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ANNUAL EMISSIONS AND AIR-QUALITY IMPACTS OF AN URBAN AREA DISTRICT-HEATING SYSTEM: BOSTON CASE STUDY

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ANNUAL EMISSIONS AND AIR QUALITY IMACTS OF AN URBAN AREA DISTRICT HEATING SYTEM -- BOSTON CASE STUDY

by

Stephen S. Bernow, David R. McAnulty and Steven Buchsbaum, ESRG
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ABSTRACT

A district heating system, based on thermal energy from power plants retrofitted to operate in the cogeneration mode, is expected to improve local air quality. This possibility has been examined by comparing the emissions of five major atmospheric pollutants, i.e., particulates, sulfur oxides, carbon monoxide, hydrocarbons, and nitrogen oxides, from the existing heating and electric system in the City of Boston with those from a proposed district heating system. Detailed, spatial distribution of existing heating load and fuel mix is developed to specify emissions associated with exsiting heating systems. Actual electric power plant parameters and generation for the base year are specified. Additional plant fuel consumption and emissions resulting from cogeneration operation have been estimated. Six alternative fuel emissions control scenarios are considered.

The average annual ground-level concentrations of sulfur oxides are calculated using a modified form of the EPA's Climatological Dispersion Model. This report describes the methodology, the results and their implications, and the areas for extended investigation.

The initial results confirm expectations. Average sulfur oxides concentrations at various points within and near the city drop by up to 85% in the existing fuels scenarios and by 95% in scenarios in which different fuels and more stringent emissions controls at the plants are used. These reductions are relative to concentrations caused by fuel combustion for heating and large commercial and industrial process uses within the city and Boston Edison Co. electric generation. Absolute values, which would require modeling of other sources near the city, have not been developed.

1 INTRODUCTION

This report examines the emissions and air-quality impacts that would occur if district heating, using cogenerated thermal energy (supplied as hot water) from the retrofit of existing central-station power plants, were implemented. In particular, the report focuses on: (1) the emissions of five atomospheric pollutants, i.e., particulates, sulfur oxides, hydrocarbons, carbon monoxide, and nitrogen oxides, and (2) the average annual ground level concentrations of one of these, i.e., the sulfur oxides. Previous work[1-4] has considered some aspects of the design, technical, economic, and fuel savings of such hypothetical district heating systems for nine northeastern and midwestern cities.

The main findings of earlier research were that in these major urban areas, space-heating and hot-water demands for the residential, commercial, and industrial sectors, could be achieved with substantial reduction in total fuel use, in particular that of oil and gas, and at costs that are presently within the range of economic feasibility. The very conditions that make these district heating systems attractive from the viewpoints of economics and scarce-fuel-savings also suggest the possibility of an additional benefit, i.e., the improvement in overall air quality, especially in the core areas of these cities. High concentrations of building space that demand heat within relatively cold climates make the major urban areas in the northern parts of the country particularly attractive for potential fuel savings. Furthermore, the high seasonal demand density (demand per unit area) should allow lower distribution and could provide more heating services. Finally, a high ratio of seasonal (or average) demand to peak demand allows more efficient use of capital. For example, a given pipe capacity [or diameter] can provide more heating services. Thus, the high-density commercial and residential areas of cities in the colder, northern latitudes afford the best opportunities for large fuel savings at competitive costs of service through district heating with combined electric/thermal plants.

The high demand density, as well as the overall density of activity in these areas, also allows the potential air-quality benefit derivable from these district heating systems. Emissions and average ground-level concentrations of the various atmospheric pollutants are substantial in these areas because of fuel combustion for: (1) domestic, commercial, and industrial heating; (2) vehicular traffic and commercial and industrial processes; and (3) utility electric generation. By reducing the overall combustion of these fuels for heating, it is possible correspondingly to reduce the associated emissions. Furthermore, because atmospheric emissions (especially sulfur oxides) per unit of fuel consumed generally are greater for fuel oil than for gas, special attention is drawn to those urban areas where high heating demand is served predominantly through the combustion of oil.

Taken together, the objectives of reducing oil consumption, providing economical heating service, and improving air quality suggest that the core areas of dense northeastern cities should be given initial attention. Among the cities studied in the previous district heating research, Boston was selected as the case study for potential emissions and air quality benefits. The tradeoffs in emissions of the five atmospheric pollutants -- particulates, sulfur oxides, hydrocarbons, carbon monoxide, and nitrogen oxides -- and in the average annual ground-level concentrations of sulfur oxides (at numerous locations in and around the city) are estimated for a hypothetical district heating system referenced to a Base Case scenario embodying the 1977 Boston area electric generation, power plants, heating fuel consumption, and air quality characteristics. Scenarios for which emissions and air quality tradeoffs were estimated inlcude:

I. implementing the district heating system by retrofitting existing power plants located in or near the city (2195 MW oil-fired and 655 MW nuclear);

II. implementing the district heating system assuming that all power plant residual oil is at 0.5% sulfur content;

III. implementing the district heating system after some of the major oil-fired facilities have been converted to coal-fired units (1487 MW of the 2195 MW total), assuming that the April, 1977 New Source Performance Standards (NSPS) governing particulates, sulfur oxides, and nitrogen oxides would apply to these units; and

IV. implementing the district heating system after coal-conversion, assuming that more stringent emissions controls for particulates and sulfur oxides (99.5% and 90% respectively) were put into effect.

In practice, the extra fuel consumed at the power plants in a cogeneration/district heating system will be far less than the heating fuel displaced in the domestic, commercial, and industrial sectors. This, by iteself, would suggest lower emissions in a district heating scenario. However, depending on the levels of control, the additional fuel consumed at the power plants could be "dirtier" than the local heating fuel displaced. Thus, for example, in Boston, power plant fuel is primarily residual oil with 1% sulfur content; whereas, local heating fuel is a mixture of gas, distillate oil (at 0.3% sulfur content) and residual oil (at 0.5% sulfur content). As a result, an overall increase of specific pollutant emissions (especially particulates and sulfur oxides) is possible if existing power plant fuels are used and sulfur oxides) is possible if existing power plant fuels are used during district heating. However, ground-level air quality within the urban region can be significantly improved by the shift of fuel combustion for heating from spatially spread load sites at low stack heights to a small number of point sources with high stack heights located away from the load sites. An urban area diffusion model is used to calculate the effects on ground-level concentrations of sulfur oxides at prevailing climatological conditions, particularly wind speed distribution, source intensities, locations, and stack parameters. Because the high-density load centers are the same areas in which air-quality improvements are most desirable, the dispersion effects on increased emissions from the point sites, along with elimination of emissions at the load sites themselves, could combine to produce improvements in local air quality.

1.1 SUMMARY OF RESULTS

The analysis of emissions and air quality (sulfur oxides concentrations) tradeoffs resulting from the implementation of cogeneration district

	No District Heating	District Heating	Emissions Characteristics
Oil Scenarios	IA	IB	Existing Residual Oil at 1% sulfur
	IIA	IIB	Residual Oil at 0.5% sulfur
Coal Scenarios	IIIA	IIIB	Coal at New Source Peformance Standards (NSPS)
	IVA	IVB	Coal at maximum control levels 99.5% particulates 90% sulfur oxides

heating in the City of Boston was applied to four pairs of scenarios: two using the existing plant fuel mix (Oil Scenarios), and two using a fuel mix from conversion of some facilities to coal (Coal Scenarios). These are specified below:

Oil Scenarios IIA and IIB were developed to explore the consequences of the Massachusetts Department of Environmental Quality Engineering regulations (Jan. 1, 1978) which restrict the sulfur content of residual oil in the Boston area to 0.5% maximum. These restrictions did not pertain to several large Boston Edison plants in 1977 because of variances issued. Nevertheless, it is important to examine the consequences of the enforcement of these limitations.

Coal Scenarios IIIA, IIIB, IVA and IVB were developed to explore the consequences of coal conversion at some of the major utility plants. One major advantage of district heating is substantial savings in scarce fuel (oil and gas). Similarly, utility conversion to coal is viewed as an instrument for scarce-fuel savings. Thus, district heating with coal would result in even greater scarce-fuel savings than district heating using the existing plant fuel mix. However, the emissions and air quality impacts of such a combined conversion (cogeneration/coal) could cause problems that might offset benefits of scarce-fuel savings. Therefore, it is important to examine these consequences. The two pairs of Coal Scenarios, III and IV, were constructed to represent different levels of controls on particulates, sulfur oxides, and nitrogen oxides.

Table 1.1 summarizes the main results of this study concerning the emissions of the five atmospheric pollutants and for the average, annual ground-level concentrations of sulfur oxides at selected locations in Boston. (These locations can be identified on the map in Fig. 1.2). Examination of the emissions associated with each scenario in Table 1.1 shows the various tradeoffs associated with: (1) district heating, (2) plant fuels, (3) plant

Table 1.1 Summary of Boston Air Quality and Emissions Study

Scenario		No.		Fuel 10^{12}Btu/yr	Parti-culates	Sulfur oxides	Carbon Mon-oxide	Hydro-carbons	Nitrogen Oxides	CBD	Back Bay	Charles-town	East Boston	South Boston	Rox-bury	Dor-chester	Brigh-ton
				Emissions from Boston Htg. and Elec. Requirements (t/yr)						Model Air Quality: Average Annual SO_x Concentration in Boston ($\mu g/m^3$)							
OIL	Existing Plant	IA	Base Scenario. (1977)	160.0	5430	64,914	2624	556	26,111	17.9	18.6	14.0	19.3	29.2	21.0	17.6	16.0
	Fuels	IB	Distr. Htg.	120.6	5551	68,754	2054	416	25,344	4.5	4.5	4.0	6.1	3.8	3.0	3.4	4.5
			Change	-39.4	+121	+3,840	-570	-140	.767	-13.4	-14.1	-10.0	-13.2	-25.4	-18.0	-14.2	-11.5
			(% Change]	(-24.6)	(+2.2)	(+5.9)	(-21.7)	(-25.2)	(-2.9)	(-75)	(-76)	(-71)	(-68)	(-87)	(-86)	(-81)	(-72)
OIL	Residual Oil at .5% Sulphur	IIA	No. Distr. Htg.	160.0	3547	34,809	2624	556	26,111	16.9	17.3	13.5	18.4	28.4	20.0	16.2	14.6
		IIB	Distr. Htg.	120.6	3222	32,347	2054	416	25,344	3.3	2.8	3.4	4.7	2.9	1.9	1.8	2.7
			Change	-39.4	-325	-2,462	-570	-140	-767	-13.6	-14.5	-10.1	-13.7	-25.5	-18.1	-14.4	-11.9
			(% Change)	(-24.6)	(-9.2)	(-7.1)	(-21.7)	(-25.2)	(-2.9)	(-80)	(-84)	(-75)	(-74)	(-90)	(-91)	(-89)	(-82)
			Change from Base Scenario	-39.4	-2210	-32,587	-570	-140	-767	-14.6	-15.8	-10.6	-14.6	-26.3	-19.1	-15.8	-13.3
			(% Change)	(-24.6)	(-40.7)	(-50.2)	(-21.7)	(-25.2)	(-2.9)	(-82)	(-85)	(-76)	(-76)	(-90)	(-91)	(-90)	(-83)
COAL	New Source Performance Standards	IIIA	No. Distr. Htg.	160.0	5309	61,310	2820	708	33,705	18.0	18.6	12.6	19.7	29.1	20.9	17.2	16.1
		IIIB	Distr. Htg.	120.6	5403	64,372	2290	597	34,700	5.0	4.3	3.9	6.3	3.7	2.9	3.0	4.4
			Change	-39.4	+94	+3,062	-530	-111	+919	-13.0	-14.3	-8.7	-13.4	-25.4	-18.0	-14.2	-11.7
			(% Change)	(-24.6)	(+1.8)	(+5.0)	(-18.8)	(-15.7)	(+2.7)	(-72)	(-77)	(-69)	(-68)	(-87)	(-86)	(-83)	(-73)
			Change from Base Scenario	-39.4	-27	-519	-333	+41	+8591	-12.9	-14.3	-10.1	-13.2	-25.5	-18.1	-14.6	-11.6
			(% Change)	(-24.6)	(-0.5)	(-0.8)	(-12.7)	(+7.4)	(+32.9)	(-72)	(-77)	(-72)	(68)	(-87)	(-86)	(-83)	(-73)
COAL	Maximum Controls	IVA	No Distr. Htg.	160.0	3543	33,682	2820	708	33,705	16.2	16.6	12.0	17.7	27.9	17.2	15.8	14.0
		IVB	Distr. Htg.	120.6	3272	31,033	2290	597	34,700	2.8	2.0	3.1	3.9	2.7	1.3	1.2	2.0
			Change	-39.4	-271	-2,649	-530	-111	+919	-13.4	-14.6	-8.9	-13.8	-25.2	-15.9	-14.6	-12.0
			(% Change)	(-24.6)	(-7.6)	(-7.9)	(-18.8)	(-15.7)	(+2.7)	(-83)	(-88)	(-75)	(-78)	(-90)	(-92)	(-92)	(-86)
			Change from Base Scenario	-39.4	-2516	-33.885	-333	+41	+8519	-15.1	-16.6	-10.9	-15.4	-26.5	-19.7	-16.4	-14.0
			(% Change	(-24.6)	(-39.7)	(-52.2)	(-12.7)	(+7.4)	(+32.9)	(-84)	(-89)	(-78)	(-80)	(-91)	(-94)	(-93)	(-88)

fuel quality, and (4) controls. Annual emissions of sulfur oxides and particulates are reduced by district heating in each scenario except IB (existing plant fuels) where they are increased only slightly. Conversion to coal at New Source Performance Standards or at maximum controls, and conversion to 0.5% residual oil at the power plants result in lower particulate and sulfur oxide emissions. Emissions of carbon monoxide, hydrocarbons, and nitrogen oxides generally are reduced by district heating but are increased by coal conversion. The one scenario in which all five atmospheric pollutant emissions are reduced by district heating is scenario IIB in which power plant residual oil is assumed to have 0.5% sulfur content.

The air quality results (average annual SO_x concentrations at ground level) are consistently favorable to conversion to cogeneration district heating. This is caused primarily by the plume rise and dispersion effects on plant emissions entering the atmosphere from high stacks. Because only Boston urban emissions associated with heating and process uses have been modeled here, the contributions from domestic, commercial, and industrial fuel combustion in adjacent and neighboring areas are not included. Thus, attention should be drawn primarily to the differences, rather than the scenario specific absolute values, which are generally lower than measured values because of restriction to Boston city sources. However, these differences must also be interpreted with some caution because by limiting the sources to those in the city alone, no calibration was performed. Nevertheless, the results are striking. Up to 90% reductions in the modeled sulfur oxides concentrations are calculated for various locations within the city.

1.2 EVALUATION OF RESULTS

In evaluating these results, it should be remembered that, although ground-level concentrations of sulfur oxides may be reduced in Boston in all the district heating scenarios, total atmospheric loadings may increase. Dispersal of this pollutant beyond the Boston area could reduce ambient air quality elsewhere.* However, the emissions increases (scenario IB) are not substantial (about 5%) and could be readily remedied by focusing on a few major utility point sources. Morevoer, even the dispersion process gives rise to ground-level concentrations over broad geographic regions, the issue of total (population integrated) impacts remains. Air quality impacts of the other pollutants have not been modeled. In the Coal Scenarios, in particular, substantial increases in emissions of carbon monoxide, hydrocarbons, and nitrogen oxides could result in smaller air quality improvements (or even deterioration at some locations) after dispersion effects are taken into account. This clearly calls for further investigation.

Table 1.2 shows the scarce-fuel savings of oil and gas, associated with each pair of scenarios, as well as with coal conversion (with and without district heating). The percentage of scare fuel saved reflects the total amount of fuel used in both the heating and non-heating categories considered here.

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*Examination of model results for areas outside the city and within 10 km of any power plant showed no net increase for any of the district heating scenarios.

Table 1.2. Scarce Fuel Savings (10^{12} Btu/Yr)

Scenarios	Fuel Type	Scarce Fuel Use No District Heating (Base Scenario)	Scarce Fuel Use District Heating	Scarce Fuel Savings
Oil	Gas	19.06	1.93	17.13 (89.9%)
	Oil	140.90	118.68	22.22 (15.8%)
Coal	Gas	19.06	1.93	17.13 (89.9%)
		87.87	54.59	33.28 (37.9%)
Savings from Base Scenario by Substituting Coal for Oil	Gas	---	---	17.13 (39.9%)
	Oil	53.03 (37.6%)	64.09 (54.0%)	86.31 (61.3%)

Figure 1.1 is an isopleth map of Boston showing the differences in ground-level, sulfur-oxides concentrations caused by district heating (scenarios IA-IB); Fig. 1.2 is a schematic map in which the major neighborhoods in the city are shown.

As can be seen in Fig. 1.1, the area of greatest reductions in average ground-level, sulfur-oxides concentration is in the South Boston and Upper Dorchester neighborhoods, (See Fig. 1.2 for neighborhoods) both of which have high-density, residential populations. The central business district (CBD) and neighboring areas have the next highest reductions, along with residential areas in Roxbury, Jamaica Plain, and Lower Dorchester. At first it may appear surprising that the CBD area does not have the greatest reductions because, as will be shown, this area has, by far, the greatest demand density. However, because a substantial portion of heating demand in this area is met by fuel combustion at existing utility steam plants with relatively high stacks (at the locations indicated in Fig. 1.1), emissions and air quality in this area are already lower than would be expected based on local heating demand itself. In effect, this area of the city can be considered as already "district heated," albeit primarily by existing, dedicated steam plants rather than through hot water from cogeneration plants. Despite this initial condition, the CBD and neighboring areas can be expected to experience substantial improvements in air quality because of the hypothetical cogeneration district heating system, as shown in Fig. 1.1.

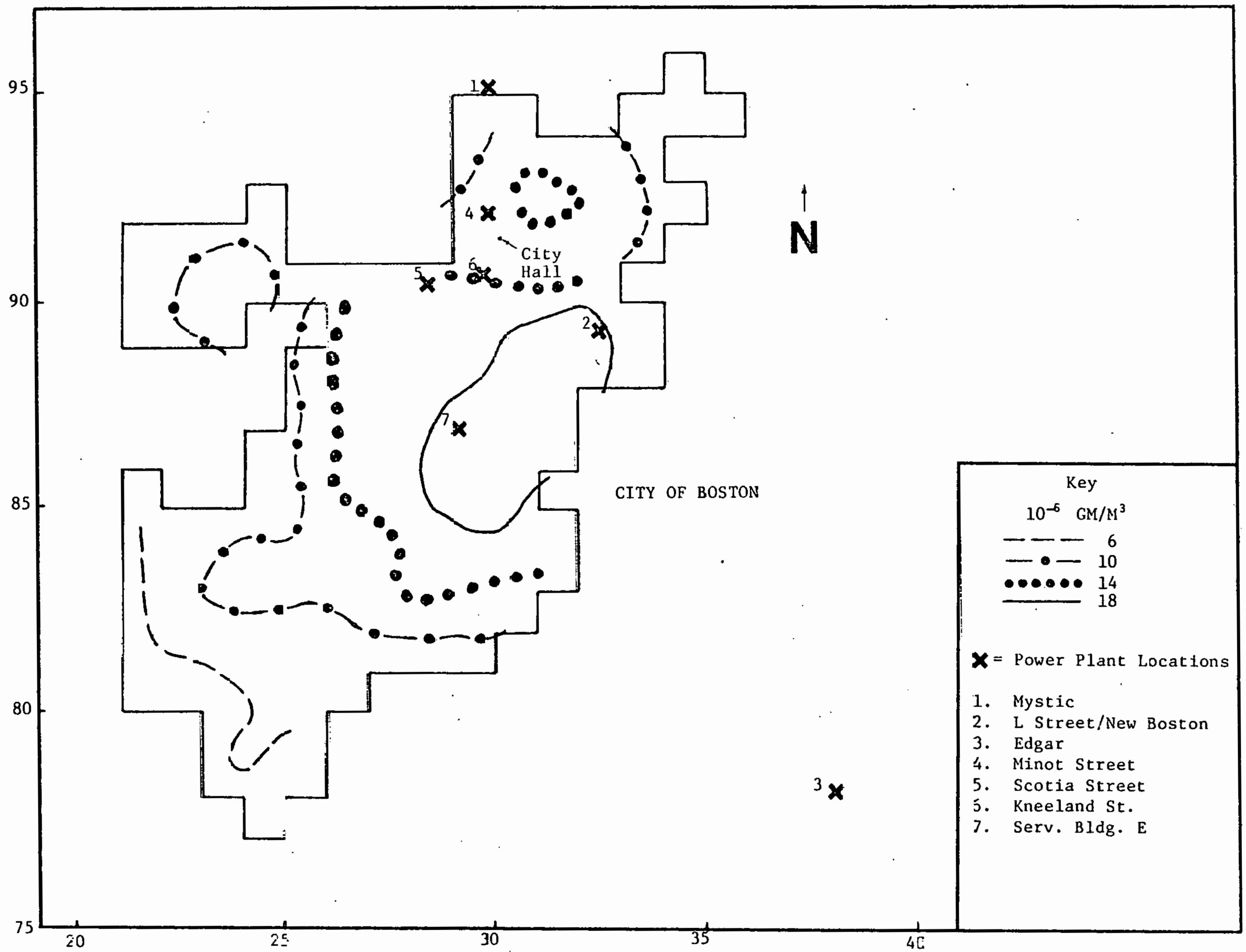

Fig. 1.1. Isopleth Map of Reductions in Average Annual Ground-Level Concentrations of Sulfur Oxides caused by District Heating Scenarios IA - Scenario IB (10^{-6}/m^3)

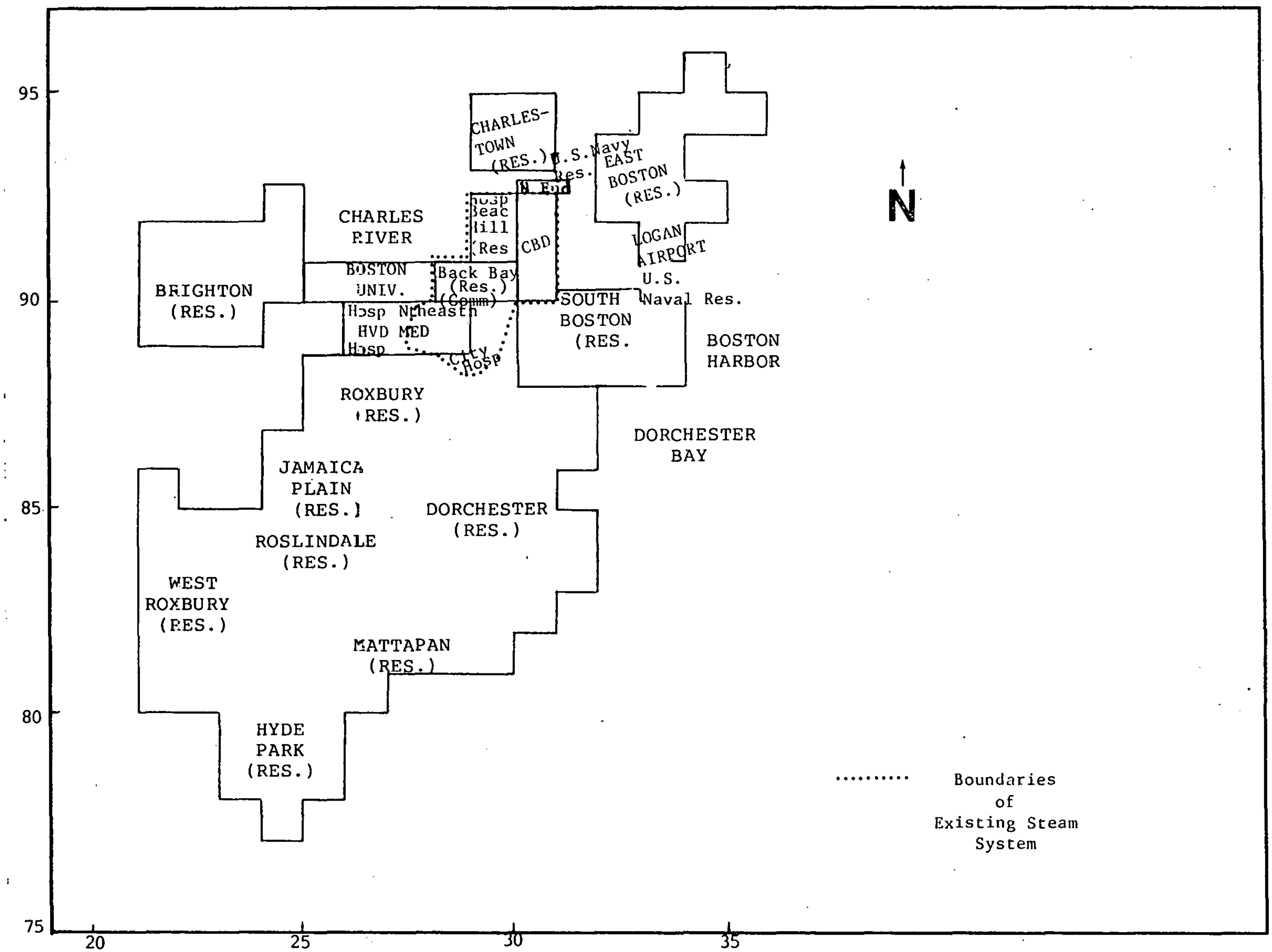

Fig. 1.2. Boston Neighborhoods

2 METHODOLOGY AND RESULTS/EMISSIONS

The first step in estimating the emissions and air-quality tradeoffs associated with district heating, is the specification of a Base Case scenario in which heating demand is met by conventional building site combustion of fuels, and in which electricity generation occurs without cogeneration. With regard to the characteristics of electricity generation, actual plant specific data for the year, 1977 are used. Heating demand was computed using various sources on building stock and fuel mix disaggregated on a small area (km^2) basis separately for the residential, commercial, and industrial sectors. Emissions from the existing power plants (both electric and dedicated steam) were estimated for the Base Case scenario. The Base Case scenario also specifies all commercial and industrial point source fuel combustion and emissions (for both heating and non heating) at sites with boilers of $>25 \times 10^6$ Btu/hr capacity. Plant retrofit to cogeneration for district heating was assumed, and the thermal and electric generation parameters were specified. Thermal and electric supply and demand were matched on peak, seasonal, and annual bases. Any additional plant fuels associated with a cogeneration dispatch approximation were estimated; associated additional emissions above Base Case scenario levels were calculated for the district heating scenario. The fuels and emissions associated with non-heating uses at the commercial and industrial point source sites are the same in the district heating scenario as in the Base Case scenario. These procedures are detailed below.

2.1 EMISSIONS FROM EXISTING THERMAL AND ELECTRIC SYSTEMS

2.1.1 Demand, Fuel Use, and Emissions from Existing Heating Systems/Local Area Sources and Point Sources

Local building thermal energy demand for space heating and hot water for assessing the hypothetical district heating system were estimated using building energy loads obtained from Arthur D. Little, Inc. (ADL) as described in a previous report[1,2] (and given in Ref. 12). Average space heating loads per square foot of floor space for each sector (residential low density, residential medium/high density, commercial/institutional, and industrial) were scaled from ADL's Northeast figures to Boston by the ratio of heating degree days. The demand factors for the commercial/institutional sector were taken as averages over the five subsectors (office, retail, school, hospital, and other) using the city-wide mix of floor space in these subsectors. The demand coefficients are given in Table 2.1.. Floor space estimates for each of the four sectors in km^2 grids spanning the city were provided by Real Estate Research Corporation (RERC). To specify final demand, fuel demand, and emissions with reasonable accuracy on this grid-square basis, it was necessary to estimate grid-square specific fuel mix by sector and end-use. For the residential sector, as a whole, 1970 Census tract data for space heating and hot water fuel mix were obtained and mapped onto the grid-squares. Similarly, data from the Boston Gas Co. for its commercial/industrial space heating demand for 14 districts spanning the city were used to estimate the gas-heated fraction of commercial/institutional and industrial floor space in the 1-km grid-squares contained within these districts. The electric-and-oil-heated fractions were apportioned from the remainder in the same ratio for each grid-square as was found for the residential sector from 1970 Census tract information.

Table 2.1. Fuel and Building Type Specific Demand Factors, Final Demand[a]

Type of Building	Space Heat			Hot Water
	Gas	Oil	Electric[b]	
Residential Low Density	58.9	79.3	30.6	13.1
Residential Medium/High Density	51.5	70.3	25.1	11.4
Commercial/ Institutional	73.0	67.2	24.1	3.7
Industrial	50.4	46.3	16.4	2.0

[a] 10^3 Btu/yr/ft^2

[b] Generally better than fossil-fuel heated homes. Electric homes are newer, tighter, and often must conform to state PUC regulations governing minimum insulation levels, storm windows, etc. However, fossil-fuel--heated homes usually are older and have lower thermal integrity. The 30.6 MBtu/yr for electric RLD* units is equivalent to about 12,000 kWh, similar to typical utility experience in the Northwest.

These improvements over the previous work in which city-wide fuel mix estimates were used, were made to specify more accurately the spatial distribution of emissions. For each grid-square (p,q) demand is given by:

$$D_{ijk}^{p,q} = F_i^{pq} \; v \; B_{ijk} \quad M_{ijk}^{pq} \; ; \qquad (2.1)$$

where:

F_i^{pq} = ft^2 of floor space of sector i;

B_{ijk} = demand coefficients;

M_{ijk}^{pq} = fuel mix;

i = 1 to 4 (Residential Low Density, Residential Medium-High Density, Commercial/Institutional, Industrial);

j = 1 to 4 (gas, oil, coal, electric); and

k = 1 to 2 (space heat, hot water).

The fuel use is given by:

$$FU_{ijk}^{pq} = D_{ijk}^{pq}/E_{ijk} \qquad (2.2)$$

*Residential Low Density

where:

E_{ijk} = Conversion efficiencies.

Finally, these results were multiplied by a matrix of emissions coefficients obtained from Ref. 5, using a sulfur content of 0.5% by wt. for residual oil and 0.3% by wt. for distillate oil. Because electric space heat fuel use and emissions occur at the power plant sites, local emissions are set at zero. Table 2.2 gives the emissions coefficient matrix for the residential, commercial, and industrial sectors along with coefficients for the utility sector.

From these considerations, emissions of the five atmospheric pollutants are given by:

$$EMM^{pg}_{ijkl} = FU^{pg}_{ijk} \quad C_{ijl} \; ; \qquad (2.3)$$

where:

C_{ijl} is the emissions coefficient matrix, and

l labels the pollutant (l = 1 to 5).

Having performed these calculations, a further adjustment is necessary to avoid double counting in the important downtown Boston area. Boston already has a limited steam district heating system (905MWt) using dedicated steam boilers and one topping unit which supplies a portion of heating and air-conditioning demand to about a 6 km^2 service territory in and around the downtown area. From detailed data obtained from the Boston Ediston Co., the heating component of the total service territory steam demand was estimated. Thus, the estimated fuel use and emissions for the grid-squares falling within the existing district steam service territory were reduced because the fuel consumed and emissions associated with this heating demand are localized at the plants (which are treated among the point sources). Customers of the existing steam system are dominated by large commercial and institutional users; thus the grid-square reductions were confined to the commercial/institutional and industrial sectors. Furthermore, because data from the Boston Gas Co. allowed a determination of grid-square gas demand for heating in these sectors, the fuel and emissions reductions were made by subtracting the contributions from the initial estimates of oil consumption and associated emissions.

The resulting spatial distribution of sulfur oxides emissions from the grid-squares (caused by local building site fuel combustion for heating) is shown in Fig. 2.1. Similar patterns for the other four atmospheric pollutants are found with variations caused by the grid-square-specific floor space and fuel mix. Figures 2.2 and 2.3 show the spatial distribution of heating demand in the city. This pattern is similar to the pattern of emissions, where some differences arise from the fuel mix distribution. However, a major difference occurs in the downtown area where demand is highest. There, present service through the existing district steam system reduces the on-site emissions substantially.

Table 2.2 Emissions Coefficients[a,b]

	Particulates	Sulfur Oxides	Carbon Monoxide	Hydro-Carbons	Nitrogen Oxides
On-Site Building Heating					
Residential[c]					
Gas	4.92	0.3	9.84	3.94	39.4
Oil	9.16	158.2	18.32	3.66	65.9
Commercial/[d] Institutional					
Gas	4.92	0.3	9.84	3.94	59.0
Oil	18.75	222.9	17.64	3.53	151.7
Industrial[e]					
Gas	4.92	0.3	8.36	1.47	86.1
Oil	18.28	220.5	17.67	3.53	148.8
Utility					
Oil 0.3%S	7.5	158.0	18.50	3.50	80.5
Oil 0.5%S	27.5	272.5	17.00	3.50	205.5
Oil 1.0%S	44.5	544.5	17.00	3.50	205.5
Oil 2.2%S	85.5	1198.0	17.00	3.50	205.5
Gas	5.0	0.3	8.50	0.50	350.0
Coal (NSPS)	50.0	600.0	20.80	6.25	350.0
Coal 10%A Max Control 1%S	16.7	79.0	20.80	6.25	350.0

[a]Tons/10^{12} Btu

[b]Coefficients were derived from Tables 1.1-2, 1.3-1, 1.4-1 in Ref. 5.

[c]Residential oil: 100% distillate

[d]Industrial oil: 45% distillate, 55% residual (from Mass. DEQE)

[e]Commercial oil: 43% distillate, 57% residual (from Mass. DEQE)

Distillate oil at 0.3% sulfur content
Residual oil at 0.5% sulfur content

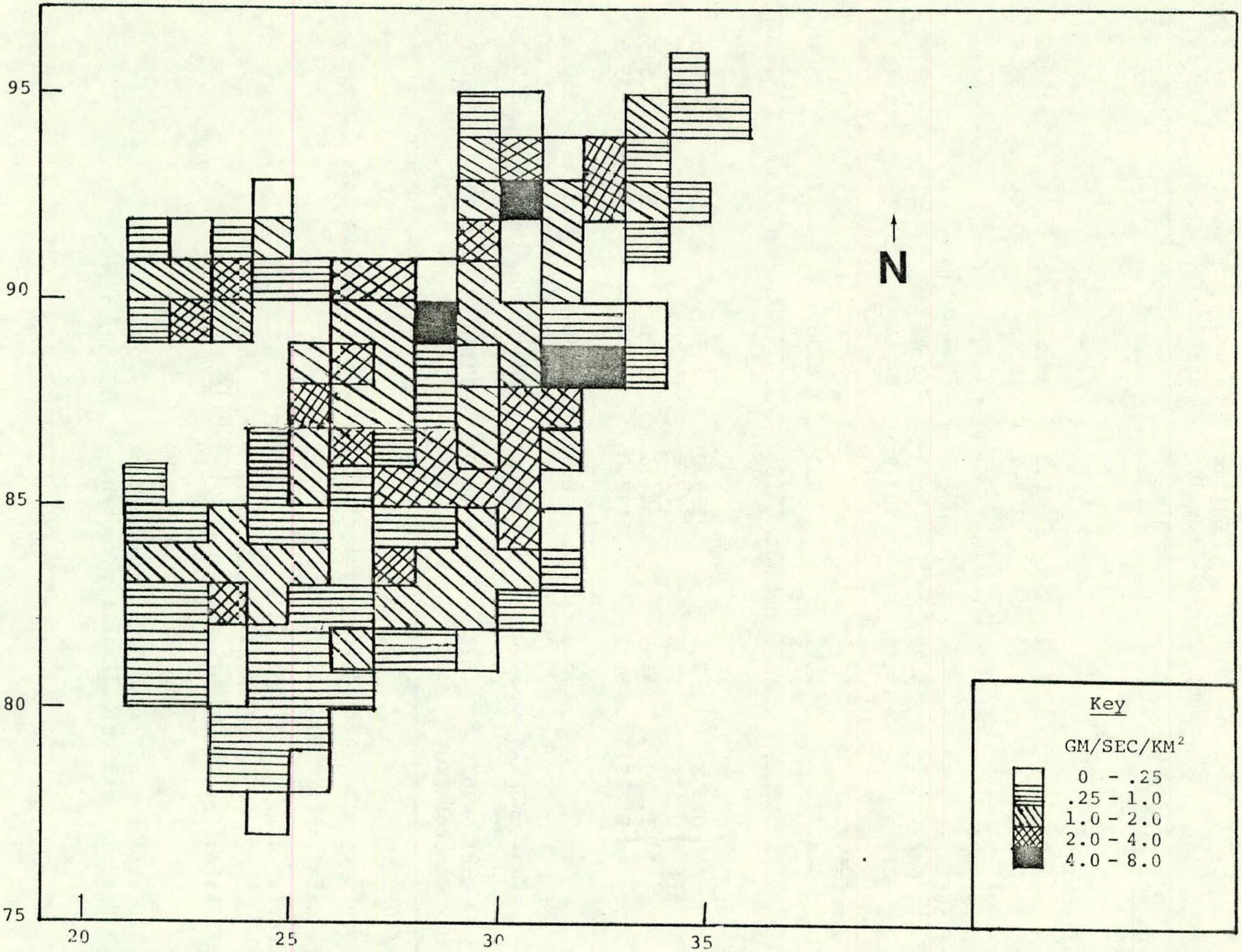

Fig. 2.1. Boston Sulfur Oxides Emissions Rates from Local Heating Sources (gm/sec/km^2)

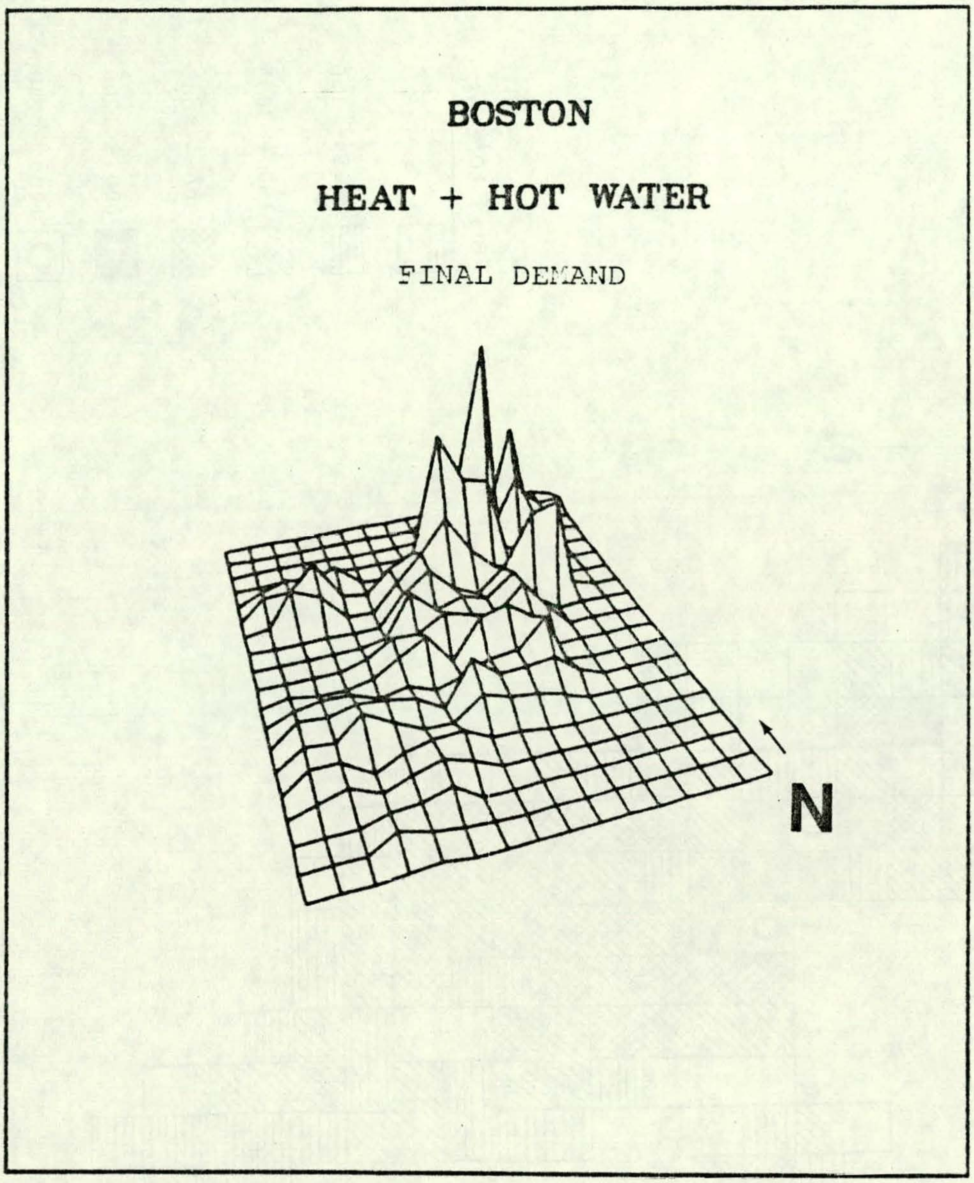

Fig. 2.2. Boston Heat and Hot Water: Spatial Distribution of Final Demand for Thermal Energy

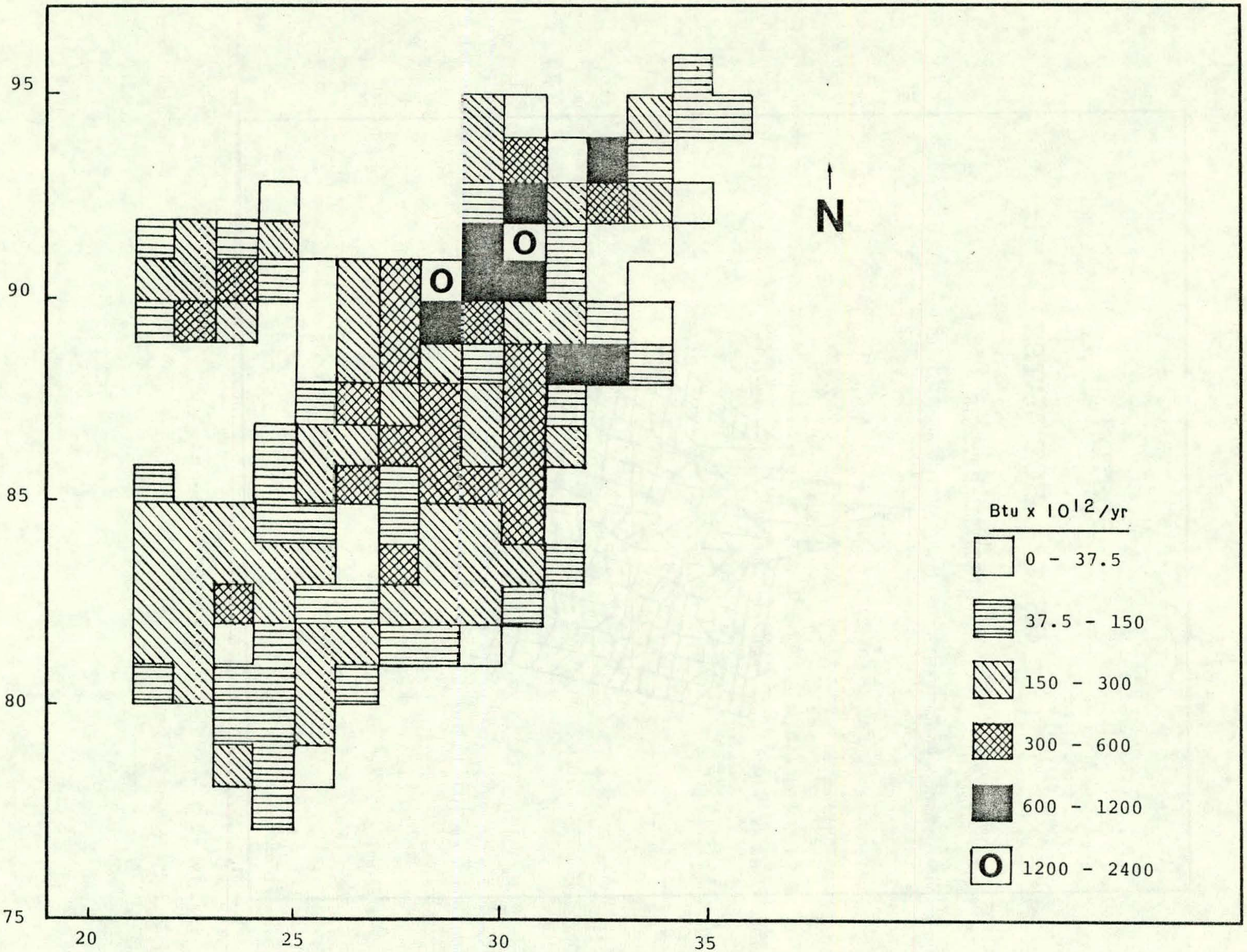

Fig. 2.3. Spatial Distribution of Heating Demand - Boston

City-wide totals are given in Table 2.3 for floor space, fuel mix, final demand; fuel use, and emissions. Table 2.4 gives the city-wide totals for demand, fuel consumption, and emissions.

The total final demand for space heat and hot water in the City of Boston is estimated to be 33 $\times 10^{12}$ Btu. This is supplied by the consumption of 45.18 $\times 10^{12}$ Btu of oil and 17.19 $\times 10^{12}$ Btu of gas (where 1.98 $\times 10^{12}$ Btu of oil is consumed at electric power plants: final demand at 0.87 $\times 10^{12}$ Btu, 76% of which is met by oil-fired generation at an average heat rate of 10.2 $\times 10^6$ Btu/MWh). A slightly lower fuel consumption (16.37 $\times 10^{12}$ Btu of gas and 34.96 $\times 10^{12}$ Btu of oil) is consumed locally at the building sites themselves. The small area (by grid-square) spatial distribution of this consumption (and associated emissions) was shown in Fig. 2.1. The remainder is consumed at the existing steam and electric generating plants and contributes to the point sources. Electric generation for space heating was apportioned according to the October through April 1, 1977 mix generation between nuclear (about 24%) and residual and distillate oil of the various sulfur contents. The small amount of nuclear fuel consumed (about 0.7 $\times 10^{12}$ Btu) is not included in Table 2.4.

Table 2.3. City-Wide Total Floor Space, Fuel Mix, Final Demand, Fuel-Use, and Emissions

	Floorspace Area (10^6 ft^2)	Fuel Mix (% Floorspace)							
		Space Heat				Hot Water			
		Gas	Oil	Coal	Elec.	Gas	Oil	Coal	Elec.
Residential Low Density	104	[a]31.0	65.6	-	3.4	52.3	40.3	-	7.4
Residential Medium/High Density	196								
Commercial/ Institutional	100	[b]18.3	77.7	-	4.0	18.3	77.7	-	4.0[c]
Industrial	64								

[a]The fractions for coal and other fuels for residential (about 2 percent in the 1970 Census) were incorporated into the oil fraction. These had dropped to less than 0.4 percent according to the 1974 Annual Housing Survey

[b]The fractions for gas heating for the Commerical/Institutional and Industrial sectors were obtained from Boston Gas Company. The remaining fraction was apportioned between oil and electricity according to the ratio in the residential sector. These numbers thus include (in the oil fraction) contributions which, in the downtown area, should be attributed to the existing district steam supply.

[c]The hot water fuel mix is assumed to be the same as the space heating fuel mix in these sectors.

Table 2.4. Annual Boston City-Wide Final Demand, Fuel Use, and Emissions for Space Heating and Hot Water Heating

		Final Demand (10^{12} Btu)	Fuel Use (10^{12} Btu)	Tons/Year Particulates	Sulfur Oxides	Carbon Monoxide	Hydrocarbons	Nitrogen Oxides
Residential Low Density	Gas	2.79	4.65	23	1	46	18	183
	Oil	5.64	11.28	103	1784	207	41	743
	Electric	.26	.59	29	368	10	2	121
Residential Medium/High Density	Gas	4.95	8.25	41	2	81	33	325
	Oil	8.65	17.30	159	2736	317	63	1140
	Electric	.37	.84	42	523	13	3	173
	Dist. Steam Gas	.05	.07	-	-	-	-	23
	Dist. Steam Oil	.34	.51	18	207	9	2	101
Commercial/ Institutional	Gas	1.28	2.14	11	1	21	8	126
	Oil	1.79	3.58	67	798	63	12	543
	Electric	.18	.41	20	255	7	2	84
	Dist. Steam Gas	.42	.62	3	-	4	2	220
	Dist. Steam Oil	3.24	4.74	169	1944	80	16	949
Industrial	Gas	.80	1.33	7	0	11	2	114
	Oil	1.40	2.80	51	617	49	10	426
	Electric	.06	.14	7	87	2	-	29
	Dist. Steam Gas	.09	.13	1	-	1	-	47
	Dist. Steam Oil	.69	1.01	36	414	17	3	202
Total for Heating	Gas	10.38	17.19	86	4	164	63	1136
	Oil	21.75	43.20	603	8500	742	147	4094
	Electric	.87	1.98	98	1233	32	6	407
	Total	33.00	62.37	787	9737	938	217	5537
Total Area Source Contribution	Gas	9.82	16.37	82	4	159	61	746
	Oil	17.48	34.96	380	5935	636	126	2842
		27.30	51.33	462	5939	795	187	3588

A further adjustment was made to these estimates, primarily to improve the air quality modeling which is discussed later. Detailed data on commercial and industrial point sources were obtained for the Boston Air Quality Control Region.[12] All commercial and industrial fuel consumption at those sites having boilers of at least 25×10^6Btu capacity was included in the analysis. Distillate oil was assumed to have 0.3% sulfur content, and residual oil was assumed to have 0.5% sulfur content, which, according to the Massachusetts Department of Environmental Quality Engineering were the prevailing conditions in 1977. Seventy-seven such point sources were included in the analysis. The fuels and emissions for both heating and non-heating uses were estimated separately. It was then necessary to adjust the initial estimates of commercial and industrial heating fuel combustion and emissions in those grid squares in which these heating sources are located. This results in a downward adjustment of some grid square emissions that are then modeled as area sources. Correspondingly, an additional 77 point sources are modeled as point sources of air pollution. Table 2.5 summarizes these adjustments on a city-wide basis.

Table 2.5. Annual Fuel Combustion and Emissions for All Boston City Heating, Major Process and Electricity Uses

		Annual Fuel Use (10^{12}Btu)		Annual Emissions (Tons)				
HEATING		Gas	Oil	Parti-culates	Sulfur Oxides	Carbon Mon-oxide	Hydro Carbons	Nitro-gen Oxide
Residential	AREA	12.90	28.58	326	4523	651	155	2391
	DSS[a] PT	.07	.51	18	207	9	2	124
	ELEC PT	-	1.43	71	891	23	5	294
Commercial/ Institutional	AREA	2.13	2.67	61	596	68	17	530
	DSS PT	.62	4.74	172	1944	84	18	1169
	ELEC PT	-	.41	20	255	7	2	84
	LOCAL PT	.27	5.30	306	1462	94	19	1077
Industrial	AREA	1.33	2.37	50	522	52	10	466
	DSS PT	.13	1.01	37	414	18	3	249
	ELEC PT	-	.14	7	87	2	-	29
	LOCAL PT	-	1.66	46	454	29	6	342
Total Heating		17.45	48.82	1114	11355	1037	237	6755
NON-HEATING								
Elec								
	PT	-	80.44	3981	50169	1379	274	16522
DSS								
	PT	1.25	1.70	66	684	35	10	767
Commercial/ Institutional	LOCAL PT	.08	1.37	38	374	24	5	287
Industrial	LOCAL PT	.28	8.57	231	2332	149	30	1782
Total Heating/Non-Heating		19.06	140.90	5430	64914	2624	556	26113
Total Local Heating		16.63	40.58	789	7557	894	207	4806
Total Local Non-Heating		.36	9.94	269	2706	173	35	2069
Total Utility Elec & DSS		2.07	90.38	4372	54651	1557	314	19238
Percent Elec		0	58.5	75.0	79.2	53.8	50.5	64.8
Perecent Heating		91.6	34.6	20.5	17.5	39.5	42.6	25.9
Percent Local		89.1	35.9	19.5	15.8	40.7	43.5	26.3
Percent Point		14.2	76.1	92.0	91.3	70.6	67.3	87.0
Percent Area		85.8	23.9	8.0	8.7	29.4	32.7	13.0

[a]District Steam System (existing).

2.1.2 Fuel Use and Emissions from Existing Electric and Thermal Plants/Utility Point Sources

After the adjustments in Table 2.5 are made, the total demand for space heat and hot water for Boston is estimated to be 35.97×10^{12} Btu and is assumed to be met by piped-in hot water derived from retrofit of existing power plants for operation in the cogenertion mode. Because this retrofit involves reductions in plant capacity and because combined electric and thermal generation requires additional fuel (and likewise more emissions) at the plants, it is necessary first to establish the fuels and emissions in the Base Case (or no district heating) scenario. Similarly, existing district steam system plants whose thermal capacity would be needed to meet peak city-wide thermal demand, would operate for different periods in the district heating scenario. Thus their Base Case scenario fuels and emissions must be established.

The actual plants, their generation (thermal and electric), and fuels used in 1977 provide the basis for establishing the Base Case scenario utility point source emissions. Tables 2.6 and 2.7 summarize the 1977 utility plant specific capacity, fuel consumption, and generation.

Table 2.6 Existing District Steam System (1977)

Plant	Thermal Capacity (Mwt)	Fuel (10^{12} Btu)	Thermal Sendout (10^{12} Btu)
L-Street	334	4.22 oil	3.34
Kneeland		3.41 oil	
	373	2.07 gas	4.19
Minot	88	.07 oil	.05
Scotia	109	.19 oil	.14
Bldg. E	Not Available	.07 oil	Not Available
TOTAL	904	7.96 oil	7.72
		2.07 gas	

Table 2.7 Existing Electric Generation System (1977)

	Capacity (MW)	Fuel (10^{12} Btu)	Electric Generation (GWh)
Mystic St	1,086	38.62	4,031
New Boston St	718	33.15	3,752
Pilgrim St(Nuclear)	655	27.40	2,652
Edgar St	300	10.21	870
L Street St	30	.38	72
Mystic Gt	14	.01	0.7
L Street Gt	19	.02	1.1
Edgar Gt	28	.01	0.8
Framingham Gt	43	.02	1.3
Totals[a]	2,893	82.42 Oil 27.40 Nuclear 109.82 Total	11,381

[a]An additional 135 Mw peaking unit at West Medway which consumed .05 trillion Btu of oil and generated 3.4 Gwh was omitted from the analysis. This plant, located about 25 miles outside the city was not included in the hypothetical district heating system.

Data for the existing district steam system were obtained from the Boston Edison Co.; data for the electric system were obtained from FERC documents. Table 2.8 shows emissions in tons per year at each stack, for each of the five pollutants; Table 2.9 shows the fuel use, sulfur content, location, sulfur oxides emissions, and stack parameters. The stack parameters, location, and sulfur oxides emissions in grams per second are used for the point source inputs to the climatological dispersion model. Stack parameters were obtained from AP-1 forms submitted to the Massachusetts DEQE.

Five existing steam plants (L-Street, Minot Street, Kneeland Street, Scotia Street, and Service Building E) are listed in Table 2.6. The plant at L-Street, which uses topping turbines and also generates electricity, has been disaggregated into its electrical and thermal sides in Table 2.8. These plants have a combined output of 7.72 $\times$ 10^{12} Btu of steam, providing about 6.52 $\times$ 10^{12} Btu for total heating and cooling demand in the service territory, of which 4.83 $\times$ 10^{12} Btu is estimated for heating demand. Table 2.6 gives the actual plant data for the 1977 system, obtained from detailed information provided by the Boston Edison Co. Monthly data provided by the Boston Edison Co. were used to estimate the portion of fuels used and steam sendout associated with heating demand. Most of the gas use at the Kneeland Plant occurs during the summer months to meet cooling demand.

The electric generating plants of the Boston Edison system also appear on Tables 2.8 and 2.9 where their 1977 fuels, emissions, and stack parameters are specified by stack. Table 2.7 summarizes the 1977 capacity, fuels, and generation for plants of the Boston Edison system. Except for the Pilgrim

Table 2.8. Base Scenario IA: No District Heating, Emissions in Ton/Yr

Plant	Stack	Particulate	SO_x	CO	HC	NO_x
Fram.	J-1	.07	1.147	.139	.035	.591
	J-2	.07	1.147	.139	.035	.591
	J-3	.07	1.147	.139	.035	.591
Edgar	J-1	.035	1.057	.139	.035	.556
	J-2	.035	1.057	.139	.035	.556
	9	282.649	3,954.896	56.523	11.298	678.379
	10	279.138	3,905.605	55.828	11.159	669.931
	11	298.083	4,170.525	59.617	11.923	715.365
Mystic	J-1	.07	1.738	.209	.035	.869
	4	146.313	1,789.30	56.280	11.263	675.215
	5	194.354	2,377.054	74.738	14.948	896.996
	6	89.025	1,088.847	34.240	6.848	410.886
	7	1,287.094	15,742.207	495.044	99.002	5,940.462
New Boston	E-W#	627.07	7,669.38	241.178	48.250	2,894.102
	E-W#	855.595	10,464.619	329.091	65.804	3,948.918
L Street	J-1	.104	2.538	.278	.070	1.286
Elec.	12	17.159	209.87	6.6	1.32	79.19
DSS	12	186.53	2,281.44	71.74	14.35	860.92
Minot St.	6	.904	8.968	.556	.104	6.779
	7	.904	8.968	.556	.104	6.779
Scotia St.	1	.382	8.447	.973	.209	4.310
	2	.382	8.447	.973	.209	4.310
	3	.382	8.447	.973	.209	4.310
Kneeland St.	1	47.068	399.727	36.813	5.701	784.333
	2/1	32.711	324.954	20.44	4.102	245.210
	2/2	23.534	199.881	12.549	8.378	392.184
Serv. Bldg. E	1(1)	.939	9.316	.591	.104	7.022
	1(2)	1.043	10.359	.660	.139	7.821
Total		4,371.713	54,651.096	1,557.147	313.968	19,238.464

Table 2.9 Control List of Boston Edison Electric and Thermal Generating Stations and their Emissions Characteristics--Existing Systems

Plant	Stack	Elec. /DSS	Type	Amount (Gal/yr)	% Sulfur Content	Location x	Location y	Sulfur Oxide Emission (gm/sec)	Stack Height (m)	Stack Diam. (m)	Discharge Velocity (m/s)	Discharge Temp. (°C)
Framingham	J-1	Elec.	#2oil	52,472	.3	1	83	.03	9.1	3.6	17.1	399
	J-2	Elec.	#2oil	52,472	.3	1	83	.03	9.1	3.6	17.1	399
	J-3	Elec.	#2oil	52,472	.3	1	83	.03	9.1	3.6	17.1	399
Edgar	J-1	Elec.	#2oil	49,644	.3	38	78.5	.03	27.4	3.6	17.1	399
	J-2	Elec.	#2oil	49,644	.3	38	78.5	.03	27.4	3.6	17.1	399
	9	Elec.	#6oil	22,570,928	2.2	38	78.5	113.77	76.2	3.6	24.4	149
	10	Elec.	#6oil	22,289,528	2.2	38	78.5	112.35	76.2	3.6	24.4	149
	11	Elec.	#6oil	23,801,528	2.2	38	78.5	119.97	76.2	3.6	24.4	149
Mystic	J-1	Elec.	#2oil	79,086	.3	30	95	.05	9.1	3.6	17.1	399
	4	Elec.	#6oil	22,465,800	1.0	30	95	51.47	102.1	3.2	25.2	149
	5	Elec.	#6oil	29,845,200	1.0	30	95	68.38	102.1	3.2	25.2	149
	6	Elec.	#6oil	13,671,000	1.0	30	95	31.32	102.1	3.2	25.2	149
	7	Elec.	#6oil	197,652,000	1.0	30	95	452.86	152.4	6.1	25.8	154
New Boston	#1East/West	Elec.	#6oil	96,293,400	1.0	32.2	89.2	220.63	76.2	3.2	30.1	148
	#2East/West	Elec.	#6oil	131,388,600	1.0	32.2	89.2	301.04	76.2	3.2	30.1	148
L Street	J-1	Elec.	#2oil	116,508	.3	32.2	89.2	.07	36.6	3.0	18.3	374
	12	Elec.	#6oil	2,639,826	1.0	32.2	89.2	6.04	81.1	5.3	25.1	149
	12	DSS	#6oil	28,697,300	1.0	32.2	89.2	65.63	81.1	5.3	25.1	149
Minot Street	6	DSS	#6oil	225,150	.5	30	92.3	26	32.0	2.1	9.6	371
	7	DSS	#6oil	225,150	.5	30	92.3	.26	41.8	2.1	5.9	293
Scotia Street	1	DSS	#2oil	390,923	.3	28.2	90.2	.24	28.4	1.7	11.0	296
	2	DSS	#2oil	390,925	.3	28.2	90.2	.24	28.4	1.7	12.2	300
	3	DSS	#2oil	390,923	.3	28.2	90.2	.24	28.4	1.7	12.2	300
Kneeland Street	1	DSS	#6oil	10,027,740	.5	30	90.5	11.49	80.8	3.7	19.3	129.4
		DSS	NatGas	1,377,324Mcf	--			.01				
	2(1)	DSS	#6oil	8,159,200	.5	30	90.5	9.35	76.2	3.7	25.2	139.4
	2(2)	DSS	#6oil	5,013,870	.5	30	90.5	5.744	80.8	3.7	25.2	188.0
		DSS	NatGas	688,663Mcf	--			.01				
Service Bldg. E	1(1)	DSS	#6oil	234,135	.5	29	87	.27	15.2	1.7	12	399
	1(2)	DSS	#6oil	260,000	.5	29	87	.30	15.2	1.7	12	399

Nuclear Plant, the plants listed in Table 2.7, along with the existing district steam plants described above, comprise the Base Case scenario utility point sources emitting the five atmospheric pollutants in the quantities shown in Table 2.8. The Pilgrim Nuclear Plant, located about 48 km outside the city, will be a supply component of the hypothetical district heating system; however, it does not contribute to the emissions of the five atmospheric pollutants studied. The Edgar Plant was taken off line in 1978; nevertheless, because it was a part of the 1977 system, it is included in this analysis. The main results and conclusions of this study would not be altered appreciably if the Edgar Plant were left out or replaced with a roughly equivalent unit. If it were left out, some of the least economical district heating service areas would have to be dropped because of insufficient peak thermal survey. However, if it were replaced, the differential emissions and air quality impacts would depend on the assumed plant location and fuel used. The Edgar Plant is the only steam-electric unit in the system which, because if its distance from the city, was burning 2.2% rather than 1% sulfur residual oil.

Figure 1.1 locates the various utility point sources.

2.2 MATCHING THERMAL ENERGY DEMAND AND SUPPLY IN THE DISTRICT HEATING SYSTEM

Matching of supply and demand in the district heating system requires three steps:

(1) providing sufficient thermal capacity to meet peak heating demand;

(2) providing sufficient thermal energy to meet annual heating demand; and

(3) dispatching the thermal energy, plant by plant, in a way such that the electric generation remains sufficient to meet demand for electricity.

In dispatching, care must be taken to maintain, at least approximately, the base case loading sequence and relative proportions of total generation from each plant operating in the cogeneration mode. In making these estimates, some slight departures have been made from previous assumptions.[3,4] Peak thermal demand is now met by using an existing district steam system (905 MWt) rather than the planned Pilgrim-II Nuclear Plant (1030 MWt). This could have the overall effect of reducing system costs caused by long-distance transmission from the Pilgrim-II unit. Furthermore, the approximation used in previous studies to simulate an essentially unaltered dispatch has been replaced here by a somewhat more detailed procedure.

2.2.1 Thermal Energy Demand/Annual Energy and Peak

Annual final demand for space heating and hot-water energy in the City of Boston has been estimated to be about 36×10^{12} Btu. Assuming an average of 10% losses between the supply points and the demand points (see losses estimations in Ref. 3) implies 40×10^{12} Btu/yr of thermal supply. It is also estimated that about 3600 MW of final peak heating demand for the city must be met by the district heating system. Assuming 10% losses, the thermal capacity required would be 4000 MW.

2.2.2 Thermal Energy Supply Capacity

A total dependable thermal energy supply of at least 4000 MW is needed for the district heating system. This supply will be provided by the 905 MW of existing thermal capacity and 3130 MW of thermal capacity derived from retrofit of existing electric power plants to operate in the cogeneration mode. Thus 4044 MW of thermal capacity will be available to meet 4000 MW of peak thermal demand. Reserve thermal capacity is not considered here. Because the 4000 MW is not a coincident demand caused by diversity of loads both within and among building sectors, and because there is some reserve capacity within the transmission and distribution system itself, reserve thermal capacity is not seen as a significant problem in the context of this study. If necessary, reserve capacity could be added to the system, but without significant impact on the average, annual energy supply, fuel use, and emissions. If reserve capacity, in the form of thermal storage, were added, a small impact on fuel use and emissions would occur.

The Mystic, New Boston, Edgar, and Pilgrim Plants are assumed to be retrofit to operate in the cogeneration mode using the intermediate cross-over extraction retrofit option appropriate to multi-stage units. (See Ref. 4 for details). Although this retrofit entails a derating of electric capacity, it has the advantage that the cross-over extraction can be temporarily shut off, thus allowing the plant to resume electric generation at its full rated capacity. This feature would be important in the operation of an actual cogeneration district heating system and has been used here in an approximate way to simulate dispatch. The L-Street, Edgar, and Mystic gas turbines are assumed to undergo the recuperator boiler retrofit option to capture the thermal energy in the turbine exhaust gases. These units would be used primarily for peaking operation. Finally, of the 905 MW of thermal capacity, 334 MW is derived from the topping turbines (already cogenerating) at the L-Street plant. Table 2.10 lists the thermal energy supply plants and the relevant parameters.

Table 2.10 Cogeneration Retrofit Parameters for Thermal Energy Supply

Facility	Type	Fuel	Before Retrofit (Mwe)	After Retrofit (Mwe)	After Retrofit (Mwth)	Electric Capacity Loss (Mwe)	Retrofit Method
Mystic	ST	Oil	1086	779	1251	308	CO
New Boston	ST	Oil	718	520	760	198	CO
Pilgrim	ST	Oil	655	467	615	188	CO
Edgar	ST	Oil	300	210	390	90	CO
L Street	ST	Oil	30	30	334	-	None
Mystic	GT	Oil	14	13	28	1	RB
L Street	GT	Oil	19	17	38	2	RB
Edgar	GT	Oil	28	25	57	3	RB
Kneeland	DSS	Oil/Gas	-	-	373	-	None
Minot	DSS	Oil	-	-	88	-	None
Scotia	DSS	Oil	-	-	109	-	None

2.2.3 Thermal Energy Supply/Energy Dispatch

Average annual emissions and air quality changes caused by operation of the district heating system will depend on the plant specific fuels consumed and the plant locations. Because the major steam-electric plants retrofitted to operate in the cogeneration mode are derated, they will have to operate more hours during the heating season to generate sufficient electricity for the Boston Edison service territory. Therefore, operation in the cogeneration mode would increase fuel consumption at each plant. Previous studies[3,4] that gave the plant specific electric and thermal heat rates after retrofit for each plant (using an accounting rule, the electric heat rate was not changed) used a gross approximation to simulate the annual dispatch of the plants. This approximation was guided by the requirement that, on an annual basis, the large newer steam-electric units would be dispatched preferentially over the older units, with gas turbines used to meet peak demand. This was to ensure that the rough sequence of electric generation was not significantly disturbed. A more detailed procedure is used here. An actual cogeneration district heating system would involve combined dispatch of thermal and electric demand as either arises on an hourly basis. Such dispatch would be optimized to take into account loads; maintenance schedules; technical, reliability, and economic considerations; and environmental effects. In an actual dispatch, the interties with the regional power pool (NEPOOL, in this case) would be an important consideration in determining the optimum (economic, reliability, environmental) schedule for generating electricity and thermal energy. In an actual dispatch, the fact that crossover extraction can be temporarily shut off could be taken into account on a detailed basis, so that as thermal loads decrease or increase across the heating season, these can be followed rather closely by plant-specific operations.

In this report, all the heating demand was assumed to occur during the October-to-April, seven-month period. In fact, because of the distribution of heating degree days in Boston, about 94% of space-heating demand is estimate to occur during these months. About 58% of hot-water demand occurs during these months. Thus, it is assumed that all -- rather than only 90% of thermal energy demand is met during the seven-month period. Although this is a departure from the actual heating load curve, it will not significantly affect the results because, on an annual basis, the actual fuels consumed (and emissions) are approximated quite well. The large steam-electric plants are assumed: (1) to operate in the cogeneration mode with thermal extraction and reduced capacity during the October-April period, and (2) to resume operation at full rated capacity for the remainder of the year. The relative dispatch over the October-April period is kept essentially the same as in the Base Case scenario. Specifically, the large (718 MW) New Boston Plant operated 2560 hr. during this period in 1977 for a 50% capacity factor. It was assumed that this plant would operate at a 70% capacity factor (October-April) under the district heating scenario. All other retrofit plant October-April operating hours were scaled up from their 1977 values by the same amount, thereby maintaining the same overall relative amounts during that period. The L-Street topping unit, already a cogenerator in the existing steam system, was assumed to generate thermal and electric energy as is did during 1977. The exisiting steam-only boilers (Kneeland, Scotia, Minot) were assumed to generate enough thermal energy (about 19% more than in 1977) to meet the remainder of the annual heating demand. Total annual thermal generation was thus matched to the 40 × 10^{12} Btu of demand (with losses).

Total annual electric generation was estimated to be 11,390 GWh as compared to the 11,380 GWh actually provided by these plants in 1977. However, 282 GWh of electricity for space heat and hot water demand is now displaced by district heating service. Thus, 11,098 GWh would actually be needed from these plants. Therefore, the assumptions used here entail 292 GWh more than would actually be required for electricity generation. Because total thermal production in the system is estimated to be 39.0 × 10^{12} Btu, just 10^{12} Btu short of the total demand (including losses), it is assumed that the 10^{12} Btu demand (292 GWh) presently served by electricity would continue to be so served. An alternative would have been to scale down the generation of the thermal/electric plants (thus eliminating 292 GWh of electric generation) and making up the difference (292 GWh + 1.62 × 10^{12} Btu) from the exising steam plants. All emissions results would be similar. Another alternative would have been to scale up the generation of the thermal/electric plants to produce the missing 10^{12} Btu, thus producing an additional 221 GWh of electricity. In this case, 513 GWh extra electricity generation would occur, which could be sent into the power pool grid and reduce generation and emissions elsewhere. Such an alternative, which could occur in a grid-connected cogeneration district heating system, would result in somewhat greater local emissions (about 1.9%) than estimated according to assumptions used here.

Table 2.11 summarizes the results of the dispatch assumptions described above. In the last column, the fractional change in annual fuel consumption for the 1977 Base Case values caused by district heating operation is given for each unit. These changes are applied to all district heating scenarios considered here. They are the basis for estimating the additional point source emissions associated with the district system.

2.3 EMISSIONS TRADEOFFS WITH DISTRICT HEATING

The emissions tradeoffs that are expected to occur with the operation of the district heating system depend on three main effects:

(1) Fuel Quantity Decreases

Fuels consumed and associated emissions from local building sites for space heat and hot water requirements are eliminated.

(2) Fuel Quantity Increases

Fuels consumed and associated emissions from power plants are increased because of cogeneration operation.

(3) Fuel Quality Changes

The average particulates, sulfur oxides, and nitrogen oxides emissions coefficients (tons/10^{12} Btu fuel) are greater in this case at the oil-burning plants than at the building sites.

Table 2.11. Distinct Heating Dispatch Assumptions

Power Plant	Electric Capacity (MW)	1977 Elec. Gen. (GWH) Ann%	Oct-Apr	Annual C.F.	Hours Oct-Apr	Thermal Capacity (MW)	Cogen Hrs Oct-Apr	Thermal Prod. (10^{12}Btu)	Revised Annual C.F.	Derated Cap. (MW)	Revised Oct-Apr Elec Gen (GWH)	Revised Annual Elec Gen (GWH)	Annual Fuel/ Fuel
Mystic ST	1086	4031	2489	42.4	2291	1251	3201	13.66	52.8	779	2493	4036	.245
New Boston ST	718	3752	1838	59.7	2560	760	3577	9.28	71.3	520	1860	3774	.194
Pilgrim I ST	655	2652	1527	46.2	2331	615	3257	6.38	56.8	467	1521	2646	.229
L Street ST	30	72	44	27.4	1487	30	1487	-	27.4	30	44	72	0
Edgar ST	300	870	482	33.1	1607	390	2245	2.99	40.4	210	471	859	.221
Mystic GT	14.2	.68	.44	.55	30	28.4	42	.044	.67	13	.55	.8	.218
L Street GT	18.6	1.08	.82	.66	44	38	61	.008	.86	17	1.04	1.30	.303
Edgar GT	28.4	.82	.44	.33	15	57	21	.004	.40	25	.53	.9	.212
Total, MWe	2850.2	11379.5	6381.7										
	Thermal Capacity (MW)	Thermal Generating (GWh) Ann	Oct-Apr										
L Street Th	334	979	680	33.5	2306	334	2036	2.32	33.5	-	-	-	0
District Steam TH	570	1240	868	24.8	1521	570	2006	3.90	30.3	-	-	-	.22
Total, MWt	904	2219	1548			4073.4		39.0		1943	6391	11390	

The first effect works to reduce overall emissions; the second and third effects work to increase overall emissions. The third effect implies that a given amount of net reduction in fuels consumed is not matched by a corresponding reduction in emissions. This condition exists because in Boston, domestic heating uses gas and 0.3% sulfur distillate oil; commercial and industrial heating uses a mix of 0.3% sulfur distillate and 0.5% sulfur residual. By comparison, the power plants use primarily 1% sulfur residual oil (the exceptions being 2.2% at Edgar and 0.5% at Minot and Kneeland). As a result of this use and their combustion characteristics, they have generally greater emissions coefficients (at least in the absence of controls). However, the Pilgrim Nuclear Plant does not contribute to emission increases of the five pollutants considered here. If alternative fuels and/or controls were employed at the other power plants, the impact of the third effect could be changed.

Tables 2.12 and 2.13 list, respectively, the utility plant specific emissions changes for the Base Case scenario (IA) and the District Heaing scenario (IB). Table 2.14 summarizes the results of all emissions changes between the two scenarios.

When a 20% reduction in overall fossil-fuel consumption for both thermal and electric requirements the district heating scenario nonetheless entails greater emissions of particulates and sulfur oxides; emissions of the other three pollutants are reduced. These results are based on emissions coefficients obtained from Ref. 5 and applied to the Boston City fuel mix for heating and electric generation. If the additional fuel consumed to provide cogenerated thermal energy at the power plants were restricted to have the same sulfur content as the building site (0.3% distillate and 0.5% residual) specific oil saved by the system, then the countervailing third effect would be reduced, and emissions reductions more in accordance with fuel savings would occur.

Table 2.12. Scenarios IA and IB--Emissions Tradeoffs for District Heating Using Existing Fuels

District Htg	Consumption of Fuel Thermal and Electric (10^{12}Btu)[a]	Annual Emissions (Tons) Particulates	Sulfur Oxides	Carbon Monoxide	Hydrocarbons	Nitrogen Oxides
Scenario IA No District Htg	160.0	5430	64,914	2624	556	26,111
Scenario IB District Htg	120.6	5551	68,754	2054	416	25,344
Difference	-39.4	+121	+3,840	-570	-140	-767
% Change	-24.6	+2.2	+5.9	-21.7	-25.2	-2.9

[a]These fuel figures exlude the Pilgrim nuclear unit and represent oil consumption only (in addition to 2.07 × 10^{12} Btu gas). With the nuclear unit included the Base and District Heating numbers become 187.4 and 154.3 × 10^{12} Btu respectively for savings of 33.1 × 10^{12} Btu. The Pilgrim unit does not contribute to emissions of the five pollutants.

Although particulate and sulfur oxides emissions would increase slightly, it will be seen that, for average, annual ground-level concentrations of SO_x, this effect is reversed because of the higher stacks, plume rise, and dispersion effects on the emissions from power plants. Section 3 will discuss the air quality model and results for the two scenarios already considered.

Table 2.13. Base Scenario IA: No District Heating, Emissions in Ton/Yr

Plant	Stack	Particulate	SO_x	CO	HC	NO_x
Fram.	J-1	.07	1.147	.139	.035	.591
	J-2	.07	1.147	.139	.035	.591
	J-3	.07	1.147	.139	.035	.591
Edgar	J-1	.035	1.057	.139	.035	.556
	J-2	.035	1.057	.139	.035	.556
	9	282.649	3,954.896	56.523	11.298	678.379
	10	279.138	3,905.605	55.828	11.159	669.931
	11	298.083	4,170.525	59.617	11.923	715.365
Mystic	J-1	.07	1.738	.209	.035	.869
	4	146.313	1,789.30	56.280	11.263	675.215
	5	194.354	2,377.054	74.738	14.948	896.996
	6	89.025	1,088.847	34.240	6.848	410.886
	7	1,287.094	15,742.207	495.044	99.002	5,940.462
New Boston	E-W#	627.07	7,669.38	241.178	48.250	2,894.102
	E-W#	855.595	10,464.619	329.091	65.804	3,948.918
L Street	J-1	.104	2.538	.278	.070	1.286
Elec.	12	17.159	209.87	6.6	1.32	79.19
DSS	12	186.53	2,281.44	71.74	14.35	860.92
Minot St.	6	.904	8.968	.556	.104	6.779
	7	.904	8.968	.556	.104	6.779
Scotia St.	1	.382	8.447	.973	.209	4.310
	2	.382	8.447	.973	.209	4.310
	3	.382	8.447	.973	.209	4.310
Kneeland St.	1	47.068	399.727	36.813	5.701	784.333
	2/1	32.711	324.954	20.44	4.102	245.210
	2/2	23.534	199.881	12.549	8.378	392.184
Serv. Bldg. E	1(1)	.939	9.316	.591	.104	7.022
	1(2)	1.043	10.359	.660	.139	7.821
Total		4,371.713	54,651.096	1,557.147	313.968	19,238.464

Table 2.14. Scenario IB: District Heating with Existing Fuels, Emissions in Ton/yr

Plant	Stack	Particulate	SO_x	CO	HC	NO_x
Fram.	J-1	.07	1.147	.139	.035	.591
	J-2	.07	1.147	.139	.035	.591
	J-3	.07	1.147	.139	.035	.591
Edgar	J-1	.042	1.281	.168	.042	.674
	J-2	.042	1.281	.168	.042	.674
	9	342.571	4,793.334	68.506	13.693	822.195
	10	338.315	4,733.593	67.664	13.525	811.956
	11	361.277	5,054.676	72.256	14.451	867.022
Mystic	J-1	.085	2.117	.255	.043	1.058
	4	182.160	2,277.679	70.069	14.022	840.643
	5	241.971	2,959.432	93.049	18.610	1,116.76
	6	110.836	1,355.615	42.629	8.526	511.533
	7	1,602.432	19,599.048	616.330	123.257	7,395.875
New Boston	E-W#1	748.722	9,157.240	287.967	57.611	3,455.558
	E-W#2	1,021.580	12,494.755	392.935	78.570	4,715.008
L Street	J-1	.136	3.307	.362	.091	1.676
Elec.	12	17.159	209.87	6.60	1.32	79.19
DSS	12	186.534	2,281.44	71.74	14.35	860.92
Minot St.	6	1.075	10.661	.661	.123	8.059
	7	1.075	10.661	.661	.123	8.059
Scotia St.	1	.454	10.042	1.156	.248	5.123
	2	.454	10.042	1.156	.248	5.123
	3	.454	10.042	1.156	.248	5.123
Kneeland St.	1	55.951	475.164	43.761	6.777	932.353
	2(1)	38.885	286.279	24.297	4.877	291.486
	2(2)	27.975	237.602	14.917	9.959	622.197
Serv. Bldg. E	1(1)	.939	9.316	.591	.104	7.022
	1(2)	1.043	10.359	.660	.139	7.821
Total		5,282.377	66,048.277	1,880.131	381.104	23,274.901

3 METHODOLOGY AND RESULTS/AIR QUALITY

3.1 THE TRADEOFFS

In addition to the three effects (discussed in Sec. 2.3) governing the tradeoffs in total emissions in going to a district heating system, other considerations are important in determining the effect on average annual ground-level concentrations of the pollutants. Although the additional fuel consumed at the plants in the district heating scenario emits more particulates and sulfur oxides per year than the greater amount of fuel initially consumed at the local building sites, it contributes substantially lower amounts, on an average annual basis, at ground level in the Boston area. This is caused primarily by the much higher stacks, the plume rise effects, and dispersion effects of average wind conditions at greater heights. These considerations are taken into account by using an urban diffusion model applied to the sulfur-oxides emissions entering the Boston city atmosphere at prevailing meterological conditions. The model is used to calculate average, annual ground-level concentrations of sulfur oxides for each scenario. The Climatological Dispersion Model was chosen.[6,7,8] This EPA model was used in a form modified at Argonne National Laboratory[7] to handle many point and area sources.

3.2 THE CLIMATOLOGICAL DISPERSION MODEL

The Climatological Dispersion Model, in its modified form (CDMQC), is based on the well-known Gaussian plume approach. It is a steady-state model that accounts for vertical and horizontal dispersion of atmospheric pollutants as a function of distance from the source. The model considers wind speed and directional effects and assumes that the lower layer of the urban atmosphere (mixing layer) is more turbulent than the higher layers. The wind speed frequency distribution accounts for six wind speed classes, six stability classes, and 16 directions (points of the compass). Day/night wind speed data used in this study take into account the bimodal effects particularly important for the Boston area because of its coastal location. The model presently can handle two pollutants at once and calculate seasonal as well as average annual ground level concentrations. The model not only takes these into account, but also provides the wind rose data and source-receptor culpability files that identify the particular points and directions from which a receptor receives contributions of varying magnitudes to total average annual concentrations of the pollutant.

3.3 INPUTS TO THE MODEL

The model requires day-night wind speed distribution data as input. In the Boston case study, an average annual distribution was used. The latest five-year average wind speed data for Boston, available from the National Climatic Center and the Regional EPA office, is the Day/Night STAR data for the 1966-1970 period. These data were used in all the scenarios. The calibration feature of the model was not employed in the current project. To calibrate properly, all relevant sources should be modeled. This study treats only those sources caused by fuel combustion for residential, commercial, and industrial heating and large commercial and industrial non-heating occuring within the Boston city boundaries and for Boston Edison Co. electrical and thermal generation. Many sources, such as those from heating in surrounding communities, from large industrial and commercial sources near Boston, and from other nearby electricity generation have been omitted. Had these sources been included, calibration would have been meaningful, and average annual 1977 wind speed data would have been appropriate. Because this extension of the modeling was beyond the scope of this phase of study, it was decided that sulfur oxides would be the focus of the air-quality analysis. In the absence of calibration, the model works best for this pollutant. Because the model treats average concentrations as linear superposition of all (point and area) source contributions, the sources not modeled would contribute the same amounts to the pairs of scenarios (No district heating vs. district heating). Thus the differences can be examined and compared with measured values at various receptor locations, although no calibration was performed. Moreover, the model outputs were found to be consistent with measured levels of sulfur oxides concentrations.

3.3.1 Area Sources

The area sources, input to the model as 132 grid squares (1 km × 1 km) spanning the city have been described earlier. Figure 2.1 shows spatial distribution of local emissions of sulfur oxides. These correspond to the initial grid square estimates made before subtracting that portion contributed by large commercial and industrial point sources. Remaining area source contributions are reduced below these initial values. Strictly speaking, none of the building sites is, of itself, an area source. Taken together, however, because of their spread-out spatial distribution, their individual comparatively low level of emissions, and the lack of buoyancy and upward momentum of the emissions, they can be approximated as square kilometer area sources. Many of the tallest commercial buildings (with large heating demands) are already heated by the existing steam system and therefore are not a part of the existing area sources. The location of each grid square area source is designated by the UTM coordinates of its southwest corner. Each grid square area source is given a stack height appropriate to that area of the city.

3.3.2 Point Sources

The thermal and electric power plant point sources described earlier are input to the model. Their locations are designated on the map in Fig. 1.1. Input parameters include UTM coordinates (in km), suflur oxides emissions (in gm/sec), stack height (in meters), stack diameter (in meters), exit velocity (in meters/sec) and temperature of emissions (in °C). Tables 3.1 and 3.2 give the relevant information for each stack in the thermal and electric systems for the Base-Case and District Heating scenarios, respectively. In addition, the 77 large commercial and industrial point sources (those with boiler capacities, >25 × 10^6 Btu/hr) within the City of Boston were added. Both heating and non-heating-related emissions were input for the base case; whereas, only non-heating-related emissions were input in the district heating case.

Table 3.1. Control List of Boston Edison Electric and Thermal Generating Stations and Their Emissions Characteristics--Scenario IA: No District Heating

Scenario IA: No District Heating								Sulfur Oxide	Stack	Stack	Discharge	
Plant	Stack	Elec. /Dss	Type	Amount (Gal/yr)	% Sulfur Content	Location x	y	Emission (g/sec)	Height (m)	Diam. (m)	Velocity (m/s)	Temp. (°C)
Framingham	J-1	Elec.	#2oil	52,472	.3	1	83	.03	9.1	3.6	17.1	399
	J-2	Elec	#2oil	52,472	.3	1	83	.03	9.1	3.6	17.1	399
	J-3	Elec.	#2oil	52,472	.3	1	83	.03	9.1	3.6	17.1	399
Edgar	J-1	Elec.	#2oil	49,644	.3	38	78.5	.03	27.4	3.6	17.1	399
	J-2	Elec.	#2oil	49,644	.3	38	78.5	.03	27.4	3.6	17.1	399
	9	Elec.	#6oil	22,570,928	2.2	38	78.5	113.77	76.2	3.6	24.4	149
	10	Elec.	#6oil	22,289,528	2.2	38	78.5	112.35	76.2	3.6	24.4	149
	11	Elec.	#6oil	23,801,528	2.2	38	78.5	119.97	76.2	3.6	24.4	149
Mystic	J-1	Elec.	#2oil	79,086	.3	30	95	.05	9.1	3.6	17.1	399
	4	Elec.	#6oil	22,465,800	1.0	30	95	51.47	102.1	3.2	25.2	149
	5	Elec.	#6oil	29,845,200	1.0	30	95	68.38	102.1	3.2	25.2	149
	6	Elec.	#6oil	13,671,000	1.0	30	95	31.32	102.1	3.2	25.2	149
	7	Elec.	#6oil	197,652,000	1.0	30	95	452.86	152.4	6.1	25.8	154
New Boston	#1East/West	Elec.	#6oil	96,293,400	1.0	32.2	89.2	220.63	76.2	3.2	30.1	148
	#2East/West	Elec.	#6oil	131,388,600	1.0	32.2	89.2	301.04	76.2	3.2	30.1	148
L Street	J-1	Elec.	#2oil	116,508	.3	32.2	89.2	.07	36.6	3.0	18.3	374
	12	Elec.	#6oil	2,639,826	1.0	32.2	89.2	6.04	81.1	5.3	25.1	149
	12	DSS	#6oil	28,697,300	1.0	32.2	89.2	65.63	81.1	5.3	25.1	149
Minot Street	6	DSS	#6oil	225,150	.5	30	92.3	.26	32.0	2.1	9.6	371
	7	DSS	#6oil	225,150	.5	30	92.3	.26	41.8	2.1	5.9	293
Scotia St.	1	DSS	#2oil	390,923	.3	28.2	90.2	.24	28.4	1.7	11.0	296
	2	DSS	#2oil	390,925	.3	28.2	90.2	.24	28.4	1.7	12.2	300
	3	DSS	#2oil	390,923	.3	30	90.2	.24	28.4	1.7	12.2	300
Kneeland St.	1	DSS	#6oil	10,027,740	.5	30	90.5	11.49	80.8	3.7	19.3	129.4
		DSS	NatGas	1,377,324MCF	--			.01				
	2(1)	DSS	#6oil	8,159,200	.5	30	90.5	9.35	76.2	3.7	25.2	139.4
	2(2)	DSS	#6oil	5,013,870	.5	30	90.5	5.744	80.8	3.7	25.2	188.0
		DSS	NatGas	688,663MCF	--			.01				
Service Bldg. E	1(1)	DSS	#6oil	234,136	.5	29	87	.27	15.2	1.7	12	399
	1(2)	DSS	#6oil	260,000	.5	29	87	.30	15.2	1.7	12	399

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Table 3.2 Scenario IB-District Heating with Existing Fuels

Plant	Stack	Function	Annual Fuel Usage Type	Amount[a]	SO_x Emissions g/sec
Framingham	J-1	Elec.	#2 Oil	52,472	.03
	J-2	Elec.	#2 Oil	52,472	.03
	J-3	Elec.	#2 Oil	52,472	.03
Edgar	J-1	DH/Cogen	#2 Oil	60,169	.04
	J-2	"	#2 Oil	60,169	.04
	9	"	#6 Oil	27,355,965	137.89
	10	"	#6 Oil	27,014,908	136.17
	11	"	#6 Oil	28,847,452	145.41
Mystic	J-1	"	#2 Oil	96,327	.06
	4	"	#6 Oil	34,822,552	64.08
	5	"	#6 Oil	37,157,274	85.13
	6	"	#6 Oil	17,020,395	39.00
	7	"	#6 Oil	246,076,740	563.81
New Boston	#1E-W	"	#6 Oil	114,974,320	263.43
	#2E-W	"	#6 Oil	156,877,990	359.44
L Street	J-1	"	#2 Oil	151,810	.10
	12	Elec.	#6 Oil	2,639,826	6.04
	12	DSS	#6 Oil	28,697,300	65.63
Minot Street	6	DSS	#6 Oil	267,640	.31
	7	"	#6 Oil	267,640	.31
Scotia Street	1	"	#2 Oil	464,697	.28
	2	"	#2 Oil	464,697	.28
	3	"	#2 Oil	464,697	.28
Kneeland St.	1	"	#6 Oil	4,744,230	13.76
	"	"	NatGas	651,626	.02
	2(1)	"	#6 Oil	3,860,204	11.11
	2(2)	"	#6 Oil	2,372,114	6.82
	"	"	NatGas	325,814	.02
Service Bldg. E	1(1)	"	#6 Oil	234,136	.27
	(2)	"	#6 Oil	360,000	.30

[a]Oil in gal/yr.
Nat Gas in Mcf/yr.

3.4 AIR QUALITY RESULTS

Table 3.3 summarizes the results of the various effects of fuels consumed, sulfur content, stack parameters, source location, and meteorological conditions. Average annual ground-level concentrations of sulfur oxides are compared at a group of receptors for the two scenarios. These receptors were chosen because, from the standpoint of atmospheric pollution, they are at points of interest in and around the city. Twelve of them had measuring instruments in 1977 by which measurements of sulfur oxides concentrations were made for that year. Table 3.4 lists these sixteen receptors, their UTM coordinate locations, and the measured values of 1977 average annual sulfur oxide concentrations. What is immediately apparent by comparing the Base Case scenario totals with measured values at various locations, is that the former are considerably lower, especially at locations outside the city. Presumably this is caused mainly by not modeling area sources outside the city. The absence of calibration also must be noted in this respect. Thus, for example, the measured value at Receptor 10 in Quincy is 24 (or 31) $\mu g/m^3$; whereas the modeled value is 11.7. Similarly, at Receptor 12 in Revere, the values are 29 and 6.9, respectively. Local industrial point sources and domestic and commercial area sources in these and neighboring areas which have not been modeled could account for the differences.

Table 3.3 Average Annual Ground-Level Sulfur Oxides Concentrations[a]

SCENARIOS IA AND IB

Receptor	Scenario IA (Base - 1977) No District Heating				Scenario IB District Heating Existing Fuels			Decrease of Modeled Concentrations	
	Point Local	Point Utility	Area	Total	Point Local	Point Utility	Total[b]	Total	%
1	5.9	2.8	12.7	21.4	1.1	3.3	4.4	17.0	79
2	5.9	2.0	13.3	21.1	2.2	2.3	4.5	16.6	79
3	5.4	2.2	12.2	19.8	3.0	2.6	5.6	14.2	72
4	2.4	3.0	6.7	12.2	0.8	3.6	4.4	7.8	64
5	2.8	1.8	3.1	7.7	1.6	2.1	3.7	4.0	52
6	4.0	1.8	8.8	14.6	2.1	2.1	4.2	10.4	71
7	1.4	1.8	1.9	5.1	0.7	2.2	2.9	2.2	43
8	1.9	1.3	2.6	5.8	1.0	1.6	2.6	3.2	55
9	3.9	3.1	4.8	11.8	2.8	3.6	6.4	5.4	46
10	2.1	4.3	5.3	11.7	1.0	5.1	6.1	5.6	48
11	1.0	2.2	1.8	5.0	0.4	2.7	3.1	1.9	38
12	1.5	3.8	1.6	6.9	0.9	4.6	5.5	1.4	20
13	4.6	2.3	11.2	18.1	2.1	2.8	4.9	13.2	73
14	2.2	2.2	13.2	17.6	0.8	2.6	3.4	14.2	81
15	2.1	2.2	9.3	13.6	1.0	2.6	3.6	10.0	74
16	1.4	1.9	9.0	12.3	0.8	2.3	3.1	9.2	75

[a]In $\mu g/m^3$

[b]Area sources make no contribution; point = total

Table 3.4 Boston Air Quality Measurement Receptors, with Measured SO Concentration

Receptor Number	Location Site	Coordinates X	Coordinates Y	Measured 1977 Average Annual SO Concentration ($\mu g/m^3$) Bubbler Method	Continuous Measuring Instrument
1	Kenmore Sqaure	27.1	90.4	34	51
2	Southampton Street	29.3	88.5	21	-
3	Visconti Street	32.0	92.5	-	-
4	Brookline High School	24.6	88.7	14	-
5	Oxford St., Cambridge	25.7	94.0	13	-
6	Trailer Science Museum	29.3	92.5	28	32
7	Chelsa Fire Hous	32.5	95.1	-	-
8	Main Street, Medord	26.3	97.8	15	-
9	Wellington Cr., Medord	28.6	96.6	22	34
10	Route 3A, Quincy	37.3	78.6	24	31
11	Hancock St., Quincy	32.4	82.1	15	-
12	Garfield Street Revere	36.0	98.1	29	-
13	Downtown Boston	30	91	-	-
14	Dorchester (Upper)	28	85	-	-
15	Dorchester (Lower)	27	82	-	-
16	Roxbury	24	82	-	-

Even at locations within the city boundaries, similar differences are found to be caused primarily by the limited nature of source inputs. For example, at Kenmore Square (Receptor 1) the measured values of 34 (or 51) g/m^3 far exceed the modeled value of 21.4. Yet this receptor is at a point in the city adjacent to such densely populated communities as Brookline, Cambridge, Somerville, Revere, Medford, and Chelsea. Industrial emissions from some of these areas also could contribute. A further source of discrepancy could be the lack of calibration.

District heating causes reductions in ground-level concentrations of sulfur oxides that occur solely from emissions related to heating demand and large industrial and commercial non-heating demand within the City of Boston, and Boston Edison Co. electric and thermal generation. These reductions range from about 20-80% of modeled concentrations at the receptor locations listed in Table 3.4. The greatest reductions in sulfur oxides concentrations occur in and around the densely populated areas of the city and the downtown central business district. A comparison of the reductions to the 1977 measured values shows the results to be similar, with the higher values occurring within Boston city limits. Figures 3.1 and 3.2 show maps of the city with the modeled values at each receptor indicated at the appropriate locations for each scenario. Figure 3.3 shows the 1977 measured values (bubbler; continuous) at these 16 receptors. Figure 3.4 locates isopleths of reductions in sulfur oxides concentrations caused by district heating. The wind rose data for these two scenarios, i.e., the contribution at each receptor from point and area sources from each of 16 compass directions, are given in the Appendix. The 132 area sources, culpability lists and contributions at each receptor from each point source have not been included here. These lists would be important in pinpointing the major sources (especially among point sources) that contribute to a particular receptor.

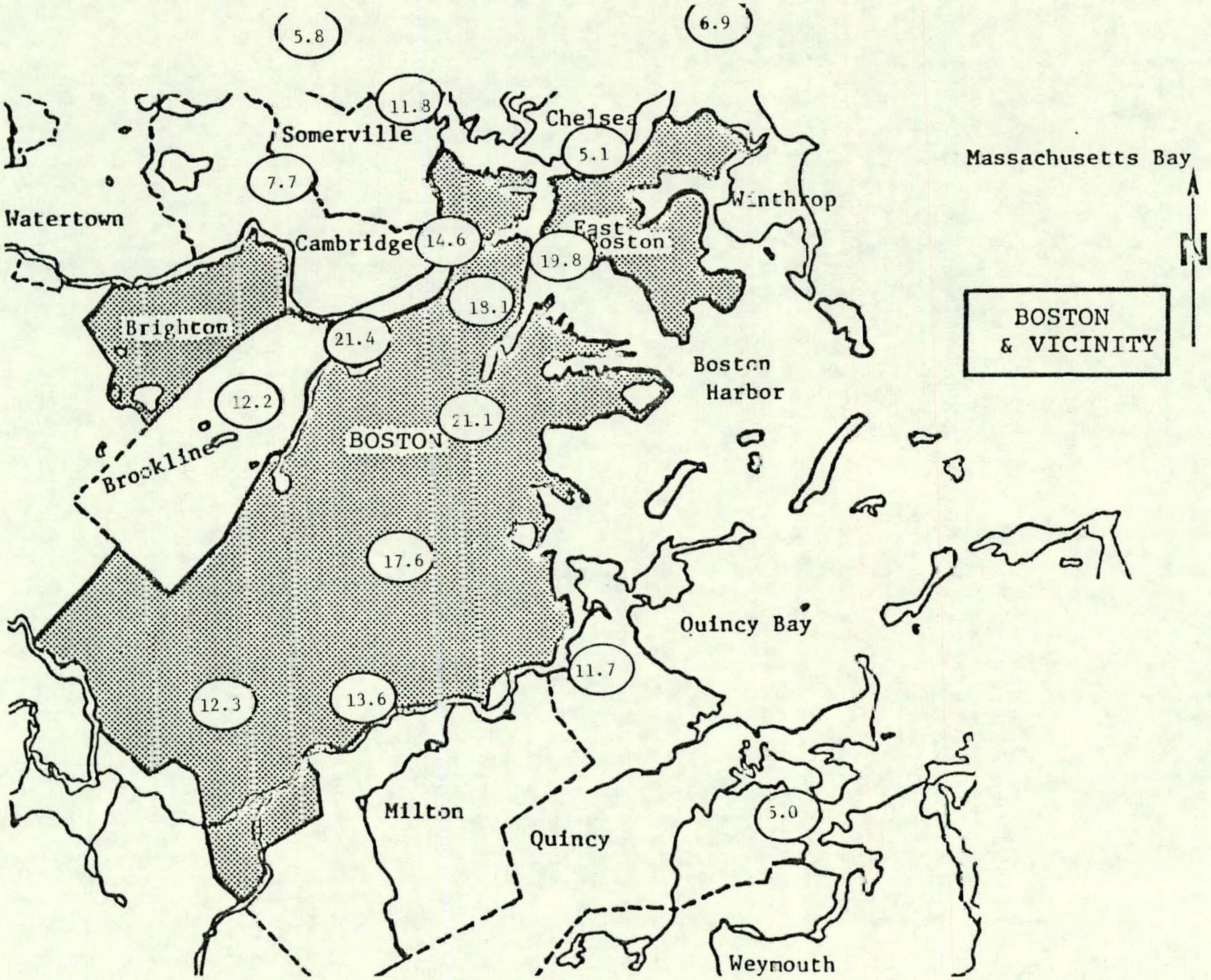

Fig. 3.1. Modeled Sulfur Oxides Concentrations at Selected Receptors ($\mu g/m^3$)--Base Scenario IA: No District Heating

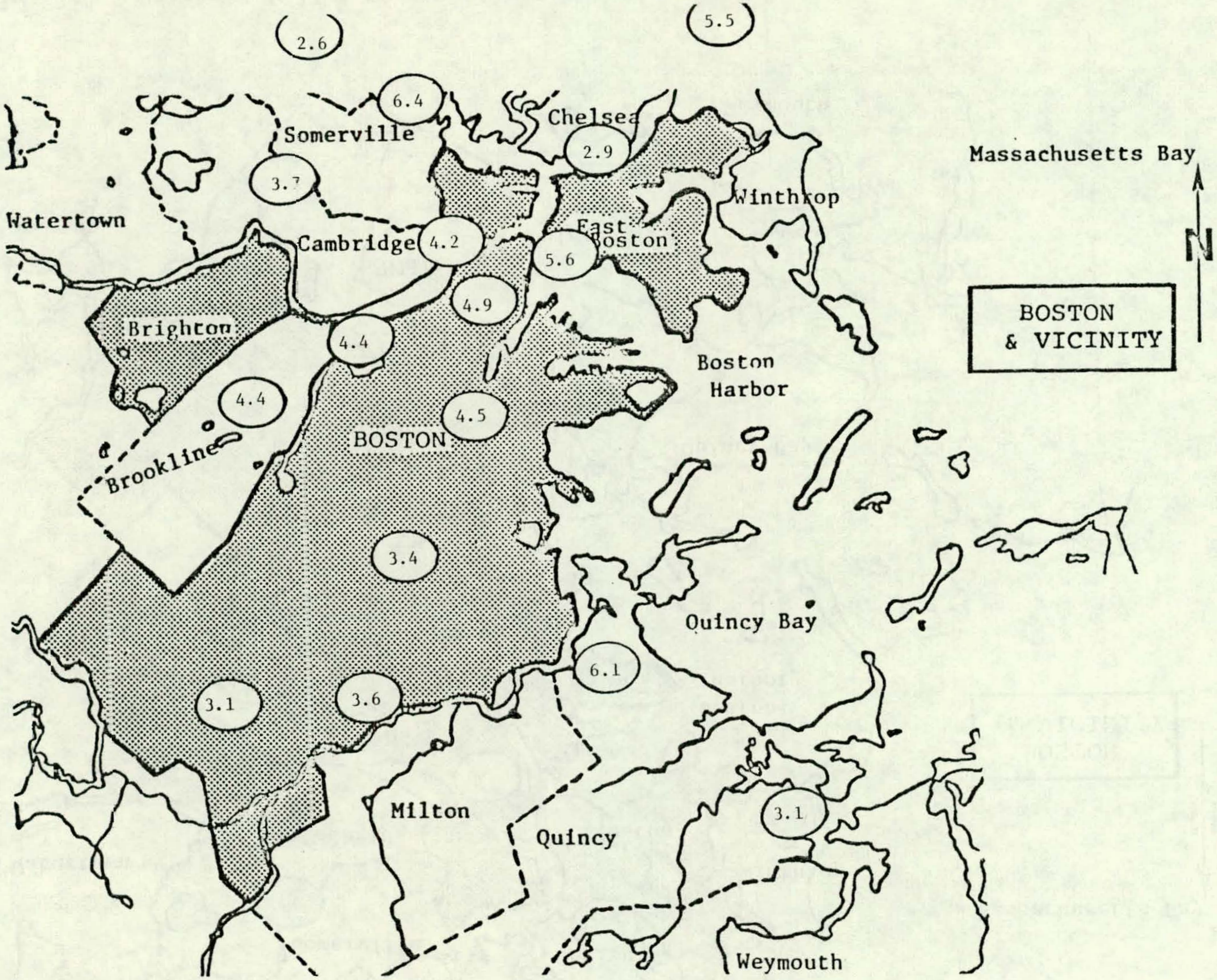

Fig. 3.2. Modeled Sulfur Oxides Concentrations at Selected Receptors ($\mu g/m^3$) --Base Scenario IB: District Heating with Existing Fuels

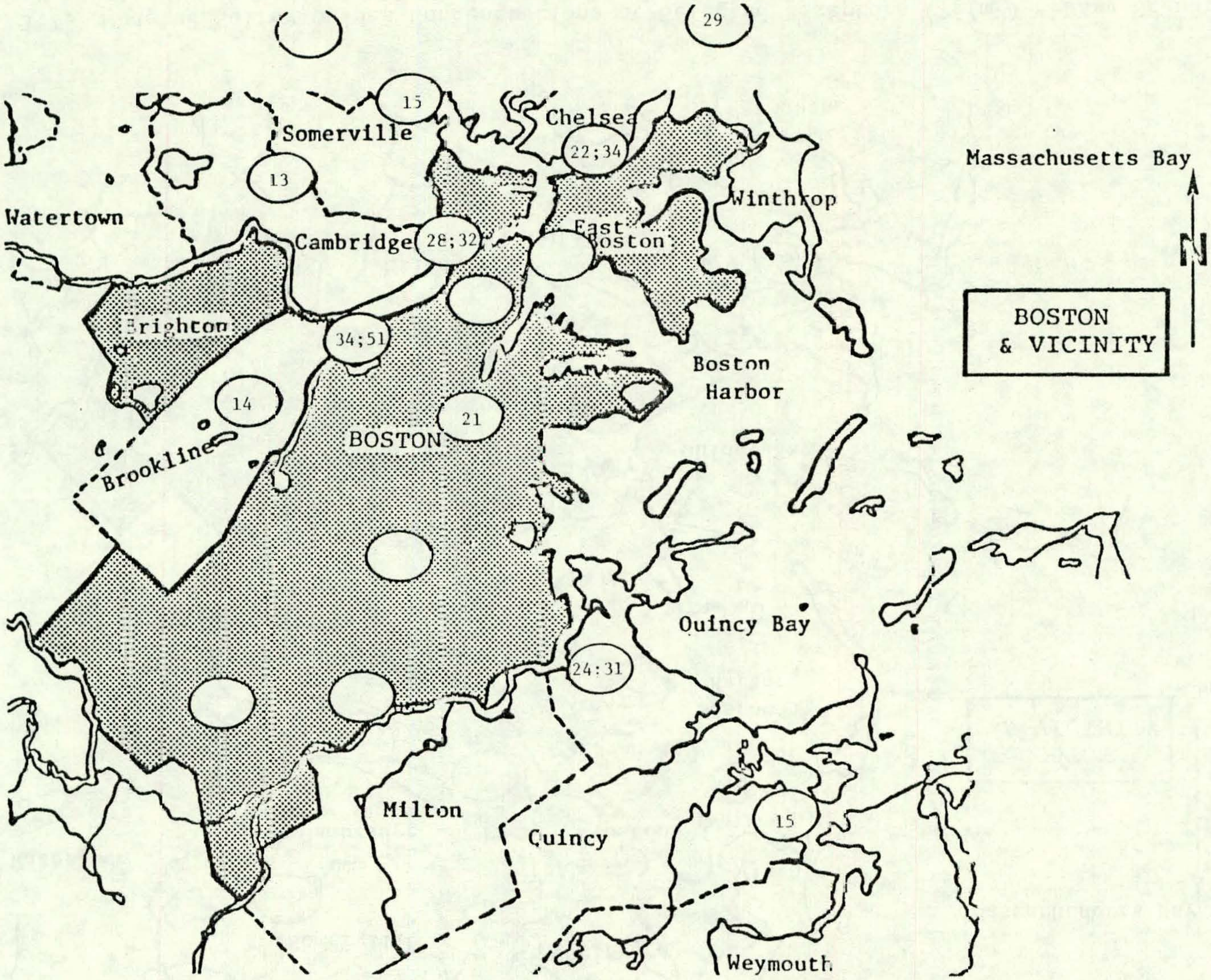

Fig. 3.3. Measured 1977 Sulfur Oxides Concentrations at Selected Receptors ($\mu g/m^3$)

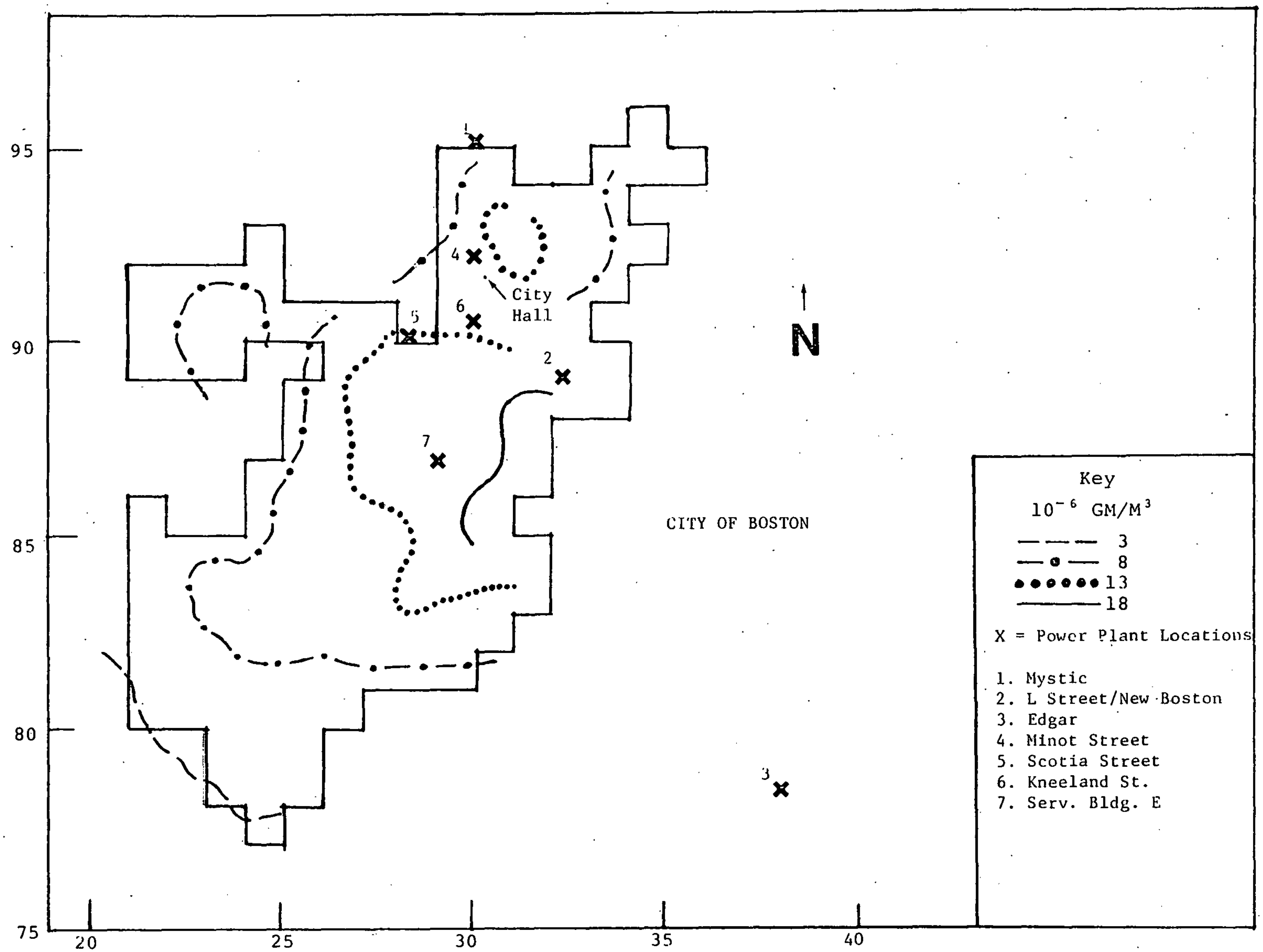

Fig. 3.4. Isopleth Map of Reductions in Average Annual Ground-Level Concentrations of Sulfur Oxides Caused by District ($\mu g/m^3$) Heating--Scenarios 0 and I

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4 ALTERNATIVE SCENARIOS

The combined objectives of saving scarce fuels and improving air quality suggest that alternative fuel scenarios should be investigated. This section considers various alternative fuel scenarios. However, they are primarily for illustrative purposes only, and essentially ignore what could be significant economic considerations.

Three pairs of alternative scenarios are considered.

4.1 SCENARIOS IIA AND IIB: POWER PLANT RESIDUAL OIL AT 0.5% SULFUR CONTENT

Scenarios IIA and IIB are modifications of scenarios IA and IB. In these scenarios it is assumed that residual oil burned at the power plants has 0.5% sulfur content. Scenarios IIA and IIB have been constructed to examine the effects of the Massachusetts Department of Environmental Quality Engineering Regulations (as amended Jan. 1, 1978) requiring 0.5% sulfur content limitation on residual oil burned in and near the City of Boston. Although combustion of lower quality residual oil is permitted at some power plants, it is conceivable that the 0.5% limitation would be imposed at some future time. If higher quality oil were used at the power plants, in particular at Mystic, New Boston, and Edgar, a pair of scenarios would exist in which the competing third effect discussed earlier (greater emissions coefficients at the plants) is reduced somewhat. Unlike Scenarios IA and IB, the emissions changes would thus more closely parallel the fuel consumption changes. However, the question remains open as to whether consumption of residual oil at greater than 0.5% sulfur content would still be permitted if cogeneration occurred with greater fuel consumption, especially at peak periods.

4.1.1 Sulfur Emissions

In these scenarios, the residual oil burned at the major steam-electric plants is assumed to have a sulfur content 0.5%. Table 4.1 summarizes the results of emission tradeoffs for district heating plant residual oil at 0.5% sulfur content. Plant-specific emissions for these scenarios are shown in Tables 4.2 and 4.3.

4.1.2 Results

Although the amount of particulate and sulfur oxides emissions will decrease somewhat in changing to district heating, they still do not decrease proportionately in accordance with the roughly 25% decrease in fuel consumption. This is true primarily because among the fuels displaced are a substantial amount of natural gas and distillate oil at 0.3% sulfur content.

4.2 SCENARIOS II AND III: COAL CONVERSION AT NEW SOURCE PERFORMANCE STANDARDS

The scarce-fuel conservation objective served by implementation of the district heating system is also served by conversion of exisiting oil-firing facilities to coal. Therefore, it is instructive to examine the emissions tradeoffs associated with coal conversion, both with and without the district heating system. Facilities that convert to coal firing are assumed to conform to the federal New Source Performance Standards (NSPS) for fossil-fuel fired stationary sources in effect during 1977. These emissions standards for solid fossil-fuels are 0.1 lb/10^6Btu for particulate matter, 1.2 lb/10^6Btu for sulfur dioxide, and 0.7 lb/10^6Btu for nitrogen oxides. Table 2.2 provides these numbers (converted to tons/10^{12}Btu) along with emissions coefficients for carbon monoxide and hydrocarbons from bituminous coal (at 24 × 10^6Btu/ton) obtained from Ref. 5.

The question as to which steam-electric plants should be converted to coal in this hypothetical scenario was difficult to answer. It may have been easiest to convert each major oil-fired unit to coal, thus illustrating the effect of a total oil-to-coal conversion. However, conversion to coal would be costly, especially with additional pollution-control equipment. Furthermore, plant and site specific limitations also could affect the technical and economic feasibility of conversion. After consultation with Boston Edison Co., an intermediate or compromise position was taken in specifying this scenario. Boston Edison confirmed that presently five units are coal capable (Mystic 4, 5, 6, and New Boston 1, 2) but that, for various technical economic reasons, coal conversion might not be feasible.

Table 4.1 Scenarios IIA and IIB--Emission Tradeoffs for District Heating; Plant Residual Oil at 0.5% Sulfur Content

	Consumption of Fuel Thermal and Electric (10^{12} Btu)	Annual Emissions (tons)				
		Particulates	Sulfur Oxides	Carbon Monoxides	Hydrocarbons	Nitrogen Oxides
Scenario IIA No District Htg	160.0	3547	34,809	2624	556	26,111
Scenario IIB District Heating	120.6	3222	32,347	2054	416	25,344
Difference (IIB - IIA)	-39.4	-325	-2,462	-570	-140	-767
% Change (IIB - IIA)	-24.6	-9.2	-7.1	-21.7	-25.2	-2.9
Net % Change from Base Scenario (IIB - IIA)	-24.6	-40.7	-50.2	-21.7	-25.2	-2.9

Table 4.2. Scenario IIA -- No District Heating; Residual Oil at 0.5% Sulfur Content (Emissions in Ton/yr)

Plant	Stack	Particulate	SO_x	CO	HC	NO_x
Fram.	J-1	.07	1.147	.139	.035	.591
	J-2	.07	1.147	.139	.035	.591
	J-3	.07	1.147	.139	.035	.591
Edgar	J-1	.035	1.057	.139	.042	.556
	J-2	.035	1.057	.139	.042	.556
	9	91.013	899.650	56.523	11.298	678.379
	10	89.882	888.525	55.828	11.159	669.931
	11	95.983	948.794	59.617	11.923	715.365
Mystic	J-1	.07	1.738	.209	.035	.869
	4	90.421	894.650	56.280	11.263	675.215
	5	120.111	1,188.537	74.738	14.948	896.996
	6	55.017	544.424	34.240	6.848	410.886
	7	795.424	7,781.104	495.044	99.002	5,940.462
New Boston	E-W#1	387.529	3,384.690	241.178	48.250	2,894.102
	E-W#2	528.758	5,232.310	329.091	65.804	3,948.918
L Street	J-1	.104	2.538	.278	.070	1.286
	12 Elec.	10.604	104.935	6.6	1.32	79.19
	12 DSS	115.276	1,140.70	71.74	14.35	860.92
Minot St.	6	.904	8.968	.556	.104	6.779
	7	.904	8.968	.556	.104	6.779
Scotia St.	1	.382	8.447	.973	.209	4.310
	2	.382	8.447	.973	.209	4.310
	3	.382	8.447	.973	.209	4.310
Kneeland St.	1	47.068	399.727	36.813	5.701	784.333
	2/1	32.711	324.954	20.44	4.102	245.210
	2/2	23.534	199.881	12.549	8.378	392.184
Serv. Bldg. E	1(1)	.939	9.316	.591	.104	7.022
	1(2)	1.043	10.359	.660	.139	7.821
Total		2,489.380	24,545.763	1,557.147	313.968	19,238.464

Table 4.3. Scenario IIB -- District Heating; Residual Oil at 0.5% Sulfur Content[a]

Plant	Stack	Particulate	SO_x	CO	HC	NO_x
Fram.	J-1	.07	1.147	.139	.035	.591
	J-2	.07	1.147	.139	.035	.591
	J-3	.07	1.147	.139	.035	.591
Edgar	J-1	.042	1.281	.168	.042	.674
	J-2	.042	1.281	.168	.042	674
	9	58.656	1,090.484	68.506	13.693	822.195
	10	108.937	1,076.892	67.664	13.525	811.956
	11	116.331	1,149.939	72.256	14.451	867.022
Mystic	J-1	.085	2.117	.255	.043	1.058
	4	112.575	1,113.839	70.069	14.022	840.643
	5	149.538	1,479.716	93.049	18.610	1,116.760
	6	68.497	677.808	42.629	8.526	511.553
	7	990.303	9,799.524	616.330	123.257	7,395.875
New Boston	E-W#1	462.710	4,578.62	287.967	57.611	3,455.558
	E-W#2	631.336	6,247.38	392.935	78.570	4,715.008
L Street	J-1	.136	3.307	.362	.091	1.676
	12 Elec.	10.604	104.935	6.60	1.32	79.190
	12 DSS	115.278	1,140.72	71.74	14.35	860.920
Minot St.	6	1.075	10.661	.661	.123	8.059
	7	1.075	10.661	.661	.123	8.059
Scotia St.	1	.454	10.042	1.156	.248	5.123
	2	.454	10.042	1.156	.248	5.123
	3	.454	10.042	1.156	.248	5.123
Kneeland St.	1	55.951	475.164	43.761	6.777	932.353
	2/1	30.885	386.279	24.297	4.877	291.486
	2/2	27.975	237.602	14.917	9.959	622.197
Serv. Bldg. E	1(1)	.939	9.316	.591	.104	7.022
	1(2)	1.043	10.359	.660	.139	7.821
Total		2,953.585	29,641.452	1,5880.131	381.104	23,274.901

[a]Emissions given in ton/yr.

The large Mystic 7 unit was said to be unacceptable for coal conversion. Among the reasons given was an estimated 40% capacity derating that such conversion would entail. No coal-firing or-handling equipment is presently in place at the Mystic and New Boston facilities. At the New Boston facility, changes in the furnace design and stacks were said to be necessary. Furthermore, additional space for coal handling at the New Boston facility could be attained only with the use of landfill. The plant at Edgar Station, presently is used in this study in the Base (1977) scenario and in the District Heating scenarios. This plant, originally built for coal firing, is also a potential candidate for the coal conversion scenarios.

If economic considerations are disregarded, it is possible to include Mystic 4, 5, 6, New Boston 1, 2, and Edgar 9, 10, 11 in scenarios IIIA and IIIB as coal-converted facilities. Because the large Mystic 7 unit is being disregarded here, these scenarios will serve to illustrate the impact, with and without district heating, of a partial conversion to coal is in an essentially all-oil-based utility system.

4.2.1 Emissions

In this scenario, eight of the nine major oil-burning units are assumed to have been converted to coal at the federal New Source Performance Standards (NSPS) for solid-fossil-fuel-burning facilities. These standards would entail net reductions in emissions of particulates and sulfur oxides in both the non-district-heating scenario (IIIA) and the district-heating scenario (IIIB) as compared with the existing fuels scenarios (IA and IB). For carbon monoxide, nitrogen oxides, and hydrocarbons, coal burning would increase net emissions. Closer inspection of the detailed plant-specific tradeoffs reveals that coal (NSPS) burning at the Mystic and New Boston facilities would increase suflur oxides and particulates emissions somewhat; whereas, at the Edgar facility these emissions would be reduced (Mystic is burning 1% sulfur oil and New Boston is burning 2.2% sulfur oil in scenarios IA and IB). These detailed tradeoffs are likely to show up in the air quality results because the reduction at Edgar occurs several miles outside the city; whereas the increases at Mystic and New Boston occur in or at the edge of the city.

4.2.2 Tradeoffs

Table 4.4 shows the net tradeoffs for scenarios IIIA and IIIB. Plant-specific emissions for these scenarios are shown in Tables 4.5 and 4.6.

Table 4.4 Scenarios IIIA and IIIB -- Emissions Tradeoffs for District Heating with Conversions to Coal at New Source Performance Standards

	Consumption of Fuel Thermal and Electric (Btu × 10^{12})	Annual Emissions (tons)				
		Parti- culates	Sulfur Oxides	Carbon Mon- Oxide	Hydro- Carbons	Nitrogen Oxides
Scenario IIIA Coal (NSPS) No Distr. Htg.	160.0	5309	61,310	2820	708	33,781
%Change from Scenario IA	-	-2.2	- 5.6	+7.5	+21.5	+ 29.4
Scenario IIIB Coal (NSPS) District Htg.	120.6	5403	64,372	2290	597	34,700
Difference (IIIB - IIIA)	-39.4	+ 94	+3,062	- 530	- 111	+ 919
Percent Change (IIIB - IIIA)	-24.6	+ 1.8	+ 5.0	-18.8	-15.7	+ 2.7
Net Percent Change from Base Scenario (IIIB - IA)	-24.6	- 0.5	- 0.8	-12.7	+ 7.4	+ 32.9

4.3 SCENARIOS IVA AND IVB: COAL CONVERSION WITH MAXIMUM CONTROLS

Another look at the coal conversion scenarios provides a useful example of the emissions and air quality impacts if converted facilities were to have near-maximum levels of controls installed. In scenarios IVA and IVB, the same units are converted to coal as in scenarios IIIA and IIIB. The average ash content of the bituminous coal is assumed to be 10%, and that the average sulfur content is assumed to be 1%. Under these conditions, approximately 3340 tons of particulates and 799 tons of sulfur oxides would be generated per 10^{12}Btu consumed. However, if 99.5% controls on particulates and 90% controls on sulfur oxides were installed, these numbers would be reduced to 16.7 tons per 10^{12}Btu and 79 tons per 10^{12}Btu, respectively--both well below the NSPS figures shown in Table 2.2. The 16.7 figure for particulates is even below the 25 ton per 1012Btu (50, if sulfur oxides controls are present) specified by the Massachusetts DEQE air pollution regulations for large, new facilities. Nevertheless, these scenarios can illustrate the impact of maximum controls on coal-converted facilities. Reference 6 estimates the control efficiencies associated with wet lime scrubbers for both particulates and sulfur oxides to be 99.5% and 90%, respectively.

Table 4.5. Scenario IIIA -- Coal at New Source Performance Standards: No District Heating

Plant	Stack	Particulate	SO_x	CO	HC	NO_x
Fram.	J-1	.07	1.147	.139	.035	.591
	J-2	.07	1.147	.139	.035	.591
	J-3	.07	1.147	.139	.035	.591
Edgar	J-1	.035	1.057	.139	.035	.556
	J-2	.035	1.057	.139	.035	.556
	9	167.81	2,013.779	69.811	20.976	1,174.705
	10	165.72	1,988.671	68.941	20.715	1,160.058
	11	176.96	2,123.573	73.617	22.119	1,238.752
Mystic	J-1	.07	1.738	.209	.035	.869
	4	164.56	1,974.74	68.458	20.569	1,151.934
	5	218.62	2,623.39	90.944	27.326	1,530.312
	6	100.14	1,201.682	41.658	12.517	700.980
	7	1,287.094	15,742.207	495.044	99.002	5,940.462
New Boston	E-W#1	701.10	8,412.19	291.623	87.623	4,907.112
	E-W#2	956.51	11,478.11	397.901	119.559	6,695.563
L Street	J-1	.104	2.538	.278	.070	1.286
	12 Elec.	17.159	209.87	6.60	1.32	79.19
	12 DSS	186.532	2,281.44	71.74	14.35	860.92
Minot St.	6	.904	8.968	.556	.104	6.779
	7	.904	8.968	.556	.104	6.779
Scotia St.	1	.382	8.447	.973	.209	4.310
	2	.382	8.447	.973	.209	4.310
	3	.382	8.447	.973	.209	4.310
Kneeland St.	1	47.068	399.727	36.813	5.701	784.333
	2/1	32.711	324.954	20.44	4.102	245.210
	2/2	23.534	199.881	12.549	8.378	392.184
Serv. Bldg. E	1(1)	.939	9.316	.591	.104	7.022
	1(2)	1.043	10.359	.660	.139	7.821
Total		4,250.908	51,046.997	1,752.61	465.615	26,908.086

Table 4.6. Coal at New Source Performance Standards--Scenario IIIB: District Heating[a]

Plant	Stack	Particulate	SO_x	CO	HC	NO_x
Fram.	J-1	.07	1.147	.139	.035	.591
	J-2	.07	1.147	.139	.035	.591
	J-3	.07	1.147	.139	.035	.591
Edgar	J-1	.042	1.281	.168	.042	.674
	J-2	.042	1.281	.168	.042	674
	9	67.931	321.359	84.611	25.423	1,423.744
	10	67.085	317.352	83.556	25.106	1,405.989
	11	71.635	338.880	89.224	26.809	1,501.367
Mystic	J-1	.085	2.117	.255	.043	1.058
	4	68.429	323.710	85.230	25.609	1,434.157
	5	90.909	430.040	113.226	34.021	1,905.239
	6	41.641	196.986	51.865	15.583	872.722
	7	1,602.432	19,599.048	616.330	123.257	7,395.875
New Boston	E-W#1	279.596	1,322.481	348.197	104.623	5,859.091
	E-W#2	381.452	1,804.473	475.102	142.753	7,994.504
L Street	J-1	.136	3.307	.362	.091	1.676
Elec.	12	17.159	209.87	6.600	1.32	79.19
DSS	12	186.534	2,281.44	71.74	14.35	860.92
Minot St.	6	1.075	10.661	.661	.123	8.059
	7	1.075	10.661	.661	.123	8.059
Scotia St.	1	.454	10.042	1.156	.248	5.123
	2	.454	10.042	1.156	.248	5.123
	3	.454	10.042	1.156	.248	5.123
Kneeland St.	1	55.951	475.164	43.761	6.777	932.353
	2(1)	38.885	386.279	24.297	4.877	291.486
	2(2)	27.975	237.602	14.917	9.959	622.197
Serv. Bldg. E	1(1)	.939	9.316	.591	.104	7.022
	1(2)	1.043	10.359	.660	.139	7.821
Total		3,003.623	28,327.234	2,116.065	562.023	32,631.019

[a]Emissions in ton/yr.

4.3.1 Emissions

In these scenarios, conversion of eight large oil-fired facilities to coal is made, assuming 99.5% particulate control and 90% sulfur oxides control (using wet lime scrubbers). This assumption substantially reduces the emissions of these two pollutants at the sites involved.

4.3.2 Results

The results are summarized in Table 4.7. Plant-specific emissions for these scenarios are shown in Table 4.8 and 4.9.

4.4 AIR QUALITY RESULTS FOR THE ALTERNATIVE SCENARIOS

4.4.1 Background

The air quality changes for the alternative scenarios for concentrations of average, annual ground-level, sulfur-oxides and differs substantially from the gross changes in emissions reported above. This is because of:

(a) the location of sources;

(b) the quantity and type of fuel burned at each location; and

(c) the enhanced dispersion effect on sources with tall stacks and hot, buoyant plumes.

For example, although the sulfur oxides emissions at the Edgar Plant would be reduced in conversion to coal at NSPS, this plant is located several miles southeast of the city; whereas, the increased emissions at the New Boston and Mystic facilities occur in and at the edge of the downtown area of the city. However, these source receptor relationships are not sufficient for an intuitive grasp of average air quality at any particular receptor point, e.g., one in the downtown area. Considerable dispersion from the plume rise above high stacks and wind conditions are important dimensions of the source-receptor relationship.

The point source input stack parameters have already been given in Table 2.9. Tables 4.10 through 4.15 give the source strengths for each stack in scenarios IIA, IIB, IIIA, IIIB, IVA and IVB. Figures 4.1 through 4.6 show the air quality results at the 16 selected receptor points for each of these five alternative scenarios. Figure 3.3 may be used for easy comparison with measured concentrations. These results are also shown in Tables 4.16 through 4.18.

Table 4.7 Scenarios IVA and IVB -- Emissions Tradeoffs for District Heating with Conversion to Coal at Maximum Controls

	Fuel Consumption Thermal and Electric (Btu × 10^{12})	Annual Emissions (Tons)				
		Parti-culates	Sulfur Oxides	Carbon Mon-oxide	Hydro-carbons	Nitrogen Oxides
Scenario IVA Coal (Max Control No District Htg	160.0	3543	33,682	2820	708	33,781
%Change from Base Scenario IA	-	-34.7	- 48.1	+ 7.5	+ 21.5	+ 29.4
Scenario IVB Coal (Max Control) District Htg	120.6	3272	31,033	2290	597	34,700
Difference (IVB - IVA)	-39.4	- 271	-2,649	- 530	- 111	+ 919
% Change (IVB - IVA)	-24.6	- 7.6	- 7.9	-18.8	- 15.7	+ 2.7
% Change from Base Scenario IA (IVB - IA)	-24.6	-39.7	- 52.2	-12.7	+ 7.3	+ 32.9

Table 4.8. Scenario IVA -- Coal at Maximum Control: No District Heating[a]

Plant	Stack	Particulate	SO_x	CO	HC	NO_x
Fram.	J-1	.07	1.147	.139	.035	.591
	J-2	.07	1.147	.139	.035	.591
	J-3	.07	1.147	.139	.035	.591
Edgar	J-1	.035	1.057	.139	.035	.556
	J-2	.035	1.057	.139	.035	556
	9	56.049	265.148	69.811	20.976	1,174.705
	10	55.350	261.842	68.941	20.715	1,160.058
	11	59.105	279.604	73.617	22.119	1,238.752
Mystic	J-1	.07	1.738	.209	.035	.869
	4	54.963	260.008	68.458	20.569	1,151.934
	5	73.019	345.413	90.944	27.326	1,530.312
	6	33.447	158.221	41.658	12.517	700.98
	7	1,287.094	15,742.207	495.044	99.002	5,940.462
New Boston	E-W#1	234.167	1,107.605	291.623	87.623	4,907.112
	E-W#2	319.474	1,511.284	397.908	119.559	6,695.563
L Street	J-1	.104	2.538	.278	.070	1.286
Elec.	12	17.159	209.87	6.60	1.32	79.19
DSS	12	186.532	2,281.44	71.74	14.35	860.92
Minot St.	6	.904	8.968	.556	.104	6.779
	7	.904	8.968	.556	.104	6.779
Scotia St.	1	.382	8.447	.973	.209	4.310
	2	.382	8.447	.973	.209	4.310
	3	.382	8.447	.973	.209	4.310
Kneeland St.	1	47.068	399.727	36.813	5.701	784.333
	2/1	32.711	324.954	20.44	4.102	245.210
	2/2	23.534	199.881	12.549	8.378	392.184
Serv. Bldg. E	1(1)	.939	9.316	.591	.104	7.022
	1(2)	1.043	10.359	.660	.139	7.821
Total		2,485.063	23,419.987	1,752.61	465.615	26,908.086

[a]Emissions in ton/yr.

Table 4.9. Scenario IVB -- Coal with Maximum Control -- District Heating; Residual Oil at 5% Sulfur Contect[a]

Plant	Stack	Particulate	SO_x	CO	HC	NO_x
Fram.	J-1	.07	1.147	.139	.035	.591
	J-2	.07	1.147	.139	.035	.591
	J-3	.07	1.147	.139	.035	.591
Edgar	J-1	.042	1.281	.168	.042	.674
	J-2	.042	1.281	.168	.042	674
	9	203.386	2,440.700	84.611	25.423	1,423.744
	10	200.853	2,410.271	83.556	25.106	1,405.989
	11	214.476	2,573.771	89.224	26.809	1,501.367
Mystic	J-1	.085	2.117	.255	.043	1.058
	4	204.877	2,458.557	85.230	25.609	1,434.157
	5	272.182	3,266.115	113.226	34.021	1,905.239
	6	124.674	1,496.094	51.865	15.583	872.722
	7	1,602.432	19,599.048	616.330	123.257	7,395.875
New Boston	E-W#1	837.113	10,044.158	348.197	104.623	5,859.091
	E-W#2	1,142.073	13,704.861	475.102	142.753	7,994.504
L Street	J-1	.136	3.307	.362	.091	1.676
	12 Elec.	17.159	209.875	6.60	1.32	79.19
	12 DSS	186.534	2,281.44	71.74	14.35	860.92
Minot St.	6	1.075	10.661	.661	.123	8.059
	7	1.075	10.661	.661	.123	8.059
Scotia St.	1	.454	10.042	1.156	.248	5.123
	2	.454	10.042	1.156	.248	5.123
	3	.454	10.042	1.156	.248	5.123
Kneeland St.	1	55.951	475.164	43.761	6.777	932.353
	2/1	38.885	386.279	24.297	4.877	291.486
	2/2	27.975	237.602	14.917	9.959	622.197
Serv. Bldg. E	1(1)	.939	9.316	.591	.104	7.022
	1(2)	1.043	10.359	.660	.139	7.821
Total		5,134.579	61,666.480	2,116.065	562.023	32,631.019

[a]Emissions in ton/yr.

Table 4.10 Residual Oil at 0.5% Sulfur Content--Scenario IIA: No District Heating

Plant	Stack	Function	Annual Fuel Usage Type	Annual Fuel Usage Amount[a]	SO_x Emissions g/sec
Framingham	J-1	Elec.	#2 Oil	52,472	.03
	J-2	Elec.	#2 Oil	52,472	.03
	J-3	Elec.	#2 Oil	52,472	.03
Edgar	J-1	DH/Cogen	#2 Oil	60,169	.03
	J-2	"	#2 Oil	60,169	.03
	9	"	#6 Oil	27,355,965	25.88
	10	"	#6 Oil	27,014,908	25.56
	11	"	#6 Oil	28,847,452	27.29
Mystic	J-1	"	#2 Oil	96,327	.05
	4	"	#6 Oil	34,822,552	25.74
	5	"	#6 Oil	37,157,274	34.19
	6	"	#6 Oil	17,020,395	15.66
	7	"	#6 Oil	246,076,740	226.43
New Boston	#1E-W	"	#6 Oil	114,974,320	110.32
	#2E-W	"	#6 Oil	156,877,990	150.52
L Street	J-1	"	#2 Oil	151,810	.07
	12	Elec.	#6 Oil	2,639,826	3.02
	12	DSS	#6 Oil	28,697,300	32.82
Minot Street	6	DSS	#6 Oil	171,564	.26
	7	"	#6 Oil	171,564	.26
Scotia Street	1	"	#2 Oil	297,883	.24
	2	"	#2 Oil	297,883	.24
	3	"	#2 Oil	297,883	.24
Kneeland St.	1	"	#6 Oil	3,041,173	11.49
	"	"	NatGas	417,709	.01
	2(1)	"	#6 Oil	2,474,490	9.35
	2(2)	"	#6 Oil	1,520,586	5.74
	"	"	NatGas	208,855	.01
Service Bldg. E	1(1)	"	#6 Oil	234,136	.27
	(2)	"	#6 Oil	260,000	.30

[a]Oil in gal/yr.
Nat. gas in Mcf/yr.

Table 4.11 Scenario IIB: District Heating; Residual Oil at 0.5% Sulfur Content

Plant	Stack	Function	Annual Fuel Usage Type	Annual Fuel Usage Amount[a]	SO_x Emissions g/sec
Framingham	J-1	Elec.	#2 Oil	52,472	.03
	J-2	Elec.	#2 Oil	52,472	.03
	J-3	Elec.	#2 Oil	52,472	.03
Edgar	J-1	DH/Cogen	#2 Oil	60,169	.04
	J-2	"	#2 Oil	60,169	.04
	9	"	#6 Oil	27,355,965	31.37
	10	"	#6 Oil	27,014,908	30.98
	11	"	#6 Oil	28,847,452	33.08
Mystic	J-1	"	#2 Oil	96,327	.06
	4	"	#6 Oil	34,822,552	32.04
	5	"	#6 Oil	37,157,274	42.57
	6	"	#6 Oil	17,020,395	19.50
	7	"	#6 Oil	246,076,740	281.91
New Boston	#1E-W	"	#6 Oil	114,974,320	131.72
	#2E-W	"	#6 Oil	156,877,990	179.72
L Street	J-1	"	#2 Oil	151,810	.10
	12	Elec.	#6 Oil	2,639,826	3.02
	12	DSS	#6 Oil	28,697,300	32.82
Minot Street	6	DSS	#6 Oil	267,640	.31
	7	"	#6 Oil	267,640	.31
Scotia Street	1	"	#2 Oil	464,697	.28
	2	"	#2 Oil	464,697	.28
	3	"	#2 Oil	464,697	.28
Kneeland St.	1	"	#6 Oil	4,744,230	13.76
	"	"	NatGas	651,626	.02
	2(1)	"	#6 Oil	3,860,204	11.11
	2(2)	"	#6 Oil	2,372,114	6.82
	"	"	NatGas	325,814	.02
Service Bldg, E	1(1)	"	#6 Oil	234,136	.27
	(2)	"	#6 Oil	260,000	.30

[a]Oil in gal/yr.
Nat. gas in Mcf/yr.

Table 4.12 Coal at New Source Performance Standards -- Section IIIA: No District Heating

Plant	Stack	Function	Annual Fuel Usage Type	Amount[a]	SO_x Emissions g/sec
Framingham	J-1	Electric	#2 Oil	52,472	.03
	J-2	"	#2 Oil	52,472	.03
	J-3	"	#2 Oil	52,472	.03
		"			
Edgar	J-1	"	#2 Oil	49,644	.03
	J-2	"	#2 Oil	49,644	.03
	9	"	Coal	139,846	57.93
	10	"	Coal	138,102	57.21
	11	"	Coal	147,470	61.10
Mystic	J-1	"	#2 Oil	79,086	.05
	4	"	Coal	137,135	56.81
	5	"	Coal	182,180	75.47
	6	"	Coal	83,450	34.58
	7	"	#6 Oil	197,652,000	452.86
New Boston	#1E-W	"	Coal	584,180	242.00
	#2E-W	"	Coal	797,091	330.20
L Street	J-1	"	#2 Oil	116,508	.07
	12	"	#6 Oil	2,639,826	6.04
	12	DSS	#6 Oil	28,697,300	65.63
Minot Street	6	"	#6 Oil	225,150	.26
	7	"	#6 Oil	225,150	.26
Scotia Street	1	"	#2 Oil	390,923	.24
	2	"	#2 Oil	390,923	.24
	3	"	#2 Oil	390,923	.24
Kneeland St.	1	"	#6 Oil	10,027,740	11.49
	"	"	NatGas	1,377,324	.01
	2(1)	"	#6 Oil	8,159,200	9.35
	2(2)	"	#6 Oil	5,013,870	5.74
	"	"	NatGas	688,663	.01
Service Bldg. E	1(1)	"	#6 Oil	234,136	.27
	(2)	"	#6 Oil	260,000	.30

[a]Oil in gal/yr.
Gas in Mcf/yr.
Coal in ton/yr

Table 4.13 Coal at New Source Performance Standards--Scenario IIIB: District Heating

Plant	Stack	Function	Annual Fuel Usage Type	Annual Fuel Usage Amount[a]	SO_x Emissions g/sec
Framingham	J-1	Elec.	#2 Oil	52,472	.03
	J-2	"	#2 Oil	52,472	.03
	J-3	"	#2 Oil	52,472	.03
Edgar	J-1	DH/Cogen	#2 Oil	60,169	.04
	J-2	"	#2 Oil	60,169	.04
	9	"	Coal	169,493	70.22
	10	"	Coal	167,380	69.33
	11	"	Coal	178,734	74.04
Mystic	J-1	"	#2 Oil	96,327	.06
	4	"	Coal	170,733	70.73
	5	"	Coal	226,814	93.96
	6	"	Coal	103,895	43.04
	7	"	#6 Oil	246,076,740	563.81
New Boston	#1E-W	"	Coal	697,511	288.95
	#2E-W	"	Coal	951,726	394.25
L Street	J-1	"	#2 Oil	151,810	.10
	12	Elec.	#6 Oil	2,639,826	6.04
	12	DSS	#6 Oil	28,697,300	65.63
Minot Street	6	"	#6 Oil	267,640	.31
	7	"	#6 Oil	267,640	.31
Scotia Street	1	"	#2 Oil	464,697	.28
	2	"	#2 Oil	464,697	.28
	3	"	#2 Oil	464,697	.28
Kneeland St.	1	"	#6 Oil	4,744,230	13.76
	"	"	NatGas	651,626	.02
	2(1)	"	#6 Oil	3,860,204	11.11
	2(2)	"	#6 Oil	2,372,114	6.82
	"	"	NatGas	325,814	.02
Service Bldg. E	1(1)	"	#6 Oil	234,136	.27
	(2)	"	#6 Oil	260,000	.30

[a]Oil in gal/yr.
Gas in Mcf/yr.
Coal in ton/yr

Table 4.14 Coal at Maximum Controls--Scenario IVA: No District Heating

Plant	Stack	Function	Annual Fuel Usage Type	Amount[a]	SO_x Emissions g/sec
Framingham	J-1	Electric	#2 Oil	52,472	.03
	J-2	"	#2 Oil	52,472	.03
	J-3	"	#2 Oil	52,472	.03
Edgar	J-1	"	#2 Oil	49,644	.03
	J-2	"	#2 Oil	49,644	.03
	9	"	Coal	139,846	7.63
	10	"	Coal	138,102	7.53
	11	"	Coal	147,470	8.04
Mystic	J-1	"	#2 Oil	79,086	.05
	4	"	Coal	137,135	7.48
	5	"	Coal	182,180	9.94
	6	"	Coal	83,450	4.55
	7	"	#6 Oil	197,652,000	452.86
New Boston	#1E-W	"	Coal	584,180	31.86
	#2E-W	"	Coal	797,091	43.48
L Street	J-1	"	#2 Oil	116,508	.07
	12	"	#6 Oil	2,639,826	6.04
	12	DSS	#6 Oil	28,697,300	65.63
Minot Street	6	"	#6 Oil	225,150	.26
	7	"	#6 Oil	225,150	.26
Scotia Street	1	"	#2 Oil	390,923	.24
	2	"	#2 Oil	390,925	.24
	3	"	#2 Oil	390,923	.24
Kneeland St.	1	"	#6 Oil	10,027,740	11.49
	"	"	NatGas	1,377,324	.01
	2(1)	"	#6 Oil	8,159,200	9.35
	2(2)	"	#6 Oil	5,013,870	5.74
	"	"	NatGas	688,663	.01
Service Bldg. E	1(1)	"	#6 Oil	234,136	.27
	(2)	"	#6 Oil	260,000	.30

[a]Oil in gal/yr.
Gas in Mcf/yr.
Coal in ton/yr

Table 4.15 Coal at Maximum Controls--Scenario IVB: District Heating

Plant	Stack	Function	Annual Fuel Usage Type	Annual Fuel Usage Amount[a]	SO_x Emissions g/sec
Framingham	J-1	Elec.	#2 Oil	52,472	.03
	J-2	Elec.	#2 Oil	52,472	.03
	J-3	Elec.	#2 Oil	52,472	.03
Edgar	J-1	DH/Cogen	#2 Oil	60,169	.04
	J-2	"	#2 Oil	60,169	.04
	9	"	Coal	169,493	9.25
	10	"	Coal	167,380	9.13
	11	"	Coal	178,734	9.75
Mystic	J-1	"	#2 Oil	96,327	.06
	4	"	Coal	170,733	9.31
	5	"	Coal	226,814	12.37
	6	"	Coal	103,895	5.67
	7	"	#6 Oil	246,076,740	563.81
New Boston	#1E-W	"	Coal	697,511	38.04
	#2E-W	"	Coal	951,726	51.91
L Street	J-1	"	#2 Oil	151,810	.10
	12	Elec.	#6 Oil	2,639,826	6.04
	12	DSS	#6 Oil	28,697,300	65.63
Minot Street	6	DSS	#6 Oil	267,640	.31
	7	DSS	#6 Oil	267,640	.31
Scotia Street	1	"	#2 Oil	464,697	.28
	2	"	#2 Oil	464,697	.28
	3	"	#2 Oil	464,697	.28
Kneeland St.	1	"	#6 Oil	4,744,230	13.76
	"	"	NatGas	651,626	.02
	2(1)	"	#6 Oil	3,860,204	11.11
	2(2)	"	#6 Oil	2,372,114	6.82
	"	"	NatGas	325,814	.02
Service Bldg. E	1(1)	"	#6 Oil	234,136	.27
	(2)	"	#6 Oil	260,000	.30

[a]Oil in gal/yr.
Nat Gas in Mcf/yr.

Table 4.16 Scenarios IIA and IIB Average Annual Ground-Level Sulfur Oxides Concentrations (μg/m³)

Receptor	Scenario IIA No Distict Heating Plant Res. Oil @ .5%S				Scenario IIB District Heating Plant Res. Oil @ .5%S			Decrease of Modeled Concentrations	
	Point Local	Point Utility	Area	Total	Point[a] Local	Point[a] Utility	Total	Total	%
1	5.9	1.4	12.7	20.0	1.1	1.6	2.7	17.3	87
2	5.9	0.9	13.3	20.1	2.1	1.1	3.2	16.9	84
3	5.4	1.1	12.2	18.7	2.1	1.2	4.3	14.4	77
4	2.4	1.4	6.7	10.6	1.8	1.7	2.5	8.1	76
5	2.8	0.8	3.1	6.7	1.5	1.0	2.5	4.2	63
6	3.9	0.9	8.8	13.6	1.5	1.0	3.0	10.6	78
7	1.4	0.9	1.9	4.1	0.7	1.0	1.7	2.4	59
8	1.8	0.6	2.6	5.1	1.1	0.7	1.8	3.8	65
9	4.0	1.5	4.8	10.2	2.7	1.8	4.5	5.7	56
10	2.1	1.9	5.3	9.3	1.0	2.2	3.2	6.1	65
11	0.9	1.1	1.8	3.9	0.5	1.3	1.8	2.1	54
12	1.5	1.7	1.6	4.8	1.0	2.0	3.0	1.8	38
13	4.6	1.1	11.2	16.9	2.2	1.3	3.5	12.4	79
14	2.1	0.9	13.2	16.2	0.7	1.1	1.8	14.4	89
15	2.1	0.9	9.3	12.3	1.0	1.0	2.0	10.3	84
16	1.3	0.8	9.0	11.2	0.8	0.9	1.7	9.5	85

[a]Area sources make no contribution; point = total

Table 4.17 Scenarios IIIA and IIIB -- Average Annual Ground-Level Concentrations of Sulfur Oxides ($\mu g/m^3$)

Receptor	Scenario IIIA Coal/NSPS No District Heating				Scenario IIIB Coal/NSPS District Heating			Decrease of Modeled Concentrations	
	Point Local	Point Utility	Area	Total	Point[a] Local	Point[a] Utility	Total	Total	%
1	5.9	2.8	12.7	21.4	1.1	3.3	4.4	17.0	79
2	6.0	1.8	13.3	21.0	2.1	2.2	4.3	16.7	80
3	5.4	2.2	12.2	19.8	3.0	2.6	5.6	14.2	72
4	2.4	3.0	6.7	12.2	0.8	3.6	4.4	7.8	64
5	2.8	1.7	3.1	7.6	1.5	2.1	3.6	4.0	53
6	4.0	1.0	8.8	14.6	2.1	2.1	4.2	10.4	71
7	1.4	1.8	1.9	5.1	0.7	2.2	2.9	2.2	43
8	1.8	1.3	2.6	5.7	1.0	1.6	2.6	3.1	54
9	3.9	3.2	4.8	11.9	2.7	3.8	6.5	5.4	45
10	2.1	4.0	5.3	11.4	1.0	4.7	5.7	5.7	50
11	0.9	2.4	1.8	5.1	0.4	2.8	3.2	1.9	37
12	1.5	3.6	1.6	6.7	1.0	4.3	5.3	1.4	21
13	4.5	2.4	11.2	18.1	2.1	2.8	4.9	13.2	73
14	2.1	1.9	13.2	17.2	0.7	2.3	3.0	14.2	83
15	2.1	1.8	9.3	13.2	1.0	2.2	3.2	10.0	76
16	1.3	1.7	9.0	12.0	0.7	2.0	2.7	9.3	78

[a]Area sources make no contribution; point = total

Table 4.18 Scenarios IVA and IVB -- Average Annual Ground-Level Sulfur Oxides Concentration ($\mu g/m^3$)

Receptor	Scenario IVA Coal/Max. Control No District Heating				Scenario IVB Coal/Max. Control District Heating			Decrease of Modeled Concentrations	
	Point Local	Point Utility	Area	Total	Point* Local	Point* Utility	Total	Total	%
1	5.9	.7	12.7	19.3	1.1	0.7	1.8	17.5	91
2	5.9	.5	13.3	19.7	2.1	0.6	2.7	17.0	86
3	5.4	.5	12.2	18.1	3.0	0.6	3.6	14.5	80
4	2.4	.7	6.7	9.8	0.8	0.7	1.5	8.3	85
5	2.8	.4	3.1	6.3	1.5	0.5	2.0	4.3	68
6	4.0	.4	8.8	13.1	2.1	0.4	2.5	10.6	81
7	1.4	.6	1.8	3.8	0.7	0.7	1.4	2.4	63
8	1.9	.3	2.6	4.8	1.0	0.4	1.4	3.4	71
9	4.0	.7	4.8	9.4	2.7	0.8	3.5	5.9	63
10	2.1	1.0	5.3	8.4	1.0	1.1	2.1	6.3	75
11	0.9	.7	1.8	3.4	0.4	0.8	1.2	2.2	65
12	1.5	.9	1.6	4.0	0.9	1.1	2.0	2.0	50
13	4.6	.5	11.2	16.3	2.1	0.6	2.7	13.6	83
14	2.2	.4	13.2	15.8	0.7	0.5	1.2	14.6	92
15	2.1	.4	9.3	11.8	1.0	0.5	1.5	10.3	87
16	1.4	.4	9.0	10.8	0.7	0.5	1.2	9.6	89

*Area sources make no contribution; point = total

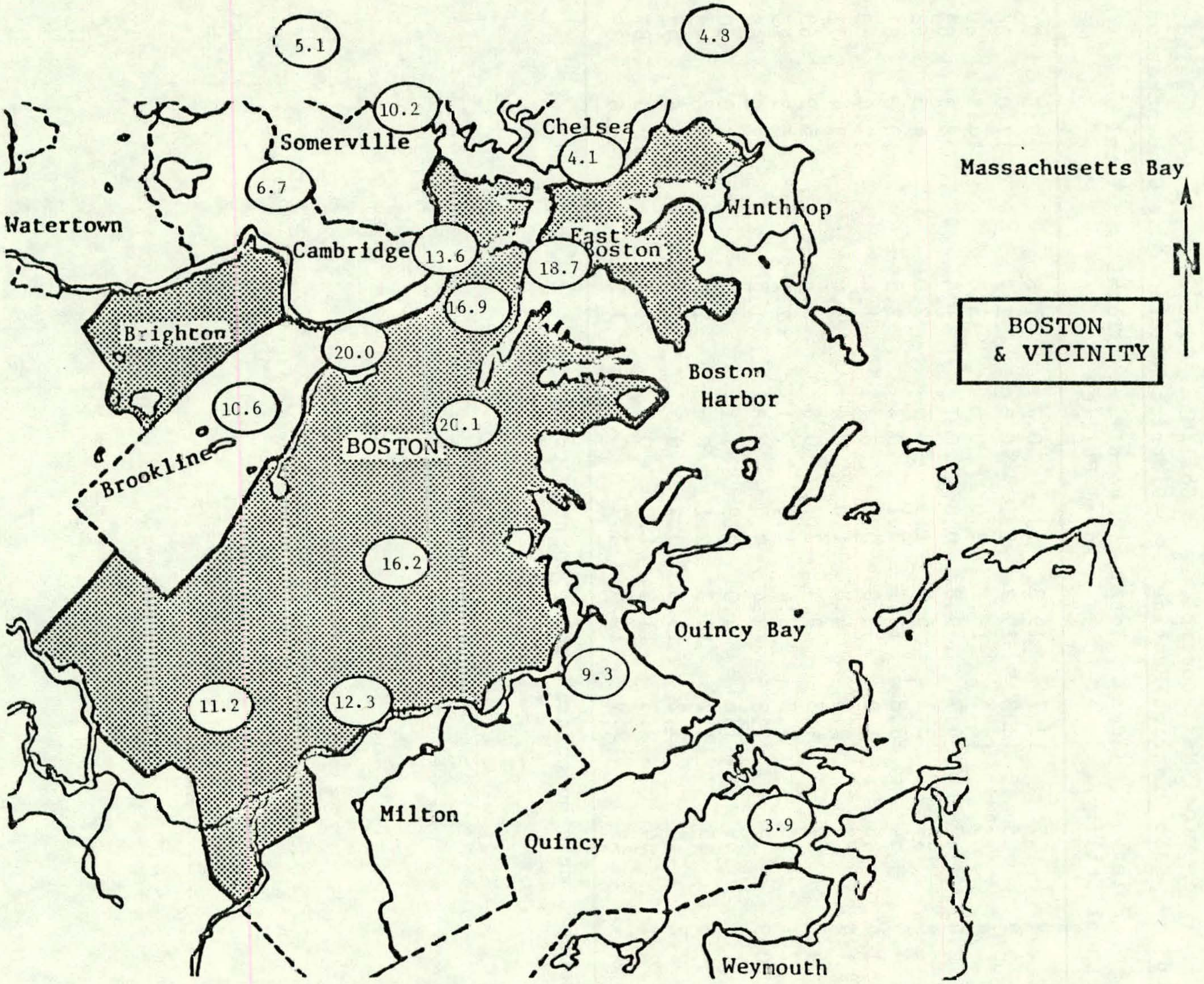

Fig. 4.1. Modeled Sulfur Oxides Concentrations at Selected Receptors ($\mu g/m^3$)--Scenario IIA: Oil at 0.5% Sulfur Content: No District Heating

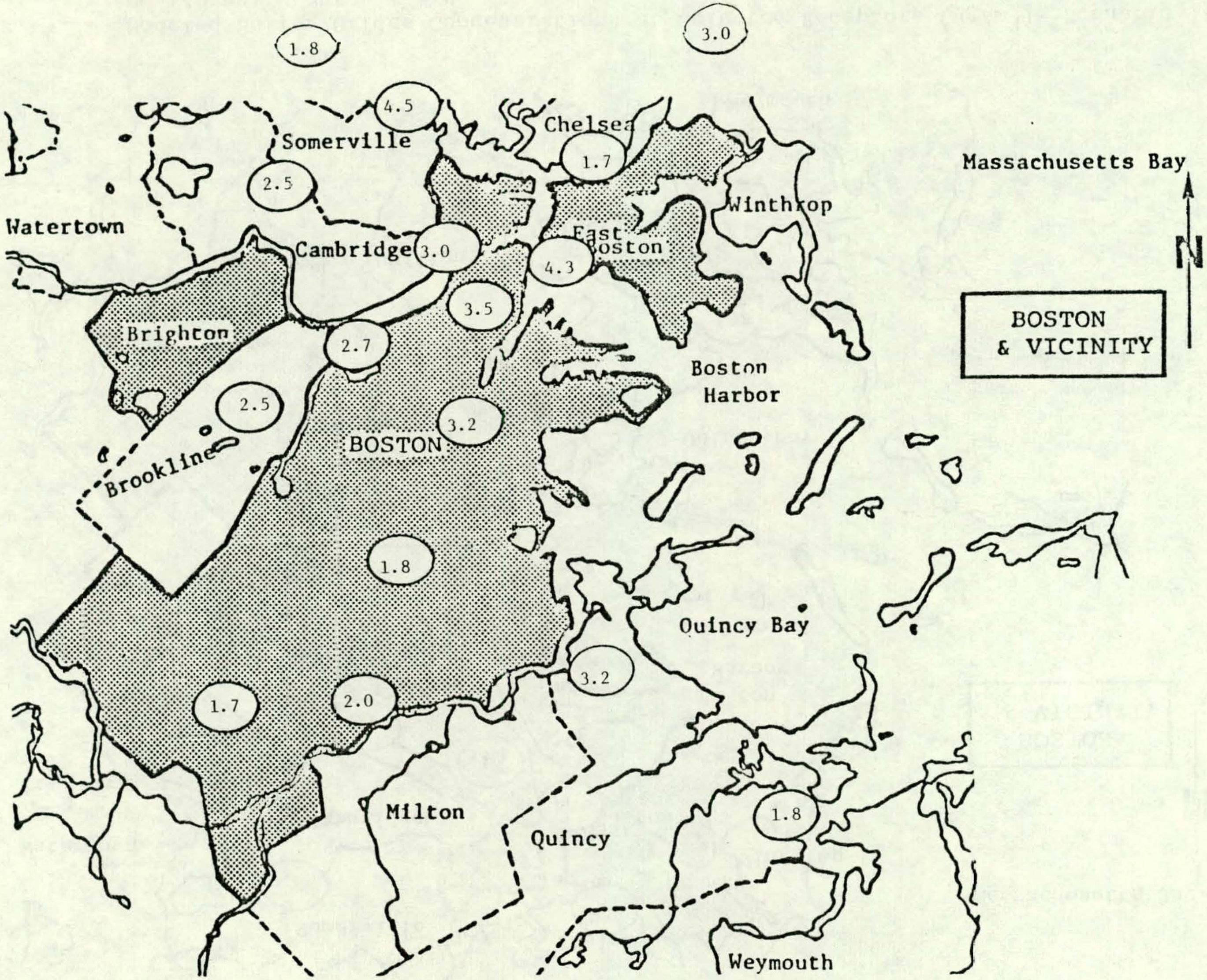

Fig. 4.2. Modeled Sulfur Oxides Concentrations at Selected Receptors ($\mu g/m^3$)--Scenario IIB: District Heating with Oil at 0.5% Sulfur Content

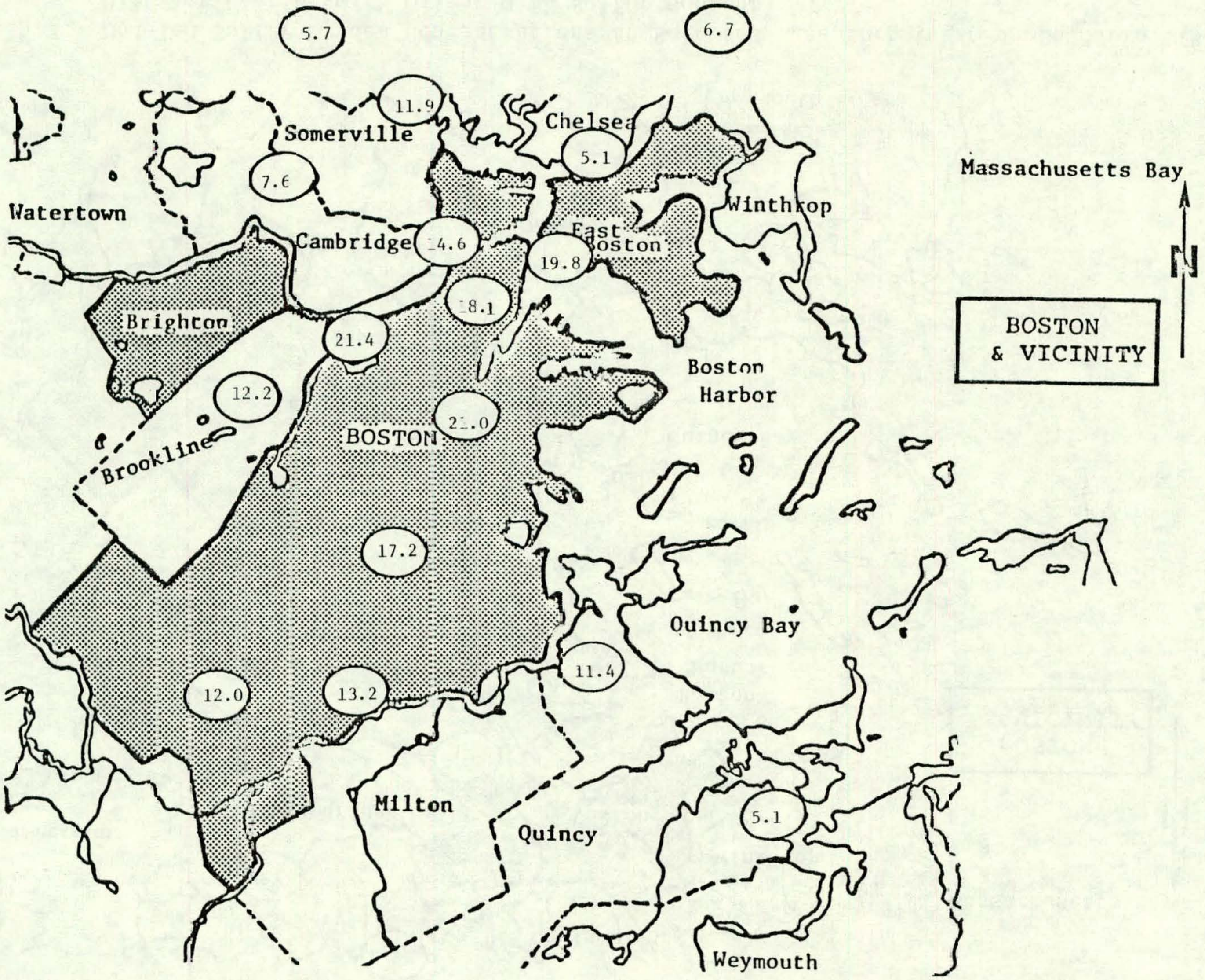

Fig. 4.3. Modeled Sulfur Oxides Concentrations at Selected Receptors ($\mu g/m^3$)--Scenario IIIA: Coal/NSPS; No District Heating

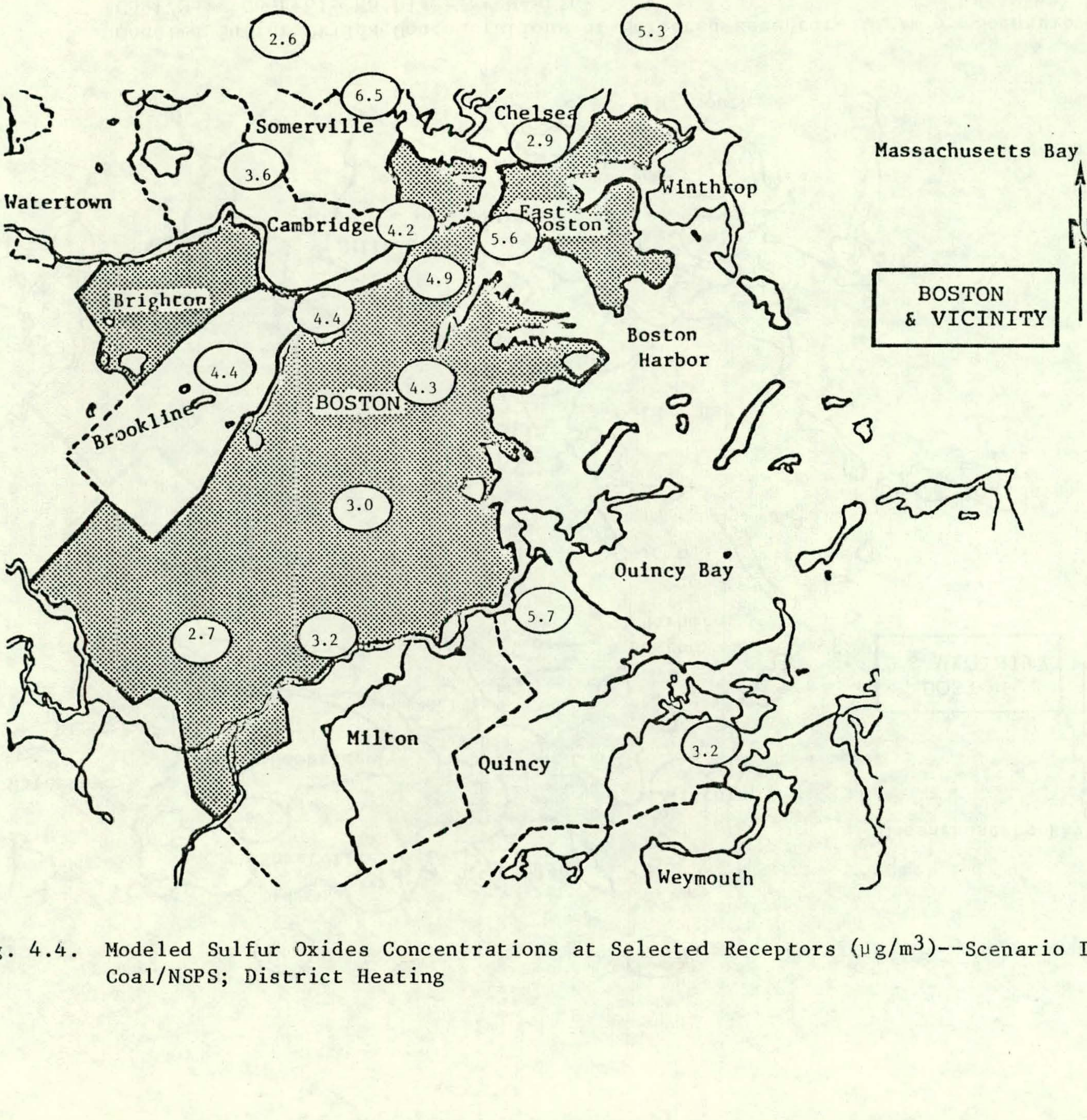

Fig. 4.4. Modeled Sulfur Oxides Concentrations at Selected Receptors ($\mu g/m^3$)--Scenario IIB: Coal/NSPS; District Heating

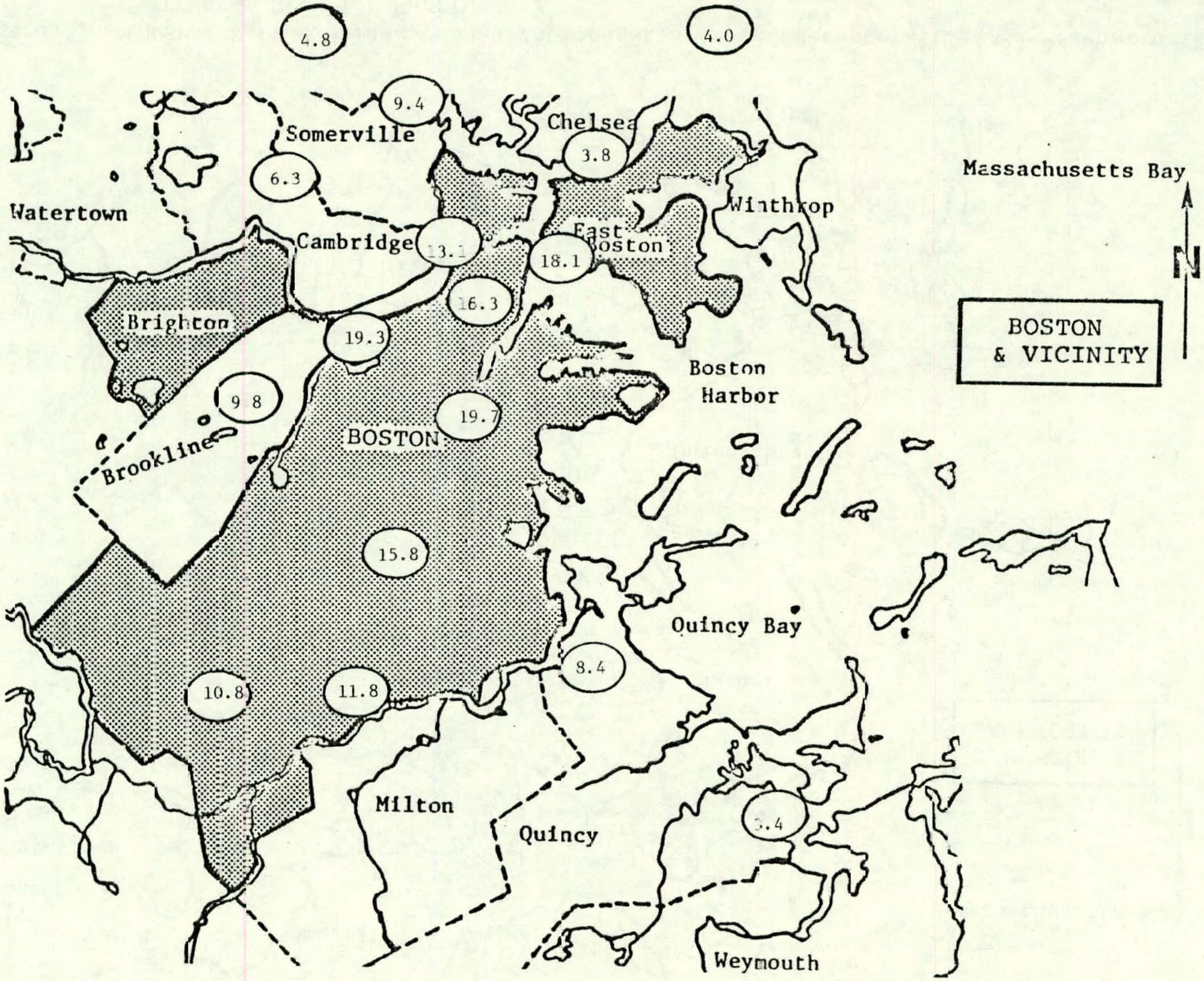

Fig. 4.5. Modeled Sulfur Oxides Concentrations at Selected Receptors ($\mu g/m^3$)--Scenario IVA: Coal/Max. Control; No District Heating

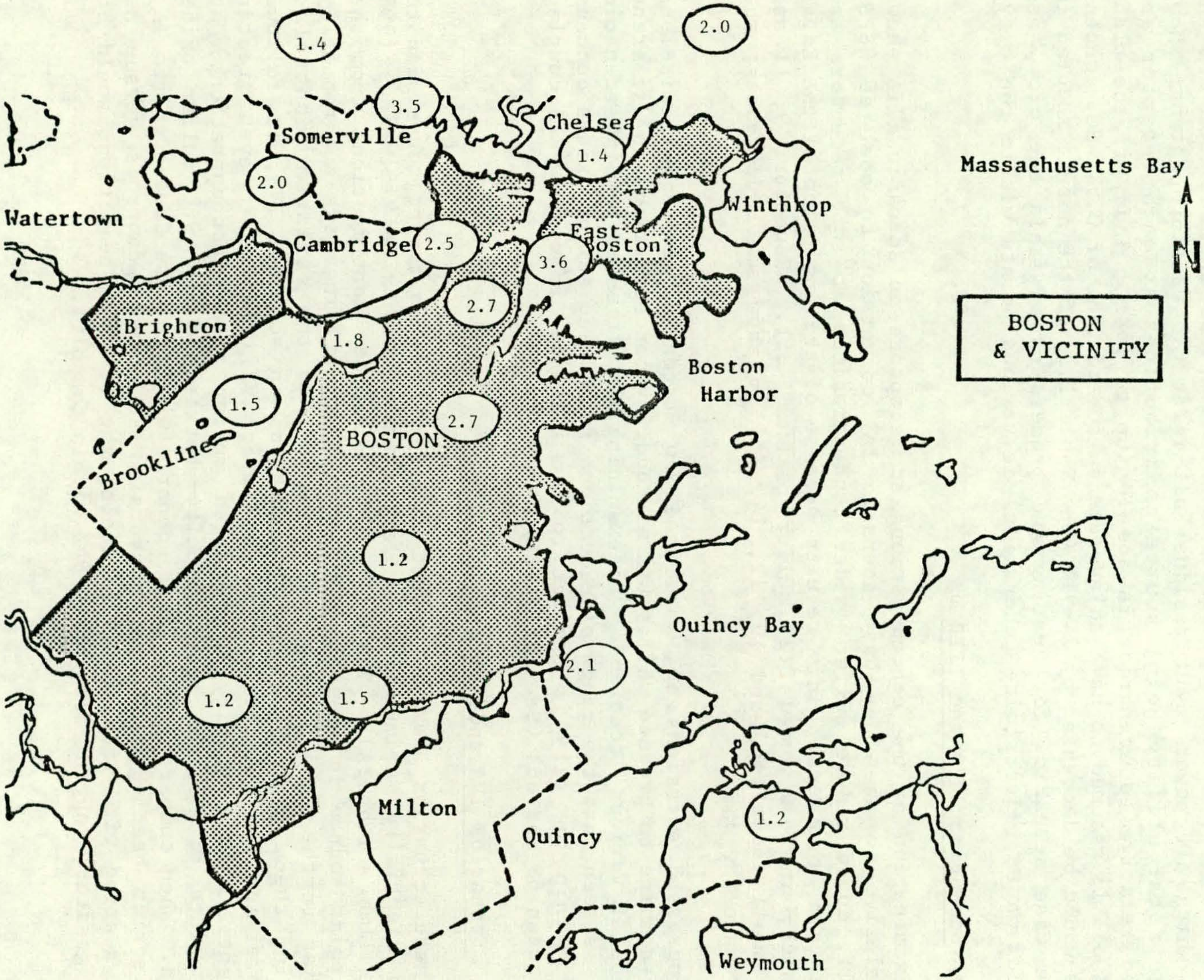

Fig. 4.6. Modeled Sulfur Oxides Concentrations at Selected Receptors ($\mu g/m^3$)--Scenario IVB: Coal/Max. Control; District Heating

4.4.2 Discussion

- Scenarios IIA and IIB

Examination of the concentrations at receptors in scenarios IIA and IIB, in which all power plant residual oil is at 0.5% sulfur content, shows that the total utility point source contributions at each receptor are decreased relative to scenarios IA and IB (up to 15%). Thus, if the plant residual oil is assumed to have an average sulfur content of 0.5%, SO concentrations would be decreased by 74-91% (See Table 1.1) of the amount modeled in the Base Case scenario (for heating and process uses within the city, and Boston Edison Co. electricity generation) at various points within the city.

- Scenarios IIIA and IIIB

Examination of the concentrations at receptors in scenario IIIA shows that (relative to the Base Case scenario IA) conversion to coal at NSPS, in itself, could reduce sulfur oxides concentrations at some receptors and increase them at others. This results because of the inclusion of the Edgar Plant which, in 1977, used 2.2% sulfur residual oil. Receptors 9, 11 and 13 show small increases, and 10, 12, 14, 15, 16 show small decreases; the others remain the same.

Increased emissions at Mystic and New Boston and decreased emissions at Edgar combine to produce shifts (in air quality concentration) in different directions at various locations. In examining the district heating scenario IIIB, it is seen that the range of reductions in modeled sulfur oxides concentrations within the city is similar to the scenario IA/scenario IB couple, i.e., between 68 and 86% (See Table 1.1).

- Scenarios IVA and IVB

These scenarios show the impact on air quality following conversion to coal at essentially maximum control levels on sulfur oxides emissions (90% with wet lime scrubbers). The first result is that contributions from the utility point source in scenario IVA (no district heating) are substantially lower than in the Base Case scenario because of the stringent controls. Considering these overall lower concentrations in scenario IVA, it follows that conversion to district heating (scenario IVB) results in even greater improvements in air quality (in modeled sulfur oxides concentrations) at various points within and near the city--between 75 and 92% sulfur oxide reduction. When comparing this final scenario with the Base Case scenario IA, i.e., district heating with coal conversion at maximum controls versus no district heating with present (1977) fuels, the relative reductions would be somewhat greater, ranging from 78 to 94% within the city.

5 CONCLUSIONS

5.1 PRINCIPAL RESULTS

The implementation of a cogeneration district heating system to meet Boston's space heating and hot water demand has reduced significantly the annual ground-level concentrations of sulfur oxides on an average annual basis at points within and near the city. This reduction is caused primarily by the replacement of fuel (especially oil) consumption that emits sulfur oxides into the atmosphere at low release heights by smaller amounts of extra fuels consumed at power plant sites that are emitted into the atmosphere from taller stacks.

Concentrations of sulfur oxides are reduced, even when overall emissions are increased because of replacement of a mix of low-sulfur distillate and residual oil and gas by extra power plant residual oil at a higher average sulfur content. Local dispersion from the fewer high stacks therefore can overcome small increases in overall emissions that result from added fuel burning to provide heat in addition to original electrical requirements provided by power plants. Among the areas of greatest reductions are those with the highest human population in the residential or commercial sectors. Because these areas have high density of heating demand, the replacement of emissions at low release heights by emissions at a small number of high stacks with pronounced dispersion effects causes a significant improvement in air quality in just those areas where it is most desirable. Because Boston already has a central steam heating system that services much of the area in and near the central business district which has the highest demand density, the effect of introducing cogeneration district heating is not as pronounced as it would otherwise have been in this area. This should be considered when evaluating the implications of district heating systems in metropolitan areas that presently have no such existing system. However, even with such systems, steam-only plants, which must be located near the load sites and which are smaller units with generally lower stack heights, could be displaced by more efficient and distant cogenerating plants with higher stacks. Then the steam-only plants could be shifted to more peaking type operation. The main result confirms the expectation that the combined objectives of saving scarce fuels, providing economic service, and improving air quality can be met simultaneously in areas where meteorological and demographic conditions are appropriate. In particular, high demand density in the central business districts and densely populated residential areas of metropolitan areas in the northern colder climates are prime candidates for such combined improvements. These improvements will vary with existing fuel mix for heating and electric generation as well as plant locations and average wind conditions. References 10 and 11 strongly suggest that, on economic grounds especially, initial focus on the downtown areas is important. The improvement in air quality can be expected to be even greater during periods of peak thermal demand when both electric generation and consumption of fuels for heating will be high.

5.2 LIMITATIONS

Several major limitations that exist in the work completed in this phase of the investigation are summarized below:

(1) No large industrial and utility point sources outside the city have been included in the modeling.

(2) No building site heating sources (area) from the residential and commercial areas outside the city limits have been included in the modeling.

(3) No calibration of sulfur oxides concentrations have been performed, mainly because of points (1) and (2).

(4) Demand was treated on a long seasonal rather than monthly or hourly basis and so, accordingly, was combined thermal and electric dispatch.

(5) Servicing of cooling demand with the district heating system was not included.

(6) Ground-level concentrations of four of the five pollutants were not analyzed.

Items 1 through 3 are important in examining the results of this study. Absolute values of ground-level sulfur oxides concentrations were not determined. However, the relative differences caused by the application of district heating can be taken as indicative of the nature of the effect. Here too the absence of calibration introduces an uncertainty in the absolute magnitude of the effect, but not in it's general direction. Finally, comparison of results (both absolute and those caused by district heating) at various receptor points with measurements taken at these points in the base year provides a basis for interpreting and assessing the implications of the results.

Item 4 indicates that this analysis has used a gross approximation in matching thermal and electric supply and demand. Nevertheless, insofar as the average annual emissions and concentrations are concerned, this approximation is believed to be accurate. A more detaild supply/demand dispatch matching would be appropriate for attending to peak and monthly impacts and to complications arising from following both electric and thermal loads with the same group of generating units. Items 5 and 6 address the scope of this study and could be considered in further work.

5.3 FURTHER WORK

Each of the six limitations listed above provide a basis for significant refinement and extension of the investigations already completed. The extension of the district heating, air quality analysis to the other northern cities studied in Refs. 3 and 4 would be a useful addition. Such an extension would illustrate the consequences of site-specific building mix, fuel mix for heating and electric generation, and meteorological conditions. Addition of northern cities to the air-quality analyses would complete the picture on this phase of the ongoing district heating investigations. Special attention could be given to the high-density core commercial and residential areas of these cities.

The development of the load and dispatch analysis suggested by item 4 deserves special attention because peak and monthly impacts can be significant. Furthermore, many of the cogenerating units will have on/off capability, and this could be taken into account.

An important, unresolved issue for district heating from the retrofit of existing power plants for cogeneration operation is the impact of such an operating system on the reliability of the system, as a whole. However, conventional reliability models could be expanded to include such an analysis. Stochastic behavior of hourly expected electricity and heating load curves could be built in on the side; whereas, stochastic plant outage behavior and maintenance schedules could be built in on the side. Dispatch could be modeled subject to demand constraints, technical constraints, (including cogeneration on/off switching), and production costs. Interconnecting to the local power grid could be taken into account for either purchases or sales of electricity as needed because of the changes imposed by effective cogeneration operation. Scenarios could be developed to assess the impact on reliability, cost of service, and emissions. Alternative peaking operations through dedicated boilers, new cogenerators, or thermal storage could be compared. Finally, such a model could include the capability of combined electric and thermal capacity expansion analysis.

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APPENDIX

SCENARIO IA -- AVERAGE ANNUAL SULFUR OXIDES CONCENTRATIONS WIND - ROSE DISAGGRATION

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RECEPTOR NUMBER	Rose type	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.3	0.5	0.5	0.2	2.3	0.7	0.0	0.6	1.4	0.0	0.2	0.1	1.9	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.5	0.2	0.4	0.6	0.8	1.4	0.9	0.8	2.1	1.1	0.4	0.7	1.1	0.9	0.4	0.3
2	POINT ROSES (MICROGRAMS/CU. METER)	1.4	0.6	0.1	1.1	1.0	0.0	0.5	0.1	0.7	0.5	0.0	0.0	0.2	1.2	0.3	0.1
	AREA ROSES (MICROGRAMS/CU. METER)	1.0	0.4	0.3	0.2	1.0	0.7	0.4	0.4	1.4	1.0	1.1	1.2	1.0	1.3	1.3	0.5
3	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.3	2.1	0.3	0.3	0.9	0.9	0.6	2.1	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.6	0.4	0.5	0.3	0.7	0.5	0.3	0.2	1.5	1.4	1.2	1.4	1.3	1.1	0.6	0.2
4	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.9	0.3	2.9	0.1	0.4	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.1	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.3	0.0	0.2	0.4	0.9	0.8	0.6	0.3	0.6	0.3	0.0	0.0	0.1	0.9	0.9	0.4
5	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.3	1.1	0.6	1.7	0.2	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.3	0.3	0.4	0.5	0.7	0.5	0.3	0.0	0.0	0.0	0.0	0.0
6	POINT ROSES (MICROGRAMS/CU. METER)	0.3	0.7	0.0	0.2	0.6	0.4	1.7	0.3	0.4	0.2	0.4	0.4	0.0	0.0	0.0	0.1
	AREA ROSES (MICROGRAMS/CU. METER)	0.5	0.2	0.3	0.4	1.1	0.5	0.3	0.6	2.1	1.2	0.6	0.6	0.2	0.1	0.1	0.1
7	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	2.3	0.4	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.8	0.4	0.0	0.0	0.0	0.0	0.0	0.0
8	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.6	1.8	0.4	0.3	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.4	1.3	0.4	0.2	0.0	0.0	0.0	0.0	0.0

RECEPTOR NUMBER		N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
9	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	2.5	0.8	1.2	1.6	0.6	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.1	0.2	0.1	0.2	1.4	1.2	1.0	0.5	0.0	0.0	0.0	0.0
10	POINT ROSES (MICROGRAMS/CU. METER)	3.9	0.0	0.0	0.0	0.0	1.2	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.1	0.4	0.5
	AREA ROSES (MICROGRAMS/CU. METER)	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.8	1.0	1.7	0.9
11	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.3	2.6
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.5	0.9	0.2
12	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	2.1	1.1	1.2	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.7	0.1	0.0	0.0	0.0	0.0
13	POINT ROSES (MICROGRAMS/CU. METER)	2.0	0.2	0.2	0.1	0.0	0.1	1.9	0.3	0.3	0.3	0.1	0.8	0.4	0.0	0.0	0.1
	AREA ROSES (MICROGRAMS/CU. METER)	0.9	0.4	0.3	0.2	0.2	0.2	0.3	0.5	1.7	1.3	1.4	1.0	1.1	0.6	0.6	0.5
14	POINT ROSES (MICROGRAMS/CU. METER)	0.1	1.0	1.2	0.0	0.0	0.9	0.0	0.0	0.0	0.2	0.1	0.0	0.1	0.0	0.0	0.6
	AREA ROSES (MICROGRAMS/CU. METER)	1.9	0.9	1.0	0.8	1.0	0.6	0.4	0.3	0.9	0.8	0.4	0.8	0.7	0.8	1.1	0.9
15	POINT ROSES (MICROGRAMS/CU. METER)	0.7	0.7	1.1	0.0	0.2	0.9	0.0	0.0	0.0	0.2	0.6	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	1.7	1.0	0.8	0.5	0.5	0.1	0.1	0.0	0.3	0.3	0.5	0.6	0.7	0.9	0.6	0.6
16	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.6	1.2	0.0	0.1	1.2	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	1.3	0.7	0.7	0.5	0.6	0.3	0.2	0.2	0.3	0.1	0.1	0.3	0.6	1.1	1.2	0.9

RECEPTOR NUMBER	ROSES (MICROGRAMS/CU. METER)	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1	POINT ROSES	0.0	0.3	0.4	0.3	0.1	2.5	0.6	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	POINT ROSES	1.5	0.4	0.0	0.3	0.8	0.0	0.6	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	POINT ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	1.6	0.1	0.1	0.3	0.5	0.5	2.1	0.0
	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	POINT ROSES	0.0	0.0	0.7	0.2	2.8	0.0	0.5	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	POINT ROSES	0.0	0.0	0.0	0.4	1.0	0.4	1.8	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	POINT ROSES	0.2	0.7	0.0	0.2	0.5	0.2	1.7	0.4	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.1
	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	POINT ROSES	0.0	0.0	0.0	0.0	0.0	0.0	2.5	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	POINT ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.7	1.7	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

RECEPTOR NUMBER

********************** POINT ROSES (MICROGRAMS/CU. METER) **********************

Receptor	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	2.6	0.6	0.6	1.5	0.8	0.0	0.0	0.0

********************** AREA ROSES (MICROGRAMS/CU. METER) **********************

N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

********************** POINT ROSES (MICROGRAMS/CU. METER) **********************

Receptor	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
10	0.2	0.0	0.0	0.0	0.0	1.4	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.1	0.3

********************** AREA ROSES (MICROGRAMS/CU. METER) **********************

N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

********************** POINT ROSES (MICROGRAMS/CU. METER) **********************

Receptor	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
11	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.1	2.0

********************** AREA ROSES (MICROGRAMS/CU. METER) **********************

N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

********************** POINT ROSES (MICROGRAMS/CU. METER) **********************

Receptor	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	2.2	0.8	1.5	0.0	0.0	0.0	0.0

********************** AREA ROSES (MICROGRAMS/CU. METER) **********************

N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

********************** POINT ROSES (MICROGRAMS/CU. METER) **********************

Receptor	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
13	1.9	0.2	0.2	0.0	0.0	0.0	1.8	0.4	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.1

********************** AREA ROSES (MICROGRAMS/CU. METER) **********************

N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

********************** POINT ROSES (MICROGRAMS/CU. METER) **********************

Receptor	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
14	0.1	0.8	1.2	0.0	0.0	1.1	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0

********************** AREA ROSES (MICROGRAMS/CU. METER) **********************

N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

********************** POINT ROSES (MICROGRAMS/CU. METER) **********************

Receptor	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
15	0.0	0.6	1.2	0.0	0.0	1.1	0.0	0.0	0.0	0.1	0.5	0.0	0.0	0.0	0.0	0.0

********************** AREA ROSES (MICROGRAMS/CU. METER) **********************

N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

********************** POINT ROSES (MICROGRAMS/CU. METER) **********************

Receptor	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
16	0.0	0.5	1.2	0.0	0.0	1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

********************** AREA ROSES (MICROGRAMS/CU. METER) **********************

N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

RECEPTOR NUMBER	ROSES (MICROGRAMS/CU. METER)	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1	POINT ROSES	0.0	0.2	0.5	0.5	0.2	1.3	0.3	0.0	0.6	1.4	0.0	0.2	0.1	1.9	0.0	0.0
	AREA ROSES	0.5	0.2	0.4	0.6	0.8	1.4	0.9	0.8	2.1	1.1	0.4	0.7	1.1	0.9	0.4	0.3
2	POINT ROSES	1.1	0.6	0.1	0.7	1.0	0.0	0.1	0.1	0.7	0.5	0.0	0.0	0.2	1.2	0.3	0.1
	AREA ROSES	1.0	0.4	0.3	0.2	1.0	0.7	0.4	0.4	1.4	1.0	1.1	1.2	1.0	1.3	1.3	0.5
3	POINT ROSES	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1	1.4	0.3	0.3	0.9	0.9	0.6	1.9	0.0
	AREA ROSES	0.6	0.4	0.5	0.3	0.7	0.5	0.3	0.2	1.5	1.4	1.2	1.4	1.3	1.1	0.6	0.2
4	POINT ROSES	0.0	0.0	0.7	0.9	1.8	0.1	0.1	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.1	0.0
	AREA ROSES	0.3	0.0	0.2	0.4	0.9	0.8	0.6	0.3	0.6	0.3	0.0	0.0	0.1	0.9	0.9	0.4
5	POINT ROSES	0.0	0.0	0.0	0.1	1.1	0.6	0.8	0.2	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES	0.0	0.0	0.0	0.0	0.3	0.3	0.4	0.5	0.7	0.5	0.3	0.0	0.0	0.0	0.0	0.0
6	POINT ROSES	0.3	0.7	0.0	0.2	0.6	0.4	1.0	0.1	0.4	0.2	0.4	0.4	0.0	0.0	0.0	0.1
	AREA ROSES	0.5	0.2	0.3	0.4	1.1	0.5	0.3	0.6	2.1	1.2	0.6	0.6	0.2	0.1	0.1	0.1
7	POINT ROSES	0.0	0.0	0.0	0.0	0.0	0.0	1.5	0.2	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.8	0.4	0.0	0.0	0.0	0.0	0.0	0.0
8	POINT ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.4	1.3	0.4	0.3	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.4	1.3	0.4	0.2	0.0	0.0	0.0	0.0	0.0

RECEPTOR NUMBER	ROSES (MICROGRAMS/CU. METER)	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
9	POINT ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	1.5	0.8	1.2	1.6	0.3	0.0	0.0	0.0
9	AREA ROSES	0.0	0.0	0.0	0.0	0.1	0.2	0.1	0.7	1.4	1.2	1.0	0.5	0.0	0.0	0.0	0.0
10	POINT ROSES	2.4	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.1	0.4	0.5
10	AREA ROSES	0.8	0.0	0.0	0.0	0.0	0.0	0.5	0.0	0.0	0.0	0.0	0.1	0.4	1.0	1.7	0.0
11	POINT ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.3	1.6
11	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.5	0.9	0.2
12	POINT ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	1.2	1.1	0.7	0.0	0.0	0.0	0.0
12	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.7	0.1	0.0	0.0	0.0	0.0
13	POINT ROSES	1.8	0.2	0.2	0.1	0.0	0.1	1.2	0.1	0.3	0.3	0.1	0.8	0.4	0.0	0.0	0.1
13	AREA ROSES	0.9	0.4	0.3	0.2	0.2	0.2	0.3	0.5	1.7	1.3	1.4	1.0	1.1	0.6	0.6	0.5
14	POINT ROSES	0.1	0.8	0.7	0.0	0.0	0.2	0.0	0.0	0.0	0.2	0.1	0.0	0.1	0.0	0.0	0.6
14	AREA ROSES	1.9	0.9	1.0	0.8	1.0	0.6	0.4	0.3	0.9	0.8	0.4	0.8	0.7	0.8	1.1	0.9
15	POINT ROSES	0.7	0.6	0.6	0.0	0.2	0.2	0.0	0.0	0.0	0.2	0.6	0.0	0.0	0.0	0.0	0.0
15	AREA ROSES	1.7	1.0	0.8	0.5	0.5	0.1	0.1	0.0	0.3	0.3	0.5	0.6	0.7	0.9	0.6	0.6
16	POINT ROSES	0.0	0.5	0.7	0.0	0.1	0.7	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	AREA ROSES	1.3	0.7	0.7	0.5	0.6	0.3	0.2	0.2	0.3	0.1	0.1	0.3	0.6	1.1	1.2	0.9

RECEPTOR NUMBER	ROSES	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.2	0.4	0.3	0.1	1.3	0.2	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	POINT ROSES (MICROGRAMS/CU. METER)	1.1	0.4	0.0	0.5	0.8	0.0	0.1	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.9	0.1	0.1	0.3	0.5	0.5	1.8	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.5	0.2	1.5	0.0	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.2	1.0	0.4	0.8	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	POINT ROSES (MICROGRAMS/CU. METER)	0.2	0.6	0.0	0.2	0.5	0.2	0.9	0.1	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.1
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	1.6	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.4	1.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

RECEPTOR NUMBER	ROSES (MICROGRAMS/CU. METER)	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
9	POINT ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	1.4	0.6	0.6	1.5	0.4	0.0	0.0	0.0
9	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	POINT ROSES	2.4	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.1	0.3
10	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	POINT ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.1	1.6
11	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	POINT ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	1.2	0.8	0.8	0.0	0.0	0.0	0.0
12	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	POINT ROSES	1.6	0.2	0.2	0.0	0.0	0.0	1.0	0.1	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.1
13	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	POINT ROSES	0.1	0.6	0.6	0.0	0.0	0.2	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0
14	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	POINT ROSES	0.0	0.5	0.6	0.0	0.0	0.2	0.0	0.0	0.0	0.1	0.5	0.0	0.0	0.0	0.0	0.0
15	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	POINT ROSES	0.0	0.3	0.7	0.0	0.0	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

RECEPTOR NUMBER		N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.3	0.5	0.5	0.2	2.5	0.5	0.0	0.6	1.4	0.0	0.2	0.1	1.9	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.5	0.2	0.4	0.6	0.8	1.4	0.9	0.8	2.1	1.1	0.4	0.7	1.1	0.9	0.4	0.3
2	POINT ROSES (MICROGRAMS/CU. METER)	1.5	0.6	0.1	1.1	1.0	0.0	0.3	0.1	0.7	0.5	0.0	0.0	0.2	1.2	0.3	0.1
	AREA ROSES (MICROGRAMS/CU. METER)	1.0	0.4	0.3	0.2	1.0	0.7	0.4	0.4	1.4	1.0	1.1	1.2	1.0	1.3	1.3	0.5
3	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1	2.2	0.3	0.3	0.9	0.9	0.6	2.1	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.6	0.4	0.5	0.3	0.7	0.5	0.3	0.2	1.5	1.4	1.2	1.4	1.3	1.1	0.6	0.2
4	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.8	0.9	3.1	0.1	0.2	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.1	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.3	0.0	0.2	0.4	0.9	0.8	0.6	0.3	0.6	0.3	0.0	0.0	0.1	0.9	0.9	0.4
5	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.3	1.1	0.6	1.6	0.2	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.3	0.3	0.4	0.5	0.7	0.5	0.3	0.0	0.0	0.0	0.0	0.0
6	POINT ROSES (MICROGRAMS/CU. METER)	0.3	0.7	0.0	0.2	0.6	0.4	1.9	0.2	0.4	0.2	0.4	0.4	0.0	0.0	0.0	0.1
	AREA ROSES (MICROGRAMS/CU. METER)	0.5	0.2	0.3	0.4	1.1	0.5	0.3	0.6	2.1	1.2	0.6	0.6	0.2	0.1	0.1	0.1
7	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	2.4	0.3	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.8	0.4	0.0	0.0	0.0	0.0	0.0	0.0
8	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.7	1.7	0.4	0.3	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.4	1.3	0.4	0.2	0.0	0.0	0.0	0.0	0.0

RECEPTOR NUMBER	ROSES (MICROGRAMS/CU. METER)	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
9	POINT ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	2.7	0.8	1.2	1.6	0.7	0.0	0.0	0.0
	AREA ROSES	0.0	0.0	0.0	0.0	0.1	0.2	0.1	0.2	1.4	1.2	1.0	0.5	0.0	0.0	0.0	0.0
10	POINT ROSES	4.1	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.1	0.4	0.5
	AREA ROSES	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.8	1.0	1.7	0.9
11	POINT ROSES	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.3	2.8
	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.5	0.9	0.2
12	POINT ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	2.3	1.1	1.3	0.0	0.0	0.0	0.0
	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.7	0.1	0.0	0.0	0.0	0.0
13	POINT ROSES	2.1	0.2	0.2	0.1	0.0	0.1	2.0	0.2	0.3	0.3	0.1	0.8	0.4	0.0	0.0	0.1
	AREA ROSES	0.9	0.4	0.3	0.2	0.2	0.2	0.3	0.5	1.7	1.3	1.4	1.0	1.1	0.6	0.6	0.5
14	POINT ROSES	0.1	1.0	1.3	0.0	0.0	0.5	0.0	0.0	0.0	0.2	0.1	0.0	0.1	0.0	0.0	0.6
	AREA ROSES	1.9	0.9	1.0	0.0	1.0	0.6	0.4	0.3	0.9	0.8	0.4	0.8	0.7	0.8	1.1	0.9
15	POINT ROSES	0.7	0.7	1.1	0.0	0.2	0.4	0.0	0.0	0.0	0.2	0.6	0.0	0.0	0.0	0.0	0.0
	AREA ROSES	1.7	1.0	0.8	0.5	0.5	0.1	0.1	0.0	0.3	0.3	0.5	0.6	0.7	0.9	0.6	0.6
16	POINT ROSES	0.0	0.7	1.2	0.0	0.1	0.9	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES	1.3	0.7	0.7	0.5	0.6	0.3	0.2	0.2	0.3	0.1	0.1	0.3	0.6	1.1	1.2	0.9

RECEPTOR NUMBER	Rose type (MICROGRAMS/CU. METER)	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1	POINT ROSES	0.0	0.3	0.4	0.3	0.1	2.7	0.4	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	POINT ROSES	1.6	0.3	0.0	1.0	0.8	0.0	0.3	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	POINT ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	1.8	0.1	0.1	0.3	0.5	0.5	2.2	0.0
	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	POINT ROSES	0.0	0.0	0.7	0.2	3.1	0.0	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	POINT ROSES	0.0	0.0	0.0	0.4	1.0	0.4	1.7	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	POINT ROSES	0.2	0.7	0.0	0.2	0.5	0.2	1.9	0.2	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.1
	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	POINT ROSES	0.0	0.0	0.0	0.0	0.0	0.0	2.6	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	POINT ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.7	1.6	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

RECEPTOR NUMBER		N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
9	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	2.8	0.6	0.6	1.5	0.8	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	POINT ROSES (MICROGRAMS/CU. METER)	4.5	0.0	0.0	0.0	0.0	0.7	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.1	[illegible]
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.1	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	2.4	0.8	1.5	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	POINT ROSES (MICROGRAMS/CU. METER)	1.9	0.2	0.2	0.0	0.0	0.0	2.0	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.1
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	POINT ROSES (MICROGRAMS/CU. METER)	0.1	0.8	1.3	0.0	0.0	0.5	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.7	1.3	0.0	0.0	0.5	0.0	0.0	0.0	0.1	0.5	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.5	1.3	0.0	0.0	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

RECEPTOR NUMBER	Rose type	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.1	0.5	0.5	0.2	0.7	0.3	0.0	0.6	1.4	0.0	0.2	0.1	1.9	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.5	0.2	0.4	0.6	0.8	1.4	0.9	0.8	2.1	1.1	0.4	0.7	1.1	0.9	0.4	0.3
2	POINT ROSES (MICROGRAMS/CU. METER)	1.0	0.6	0.1	0.5	1.0	0.0	0.1	0.1	0.7	0.5	0.0	0.0	0.2	1.2	0.3	0.1
	AREA ROSES (MICROGRAMS/CU. METER)	1.0	0.4	0.3	0.2	1.0	0.7	0.4	0.4	1.4	1.0	1.1	1.2	1.0	1.3	1.3	0.5
3	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	1.0	0.3	0.3	0.9	0.9	0.6	1.8	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.6	0.4	0.5	0.3	0.7	0.5	0.3	0.2	1.5	1.4	1.2	1.4	1.3	1.1	0.6	0.2
4	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.6	0.9	1.1	0.1	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.1	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.3	0.0	0.2	0.4	0.9	0.8	0.6	0.3	0.6	0.3	0.0	0.0	0.1	0.9	0.9	0.4
5	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.1	1.1	0.6	0.5	0.2	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.3	0.3	0.4	0.5	0.7	0.5	0.3	0.0	0.0	0.0	0.0	0.0
6	POINT ROSES (MICROGRAMS/CU. METER)	0.3	0.6	0.0	0.2	0.6	0.4	0.6	0.0	0.4	0.2	0.4	0.4	0.0	0.0	0.0	0.1
	AREA ROSES (MICROGRAMS/CU. METER)	0.5	0.2	0.3	0.4	1.1	0.5	0.3	0.6	2.1	1.2	0.6	0.6	0.2	0.1	0.1	0.1
7	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	1.3	0.2	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.8	0.4	0.0	0.0	0.0	0.0	0.0	0.0
8	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.4	1.0	0.4	0.3	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.4	1.3	0.4	0.2	0.0	0.0	0.0	0.0	0.0

RECEPTOR NUMBER		N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
9	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.8	1.2	1.6	0.2	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.1	0.2	0.1	0.2	1.4	1.2	1.0	0.5	0.0	0.0	0.0	0.0
10	POINT ROSES (MICROGRAMS/CU. METER)	1.6	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.1	[illegible]	0.5
	AREA ROSES (MICROGRAMS/CU. METER)	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.8	1.0	1.7	[illegible]
11	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.3	1.1
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.5	0.9	0.7
12	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.6	1.1	0.6	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.7	0.1	0.0	0.0	0.0	0.0
13	POINT ROSES (MICROGRAMS/CU. METER)	1.7	0.2	0.2	0.1	0.0	0.1	0.7	0.0	0.3	0.3	0.1	0.8	0.4	0.0	0.0	0.1
	AREA ROSES (MICROGRAMS/CU. METER)	0.9	0.4	[illegible]	0.2	0.2	0.2	0.3	0.5	1.7	1.3	1.4	1.0	1.1	0.6	0.6	0.5
14	POINT ROSES (MICROGRAMS/CU. METER)	0.1	0.8	0.4	0.0	0.0	0.1	0.0	0.0	0.0	0.2	0.1	0.0	0.1	0.0	0.0	0.6
	AREA ROSES (MICROGRAMS/CU. METER)	1.9	0.9	1.0	0.8	1.0	0.6	0.4	0.3	0.9	0.8	0.4	0.8	0.7	0.8	1.1	0.9
15	POINT ROSES (MICROGRAMS/CU. METER)	0.7	0.6	0.3	0.0	0.2	0.1	0.0	0.0	0.0	0.2	0.6	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	1.7	1.0	0.8	0.5	0.5	0.1	0.1	0.0	0.3	0.3	0.5	0.6	0.7	0.9	0.6	0.6
16	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.5	0.5	0.0	0.1	0.5	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	1.3	0.7	0.7	0.5	0.6	0.3	0.2	0.2	0.3	0.1	0.1	0.3	0.6	1.1	1.2	0.9

RECEPTOR NUMBER		N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.1	0.4	0.3	0.1	0.5	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	POINT ROSES (MICROGRAMS/CU. METER)	1.0	0.4	0.0	0.2	0.8	0.0	0.0	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.1	0.1	0.3	0.5	0.5	1.7	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.4	0.2	0.7	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.1	1.0	0.4	0.4	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	POINT ROSES (MICROGRAMS/CU. METER)	0.2	0.6	0.0	0.2	0.5	0.2	0.4	0.0	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.1
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	1.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.8	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

RECEPTOR NUMBER		N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
9	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.6	0.6	1.5	0.3	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	POINT ROSES (MICROGRAMS/CU. METER)	1.5	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.1	0.3
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.1	1.1
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.5	0.8	0.7	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	POINT ROSES (MICROGRAMS/CU. METER)	1.5	0.2	0.2	0.0	0.0	0.0	0.4	0.0	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.1
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	POINT ROSES (MICROGRAMS/CU. METER)	0.1	0.6	0.3	0.0	0.0	0.1	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.5	0.2	0.0	0.0	0.1	0.0	0.0	0.0	0.1	0.5	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	POINT ROSES (MICROGRAMS/CU. METER)	0.0	0.3	0.4	0.0	0.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	AREA ROSES (MICROGRAMS/CU. METER)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0