MMBtu heat input and 90 percent reduction of uncontrolled emissions OR 0.6 lb/MMBtu and 70 percent reduction of uncontrolled emissions[a]
Nitrogen Oxides	Gaseous fossil fuel: 0.2 lb/MMBtu heat input of NO_2[a] Liquid fossil fuel: 0.3 lb/MMBtu heat input of NO_2[a] Subbituminous coal, shale oil, or any solid, liquid, or gaseous fuel derived from coal: 0.5 lb/MMBtu of NO_x[a] Bituminous or anthracite coal: 0.6 lb/MMBtu of NO_2[a]

Source: 40 CFR 60, Subparts D, Da.
[a] 30-day rolling average

fuel-burning sources (COMAR 10.18.09). The NSPS for utility boilers apply to Maryland power plant boiler, however, and are equal to or more stringent than the Maryland regulations. NSPS are considerably more stringent than emissions limits for older sources. For example, the SO_2 emissions limits of most coal-fired boilers in Maryland are double the NSPS; SO_2 emissions limits of oil-fired boilers are more than five times NSPS. NSPS also require new facilities to reduce uncontrolled emissions by 70 to 99 percent depending on pollutant and type of fuel. Additional NSPS have been promulgated that will affect gas turbines and diesel generators, particularly important for smaller power generation units.

EPA regulations restrict the ways in which stack height may be used in calculating air quality impact for purposes of determining allowable emissions (40 CFR Part 51). In general, the use of tall stacks enhances pollutant dispersion further and thereby lessens the apparent air quality impact of a given rate of emissions; some facilities might therefore use tall stacks in order to avoid restrictive emissions limitations. Prompted by concern over the effects of long range transport of SO_2, EPA's regulations define a Good Engineering Practice (GEP) stack height. Regardless of how high stacks are actually built, for purposes of modeling air quality impact they must be assumed to be no higher than the greater of 65 meters or 2.5 times the height of nearby structures.

Prevention of Significant Deterioration (PSD) regulations are designed to limit air pollution by major new sources or major modifications to existing sources in attainment areas. Most new power plants or major modifications will fall under this guideline. Sources desiring to construct in nonattainment areas are subject to stricter regulations. PSD review will be required for each regulated pollutant unless the new source is located in a nonattainment area for that pollutant or the pollutant will be emitted in amounts less than prescribed levels (listed in Table III-8). To obtain a PSD permit, the source must provide the following on the pollutants requiring PSD review:

- A pollutant-specific Best Available Control Technology (BACT) demonstration. This requires consideration of all technically feasible alternatives for reducing emissions, taking into account energy, environmental, and economic impacts.

Table III-8

Prevention of Significant Deterioration (PSD) significant emission rates

Pollutant	Significant Emission Rate (ton/year)
Total Particulate Matter	25
PM_{10}	15
Sulfur Dioxide	40
Nitrogen Dioxide	40
Ozone	40[a]
Carbon Monoxide	100
Lead	0.6
Gaseous Fluorides	3
Asbestos	0.007
Beryllium	0.0004
Mercury	0.1
Vinyl Chloride	1
Fluorides	3
Sulfuric Acid Mist	7
Hydrogen Sulfide (H_2S)	10
Total Reduced Sulfur (including H_2S)	10
Reduced Sulfur Compounds (including H_2S)	10

Source: 40 CFR 51-52
[a]Emissions of volatile organic compounds.

- An ambient air quality impact analysis to determine whether or not the allowable net emissions from the proposed source, in conjunction with all other applicable sources, would cause or contribute to a violation of the NAAQS or any exceedance of allowable PSD increments. This analysis requirement does not apply to pollutants that have insignificant ground-level impacts.

- Preconstruction ambient air quality monitoring, if ambient levels of the source are demonstrated to be above *de minimis* amounts (see Table III-9) or if representative monitoring data are not available.

- An assessment of the effects of the proposed project and its associated secondary growth (commercial, residential, industrial, and other) on soils, vegetation, and visibility.

- An assessment of the impact on Class I areas (e.g., national parks).

PSD regulations establish "increments," or maximum allowable increases in pollutant concentrations above a baseline. The baseline concentration is determined by air quality on the "trigger date," or the date of the first complete application for PSD review in an area. From that time onward, increases in emissions from all sources, old and new, must not cause exceedances of the increment. Table III-10 lists the increments that have been established to date, for SO_2 and particulates. New sources that require PSD permits must demonstrate that their net emissions will not cause a violation of the NAAQS and PSD increment, and demonstrate that they are employing Best Available Control Technology as defined by federal regulations. For new Maryland power plants or major modifications, PSD review will occur during the Public Service Commission licensing process.

In nonattainment areas, significant new sources must meet the even more stringent requirements of Maryland's New Source Impacting on Nonattainment Area (NSINA) regulations (COMAR 10.18.06.11). These requirements include

Table III-9

Prevention of significant deterioration (PSD) monitoring *de minimis* concentrations

Pollutant	Averaging Period	Monitoring *De Minimis* Concentration (mg/m^3)
Total particulate matter	24-hour	10
PM_{10}	24-hour	10
Sulfur dioxide	24-hour	13
Nitrogen dioxide	Annual (Arithmetic mean)	14
Ozone	1-hour	(a)
Carbon monoxide	8-hour	575
Lead	Calendar Quarter	0.1[b]
Gaseous fluorides	24-hour	0.25

Source: 40 CFR 51-52
[a]Increase in volatile organic compounds of greater than 100 ton/yr.
[b]Three-month average.

Table III-10

Prevention of significant deterioration increments

Pollutant	Averaging Period	Class I	Class II	Class III
Total Particulates	Annual	5	19	37
	24-Hour[a]	10	37	75
Sulfur Dioxide	Annual	2	20	40
	24-Hour[a]	5	91	182
	3-Hour	25	512	700

Source: 40 CFR 51-52.
[a]Concentration not to be exceeded more than once per year.
Note: All Maryland Air Quality Control Regions are Class II.

meeting the lowest achievable emission rates as defined by regulation, securing emissions reductions from nearby sources, bringing all sources owned by the applicant into compliance with the NAAQS by a specified time, and a general improvement in ambient air quality levels.

Recent and Proposed Regulations and Policies

Several new and proposed regulations may have significant implications for how Maryland power plants control their emissions.

- PM_{10}

The recent shift from TSP to a PM_{10} air quality standard is expected to be followed by PSD increments and NSPS for PM_{10}. In the meantime, new source reviews will consider both types of emissions. All of Maryland except Baltimore has been classified as "Group III" for PM_{10}, meaning that the area is believed to be in attainment of the new standard; attainment is uncertain for Baltimore (EPA 1987b). New PM_{10} emissions limits may affect sources with particulate controls already installed as much as those without, since fine particles tend to escape current control devices (EPA 1985a).

In recent years the principal concern over the Maryland power industry's particulate emissions has centered on fugitive emissions form coal and ash handling. Fugitive emissions have proven difficult to quantify, particularly for PM_{10}, and thus compliance demonstrations for new licensing may become more difficult.

- Emissions Trading Policies

Recent EPA policy statements allow for emissions trading -- versions of which may be referred to as bubbles, netting, offsets and banking of emissions reduction credits. All rely essentially on the the concept of "averaging" emissions from adjacent or nearby sources, and assuming that lower emissions from one source compensate for higher emissions from another. Emissions reduction efforts can thus be concentrated on the most easily- or cheaply-controlled source, and the resulting "credit" applied to existing or new sources where control might be more difficult or expensive. This concept can be applied to existing sources (bubbling), PSD permitting (netting), and nonattainment reviews (offsets), and has recently been expanded to include NSPS.

The Maryland Air Management Administration (AMA) does not have a formal bank for emissions reduction credits, but will recognize internal company banking of emissions reduction credits (Solomon 1987b). The EPA will allow the state to approve individual trades without case-by-case review. Emissions trading may be important to the power industry in fuel switching cases.

- Other Recent Developments

Some other recent regulatory developments will have uncertain effect on the Maryland power industry's emissions. The EPA is now under court order to issue PSD increment standards for NO_2 by October 1988, which could affect expansion of existing power plants as well as the growth of smaller power production facilities, particularly those using diesel units (EPA 1987a).

The EPA is considering strategies for ozone nonattainment zones, which include Baltimore and the Maryland portion of the Washington DC area. While power plant emissions of VOC's, precursor pollutants to O_3, are high enough to be considered for new source review, no regulatory strategy has yet appeared; and EPA's main efforts in that area to date have focused on automobile-related rather than large stationary sources.

The EPA is now considering a secondary NAAQS for particulate matter under 2.5 um in diameter, which can affect visibility and climate. Since these impacts occur in conjunction with sulfur oxide emissions, the issue of a fine particle standard is related to that of acid deposition control. Efforts are being made to coordinate strategies on the two issues. Acid deposition control strategies are discussed in Chapter VIII.

New EPA guidelines on air quality modeling (EPA 1986) are expected to have relatively little effect on the power industry for the most part (Lee *et al.* 1986). One new model, the Rough Terrain Dispersion Model, will likely be used to evaluate impacts from the Dickerson Generating Station, its planned Station H expansion, and other sources planned for construction in or near rough terrain.

Energy Conservation Laws and Regulations

Laws stemming from energy conservation concerns have also affected power plant operations. These laws set forth guidelines requiring the use of indigenous coal as the primary fuel source for electric power plants and other fuel-burning installations in the United States. The original legislation was the Energy Supply and Environmental Coordination Act of 1974 (ESECA), which was later expanded and amended by the Energy Policy and Conservation Act of 1975, the National Gas and Petroleum Conservation and Coal Utilization Act of 1977 and the Power Plant and Industrial Fuel Use Act of 1978. The intent of all of this legislation was to lessen dependence on foreign oil supplies, and its overall result has been a nationwide reduction in oil consumption over the last several years (MD-PPRP 1986).

Under the Fuel Use Act, prohibition orders were issued for several power plants in Maryland that would have required conversion from oil to coal. The orders were subsequently dropped for all plants except Brandon Shores (the first unit of which was under construction at the time), before any action on the orders was taken by the utilities. The first Brandon Shores unit came on-line in 1984 and the second unit is scheduled for 1992. The second unit will be required to burn coal under prohibition orders of the Fuel Use Act also. For a variety of reasons, including the high cost of oil and associated supplies in the late 1970's and early 1980's, even plants not specifically required by legislation to convert to coal elected to burn coal where possible. The C.P. Crane and Morgantown plants, and a unit at Wagner, for example, elected to switch to coal. The overall results of the greater dependence on domestic coal can be seen in Figure III-3, which shows oil and coal consumption for all large power plants in and around Maryland from 1976-1986 (in barrels of oil and tons of coal burned converted to Btu input).

Another important feature of the energy conservation legislation is that the coal conversions that were ordered were not subject to PSD review. The conversions were, however, considered to consume PSD increments and were subject to NSPS.

Summary

Government regulation has become one of the most critical influences on power plant emissions, and thereby on their air quality impact. Federal and state regulations promulgated in compliance with the Clean Air Act limit emissions from existing plants to certain levels, and limit emissions from new plants and expansions even more stringently -- particularly in some already-polluted areas. Laws affecting petroleum consumption, together with rising petroleum prices, caused some oil-burning units to convert to coal, thus requiring new emissions control strategies for those units.

D. Future Air Quality Impact Scenarios

This section investigates changes that may occur in the future and affect the cumulative air quality impact of power plants. The potential impacts of currently-imposed new regulations are discussed in Section C. The influencing factors examined here are forecast growth in utility generating capacity, utility decisions to emit sulfur dioxide up to regulated emissions limits, reductions due to proposed acid deposition control legislation and the potential introduction of new technologies. All of these scenarios are subject to change and involve some uncertainty. Further discussion of projected SO_2 and NO_x emissions may be found in Chapter VIII.

Growth in Utility Generating Capacity

Chapter II of this report discusses forecast generation capacity changes in detail. Table III-11 lists planned changes through the year 2000 by each utility operating in Maryland, as forecast by the Public Service Commission of Maryland (MD-PSC 1987). Only those utilities planning any change are included. The base year for tracking changes in generation capacity is 1985, the latest full year for which utility emissions inventories are currently available.

Table III-11

Summary of planned capacity changes and their emissions impact (1988-2001)

Utility	Plant Name and Unit	Capacity Change (MW)	Year Planned	New Unit (N) or Modification (M)	Existing Capacity (MW)	Plant Type	Primary Fuel	Change in Emissions (ton/yr) SO_2	NO_x	PM
BG&E	Wagner #4	+33	1986	M	365	steam boiler	oil	230	155	10
	Wagner #3	+49	1987	M	270	steam boiler	coal	840	460	30
	Brandon Shores #1	+20	1991	M	620	steam boiler	coal	530	250	14
	Brandon Shores #2	+620	1992	N	N/A	steam boiler	coal	16,450	7,700	425
	Westport #3 and #4	-126	1992	M	126	steam boiler	coal	-3,700	-1,600	-100
	Unnamed	+100	1996	N	N/A	combustion turbine	oil	600	900	80
	Unnamed	+100	1997	N	N/A	combustion turbine	oil	600	900	80
	Perryman	+400	1999	N	N/A	steam boiler	coal	3,000	2,900	290
DP&L	Nanticoke #1	+150	1999	N	N/A	steam boiler	coal	1,200	1,100	110
EUC[a]	Power Plant #2	+12.5	1988	N	N/A	diesel	oil	110	950	95
	Unnamed	+15	1992	N	N/A	diesel	oil	130	1,145	114
	Unnamed	+20	1996	N	N/A	diesel	oil	175	1,500	150
	Unnamed	+20	2000	N	N/A	diesel	oil	175	1,500	150

Table III-11 (continued)

Summary of planned capacity changes and their emissions impact (1988-2001)

Utility	Plant Name and Unit	Capacity Change (MW)	Year Planned	New Unit (N) or Modification (M)	Existing Capacity (MW)	Plant Type	Primary Fuel	Projected Change in Emissions (ton/yr) SO_2	NO_x	PM
PEPCO	Dickerson	+125	1994	N	N/A	combustion turbine	oil	750	1,100	100
	Dickerson	+125	1995	N	N/A	combustion turbine	oil	750	1,100	100
	Dickerson	+125	1996	N	N/A	combustion turbine	oil	750	1,100	100
	Dickerson	+125	1998	N	N/A	combustion turbine	oil	750	1,100	100
	Dickerson	+125	1999	N	N/A	steam boiler/ turbine	N/A(b)	0	0	0
	Dickerson	+125	2000	N	N/A	steam boiler/ turbine	N/A(b)	0	0	0
	Chalk Point(c)	+60	1991	N	N/A	gas turbine	gas	5	200	12

Source: PSC 1987; EPA 1985c; MD-AMA 1985.

(a) Easton Utilities Commission
(b) These steam units will be powered by exhaust gases from the four gas turbine units in a combined-cycle configuration. Therefore, no additonal fuel (or emissions) are expected from these units.
(c) This is a peaking unit limited to a maximum of 1500 operating hrs/yr, on which the yearly emission estimates are based.

The power plants listed in Table III-11 plan a net total of 2,224 MW of additional utility capacity, about a 28 percent increase. About 51 percent of the planned net increase in capacity is from new coal-fired facilities, 48 percent is from new gas turbines or diesel units fired by oil or natural gas, and the remaining 1 percent is attributable to fuel-independent "up-rating," or modifications to existing systems in order to increase their output. These capacity additions and deletions have been used to estimate annual stack emissions increases (or decreases) in SO_2, NO_x, and particulates; the results are included in Table III-11. The latest available emissions data from the Maryland AMA have been used to compute the emissions changes for existing plants. For new facilities, a combination of EPA-recommended emission factors (EPA 1985c) and, where applicable, New Source Performance Standards (NSPS) were used in the computations. For both new plants and modifications to existing plants, a capacity factor of 55 percent was assumed, which appears to be typical of Maryland utilities (MD-PSC 1987).

The projected trends in total annual stack emissions from Maryland utilities resulting from the estimated changes are shown in Figure III-15. SO_2 emissions show an increase of about 11 percent during the period 1985-2000. The increase is relatively low compared to the net capacity increase of 28 percent, due to the NSPS limitations on SO_2 emissions from new sources. Because it is such a large source, the planned introduction of the 620 MW Brandon Shores Unit 2 by BG&E in 1992 is projected to have the most significant effect on annual SO_2 emissions during the period.

Annual NO_x emissions are projected to remain relatively steady until 1991, after which the Brandon Shores Unit 2 will cause a sharp increase. Thereafter, NO_x emissions will grow steadily through the year 2000, mainly due to the planned introduction of several combustion turbines and diesel units. Total NO_x emissions should increase by about 34 percent over the 1985-2000 time frame. Projected PM emissions show a trend very similar to that for NO_x, for an increase of 45 percent over the period. The increase is slightly higher than the NO_x increase due to the assumption that, as in current practice, combustion turbines and diesel units will not be fitted with particulate controls.

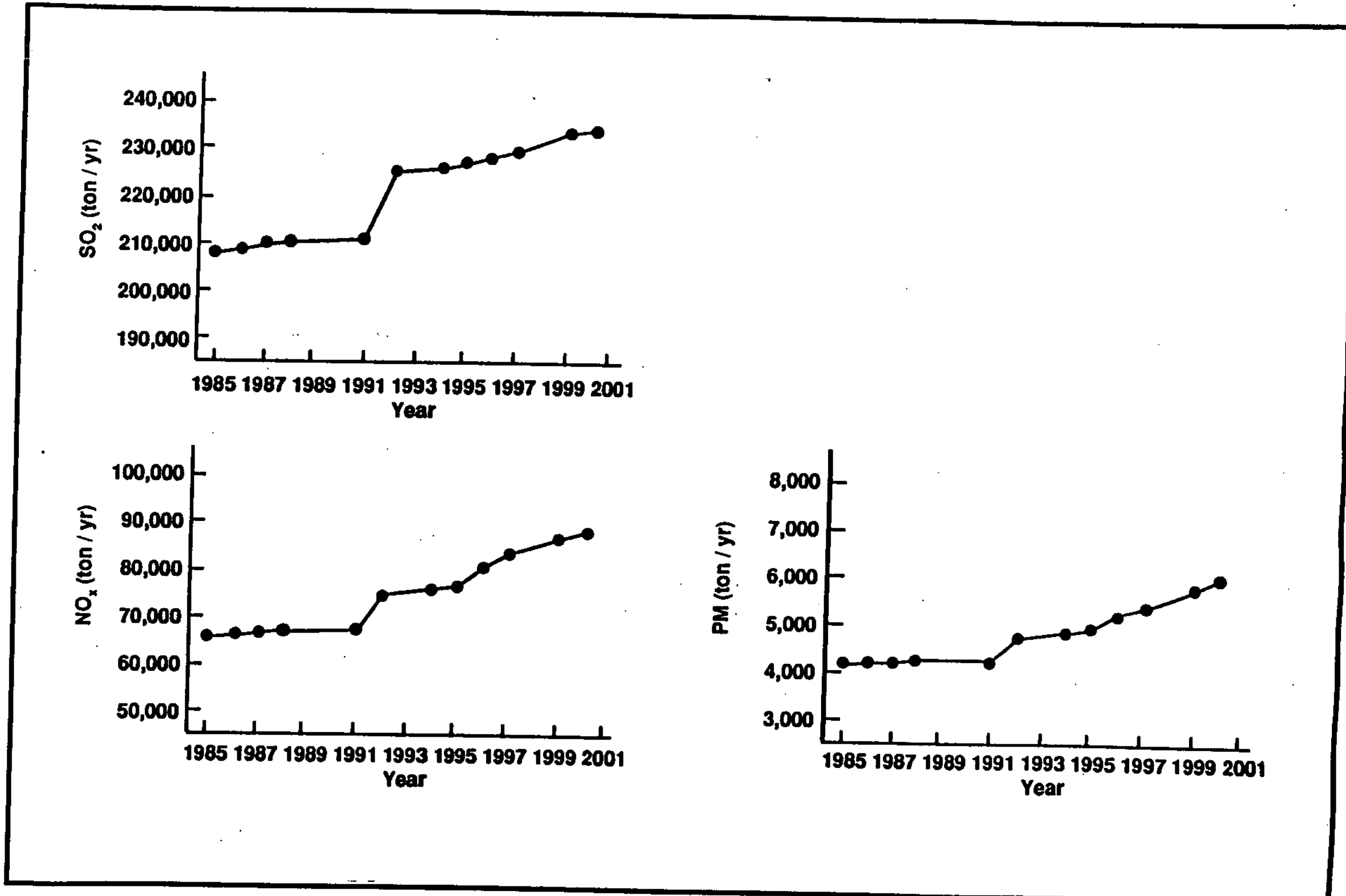

Figure III-15. Projected emission, 1987-2000, of SO_2 (left top), NO_x (left bottom), and particulate matter (right)

The emissions increases described above do not directly translate into commensurate increases in ground-level concentrations of pollutants, because they do not all occur over the same area. The biggest projected increase in emissions at any one location is due to the introduction of the 620 MW Brandon Shores plant Unit 2. Therefore, examining the impact of this addition can provide an indication of worst-case air quality impact (i.e., the highest expected increase in ground-level concentrations of pollutants at any one location). A previous study (Kumar *et al.* 1986) estimated that the addition of Brandon Shores Unit 2 will cause a maximum increase of about 22 ug/m^3. This increase (22 ug/m^3) in 24-hr average ground-level concentrations of SO_2 is about 20 percent of the maximum concentration that would be observed in the area without any changes. The maximum increase in 24-hr average PM concentrations is forecast to be about 1 ug/m^3, or less than 1 percent of the maximum that would be observed in the vicinity. Annual-average values of SO_2, PM, and NO_2 are projected to increase by about 0.5, 0.03, and 0.32 ug/m^3, respectively, within a radius of about 10 km of the plant. These increases are small (less than 1 percent) compared to the maximum concentrations that could be observed in the vicinity of the plant.

Increases Due to Plants Emitting SO_2 Up to Their Regulated Limits

In 1984, all of Maryland's major power plants emitted SO_2 at rates below their regulated limits. Under a "worst case" scenario, the plants could legally increase their SO_2 emissions up to the regulated limits. The Model States Program described in Section A of this chapter was used to investigate the impacts of air quality under this scenario.

For this scenario, 1984 SO_2 emissions, fuel use, and fuel heat content data from the Maryland AMA were used to compute potential SO_2 emission rates. The 1984 actual emission rates obtained from the AMA were adjusted upward by the ratio of the regulated SO_2 emission limits to the actual 1984 emission rates. These adjusted emission rates were then used to compute annual average SO_2 impacts from power plants burning fuel at their SO_2 limits. Model assumptions were the same as those used for the Model States impact analysis described in Section B.

Overall, the maximum annual SO_2 ground-level concentration was predicted to be about 5.9 ug/m^3, a 13.5 percent increase above the 5.2 ug/m^3 calculated at the actual 1984 emission rates, which were around 90% of designated emissions limits for most plants. The pattern of the SO_2 impact was similar to actual 1984 patterns (see Figure III-10), with the maximum impact occurring east of the Baltimore area. The area with the greatest increase in ground-level impact was the area around Charles-St. Marys Counties, not the Baltimore metropolitan area. (See Figure III-16, which shows the increase in SO_2 ground-level concentration under the worst case scenario.) This worst case increase of about 20 percent occurred here because the actual emission rates at the two power plants in the vicinity (Morgantown and Chalk Point) are currently under their regulated limits. Also, because these two plants are among the largest in the state, any change in their emissions will have a large observable impact relative to other plants in the state.

Results of the modeling indicate that overall maximum ground-level SO_2 concentrations in Maryland could increase by 13 percent if power plants emit SO_2 at their regulated limits. The increase could be as much as 20 percent in certain areas where larger power plants have emitted SO_2 below their regulated limits.

Reductions Due to Proposed Acid Deposition Control Bills

Current acid deposition control proposals include provisions for control of SO_2 and NO_x emissions from both existing and new sources. Those proposals are discussed in Chapter VIII. The Maryland Power Plant Research Program, in cooperation with the utilities, developed a hypothetical acid rain control scenario that integrates many of the common elements of the proposals (MD-PPRP 1985). The hypothetical scenario was used to estimate statewide SO_2 emission reductions and to apportion them among utilities operating in Maryland. The principal assumptions made pertaining to power plants operating in Maryland were that:

- National legislation would be passed requiring a 12 million ton reduction by 1995 from 1980 SO_2 emission levels. The bill would not include an emissions cap.

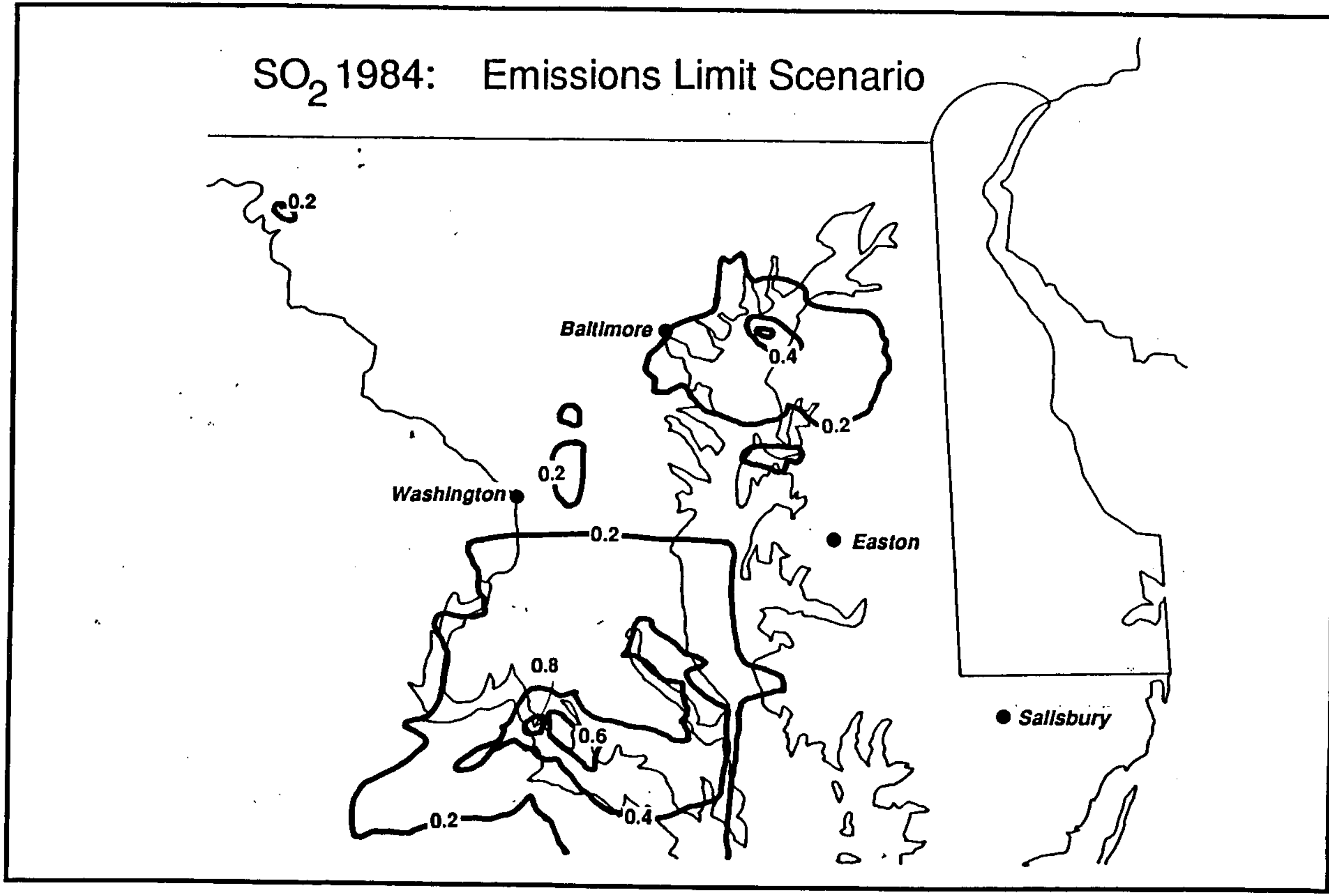

Figure III-16. **Contours of increases in model-predicted annual SO_2 ground-level concentrations ($\mu g/m^3$) attributable to power plants emitting at their SO_2 limits. Minimum contour is 0.2 $\mu g/m^3$, contour interval is 0.2 $\mu g/m^3$**

- Only reductions in SO_2 emissions would be required.

- All reductions in Maryland would come from utilities and would be allocated to them according to their emissions in excess of 1.2 lb/MMBtu.

According to this scenario, a total reduction in SO_2 emission of 125,000 ton/yr would result by 1995. The new level would be about 55 percent below the projected 1995 emissions of 225,000 ton/yr in the absence of acid deposition legislation.

Although the acid deposition bills currently pending in Congress focus more on NO_x control than did earlier legislation, it is difficult to quantify the effect of these provisions, since analyses giving the required state-by-state emission reduction allocations are lacking at this time.

New Technologies and Pollution Control

Concern over the environmental impacts of fossil-fuel combustion has been a major driving factor in the development of new technologies for power production and pollution control. Electric utilities use over 80 percent of U.S. coal production. Thus, improvements in the environmental impacts caused by this sector are worth seeking and can be of great significance. This subsection lists new, environmentally "cleaner" technologies for power production, their advantages and their status:

- Advanced coal cleaning methods, which have the potential to remove around 80% of pyritic sulfur. These technologies are currently in the developmental stage.

- Advanced conventional flue gas desulfurization techniques, which can achieve 90-95 percent SO_2 control. Several processes are being or have been tested at the large pilot and commercial scale.

- Advanced regenerable FGD systems, which recover sulfur byproducts and can remove more than 95 percent of the SO_2 and up to 90 percent of the NO_x. These processes are currently at the small pilot scale except for the activated carbon process, which has been tested at commercial scale in Japan.

- Furnace sorbent injection, which can achieve between 35 and 60 percent SO_2 removal. This process is under demonstration at two U.S. power plants.

- Duct sorbent injection processes, which can capture 40 to 70 percent of SO_2. These processes are in various stages of development.

- Combustion modifications for NO_x control, such as redesign of burners or rearrangement of fuel and oil flows to the furnace, which typically achieve 40-60 percent removals singly and up to 80 percent in combination. These processes have been widely applied on new units to meet NSPS.

- Post-combustion NO_x control, capable of NO_x reductions up to 80 percent or more alone and up to 90 percent in conjunction with a low-NO_x burner. One process, selective catalytic reduction, has been commercially applied in Japan.

- Atmospheric Fluidized Bed Combustion (AFBC), capable of removing high percentages of SO_2 and lowering NO_x emissions. AFBC is now undergoing a demonstration program sponsored by several U.S. electric utilities.

- Pressurized Fluidized Bed Combustion, which can exceed 90 percent SO_2 removal and achieve NO_x emissions 2-3 times lower than current NSPS. The PFBC boiler is now at the point of readiness for commercial demonstration.

- Coal Gasification Combined Cycle (GCC), which can produce low SO_2 emissions, is now slated for installation at PEPCO's Dickerson site.

Summary

Utility capacity has been forecast to grow by about 28 percent in the next 15 years. It has been estimated that growth in SO_2 emissions will be limited to about 11 percent due to NSPS limits on new units, while NO_x and PM increases will be about 34 percent and 45 percent, respectively, mainly due to the planned introduction of several gas turbine and diesel units. These emissions increases do not imply a commensurate increase in ground-level pollutant concentrations, and it is expected that even the worst-case impacts will not cause any PSD violations. Acid deposition control legislation could require as much as a 55 percent reduction in utility SO_2 emissions in Maryland by 1995. The implications for NO_x emissions cannot be quantified at this time. Several new technologies for power production and pollution control are in various stages of development and demonstration, with the potential to significantly reduce pollutant emissions.

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CHAPTER IV

AQUATIC IMPACT

The generation of electricity is closely associated with rivers, lakes and estuaries. They serve as sources of cooling water, receiving bodies for effluents and sites for hydroelectric generation. Power generation activities can affect the aquatic environment in several ways, which ultimately affect humans through their impact on food supplies and to some extent on recreational areas.

The Chesapeake Bay is one of the largest and most productive estuaries in the world, supporting a complex food web that produces large quantities of fish and shellfish. The Bay's food web includes microscopic algae, called phytoplankton; small animals, called zooplankton; dead and decaying matter, called detritus, and the microorganisms that decompose it; biota that live on the bottom, called benthic organisms; forage fish such as anchovies and menhaden; larger fish, like white perch, striped bass and bluefish; and crabs. Maryland's rivers and streams also support complex assemblages of organisms, comprising food webs comparable to those found in the Chesapeake Bay.

The Chesapeake Bay and its tributaries serve as the major source of cooling water for electric generation in Maryland and also as receiving water bodies for power plant effluents. A steam power plant using fossil fuel must expel about 4,400 Btu of excess heat via its condenser for each kilowatt-hour of electricity generated. (For a nuclear power plant, the figure is about 6,600 Btu/kWh.) Most Maryland steam power plants use once-through cooling systems to transport this excess heat from the condensers to the environment. Such systems continuously draw "new" water into the plant from a source water body, heat it 5° to 17°C as it passes the condenser and discharge it into a receiving water body. Approximately 1,440 million gallons per day (mgd) of water (or 63 m^3/sec) is required for each 1,000 MW of generating capacity with once-through cooling. Closed-cycle cooling, which is used at three major Maryland power plants, "recycles" cooling water in a cooling tower. Facilities with closed-cycle cooling draw new water to make up for evaporative losses and to clean internal parts of their cooling towers. Water requirements for closed-cycle systems are 2 to 25% of those for once-through systems.

Hydroelectric power plants utilize the potential energy of impounded water to generate electricity. The construction, filling and operation of dams (for hydroelectric power or for other purposes) may change water quality and the physical characteristics of upstream and downstream habitats, and alter the migration patterns of anadromous fish. Some hydroelectric facilities in Maryland are installed where impoundments already exist; in such cases, no dam construction impacts are attributable to the power facility.

This chapter is the cumulative impact assessment for the aquatic environment. It discusses information from current research into power plant impacts in detail, and summarizes studies covered in earlier CEIR's. For details of these earlier studies, readers should refer to previous CEIR's (MD-PPRP 1975, 1978, 1982, 1984, 1986) or the original sources cited.

A. Sources and Nature of Impact

As water is drawn through a steam or hydroelectric power plant and returned to the receiving water body, aquatic biota may be injured or killed by their interaction with plant structures or by plant-related environmental alterations. The location and nature of these interactions and the ensuing stresses encountered by aquatic biota are briefly described below. A detailed description of these interactions, and the stresses to aquatic biota associated with them, was presented in previous CEIR's (MD-PPRP 1975, 1978, 1982, 1984, 1986). Different organisms are susceptible to damage from different types of interaction, as shown in Table IV-1.

Types of Impacts for Steam Electric Stations

For steam electric stations, impacts can be classified in four major categories: entrapment, impingement, entrainment and discharge effects. Figure IV-1 illustrates where these impacts occur.

Table IV-1
Major types of aquatic effects of steam electric and hydroeletric power plant operations.

Source of Effects	Primary Susceptible Organisms	Type of Stress: Low DO	Mechanical	Thermal	Chemical	Habitat Alteration
		STEAM ELECTRIC POWER PLANTS				
Entrainment	Phytoplankton (a)		X	X	X	
	Zooplankton (b)		X	X	X	
	Ichthyoplankton (c)	X	X	X	X	
	Adult and juvenile fish	X	X	X	X	
Entrapment	Adult and juvenile fish and crabs	X				
Impingement	Adult and juvenile fish and crabs		X	X(d)	X(d)	
Discharge	Benthos (e)	X		X	X	X
	Shellfish (e)	X				
	Adult and juvenile fish (f)	X				
		HYDROELECTRIC FACILITIES				
Creation of Impoundment	All biota	X				X
Entrainment	Adult and juvenile fish	X	X			
Discharge	Benthos	X				X
	Adult and juvenile fish (e)	X				X
	Ichthyoplankton (f)	X				X

(a)Minute plants present in the water.
(b)Weak swimming animals in the water.
(c)Eggs and larvae of fish.
(d)Only applicable for power plants where impinged biota are returned to the receiving water with discharge waters.
(e)Organisms living in or on the bottom, including shellfish.
(f)Discharge effects on mobile taxa, such as fish, crabs, or plankton, whose behavior and distributions may be strongly influenced by hydrodynamic conditions are extremely difficult to detect.

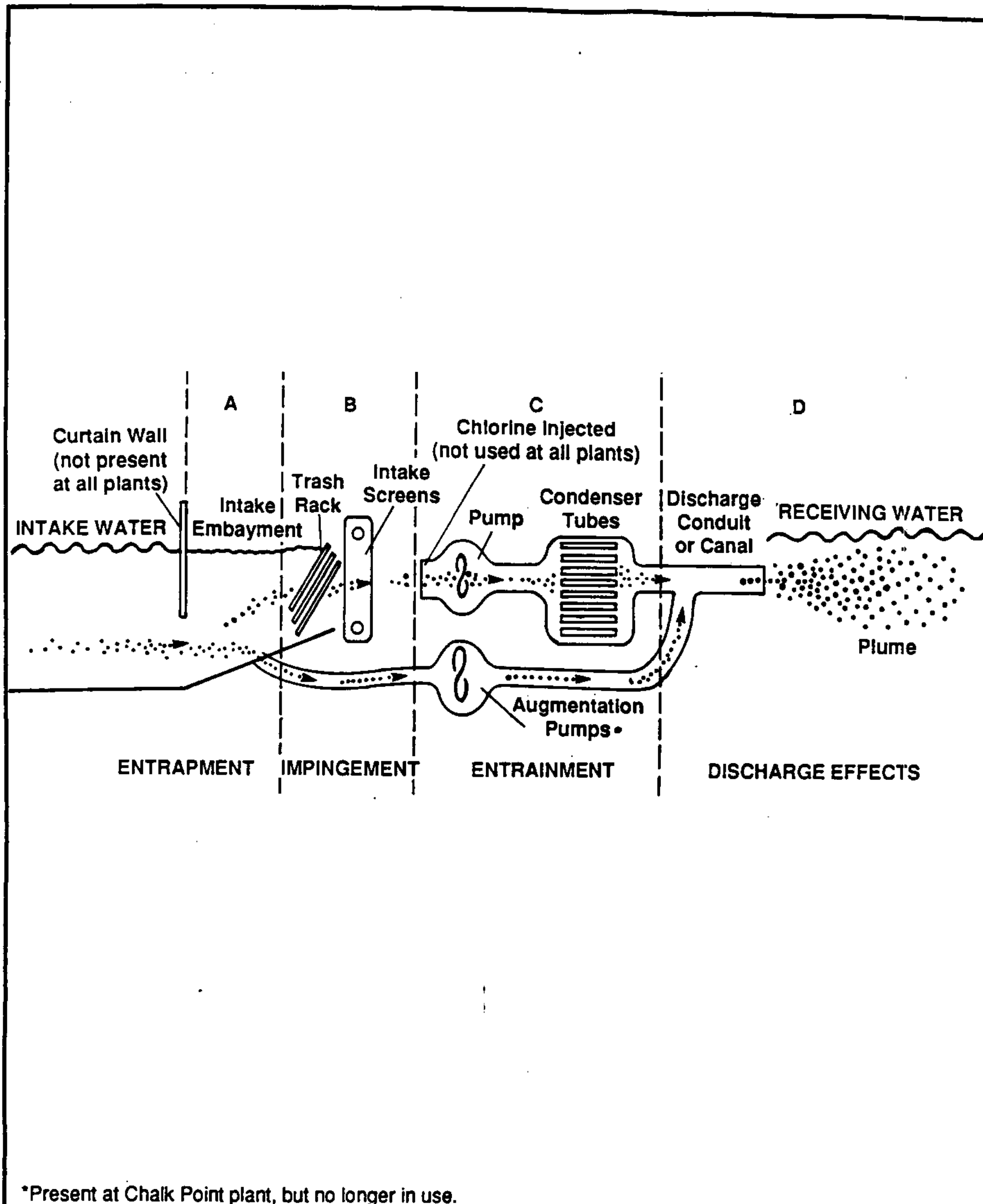

Figure IV-1. Path of water flow through a power plant using once-through cooling and zones of effects on organisms

- Entrapment

Entrapment is the accumulation of fish and crabs (brought in with cooling water flows) in the intake region (Area A in Figure IV-1). Plant intake regions are not always clearly delineated. There they may be exposed to water of low dissolved oxygen content that is drawn in with intake flows, which can weaken or kill them. They may also become weak from prolonged swimming against intake flows and eventually die or become impinged.

- Impingement

Larger organisms may become trapped on barriers protecting internal plant structures (e.g., intake screens, barrier nets) (Area B, Figure IV-1). They may become physically damaged and thus more susceptible to disease and less able to compete when returned to the receiving water body. The methods used to remove impinged organisms from barriers and return them to the receiving water body determine, to a large degree, the magnitude of impingement mortality.

- Entrainment

Smaller organisms such as plankton may become entrained, or transported through the plant cooling system and auxiliary pumps. During entrainment, their contact with cooling system structures and their exposure to high-velocity water, heated effluents and chemicals used to prevent biofouling, may cause physical damage and death. Larger organisms became entrained by unscreened augmentation pumps at Chalk Point, before its pumps were shut down. (Area C of Figure IV-1). Entrainment and impingement are believed to be the primary mechanisms through which power plants adversely effect Maryland's aquatic habitats (MMES 1985a).

- Discharge Effects

Discharge effects are the behavioral and physiological changes (including death) that result from the exposure of aquatic biota to heated effluents, chemicals used to control biofouling (e.g., chlorine) and metals eroded from internal plant structures (e.g., copper). Discharges may also modify the overall physical and chemical properties of the water downstream (e.g., salinity regime, sediment characteristics), thus changing the kinds and abundance of organisms at the discharge site. Biological effects resulting from exposure to thermal effluents depend upon the maximum temperature reached, the magnitude of the temperature increase and the duration of exposure. Thermal mortality is generally a major concern when discharge temperature exceeds 35° C (95° F). Chlorine, toxic to most biota in the ppb to ppm range, is a major concern when the concentration in plant effluents is greater than 0.2 ppm. Copper eroded from condenser tubes accumulates in the tissues of some aquatic biota (e.g., oysters). High tissue copper levels (0.5-100 ppm) may cause direct mortality or adversely affect growth and reproduction. When organisms containing high tissue levels of copper are eaten, copper may be passed up the food web and adversely affect higher trophic levels. Copper that accumulates in sediments is a potential long-term risk to the aquatic ecosystem.

Although fewer organisms are entrained by closed-cycle cooling systems, their high retention time causes essentially 100% mortality. Concentrations of pollutants in water discharged from cooling towers (blowdown) can be from five to 200 times as high as in once-through cooling water. Because less water is discharged in blowdown release, discharge effects occur in a smaller area.

Types of Impacts for Hydroelectric Facilities

The development and operation of hydroelectric facilities can cause three types of impacts: alterations of water quality, fluctuations in water level and prevention of successful fish passage.

- Alterations of Water Quality

The major water quality parameters that are affected by hydroelectric generation are turbidity, dissolved oxygen concentration, nutrient concentrations and water temperature. These can occur both upstream and downstream of the dam (Areas A and E, Figure IV-2). Changes in turbidity are usually associated with activities for clearing sediment, such as dredging or the deliberate discharge of water through mud gates. Turbidity is a special concern when sedimentation of the