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GRAPHICAL REPRESENTATIONS OF 1991 STEAM-ELECTRIC POWER PLANT OPERATION AND AIR EMISSIONS DATA

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16. ABSTRACT The report provides graphical representations of data derived from the U.S. Department of Energy's (DOE's) Energy Information Administration's (EIA's) Form EIA-767 (Steam Electric Plant Operation and Design Report). For more than 10 years, EIA has collected monthly boiler level data from EIA-767. The U.S. EPA has contributed funding to DOE for this effort. The report summarizes information from the EIA-767 database that is otherwise not readily available to the community of electric utility data users or other members of the general public. To facilitate interpretation by non-technical readers, the report emphasizes graphical displays of data, consisting of 98 charts and 3 tables. The graphics present national data, national coal data, regional data, specified state data, and specified operating utility company data. Data tables show sulfur dioxide (SO2) and nitrogen oxide (NOx) emissions by state, and the highest emitting electric utility companies. Charts show SO2 and NOx emissions by fuel type, fuel type and sulfur content, and fuel type and boiler capacity. Charts also present data on boiler utilization, and heat input by fuel type and sulfur content. Additional charts for coal display coal quantities by sulfur content, quantities of scrubbed and not scrubbed coal, and boiler capacity and utilization.

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a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Pollution	Coal	Pollution Control	13B	21D
Steam Electric Power Generation	Sulfur Dioxide	Stationary Sources		07B
	Nitrogen Oxides		10A	
Electric Utilities	Fuels			
Emission Data	Boilers		14G	13A

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ABSTRACT

For over 10 years the U. S. Department of Energy (DOE) Energy Information Administration (EIA) has collected monthly boiler level data from the EIA Form 767 (Steam Electric Plant Operation and Design Report). The U.S. EPA has contributed funding to DOE for this effort. This report presents summary data from the 1991 Form 767 database for public information. The report summarizes information from the Form 767 database that is otherwise not readily available to the community of electric utility data users or other members of the general public. To facilitate ease of interpretation by non-technical readers, the report emphasizes graphical displays of data, including 98 charts and 3 tables. The graphics present national data, national coal data, regional data, specified state data, and specified operating utility company data. Data tables show sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions by state, and the highest emitting electric utility companies. Charts show SO_2 and NO_x emissions by fuel type, fuel type and sulfur content, and fuel type and boiler capacity. Charts also present data on boiler utilization, and heat input by fuel type and sulfur content. Additional charts for coal display coal quantities by sulfur content, quantities of scrubbed and not scrubbed coal, and boiler capacity and utilization.

EPA REVIEW NOTICE

CONTENTS

FIGURES

TABLES

Number **Page**

ABBREVIATIONS AND ACRONYMS

bbl	Barrel	(One barrel = 42 gallons = 158.97 liters)
Btu	British thermal unit	(One Btu = 0.253 kilocalories)
Btu/lb	Btu per pound	(One Btu/lb = 0.5556 kilocalories/kilogram)
CAAA	Clean Air Act Amendments of 1990	
cf	Cubic feet	(One cubic foot = 0.02832 cubic meters)
DOE	U.S. Department of Energy	
EIA	Energy Information Administration	
EPA	U.S. Environmental Protection Agency	
FGD	Flue gas desulfurization	
gal	Gallons	(One gallon = 3.785 liters)
GT	Gas turbine	
GW	Gigawatts (10^9 watts)	
IC	Internal combustion	
ID	Identification number	
kton	Thousand tons	(One ton = 2000 pounds = 907.2 kilograms)
lb	Pounds	(One pound = 453.6 grams)
MMBtu	Million Btus	
MMcf	Million cubic feet	
MMton	Million tons	
MW	Megawatts (10^6 watts)	
NAPAP	National Acid Precipitation Assessment Program	
NO_x	Oxides of nitrogen	
NURF	National Utility Reference File	
OAQPS	Office of Air Quality Planning and Standards	
PC	Personal (micro)computer	
Pechan	E.H. Pechan & Associates, Inc.	
ROM	Regional Oxidant Modeling	
SAS	Statistical Analysis System	
SCC	Source Classification Code	
SO_2	Sulfur dioxide	

SECTION I

INTRODUCTION

In 1985, the electric utility industry in the United States accounted for 69 percent of all U.S. emissions of sulfur dioxide (SO_2) and 32 percent of emissions of oxides of nitrogen (NO_x). As a result of the Acid Deposition Control Title IV of the Clean Air Act Amendments of 1990 (CAAAs), electric utilities by the year 2010 will be expected to account for 8.7 million tons (87 percent) of sulfur dioxide (SO_2) emission reductions and 2 million tons (100 percent) of oxides of nitrogen (NO_x) emission reductions. Thus, there is a heightened interest in electric utility data that are currently available for review and analysis.

Each year, the U.S. Department of Energy (DOE) Energy Information Administration (EIA) collects monthly boiler-level data from Form EIA-767 ("Steam-Electric Plant Operation and Design Report"). Only data from steam boilers are included, not data for gas turbines (GT) or internal combustion (IC) engines.

For over 10 years, the U.S. Environmental Protection Agency (EPA) has helped fund EIA for the production of the annual boiler-level Form EIA-767 data, which are transferred to data tapes that are not readily available to the public. EPA has used these data in the past to aid in the development of the National Utility Reference File (NURF) for the National Acid Precipitation Program (NAPAP), for preparation of *National Air Pollution Emission Estimates* (Trends) reports, and as the basis for the fossil-fuel steam utility component of the Interim Inventory that is used to support the Regional Oxidant Modeling (ROM) program.

EPA has not previously used these data (which are usually presented as aggregated monthly electric utility boiler-level data) to graphically display data elements that are of interest. This report presents summary information to the public from a graphical perspective, highlighting information that would be useful for those concerned about the CAAAs.

SECTION II

DATA SOURCE

The data used to produce the graphics included in this report were derived from a master data base that is based on the 1991 Form EIA-767 data (EIA, 1991).

All electric utilities with plants that have at least one operating fossil-fuel steam boiler of at least 10 megawatts (MW) are required to provide information to EIA on Form EIA-767, although the amount of data required from plants with less than 100 MW of steam-electric generating capacity is much less. For plants with a nameplate rating of at least 10 MW to less than 100 MW, only selected pages of the Form EIA-767 must be completed. (Stack and flue information is not required for these smaller plants.)

The written form is designed so that information for each plant is reported on separate pages that relate to different levels of data that are described below:

- Plant level: One page for delineating the plant configuration, which establishes the number of boilers and the identification numbers (IDs) for each boiler, as well as the associated generator(s), flue gas desulfurization (FGD) unit(s), flue(s), and stack(s). Boilers and generators do not necessarily have a one-to-one correspondence.

- Boiler level: One page per boiler for monthly fuel quantity and quality data (for coal, oil, gas, and other), one page for regulatory data, and one page for design parameters.

- Generator level: One page for data relating to up to five generators.

- Flue gas desulfurization (FGD) level: One page for up to five FGD units for annual operating data and one page for each FGD unit for design parameter data.

- Flue and stack level: One page per flue-stack for design parameter data.

The master data base was created on EPA's mainframe IBM computer using customized software written in SAS, the Statistical Analysis System software package.

DATA PROCESSING

Form EIA-767 is processed in a series of steps aimed at converting the computerized data into data base form. The 1991 Form EIA-767 data graphically described in this project were processed in the same manner as was employed under EPA's ROM project. (For further information, see the associated technical document [Pechan, 1993].) Each "page" format is reproduced on the computer file exactly as it appears on the written page of the form. The data from each page must be extracted from the computer file, associated with the correct boiler, and combined with all corresponding data from the other pages for that boiler.

For example, fuel-related boiler data -- monthly values for each fuel burned, along with the fuel's associated sulfur, ash, and heat content -- are reported on page six. These data must be aggregated for each fuel in order to produce annual fuel quality and quantity estimates for each boiler before they are combined with the other data (such as control devices and efficiencies, plant location data, associated generator generation, and associated stack parameters).

After Source Classification Codes (SCCs) are assigned to each reported fuel for each boiler within a plant, the SCC-specific data are then separated so that each data base observation is on the plant-boiler-SCC level.

Although Form EIA-767 data are collected from plants with a total plant capacity of at least 10 MW, there are fewer data elements required for those plants with a total capacity less than 100 MW but at least 10 MW. These plants, therefore, will have certain data elements that have missing values that will default to zero, with the exceptions that if either boiler firing type or bottom type data are missing, default values of "wall-fired" and "dry bottom," respectively, are assigned, based on a previous review of the data, since these two data elements are needed in determining the SCC assignment.

Form EIA-767 data were subject to a review that resulted in some changes to boiler firing configuration and bottom type. However, some more recent data changes resulting from EPA's public reviews are not reflected in these data.

It should be noted that emissions data are not presently reported on the Form EIA-767 and must be calculated based on the reported data.

VARIABLE DEVELOPMENT

Data that were not obtained directly from the computerized data files (or converted to other measurement units) were developed using existing algorithms. For example, in an attempt to find a surrogate for capacity factor (which relies on generator generation), a relatively new variable -- boiler utilization, with a range between 0 and 1.0 -- was developed and selected to be graphically analyzed for this project. Boiler utilization is defined as the total heat input (in MMBtu) divided by the product of a units conversion factor of 8,760 hours/year, the sum of the products of the fuel design firing rate at the maximum steam flow (in tons, barrels, or 1,000 cubic feet per hour), and the fuel heat content.

Other algorithms have been utilized since the 1980s. These algorithms relate to SCC assignment and the calculation of SO_2 and NO_x emissions, heat input, NO_x control efficiency. A description for each of these follows.

- The appropriate SCC is assigned to each fuel based on its characteristics. For coal, the SCC is based on the American Society for Testing and Materials (ASTM) criteria for moisture, mineral-free matter basis. If greater than 11,500 Btu/lb, coal type is designated as bituminous. If between 8,300 and 11,500 Btu/lb, coal type is designated as subbituminous. If less than 8,300 Btu/lb, coal type is designated as lignite. The SCC is then based on the coal designation and the boiler type (firing configuration and bottom type) as specified by EPA's AP-42 document (EPA, 1991). If both coal and oil were burned in the same boiler, it is assumed that the oil is distillate; if not, it is assumed to be residual. Then, based on the oil designation and boiler type, the SCC is assigned. For natural gas, the SCC is based on firing type.

- Emissions calculations depend on AP-42 emission factors (EPA, 1991), which were obtained from EPA's Office of Air Quality Planning and Standards (OAQPS). In turn, the emission factor used depends on the SCC and pollutant. The following equation is used to compute controlled NO_x emissions:

$$\underset{(tons)}{NO_x} = \underset{burned}{fuel} * \underset{emf}{AP-42} * (1 - eff/100) * (1/2000) \qquad (1)$$

  The following equation is used to compute controlled SO_2 emissions:

$$\underset{(tons)}{SO_2} = \underset{burned}{fuel} * \underset{emf}{AP-42} * \%\,sulfur * (1 - eff/100) * (1/2000) \qquad (2)$$

  The following equation is used to compute heat input:

$$\underset{(MMBtu)}{heat\ input} = \underset{burned}{fuel} * \underset{content}{heat} \qquad (3)$$

- The NO_x control efficiency is estimated based on the assumption that the unit would be controlled so that its emission rate would equal its regulatory emissions limit, expressed on an annual equivalent basis. After calculating the heat input, controlled emissions assuming compliance with the applicable standard is back-calculated. After calculating the uncontrolled NO_x emissions, the presumed net control efficiency is calculated.

- The AP-42 emission factor used to compute SO_2 emissions, 39S, (39 times the weight percent fuel sulfur content) assumes an average of 2.5 % retention of sulfur in the bottom ash, while the subbituminous coal emission factor, 35S, assumes an average of 12.5 % retention of sulfur in the bottom ash.

SECTION III

GRAPHICS PREPARATION

There are 98 charts and 3 tables presented in this report to describe the 1991 Form EIA-767 reported and derived data. The following listing presents the variables in the master data base.

E767 Variable Definitions for 1991

No.	Variable Name	Type	Description
1	ORISPL	Num	Plant ID Code (unique)
2	BLRID	Char	Boiler ID Code (right justified)
3	UTNAME	Char	Operating Utility Name (unique)
4	STABB	Char	Postal Code for Plant Location State
5	FUELTYPE	Char	Fuel Type Code (coal, residual, distillate, natural gas)
6	SCRUBTYP	Num	SO_2 Scrubber Status (scrubbed, not scrubbed)
7	SULFCAT	Char	Sulfur Content Category: (0,0-.3,.3-.6,.6-1,1-2,2-3,>3)
8	SULF3	Char	Sulfur Content 3 Category: (0,0-1,1-3,>3)
9	MWCAT	Char	Boiler Nameplate Capacity Category: (0,0-25,25-100,100-200, 200-400,400-600,600-800,>800)
10	BLRUTCAT	Char	Boiler Utilization Category: (0,0-.2,.2-.4,.4-.6,.6-.8,.8-1,>1)
11	SO2	Num	SO_2 Controlled Emissions (tons)
12	NOX	Num	NO_x Controlled emissions (tons)
13	HTINPT	Num	Heat Input (MMBtu)
14	COALQUAN	Num	Annual Coal Operating Rate (SCC unit*)
15	NETDC	Num	Boiler Maximum Nameplate Capacity (MW)
16	BLRUTIL	Num	Boiler Utilization (decimal 0-1)
17	EPARGN	Num	EPA Region Number for Plant Location

* SCC units are tons (coal), thousand gallons (oil), and MMcf (gas).

Separate data files that include only the records and variables necessary for the charts were created and downloaded from the mainframe to the PC. These files were input into Microsoft Excel, a PC software package with spreadsheet and graphics capabilities. Different chart types were used both to better describe the data and to vary the presentation. The graphics were produced and grouped to represent national data, national coal data, regional data, specified State data, or specified operating utility data.

The tables were prepared on the mainframe using SAS and then downloaded to the PC and input into word processing software used to produce this report.

SUMMARY

The charts and tables included in this report present data collected from the 1991 Form EIA-767. These are organized as follows:

- Figures 1 through 14 present national data for all types of fuels used by electric utilities.

- Figures 15 through 24 present national data for coal consumption by electric utilities.

- Figures 25 and 26 present national data for electric utility boiler capacity and utilization.

- Figures 27 through 76 present data for each of the 10 EPA Federal regions. For the purposes of this report, the states included in each Federal region are listed below. Territorial possessions of the United States and Puerto Rico are not included in the Form EIA-767 survey. The data shown for each Federal region in Figures 27 through 76 correspond to the national data shown in Figures 1, 2, 5, 6, and 19. Regional differences are evident from an examination of these figures.

States Included in Each EPA Region

Region 1
Connecticut
Maine
Massachusetts
New Hampshire
Rhode Island
Vermont

Region 2
New Jersey
New York

Region 3
Delaware
District of Columbia
Maryland
Pennsylvania
Virginia
West Virginia

Region 4
Alabama
Florida
Georgia
Kentucky
Mississippi
North Carolina
South Carolina
Tennessee

Region 5
Illinois
Indiana
Michigan
Minnesota
Ohio
Wisconsin

Region 6
Arkansas
Louisiana
New Mexico
Oklahoma
Texas

Region 7
Iowa
Kansas
Missouri
Nebraska

Region 8
Colorado
Montana
North Dakota
South Dakota
Utah
Wyoming

Region 9
Arizona
California
Hawaii
Nevada

Region 10
Alaska
Idaho
Oregon
Washington

- Table 1 shows the 1991 total SO_2 and NO_x emissions from electric utilities for each state and for the United States as a whole. The table also shows the rank for each state for SO_2 and NO_x emissions.

- Figures 77 through 89 present data for the states with the highest SO_2 and NO_x emissions from electric utilities. Figures 77 through 79 show comparisons for the top 5 emitting states for SO_2 and NO_x emissions by fuel type and SO_2 emissions for scrubbed and not scrubbed coal. For each of the top 5 emitting states, Figures 80 through 89 present data for SO_2 emissions by fuel type and sulfur content and SO_2 emissions by fuel type and boiler capacity. These correspond to the national data presented in Figures 5 and 7.

- Tables 2 and 3 show the 10 electric utility companies with the highest SO_2 and NO_x emissions, respectively.

- Figures 90 through 98 present data for the top 3 electric utility companies with the highest SO_2 and NO_x emissions.

HIGHLIGHTS

As shown in Figures 1 and 2, on a national basis coal combustion by electric utilities contributes the most to SO_2 and NO_x emissions. Combustion of distillate oil, residual oil, natural gas, and other fuels (not included in any of the figures due their relatively small emissions) produce lesser amounts of SO_2 and NO_x emissions on a national basis. The same was true in all Federal regions, except Region 1, where combustion of residual oil produces more SO_2 emissions than the combustion of coal (See Figure 27). Even though there are no other regions where emissions from other fuels are greater than from coal combustion, in selected regions the emissions from other fuels are much more significant than for the nation as a whole. For example, in Region 1 (Figure 28), NO_x emissions from residual oil use are about two-thirds of the emissions from coal combustion. Other regions where emissions from oil and gas use are significant are Region 2 (Figures 32 and 33), Region 6 (Figure 53), and Region 9 (Figure 68).

Figure 3 shows mean boiler utilization by fuel type. The mean values shown in the figure represent arithmetic averages of boiler utilization for each fuel type. These were calculated by first computing a boiler utilization fraction for each individual boiler and then computing the overall average of the individual values. Figure 3 shows that the mean boiler utilization was about 50 percent for boilers burning coal and distillate oil, but was much lower for boilers burning residual oil and natural gas.

Figures 4 and 5 present data according to fuel type and sulfur content ranges. Sulfur content ranges are expressed as average weight percents of sulfur in the fuel on an as burned basis. The missing category represents those utility boilers for which no data were reported on the Form EIA-767. Comparing Figures 4 and 5 shows that about half of the national heat input from coal combustion was from coal with a sulfur content of 1 percent or more, but that SO_2 emissions from combustion of coal with a sulfur content of 1 percent or more represents over three-fourths of the total.

Figures 6, 7, and 8 display national heat input, SO_2, and NO_x emissions according to generator nameplate capacity ratings in megawatts. These figures show similar distributions of heat input, SO_2 emissions, and NO_x emissions by capacity category for all cases except for SO_2 emissions from natural gas combustion. Since the sulfur content of natural gas is negligible, SO_2 emissions from natural gas combustion are small for all capacity category ranges.

Figure 14 shows that for 1991, coal accounted for over 80 percent of the total heat input to electric utility boilers. Natural gas was a distant second, accounting for about 13 percent of total heat input, and residual oil accounted for less than 6 percent. Heat input from distillate oil was very small, less than 0.2 percent of the national total.

Figures 15 through 24 present data for coal only. Figure 16 shows that about 26 percent of the coal burned was scrubbed, i.e. controlled by a flue gas desulfurization system for SO_2 emissions. Figure 22 shows that the capacity of coal-fired units with scrubbers was about 21 percent of the total. The capacity utilization of units with scrubbers was higher than for non-scrubbed units. This was true for all sulfur content ranges, as shown in Figure 24. Figure 17 shows a breakdown of the scrubbed and not scrubbed coal according to sulfur content ranges. This shows that a much higher portion (about 38 percent) of the coal with a sulfur content greater than 3 percent was scrubbed than for coal with lower sulfur contents. About 19 percent of the coal with sulfur content between 1 and 3 percent was scrubbed, while about 28 percent of the coal with a sulfur content of less than 1 percent was scrubbed. Figure 20 shows that about 95 percent of the SO_2 emissions from coal combustion came from units that were not scrubbed. Coal with a sulfur content between 1 and 3 percent accounts for over half of this total, while coal with a sulfur content of less than 1 percent and coal with a sulfur content in excess of 3 percent account for approximately the same level of SO_2 emissions.

Figures 25 and 26 present national data on electric utility boiler capacity and utilization. As was the case for Figure 3, mean boiler utilization in these figures represents an arithmetic average of the calculated boiler utilization rates for individual boilers. Figure 25 shows the overall distribution of national utility boiler capacity according to fractional utilization ranges. Figure 26 shows the mean boiler utilization level for different boiler capacity size ranges. Figure 26 clearly shows that mean boiler utilization increases as boiler capacity increases.

REFERENCES

EIA, 1991: Energy Information Administration, "Steam-Electric Plant Operation and Design Report," Form EIA-767, 1991.

EPA, 1991: U.S. Environmental Protection Agency, "Supplement D to Compilation of Air Pollutant Emission Factors," *Volume I: Stationary Point and Area Sources*, AP-42 (GPO 055-000-00391-2), September 1991.

Pechan, 1993: E.H. Pechan & Associates, Inc., "Regional Interim Emission Inventories (1987-1991)," Vols. I (Development Methodologies) and II (Emission Summaries), EPA-454/R-93-021a and -021b (NTIS PB93-236107 and -236115, May 1993.

Figure 1
National SO2 Emissions by Fuel Type
(15.65 MMtons total)

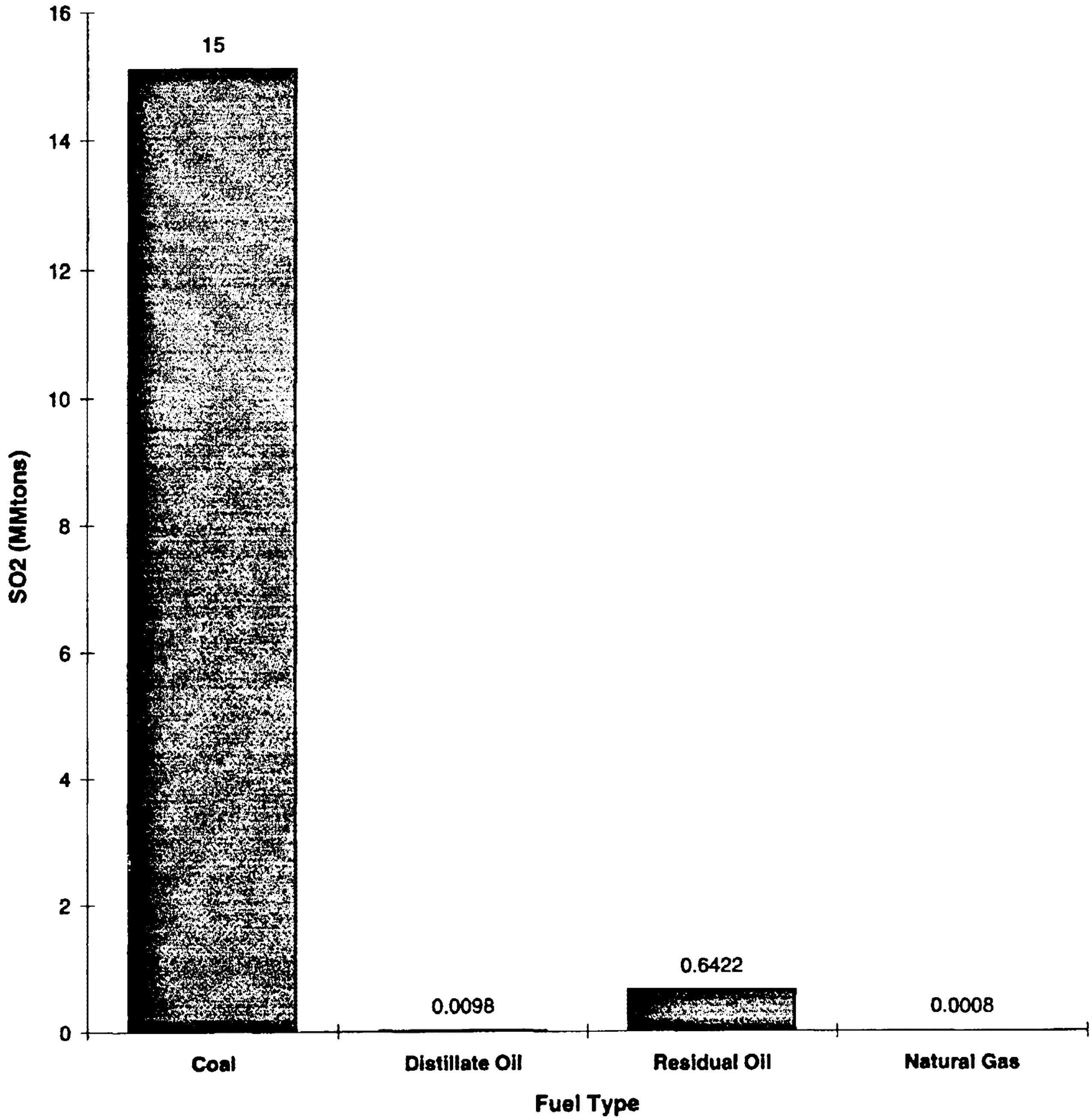


Figure 2
National NOx Emissions by Fuel Type
(7,204 ktons total)

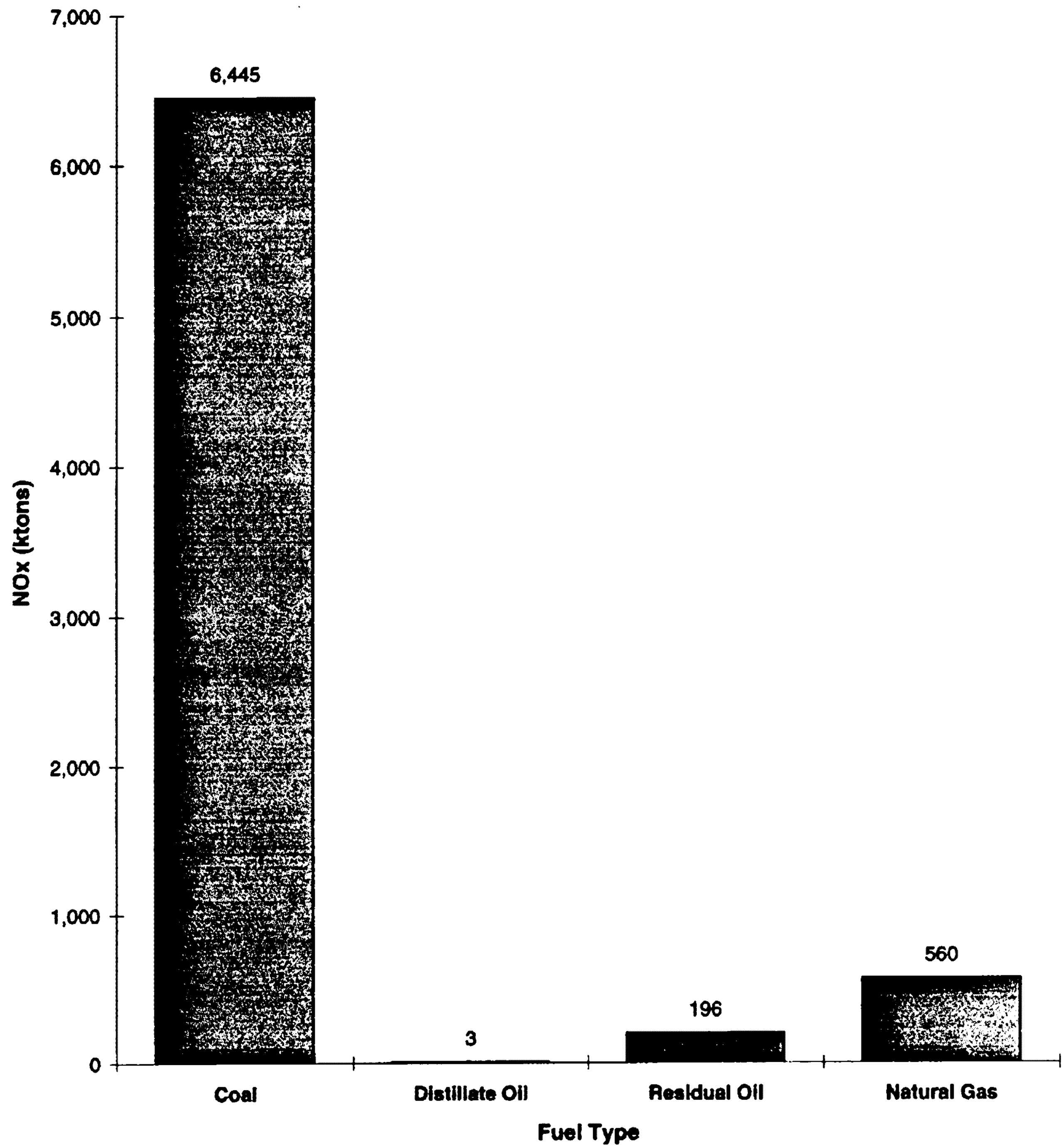


Figure 3
Mean Boiler Utilization by Fuel Type

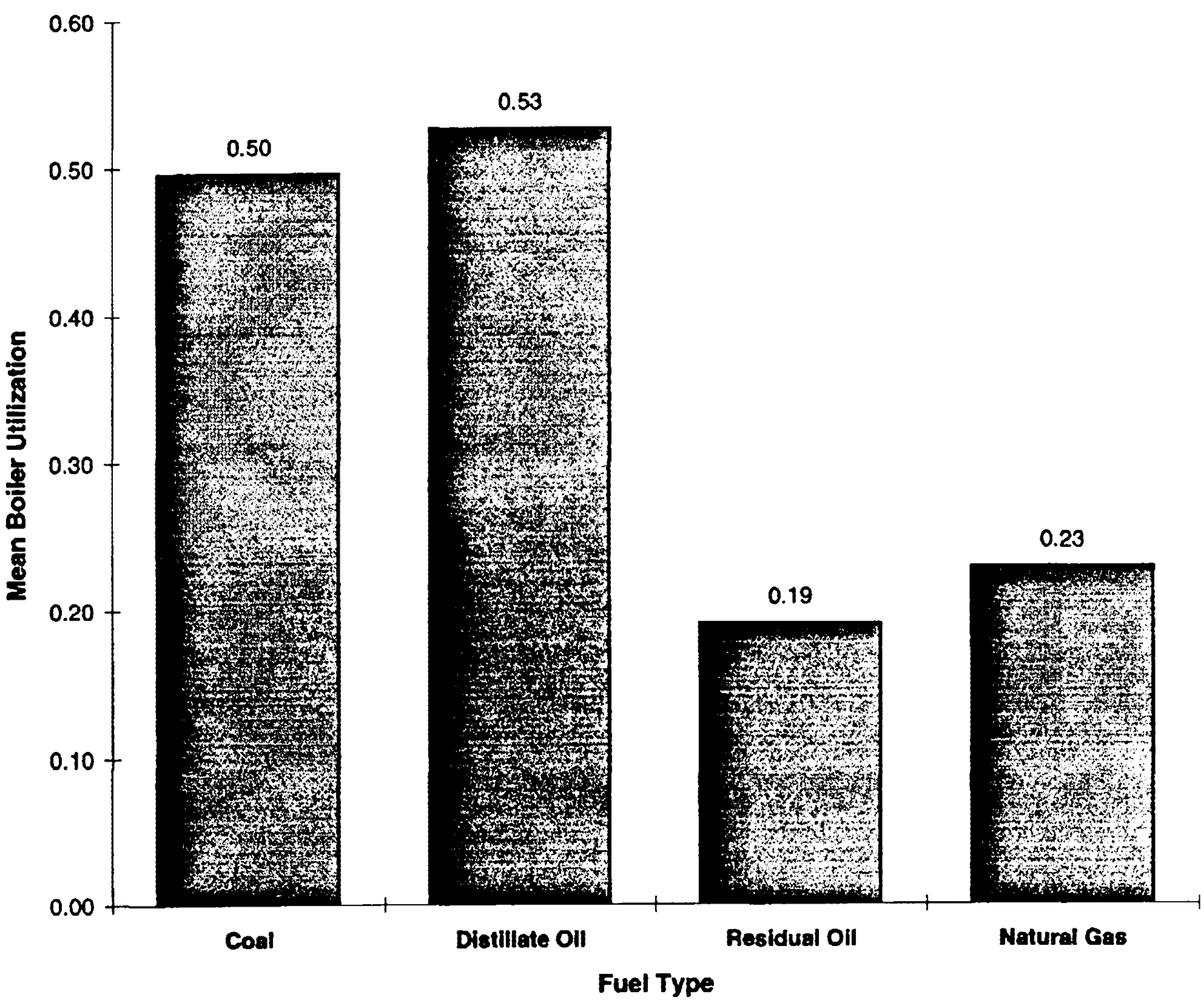


Figure 4
National Heat Input by Fuel Type and Sulfur Content
(19,812 MMBtu total)

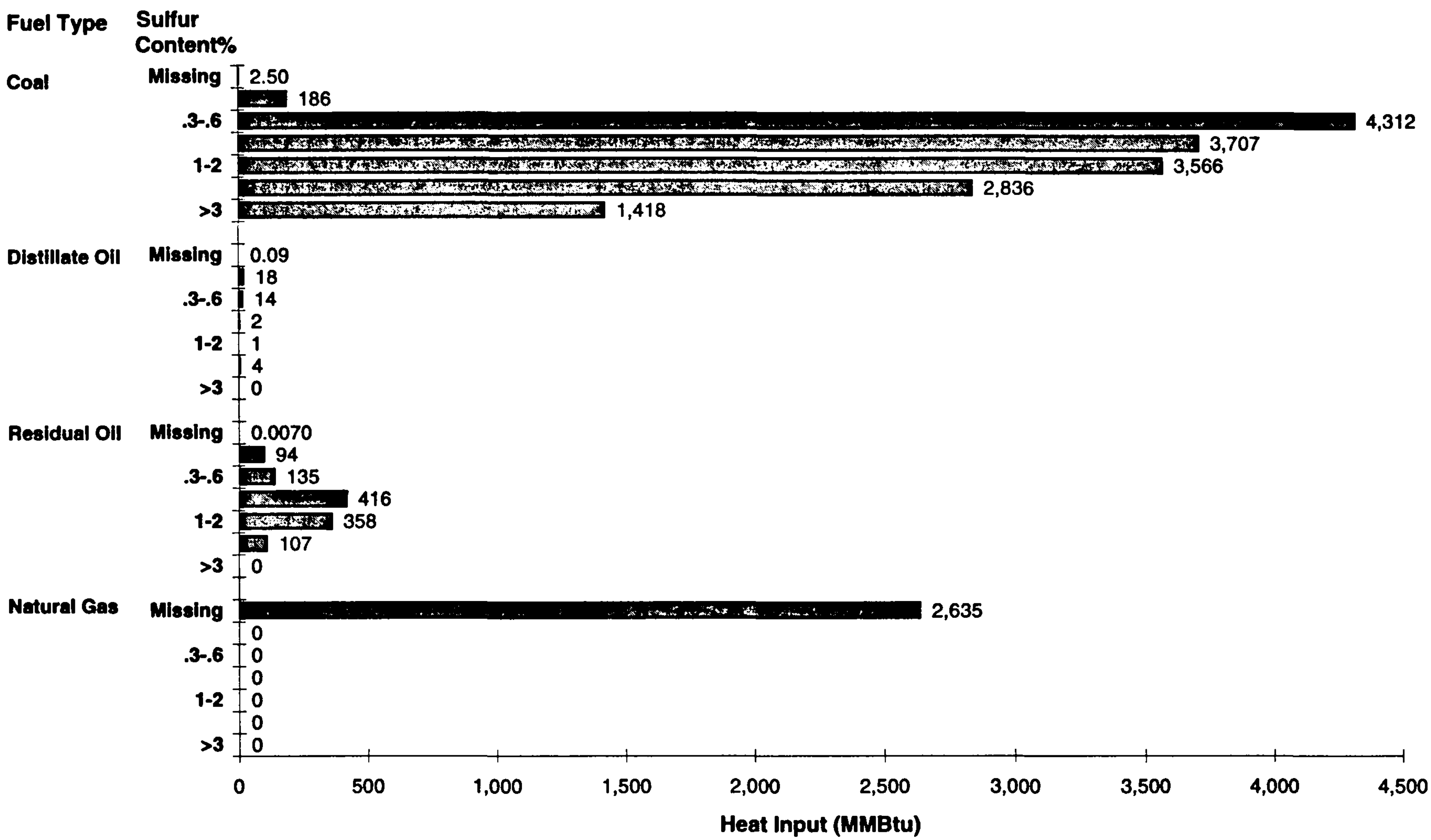


Figure 5
National SO2 Emissions by Fuel Type and Sulfur Content
(15,757 ktons total)

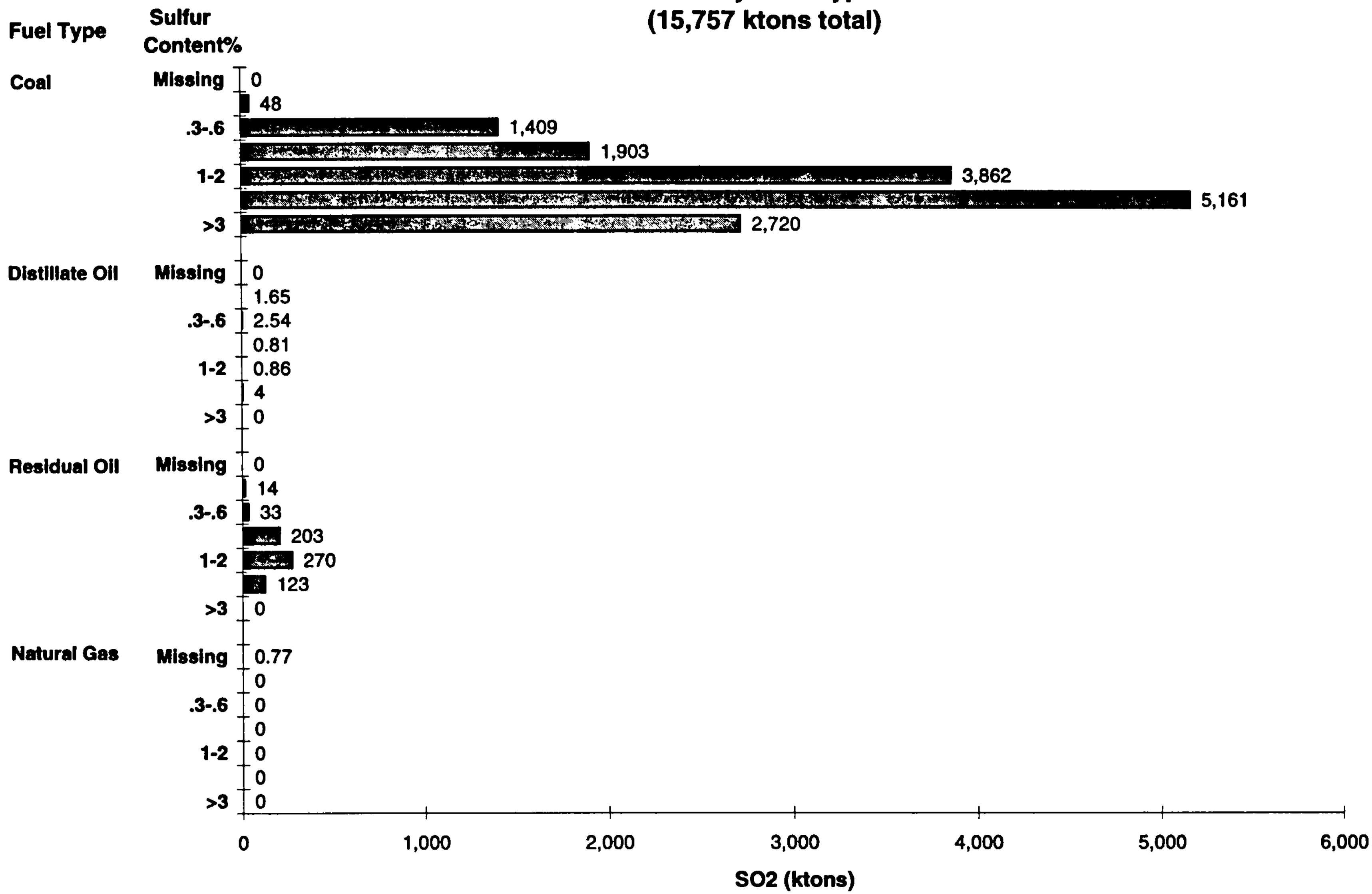


Figure 6
National Heat Input by Fuel Type and Boiler Capacity
(19,812 MMBtu total)

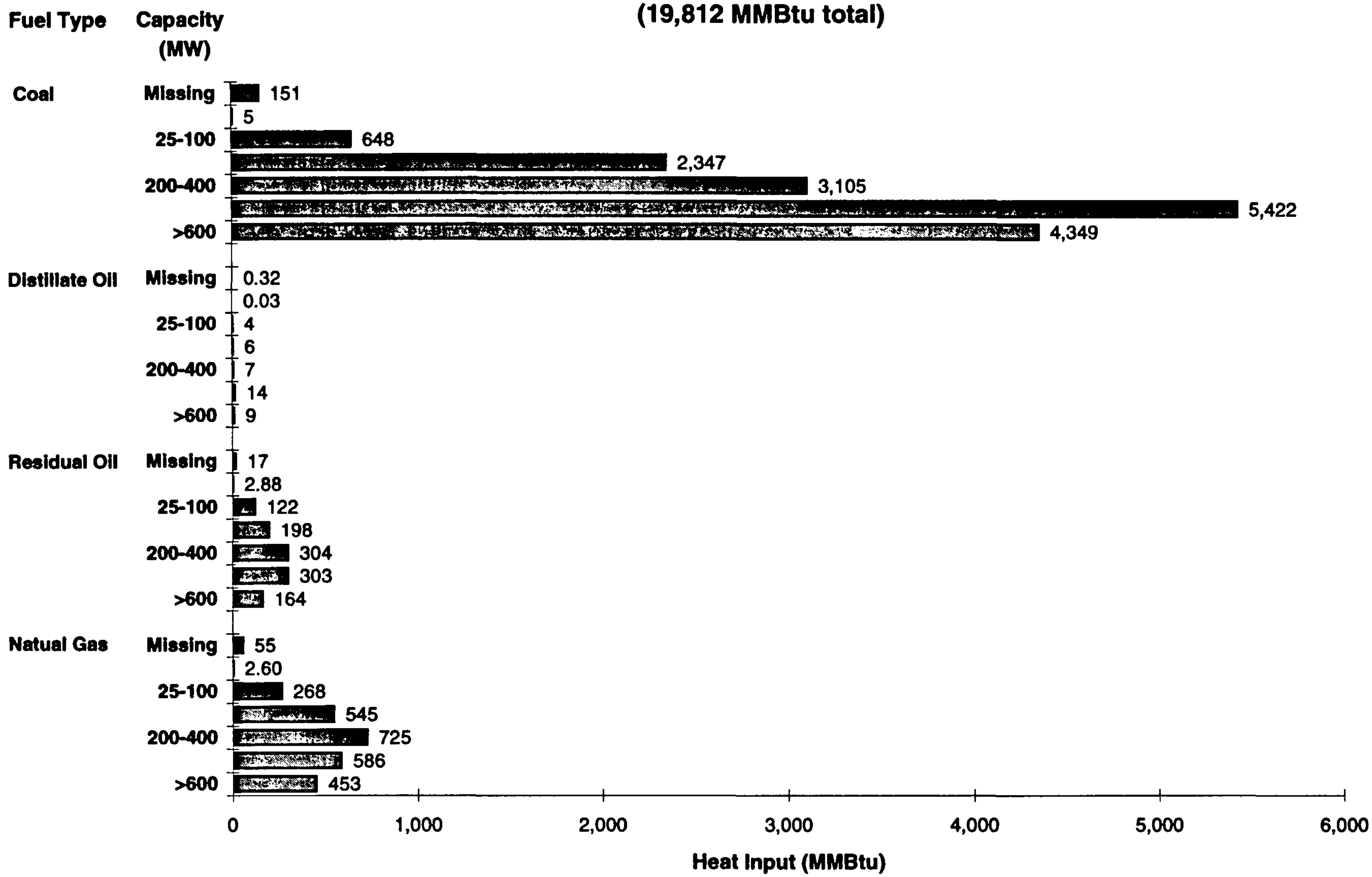


Figure 7
National SO2 Emissions by Fuel Type and Boiler Capacity
(15,754 ktons total)

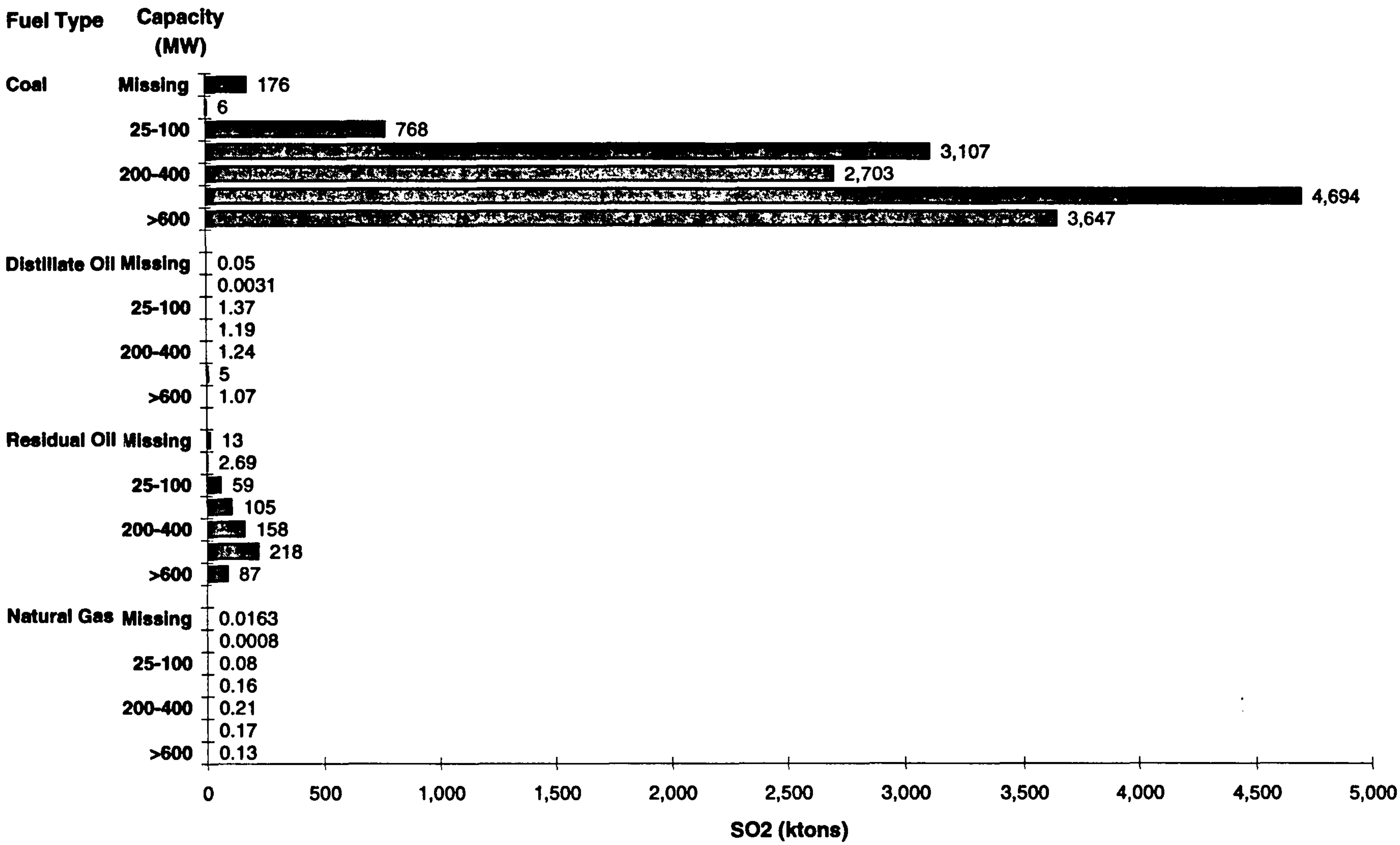


Figure 8
National NOx Emissions by Fuel Type and Boiler Capacity
(7,205 ktons total)

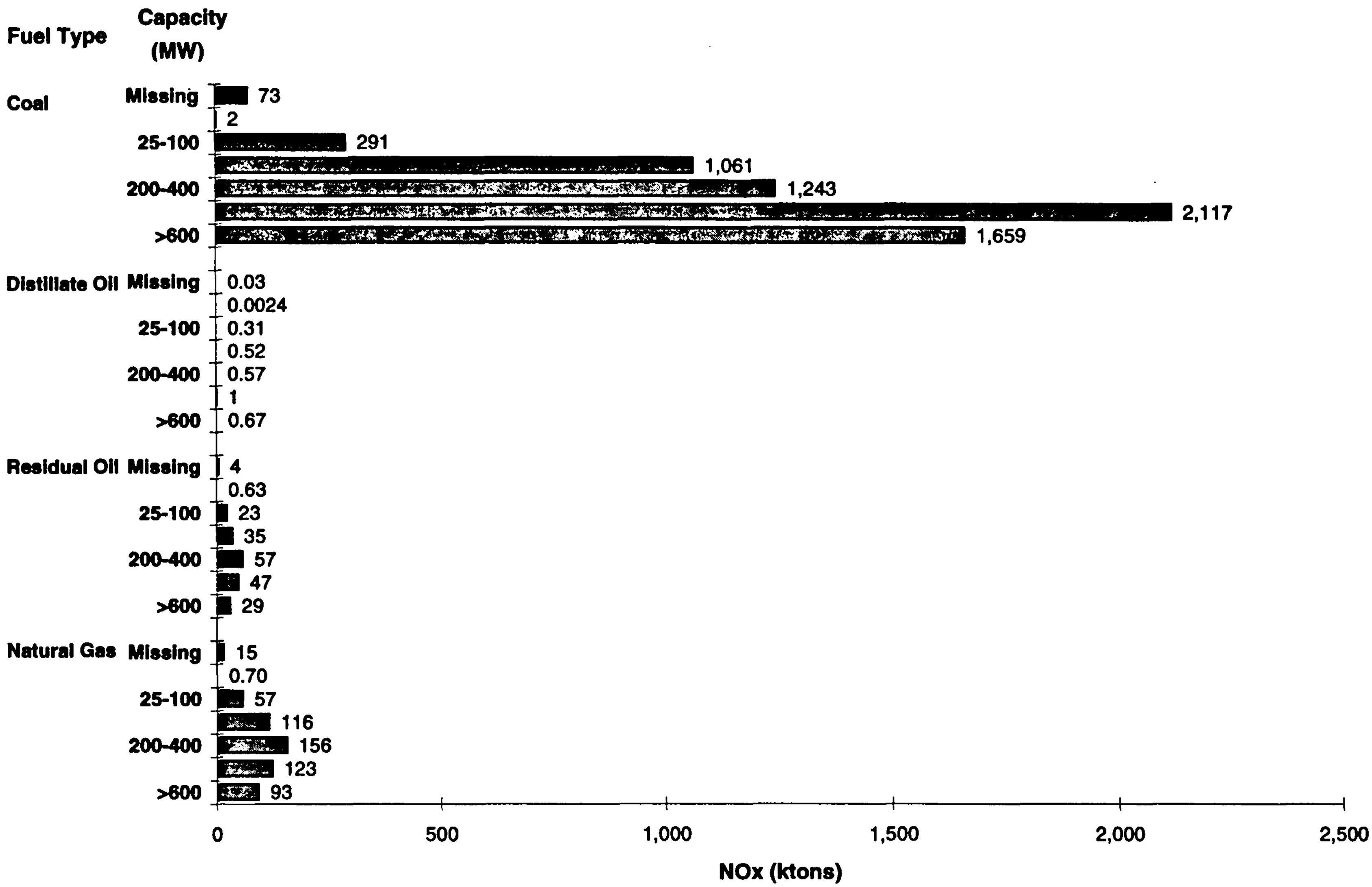


Figure 9
National Heat Input by Sulfur Content
(19,811 MMBtu total)

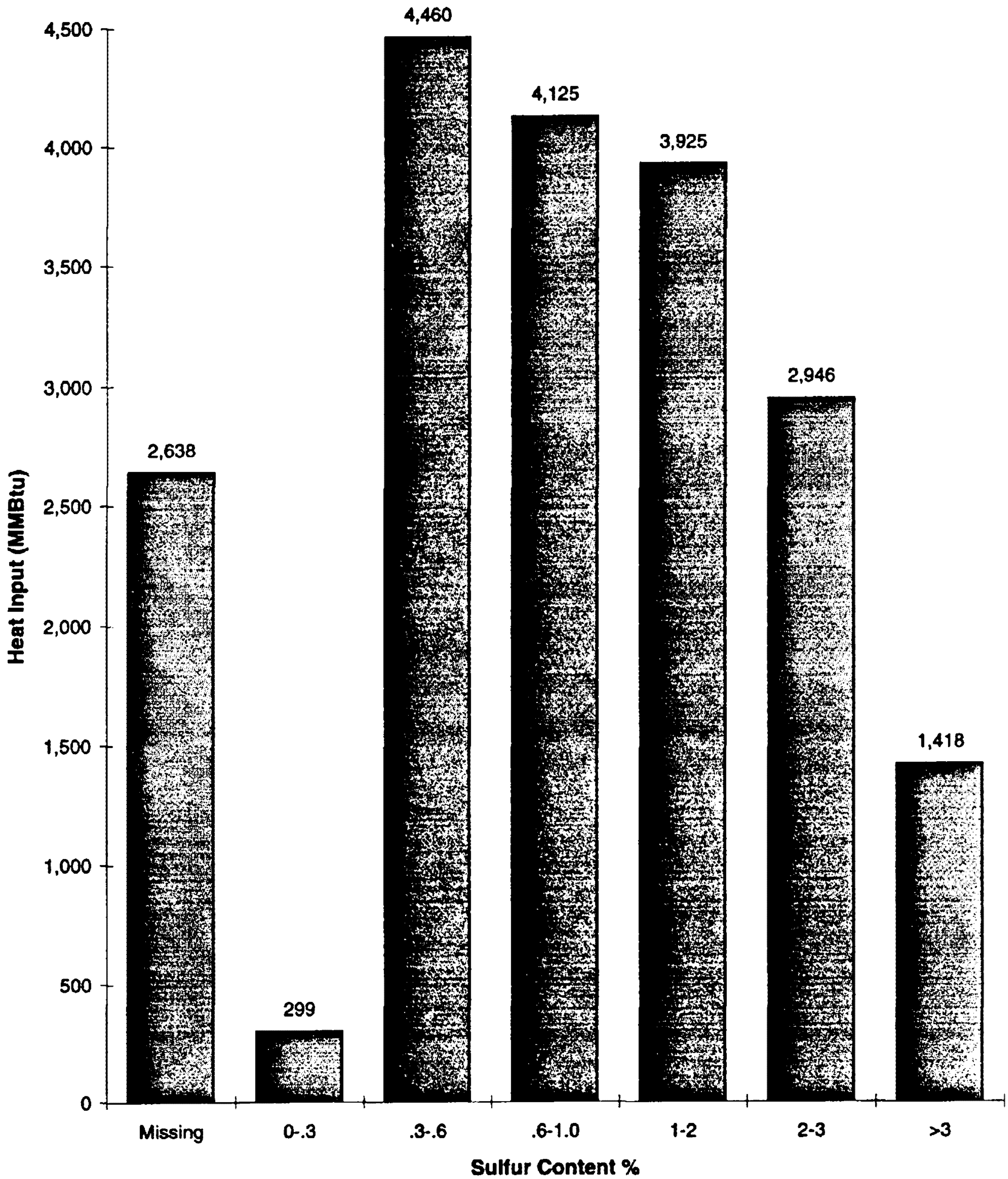


Figure 10
National SO2 Emissions by Sulfur Content
(15,754 ktons total)

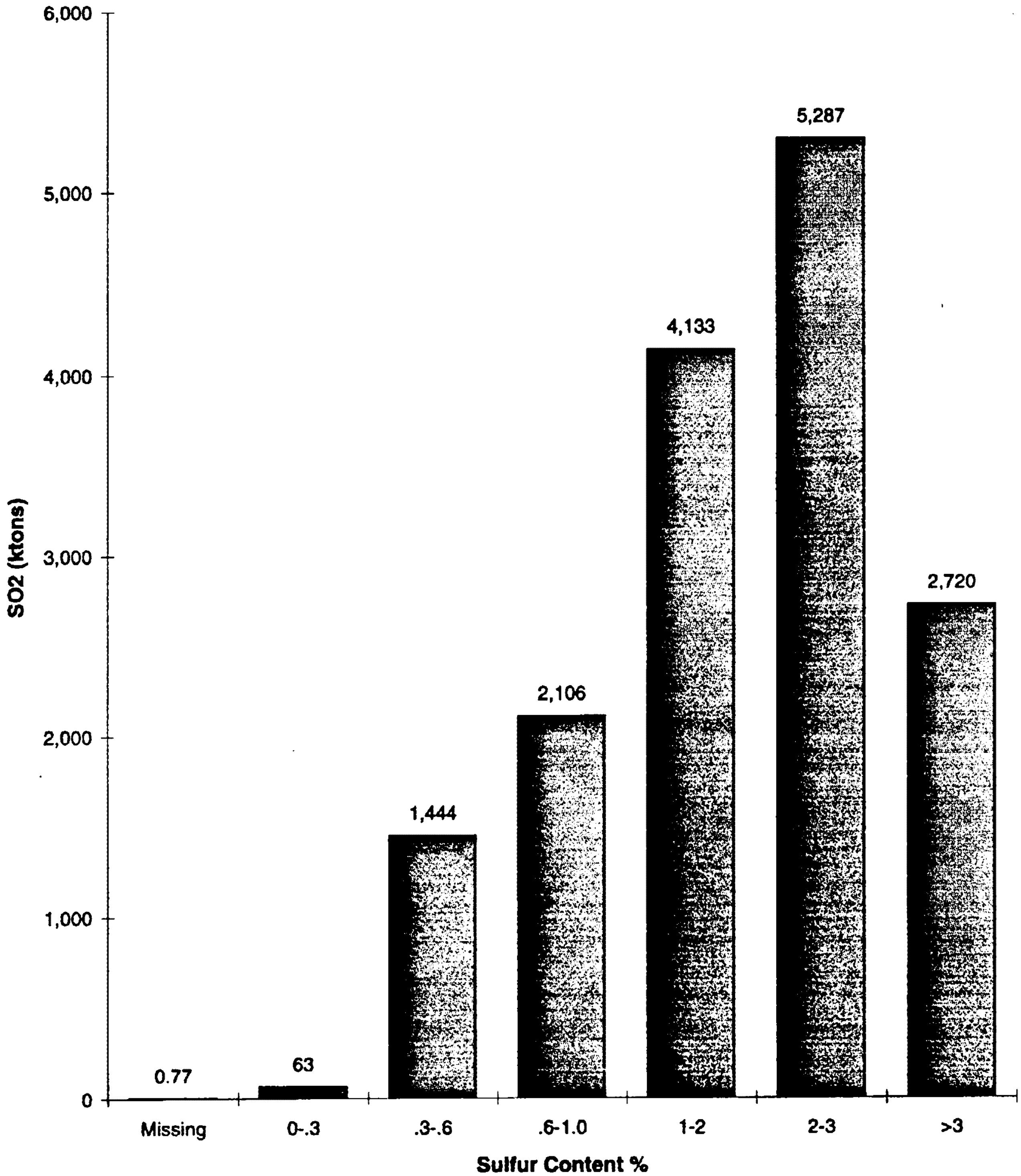


Figure 11
National Heat Input by Boiler Capacity
(19,812 MMBtu total)

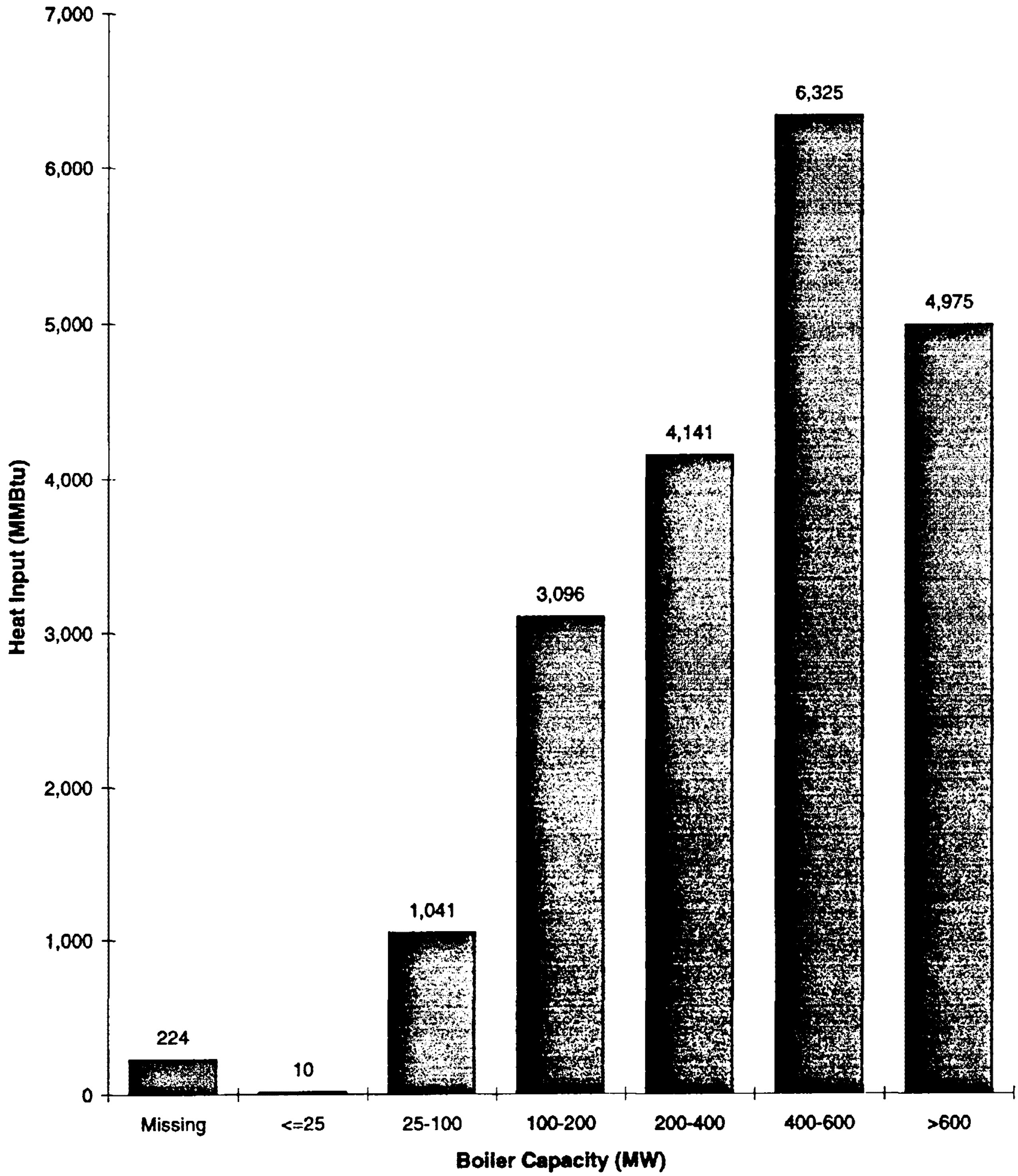


Figure 12
National SO2 Emissions by Boiler Capacity
(15,753 ktons total)

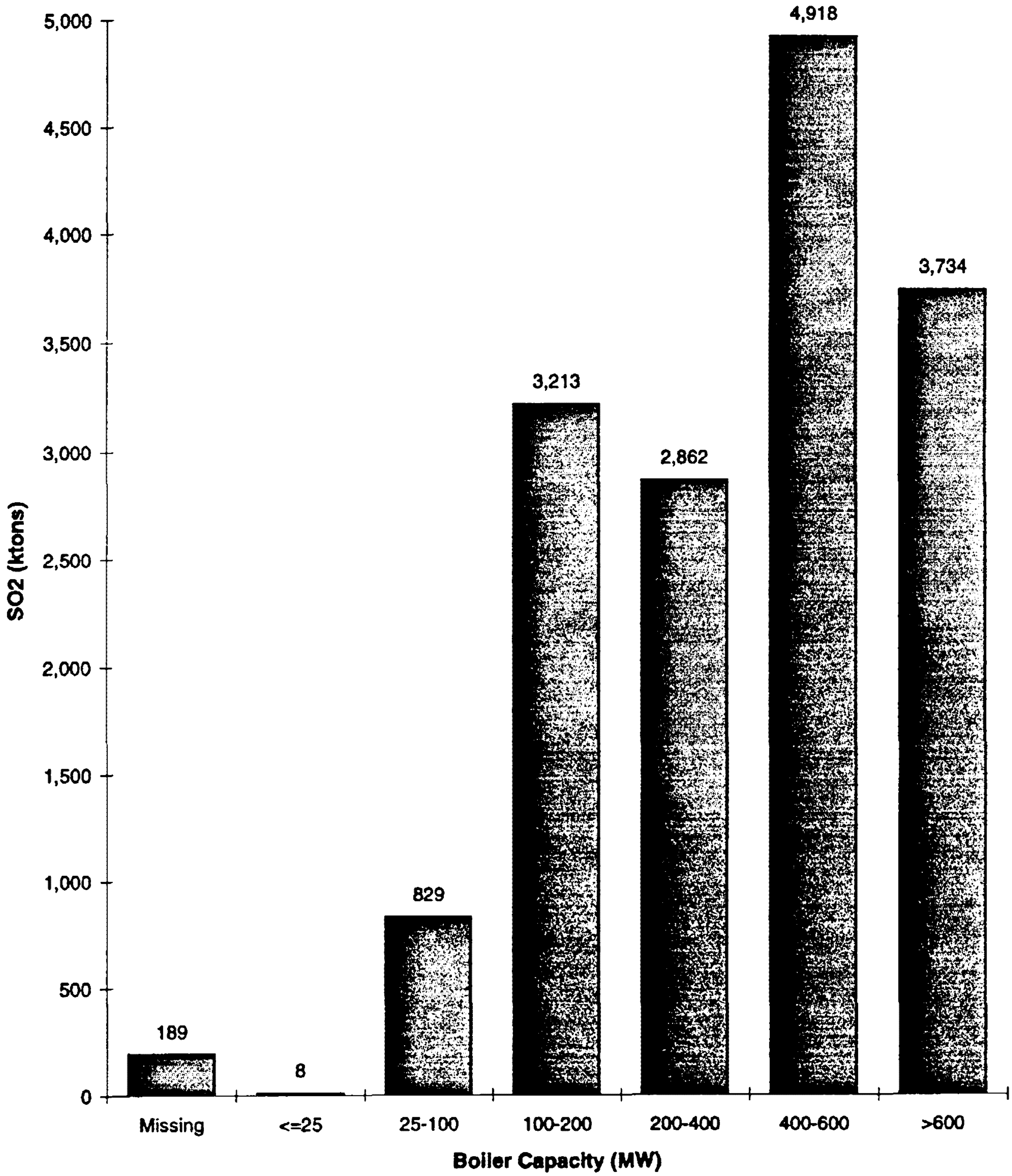


Figure 13
National NOx Emissions by Boiler Capacity
(7,205 ktons total)

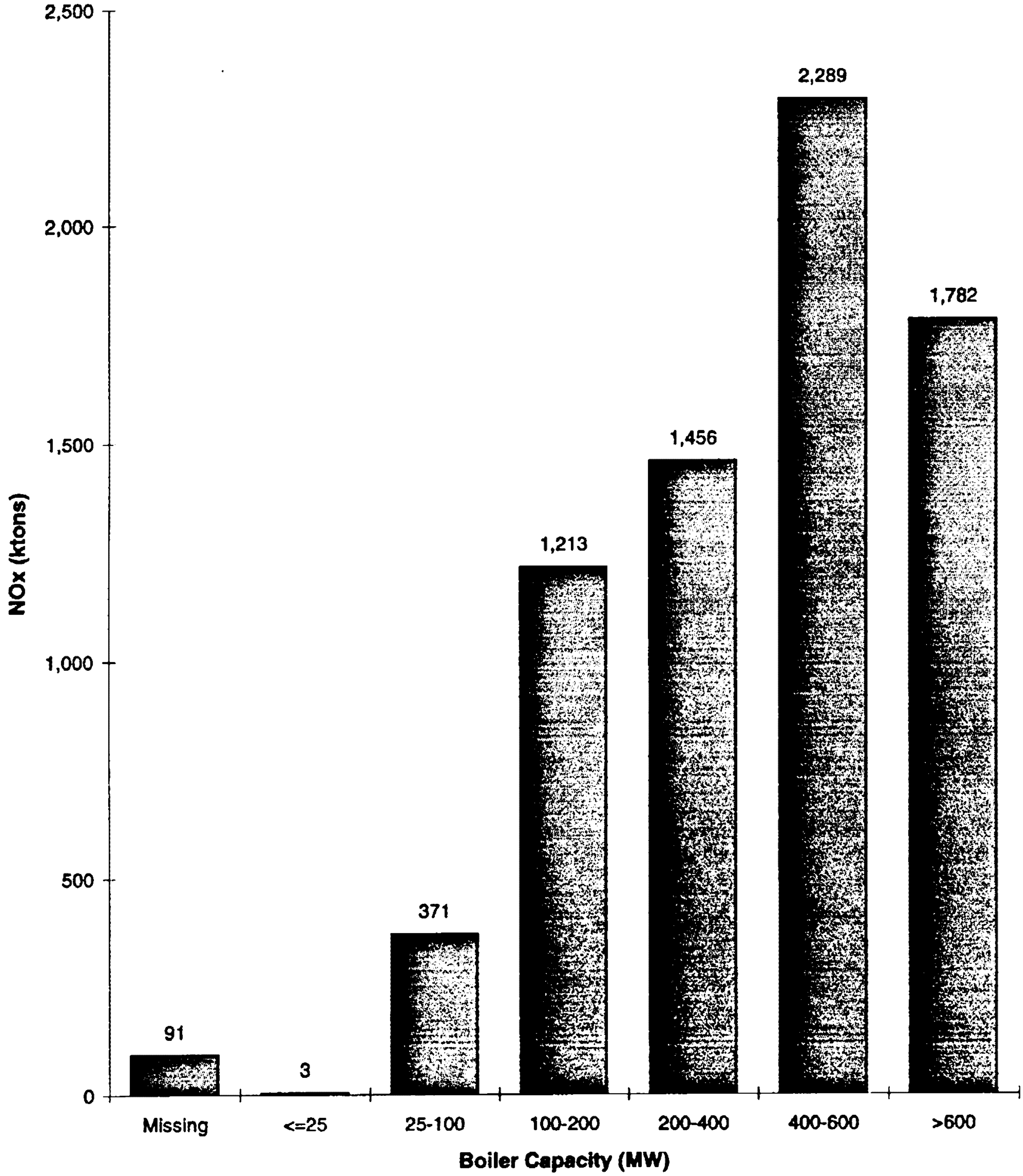


Figure 14
National Heat Input (MMBtu) by Fuel Type
(19,812 MMBtu total)

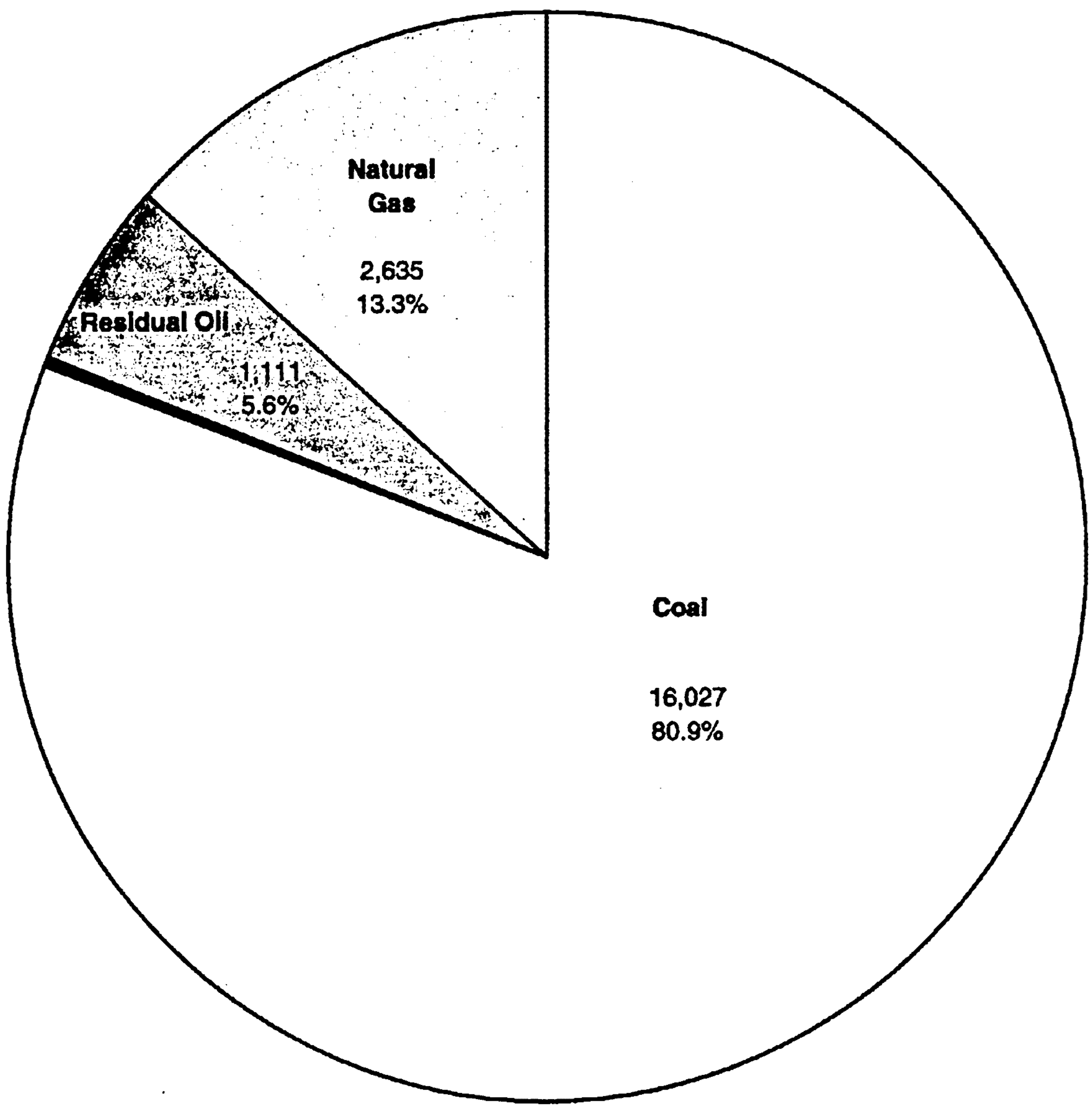


Figure 15
National Coal Quantities by Sulfur Content
(775 MMtons total)

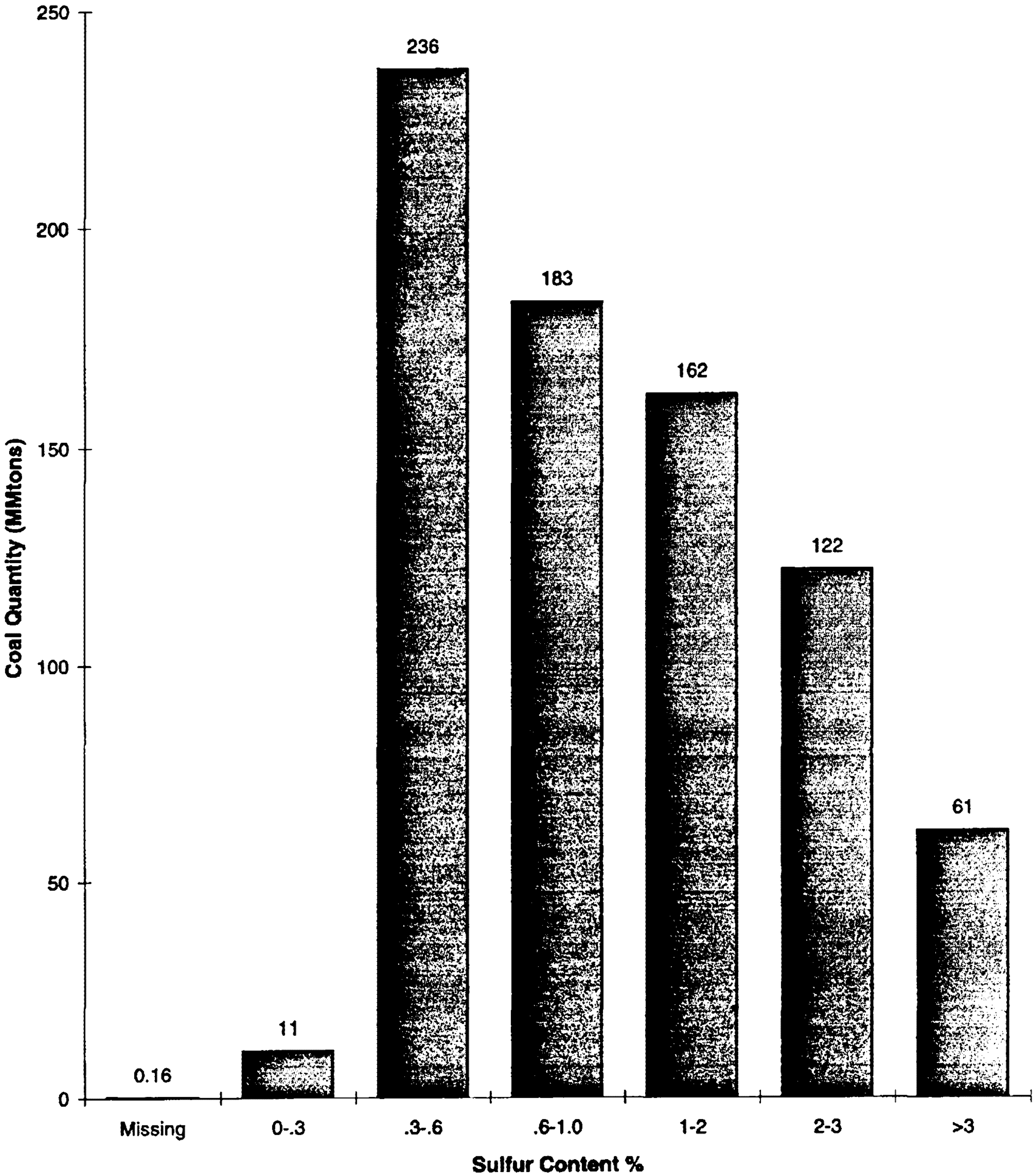


Figure 16
National Coal Quantities (MMtons) for Scrubbed and Not Scrubbed Coal

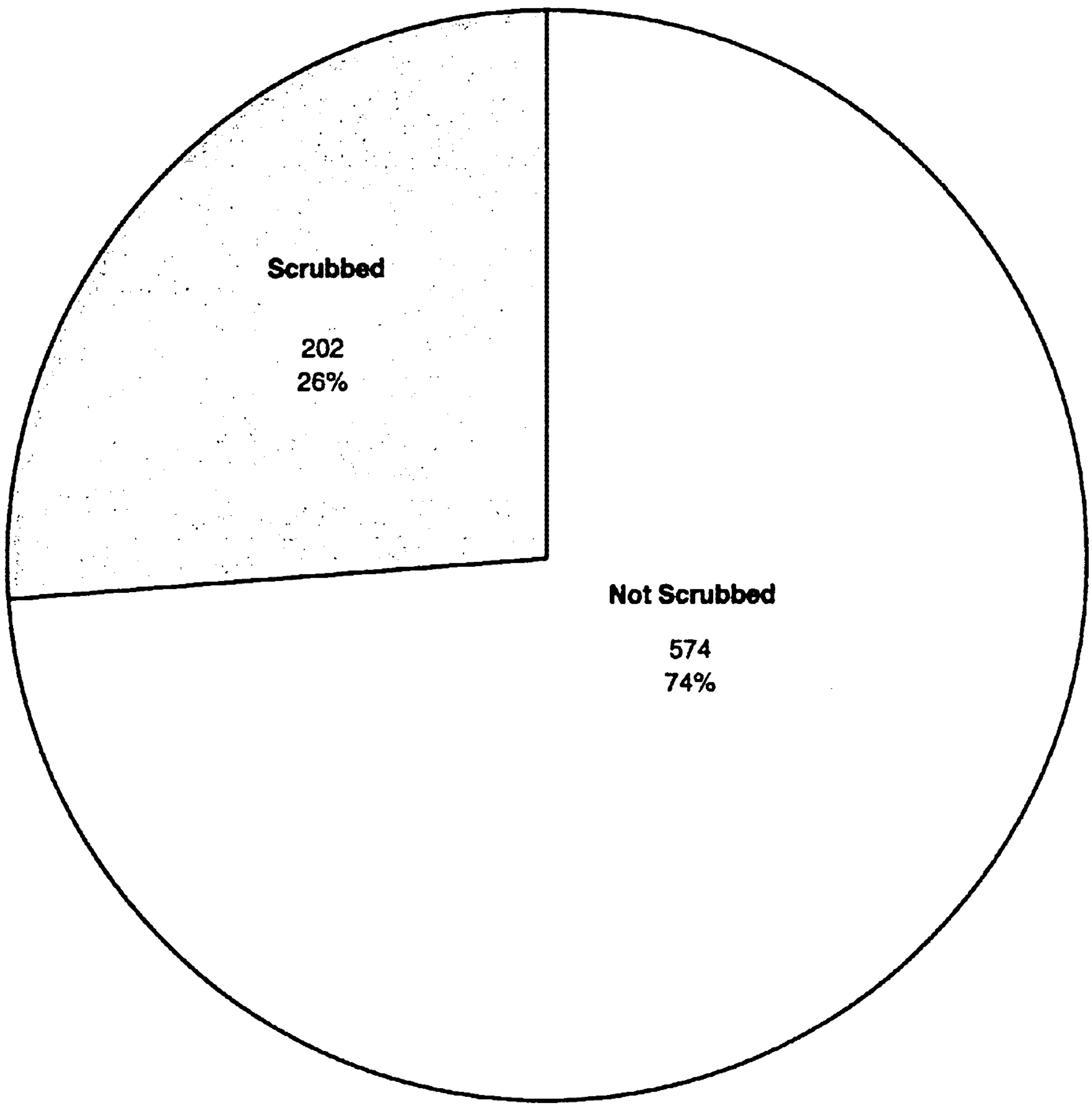
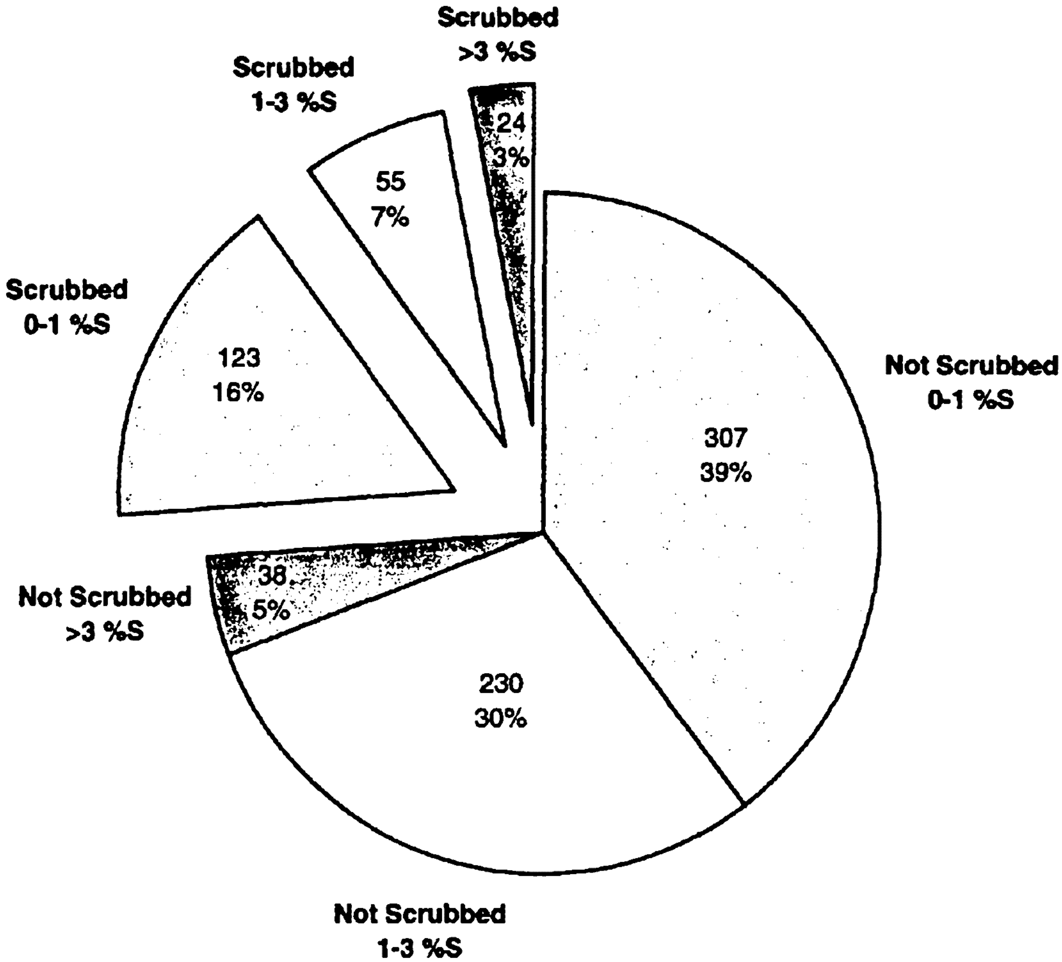


Figure 17
National Coal Quantities (MMtons) by Sulfur Content for Scrubbed and Not Scrubbed Coal



Note: Records with missing sulfur content are not included.

Figure 18
National Coal Heat Input (MMBtu) for Scrubbed and Not Scrubbed Coal

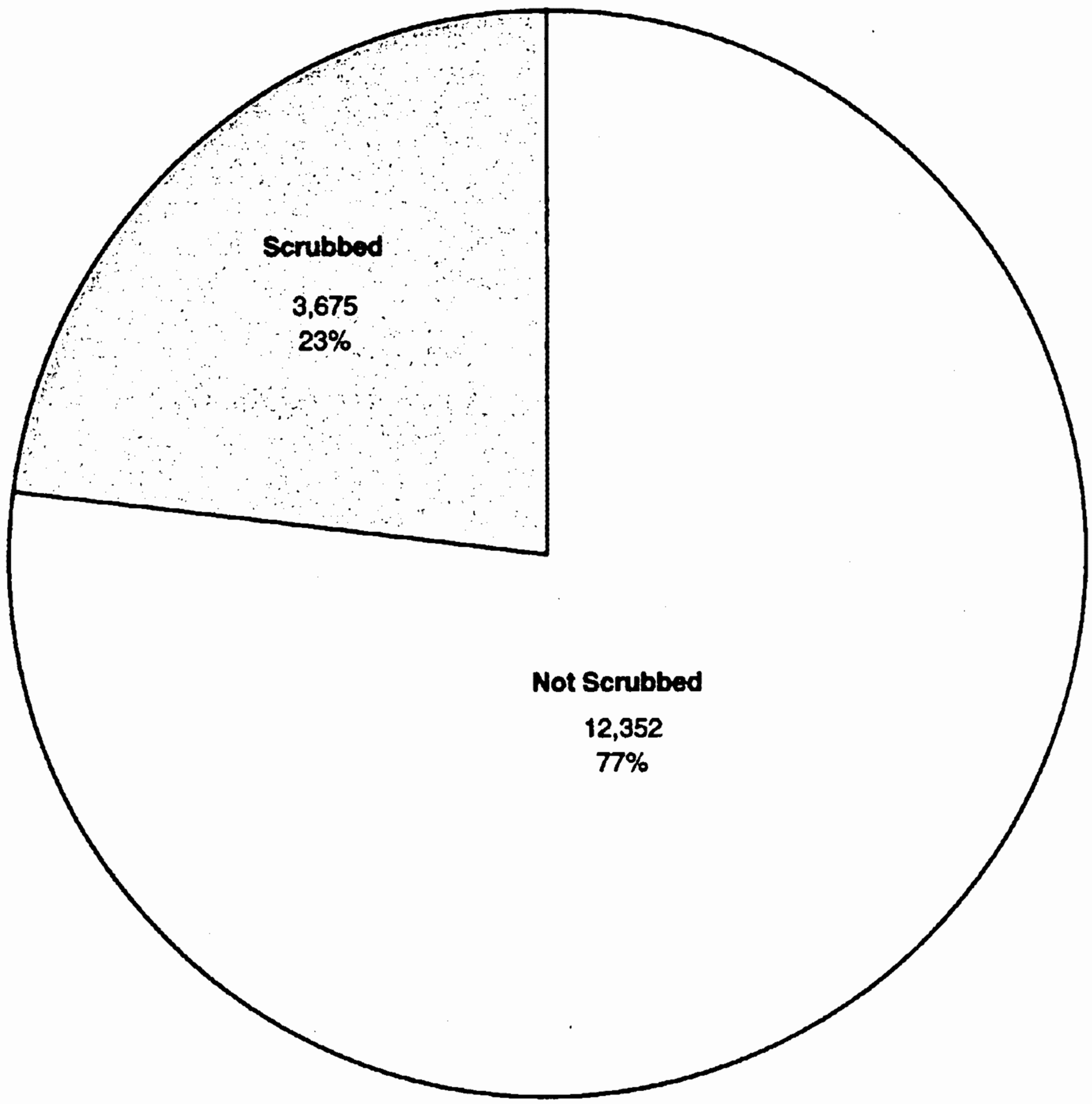


Figure 19
National Coal SO2 Emissions (ktons) for Scrubbed and Not Scrubbed Coal

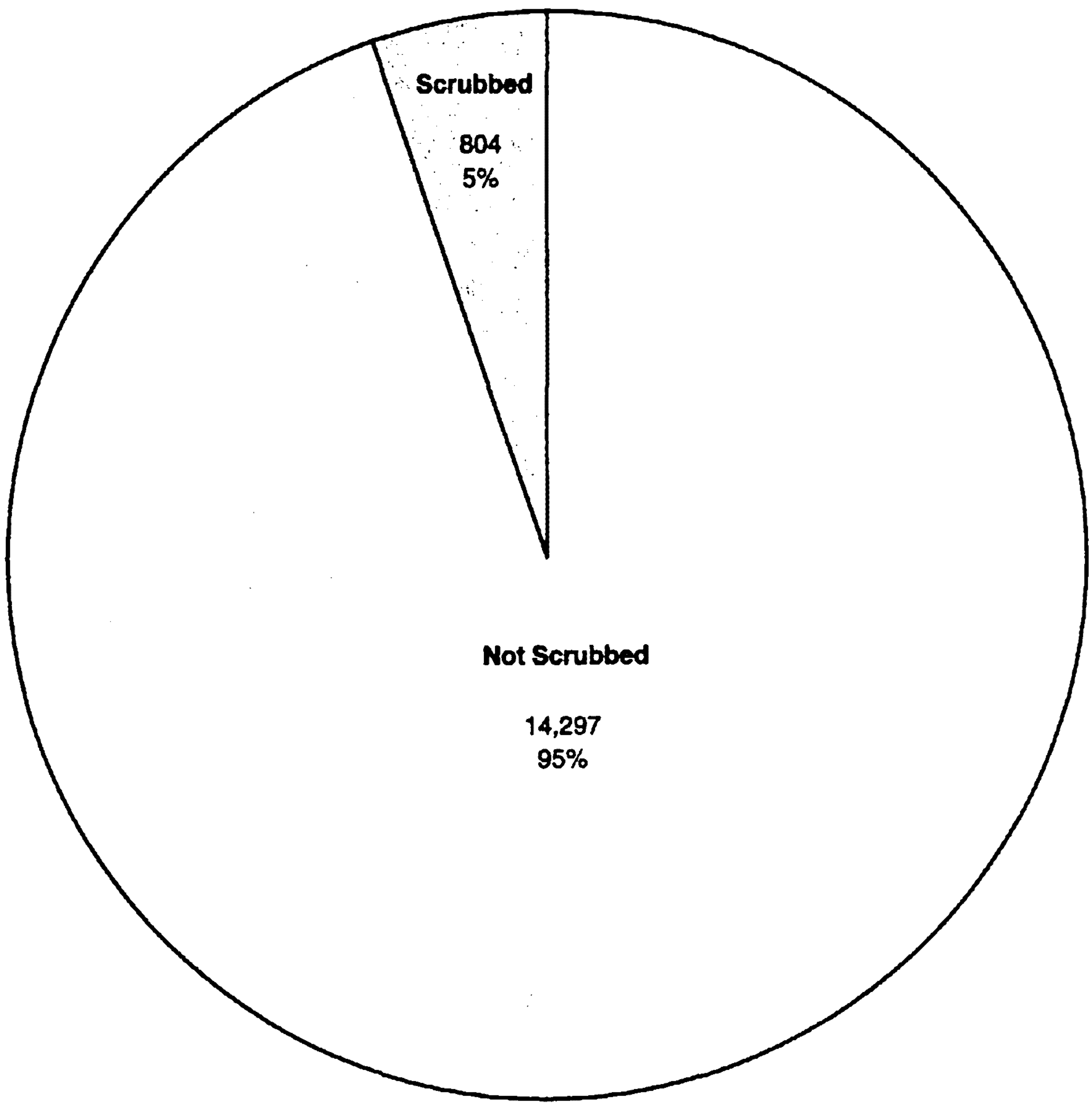
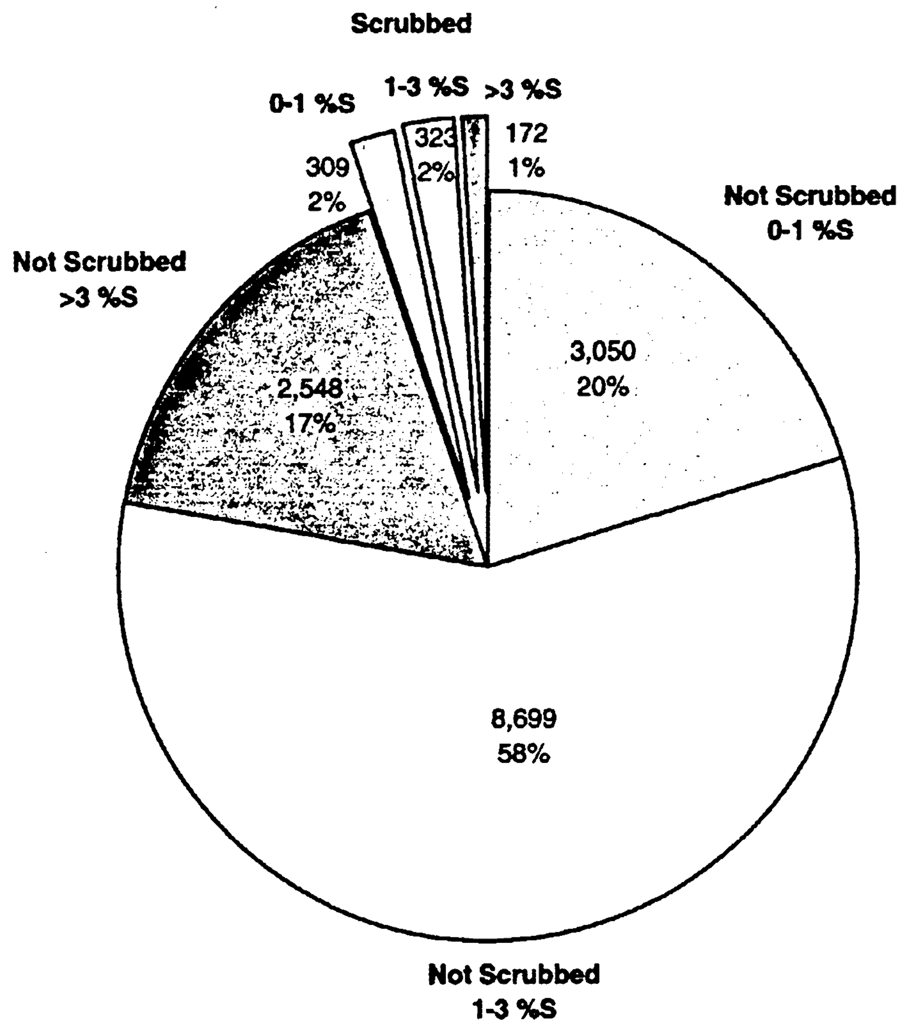
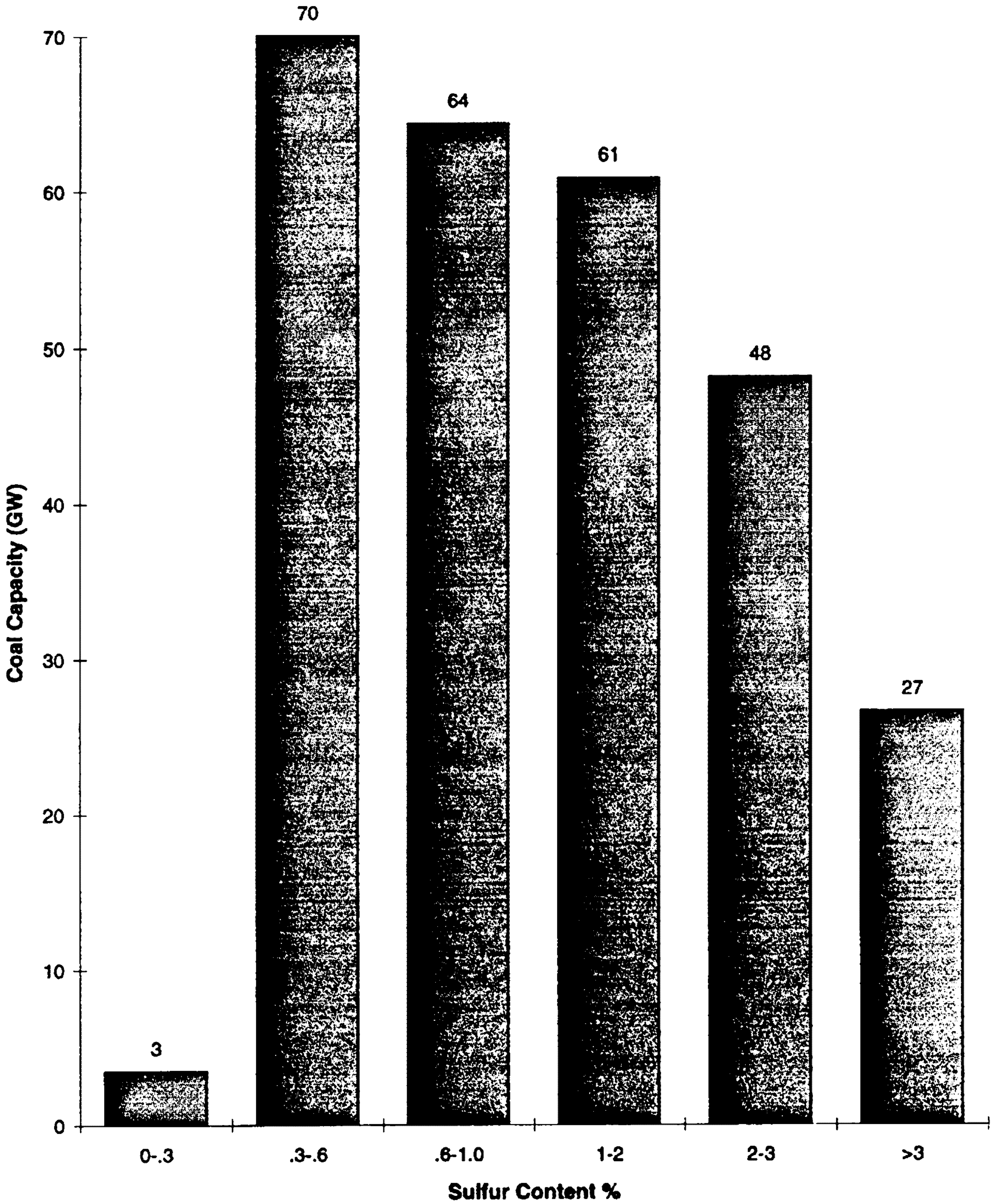


Figure 20
National Coal SO2 Emissions (ktons) by Sulfur Content for Scrubbed and Not Scrubbed Coal



Note: Records with missing sulfur content are not included.

Figure 21
National Coal Boiler Capacity by Sulfur Content
(273 GW total capacity)



Note: Records with missing sulfur content are not included.

Figure 22
National Coal Boiler Capacity (GW) for Scrubbed and Not Scrubbed Coal

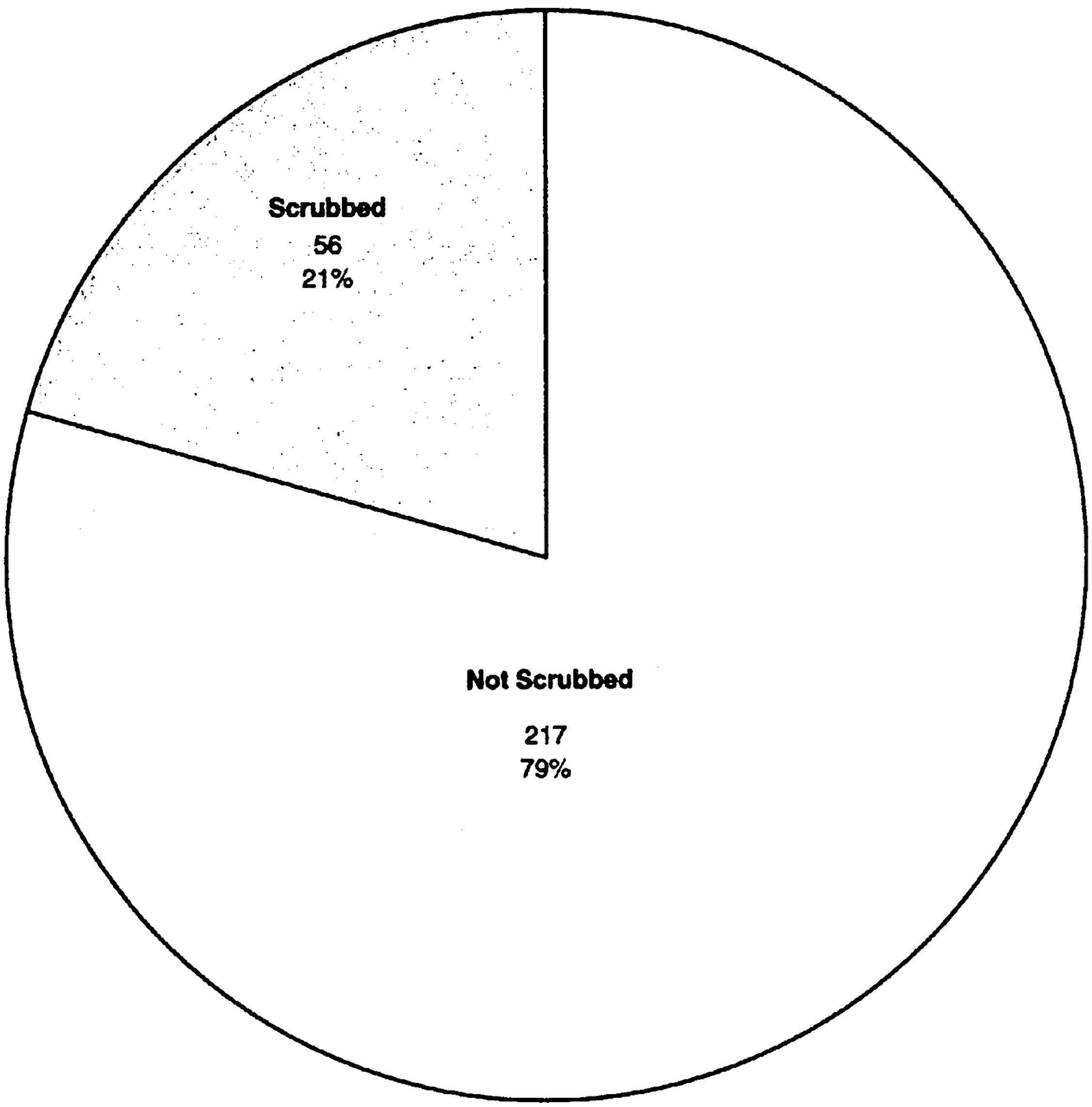
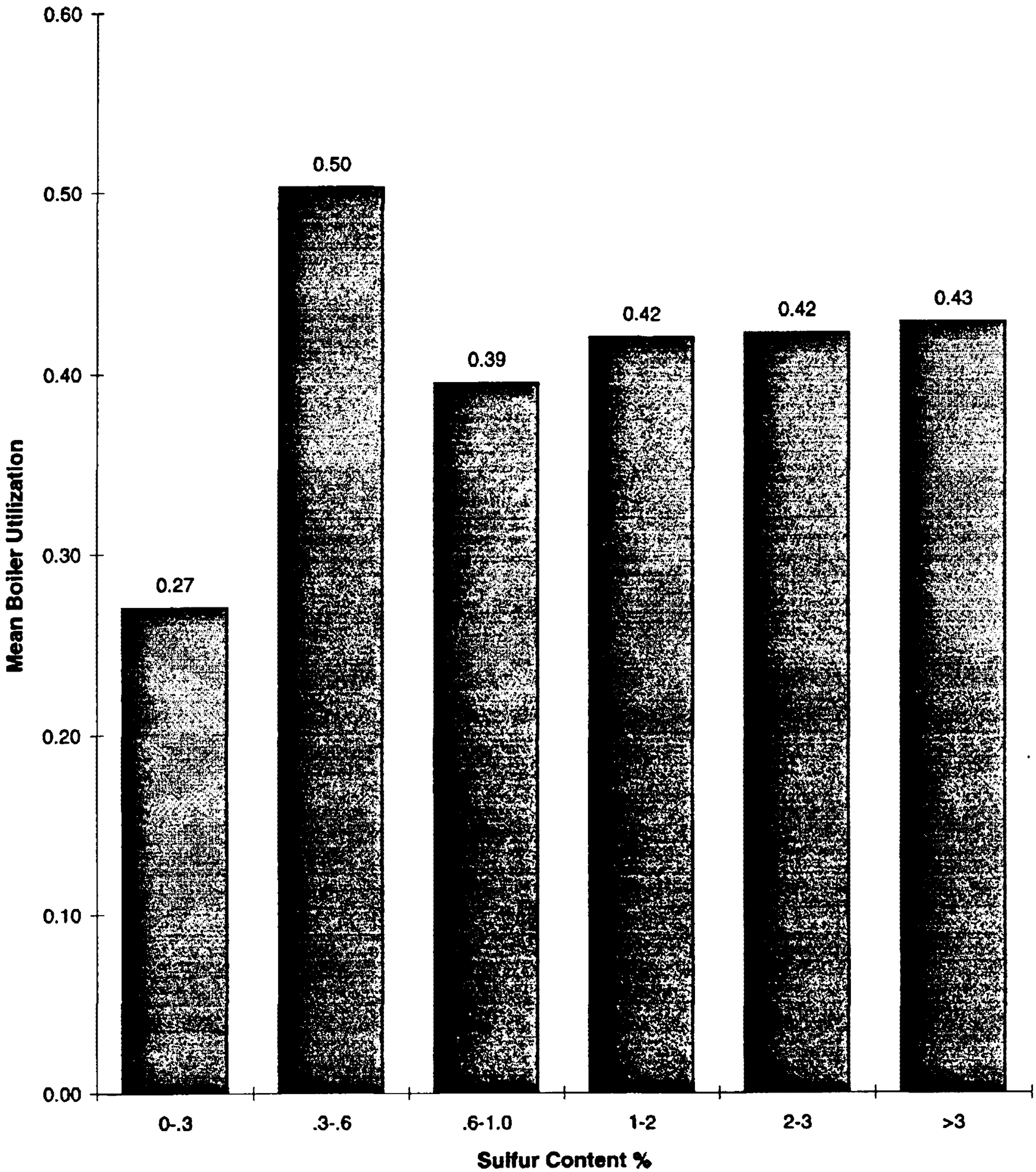
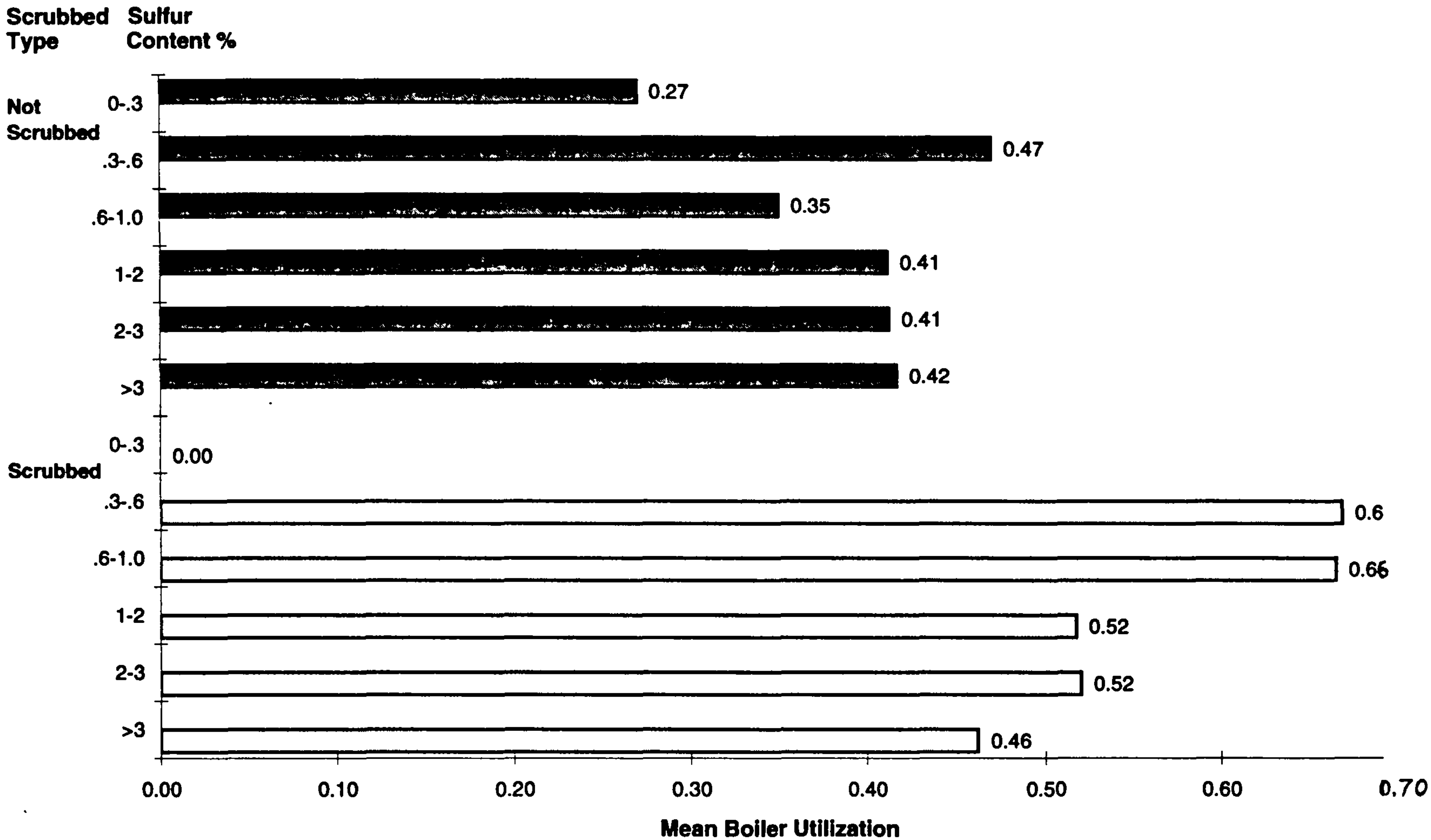


Figure 23
National Coal Mean Boiler Utilization by Sulfur Content



Note: Records with missing sulfur content are not included.

Figure 24
National Coal Mean Boiler Utilization by Sulfur Content for Scrubbed and Not Scrubbed Coal



Note: Records with missing sulfur content are not included.

Figure 25
National Boiler Capacity by Mean Boiler Utilization
(397 GW total boiler capacity)

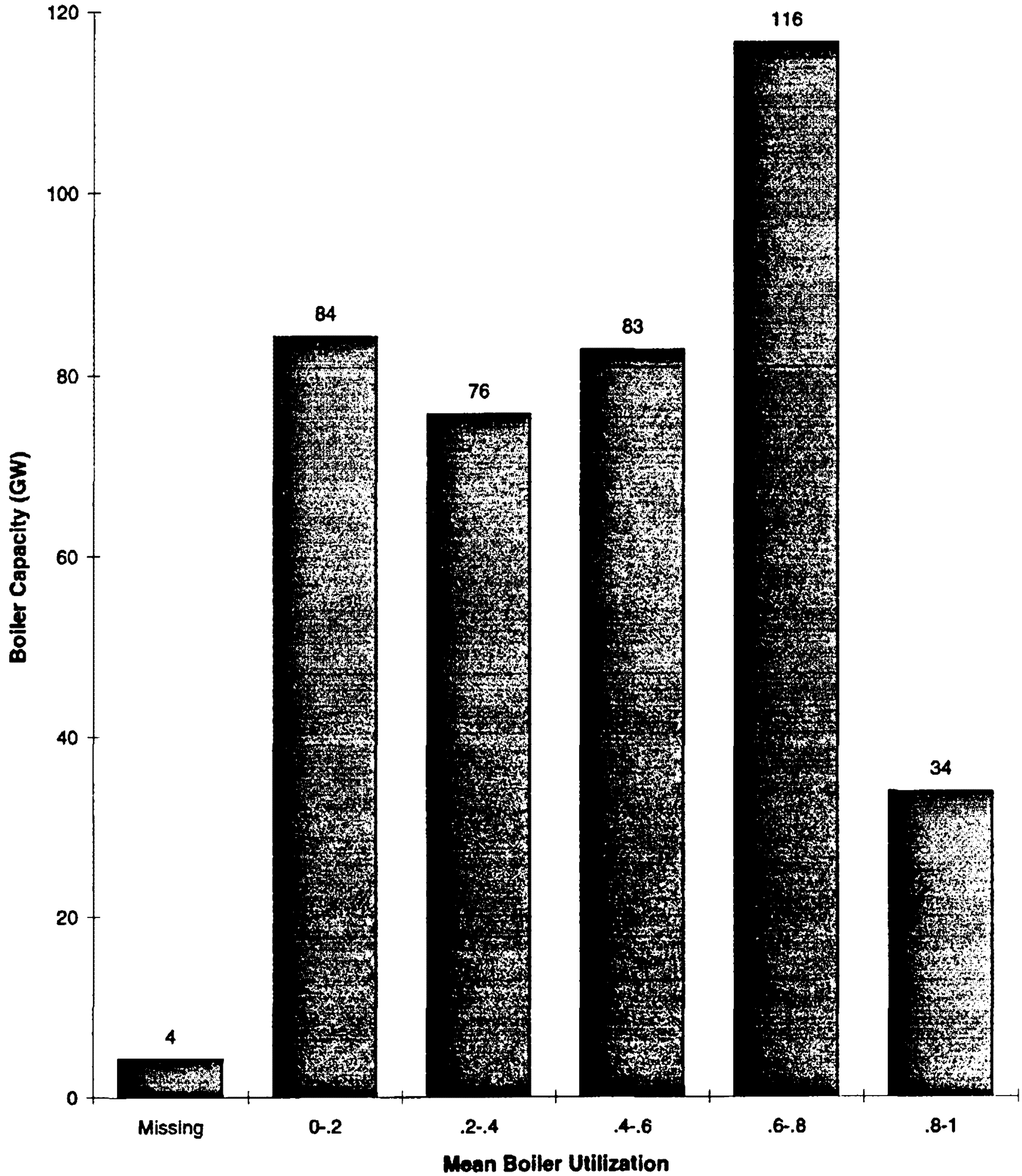


Figure 26
National Mean Boiler Utilization by Boiler Capacity

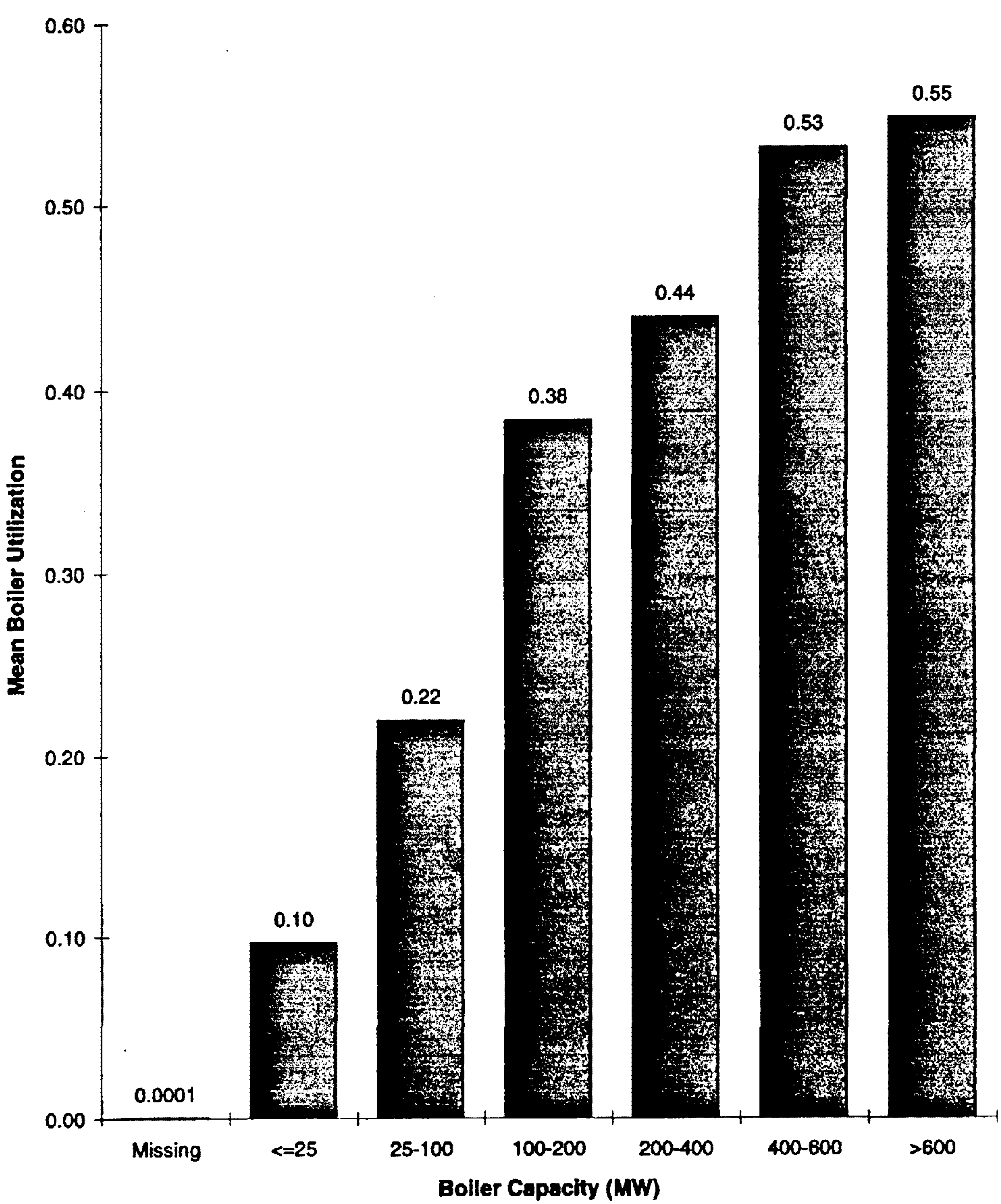


Figure 27
Region 1 SO2 Emissions by Fuel Type
(345 ktons total)

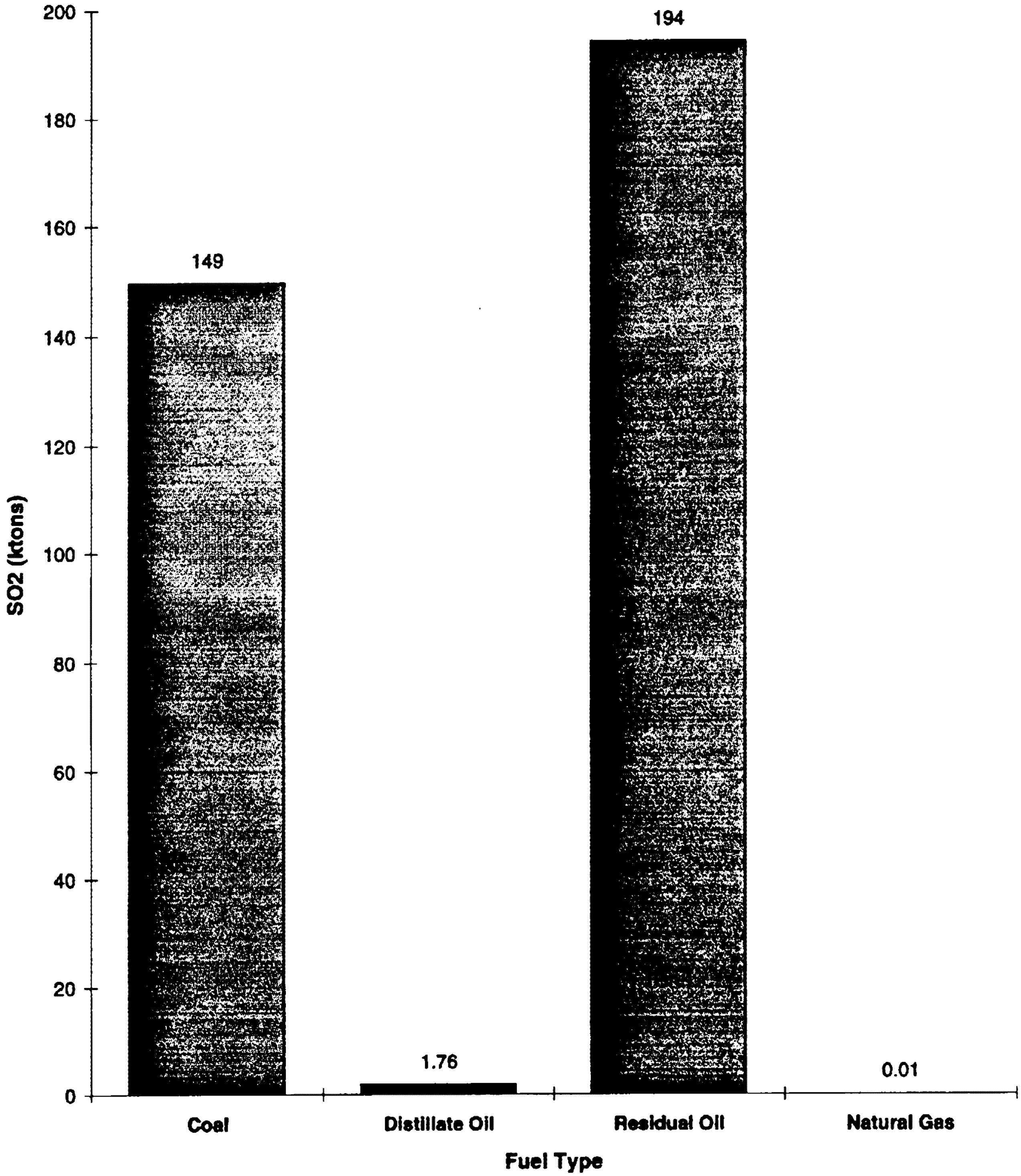


Figure 28
Region 1 NOx Emissions by Fuel Type
(123 ktons total)

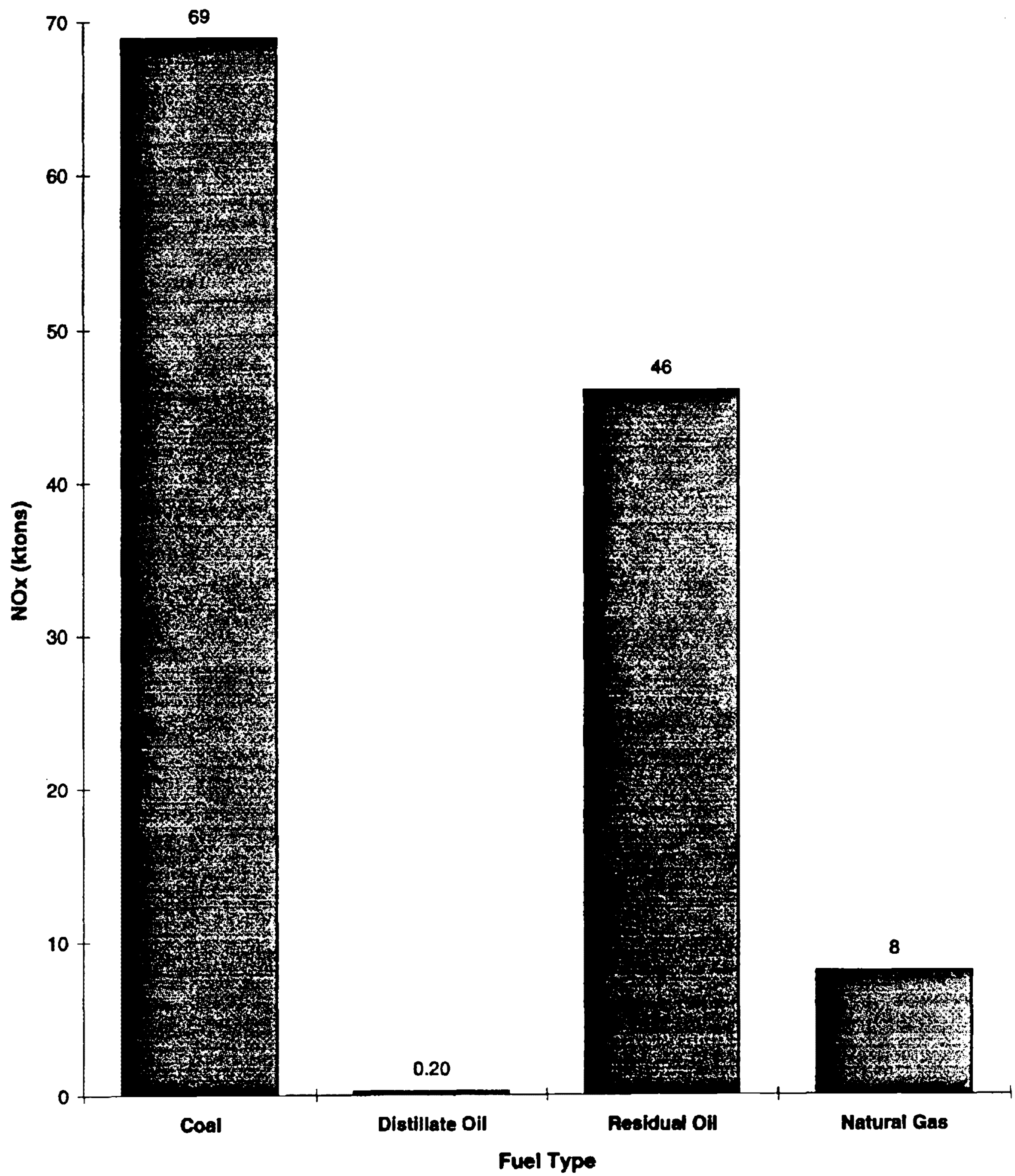


Figure 29
Region 1 SO2 Emissions by Fuel Type and Sulfur Content
(345 ktons total)

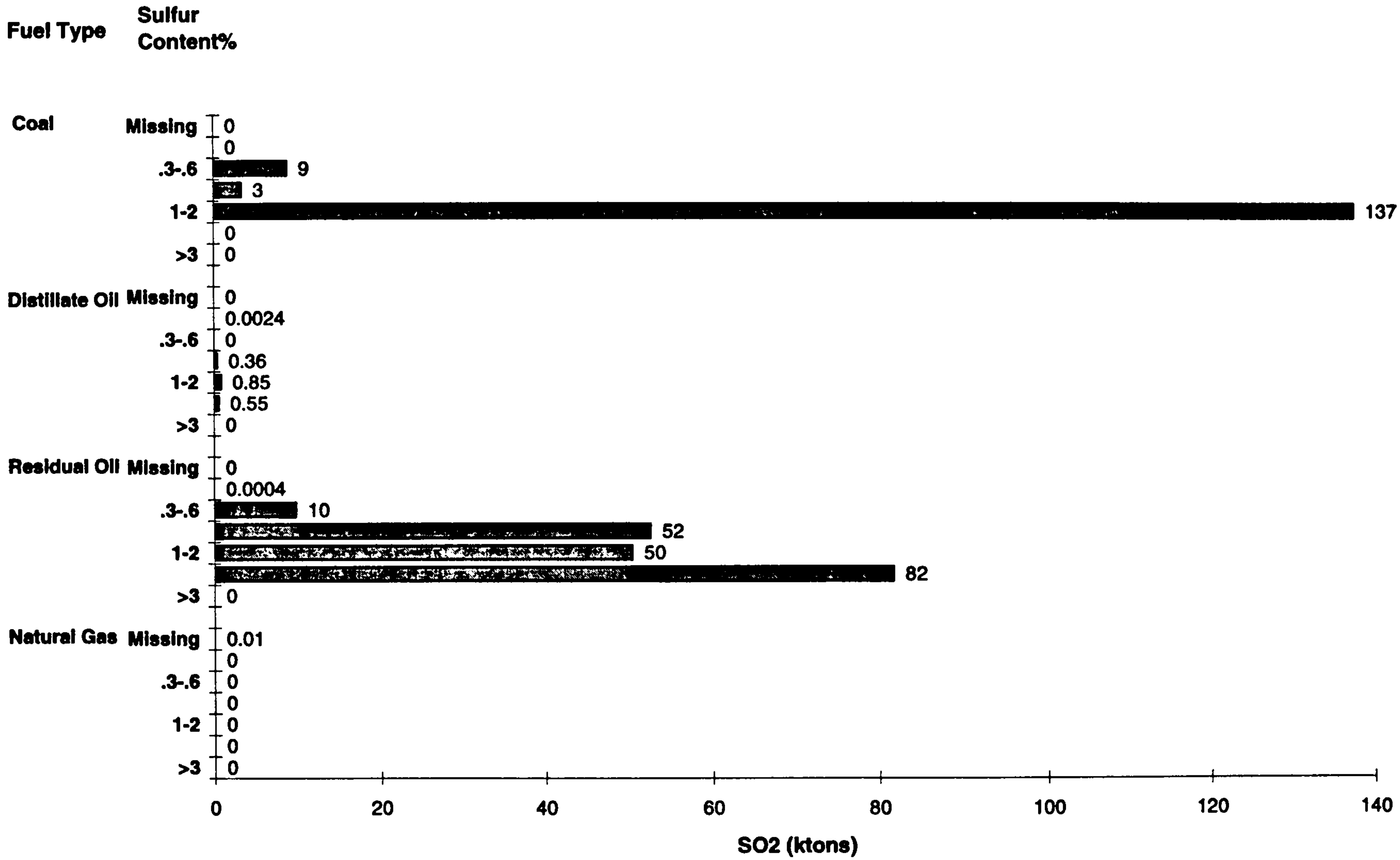


Figure 30
Region 1 SO2 Emissions by Fuel Type and Boiler Capacity
(345 ktons total)

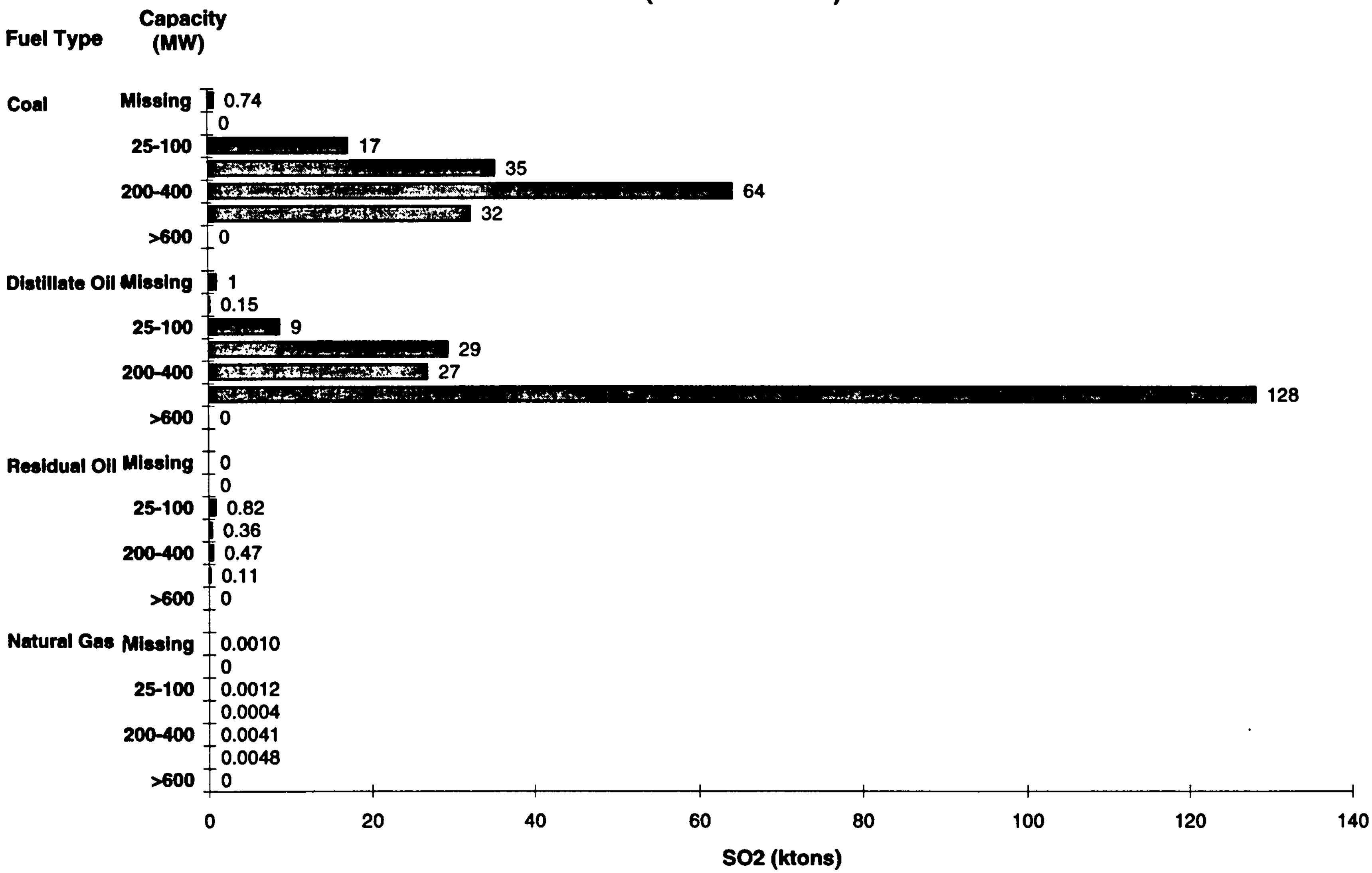


Figure 31
Region 1 Coal SO2 Emissions (ktons) for Scrubbed and Not Scrubbed Coal

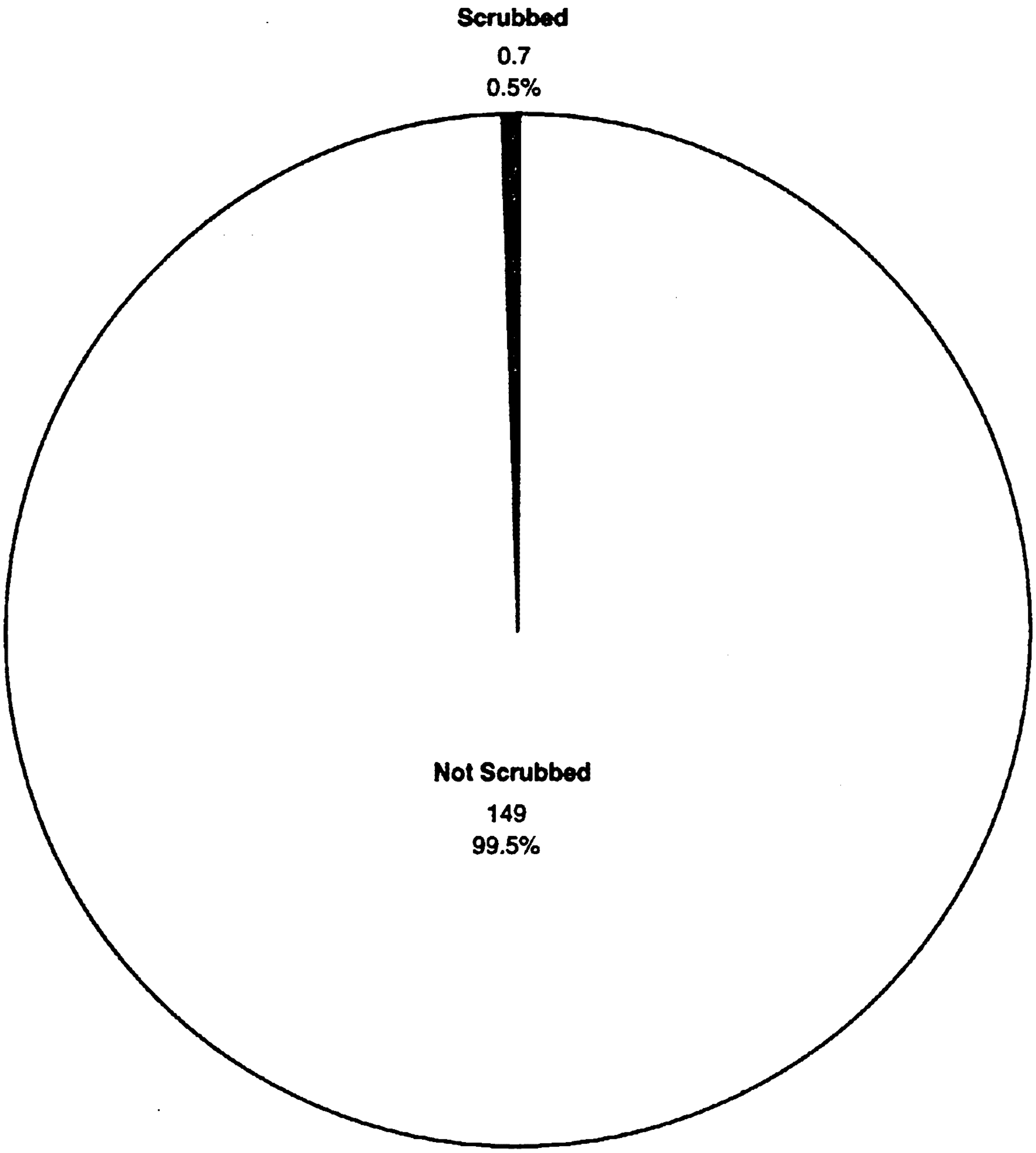


Figure 32
Region 2 SO2 Emissions by Fuel Type
(454 ktons total)

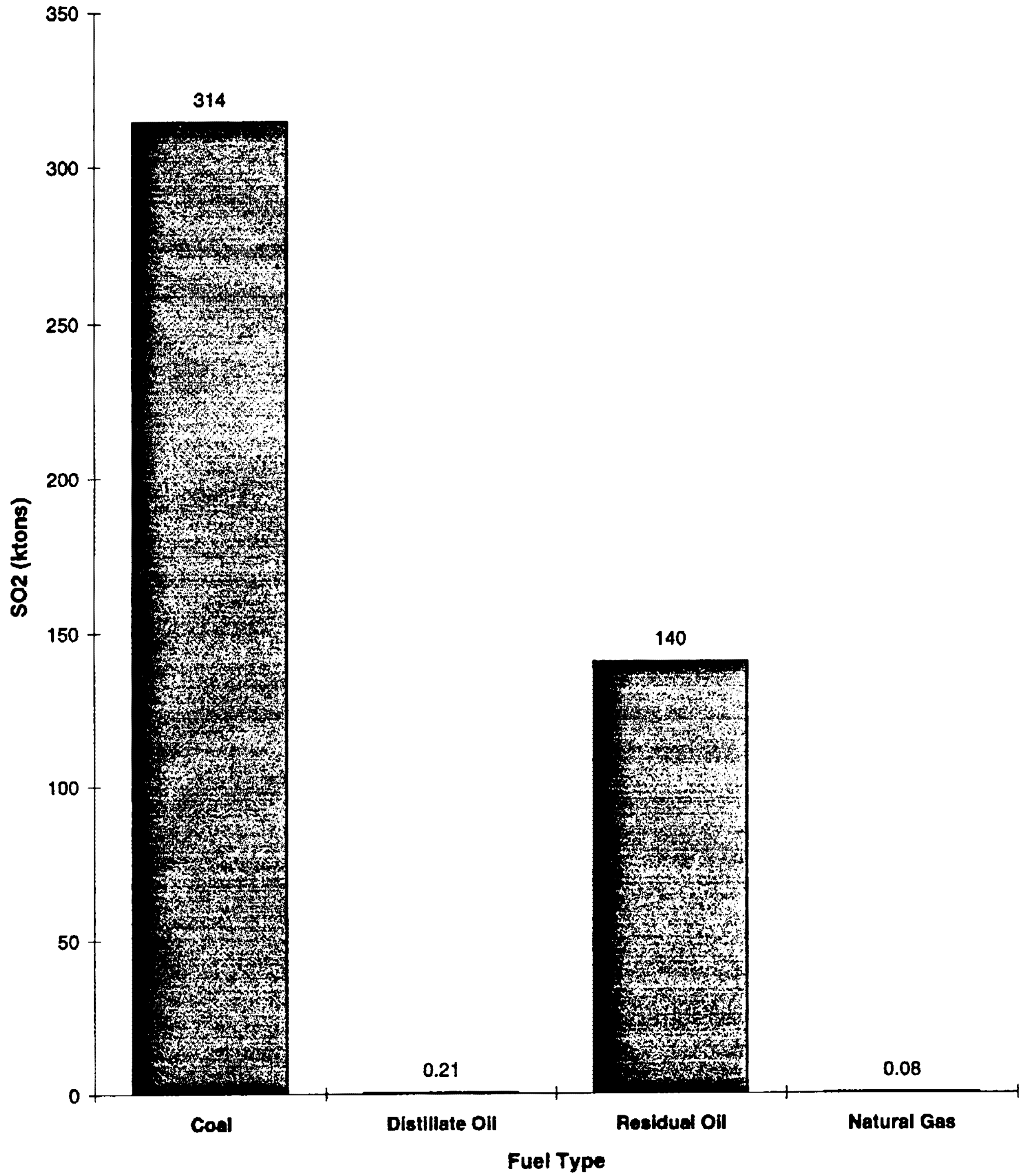


Figure 33
Region 2 NOx Emissions by Fuel Type
(221 ktons total)

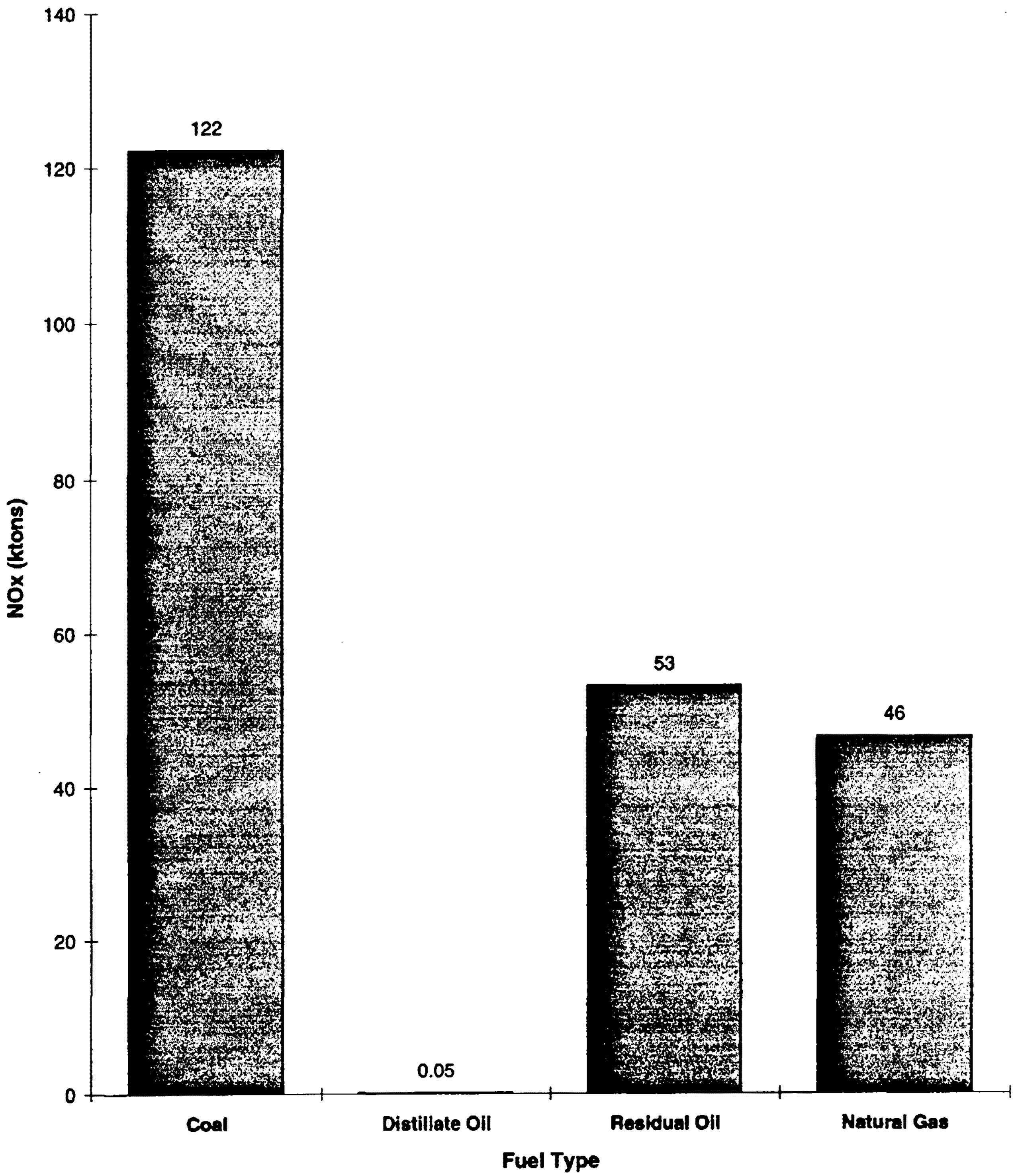


Figure 34
Region 2 SO2 Emissions by Fuel Type and Sulfur Content
(454 ktons total)

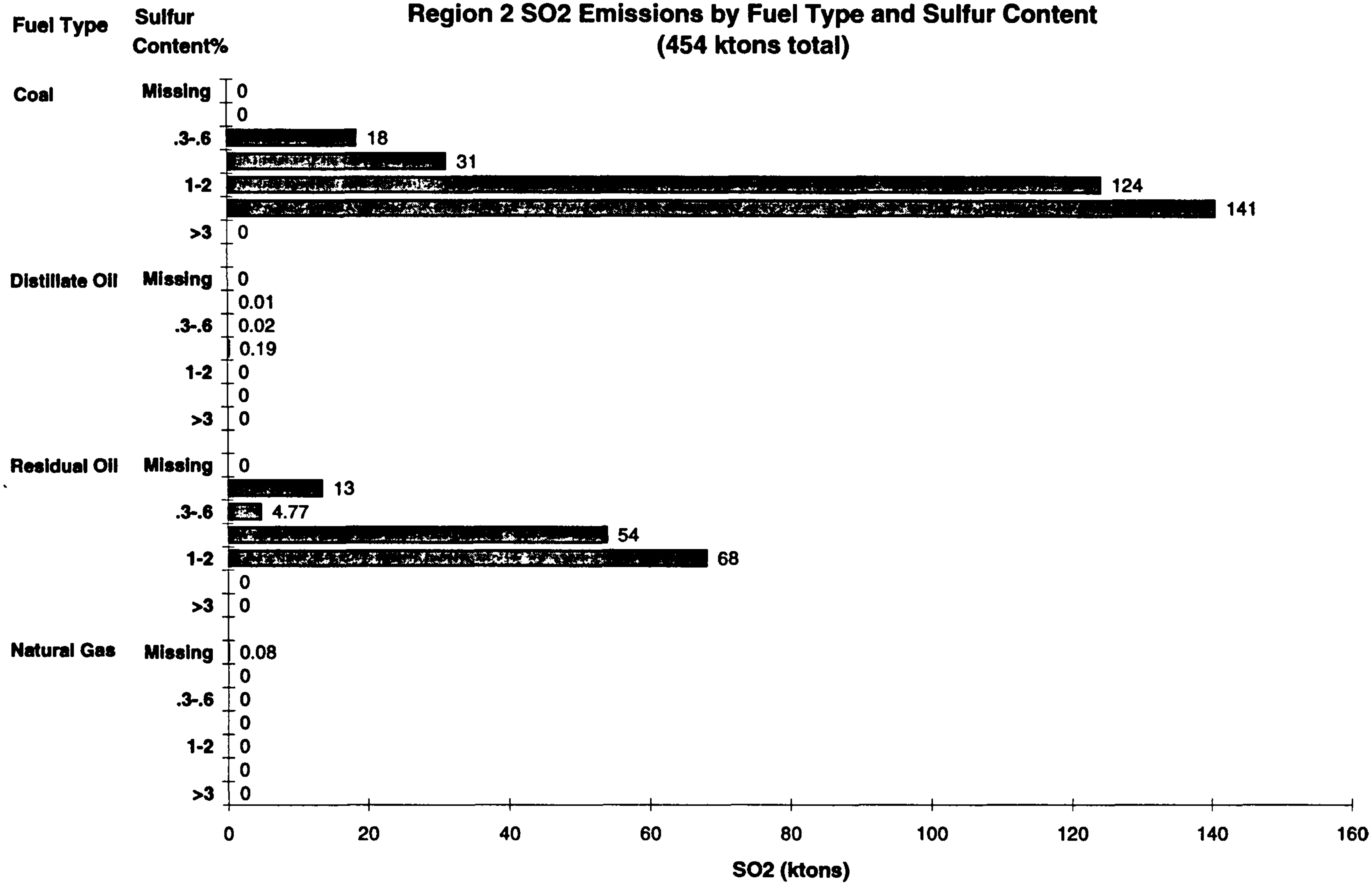


Figure 35
Region 2 SO2 Emissions by Fuel Type and Boiler Capacity
(454 ktons total)

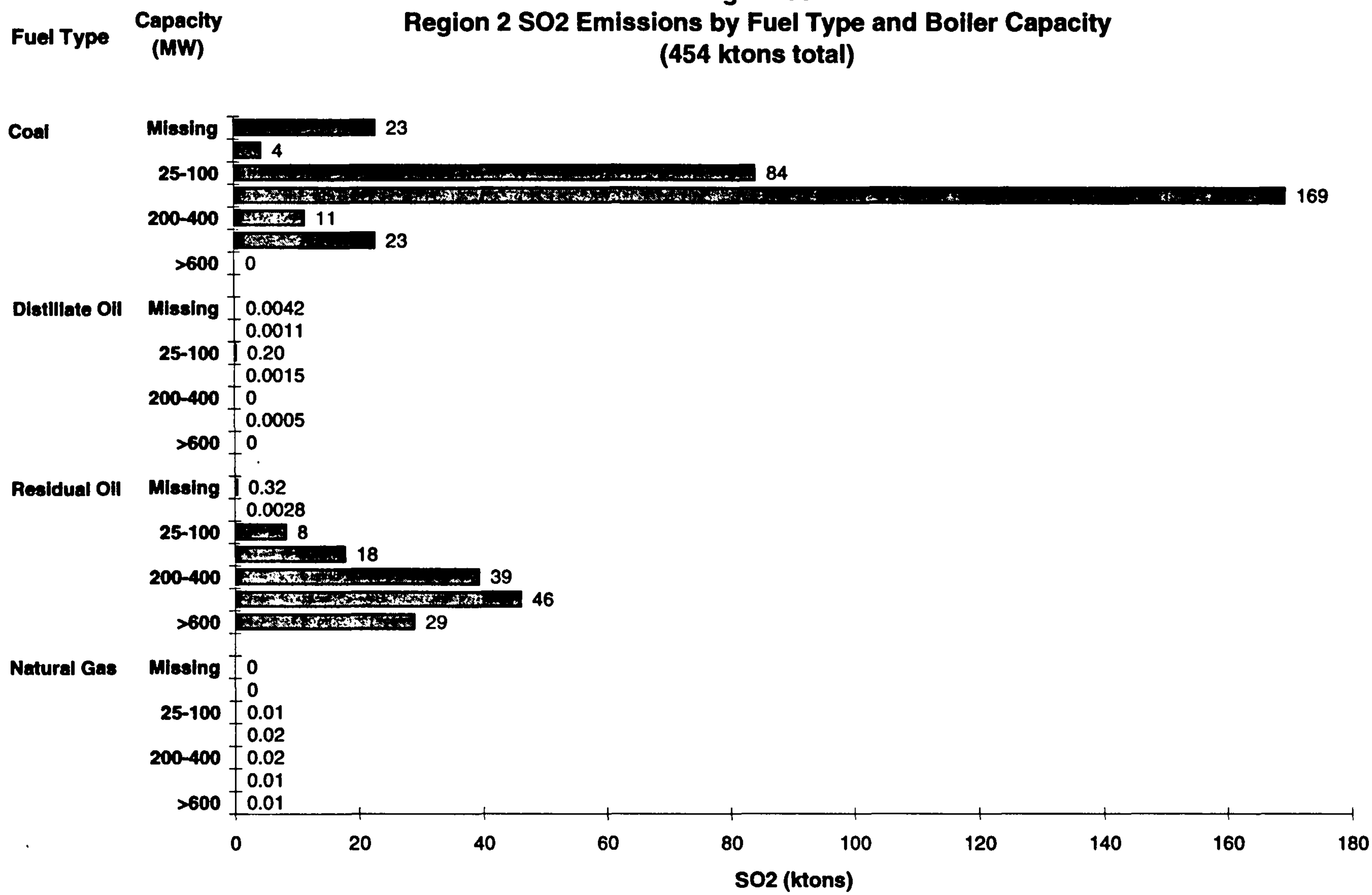


Figure 36
Region 2 Coal SO2 Emissions (ktons) for Scrubbed and Not Scrubbed Coal

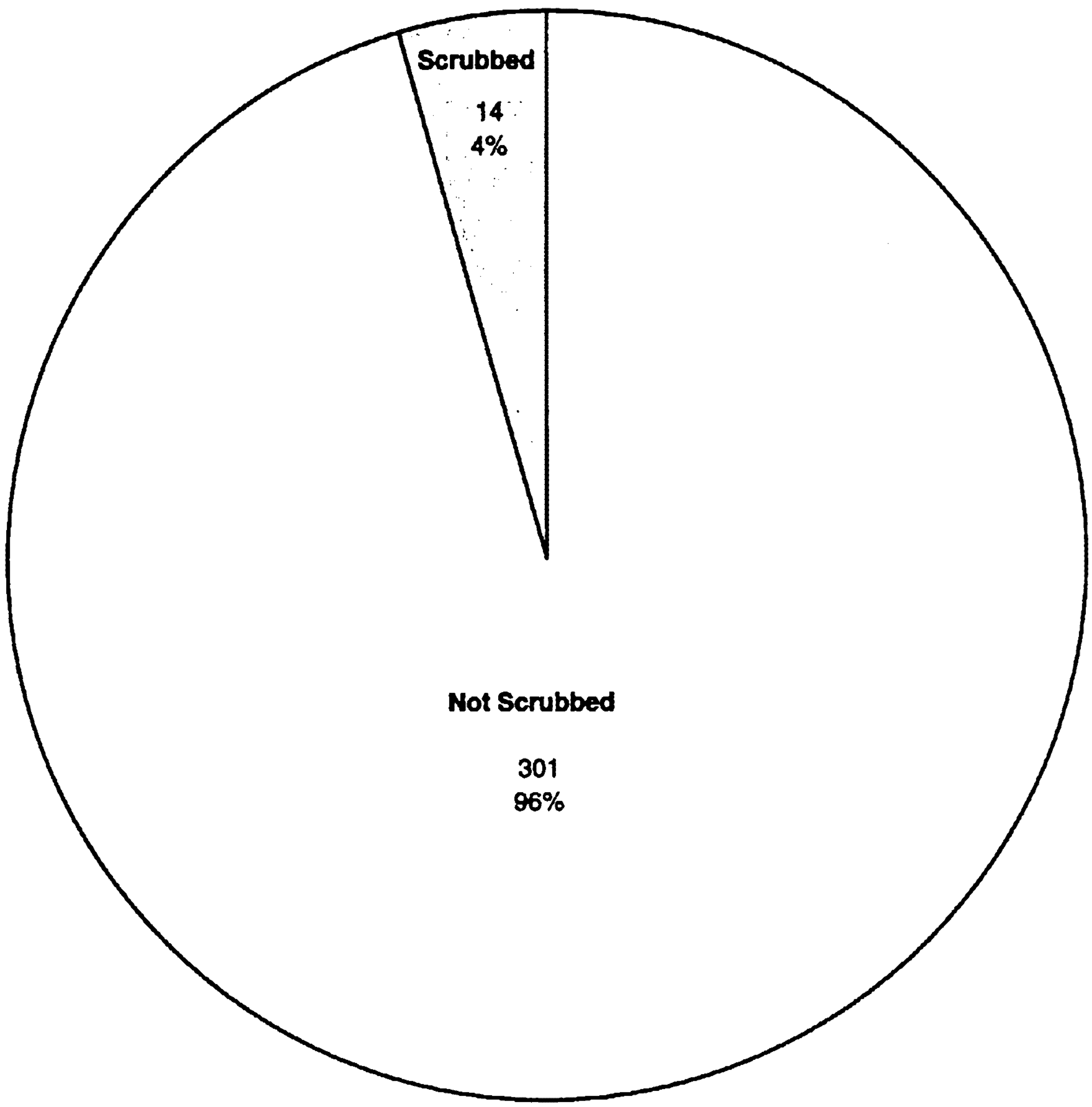


Figure 37
Region 3 SO2 Emissions by Fuel Type
(2,784 ktons total)

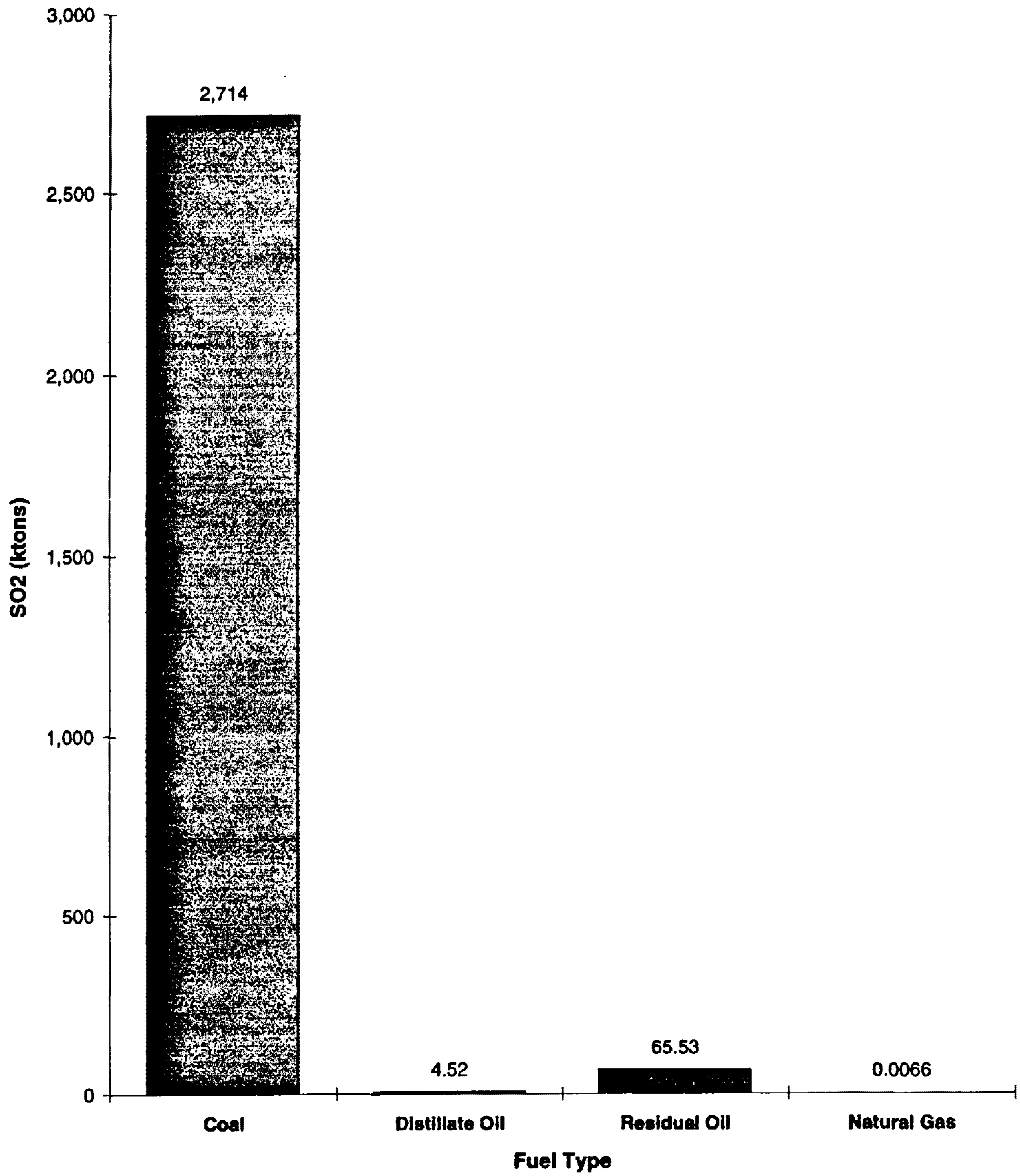


Figure 38
Region 3 NOx Emissions by Fuel Type
(835 ktons total)

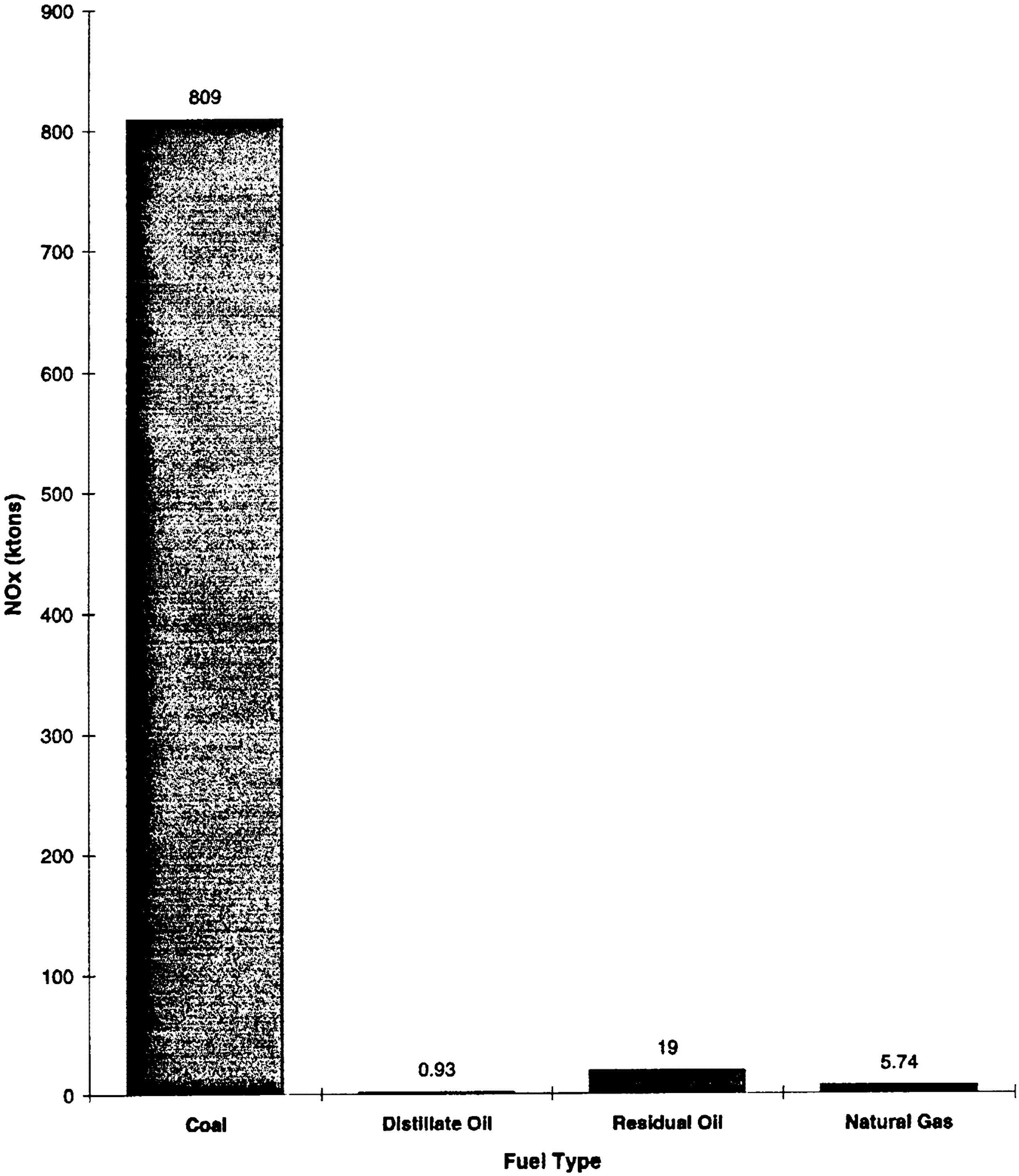


Figure 39
Region 3 SO2 Emissions by Fuel Type and Sulfur Content
(2784 ktons total)

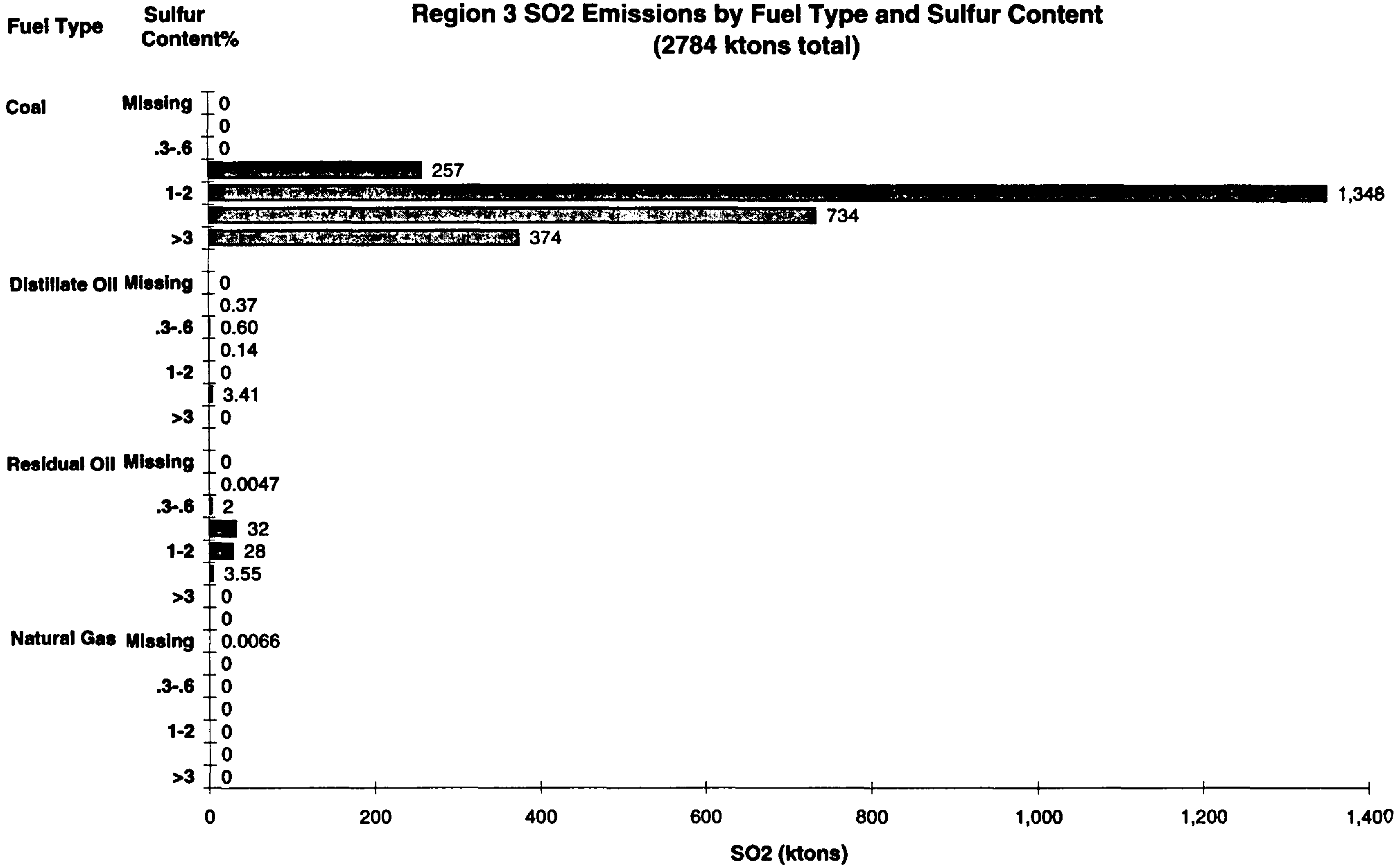


Figure 40
Region 3 SO2 Emissions by Fuel Type and Boiler Capacity
(2,784 ktons total)

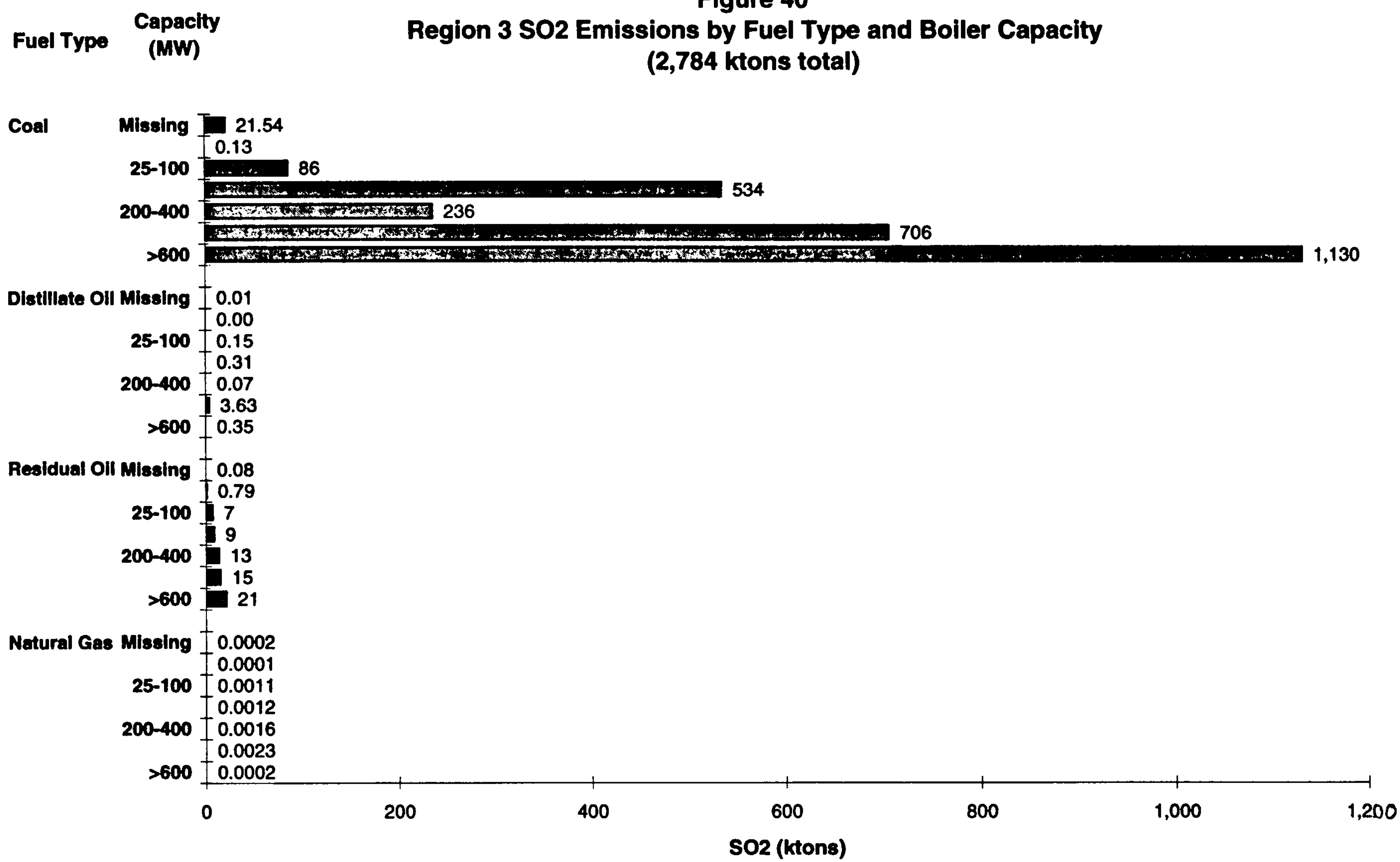


Figure 41
Region 3 Coal SO2 Emissions (ktons) for Scrubbed and Not Scrubbed Coal

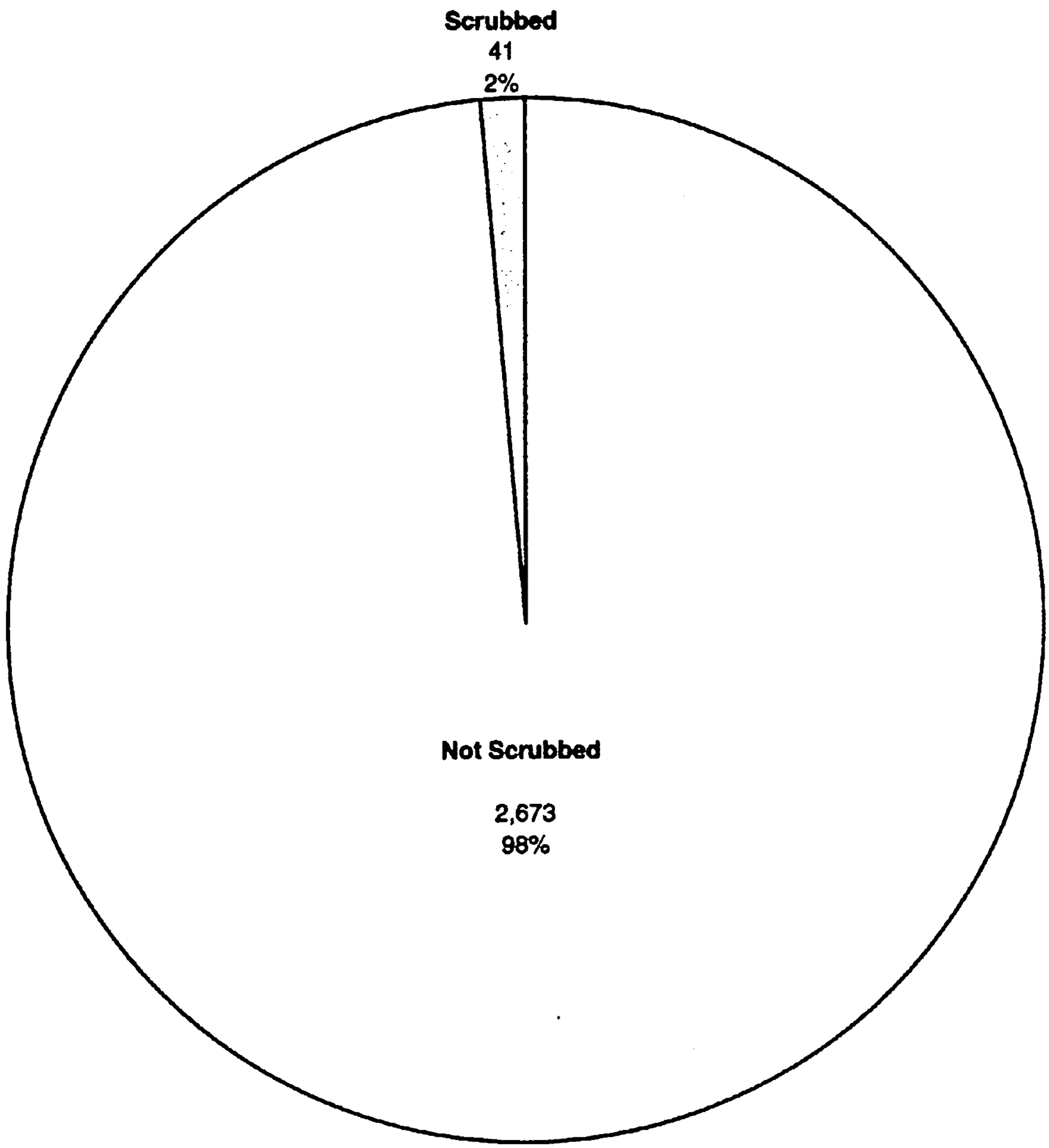


Figure 42
Region 4 SO2 Emissions by Fuel Type
(4,283 ktons total)

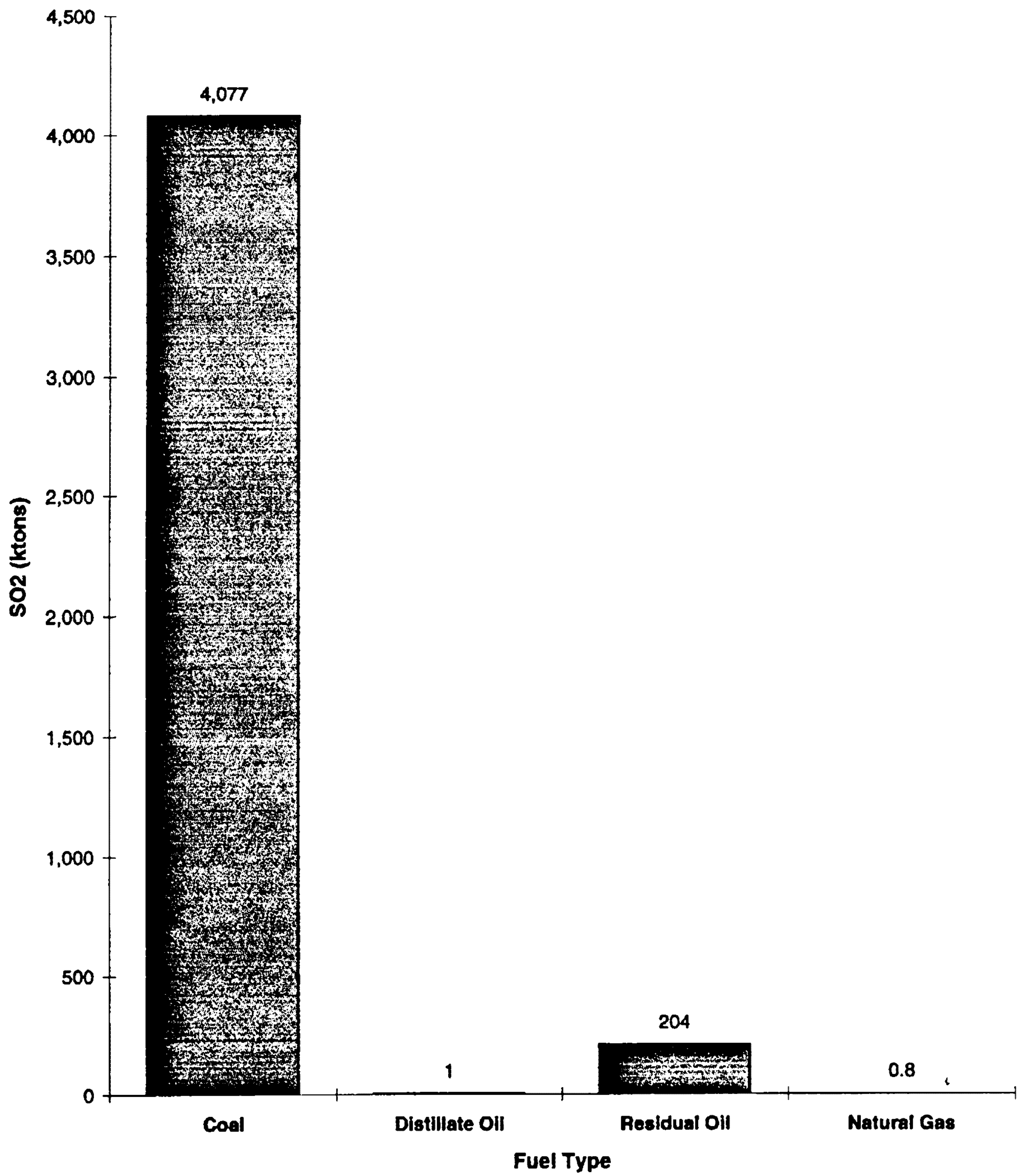


Figure 43
Region 4 NOx Emissions by Fuel Type
(1,560 ktons total)

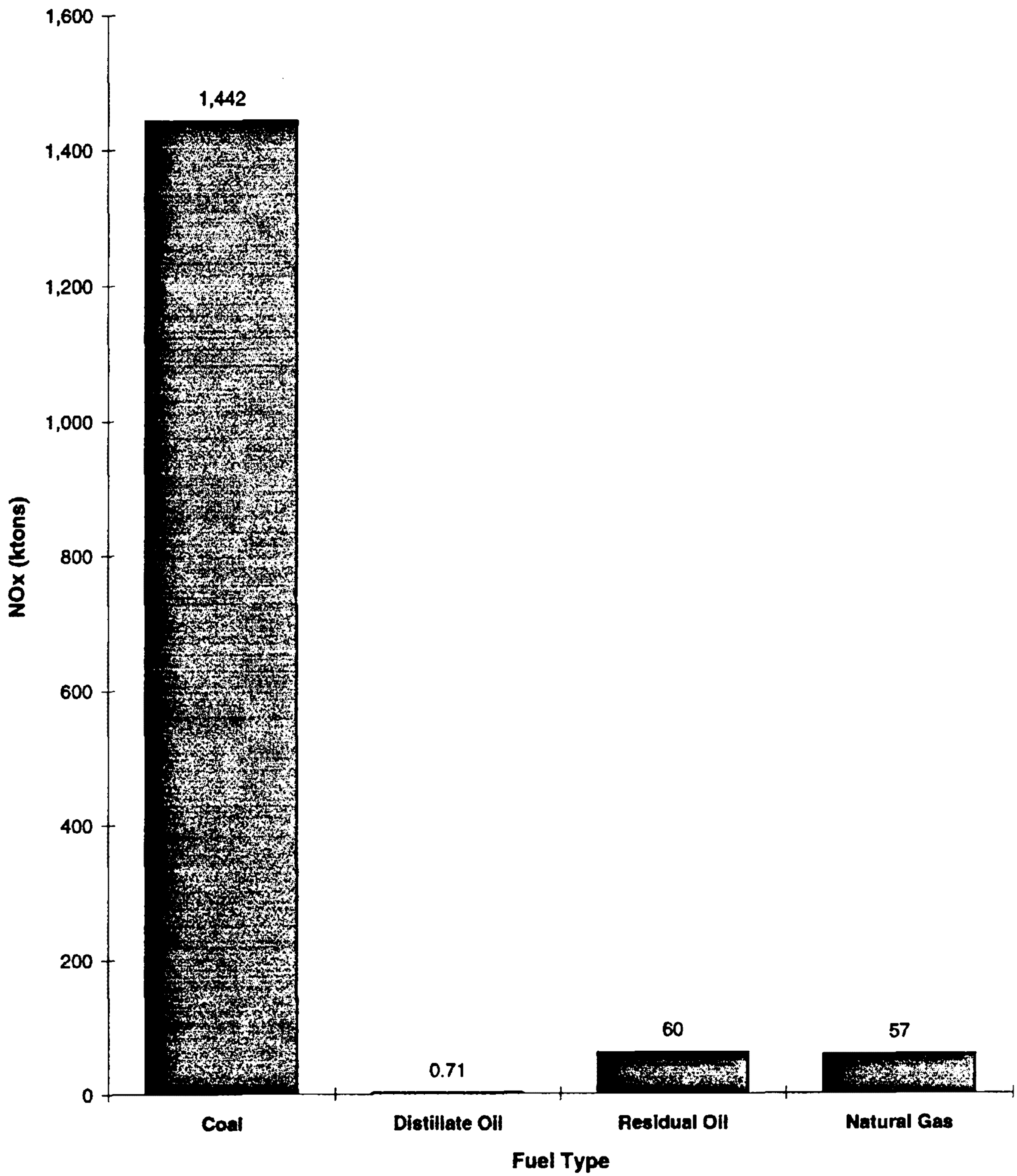


Figure 44
Region 4 SO2 Emissions by Fuel Type and Sulfur Content
(4,283 ktons total)

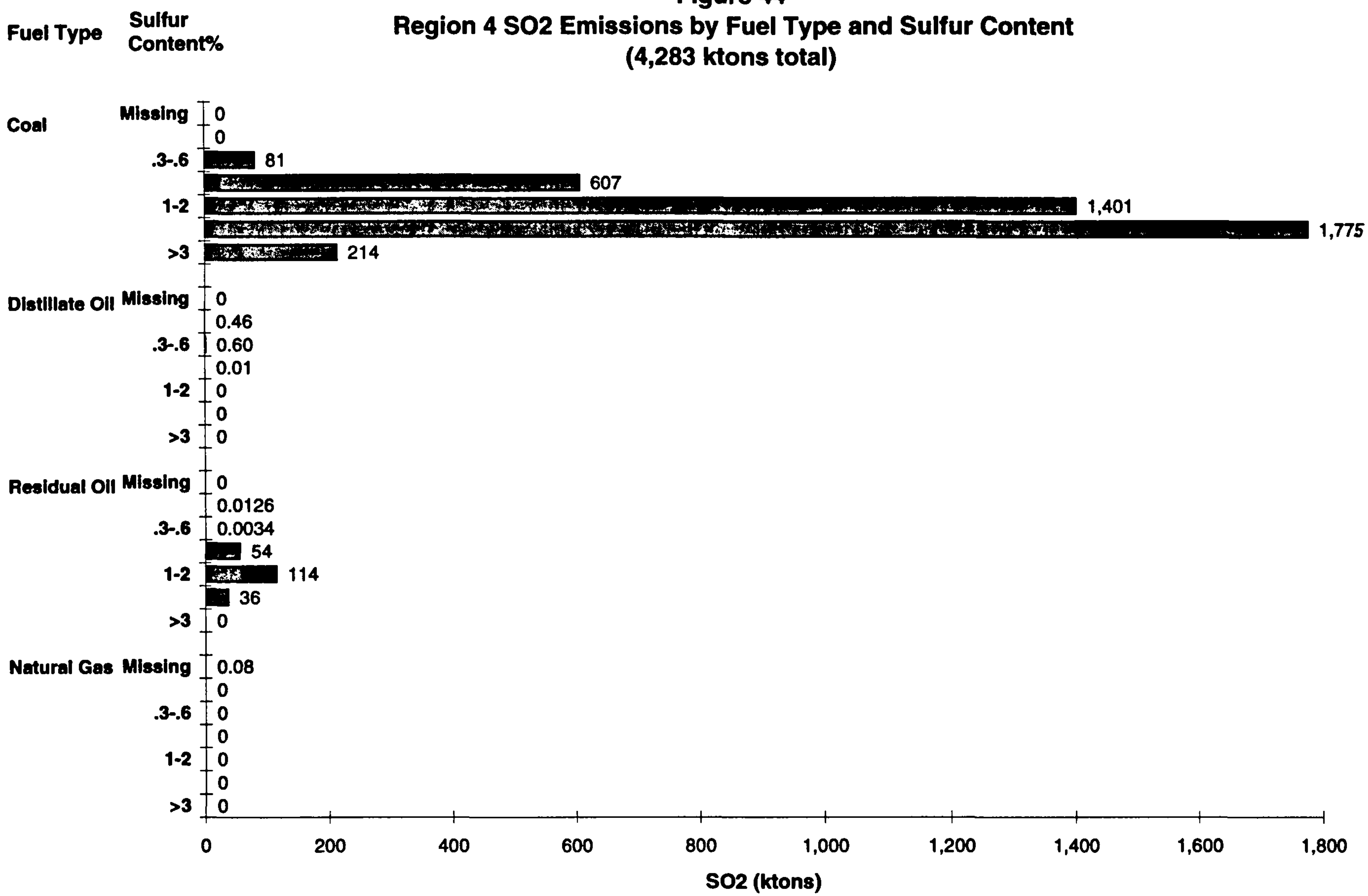


Figure 45
Region 4 SO2 Emissions by Fuel Type and Boiler Capacity
(4,283 ktons total)

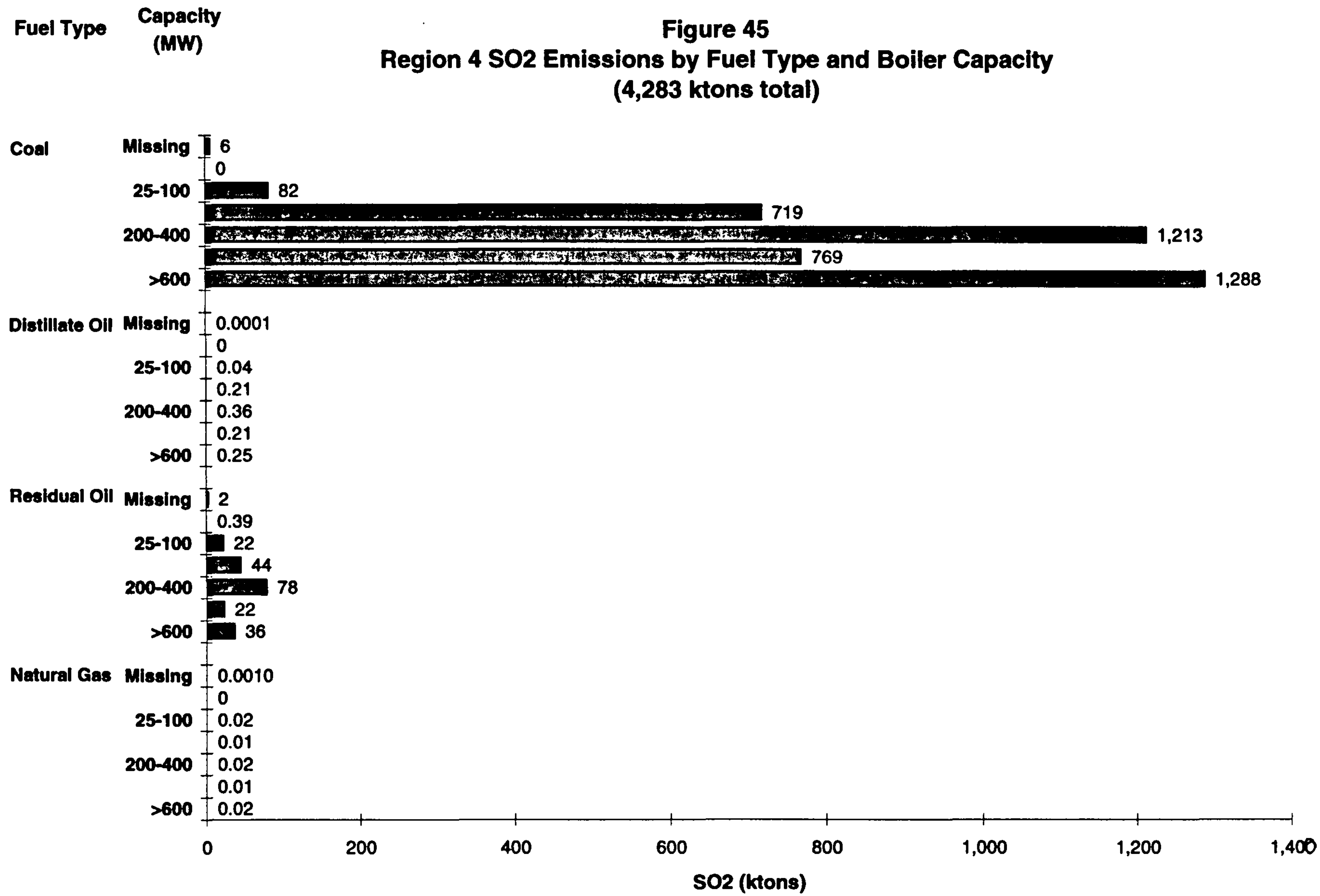


Figure 46
Region 4 Coal SO2 Emissions (ktons) for Scrubbed and Not Scrubbed Coal

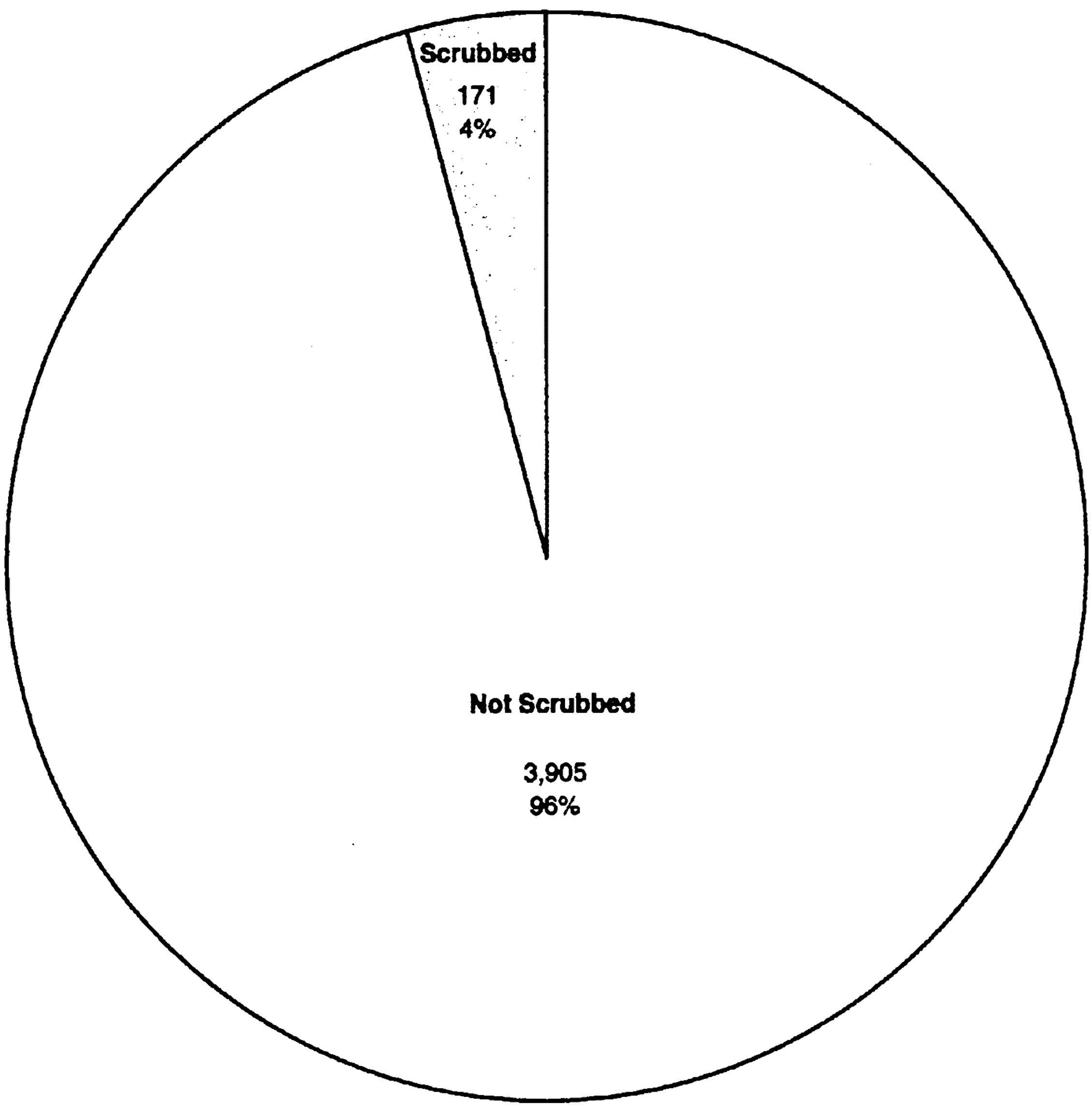


Figure 47
Region 5 SO2 Emissions by Fuel Type
(5,339 ktons total)

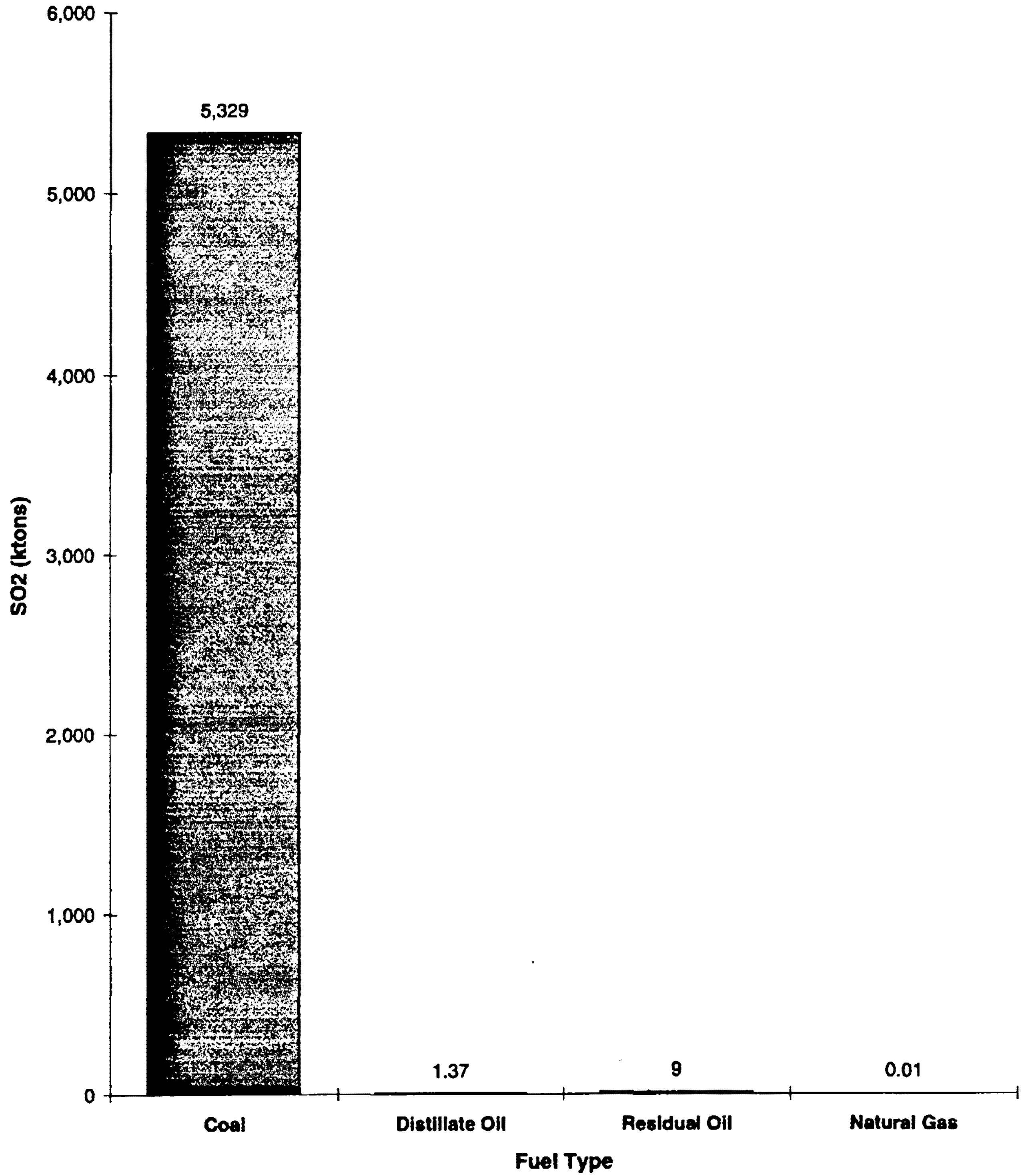


Figure 48
Region 5 NOx Emissions by Fuel Type
(1,947 ktons total)

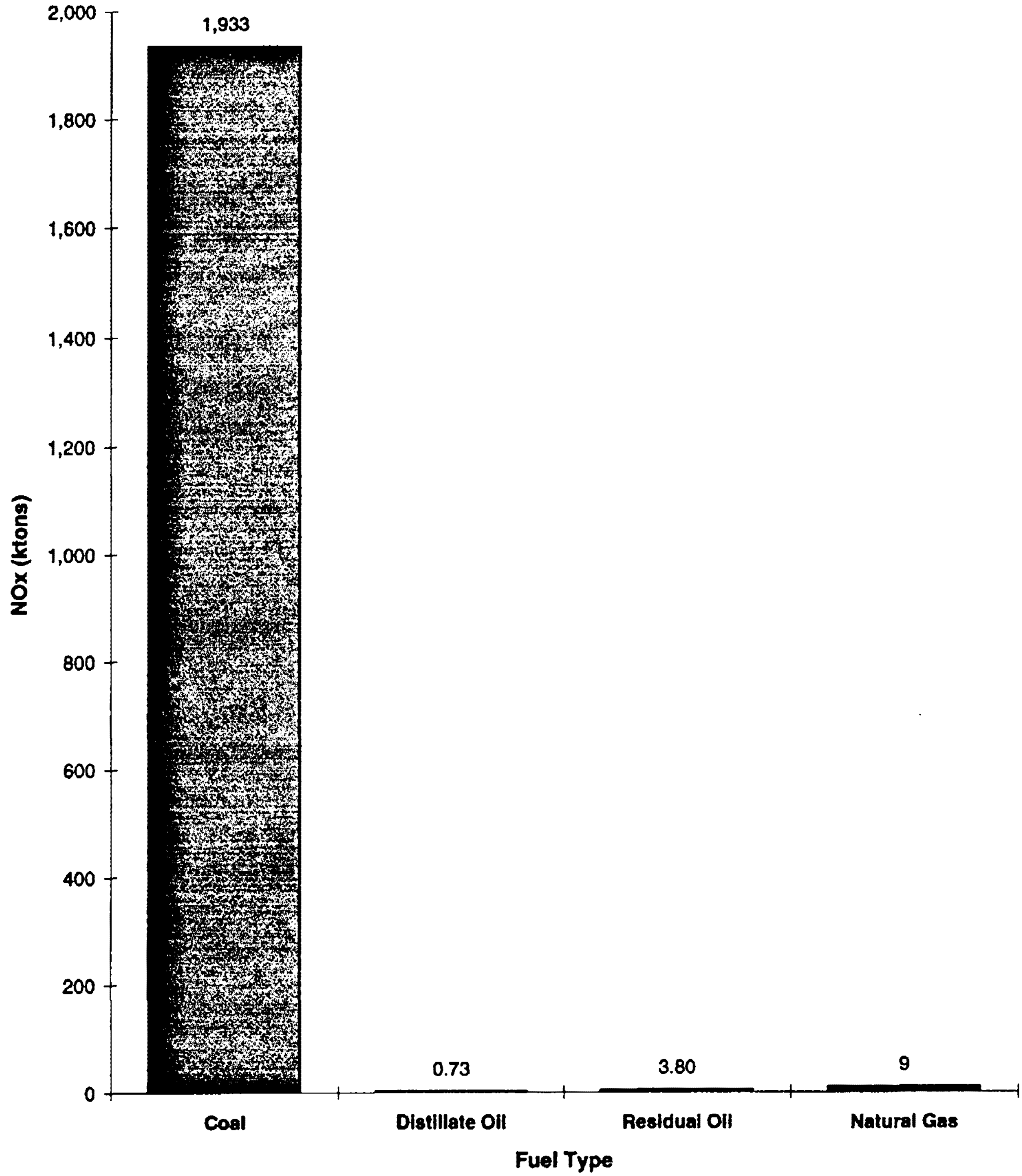


Figure 49
Region 5 SO2 Emissions by Fuel Type and Sulfur Content
(5,339 ktons total)

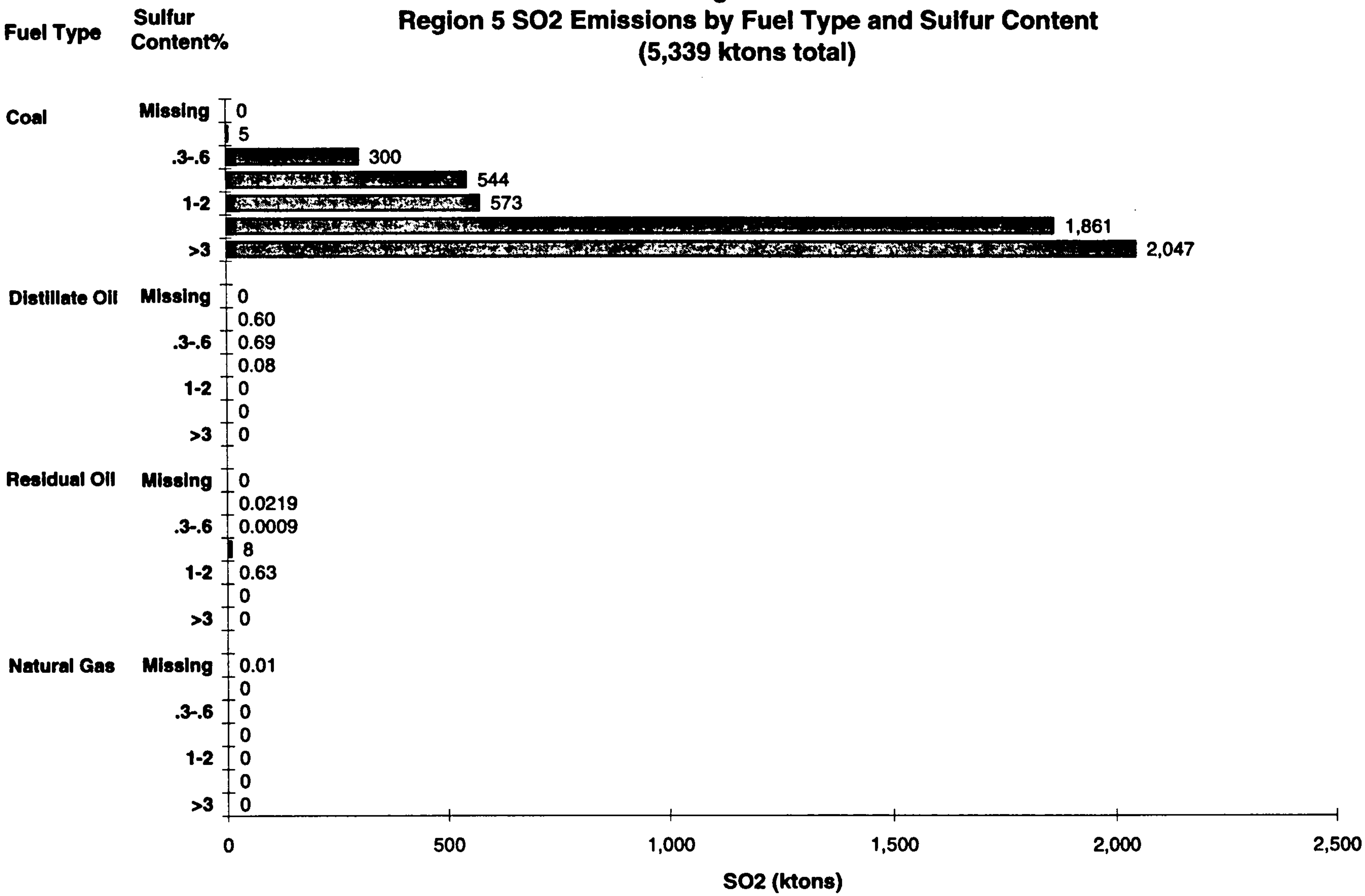


Figure 50
Region 5 SO2 Emissions by Fuel Type and Boiler Capacity
(5,339 ktons total)

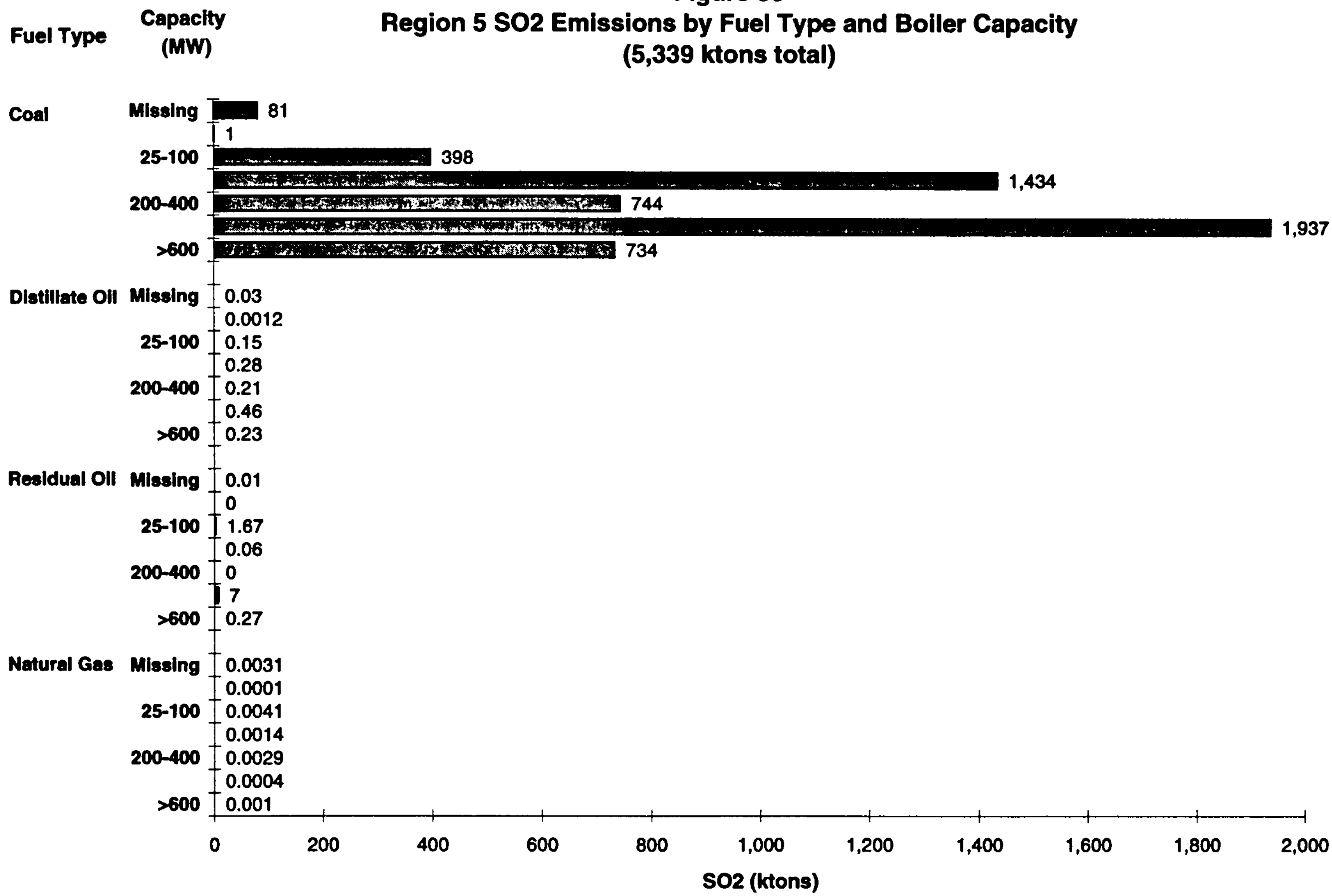


Figure 51
Region 5 Coal SO2 Emissions (ktons) for Scrubbed and Not Scrubbed Coal

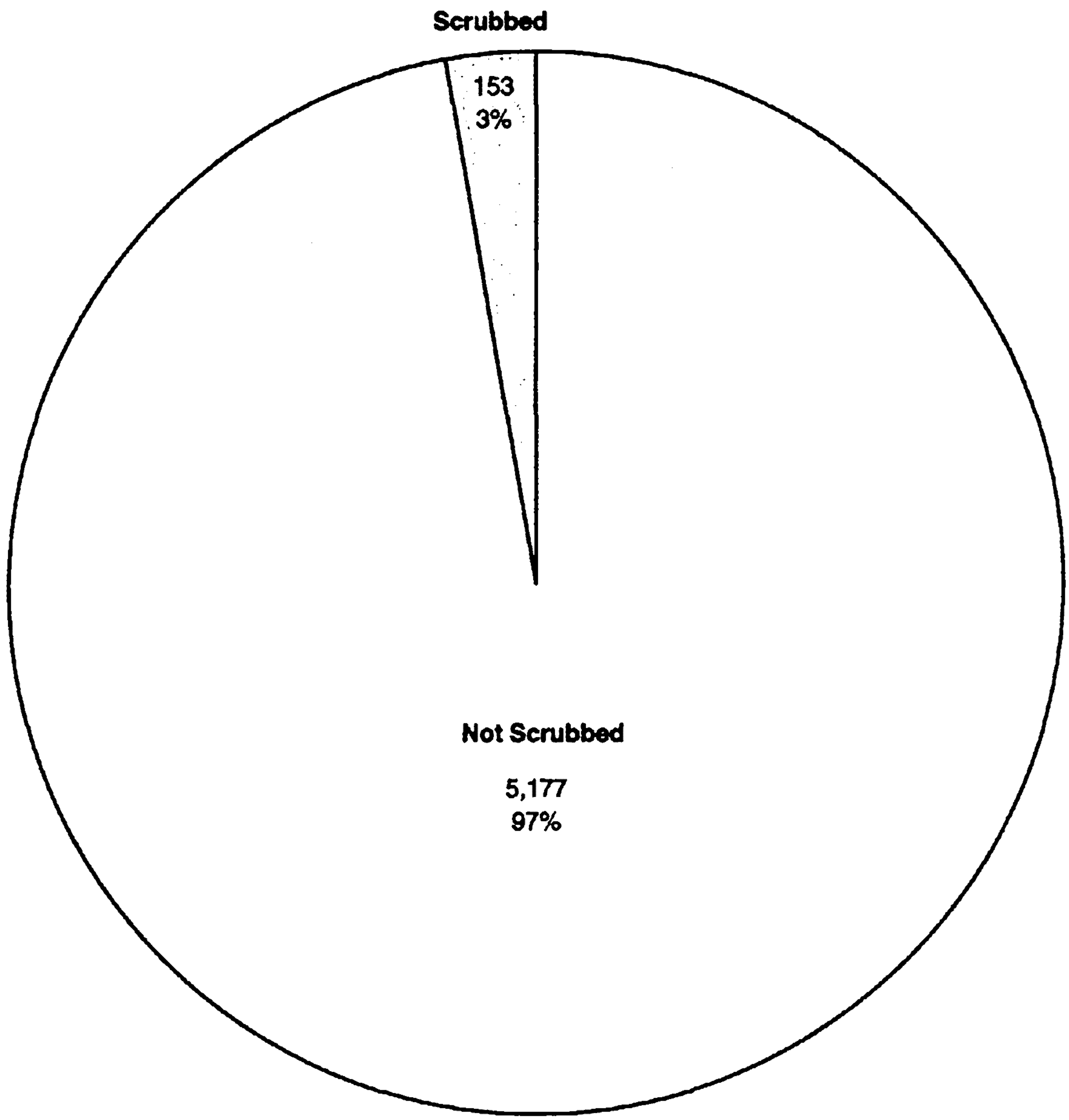


Figure 52
Region 6 SO2 Emissions by Fuel Type
(803 ktons total)

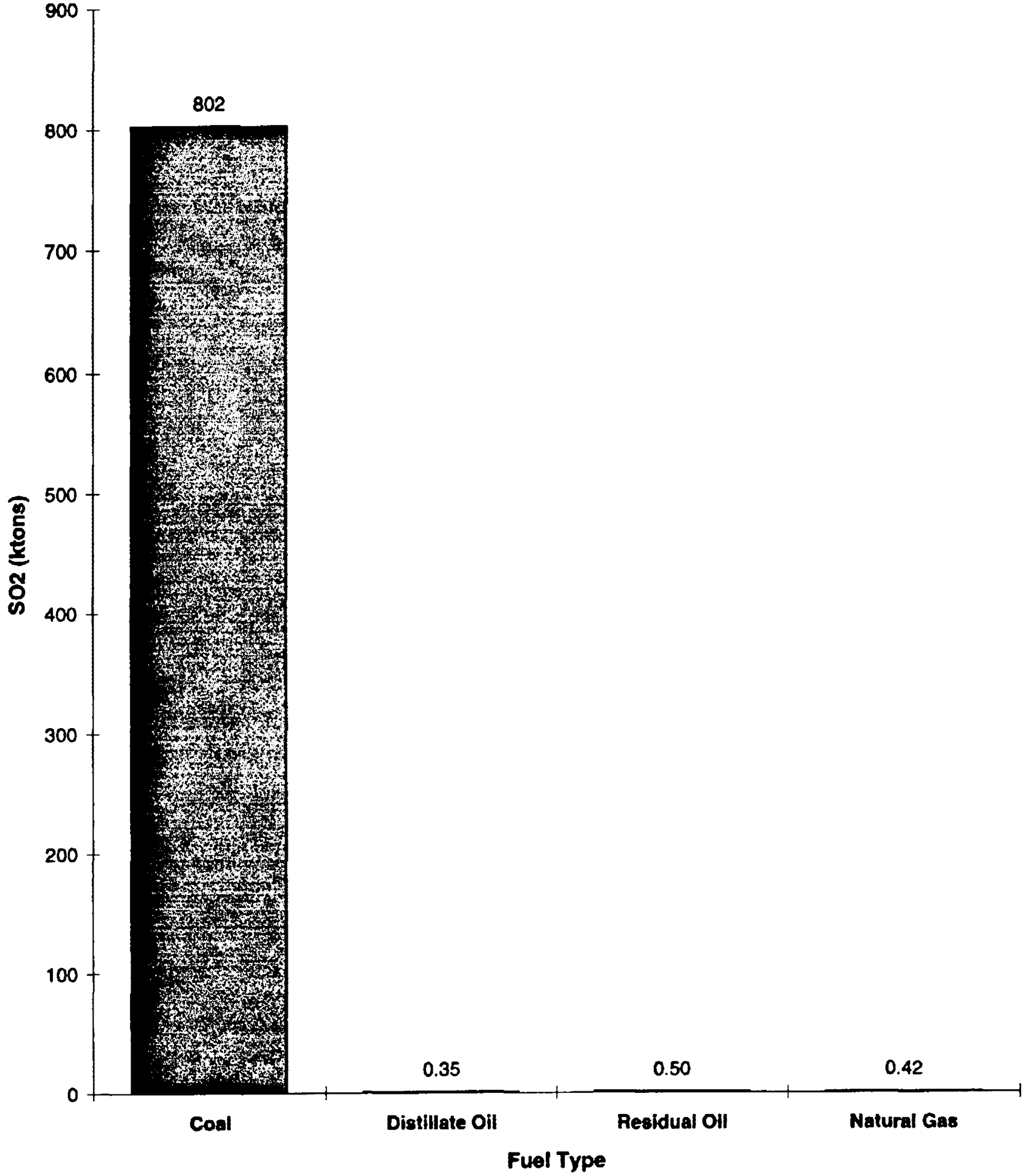


Figure 53
Region 6 NOx Emissions by Fuel Type
(1,053 ktons total)

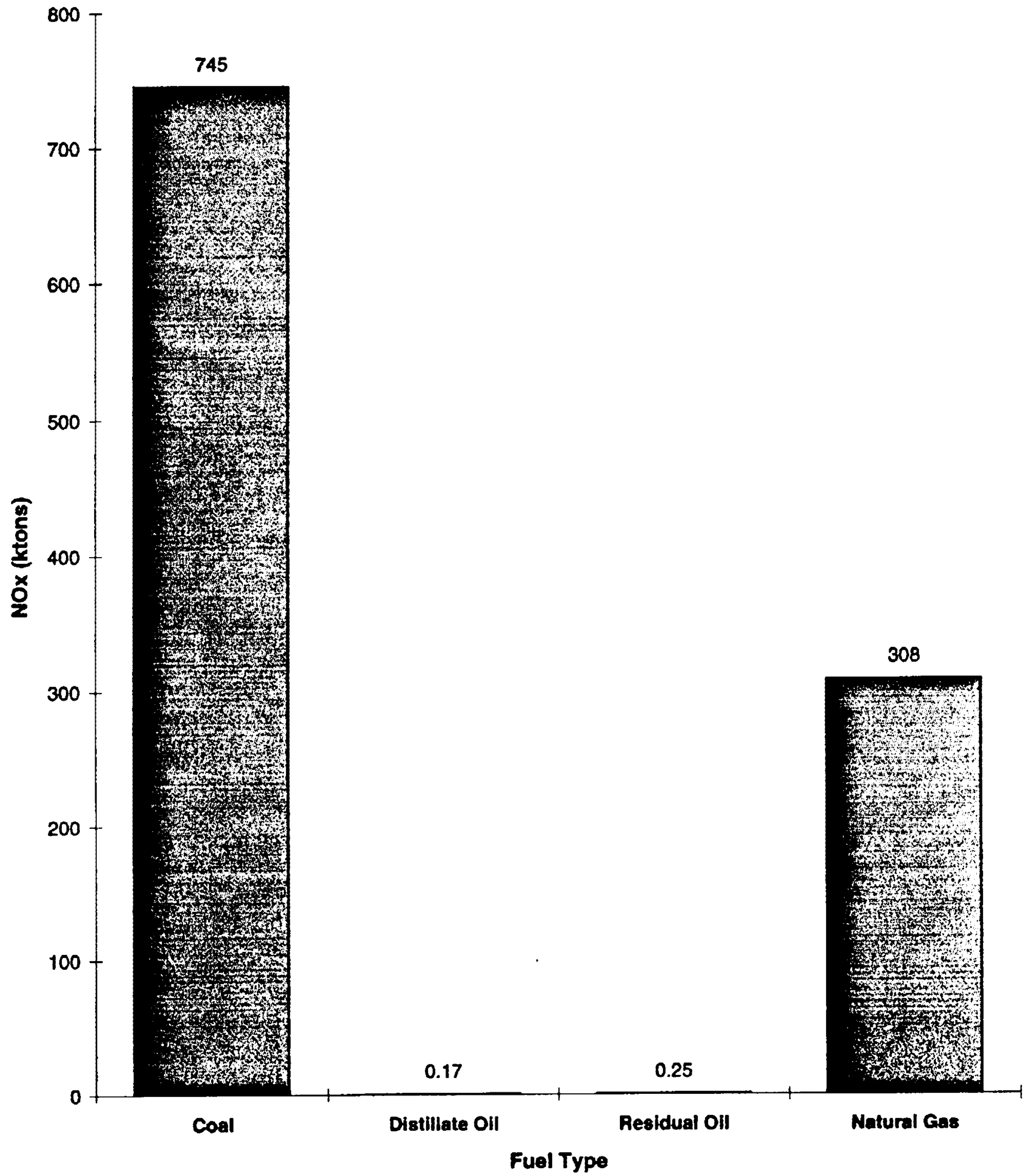


Figure 54
Region 6 SO2 Emissions by Fuel Type and Sulfur Content
(803 ktons total)

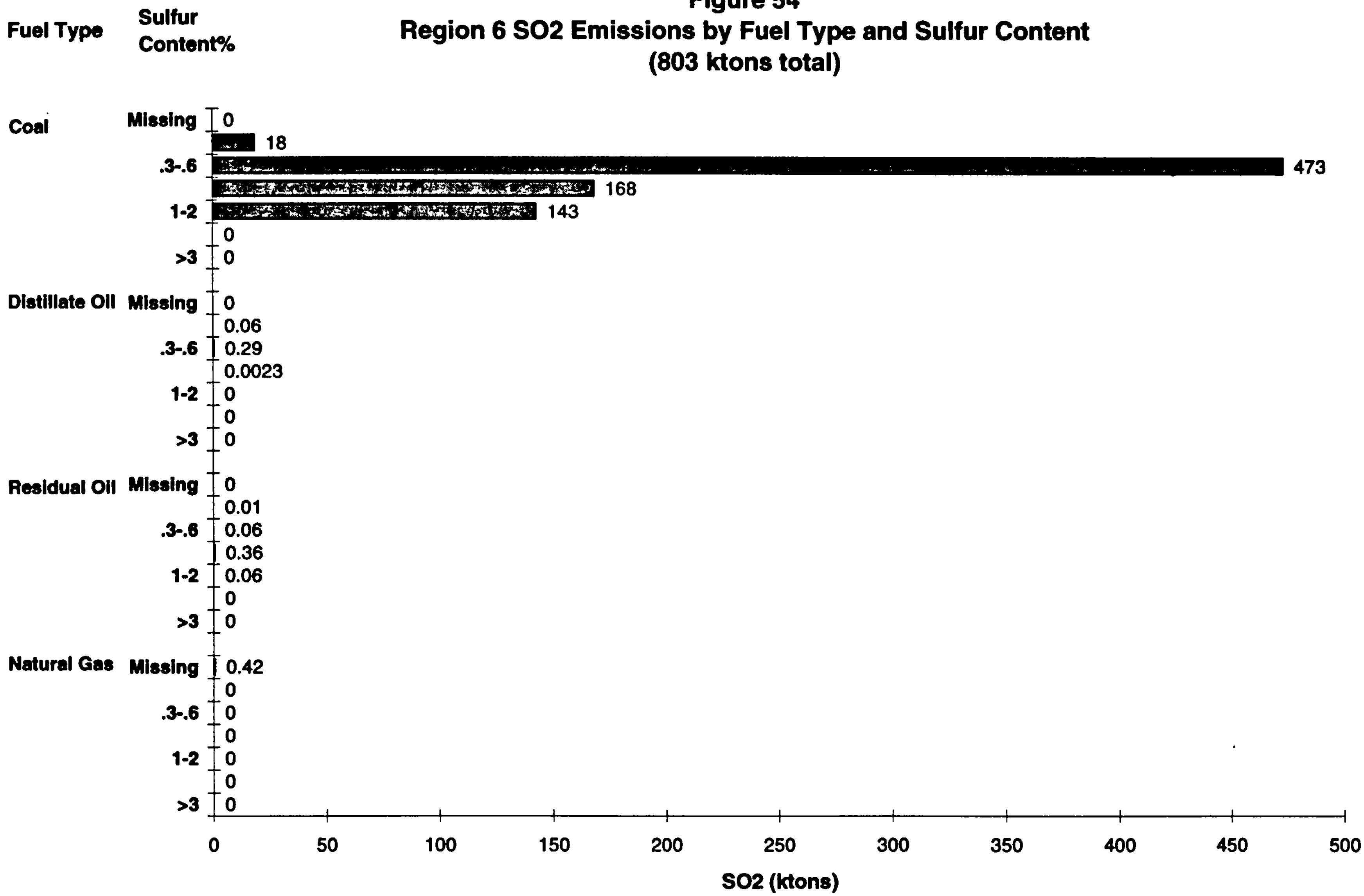


Figure 55
Region 6 SO2 Emissions by Fuel Type and Boiler Capacity
(803 ktons total)

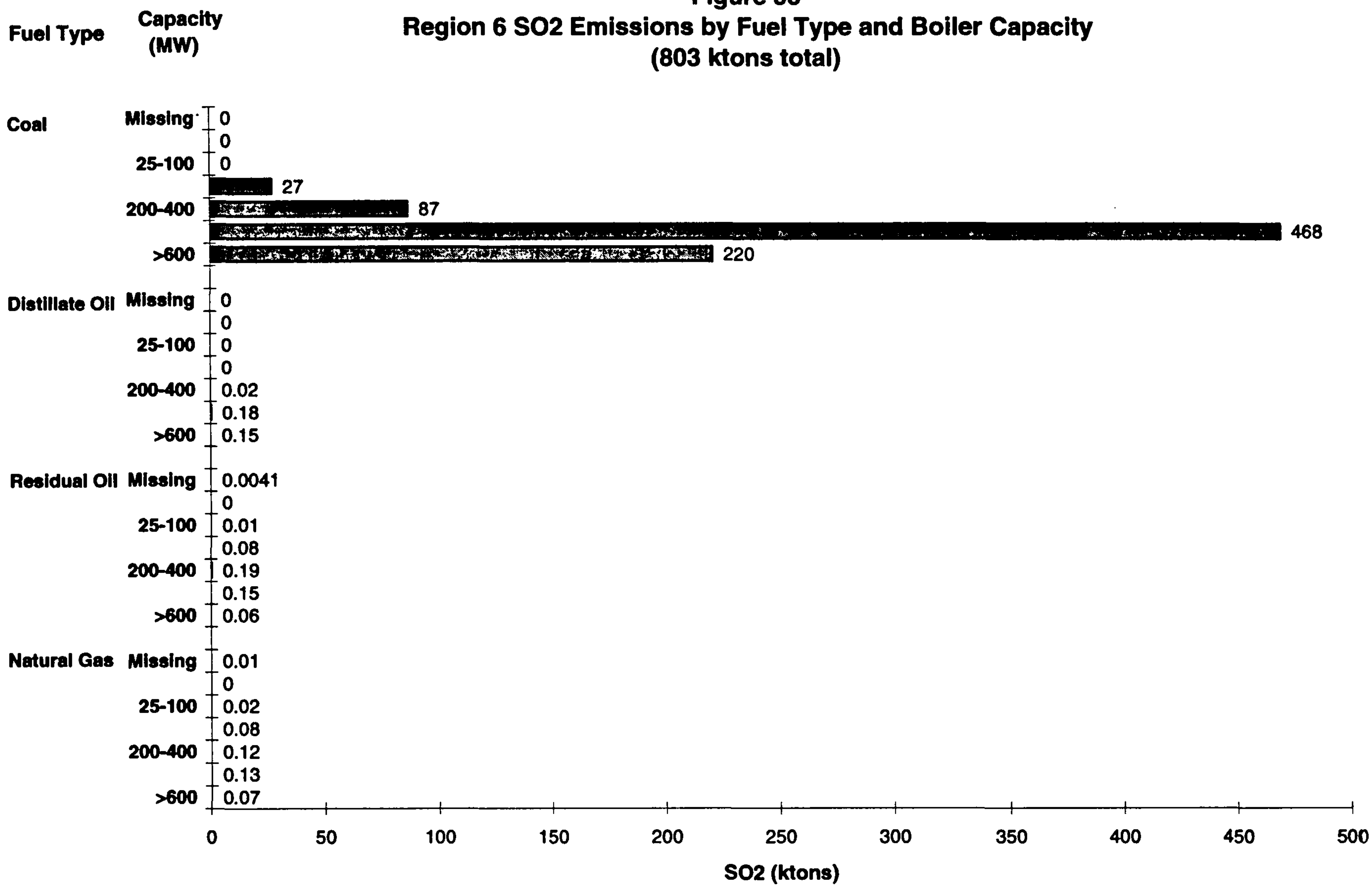


Figure 56
Region 6 Coal SO2 Emissions (ktons) for Scrubbed and Not Scrubbed Coal

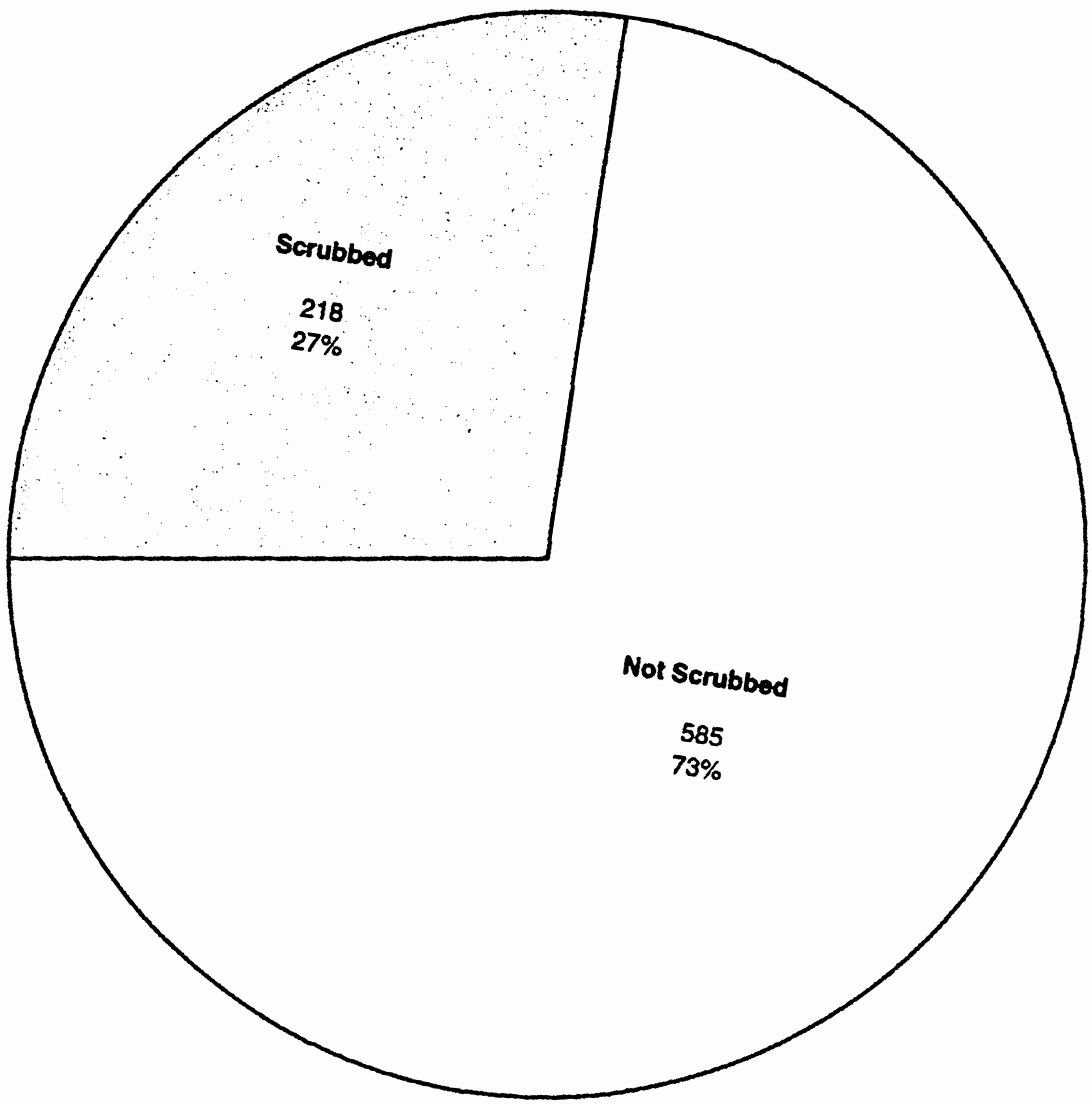


Figure 57
Region 7 SO2 Emissions by Fuel Type
(1,049 ktons total)

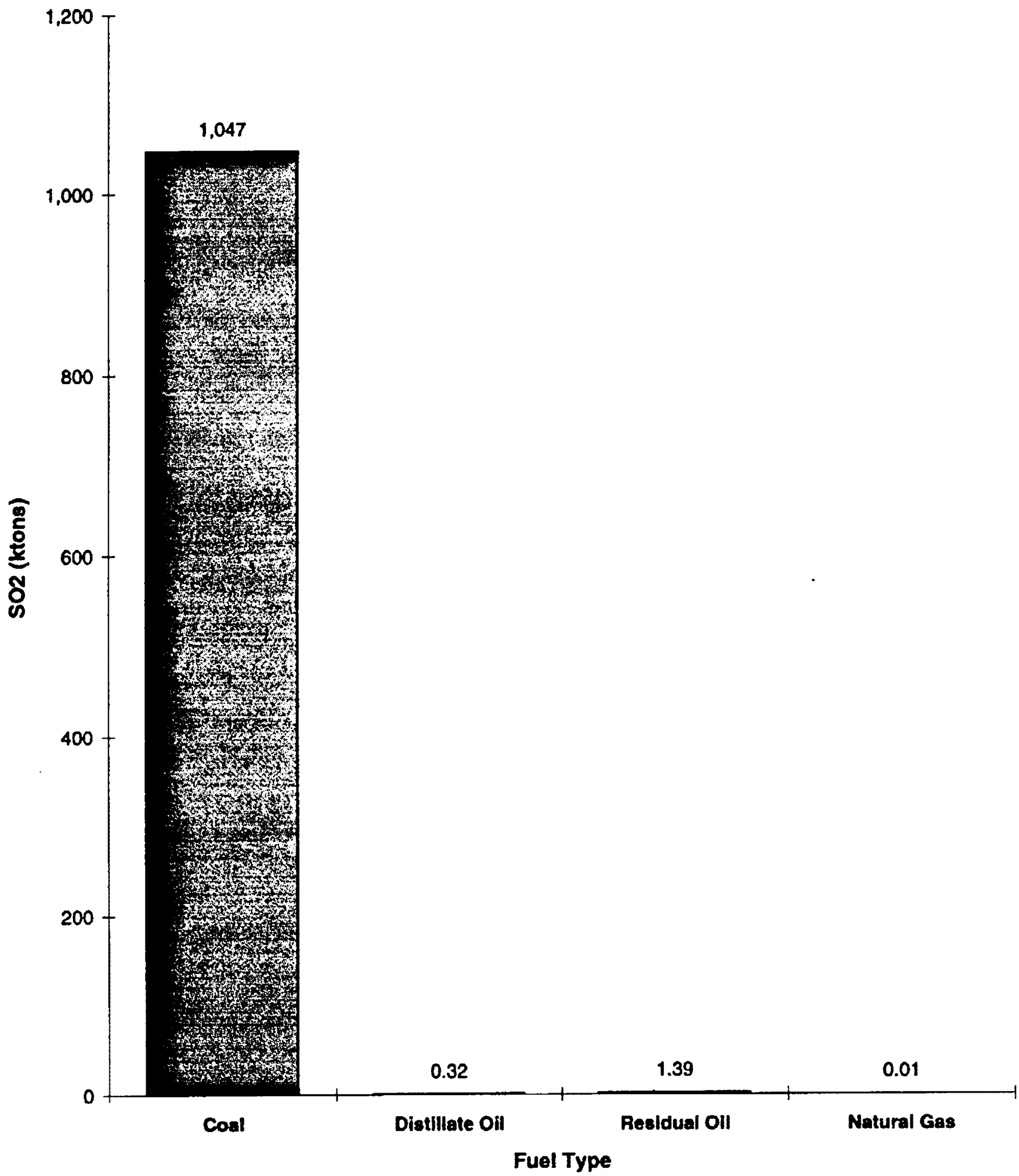


Figure 58
Region 7 NOx Emissions by Fuel Type
(562 ktons total)

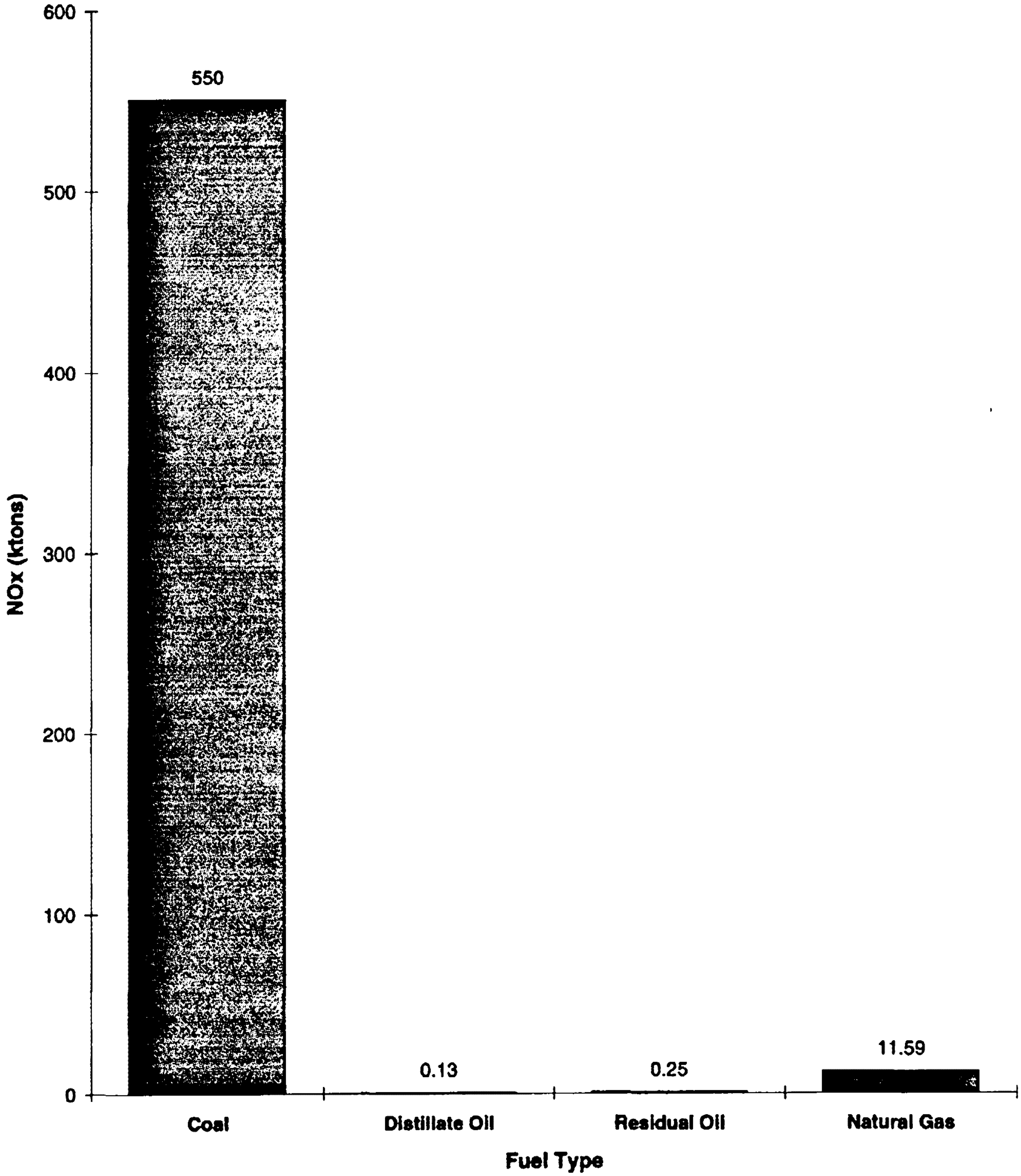


Figure 59
Region 7 SO2 Emissions by Fuel Type and Sulfur Content
(1,049 ktons total)

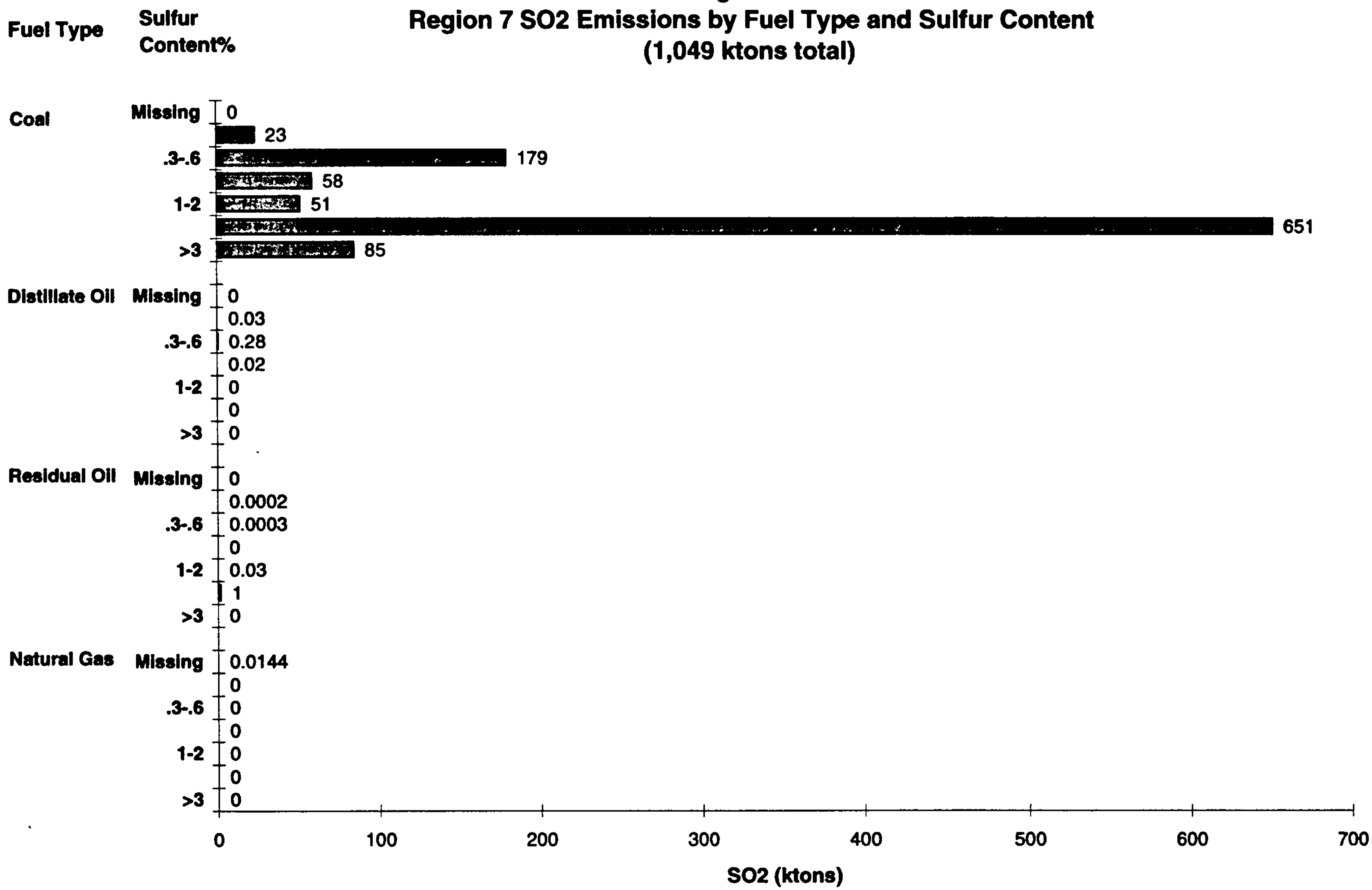


Figure 60
Region 7 SO2 Emissions by Fuel Type and Boiler Capacity
(1,049 ktons total)

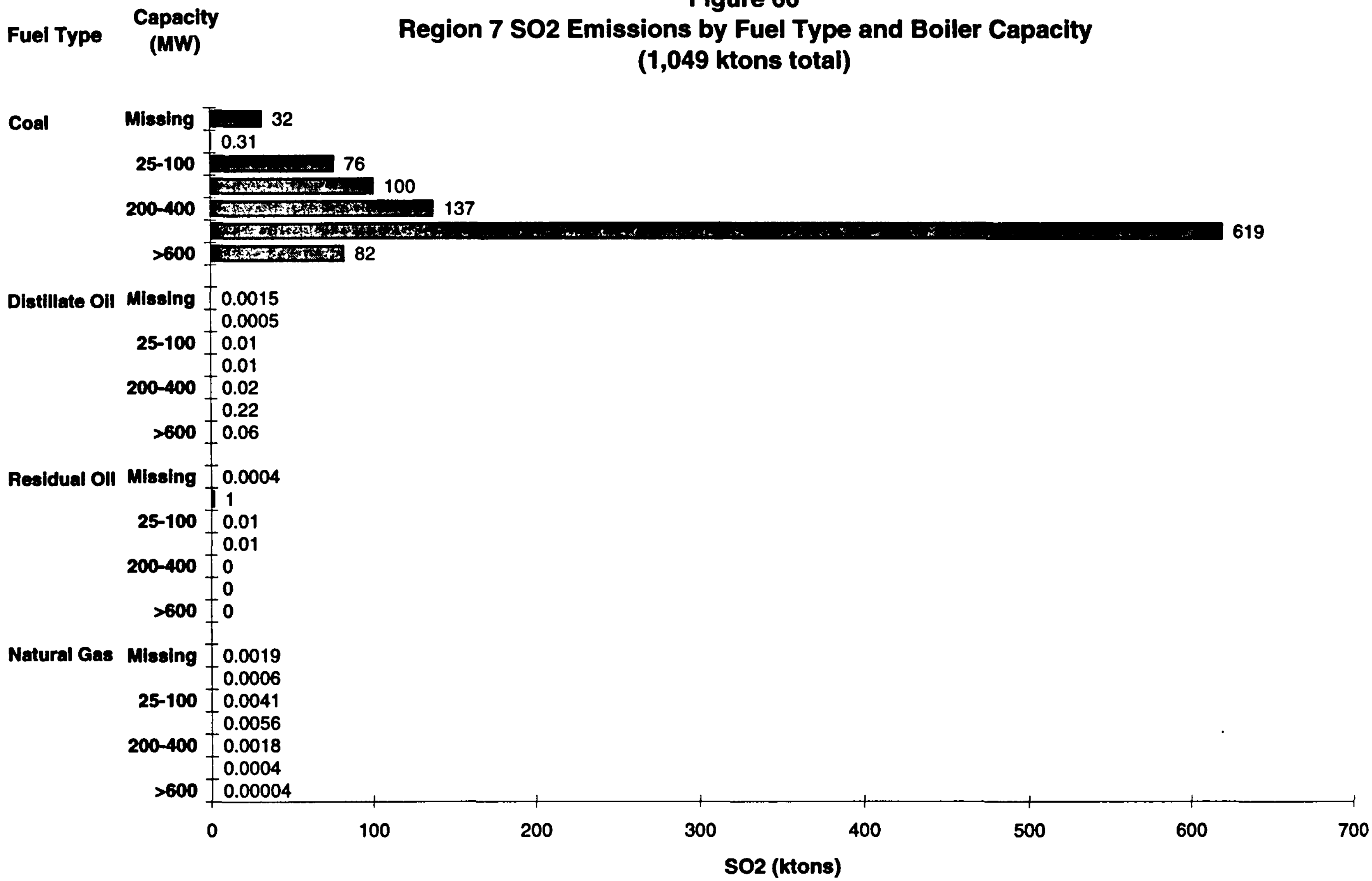


Figure 61
Region 7 Coal SO2 Emissions (ktons) for Scrubbed and Not Scrubbed Coal

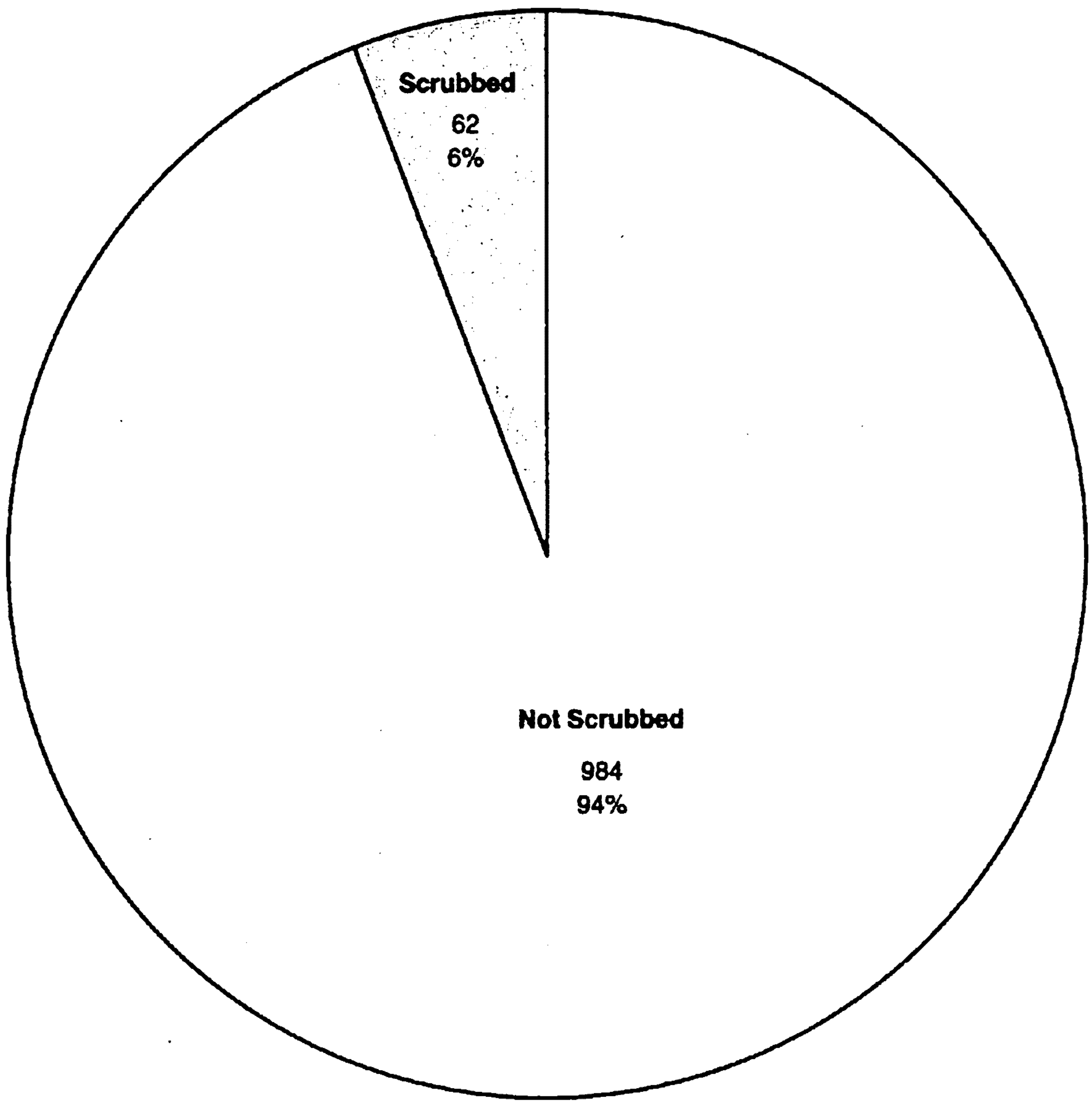


Figure 62
Region 8 SO2 Emissions by Fuel Type
(417 ktons total)

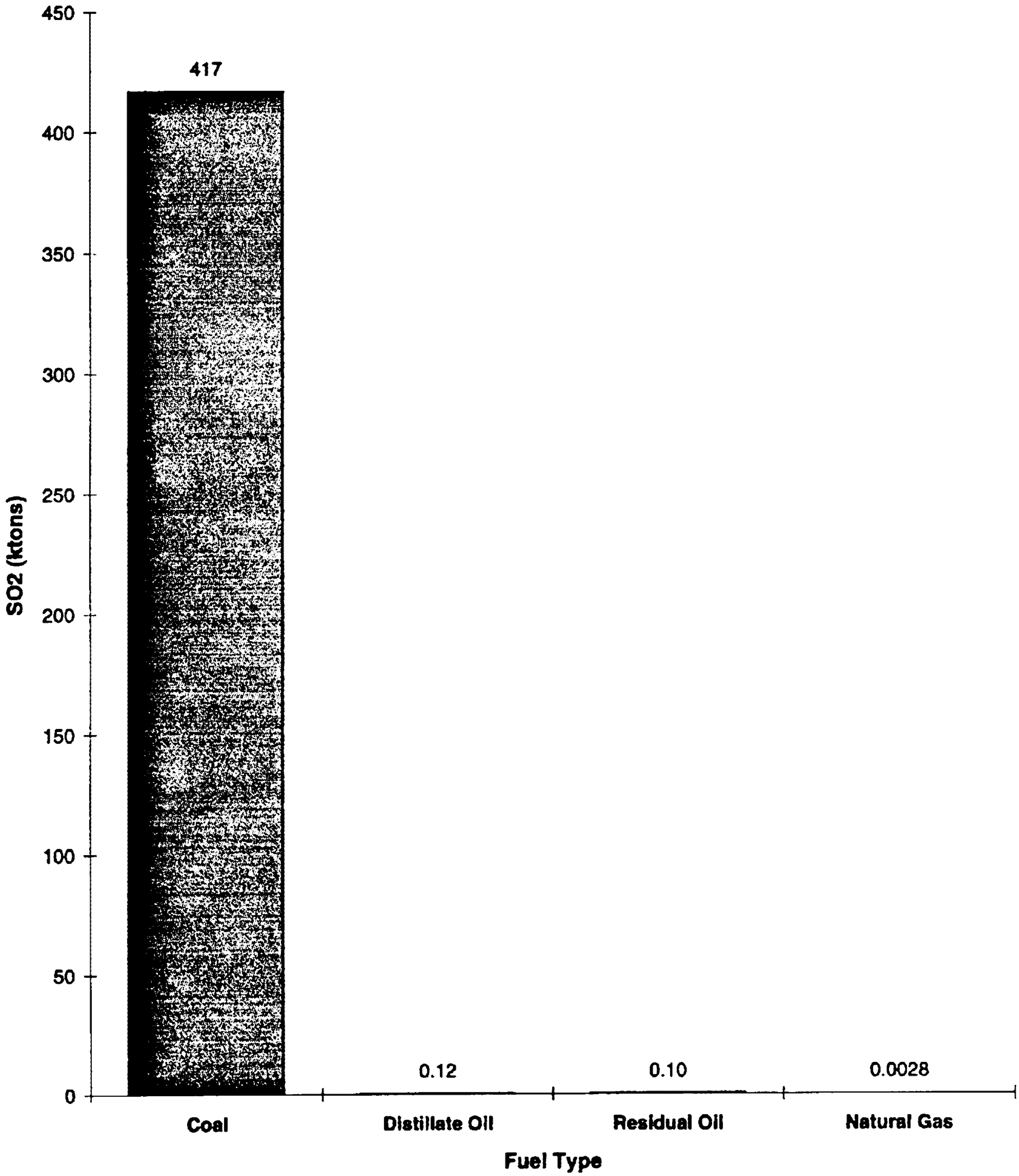


Figure 63
Region 8 NOx Emissions by Fuel Type
(549 ktons total)

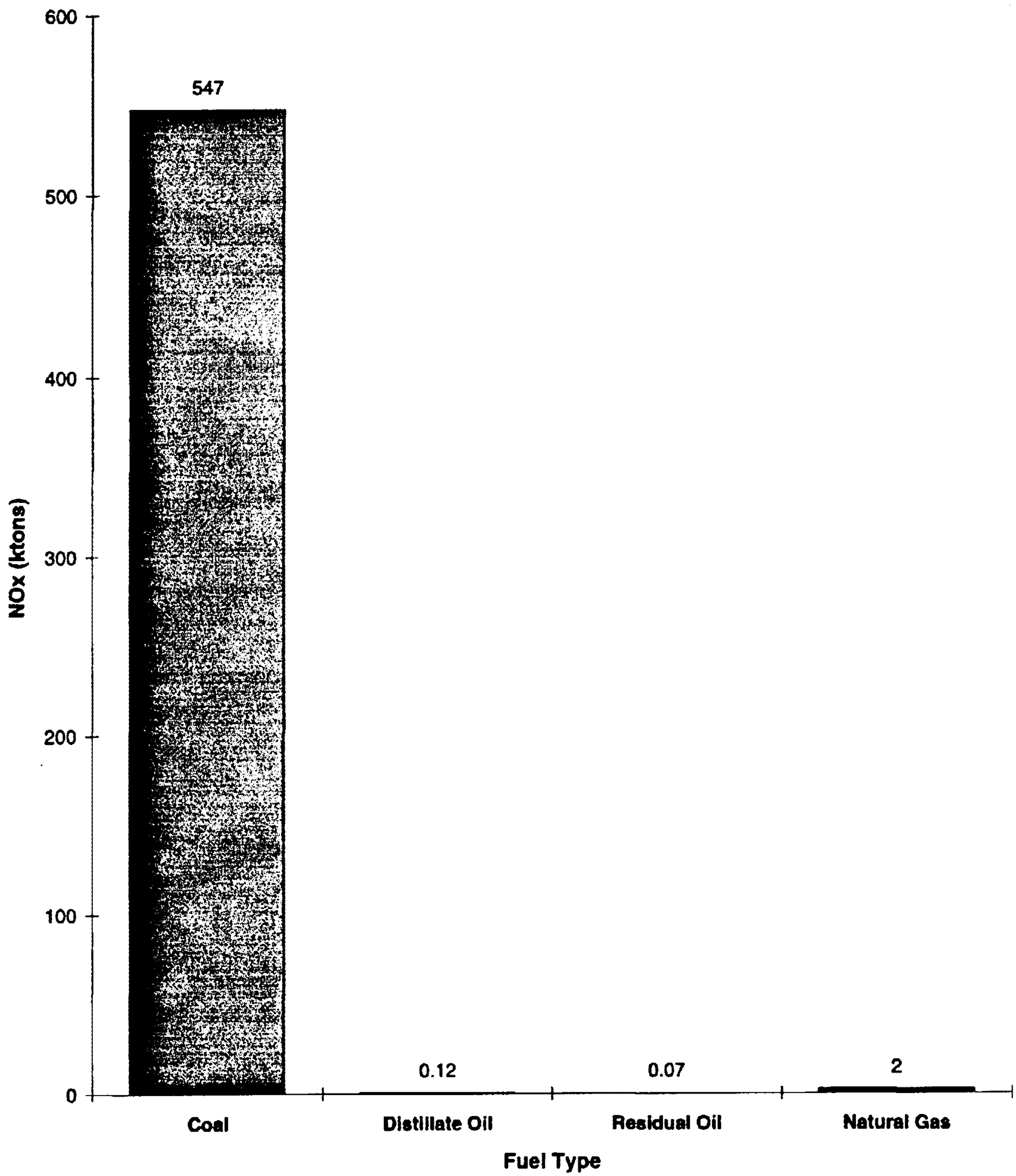


Figure 64
Region 8 SO2 Emissions by Fuel Type and Sulfur Content
(417 ktons total)

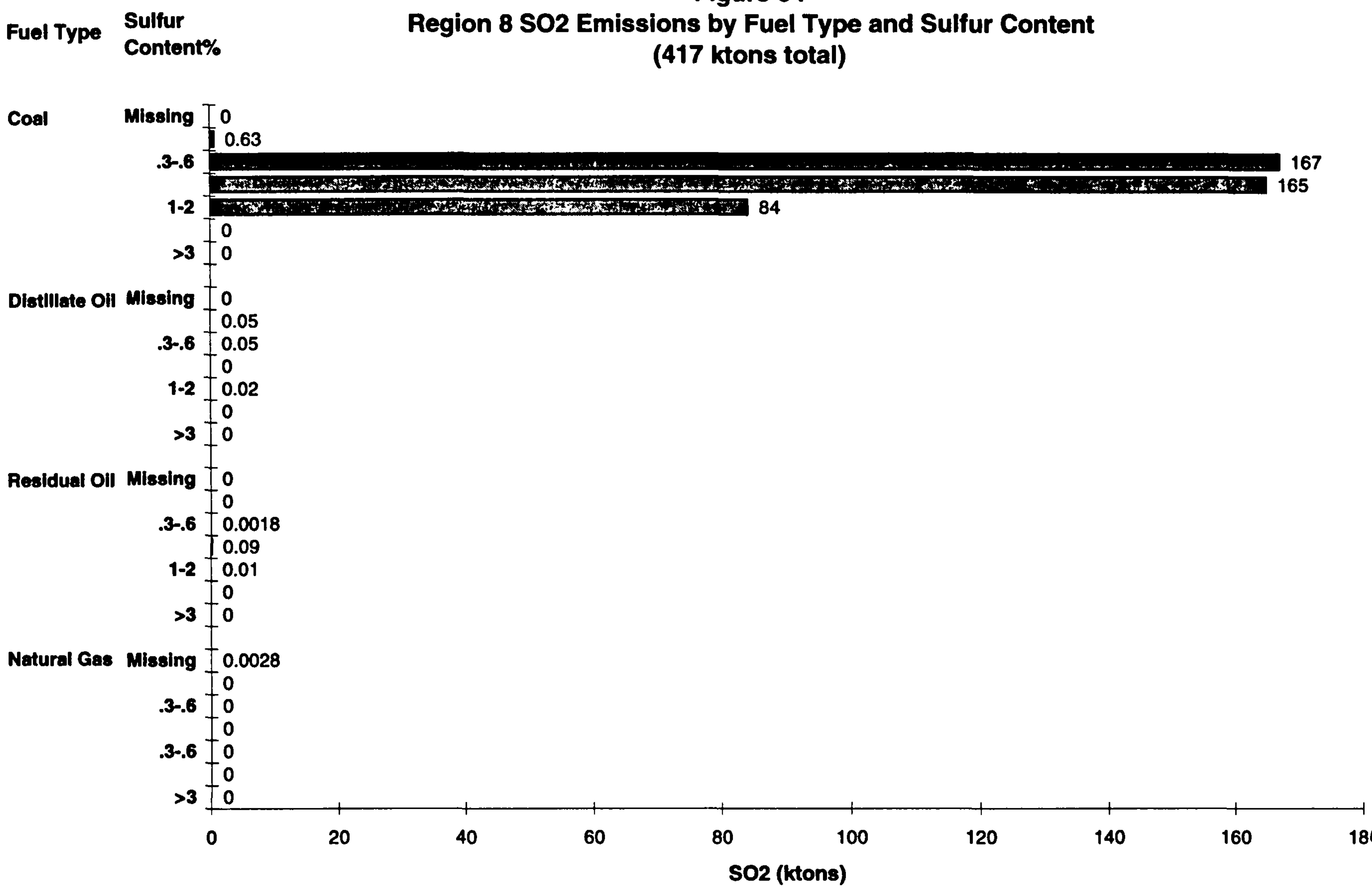


Figure 65
Region 8 SO2 Emissions by Fuel Type and Boiler Capacity
(417 ktons total)

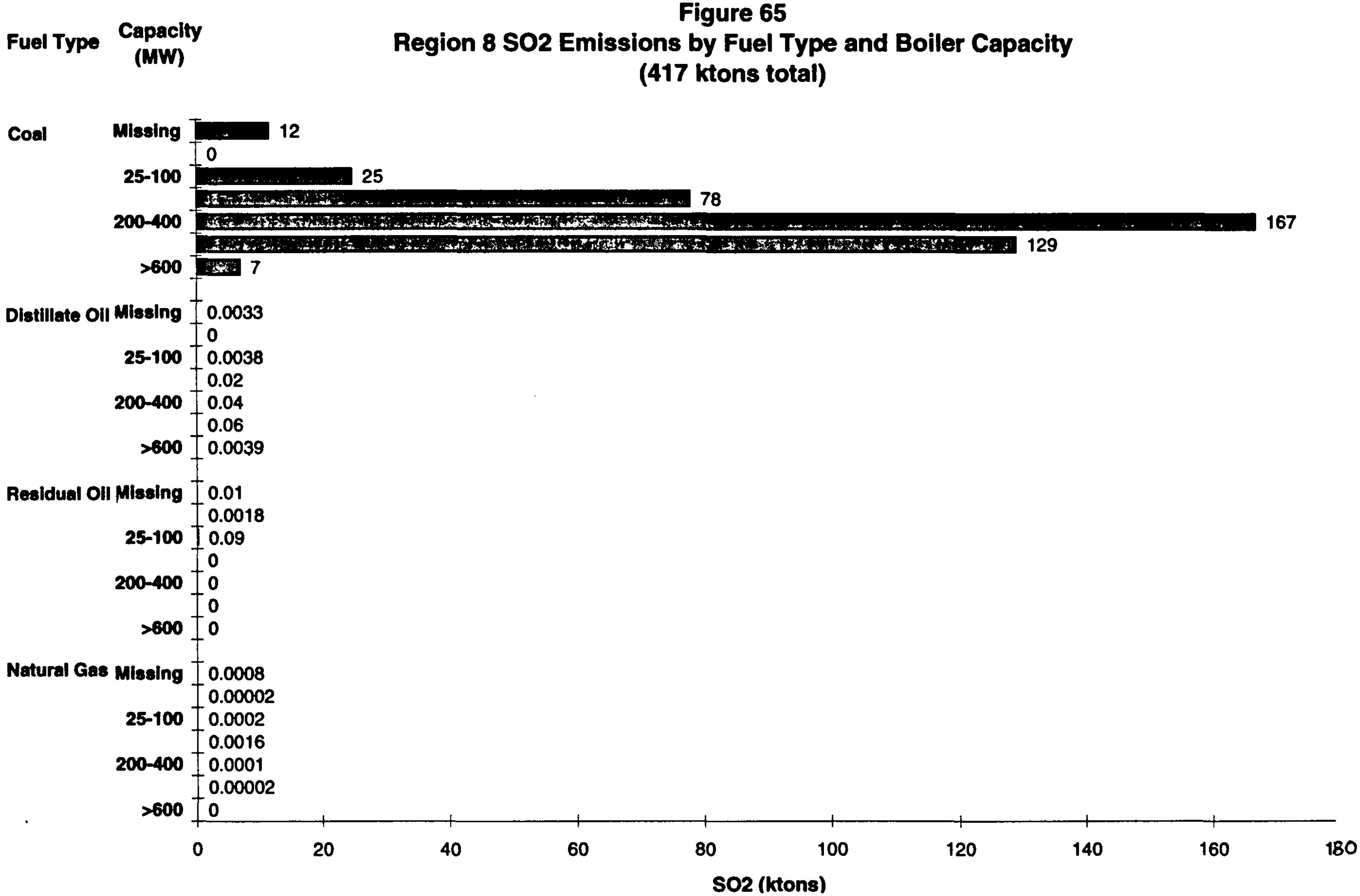


Figure 66
Region 8 Coal SO2 Emissions (ktons) for Scrubbed and Not Scrubbed Coal

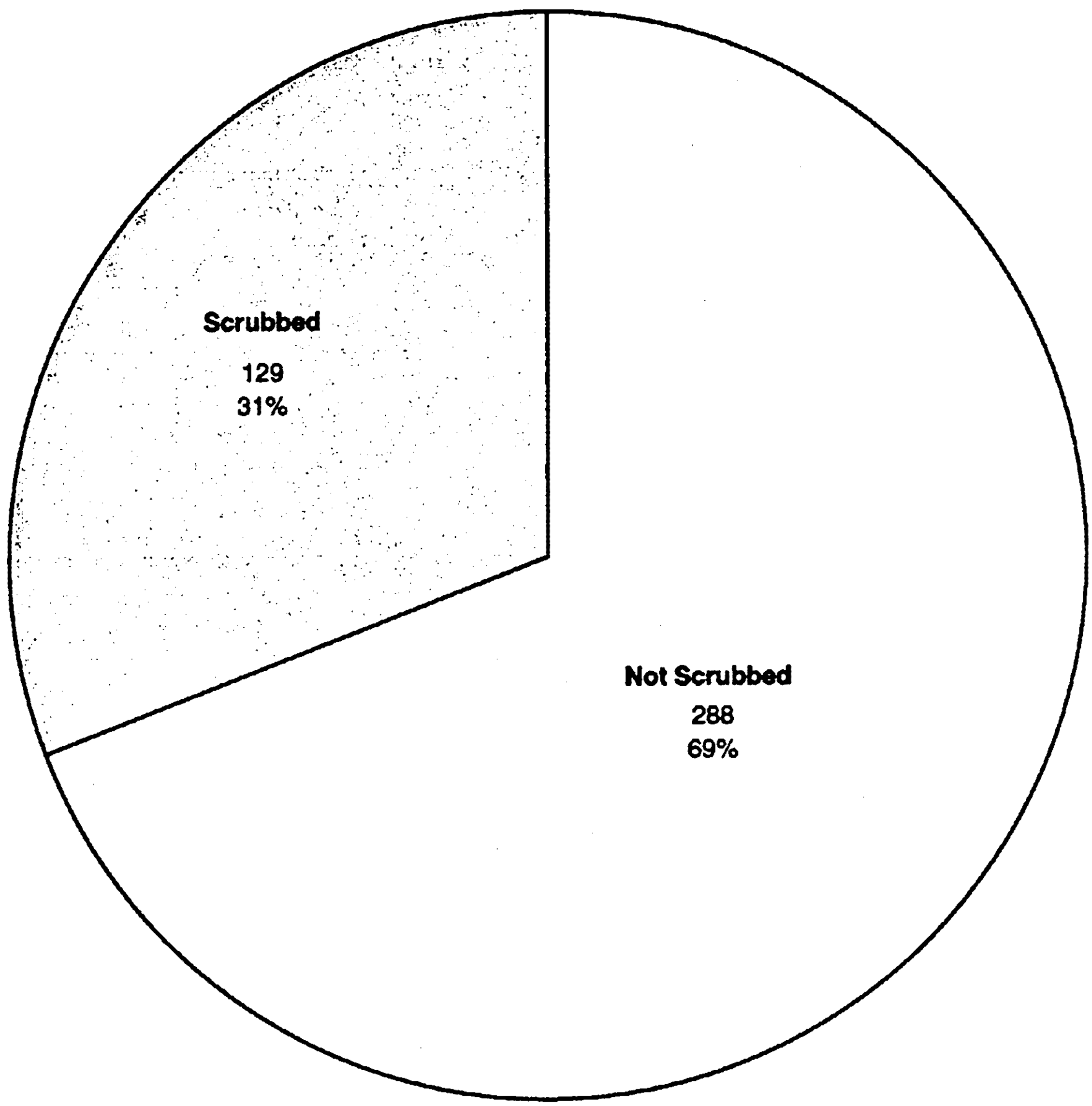


Figure 67
Region 9 SO2 Emissions by Fuel Type
(208 ktons total)

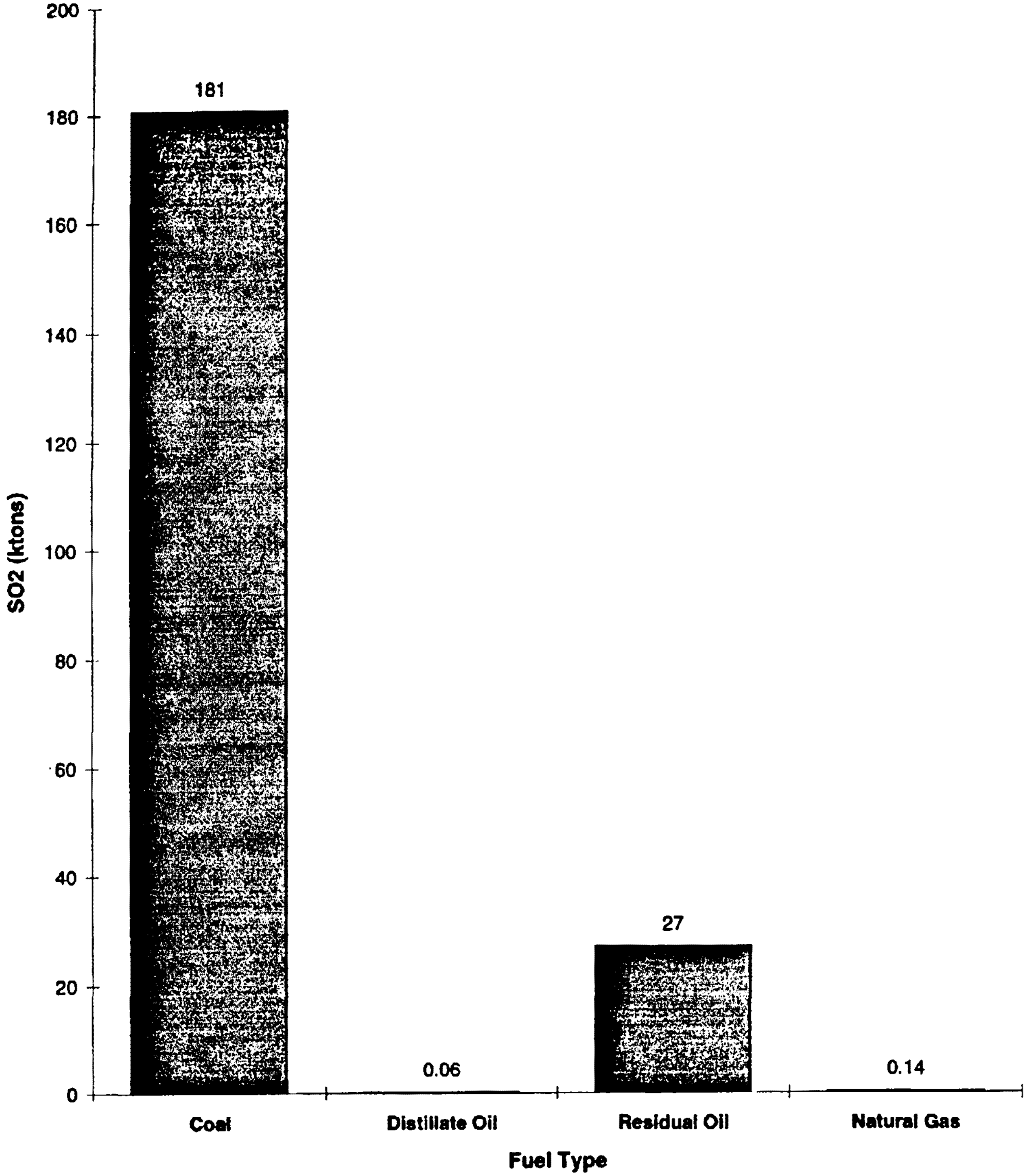


Figure 68
Region 9 NOx Emissions by Fuel Type
(303 ktons total)

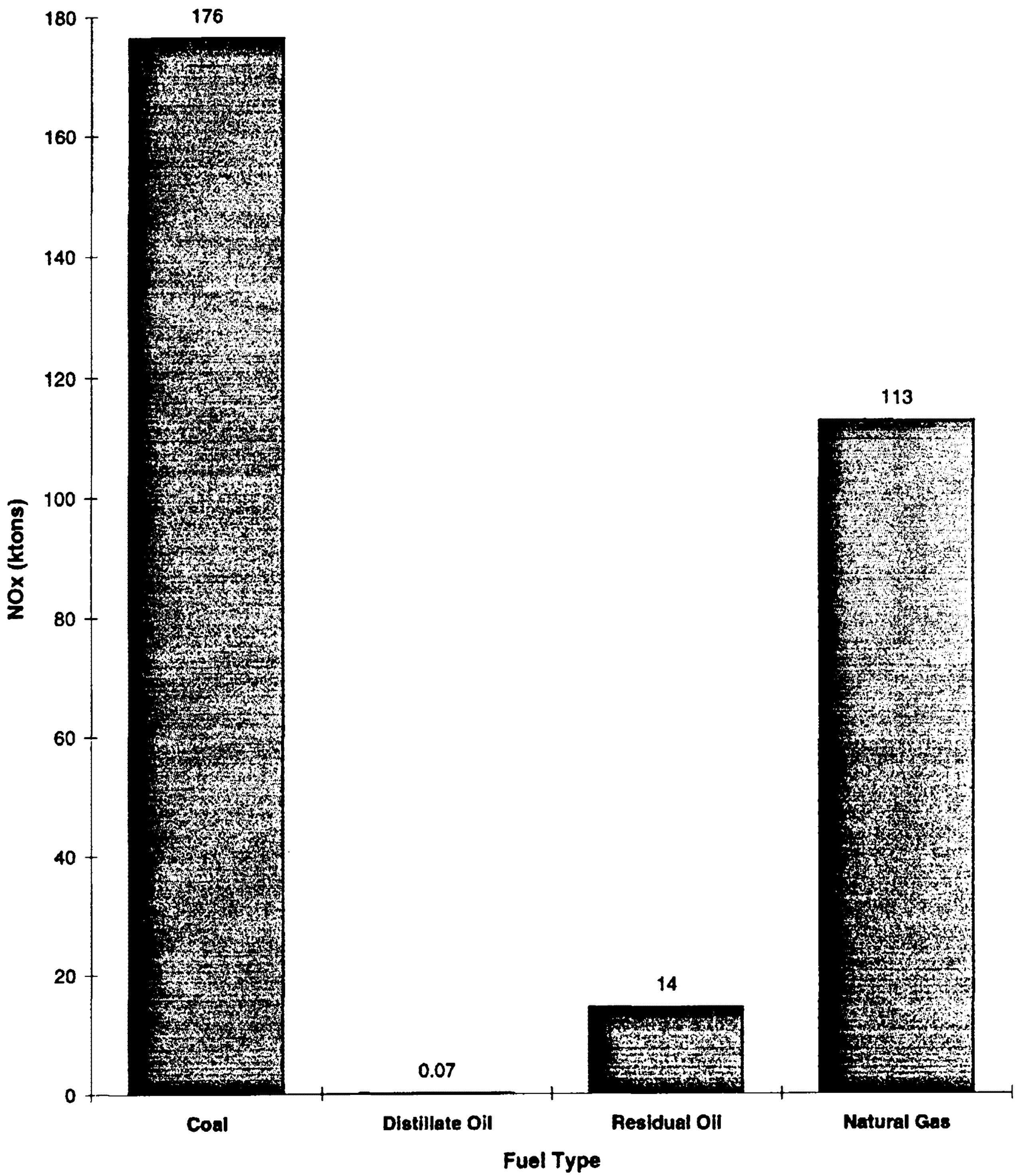


Figure 69
Region 9 SO2 Emissions by Fuel Type and Sulfur Content
(208 ktons total)

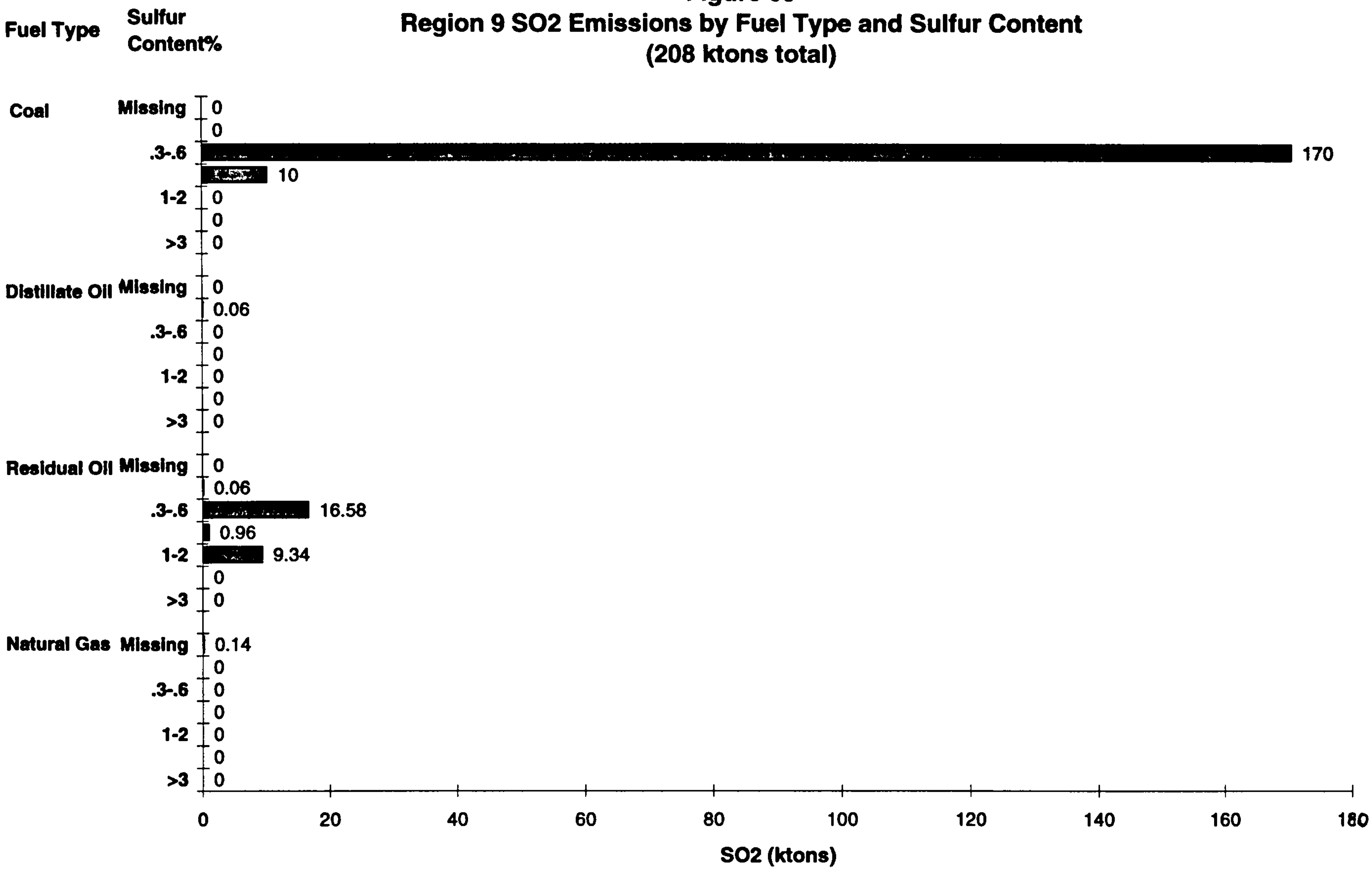


Figure 70
Region 9 SO2 Emissions by Fuel Type and Boiler Capacity
(208 ktons total)

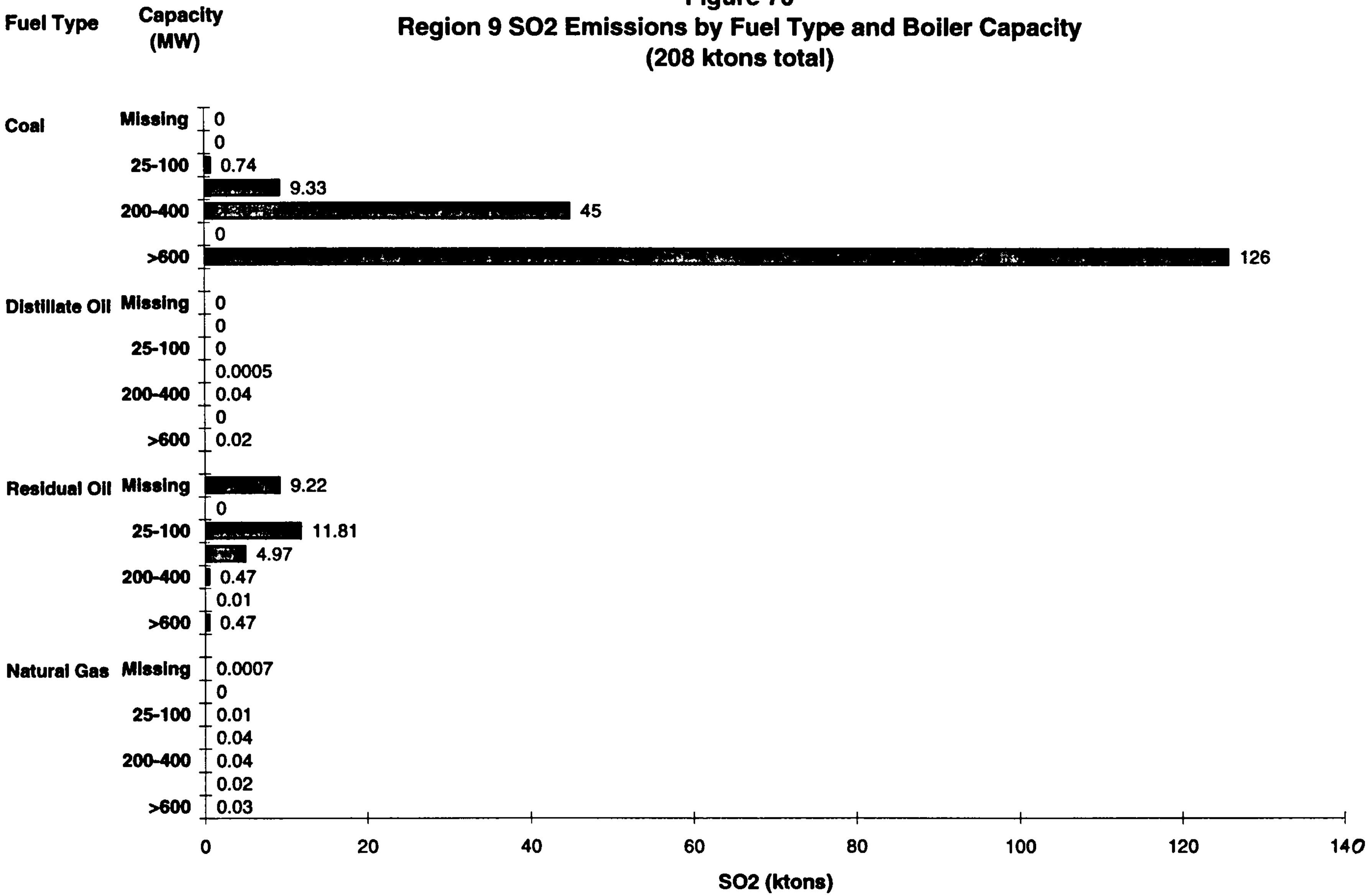


Figure 71
Region 9 Coal SO2 Emissions (ktons) for Scrubbed and Not Scrubbed Coal

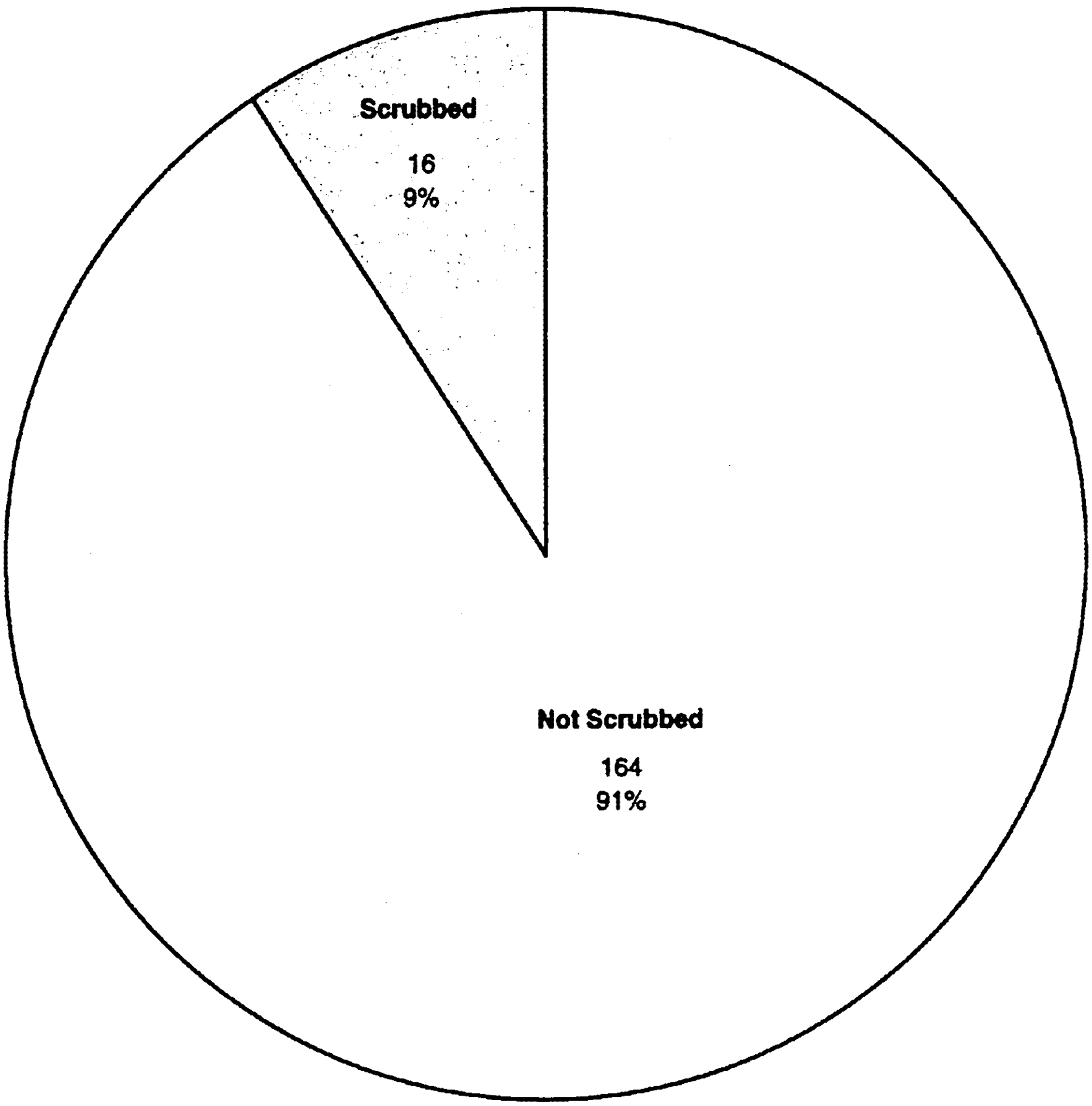


Figure 72
Region 10 SO2 Emissions by Fuel Type
(71 ktons total)

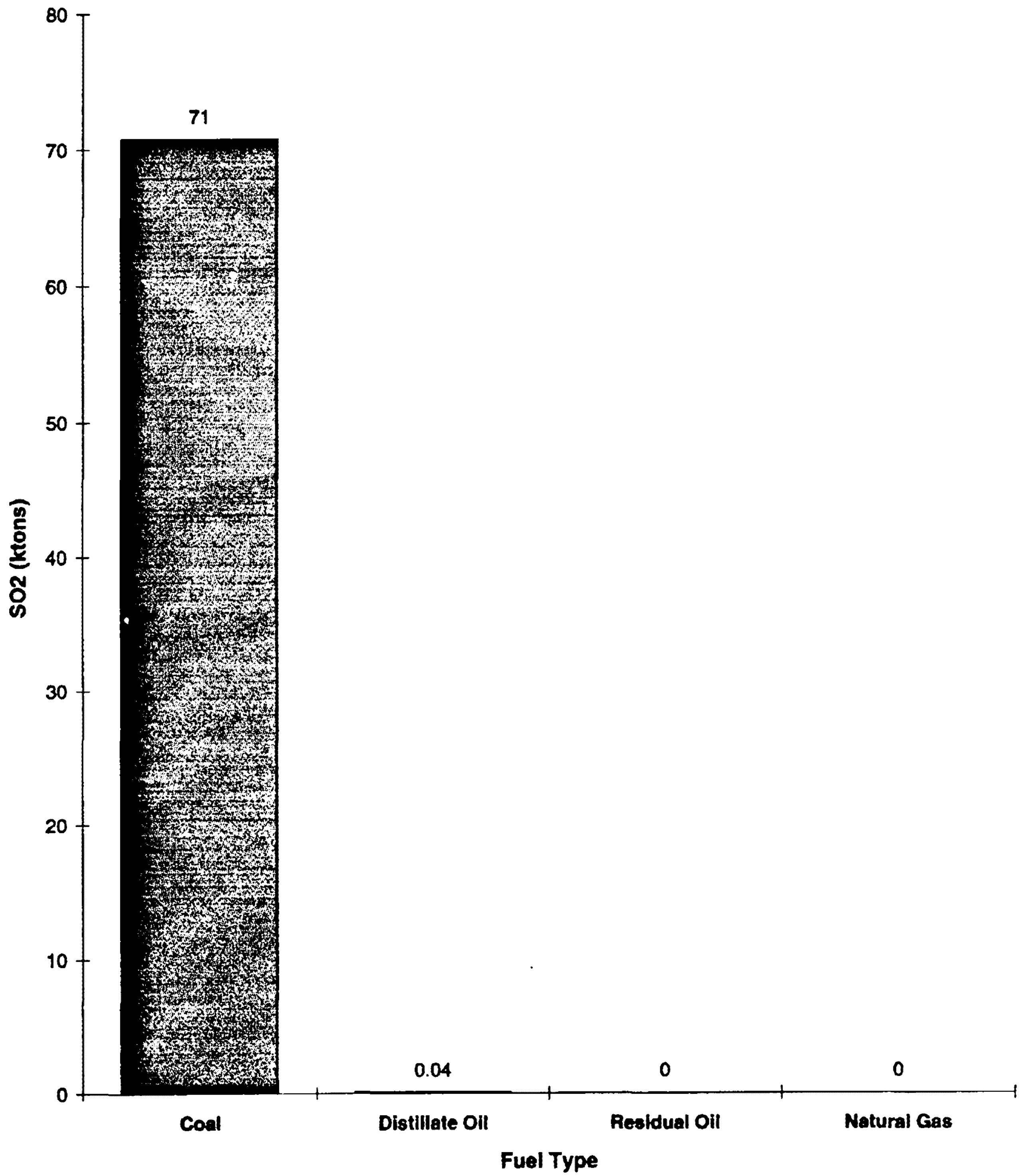


Figure 73
Region 10 NOx Emissions by Fuel Type
(52 ktons total)

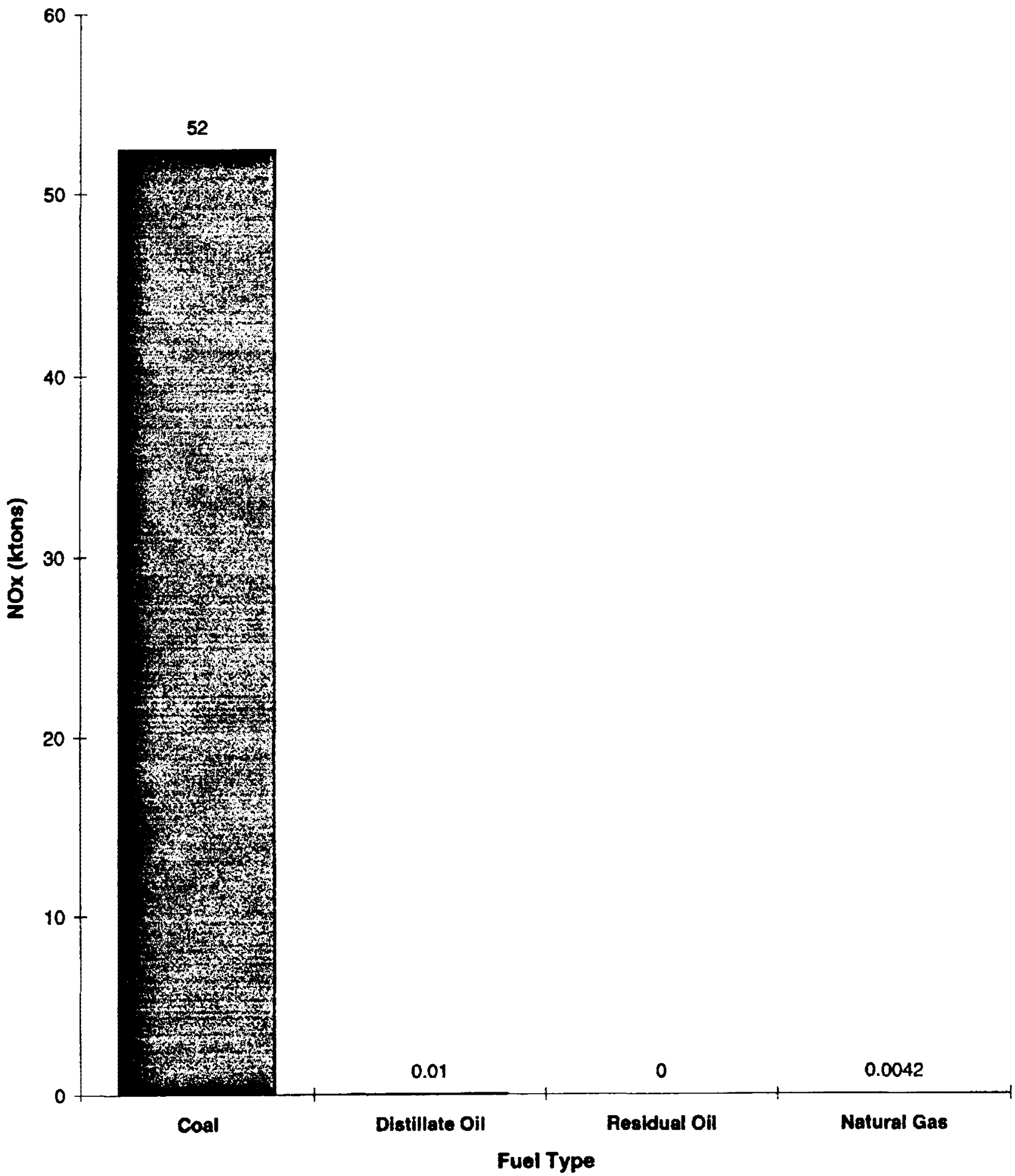


Figure 74
Region 10 SO2 Emissions by Fuel Type and Sulfur Content
(71 ktons total)

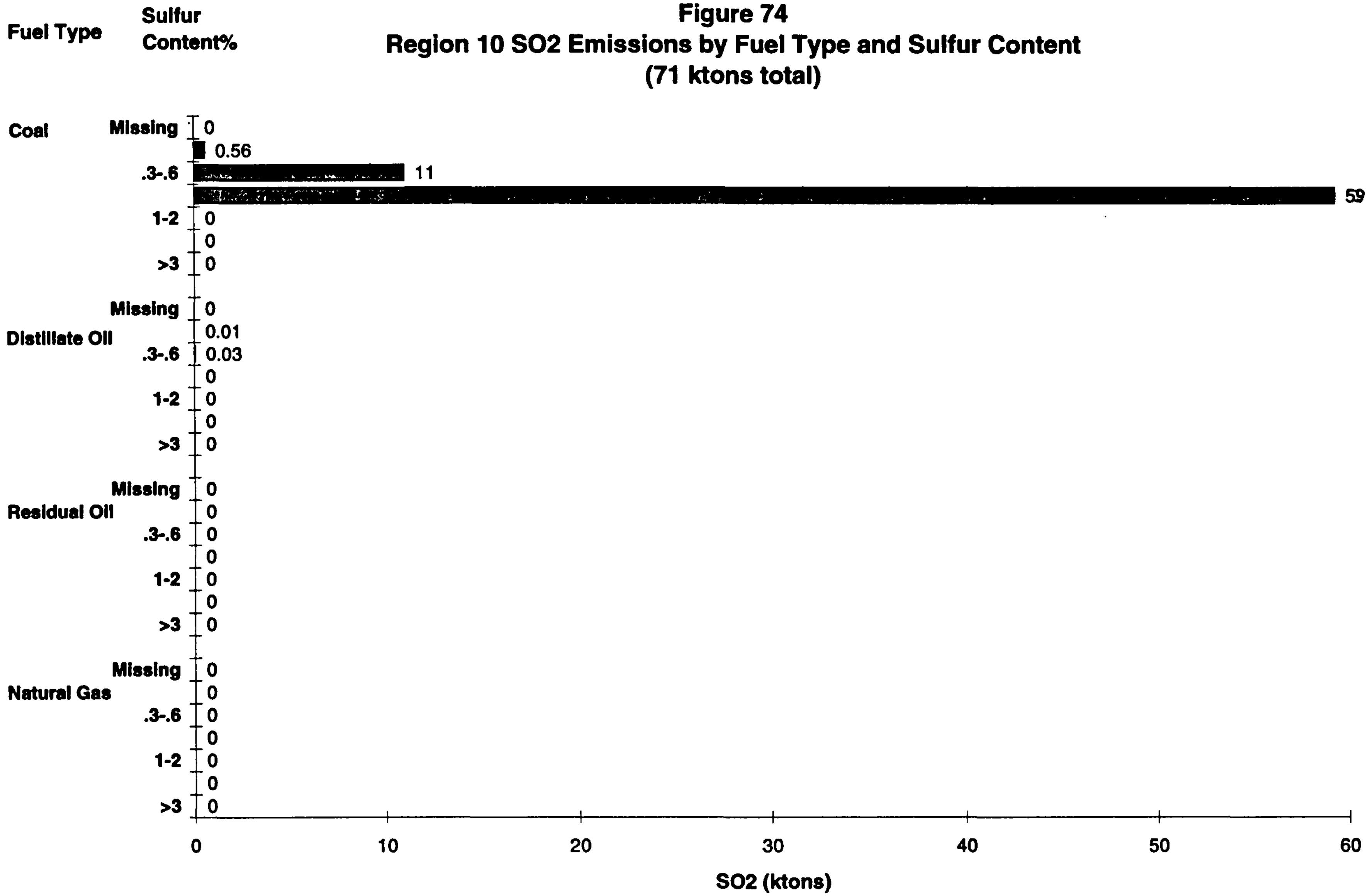


Figure 75
Region 10 SO2 Emissions by Fuel Type and Boiler Capacity
(71 ktons total)

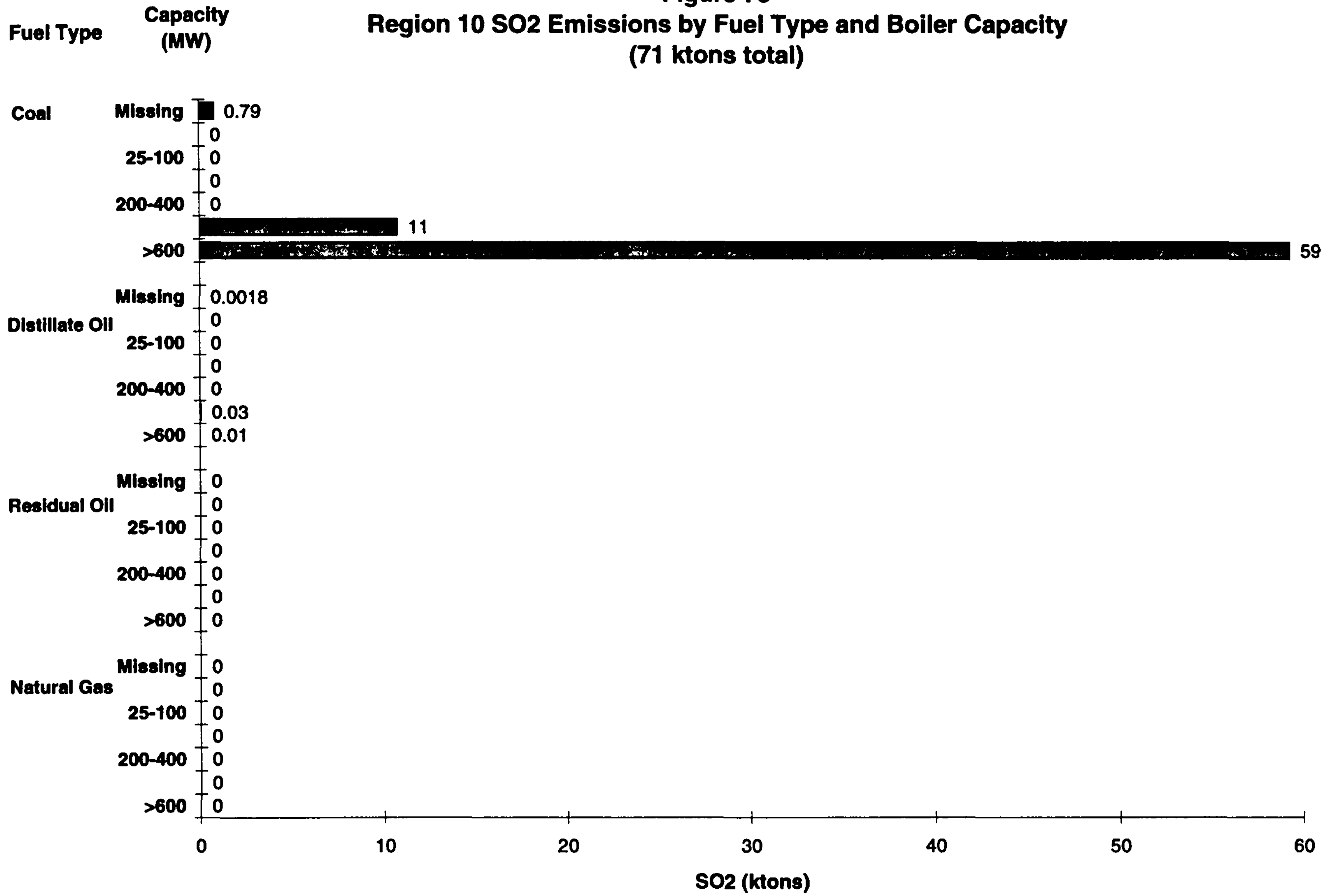


Figure 76
Region 10 Coal SO2 Emissions (ktons) for Scrubbed and Not Scrubbed Coal

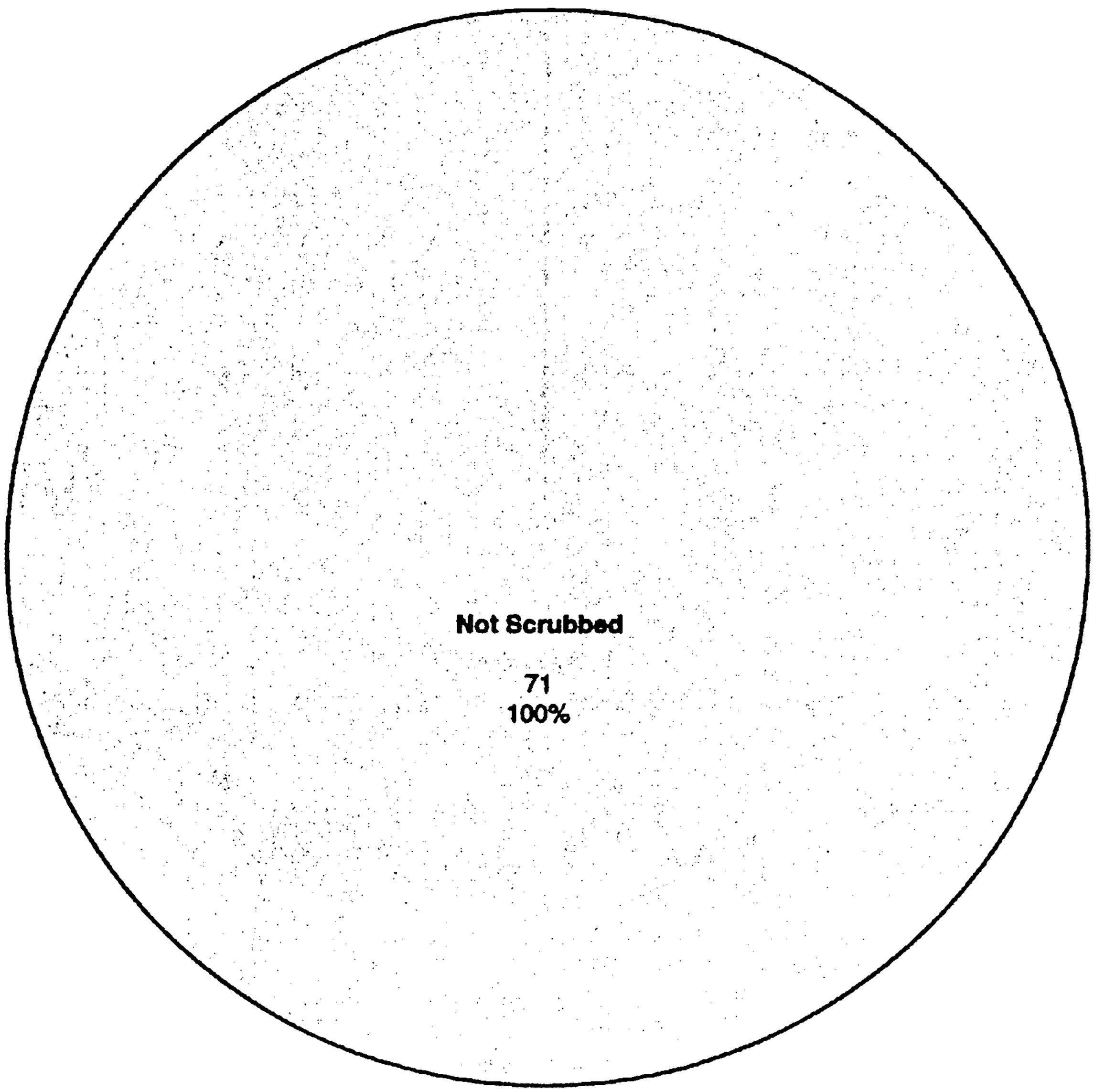


Table 1
State SO_2 and NO_x Emissions and Ranks

State	SO_2 (tons)	SO_2 Rank	NO_x (tons)	NO_x Rank
AK	563	48	2,611	46
AL	533,182	11	211,499	11
AR	66,422	31	77,910	30
AZ	125,358	23	120,983	20
CA	1,488	46	104,520	26
CO	83,013	27	118,191	22
CT	48,906	37	21,007	43
DC	1,372	47	390	49
DE	48,800	38	24,307	40
FL	725,666	10	340,529	5
GA	793,728	7	200,350	12
HI	24,627	42	12,620	44
IA	181,578	19	118,937	21
ID	0	51	0	51
IL	873,930	6	336,103	6
IN	1,468,234	2	491,076	3
KS	75,850	30	113,525	25
KY	874,894	5	335,328	7
LA	106,468	24	116,744	23
MA	236,508	18	75,040	32
MD	262,686	17	88,943	27
ME	11,403	44	2,309	47
MI	384,428	14	284,926	8
MN	79,696	29	146,670	17
MO	738,043	9	265,166	10
MS	105,470	25	45,658	38
MT	19,555	43	62,739	36
NC	330,555	15	164,064	15
ND	172,674	21	114,756	24
NE	53,177	36	64,359	35
NH	48,206	39	23,738	41
NJ	64,479	32	50,805	37
NM	53,983	35	76,688	31
NV	56,361	34	65,364	34
NY	390,309	13	170,873	14
OH	2,241,387	1	527,182	2
OK	103,159	26	129,106	19
OR	10,755	45	10,722	45
PA	1,225,024	3	363,429	4
RI	374	49	607	48
SC	163,410	22	81,785	29
SD	32,629	40	22,467	42
TN	755,348	8	180,336	13
TX	473,572	12	652,659	1
UT	28,826	41	85,763	28
VA	179,800	20	74,949	33
VT	1	50	298	50
WA	59,447	33	39,068	39
WI	291,966	16	160,314	16
WV	1,066,396	4	281,900	9
WY	80,113	28	145,411	18
US	**15,753,821**		**7,204,725**	

Figure 77
Top 5 Emitting States SO2 Emissions by Fuel Type

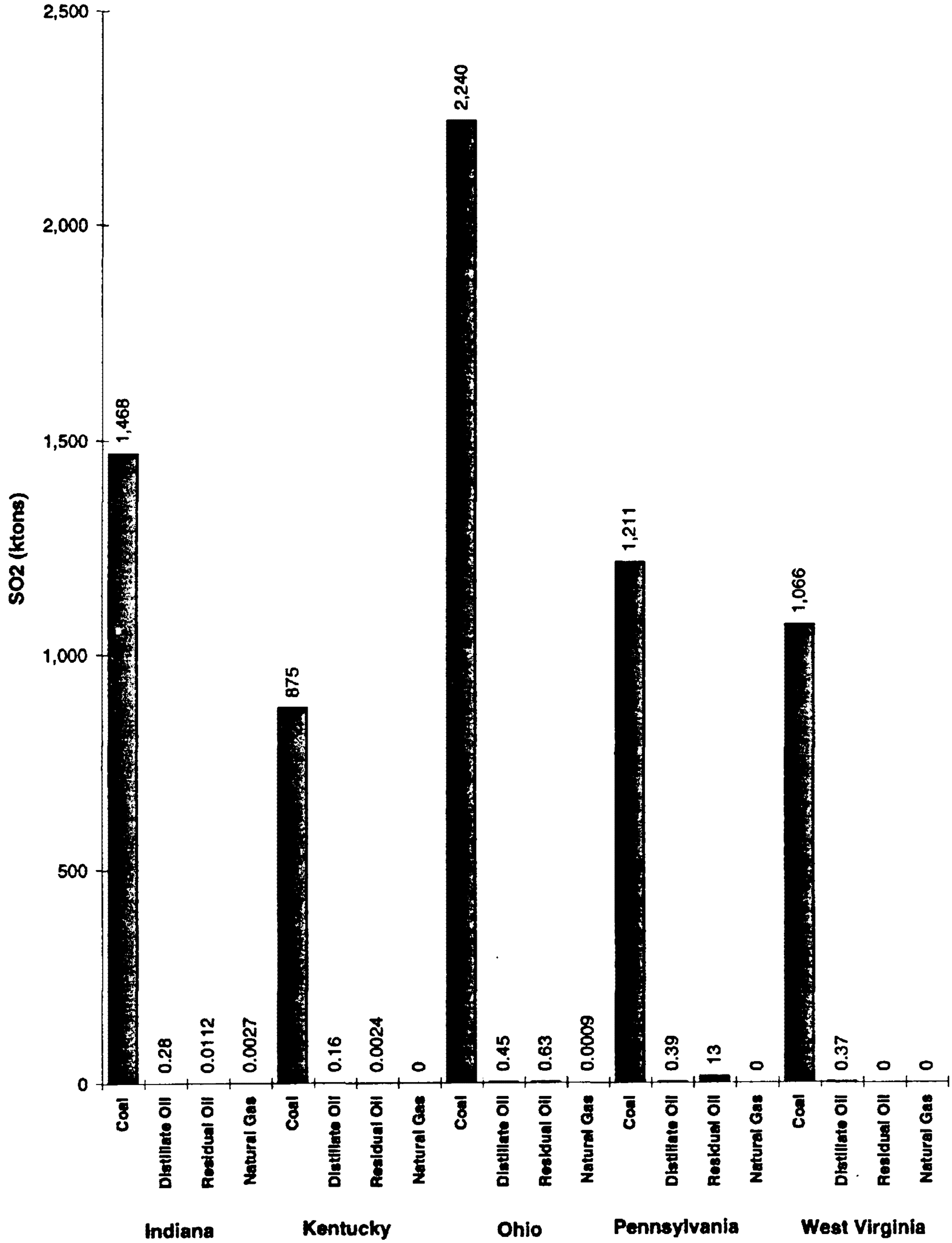


Figure 78
Top 5 Emitting States SO2 Emissions (ktons) for Scrubbed and Not Scrubbed Coal

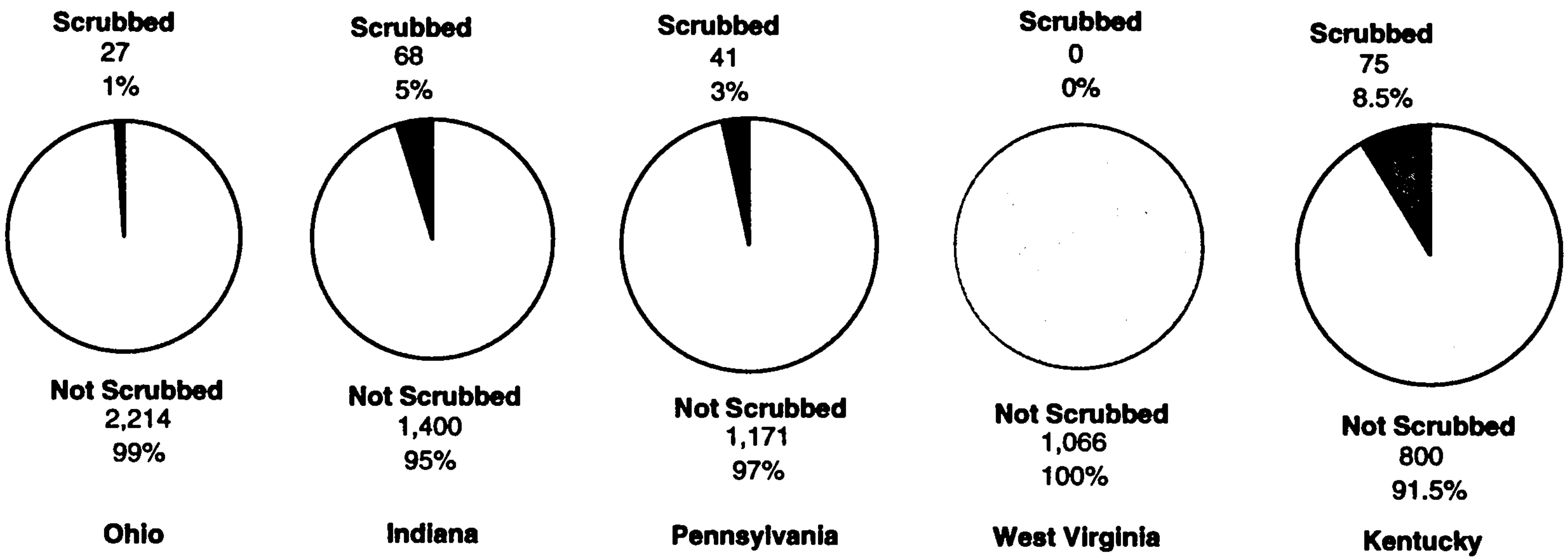


Figure 79
Top 5 Emitting States NOx Emissions by Fuel Type

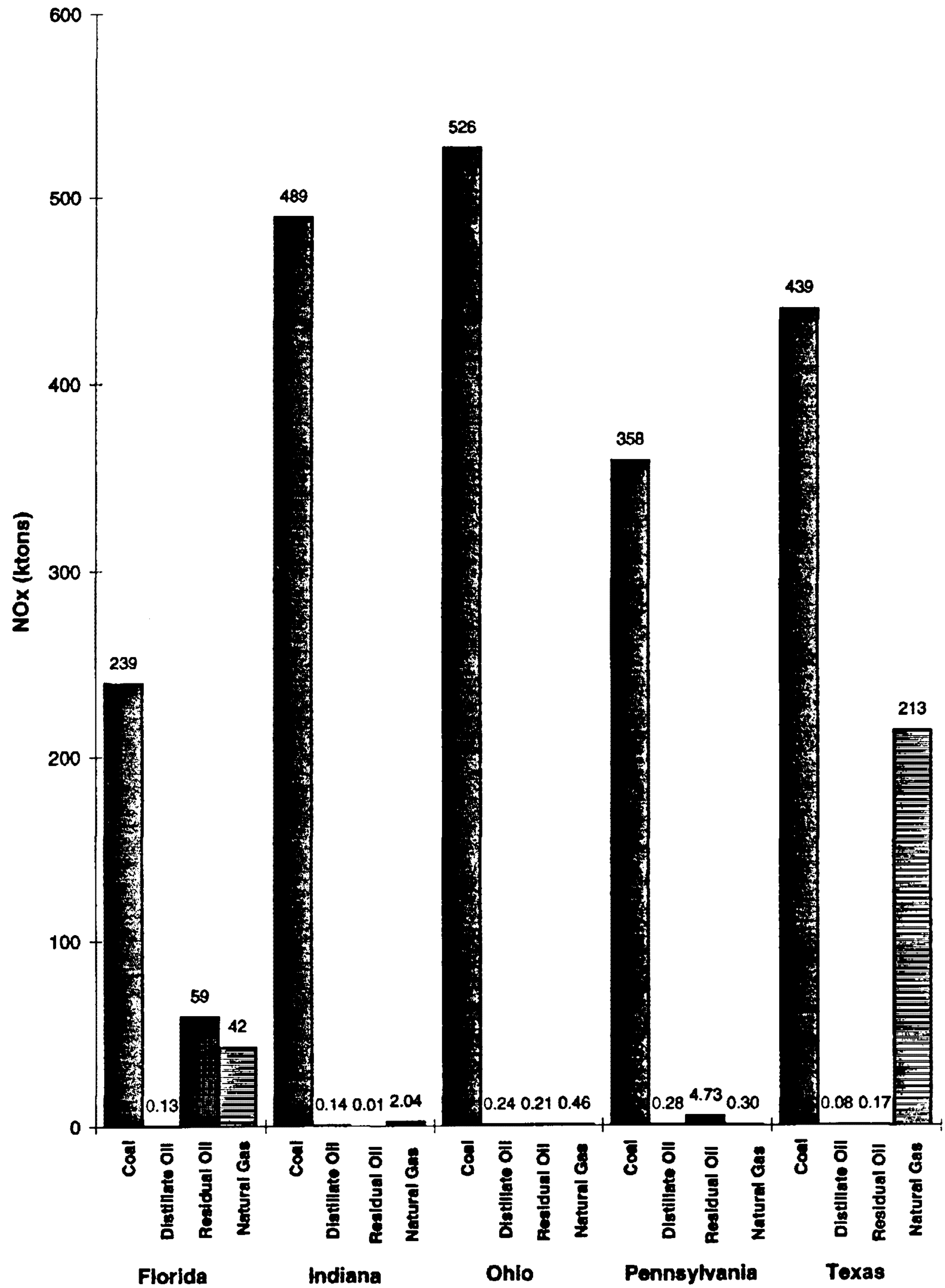


Figure 80
Indiana (ranked 2nd) SO2 Emissions by Fuel Type and Sulfur Content
(1,468 ktons total)

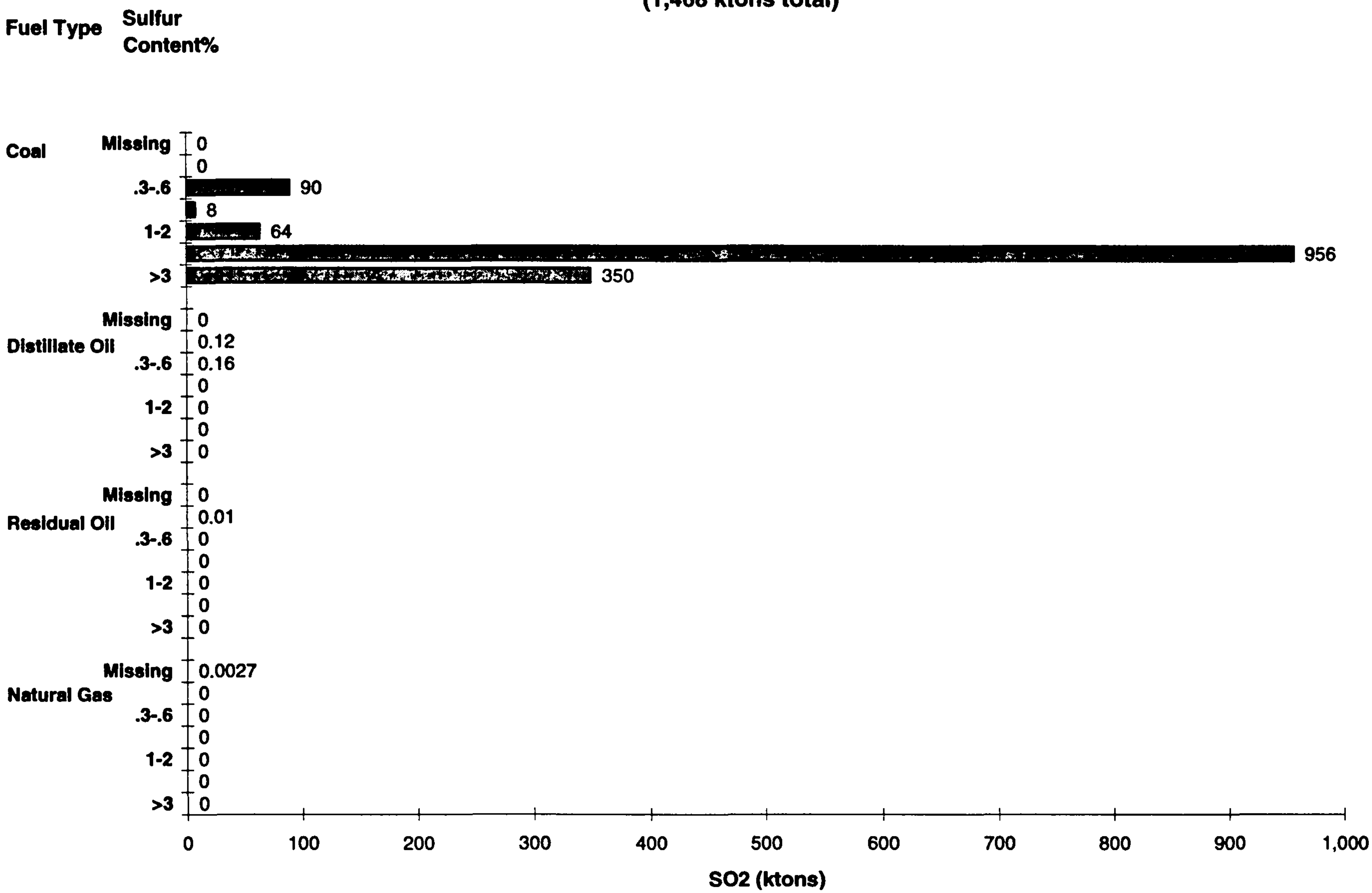


Figure 81
Indiana (ranked 2nd) SO2 Emissions by Fuel Type and Boiler Capacity
(1,468 ktons total)

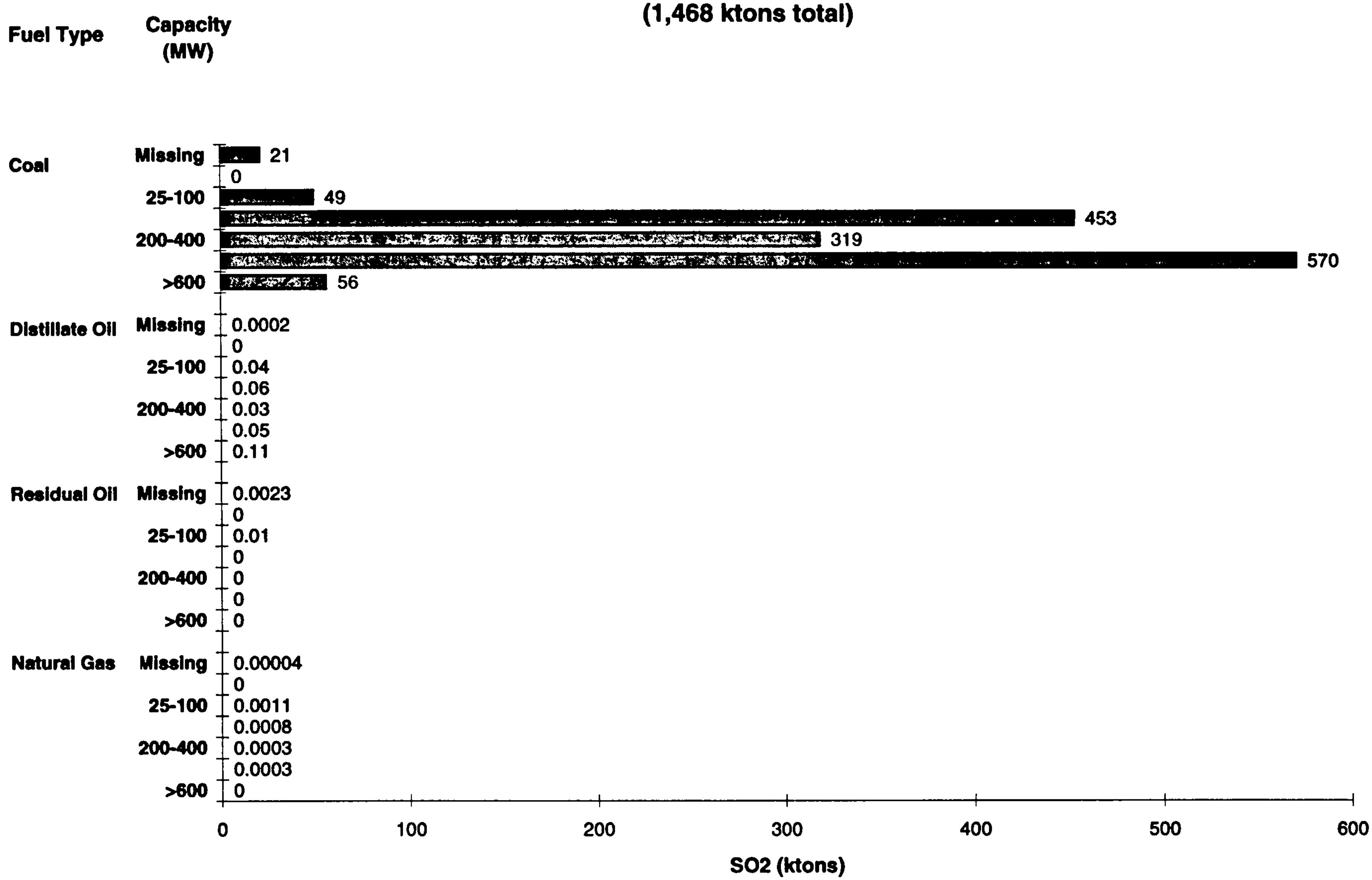


Figure 82
Kentucky (ranked 5th) SO2 Emissions by Fuel Type and Sulfur Content
(875 ktons total)

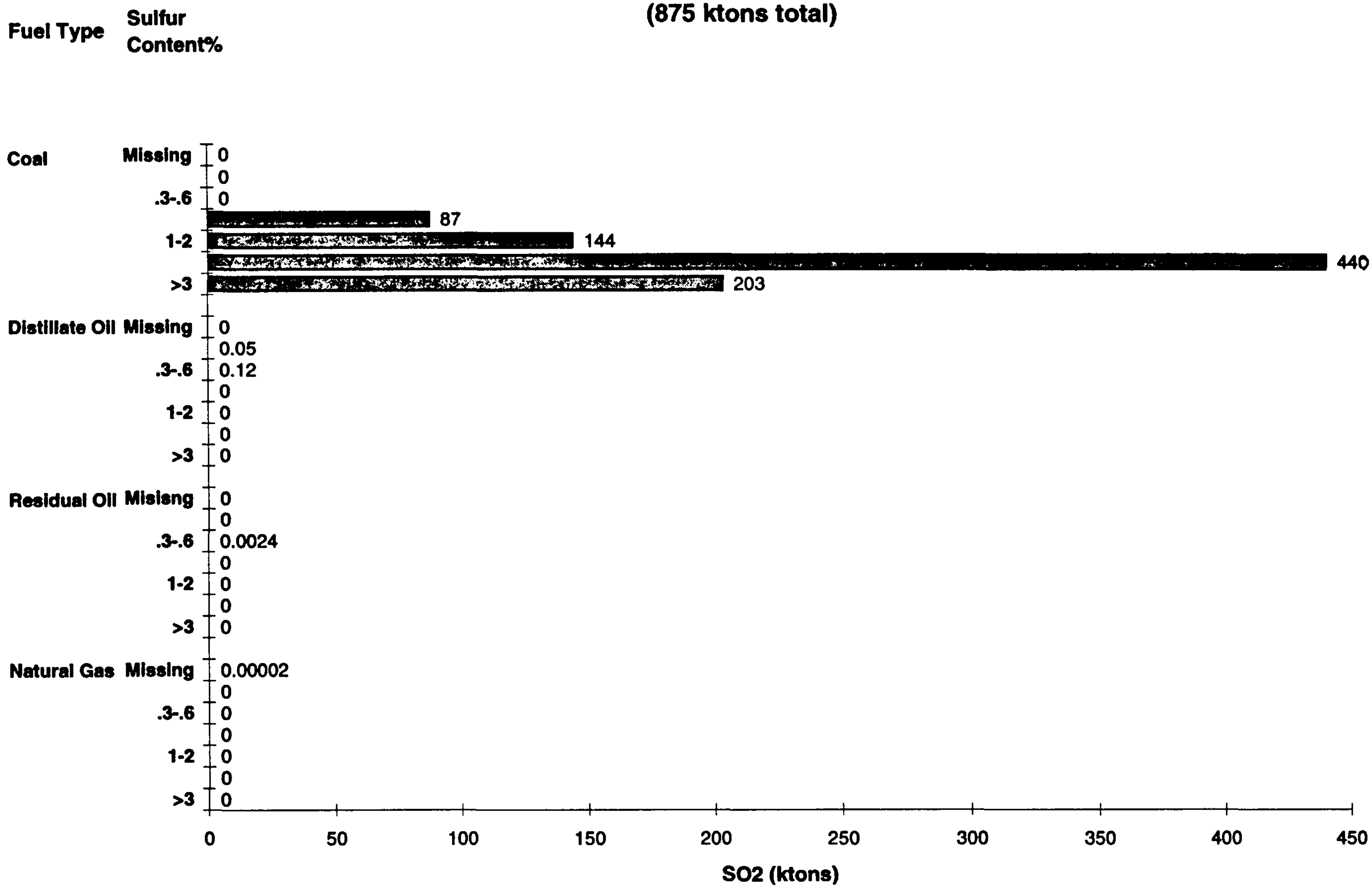


Figure 83
Kentucky (ranked 5th) SO2 Emissions by Fuel Type and Boiler Capacity
(875 ktons total)

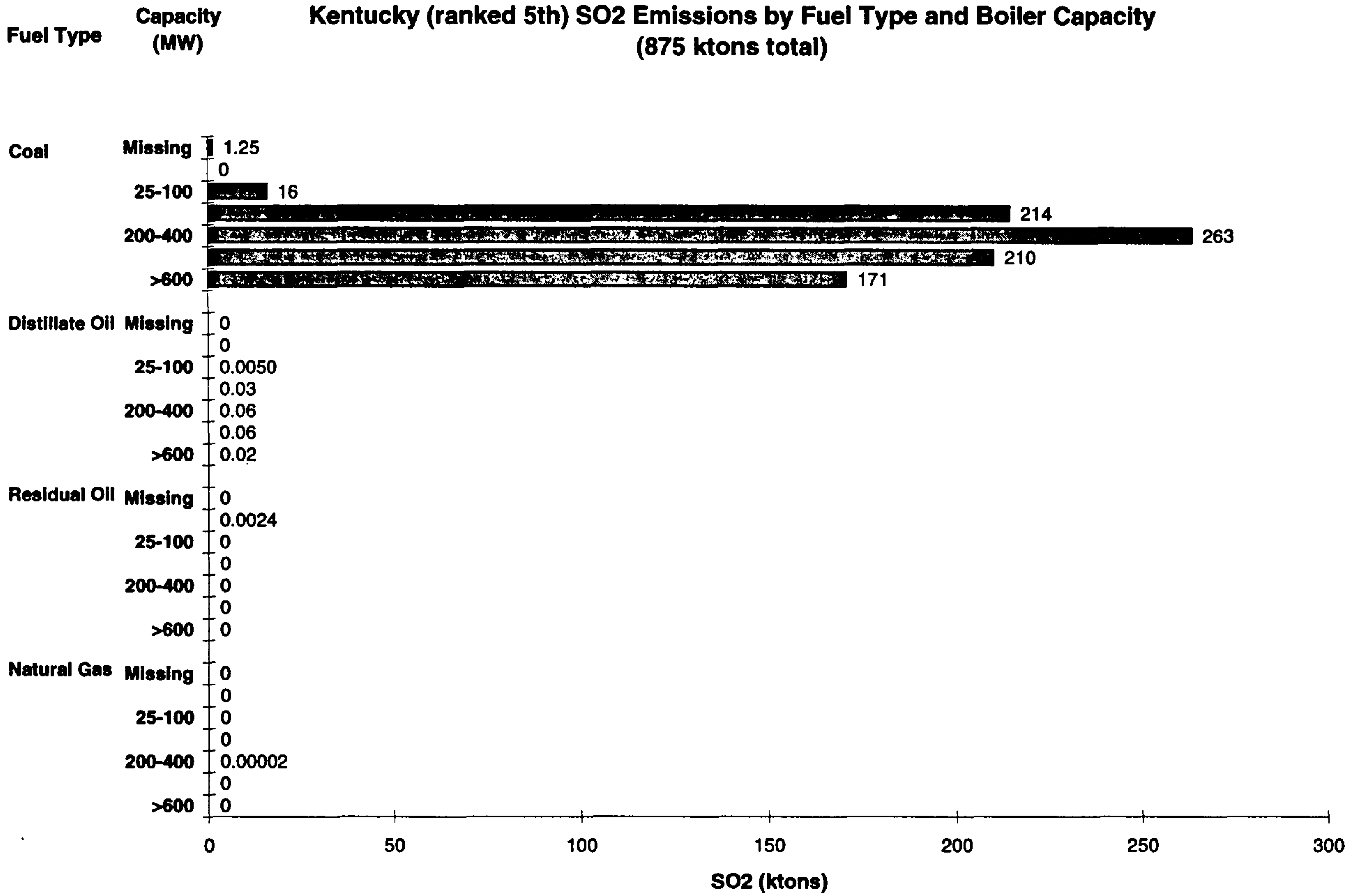


Figure 84
Ohio (ranked 1st) SO2 Emissions by Fuel Type and Sulfur Content
(2,241 ktons total)

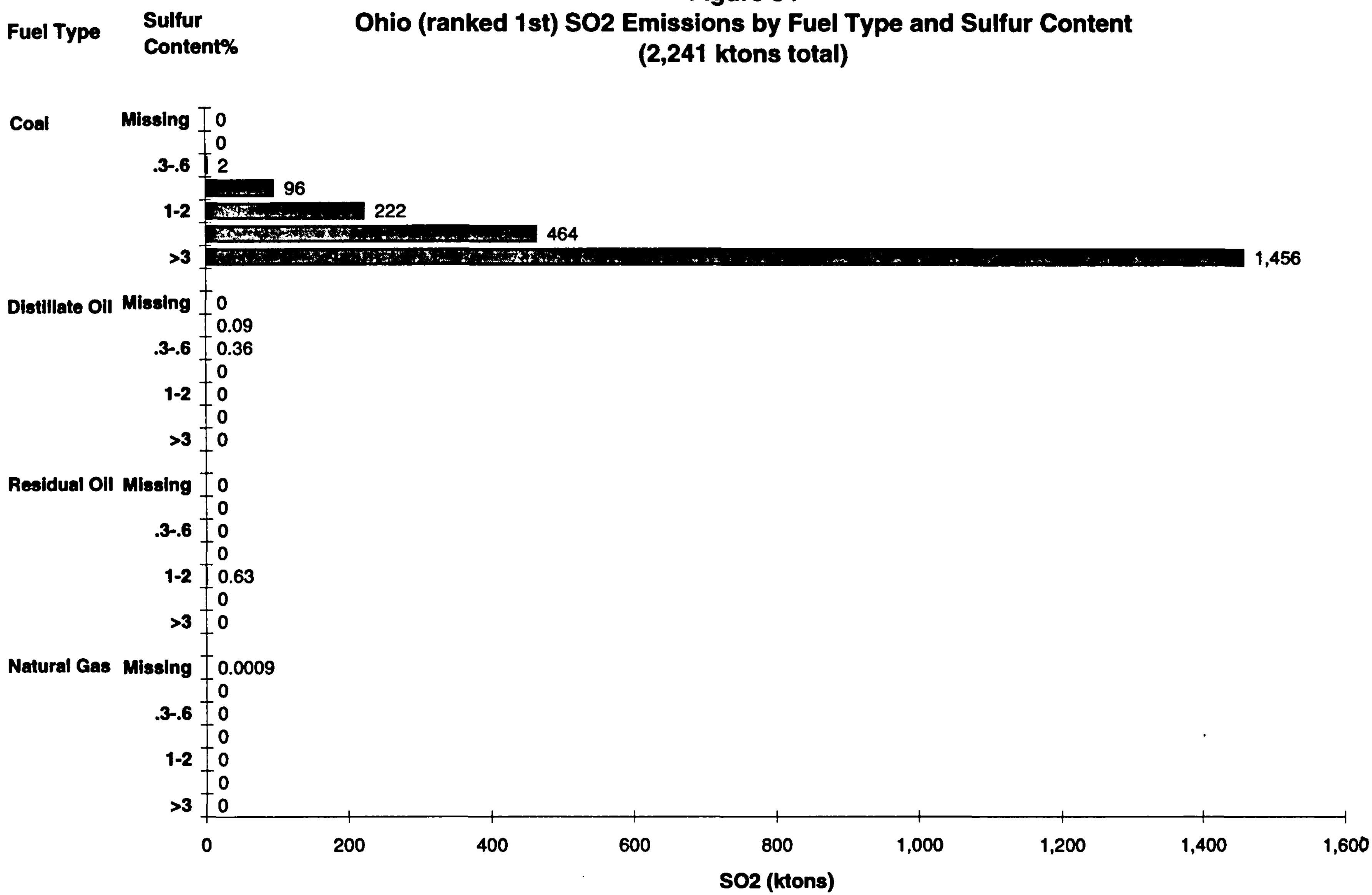


Figure 85
Ohio (ranked 1st) SO2 Emissions by Fuel Type and Boiler Capacity
(2,241 ktons total)

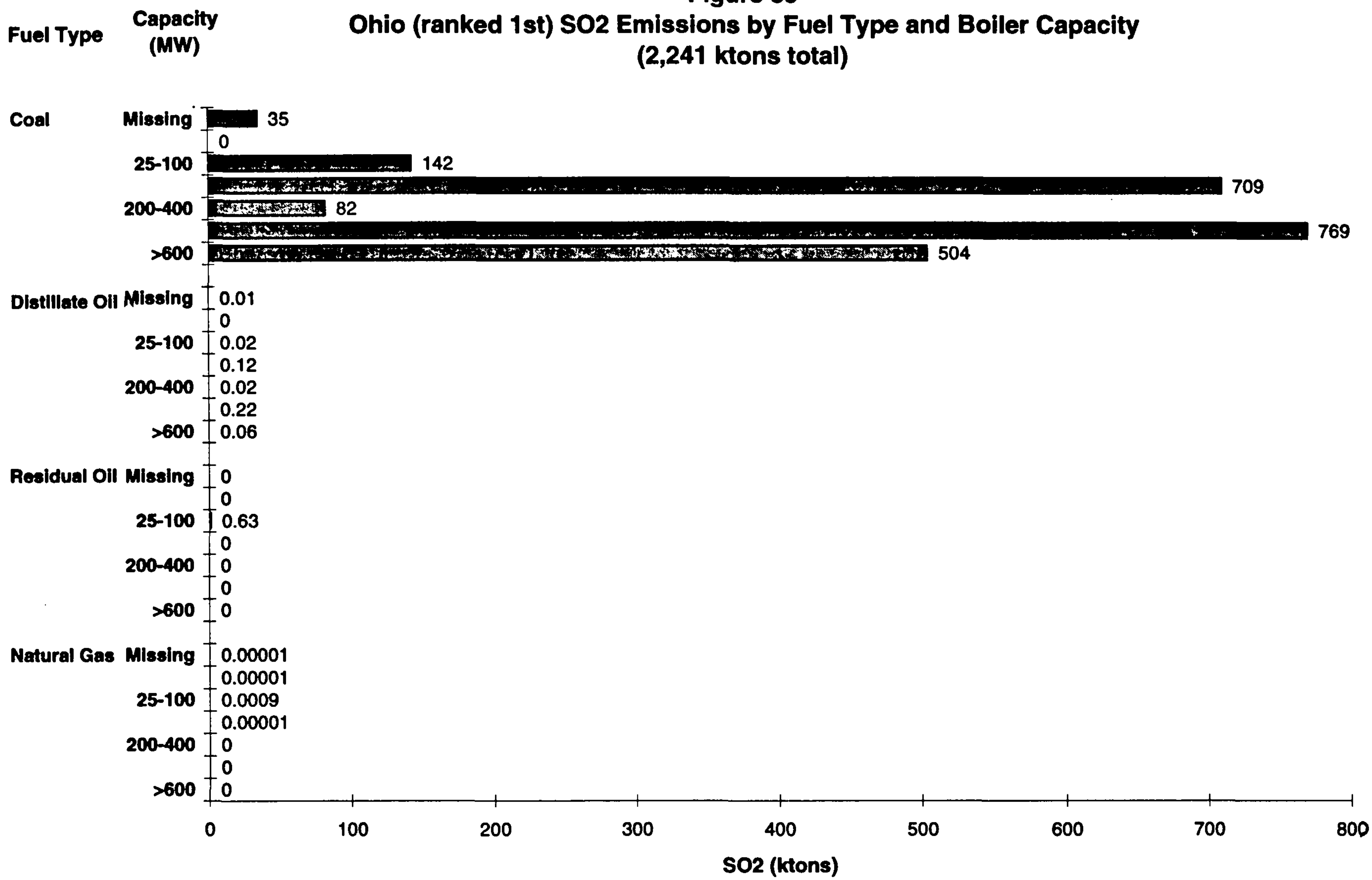


Figure 86
Pennsylvania (ranked 3rd) SO2 Emissions by Fuel Type and Sulfur Content
(1,225 ktons total)

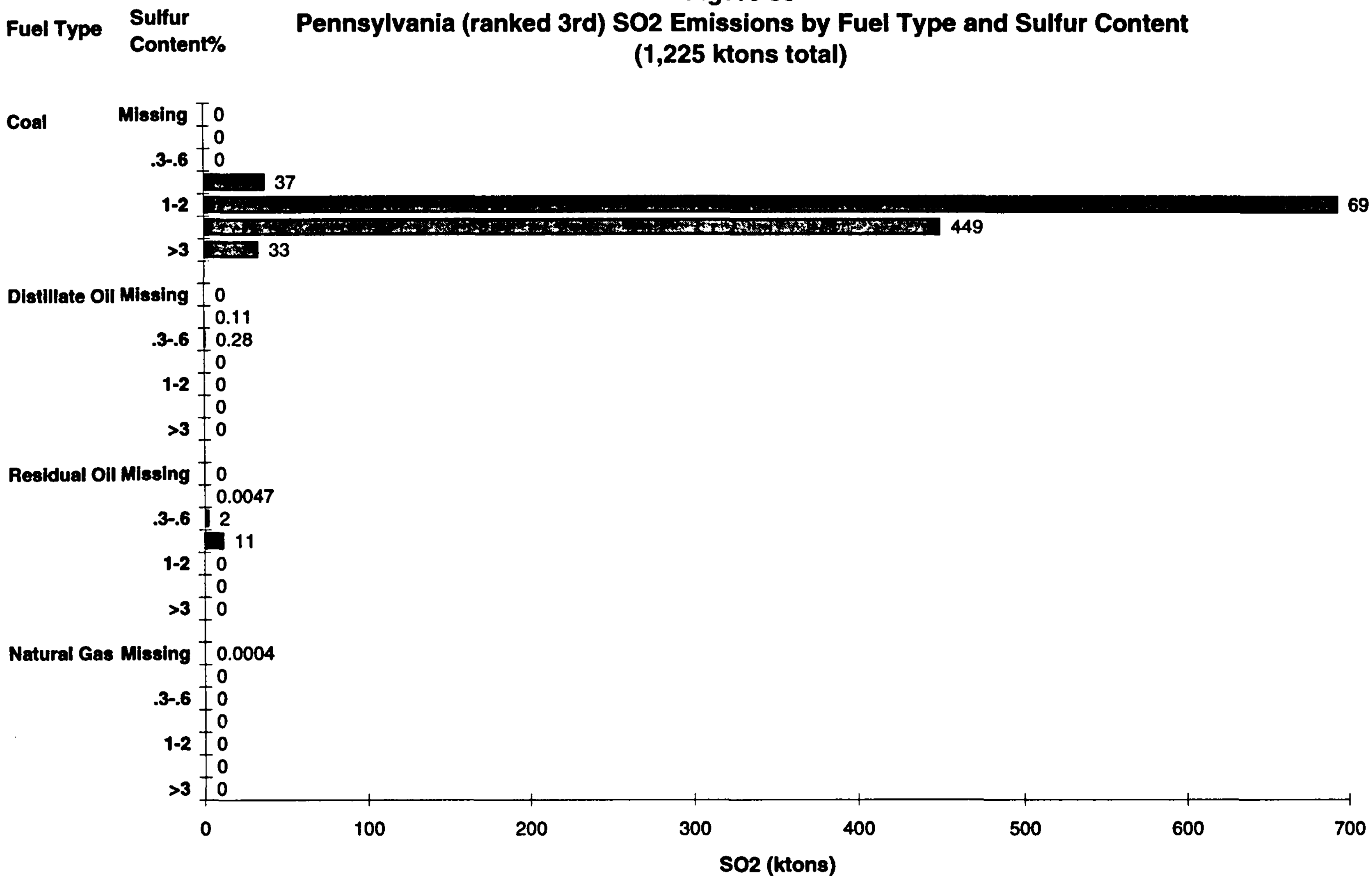


Figure 87
Pennsylvania (ranked 3rd) SO2 Emissions by Fuel Type and Boiler Capacity
(1,225 ktons total)

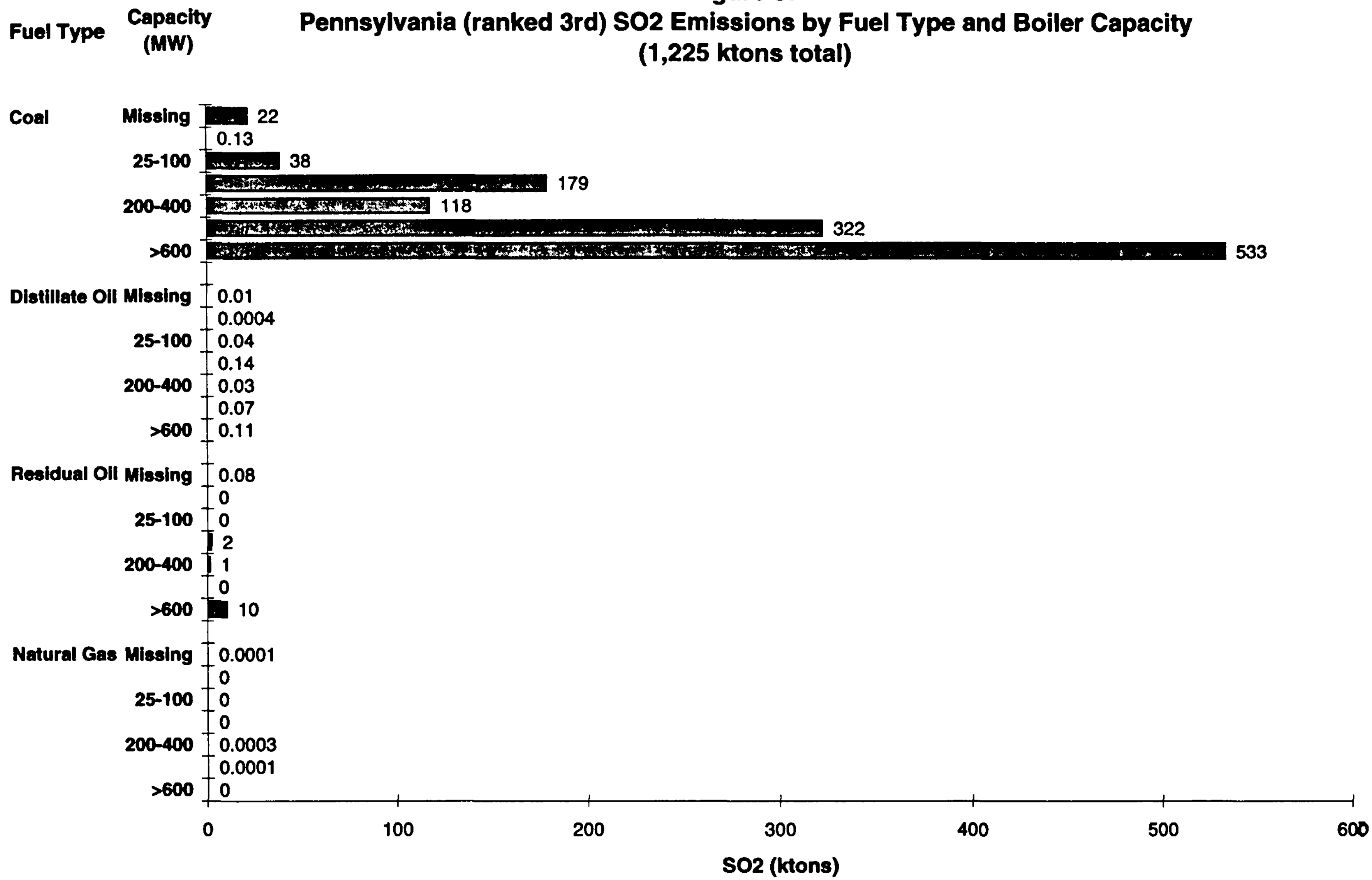
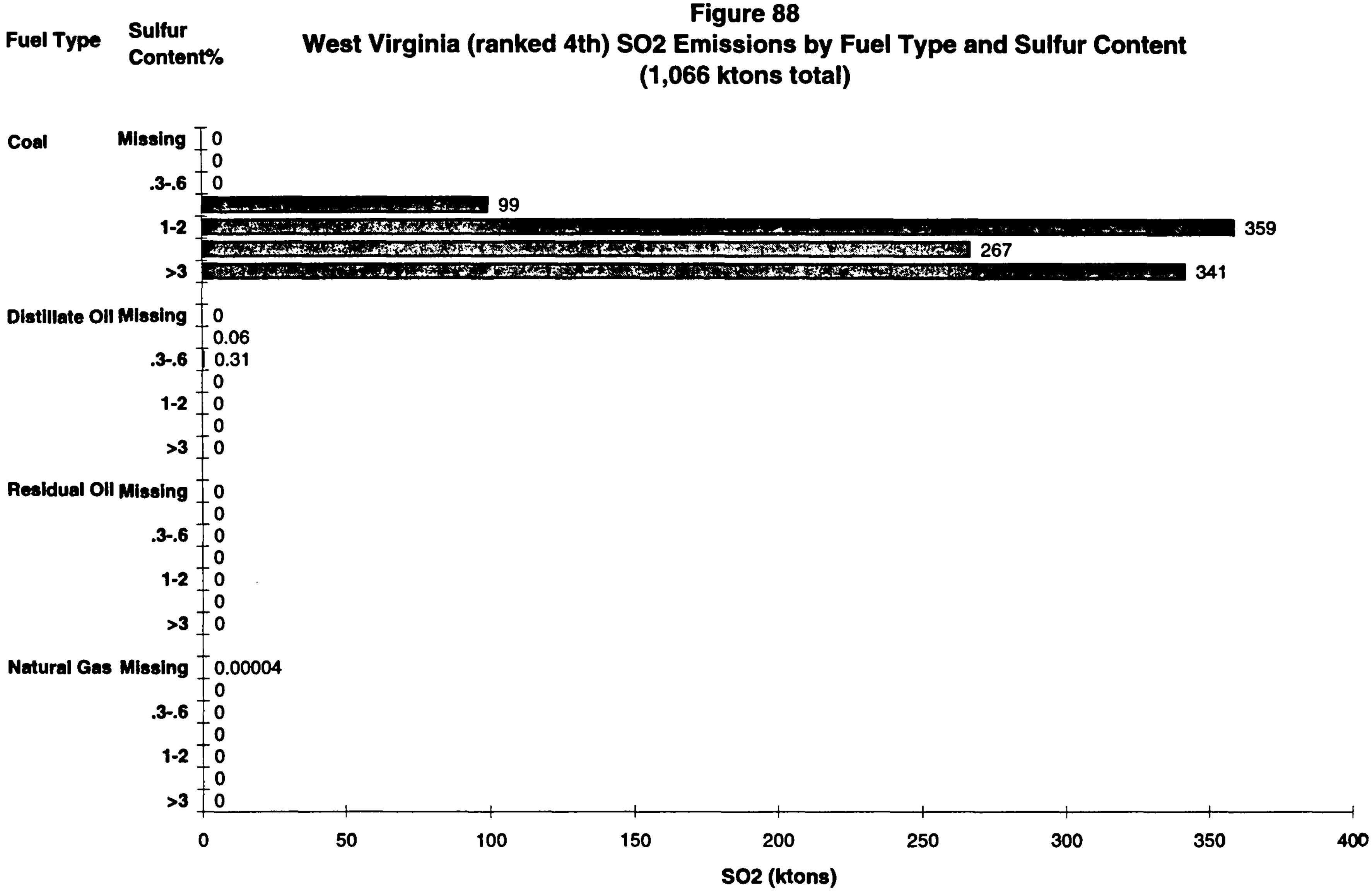


Figure 88
West Virginia (ranked 4th) SO2 Emissions by Fuel Type and Sulfur Content
(1,066 ktons total)



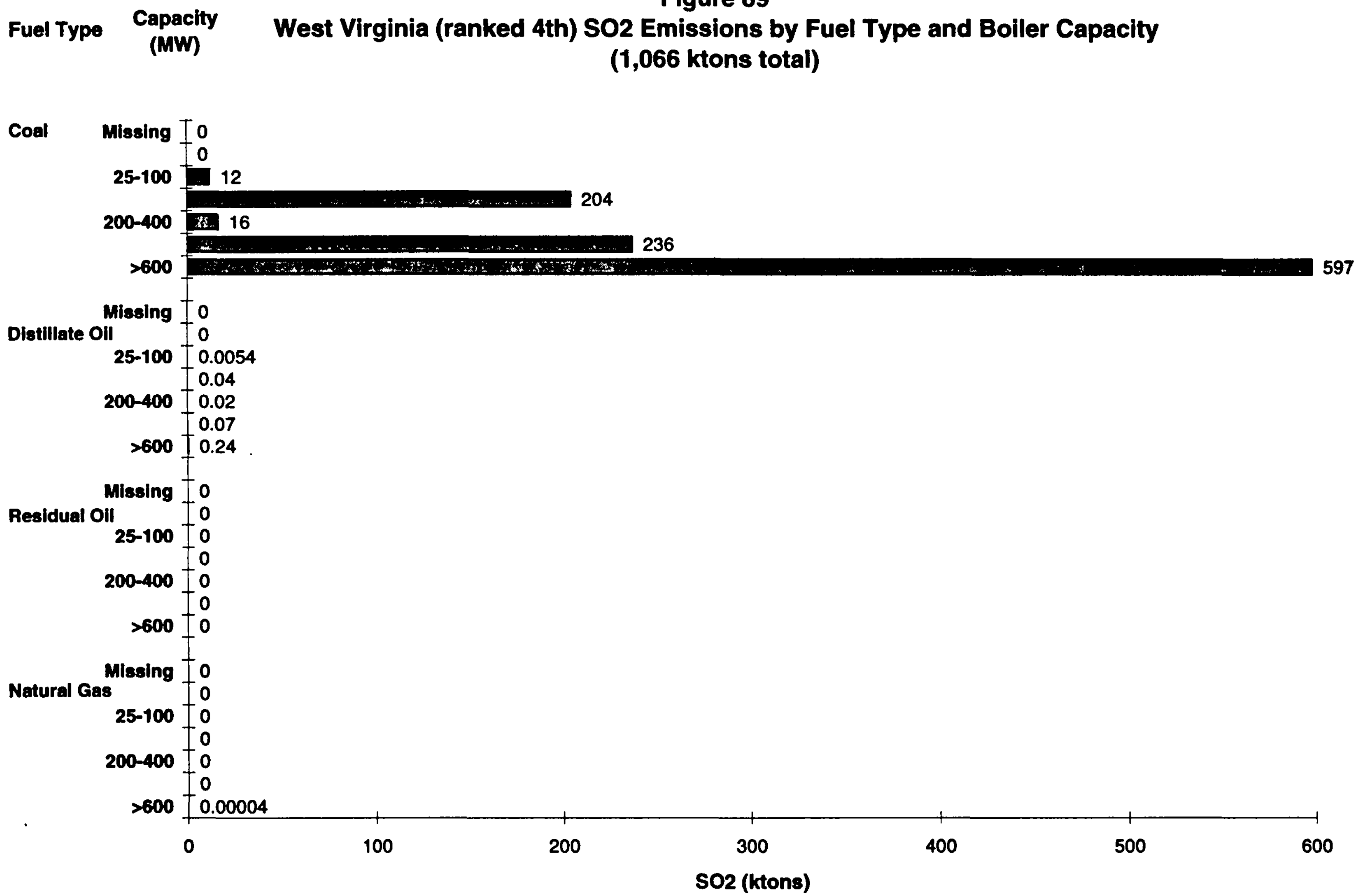


Figure 89
West Virginia (ranked 4th) SO2 Emissions by Fuel Type and Boiler Capacity
(1,066 ktons total)

Table 2
Top 10 SO_2-Emitting Operating Utilities

Utility Name	SO_2 (tons)	SO_2 Rank
TENNESSEE VALLEY AUTHORITY	1,064,194	1
OHIO POWER CO	891,188	2
GEORGIA POWER CO	788,480	3
MONONGAHELA POWER COMPANY	563,703	4
PENNSYLVANIA ELECTRIC CO	506,402	5
PSI ENERGY, INC.	505,710	6
ALABAMA POWER CO	421,721	7
UNION ELECTRIC CO	368,465	8
PENNSYLVANIA POWER & LIGHT CO	326,268	9
ILLINOIS POWER CO	302,309	10

Table 3
Top 10 NO_x-Emitting Operating Utilities

Utility Name	NO_x (tons)	NO_x Rank
TENNESSEE VALLEY AUTHORITY	365,732	1
TEXAS UTILITIES ELECTRIC CO	265,825	2
GEORGIA POWER CO	198,068	3
PACIFICORP	192,148	4
DETROIT EDISON CO	188,320	5
OHIO POWER CO	167,543	6
ALABAMA POWER CO	148,534	7
PENNSYLVANIA ELECTRIC CO	132,616	8
COMMONWEALTH EDISON CO	132,451	9
HOUSTON LIGHTING & POWER CO	130,431	10

Figure 90
Top 3 Emitting Operating Utilities SO2 Emissions by Fuel Type

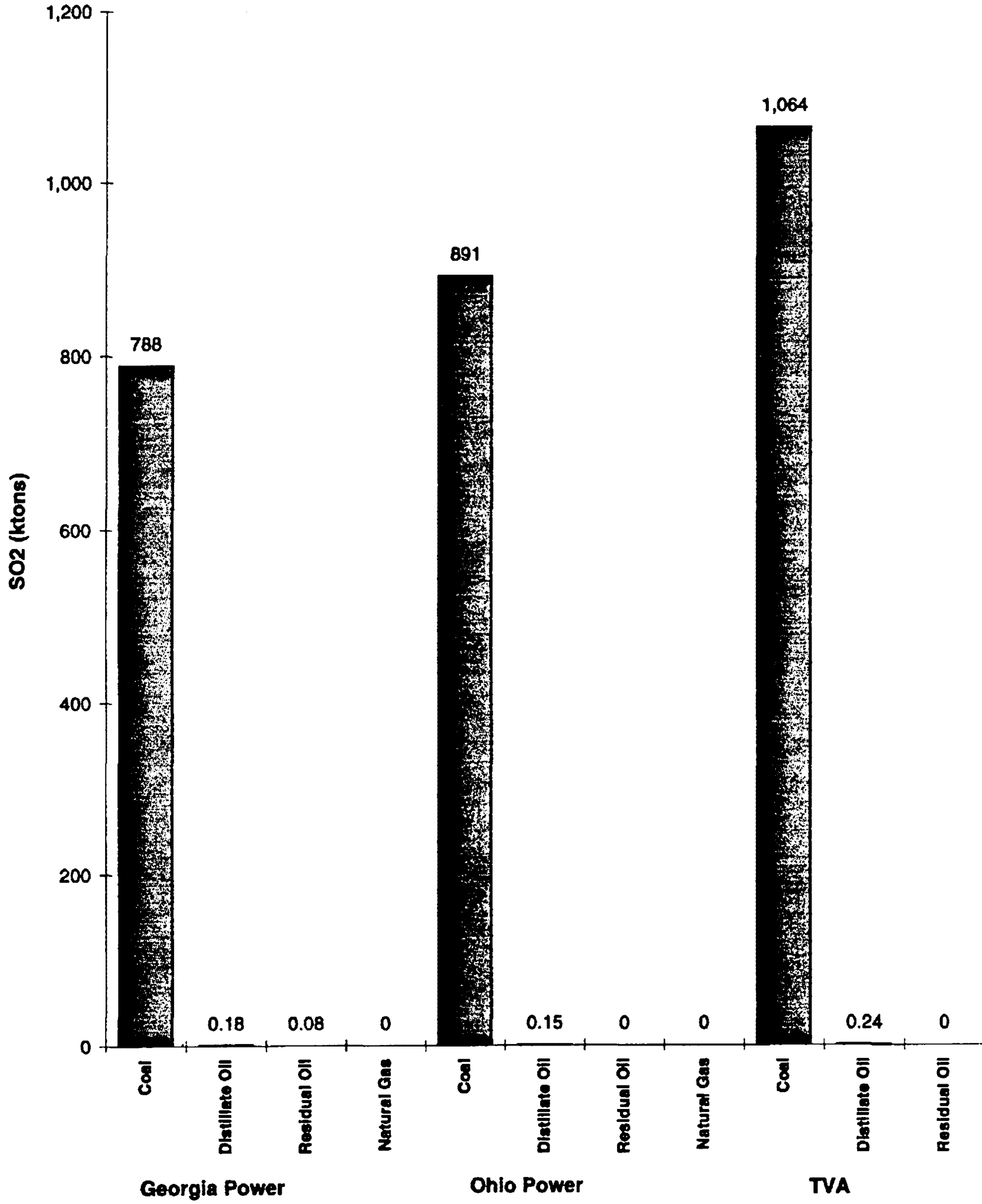


Figure 91
Top 3 Emitting Operating Utilities SO2 Emissions (ktons) for Scrubbed and Not Scrubbed Coal

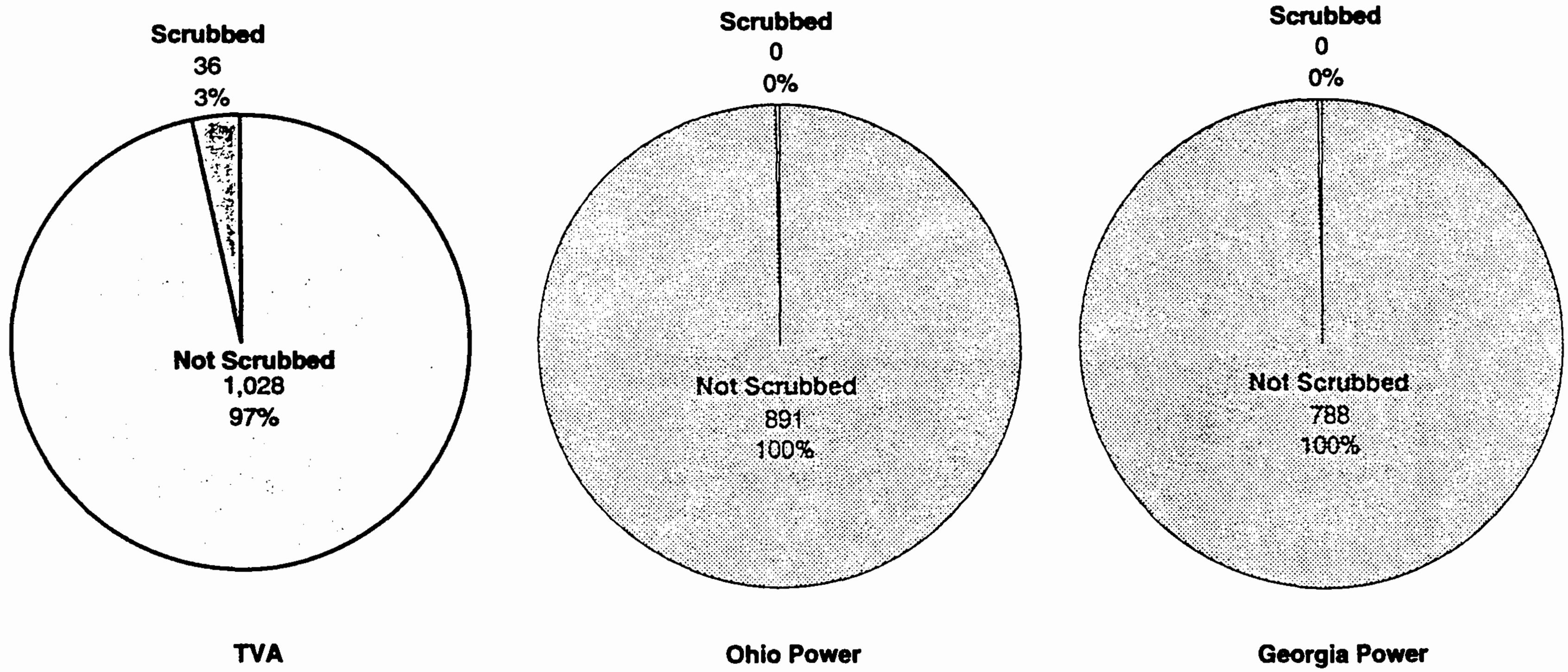
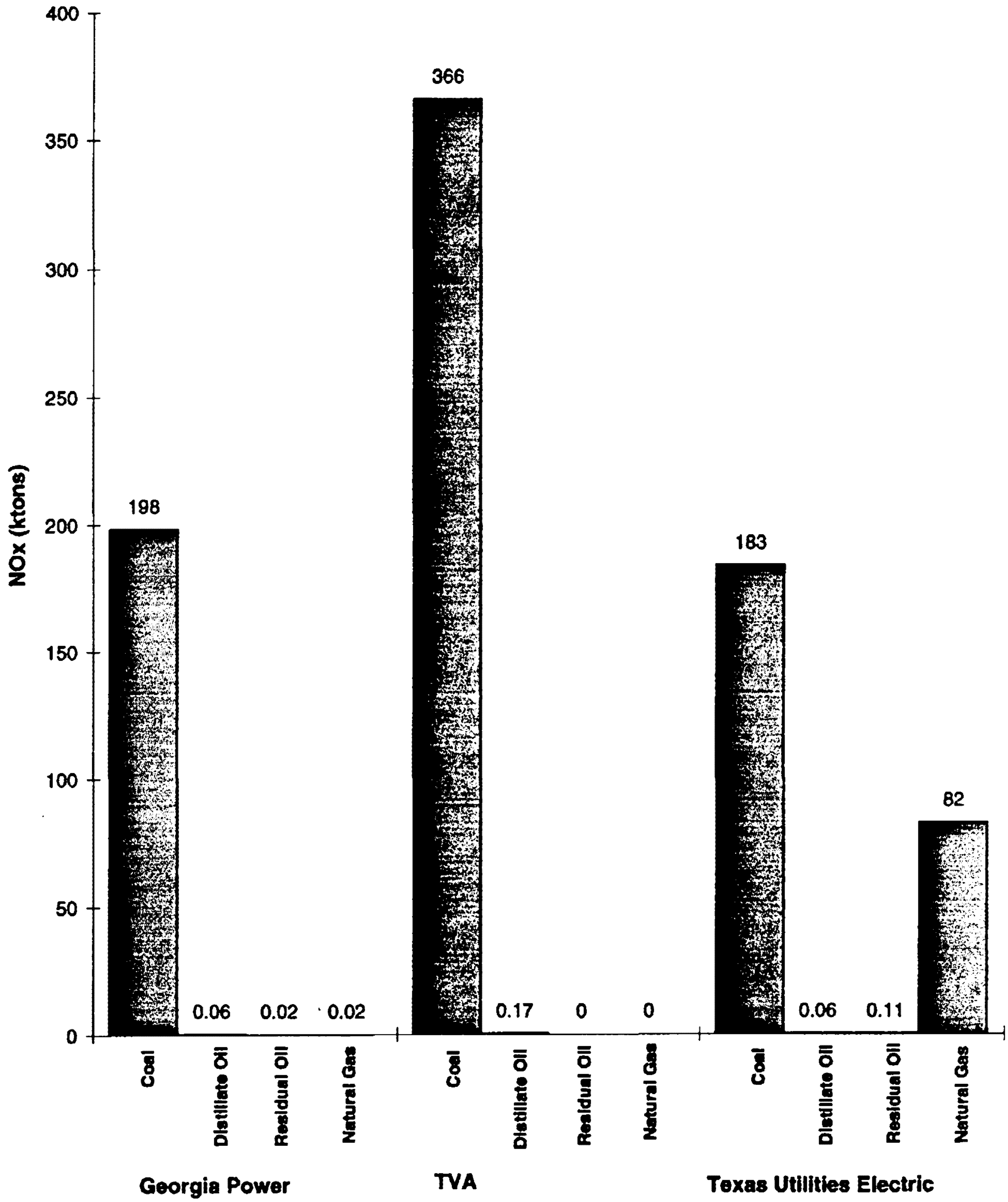


Figure 92
Top 3 Emitting Operating Utilities NOx Emissions by Fuel Type



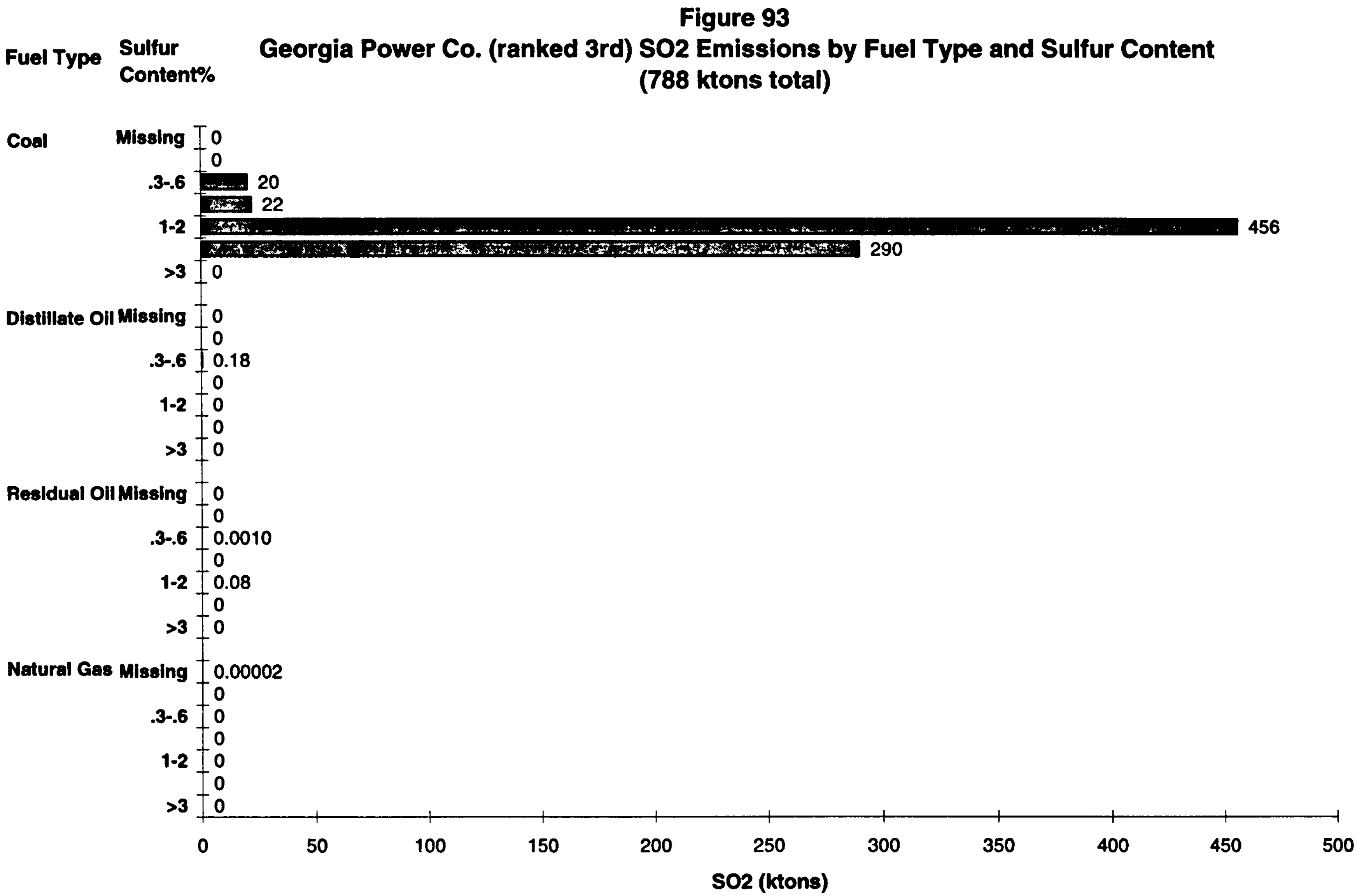


Figure 93
Georgia Power Co. (ranked 3rd) SO2 Emissions by Fuel Type and Sulfur Content
(788 ktons total)
Fuel Type
Sulfur Content%
Coal
Distillate Oil
Residual Oil
Natural Gas
Missing
.3-.6
1-2
>3
0
20
22
456
290
0.18
0.0010
0.08
0.00002
0
50
100
150
200
250
300
350
400
450
500
SO2 (ktons)

Figure 94
Georgia Power Co. (ranked 3rd) SO2 Emissions by Fuel Type and Boiler Capacity
(788 ktons total)

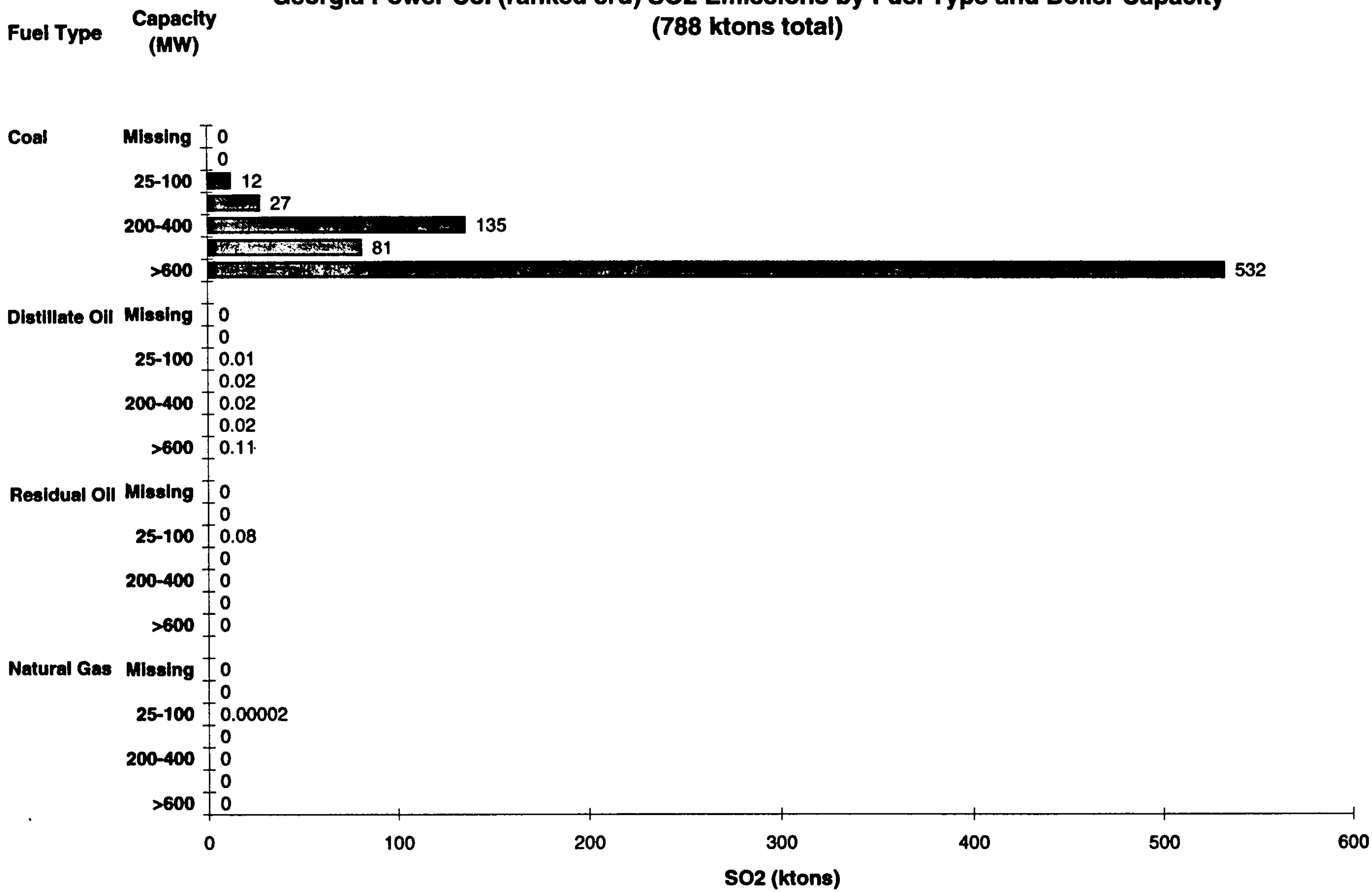


Figure 95
Ohio Power Co. (ranked 2nd) SO2 Emissions by Fuel Type and Sulfur Content
(891 ktons total)

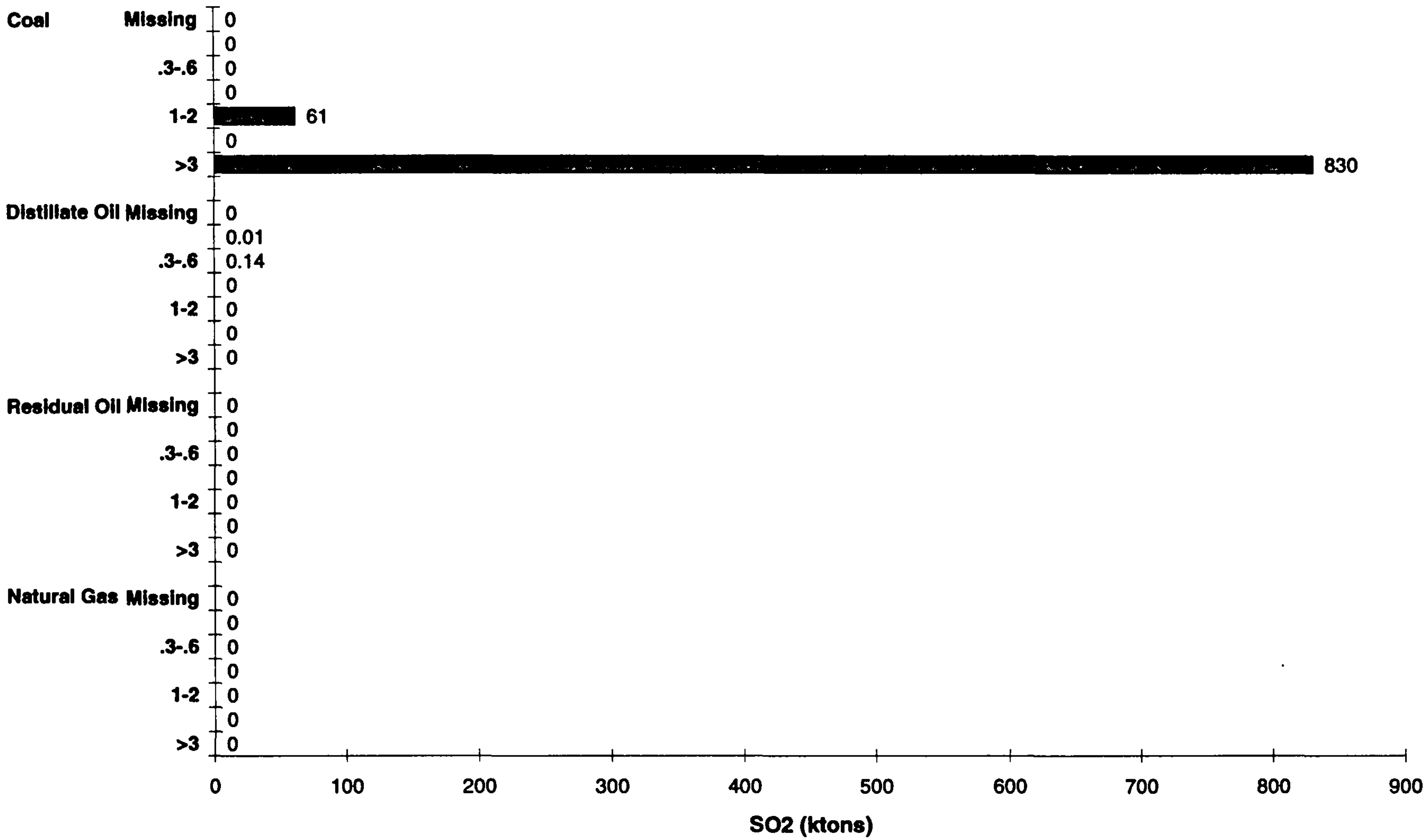


Figure 96
Ohio Power Co. (ranked 2nd) SO2 Emissions by Fuel Type and Boiler Capacity
(891 ktons total)

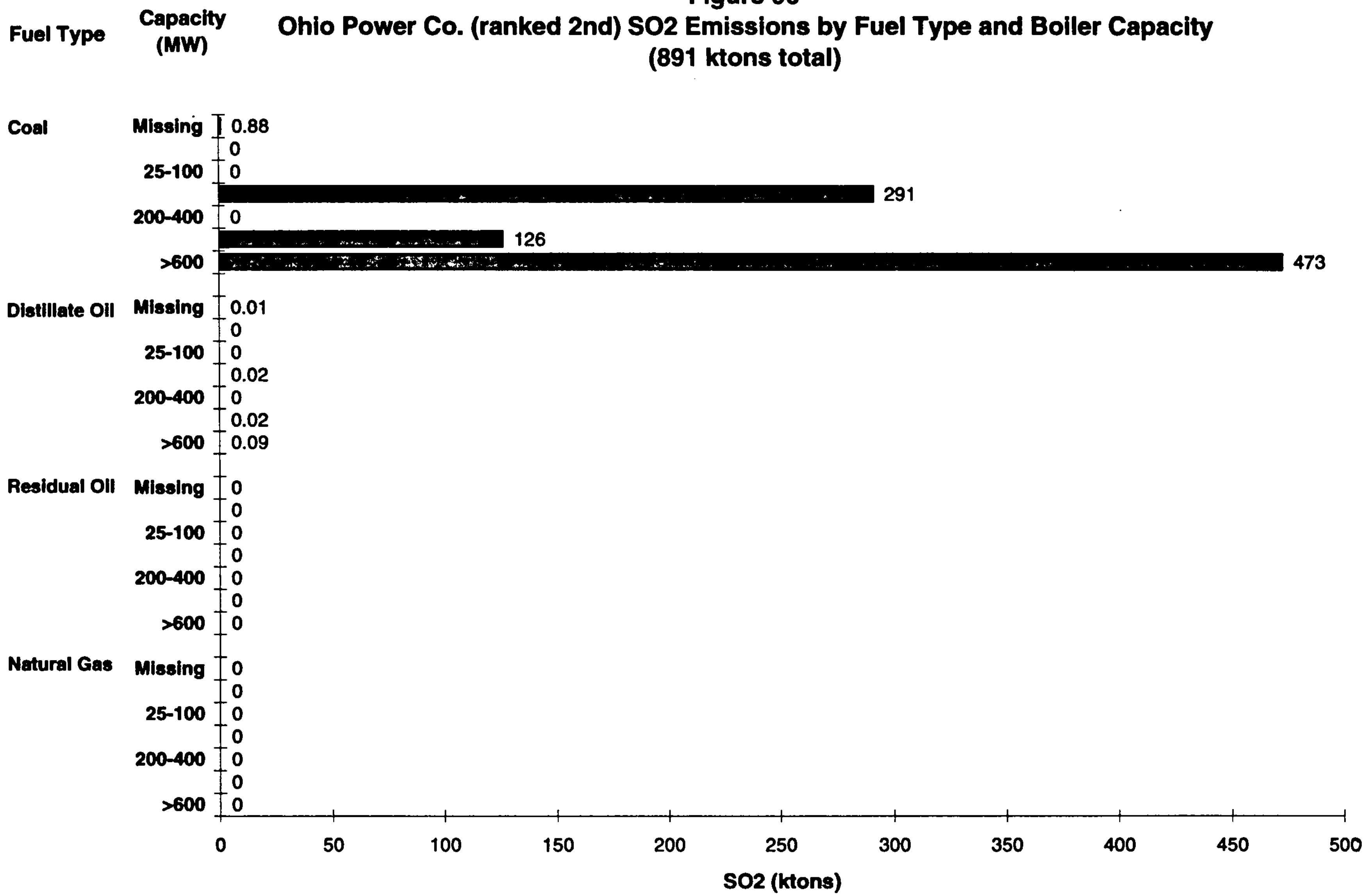


Figure 97

Tennessee Valley Authority (ranked 1st) SO2 Emissions by Fuel Type and Sulfur Content (1,064 ktons total)

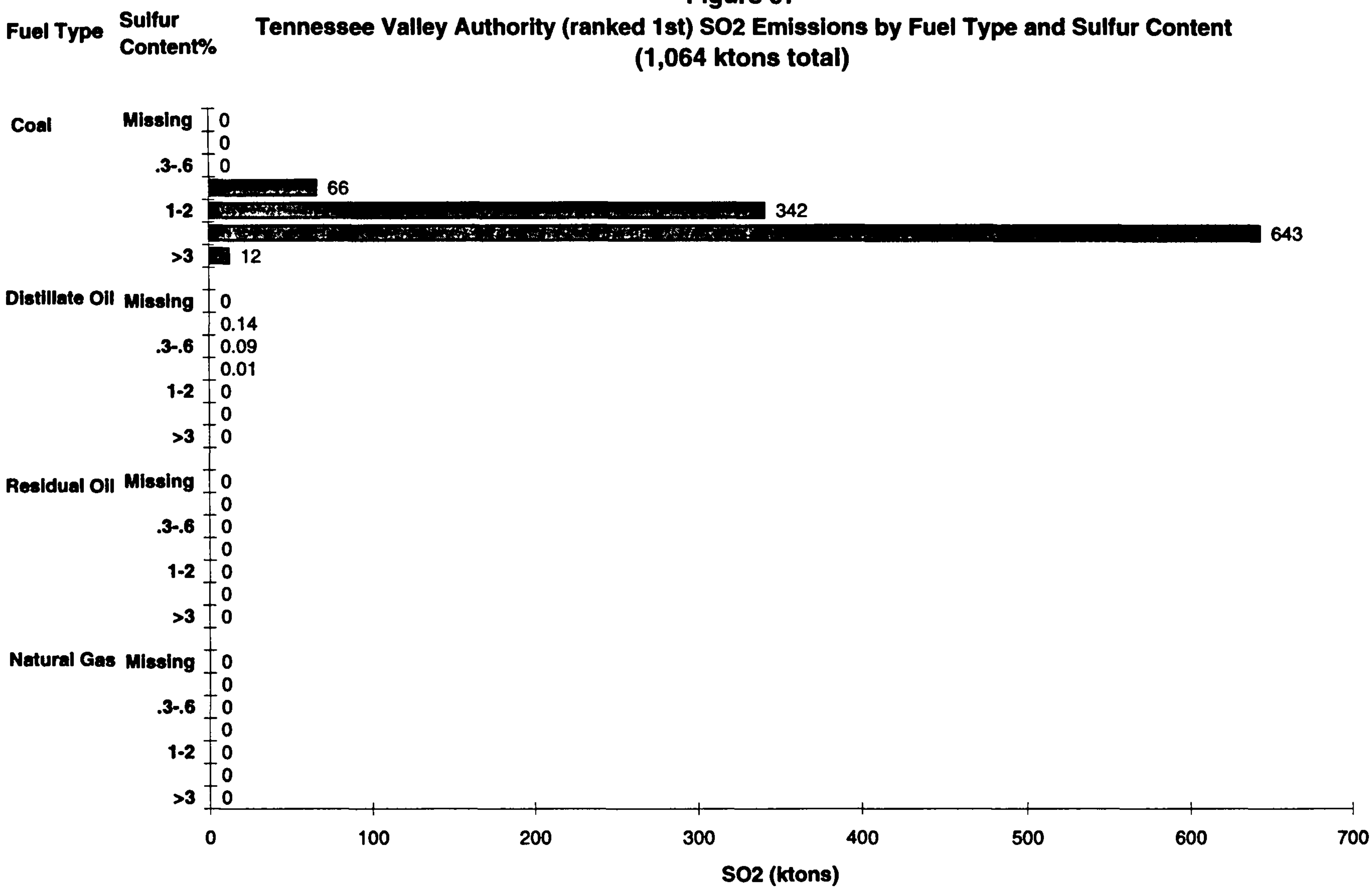


Figure 98
Tennessee Valley Authority (ranked 1st) SO2 Emissions by Fuel Type and Boiler Capacity
(1,064 ktons total)