United States
Environmental Protection
Agency

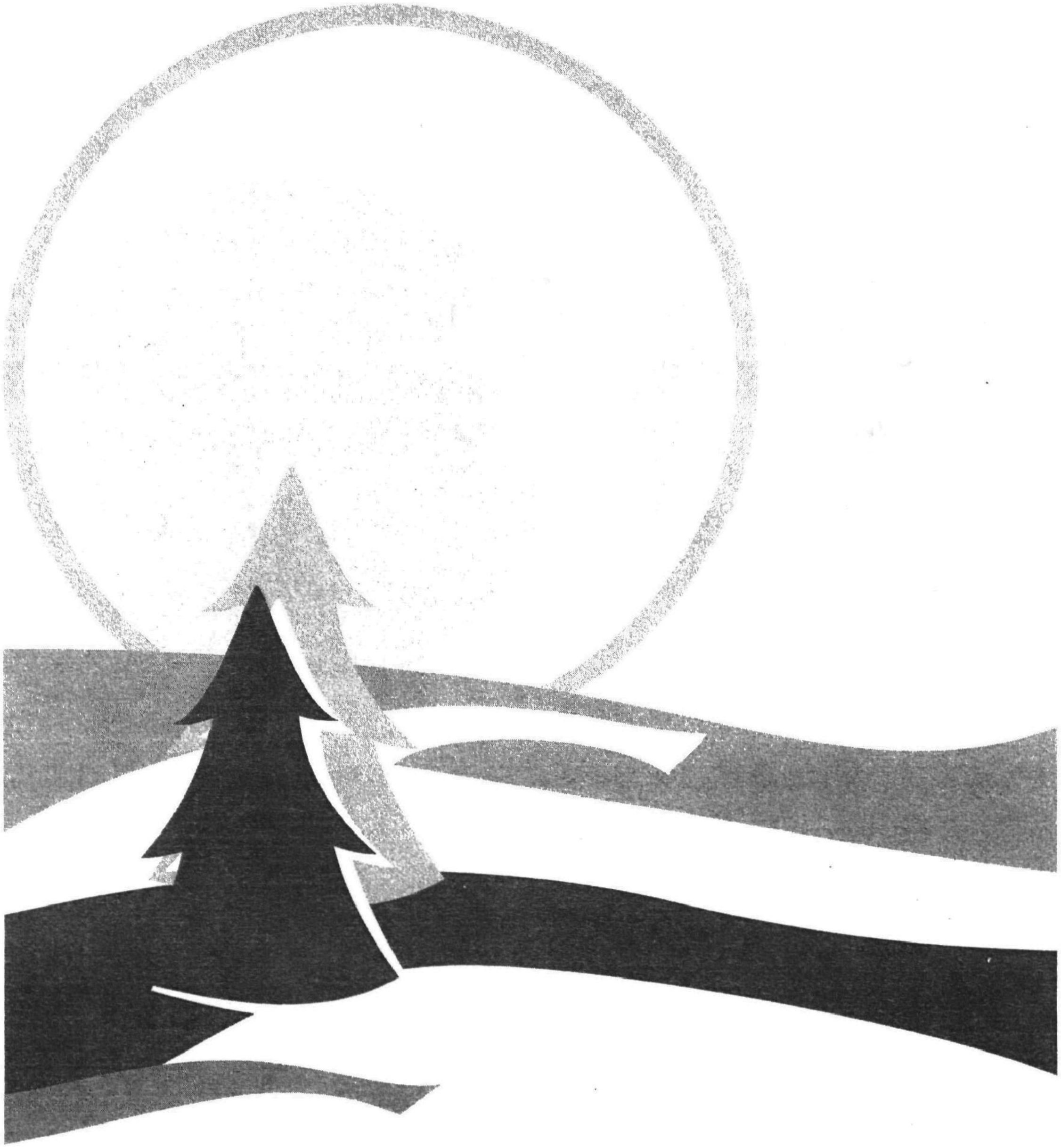
Office of Air and Radiation
Acid Rain Division

EPA 430-R-94-002
February 1994

EPA

Do the Acid Rain SO_2 Regulations Apply to You?

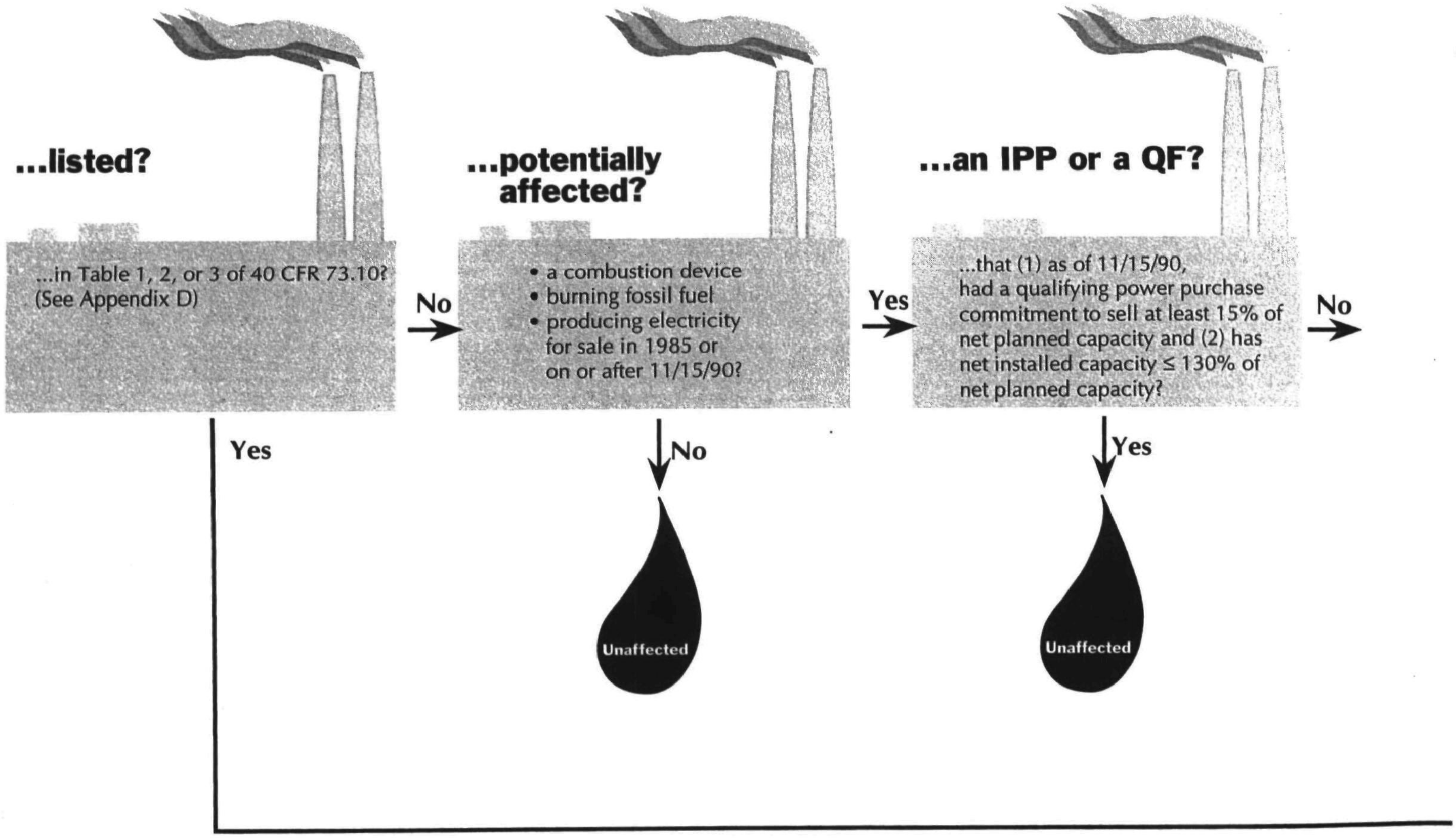
A Guide for Utilities and Other Electricity Generators



ACID RAIN
PROGRAM

Do the Acid Rain Regulations Apply to You?

s the unit...



A unit that is exempted or unaffected must continue to meet certain requirements in order to maintain exempted or unaffected status. See the appropriate section of this guide for information on the continuing requirements for your unit.

...a cogenerator?

...that (1) supplied an annual average of ≤ 1/3 of potential electrical output capacity or ≤ 219,000 MWe-hrs to the grid for sale for any three year period after 11/15/90 and (2) was constructed for the purpose outlined in (1) if construction commenced on or before 11/15/90?

Yes → **Unaffected**

No →

...an incinerator?

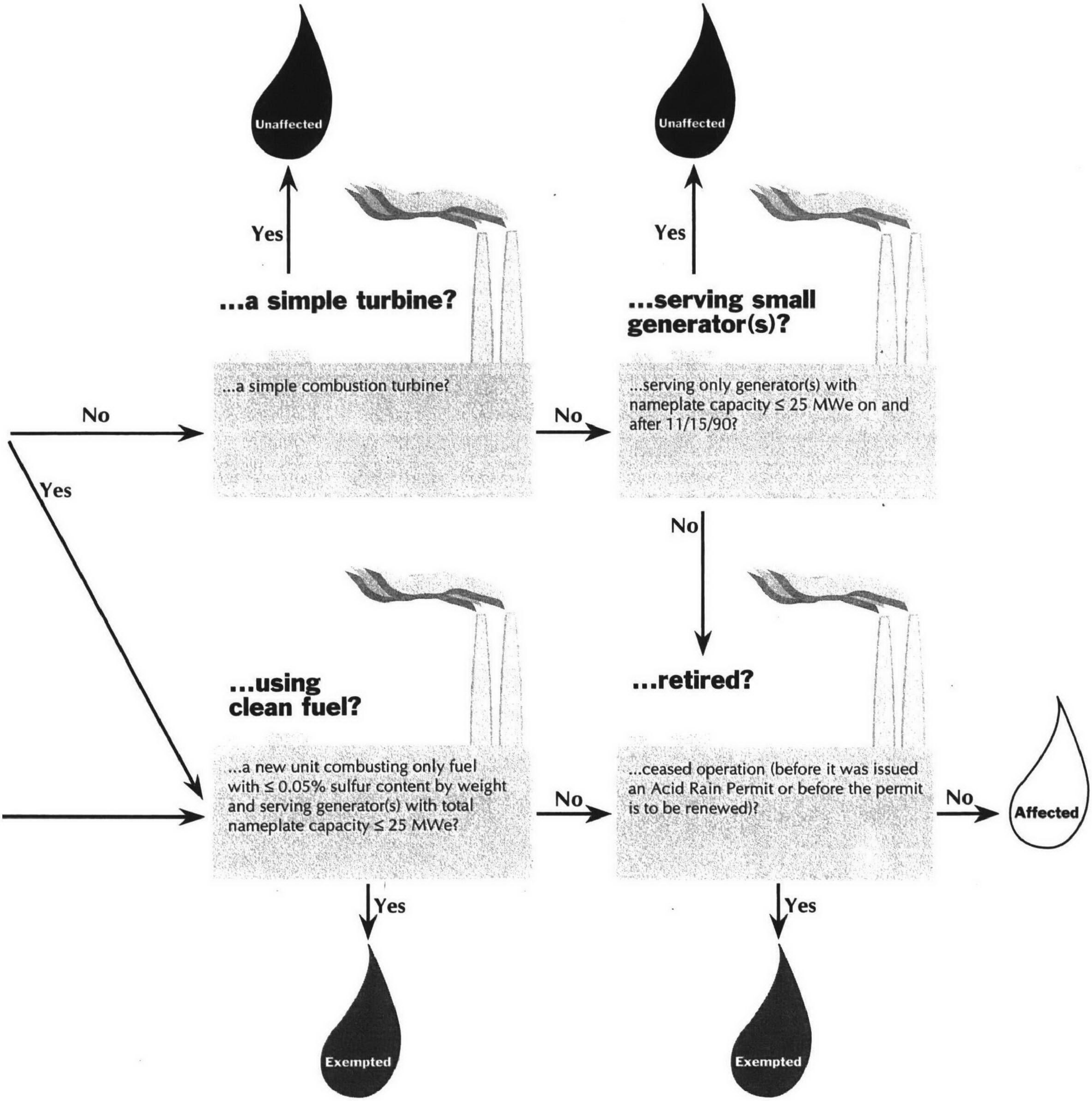
...that (1) combusted<20% fossil fuel (on a Btu basis) on average for the first three years of operation or from 1985-1987, whichever is later and (2) combusted < 20% fossil fuel (on a Btu basis) on average for any three year period after 11/15/90?

Yes → **Unaffected**

No →

...new?

...a unit that commenced commercial operation on or after 11/15/90?



Unaffected
Yes
...a simple turbine?
...a simple combustion turbine?
Unaffected
Yes
...serving small generator(s)?
...serving only generator(s) with nameplate capacity ≤ 25 MWe on and after 11/15/90?
No
No
Yes
No
...using clean fuel?
...a new unit combusting only fuel with ≤ 0.05% sulfur content by weight and serving generator(s) with total nameplate capacity ≤ 25 MWe?
No
...retired?
...ceased operation (before it was issued an Acid Rain Permit or before the permit is to be renewed)?
No
Affected
Yes
Exempted
Yes
Exempted

ACKNOWLEDGEMENTS

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The U.S. Environmental Protection Agency has reviewed and approved this document for publication.

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Preface

This guidance is designed to assist electricity producers in determining whether or not the Acid Rain Program's sulfur dioxide (SO_2) regulations apply to their units. The information provided in this guidance document may be updated as EPA makes additional decisions and determinations regarding implementation of the Acid Rain Program. EPA will seek to reconcile implementation of the Acid Rain Program with new legislation, such as the Energy Policy Act of 1992.

If desired, the owner or operator of a unit may request that EPA determine if a unit is affected by the regulations under the procedures described in 40 CFR 72.6(c). Publication of this document is not an applicability determination under 40 CFR 72.6(c). If you have further questions on applicability, please call the **Acid Rain Hotline** at **(202) 233-9620**, or submit questions in writing to:

U.S. EPA
Acid Rain Division (6204J)
ATTN: Applicability
401 M Street, SW
Washington, D.C. 20460

Legal Statement

This document is intended solely as guidance. It does not represent final Agency action. This document is not intended, nor can it be relied upon, to create any rights enforceable by any party in litigation with the United States. Only a formal applicability determination under the procedures described in 40 CFR 72.6(c) will be enforceable. EPA officials may decide to follow the guidance provided in this document or to vary from it, depending on the specific circumstances encountered. The Agency may change this guidance at any time without public notice.

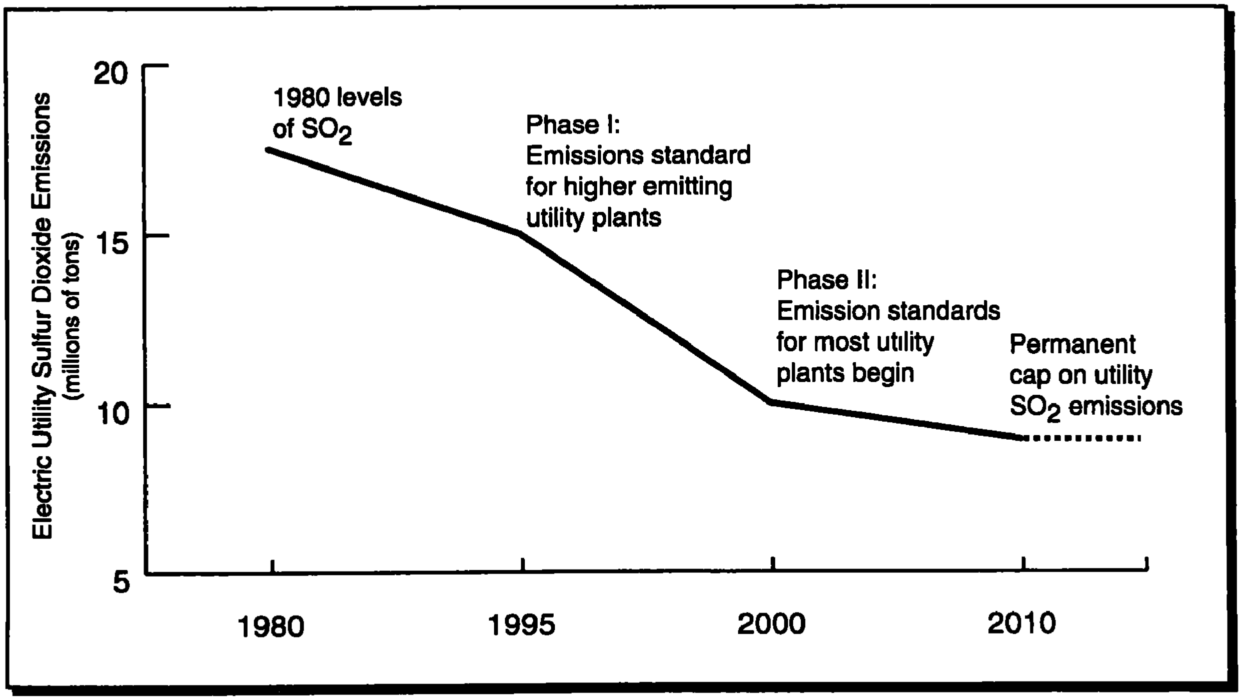
Overview

Of the approximately 23 million tons of sulfur dioxide (SO_2) and 19 million tons of nitrogen oxides (NO_X) emitted from all sources in the United States in 1985, about 16 million tons of SO_2 and seven million tons of NO_X were emitted by electric utility companies. Emissions of SO_2 and NO_X are the primary causes of acid rain.

In order to reduce acid rain in the U.S. and Canada, Title IV of the Clean Air Act Amendments of 1990 requires the Environmental Protection Agency (EPA) to establish a program to reduce emissions, called the Acid Rain Program. The overall goal of the Acid Rain Program is to achieve significant environmental benefits through reductions in SO_2 and NO_X emissions. To achieve this goal at the lowest cost to society, the Program employs both traditional and innovative market-based approaches for controlling air pollution. In addition, the Program encourages energy efficiency and promotes pollution prevention.

Title IV sets as its primary goal the reduction of annual SO_2 emissions by 10 million tons below 1980 levels. Approximately 85 percent of the reduction in emissions is to be achieved by electric utilities. To achieve these SO_2 reductions, the law requires a two-phase tightening of the restrictions placed on fossil fuel-fired power plants. Phase I, which begins in 1995, requires 110 higher-emitting utility plants in 21 eastern and midwestern states to meet an intermediate SO_2 emissions limitation. Phase II, which begins in the year 2000, tightens the annual emissions limitation and expands coverage to most utility units.

Under the Program, units are allocated "allowances" by EPA. An allowance is a limited authorization to emit up to one ton of SO_2 during or after a specified calendar year. Once allowances are allocated, owners or operators may use their allowances to cover emissions, or they may trade their allowances to other units under a marketable allowance program. EPA will keep track of the allowances held by each unit by using the Allowance Tracking System (ATS).



Utility units that began operation prior to the passage of the Clean Air Act Amendments (November 15, 1990) are allocated emission allowances based on their historic fuel usage and emission rates specified in Title IV and its implementing regulations. Most units commencing operation from November 15, 1990, through December 31, 1995, will also be allocated allowances under Phase II.* The National Allowance Data Base (NADB), developed by EPA, lists utility units – existing and planned – as well as the information necessary to allocate allowances to these units.

Units that are affected by the acid rain regulations are required to limit SO_2 emissions to the number of allowances they hold. Some utilities may benefit by selling their allowances while reducing their emissions. Since allowances are fully transferable, these utilities may choose to emit less than their allocated allowances and sell the difference to utilities that would benefit from buying allowances and emitting more than their initial allocation. This trading achieves economic efficiency while capping total SO_2 emissions nationwide.

* Certain other facilities may be allocated allowances, but they are not subject to emissions limitations under Title IV. These allowances are allocated to provide financial incentives for indirect reductions of SO_2 emissions. Small diesel refining facilities are eligible for allocations based on fuel desulfurization, which will reduce SO_2 emissions from diesel-burning vehicles (see 40 CFR 73 Subpart G). Also, utilities using renewable energy or employing energy conservation measures may be eligible for certain allowances (see 40 CFR 73 Subpart F).

In order to maintain a permanent cap on utility SO_2 emissions of 8.95 million tons per year, utility units that begin operation after 1995 generally are not allocated allowances. Affected units not allocated allowances may not emit SO_2 unless they purchase allowances.

In any year that a source fails to hold sufficient allowances to cover its emissions, excess emissions penalties will apply. Also, the source must submit a plan to EPA that specifies how the excess SO_2 emissions will be offset, or it will have allowances deducted immediately from its unit account.

The Act also calls for a two million ton reduction in NO_X emissions by the year 2000. A significant portion of this reduction will be achieved by requiring coal-fired utility boilers to meet new NO_X emissions requirements. A marketable allowance program is not part of the NO_X reduction program.

What This Guide Will Tell You

This guide is designed to help utilities and other electricity generators determine whether they are affected by the SO_2 and monitoring regulations of the Acid Rain Program. The *flow chart* on the inside cover provides a quick-reference guide showing categories of units that are affected by, eligible for exemption from, or unaffected by the regulations. The document presents descriptions of these categories, requirements for affected units, and requirements for obtaining exemptions. Specific sections of the document are described below.

Section 1: Determining Applicability

This section outlines how to determine if a unit is affected by the SO_2 and monitoring provisions of the Acid Rain Program. It describes various types of units as defined by the Acid Rain Program and states whether those types are affected by, may be eligible for an exemption from, or are unaffected by the Acid Rain Program. This section also outlines the information that needs to be included in a request for an applicability determination from EPA.

Section 2: Requirements for Affected and Exempted Units

A unit that becomes affected by the Program must meet several initial and continuing requirements. This section outlines these requirements and provides references for further information. This section also provides compliance timelines for meeting Phase I, Phase II, and continuous emission monitoring (CEM) requirements, and it lists permit deadlines and dates when units must hold allowances.

Appendix A: Selected Acid Rain Regulations and Documents

Appendix A lists several acid rain regulations and informational documents, including publication dates and dockets.

Appendix B: EPA Regional and State Office Addresses

Appendix B presents a list of EPA Regional offices and State environmental offices relevant to the Acid Rain Program.

Appendix C: Applicability Determination Examples

Appendix C presents several case studies demonstrating how to determine whether the regulations affect certain utility units.

Appendix D: Selected List of Units Affected by the Acid Rain Regulations

Appendix D provides lists of units affected by the acid rain regulations. These lists were published in the Clean Air Act or in regulations.

Appendix E: Certificate of Representation

Appendix E contains the Certificate of Representation form and its instructions.

What This Guide Won't Tell You

This document does not address Title IV NO_X control requirements, which establish new NO_X emissions limits for existing coal-fired electric utility units.

This document also does not address requirements applicable to unaffected units that voluntarily participate in the Acid Rain Program. Sources of SO_2 that are not required to meet Title IV emissions limitations may choose to "opt-in" to the Acid Rain Program. The Opt-In Program encourages these sources to reduce emissions of SO_2 in circumstances under which it will be less costly for them to do so than it would be for an affected unit.

Note that many units are required to meet SO_2 emissions limitations or control requirements under other programs, whether or not they are affected by acid rain regulations. These other limitations may be more stringent than the limitations under Title IV. Non-Title IV requirements are not covered in this guidance.

For questions about the Acid Rain Program, or for more information on the NO_X requirements or the Opt-In Program, please contact the **Acid Rain Hotline** at **(202) 233-9620.** For questions or information on other Federal or State clean air programs, please contact your State air quality office (see *Appendix B*).

Section 1
Determining Applicability

In general, the acid rain regulations for sulfur dioxide (SO_2) are applicable to existing utility units serving a generator with nameplate capacity of 25 megawatts of electricity (MWe) or greater and almost all new utility units located in the 48 contiguous States and the District of Columbia. For the purposes of the Acid Rain Program, the term "utility units" includes units serving generators that supply electricity for sale, whether wholesale or retail.

There are, however, applicability exceptions for certain types of units and units meeting specific criteria. These units may be eligible for an exemption or may be unaffected by the acid rain regulations. This section provides the necessary information for determining whether a unit is affected. Note that once a unit becomes affected, it remains affected for the duration of the Program.

Section 1 is presented in three parts. The first part describes the characteristics of affected units. The second part describes the characteristics of units that may be exempted from certain acid rain regulations. The third part describes six types of units that are unaffected by the regulations. Following the descriptions of each of these unit types are checklists of information to include in a request for an applicability determination. If you do not know which type of unit you have, or if you have a unit that may qualify as more than one type, be sure to submit the necessary material for all potentially relevant categories.

The following are general requirements for filing an applicability determination request:

✓ The letter requesting an applicability determination must be signed by a "certifying official."

✓ The letter must specify the unit. Information should include the plant that contains the unit, the location of the unit (i.e., State and county), the "ORISPL" (a plant code used by the Department of Energy) if appropriate, and a name or number for the unit.

✓ The letter must include the following statement: "I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

✓ The letter must be sent to the following address: U.S. Environmental Protection Agency; Director, Acid Rain Division (6204J); ATTN: Applicability; 401 M Street, SW; Washington, DC 20460.

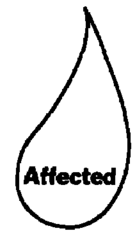
✓ The certifying official must send copies of the request to each owner or operator of the facility.

Applying for an Applicability Determination by EPA

EPA has adopted a procedure by which owners and operators of any potentially affected unit may choose to ask EPA to determine whether or not Title IV SO_2 requirements apply to their source. See 40 CFR 72.6(c). This procedure is <u>optional</u>; EPA does not require any owner or operator to request a determination of applicability. Those sources that clearly fit into an unaffected or exempted category should not feel compelled to request an applicability determination.

This procedure requires submittal of a written request, including certain information about the unit. In response to that request, EPA will determine if a unit is affected, based on information included in the submittal. EPA will then write a letter stating that the unit is either affected or unaffected. This response letter will constitute final agency action in the absence of an administrative appeal and will be binding upon the permitting authority administering the Acid Rain Program for the unit (i.e., the State or EPA Region). EPA's determination may be appealed through the Acid Rain Appeals process. If the information originally submitted by the unit was inadequate to make an applicability determination, EPA may request additional data or write a letter stating that EPA cannot make a determination based on the information submitted.

Affected Units



EPA has compiled a list of the sources of SO_2 emissions known to be affected by the acid rain regulations. All of these "listed units," which are discussed below, are Phase I or Phase II affected sources. A list of these units is included in *Appendix D*. If a unit or source is listed in the appendix, it is affected. Some of these units may be eligible for exemptions from certain Acid Rain Program requirements, as discussed below. See 40 CFR 72.6(a).

Listed Units

Phase I requirements initially affect only the 263 units at the 110 power plants specifically listed in the Clean Air Act and provided in Table 1 of 40 CFR 73.10 (see Exhibit 1 of *Appendix D*). Phase II requirements affect a broader group of utility units. Tables 2 and 3 of 40 CFR 73.10 (see Exhibits 2 and 3 of *Appendix D*) list approximately 2,300 utility units affected by Phase II requirements.

Additional units may become affected under Phase I if they are either "substitution units" or "compensating units." Utilities have already notified EPA as to which units will be brought into Phase I in this manner. Substitution units are existing units affected under Phase II that are designated under approved substitution plans and that accept the emission reduction obligation of a unit required to comply with Phase I. Compensating units are Phase II units that are designated under approved reduced utilization plans and that generate electricity to replace electricity historically generated by Phase I units.

Unlisted Units

The *Appendix D* listings do not include all units that are or may become affected. Other potentially affected units include:

- ❑ Units not in the NADB,
- ❑ Units that are planned, and
- ❑ Units owned by industrial or commercial entities that sell electricity.

If a unit is not listed in *Appendix D*, it may be affected by the acid rain regulations only if it meets *all three* of the following conditions:*

- ❑ The unit is a combustion device.
- ❑ The unit is fossil fuel-fired.
- ❑ The unit supplies electricity for sale or serves an electricity-generating device that supplies electricity for sale.

Definitions

Unit vs. Generator

A unit is a fossil fuel-fired combustion device, such as a boiler. A generator is a device that produces electricity. A unit may be subject to the acid rain regulations if it provides steam or is capable of providing steam or hot air to a generator that produces electricity. A generator itself is not affected by the acid rain regulations. For the purposes of the Acid Rain Program, a combined cycle turbine – a turbine with a heat recovery steam generator – will be treated as a single unit.

Combustion Devices

A combustion device is a device that initiates the chemical reaction of fuel and oxygen with the addition of heat. In the case of a combustion device that uses fossil fuels to produce electricity, the combustion of fossil fuels causes the reaction of carbon and hydrogen in the fuel with oxygen in the air to form carbon dioxide and water vapor. Other substances, such as sulfur in the fuel and nitrogen in the air, may also react with the oxygen and thereby produce air pollutants.

Fossil Fuel-Fired

A source is "fossil fuel-fired" if it combusts any amount of fossil fuel, no matter how small. The definition of fossil fuel includes natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from these materials, such as petroleum coke. The definition of natural gas *does not* include landfill gas, digester gas, or biomass.** Waste fuels, including anthracite culm and bituminous coal waste, are also considered fossil fuels for the purposes of the Acid Rain Program. A unit, by definition, is fossil fuel-fired. Thus, a boiler fueled exclusively by fuels other than fossil fuels is not a "unit" or "utility unit" under the regulations, and therefore is not subject to the acid rain regulations.

Examples of Combustion and Non-Combustion Devices

Combustion Devices

Combustion Turbine. A combustion turbine uses air heated from the combustion of fuel to spin the turbine in a magnetic field, thus creating electricity. Since it is a device that uses combustion to produce electricity directly, it is a combustion device.

Boiler. A boiler is an enclosed device that combusts fuel to produce and transfer heat to recirculating water, steam, or any other medium. Since it combusts fuel, it is a combustion device.

Non-Combustion Devices

Fuel Cell. A fuel cell relies on a electrochemical reaction of fuel (usually pure hydrogen) with pure oxygen to yield energy and water. Since this reaction is not produced by the addition of heat, it is not a combustion device.

* See 40 CFR 72.2 for the definition of "utility unit."

** See preamble to the final acid rain "core" rules, 58 FR 3596, January 11, 1993.

Submit the following for all units to have EPA determine whether your unit is affected:

✓ Information regarding the type of device (e.g., boiler, turbine, fuel cell).

✓ Information regarding the types of fuel consumed. (This information is reported on Forms EIA-767 and EIA-860.)

Supplies Electricity for Sale

Any unit that served a generator producing electricity for sale in 1985 or on or after November 15, 1990, is potentially affected by the acid rain regulations. The sale may be wholesale or retail. The "sale of electricity" is the sale of electrical output or capacity or the sale of steam to a steam-electric generator that produces electrical energy for sale.

Units that do not produce electricity or steam for sale are not affected. Also, a unit that produces steam or heat rather than electricity for sale is not affected so long as the purchaser of the steam or heat does not produce electricity for sale. A unit that produces limited amounts of electricity for sale may not be affected if the unit's combustion device is used primarily to produce steam or heat. (See *Cogeneration Unit*, below.)

Even if a unit meets all three of the conditions discussed above, it may be eligible for an exemption or qualify as one of six types of unaffected units. Exemptions may be granted to new utility units generating less than 25 MWe *and* using fuel with a sulfur content less than or equal to 0.05 percent, as well as to units that retire. The six categories of unaffected units are existing simple combustion turbines, existing small units, cogenerators, independent power production facilities, qualifying facilities, and solid waste incinerators. The categories are described below in the sections *Exempted Units* and *Unaffected Units*.

Exempted Units

Two categories of affected utility units may be eligible for exemptions from many – but not all – of the acid rain regulations: small new units burning clean fuels and retired units. These exempted units must continue to meet certain continuing requirements of the Acid Rain Program to remain exempted. Please refer to *Section 2: Requirements for Affected and Exempted Units* for a list of these requirements.

<u>In order for a unit to be considered for an exemption, it must submit an application to EPA</u>. The Agency does not require eligible units to apply for an exemption in cases where the owner of a unit does not want the unit exempted. Units that do not obtain an exemption, however, must fully comply with the Acid Rain Program requirements. If a unit decides to seek and is granted an exemption, it is not eligible to join the Program on a voluntary basis as a substitution unit, a compensating unit, or an opt-in unit.

Small New Units Burning Clean Fuels

A utility unit may be granted an exemption from acid rain regulations if it meets *all three* of the following requirements:*

- ❑ The unit is a new unit (i.e., commenced commercial operation on or after November 15, 1990).
- ❑ The unit is a small unit (i.e., serves generator(s) with total nameplate capacity of 25 MWe or less).
- ❑ The unit burns clean fuels (i.e., only fuels with sulfur content of 0.05 percent or less by weight).

Although the statutory exemption for *existing* units that serve generators with nameplate capacities of 25 MWe or less does not sum the nameplate capacities of all the generators served by the unit, the exemption for *new* units requires that the <u>total</u> nameplate capacity served by the unit be 25 MWe or less. For example, boilers headered to more than one generator (multi-header units) will be treated as serving all generators to which they are headered, regardless of the steam capacity of the boiler.

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* See 40 CFR 72.7.

A small, new unit that is granted an exemption will have to forfeit any allowances it received or was to receive as an initial allocation for all years for which the exemption is granted. Also, if the unit gains an exemption, it must comply with the acid rain regulations for all years prior to January 1 of the year after it is issued the exemption. For information on applying for a new unit exemption see *Section 2: Requirements for Affected and Exempted Units.*

Definitions

Commence Commercial Operation

A unit "commences commercial operation" when it begins to generate electricity for sale, including the sale of test generation. The National Allowance Data Base (NADB Version 2.11) includes the boiler on-line date and generator on-line date (month and year). For units in the NADB that commenced commercial operation by December 1992, the boiler on-line date in the NADB will be used as the date the unit commenced commercial operation. If a unit is not listed in the NADB or if a unit commenced commercial operation after December 1992, the first commercial on-line date will be determined in accordance with standards used by the Energy Information Administration (EIA). In general, generator first-electricity dates are reported to the U.S. Department of Energy (DOE), Energy Information Administration on Form EIA-860,* and boiler first-fuel consumption is reported on Form EIA-767.*

Each unit should have only one date of commencement of commercial operation, even if the unit is relocated or restarted after retirement. However, a unit that was substantially modified before November 15, 1990, may be treated as a unique unit with a new commencement of commercial operation date.

Nameplate Capacity

"Nameplate capacity" is a measure of the capacity of a generator. For a unit listed in the NADB, the nameplate capacity of a generator is defined as the capacity listed for the generator in the NADB. If a unit is not listed in the NADB, the nameplate capacity will be determined in accordance with the DOE standards using Form EIA-860. Generator nameplate capacity as defined on Form EIA-860 is the full-load continuous rating of a generator, prime mover, or other electric power production equipment under specific conditions as designated by the manufacturer. Installed generator nameplate rating is usually indicated on the nameplate physically attached to the generator. If more than one capacity appears on the nameplate, the highest capacity is reported on Form EIA-860.

Example of New Commercial Commencement

The Tidd plant in Ohio was retired prior to 1985. The plant was substantially modified and repowered through a Clean Coal Technology project and began operation again in October, 1990. Therefore, EPA assigned this plant a commenced commercial operation date of October 1990.

* A description of Forms EIA-860 and EIA-767 is provided in the *Glossary*.

Burns Clean Fuel

Clean fuels are fuels with sulfur content of 0.05 percent or less by weight. All natural gas, including most "sour" gases, meets this standard. On-road diesel fuel meeting the new requirements of the Clean Air Act (Section 211(i)) will also meet this standard. A unit obtaining an exemption under this provision must test petroleum or petroleum products and gaseous fuels, other than natural gas, according to the appropriate ASTM methods to assure compliance starting on the first day the exemption takes effect.

Retired Units

A utility unit may be granted an exemption from the acid rain regulations if it retires before the issuance (or renewal) of its Phase II acid rain permit (see 40 CFR 72.8). These "retired" units must document the actual or expected date of retirement as well as any actions that have been taken to retire the unit and to prevent any further emissions of SO_2 and NO_X. If the unit gains an exemption, it must comply with the acid rain regulations until January 1 of the year after it is issued the exemption. Therefore, to avoid installation and testing of continuous emission monitoring (CEM) systems required by the Acid Rain Program, a unit must apply for this exemption prior to January 1, 1995.

If a retired unit is to resume operation, its Designated Representative must submit an acid rain permit application not less than 24 months prior to January 1, 2000 or the date the unit is to resume operation, whichever is later.

For information on applying for a retired unit exemption see *Section 2: Requirements for Affected and Exempted Units.*

Unaffected Units

Some sources of SO_2 emissions that generate electricity for sale or provide steam or heat for electricity generation are not subject to emissions limitations under Title IV. The following six types of electricity-generating units are not affected by the regulations under certain conditions:

- ❑ Existing Simple Combustion Turbines, under 40 CFR 72.6(b)(1).
- ❑ Existing Small Units, under 40 CFR 72.6(b)(2).
- ❑ Cogenerators, under 40 CFR 72.6(b)(4).
- ❑ Independent Power Production Facilities, under 40 CFR 72.6(b)(6).
- ❑ Qualifying Facilities, under 40 CFR 72.6(b)(5).
- ❑ Solid Waste Incinerators, under 40 CFR 72.6(b)(7).

Units in each category must meet requirements specific to that category to be unaffected. These requirements are discussed below. A unit need only qualify as unaffected under one of these categories in order to be unaffected. In order to remain unaffected, these units must meet a set of "continuing requirements," also discussed below.

If a facility is unaffected under more than one provision, it will remain unaffected until it loses its unaffected status for all appropriate provisions. For example, if a unit is unaffected as both an IPP and a QF, then it will remain unaffected if it loses its status as unaffected IPP but retains its status as an unaffected QF.

The Acid Rain Program does not require an unaffected unit to submit proof of its status. However, units may be required to provide documentation supporting their claim of unaffected status, if requested by EPA or the State or Regional permitting authority. Unaffected units may become affected under certain operating or construction conditions. It is the duty of the unit's owner and operator to meet the requirements of the Acid Rain Program if the unit becomes affected. Also, unaffected units may be eligible to opt-in to the Program, as discussed above in *What This Guide Won't Tell You*.

Submit the following to have EPA determine whether your combustion turbine is affected:

✓ Information on the unit's operational characteristics (i.e., whether the system captures hot air exiting the turbine through a heat recovery steam generator or a waste heat boiler or lacks such capability), such as a system diagram.

✓ Information demonstrating that the unit did not use auxiliary firing from 1985 to 1987 nor after November 15, 1990.

✓ The date the unit commenced commercial operation, as reported to EIA.

Examples of Combustion Turbines

Example 1: Two simple turbines feed a common header to a single heat recovery steam generator (i.e., together they constitute a combined cycle unit) that has auxiliary firing. Neither turbine qualifies as a simple combustion turbine.

Example 2: A combustion turbine serves a heat recovery generator that installed a duct burner in 1983. Due to poor efficiency in the duct burner, the duct burner is not utilized after 1984, although not removed. The turbine is a "simple combustion turbine" as defined.

(1) Existing Simple Combustion Turbines

A utility unit is not affected by the acid rain regulations if it meets *both* of the following conditions:

- ❑ The unit is a simple combustion turbine.
- ❑ The unit is an existing unit (i.e., commenced commercial operation before November 15, 1990).

Definitions

Simple Combustion Turbine

For the purposes of the acid rain regulations, a "simple combustion turbine" is defined to include a combined cycle unit that did not use auxiliary firing in 1985 through 1987 and will not use auxiliary firing at any time after November 15, 1990. A combined cycle unit that uses auxiliary firing during these periods does not qualify as a simple combustion turbine.

Combined Cycle Unit

In a combustion turbine, air heated from the combustion of fuel causes a turbine to spin in a magnetic field, which, in turn, creates electricity. If the hot air exiting the turbine is captured through a heat recovery steam generator or waste heat boiler, the turbine is a combined cycle unit.

Auxiliary Firing

In some combined cycle units, additional fuel is burned in a duct or in a heat recovery steam generator in order to enhance the production of steam. This is called auxiliary, or supplemental, firing.

Continuing Requirements

If a simple combustion turbine installs and uses auxiliary firing, it will become an affected unit. To remain unaffected, a simple combustion turbine may not add or begin using auxiliary firing.

(2) Existing Units Serving Generators Less Than or Equal To 25 MWe

A utility unit is not affected if it meets *both* of the following requirements:

- ☐ The unit serves a small generator (i.e., the largest generator served by the unit, on or after November 15, 1990, has a nameplate capacity less than or equal to 25 MWe).
- ☐ The unit is an existing unit (i.e., commenced commercial operation before November 15, 1990).

The term "serve" means either providing steam or being capable of providing steam to a generator. A unit on cold standby is considered capable of providing steam. The only units EPA can confirm through DOE/EIA data as not serving a generator are those units that are reported as retired.

Generators listed in the NADB are defined to have the nameplate capacity listed in the NADB. The regulations are not designed to penalize units that improve efficiency without increasing emissions. Thus, if a generator listed in the NADB is modified to produce over 25 MWe capacity because of significant improvements in turbine efficiency only, the units serving this generator do not become affected. For example, a boiler that in 1988 served a generator of 22 MWe nameplate capacity, as listed in the NADB, may retain its unaffected status if that generator is renovated to increase its output capacity from the same steam input. Unaffected units are required to submit information on improved turbine efficiency only if specifically requested by EPA or the State or Regional permitting authority.

However, if a boiler served a generator of 22 MWe nameplate capacity before November 15, 1990, that is *replaced* with a new generator of greater than 25 MWe nameplate capacity after November 15, 1990, then that boiler will be affected. Also, if a new generator is linked to that boiler and if that generator has a nameplate capacity of greater than 25 MWe, the boiler will be affected. On the other hand, if a boiler that serves a generator of 22 MWe nameplate capacity is linked to a new generator of 5 MWe nameplate capacity, the boiler will not be affected because it is not serving any individual generator of greater than 25 MWe nameplate capacity.

Continuing Requirements

If after November 15, 1990, the existing utility unit serves a generator with a nameplate capacity of greater than 25 MWe, it will become an affected unit.

Submit the following to have EPA determine whether your small unit is affected:

✓ The nameplate capacity of all generators served by the unit on or after November 15, 1990.

✓ The date the unit commenced commercial operation.

Examples of Existing Units

Example 1: Unaffected Unit. In 1985, a boiler served a 5 MWe generator and a 45 MWe generator that were used to produce electricity for sale. In 1988, the 45 MWe generator was retired. The boiler is not affected because, as of November 15, 1990, it did not serve a generator with nameplate capacity greater than 25 MWe.

Example 2: Affected Unit. Three boilers, two consuming coal and one burning natural gas, commenced commercial operation in 1967. The boilers feed a common header that serves two generators, one of 11 MWe nameplate capacity and one of 26 MWe nameplate capacity, that are used to produce electricity for sale. All three boilers are affected because one of the generators has a nameplate capacity greater than 25 MWe. Even if no one boiler could produce enough steam to feed the 26 MWe generator, all boilers are affected.

(3) Cogeneration Units

A cogeneration unit (or cogenerator) is a unit that produces steam or heat both for direct use and to run an electricity generator.

Definition

Cogeneration Unit

A cogeneration unit is a unit that produces electric energy and various forms of useful thermal energy (such as heat or steam) for heating or cooling purposes by using the waste heat of one process as the energy input into a subsequent process. For example, a unit that produces electricity and then uses the waste heat of that process as energy to run a process that cools another unit is a cogenerator.

The statute provides that some cogenerators may not be affected by the Title IV regulations. Although many cogenerators were constructed primarily to serve a specific industrial need, they often sell excess electricity to local utilities for distribution to the utilities' customers. Because only "utility units" (i.e., units that are used to produce electricity for sale) are affected by Title IV regulations, EPA makes a distinction between cogenerators operating to sell electricity and those operating primarily for self-generation (e.g., boilers for in-house use that do not sell electricity).* The key factors are the portion of "potential electrical output capacity" (a capacity-equivalent of the boiler) sold and the actual MWe-hrs of electrical output sold.

Which Cogenerators are Unaffected?

For cogeneration units that commenced construction on or before November 15, 1990, a unit is unaffected if it was constructed *for the purpose* of supplying less than or equal to one third of its potential electrical output capacity *or* less than or equal to 219,000 MWe-hrs of annual electrical output.** Documents that can be used for determining the purpose of construction include permitting applications, construction contracts, and original plant diagrams. In the absence of information regarding the purpose of construction (often the case with very old plants), EPA will assume that actual operations from 1985 through 1987 represent that purpose. If the unit began operations after 1985, EPA will use the operational data for the first three calendar years of operation to make the determination of purpose.

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* A cogenerator also may be unaffected by the regulations because it is a qualifying facility or an independent power production facility. These types of facilities are discussed below.

** 219,000 MWe-hours is equal to 25 MWe multiplied by 8,760 hours, the number of hours in a year.

Potential electrical output capacity is the MWe capacity rating for the unit, which is equal to 33 percent of the maximum design heat input capacity of the steam generating unit for boilers and simple combustion turbines. The potential electrical output capacity for these units is calculated using the following equation:*

(Maximum Design Heat Input (mmBtu/hr)) x (1,000,000 Btu/1 mmBtu) x (33%) x (1 kw-hr/3,413 Btu) x (1 MWe/1,000 kw) = MWe

For multi-headered boilers, the potential electrical output capacity for the entire source is equal to the sum of the potential electrical output capacities for each boiler. To compare an individual boiler's potential electrical output capacity to the generator capacity (in MWe), determine the total generator nameplate capacity (if there are multiple generators) and divide by the boiler's proportional share of steam based on the unit's potential electrical output capacity (see example). EPA will work with the unit to determine the appropriate sharing of output capacity.

For combined cycle combustion turbines, the Agency will consider information as to actual efficiency of a specific system. EPA understands that many combined cycle combustion turbines operate at approximately 50 percent efficiency. Thus, to calculate the actual electrical output, the maximum fuel flow (in mmBtu/hr as an aggregate value for the turbine and any supplemental or auxiliary burners) multiplied by 50 percent, should be substituted for the first term in the equation presented above:

(Maximum Fuel Flow (mmBtu/hr)) x (1,000,000 Btu/1 mmBtu) x (50%) x (1kw-hr/3,413 Btu) x (1 MWe/1,000 kw) = MWe

For complex multi-headered combined cycle units, the owner/operator may request to use a formula that more accurately estimates the potential electrical output capacity for the unit(s).

To determine whether the unit is affected, compare the potential electrical output capacity to the nameplate capacity of the generator. If the nameplate capacity of the generator is more than one third of the potential electrical output capacity, then the annual sales must be evaluated. If the annual electrical sales exceed 219,000 MWe-hrs, the unit will be affected.

The calculation of actual electrical output should incorporate indirect steam supplied to a steam-electric generator that will produce electrical energy for sale. Convert the Btus of steam sold to MWe-hrs based on the equation for potential electrical output capacity above assuming 33 percent efficiency. Add the MWe-hrs of steam to the direct MWe-hrs supplied for a total.

Example of Potential Electrical Output Capacity

A boiler has a maximum design heat input capacity of 340 mmBtu/hr. Using the conversion equation,

(340,000,000 Btu/hr) x (1/3) x (1 kw-hr/3,413 Btu) x (1 MWe/1,000 kw),

this boiler has a potential electrical output capacity of 33.2 MWe.

Example of Actual Electrical Output from a Cogenerator Providing Steam to a Generator That Provides Electricity

A cogeneration unit provides 175,000 MWe-hrs of electricity to the grid and 100 mmBtu/hr of steam to a second generator that sells electricity.

(100,000,000 Btu/hr) x (1/3) x (1 kw-hr/3,413 Btu) x (1 MWe/1,000 kw) x 8,760 hrs/yr = 85,555 MWe-hrs

Thus, the total electricity sold is 175,000 + 85,555 = 260,555 MWe-hrs.

* Appendix D of 40 CFR 72.

Example of Cogenerator Determinations

Situation I:

Boiler 1 (1,024 mmBtu/hr) serves Generator A (50 MWe nameplate)
Boiler 2 (4,100 mmBtu/hr) serves Generator B (50 MWe nameplate)

To calculate Potential Electrical Output Capacity:

Boiler 1 = (1,024,000,000 Btu/hr) x (33%) x (1 kw-hr/3,413 Btu) x (1 MWe/1,000 kw)
= 100 MWe
Boiler 2 = (4,100,000,000 Btu/hr) x (33%) x (1 kw-hr/3,413 Btu) x (1 MWe/1,000 kw)
= 400 MWe

First, compare nameplate capacity of generator served to potential electrical output capacity of boiler :

Boiler 1 serves 50 MWe/100 MWe = 50% of potential capacity
Boiler 2 serves 50 MWe/400 MWe = 12.2% (Boiler 2 is unaffected because 12.2% is less than 33%.)

Because Boiler 1 serves over 50% of potential electrical output capacity, ***calculate the actual electrical output at 1/3 potential electrical output capacity for Boiler 1 only:***

Boiler 1 = 1/3 x 100 MWe x 8,760 hr/year = 292,000 MWe-hrs
If Generator A sells less than this every year, Boiler 1 is unaffected as well.

Situation II:

If Boilers 1 and 2 are multi-headered to Generators A and B, we compare the proportion of electrical output to total nameplate capacity.

Boiler 1 serves 100 MWe/500 MWe (total unit capacity) x 100 MWe (total generator nameplate) = 20 MWe
= 20% of its Potential Electrical Output Capacity
Boiler 2 serves 400 MWe/500MWe x 100 MWe = 80 MWe
= 20% of its Potential Electrical Output Capacity
(Result - both boilers are unaffected because both produce less than 33% of potential capacity.)

Continuing Requirements

Unaffected cogenerators must continue to supply one-third or less of potential electrical output capacity or 219,000 MWe-hrs or less of actual electrical output to any utility power distribution system for sale annually calculated as an average over any three calendar year period after November 15, 1990. If a cogenerator does not meet this requirement, it will become affected.

Example of Continuing Requirements and Applying the Three-Year Rolling Average

Year 1 - sold 210,000 MWe-hrs electricity

Year 2 - sold 215,000 MWe-hrs electricity

Year 3 - sold 200,000 MWe-hrs electricity

Year 4 - sold 248,000 MWe-hrs electricity

The three calendar year rolling average for Years 2 through 4 is 221,000 MWe-hrs. Thus, if the average electrical output exceeds 1/3 of the potential electrical output capacity in Years 2 through 4, the unit would become affected beginning in Year 4.

Submit the following to have EPA determine whether your cogeneration unit is affected:

✓ The date the unit commenced construction.

✓ A system diagram of the steam/electric facility.

✓ If the unit commenced construction before November 15, 1990, information as to the purpose of the unit and/or steam and electricity sales and use data from 1985 through 1987.

✓ The nameplate capacity of each generator served by the unit.

✓ The maximum design heat input (in mmBtu/hr) of the unit and of all other units headered to the generators it serves.

✓ If the facility is in operation, the annual electrical sales (in MWe-hrs).

✓ The annual steam sales (mmBtu) that are used to produce electricity.

(4) Independent Power Production Facilities and (5) Qualifying Facilities

Certain independent power production facilities and qualifying facilities are not affected by the Acid Rain Program regulations.

Definition

Independent Power Production Facility (IPP)

An "independent power production facility" (IPP) is a source developed, usually by private investors, to serve as a wholesaler of power to a public utility. The Public Utility Regulatory Policies Act of 1978 (PURPA) provided a loose framework for the IPP industry. IPPs may offer utilities energy at lower cost and lesser risk than building electric plants or purchasing power from other utilities. IPPs and utilities negotiate preliminary power commitments, which often include 20- or 30-year terms. After obtaining the commitment, the project developers negotiate fuel supply, transportation contracts, construction contracts, site lease, and other project specifications. For these projects, lenders have recourse only to the assets and cash flows associated with a specific project and not to a parent company or partner companies that provide equity or other assurances. This type of financing is called "nonrecourse project financing."

In order for an IPP project to be unaffected by the Title IV regulations, it must meet the following requirements:

- ❑ The project must be nonrecourse project financed.
- ❑ The project must sell at least 80 percent of the power generated at wholesale.
- ❑ The project must have no more than 50 percent direct public utility ownership. This does not preclude indirect ownership of an IPP by a public utility through its unregulated subsidiaries or affiliates.

Definition

Qualifying Facility (QF)

A "qualifying facility" (QF) is a qualifying cogeneration facility or qualifying small power production facility as defined under PURPA. Small power production facilities are facilities generating not more than 80 MWe that employ renewable resources – such as water power, solar energy, wind energy, geothermal energy, biomass, or waste – as a primary fuel.

In order for a cogeneration facility to be a qualifying facility, it must meet the following requirements:

- ❑ No electric utility or public utility holding company or any organization* owned by either may own more than 50 percent of equity interest in the facility.
- ❑ The unit must meet operating and efficiency standards specified in 18 CFR 292.205.

Many cogenerators meet these requirements.

In order for a small power production facility to be a qualifying facility, it must meet *all three* of the following requirements:

- ❑ The unit must use fuel that is composed of more than 75 percent biomass, waste, renewable resources, geothermal resources, or some combination of the above.
- ❑ Fossil fuels must compose less than 25 percent of the fuel used by the facility.
- ❑ No electric utility or public utility holding company or any organization* owned by either may own more than 50 percent of equity interest in the facility.

As few small power production facilities meet QF fuel requirements, most QFs are qualifying cogeneration facilities.**

In some instances, a qualifying small power production facility may be unaffected under the provisions applicable to solid waste incinerators. Qualifying cogeneration facilities may also be unaffected under the cogenerator provisions, but qualifying cogeneration facilities need only satisfy the provisions for any one of the six types of electricity-generating units described (see 40 CFR 72.6(b)) in order to be unaffected.

* Organization as defined as "person" in the Federal Power Act, Section 3. This definition includes municipalities as well as other individuals and organizations.

** See 18 CFR 292.204.

Example of Whether a Unit is Affected based on Total Planned Net Output Capacity

Example 1: An IPP had qualifying power purchase commitments demonstrating that 100 MWe of capacity was planned and that 17% of its total planned net output capacity would be sold. The facility commences commercial operation with 110 MWe capacity. As such, all units at the facility are unaffected (assuming all other requirements are met) If an additional boiler-generator pair, with the same emission rates as the rest of the facility, is added for more than 20 MWe additional capacity (bringing the total capacity of the facility to over 130 MWe), this new boiler would be affected.

Example 2: An IPP has a power purchase commitment in 1989 for 50 MWe, but the power purchase commitment did not list planned capacity. In 1989, the IPP signed a construction contract for two coal-fired boilers and generators, with each generator rated at 50 MWe capacity. In 1992, the IPP signed another power purchase commitment for 70 MWe and contracted construction of another 50 MWe generator to be served by a gas-fired boiler. The entire facility commences commercial operation in 1996. From these facts, the total planned net output capacity of the facility on November 15, 1990 was 100 MWe. However, part of the facility is affected by the Acid Rain Program because, as constructed, the facility's total installed net output capacity is greater than 130% of that planned. Because the emission rates of SO_2 and NO_x of the coal-fired and gas-fired boilers are different, EPA may choose which boiler is affected. Only one boiler, however, will be affected.

While EPA's rules provide the limit on ownership interest for unaffected independent power production facilities, Federal Energy Regulatory Commission (FERC) rules established under PURPA limit ownership interests for QFs. FERC rules generally do not allow a partially or wholly owned subsidiary of an electric utility or electric utility holding company to have more than 50 percent ownership in a qualifying facility.*

IPPs and QFs may be regulated under both Title IV and Title III. For example, a unit burning waste fuels for more than 20 percent of its fuel may be regulated as both a solid waste incinerator under Title III and as an affected unit under Title IV. This would occur if "waste fuel," which is considered a "fossil fuel" under the Acid Rain Program, is considered also to be a "refuse-derived fuel" under the solid waste incinerator provisions of Title III.**

Which IPPs and QFs are Unaffected?

In order for an IPP or a QF to be unaffected, it must meet *all three* of the following requirements:

- ❑ The facility must meet the definition of an IPP or a QF as described above.
- ❑ The facility must have, as of November 15, 1990, a "qualifying power purchase commitment" to sell at least 15 percent of its total planned net output capacity.
- ❑ The total installed net output capacity of the facility must not exceed 130 percent of the total planned net output capacity.

The total planned net output capacity of a facility is established by reference to the power purchase commitment in place as of November 15, 1990 or by reference to other contemporaneous documents, such as submissions to a State environmental authority or construction contracts.

For example, a facility with a planned net output capacity of 100 MWe must have, as of November 15, 1990, a qualifying power purchase commitment of at least 15 MWe. If the facility has more than one qualifying power purchase commitment, the sum of the committed capacities is compared to the planned capacity (e.g., a facility planned for 200 MWe could have two qualifying power purchase commitments for 15 MWe each and be unaffected).

* See 18 CFR 292.206.

** See Title III implementing regulations for details. Some Title III regulations, specifically those for non-municipal waste, have not been written at this time.

Definition

Qualifying Power Purchase Commitment

A qualifying power purchase commitment is a formal agreement or requirement with a utility for the purchase of power. Utilities may include cooperative utilities, municipal electric authorities, and other sellers of electricity. The most common type of power purchase commitment is the power sales agreement (PSA). Other types of power purchase commitments include a letter of intent to purchase power at a given price, a State regulatory authority order to purchase power, and the selection of the facility as the winning bidder in a utility competitive bid solicitation.

To be a qualifying power purchase commitment, the power purchase commitment must meet *all three* of the following requirements:

- ❑ The commitment must have been entered into on or before November 15, 1990.
- ❑ At least one of the following two elements must remain unchanged (from November 15, 1990 to the present):
  - – The identity of the electricity purchaser.
  - – The identity of the steam purchaser and the planned location of the facility.
- ❑ The commitment must not shift or allow the shift of the cost of compliance with the acid rain regulations to the purchaser.

Continuing Requirements

For IPPs and QFs to remain unaffected, they must continue to meet the definition of an IPP and QF, respectively, and continue to meet the requirements stated above. For example, if an IPP continues to have less than 50 percent direct ownership by a public utility, it will still meet the definition of an IPP and, if it continues to meet the other requirements, will remain unaffected. If an IPP or QF adds capacity such that the total installed net output capacity is greater than 130 percent of total planned net output capacity, then either some portion or all of the facility – depending on the facility configuration – will become affected.

Submit the following to have EPA determine whether your IPP or QF is affected:

✓ The date the power purchase commitment was entered.

✓ The type of power purchase commitment.

✓ If the power purchase commitment was a letter of intent, the date the power sales agreement was entered.

✓ The total planned net output capacity, as specified in the power purchase commitments or contemporaneous documents as of November 15, 1990.

✓ The output capacity committed through the power purchase commitment.

✓ Any changes to the power purchase commitments affecting the identity of the electrical or steam purchaser, location of the facility, or terms that would allow the costs of compliance to be shifted to the purchaser.

✓ If the facility has commenced operation, the date of commencement and the total installed net output capacity.

✓ If an IPP, information showing that the facility is nonrecourse financed.

✓ If an IPP, information showing that the portion of the facility owned directly by public utilities is less than or equal to 50 percent.

✓ If an IPP, information that 80% or more of the electricity generated will be sold at wholesale.

✓ If a QF, verification of qualifying facility status under the Public Utility Regulatory Policies Act (e.g., FERC docket number).

Submit the following to have EPA determine whether your incinerator is affected:

✓ Information as to the purpose of the unit and the data on any steam and electric sales and use.

✓ If the unit commenced commercial operation after January 1, 1985, information on operations, including fuel/waste burned, for the first three years of operation and the years 1991 on.

✓ If the unit commenced commercial operation before 1985, information on operations, including fuel/waste burned, for 1985, 1986, and 1987, as well as for the years 1991 on.

✓ Information provided on Form 767 of the Department of Energy, Energy Information Administration (EIA), including:

- Data on the types of waste burned in the unit.
- Data on the types of fuels used by the unit including Btus of waste fuel and Btus of fossil fuel burned.

(6) Solid Waste Incinerators

If a unit is a "solid waste incinerator" that produces electricity for sale or provides steam or heat for electricity generation, it may be affected by the acid rain regulations. A solid waste incinerator is a unit that burns nonhazardous solid wastes from commercial or industrial establishments or the general public (e.g., residences). For example, a QF that burns municipal solid waste is a solid waste incinerator and may be unaffected under this provision if it meets the requirements discussed below.

The definition of a solid waste incinerator *does not* include the following categories of facilities:

- Incinerators of hazardous wastes;
- Materials recovery facilities;
- Qualifying facilities that burn homogeneous wastes (except for refuse-derived fuel), including tires and used oil; and
- Air curtain incinerators burning wood wastes, yard wastes, and clean lumber.

Which Solid Waste Incinerators are Unaffected?

Solid waste incinerators burning less than 20 percent fossil fuels (on a Btu, or heat input, basis) are not affected by the acid rain regulations. The unit must meet this requirement on average for the three years from 1985 to 1987 or for the first three calendar years of operation if the unit began operation after 1985. Solid waste incinerators may also be subject to other control technology-based requirements under the Clean Air Act.

Continuing Requirements

An unaffected solid waste incinerator must continue to combust less than 20 percent fossil fuels (on a Btu basis) on three-calendar-year rolling average for any period after November 15, 1990, in order to stay unaffected. Fuel consumption for most units is reported to the Department of Energy, Energy Information Administration, in Btus, on Form EIA-767.

:ample of Three-Calendar-Year Rolling Basis

ır 1 - burns 16% fossil fuel, raged over the year

ır 2 - burns 16% fossil fuel

ır 3 - burns 19% fossil fuel

ır 4 - burns 31% fossil fuel

three calendar year rolling av- ge for years 1 through 3 is 17 %. vever, the three calendar year ng average for years 2 through 22%, making the unit affected inning in Year 4. (Note that the must have allowances for Year January 30 of Year 5.)

Section 2

Requirements for Affected and Exempted Units

An affected unit must comply with acid rain regulations, including holding allowances sufficient to cover its annual SO_2 emissions, obtaining an acid rain permit (which is part of the unit's general air permit), having a Designated Representative (DR), and installing and operating systems that continuously monitor emissions of SO_2, NO_X, and other related pollutants. These requirements are discussed below.

The only way an affected unit may avoid the full requirements of the Acid Rain Program is by qualifying for an "exemption," as described in *Section 1*. Even if a unit is awarded an exemption, it is subject to certain minimum requirements.

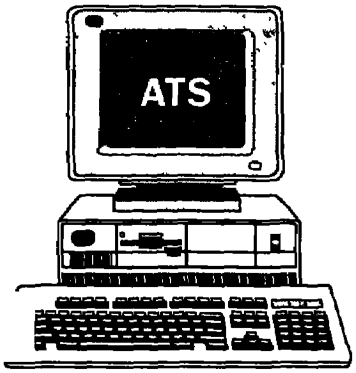
Information presented in this section is provided as summary guidance for the Acid Rain Program requirements. This section also provides compliance timelines for Phase I and Phase II of the Program as well as for continuous emission monitoring (CEM). For more detailed information on the regulations, please refer to 40 CFR 72-78, or call the **Acid Rain Hotline** at **(202) 233-9620**.

What Are the Monitoring Requirements?

The owner or operator of an affected unit must install CEM system on the unit and provide emission reports to EPA unless otherwise specified in the regulations. CEM systems include the following:

- ❑ An SO_2 pollutant concentration monitor
- ❑ A NO_x pollutant concentration monitor
- ❑ A volumetric flow monitor
- ❑ An opacity monitor
- ❑ A diluent gas (oxygen or CO_2) monitor that monitors CO_2
- ❑ A data acquisition and handling system (computer-based) for recording and performing calculations with the data.

Refer to 40 CFR 75 for exceptions and other additional requirements.



Continuous Emission Monitoring

Each affected unit must continuously measure and record its emissions of SO_2, NO_X, and carbon dioxide, as well as volumetric flow, opacity, and diluent gas, unless otherwise specified in regulations at 40 CFR 75. Most units must be equipped with a continuous emission monitoring (CEM) system. CEM systems are critical to the Acid Rain Program for several reasons:

- ❑ They ensure compliance with the emissions limitations.
- ❑ They instill confidence in allowance transactions by certifying the existence and quantity of the commodity being traded.
- ❑ They track the progress of the Program.

The CEM rule (40 CFR 75) also contains provisions for initial equipment certification procedures, periodic quality assurance and quality control procedures, recordkeeping and reporting, and procedures for filling in missing data periods. Affected units are required to report emissions data to EPA's Emission Tracking System on a quarterly basis. Please refer to the compliance timeline table at the end of this section for dates by which installation and certification testing of CEM systems must be complete.

Holding Allowances

Each affected unit must hold an allowance for every ton of sulfur dioxide emitted during a calendar year. To support this requirement, EPA has developed an electronic recordkeeping and notification system, called the Allowance Tracking System (ATS), to keep track of allowance transactions and the status of allowance accounts. ATS will provide the official tally of allowances by which EPA will determine compliance with the emissions limitations.

An ATS account has been established for each unit listed in Exhibits 1, 2, and 3 of *Appendix D*. EPA will open an account for affected units not listed in Exhibits 1, 2, or 3 of *Appendix D* upon submittal of Certificate of Representation for the source identifying a Designated Representative. Once EPA receives a Certificate of Representation, it will establish an account for each unit at the source. This certificate must be submitted to EPA with or prior to the permit application for the unit. Any other party interested in participating in the trading system may open an ATS account by submitting a general account application to EPA.

The ATS also provides the allowance market with a record of who is holding allowances, the date of allowance transfers, and the allowances transferred. The ATS does not, however, record the price or other terms associated with allowance trades; such information is better collected and reported by the private sector through established exchanges or other trade information brokers.

What Information Is Contained In ATS Accounts?

ATS accounts include the name and address of the authorized account representative (the official contact person for the account); the allowances in current and future subaccounts; and a record of allowance transfers to and from the account. Information in the ATS accounts is available to the public.

Each affected unit must hold sufficient allowances in its account by January 30 (or, if January 30 is not a business day, the first business day thereafter) to cover its emissions for the previous year. For example, a new affected unit that commences commercial operation during 2002 must hold sufficient allowances in its account to cover its emissions of SO_2 during the year 2002 by January 30, 2003.

If a unit emits more tons of SO_2 than allowances it holds in its account, the additional tons of SO_2 emitted and not covered by allowances are called "excess emissions." Under the Acid Rain Program, if a unit has excess emissions, it must pay $2,000 (adjusted by the Consumer Price Index) per ton of excess emissions and submit an offset plan. The offset plan tells how many allowances are to be deducted from the unit's allowance account for future years to offset the previous year's excess emissions. Thus, a unit must make up for all excess emissions.

Designated Representatives

Each source must appoint one individual, the Designated Representative, to represent the owners and operators of the source in all matters relating to the holding and disposal of allowances for its affected or exempted units. The Designated Representative is also responsible for all submissions pertaining to permits, compliance plans, emission monitoring reports, offset plans, compliance certification, and other required information. To specify a Designated Representative, complete the Certificate of Representation. The Certificate of Representation form and instruction are provided in *Appendix E.*

Permitting

The Designated Representative for each affected source is required to file a permit application for the source and a compliance plan for each affected or exempted unit at the source with the permitting authority. The permitting authority is either the approved State permitting authority or EPA. Contact the EPA Regional office to determine the appropriate permitting authority for your unit(s). See *Appendix B.*

For exempted units, the exemption itself serves as a permit for the unit. Both permits (for affected units) and exemptions (for exempted units) must be renewed every five years.

What Information Must Be Included In Permit Applications?

The source must complete standard forms when applying for an acid rain permit. The forms request information about the Designated Representative, general plant information, specific unit information, and a compliance plan for each affected unit. Forms can be obtained from a permitting authority. Please refer to *Appendix B.*

The Acid Rain Program operating permit details the specific program requirements and compliance options chosen by each source. The permits and compliance plans aim to provide flexibility, which is a goal of the Acid Rain Program as a whole; permits and compliance plans are designed to complement the marketable allowance program and foster trading. The permits and compliance plans also let sources fashion a compliance strategy tailored to their individual needs.

The permit stipulates the initial annual allowance allocation for each affected unit at a source. The permit application must certify that each unit's account will hold a sufficient number of allowances to cover the unit's SO_2 emissions for the year and that the unit will comply with the applicable NO_X limit. In addition, the compliance plans may specify alternative measures that will be taken to ensure compliance. Permits are subject to public comment before approval.

Applying for an Exemption

Small, new units burning clean fuel and retired units that meet the requirements stated in *Section 1: Exempted Units* can apply for an exemption with the permitting authority. The Designated Representative for a *small, new unit* can apply for an exemption. Any allowances allocated to a small, new unit must be surrendered for any year for which the unit is exempted.

For *retired units,* the Designated Representative must submit a petition for written exemption to the permitting authority on or before (1) the deadline for submitting an acid rain permit application for Phase II, or (2) if the unit has a Phase II acid rain permit, the deadline for reapplying for that permit. The petition for written exemption must contain:

- ❑ Identification of the unit,
- ❑ The applicable deadline for submission,
- ❑ The actual or expected date of retirement of the unit,
- ❑ A description of any actions that have been or will be taken with regard to the retirement of the unit, and
- ❑ The following statement: "I certify that this unit ['is' or 'will be' as applicable] permanently retired on the date specified in this petition and will not emit any sulfur dioxide or nitrogen oxides after such date."

This information must be supplied to the permitting authority on forms as stipulated by the permitting authority.

A retired unit obtaining an exemption must comply with the monitoring requirements, as previously discussed, unless an exemption from these requirements is obtained from the permitting authority. Units that will be permanently retired prior to January 1, 1995 can be exempted from installing and certifying a continuous emission monitoring system if the Designated Representative completes a written exemption petition prior to the deadline for completion of certification tests for the continuous emission or opacity monitoring systems. Retired units will retain any allowances they are allocated in 40 CFR 73. An exempted unit shall not resume operation unless the Designated Representative submits an acid rain permit application for the unit not less than 24 months prior to the later of January 1, 2000 or the date the unit is to resume operation. A unit must comply with all of the acid rain regulations as of the earlier of the date an exemption expires or the date a permit application is submitted (or required to be submitted).

The exemption of a small, new unit or a retired unit will take effect beginning January 1 of the year following the issuance of the written exemption.

Compliance Timelines

The following table indicates when a specific type of unit becomes affected by the acid rain regulations, the deadline for that unit to apply for an acid rain permit, the deadline for completing continuous emission and opacity monitoring compliance testing, and the first date on which a unit is required to hold allowances.

Compliance Timelines

Category	Phase and Date Unit Is "Affected"	Acid Rain Permit Application Due	CEMS Tests Due (see note)	First Date to Hold Allowances for Previous Year's Emissions (see note)
Unit Listed in Table 1 of 40 CFR 73.10	Phase I, January 1, 1995	February 15, 1993	November 15, 1993	January 30, 1996
Substitution or Compensating Unit	Phase I, the later of January 1, 1995, or the date the plan is activated	The later of February 15, 1993, or 90 days before the plan is activated	The later of November 15, 1993, or 90 days after issuance of the plan	The later of Jan. 30, 1996, or Jan. 30 of the year after the plan is activated
Unit Listed in Tables 2 or 3 of 40 CFR 73.10 (other than a substitution or compensating unit)	Phase II, January 1, 2000	January 1, 1996	The later of January 1, 1995 or 90 days after unit commences commercial operation, not to exceed date unit is declared commercial	January 30, 2001
A New Affected Unit	Phase II. The later of January 1, 2000, or 90 days after commencement of commercial operation, but not after date the unit declares itself commercial	The later of January 1, 1998, or 24 months before the date the unit commences operation	The later of January 1, 1995 or 90 days after commencement of commercial operation, not to exceed date unit declared commercial	The later of January 30, 2001 or January 30 of year after unit commences commercial operation
A Previously Affected Existing Small Unit that fails to meet continuing requirements	Phase II. The later of January 1, 2000, or 90 days after the unit begins to serve a generator with nameplate capacity > 25 MWe	The later of January 1, 1998, or 24 months before the unit begins to serve a generator with nameplate capacity > 25 MWe	The later of January 1, 1995 or 90 days after unit serves generator with nameplate capacity > 25 MWe	The later of January 30, 2001 or January 30 of year after unit is affected
A Previously Affected Existing Simple Combustion Turbine that fails to meet continuing requirements	Phase II. The later of January 1, 2000, or 90 days after auxiliary firing commences	The later of January 1, 1998, or 24 months before auxiliary firing commences	The later of January 1, 1995 or 90 days after auxiliary firing commences	The later of January 30, 2001 or January 30 of year after unit is affected
A Previously Unaffected Cogenerator that fails to meet continuing requirements	Phase II. The later of January 1, 2000, or 90 days after a 3 calendar year period during which continuing requirements are not met	The later of January 1, 1998, or March 1 of the year following 3 calendar years during which continuing requirements are not met	The later of January 1, 1995 or 90 days after the facility fails to meet the definition of qualifying facility	The later of January 30, 2001 or January 30 of year after unit is affected
A Previously Unaffected Qualifying Facility that fails to meet the definition of a qualifying facility	Phase II. The later of January 1, 2000, or 90 days after the facility fails to meet the definition of a qualifying facility	The later of January 1, 1998, or March 1 of the year following the year during which the facility fails to meet the definition of a qualifying facility	The later of January 1, 1995 or 90 days after the facility fails to meet the definition of qualifying facility	The later of January 30, 2001 or January 30 of year after unit is affected
A Previously Unaffected Independent Power Production Facility that fails to meet the definition of an independent power production facility	Phase II. The later of January 1, 2000, or 90 days after the facility fails to meet the definition of an independent power production facility	The later of January 1, 1998, or March 1 of the year following the year during which the facility fails to meet the definition of an independent power production facility	The later of January 1, 1995 or 90 days after the facility fails to meet the definition of Independent Power Production Facility	The later of January 30, 2001 or January 30 of year after unit is affected
A Previously Unaffected Solid Waste Incinerator that fails to meet continuing requirements	Phase II. The later of January 1, 2000, or 90 days after a 3 calendar year period during which continuing requirements are not met	The later of January 1, 1998, or March 1 of the year following 3 calendar years during which continuing requirements are not met	The later of January 1, 1995 or 90 days after a 3 calendar year period during which continuing requirements are not met	The later of January 30, 2001 or January 30 of year after unit is affected

Examples of Compliance Schedules

Case 1: A previously unaffected cogeneration unit exceeds the 1/3 potential electrical output capacity and 219,000 MWe hours criteria, when averaged, for 1993, 94, and 95.

The unit must:

No later than March 30, 1996, complete CEMS tests.
No later than January 1, 1998, submit a permit application.
No later than January 30, 2001, hold allowances to cover 2000 emissions.

Case 2: A previously unaffected solid waste incinerator combusts greater than 20% fossil fuel, when averaged, for 2003, 04, and 05.

The incinerator must:

No later than March 1, 2006, submit a permit application.
No later than March 30, 2006, complete CEMS tests.
No later than January 30, 2007, hold allowances to cover 2006 emissions.

Case 3: A boiler that commenced operation in 1965 serving a 21 MWe generator has that generator replaced on June 1, 1996 with a 27 MWe generator.

The boiler must:

No later than August 29, 1996, complete CEMS tests.
No later than January 1, 1998, submit a permit application.
No later than January 30, 2001, hold allowances to cover 2000 emissions.

Case 4: An unaffected IPP with 100 MWe total planned net output capacity in 1996 installs that capacity with three natural gas fired turbines. On November 11, 2002, the facility commences commercial operation of another natural gas turbine of 40 MWe (it has the same emission rate as the other turbines).

The original three turbines remain unaffected.

The new turbine must:

No later than November 11, 2000, submit a permit application.
No later than January 29, 2003, complete CEMS tests.
No later than January 30, 2004, hold allowances to cover 2003 emissions.

Notes on the timelines:

For Phase I units, if the unit was shut down and not yet operating by November 15, 1993, then all monitoring certification tests must be completed no later than 90 days after the unit recommences commercial operation (not to exceed the date the unit is turned over to the dispatcher).

For Phase II units, if the unit was shut down and not yet operating by January 1, 1995, then all monitoring certification tests must be completed no later than 90 days after the units recommences commercial operation (not to exceed the date the unit is turned over to the dispatcher).

The allowance holding date (allowance transfer deadline), if January 30 is not a business day, is the first business day thereafter.

Glossary

Many of these definitions have been paraphrased from the definitions included in the Code of Federal Regulations (40 CFR 72.2). References have been provided where applicable. The Code of Federal Regulations also contains additional definitions relating to the Acid Rain Program that are not included here.

Acid Rain Permit: The acid rain portion of a source's operating permit. It is the legally binding document specifying acid rain requirements applicable to an affected source. See 40 CFR 72.2.

Affected Unit: A unit that is subject to any acid rain emissions reduction requirement or acid rain emissions limitation. See 40 CFR 72.2.

Allowance: Under the Acid Rain Program, an authorization to emit up to one ton of sulfur dioxide during or after a specified calendar year.

Auxiliary Firing: The use of fuel in addition to the primary fuel supply to enhance the production of steam. For example, a cogeneration facility in which the energy input to the facility is first used to produce power, and the waste heat is used to provide useful steam where additional natural gas firing is used to boost the steam/thermal process. This addition of natural gas is called auxiliary firing. See 18 CFR 292.202.

Boiler: An enclosed fossil or other fuel-fired combustion device used to produce and transfer heat to recirculating water, steam, or any other medium. See 40 CFR 72.2.

Certifying Official: The person required to sign a request for an applicability determination by EPA. For a corporation, this should be the president, secretary, treasurer, or vice-president in charge of a principal business function, or other person who performs similar policy or decision-making functions. For a partnership or sole proprietorship, this should be a general partner or the proprietor.

Clean Fuels: Fuels with sulfur content of 0.05 percent or less by weight.

Cogeneration: The combined production of power and useful heat that uses the reject heat of one process as the energy input into a subsequent process. These processes may be for industrial, commercial, heating, or cooling purposes. See 18 CFR 292.202.

Cogeneration Unit: A unit that has equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes, using the reject heat of one process as the energy input into a subsequent process; a unit that uses cogeneration. These units are also known as "cogenerators." See 40 CFR 72.2, Federal Power Act Section 3(18)(A), and 18 CFR 292.202.

Combined Cycle Unit: A unit that uses a heat recovery steam generator or waste heat boiler to capture hot air exiting a steam turbine.

Combustion Device: A device that initiates the chemical reaction of fuel and oxygen with the addition of heat.

Commence Commercial Operation: To begin to generate electricity for sale, including the sale of test generation. See 40 CFR 72.2.

Commence Construction: To undertake a continuous program of construction or enter into a contractual obligation to undertake and complete, within a reasonable amount of time, a continuous program of construction. See 40 CFR 72.2.

Compensating Unit: A unit not otherwise subject to acid rain regulations during Phase I that is designated as a Phase I unit in a reduced utilization plan. See 40 CFR 72.2.

Construction: The fabrication, erection, or installation of a unit or any portion of a unit. See 40 CFR 72.2.

Designated Representative: The person authorized by the owners and operators of an affected source to represent the source in matters pertaining to the Acid Rain Program. See 40 CFR 72.2.

Direct Public Utility Ownership: Direct ownership of equipment and facilities by one or more corporations, the principal business or which is the sale of electricity to the public at retail. See 40 CFR 72.2.

Emissions: Air pollutants exhausted from a unit or source into the atmosphere. See 40 CFR 72.2.

Exemption: An authorization by the EPA Administrator, under 40 CFR 72.7 or 72.8, that exempts a utility unit from certain acid rain regulations.

Existing Unit: A unit that commenced commercial operation before November 15, 1990, that served, on or after that date, a generator with nameplate capacity greater than 25 MWe, and that is not a simple combustion turbine. See 40 CFR 72.2.

Facility: Any institutional, commercial, or industrial structure, installation, plant, source, or building. For the purposes of the Acid Rain Program, this usually refers to an independent power production facility or a qualifying facility. See 40 CFR 72.2.

Form EIA-767: Steam-Electric Plant and Design Report submitted to the Department of Energy containing boiler and fuel consumption information. To obtain this form, write to: US Department of Energy, Energy Information Administration (EIA), EI-521, Mail Stop: BG-094 (Form EIA-767), Washington, DC, 20585.

Form EIA-860: A Department of Energy form completed by each electric utility that operates a power plant in the United States or plans to operate the plant within 10 years of the filing of the form. The form includes site information, generator information, operations, energy sources, and capacity. For the purposes of Form 860, an electric utility is a corporation, person, agency, authority, or other legal entity or instrumentality that owns or operates facilities within the United States for the generation, transmission, distribution, or sale of electric energy primarily for use by the public. To obtain this form, write to: US Department of Energy, Energy Information Administration (EIA), EI-521, Mail Stop: BG-094 (Form EIA-860), Washington, DC, 20585.

Fossil Fuel: Natural gas, petroleum, coal, or any fuel derived from such material. See 40 CFR 72.2.

Fossil Fuel-Fired: Combustion of fossil fuel or any derivative of fossil fuel, alone or in combination with any other fuel, independent of the percentage of fossil fuel consumed in any calendar year. See 40 CFR 72.2.

Generator: A device that produces electricity and was or would have been required to be reported as a generating unit pursuant to the United States Department of Energy Form 860 (1990 edition). See 40 CFR 72.2.

Independent Power Production Facility (IPP): An electricity-generating facility that is generally not regulated by State public utility commissions and that sells power at wholesale, usually to public utilities. See 40 CFR 72.2.

Listed Units: Units that are listed in Tables 1, 2, or 3 of 40 CFR 73.10 (Exhibits 1, 2, and 3 of *Appendix D*). These units are affected (unless exempted) by either Phase I or Phase II of the acid rain regulations.

Multi-header Generator: A generator served by ductwork from more than one unit. See 40 CFR 72.2.

Multi-header Unit: A unit with ductwork serving more than one generator. See 40 CFR 72.2.

Nameplate Capacity: The maximum electrical generating output that a generator can sustain over a specified period of time when not restricted by deratings. This figure is listed in the NADB and on Form EIA-860 for most utility units. See 40 CFR 72.2.

National Allowance Data Base (NADB): A data base established by EPA in order to calculate Acid Rain Program SO_2 emissions allowances. Version 2.11 includes detailed information on 3,800 boiler-generator pairs and lists the boiler on-line date and generator on-line date. Most of the boilers and turbines listed in the data base are affected units. See 40 CFR 72.2.

New Unit: A unit that commences commercial operation on or after November 15, 1990, including any such unit that serves a generator with a nameplate capacity of 25 MWe or less or that is a simple combustion turbine. See 40 CFR 72.2.

Nonrecourse Project Financing: Financing in which lenders have recourse only to assets and cash flows associated with a specific project and not to a parent company or partner companies that provide equity or other assurances. See independent power production facilities and 10 CFR 715.3.

Opt-In: To participate in the Acid Rain Program voluntarily. Units that opt-in to the Program are given emissions allowances that can be sold to other units, with some restrictions. Exempted units (i.e., retired units and new units that are granted an exemption) and units otherwise affected are not allowed to opt-in to the Program. Note that the Opt-In Program has not been finalized as of January 1, 1994.

Phase I Unit: Any affected unit that is subject to an acid rain emissions reduction requirement or acid rain emissions limitation beginning in the period from January 1, 1995, to December 31, 1999. All Phase I units continue to be affected in Phase II. See 40 CFR 72.2.

Phase II Unit: Any affected unit that is subject to an acid rain emissions reduction requirement or acid rain emissions limitation only after January 1, 2000. See 40 CFR 72.2.

Potential Electrical Output Capacity: The MWe capacity rating for a unit. For simple combustion turbines and boilers, this rating is equal to 33 percent of the maximum design input capacity (in mmBtu/hr) of the steam generating unit converted to MWe. See 40 CFR 72.2.

Power Purchase Commitment: A commitment or obligation of a utility to purchase electric power from a facility pursuant to a power sales agreement, a State regulatory authority order, a letter of intent to purchase power from the source at a previously offered or lower price, or a utility competitive bid solicitation that has resulted in a winning bidder. See 40 CFR 72.2.

Power Sales Agreement (PSA): A legally binding agreement between a qualifying facility, an independent power production facility, an new independent power production facility, or a firm associated with such facility and a regulated electric utility that establishes the terms and conditions for the sale of power from the facility to the utility. See 40 CFR 72.2.

Qualifying Facility: A qualifying small power production facility or a qualifying cogeneration facility as administered under the Federal Energy Regulatory Commission (FERC). See 18 CFR 292 and Federal Power Act, Sections 3(17)(C) and 3(18)(B).

Qualifying Power Purchase Commitment: A power purchase commitment in effect as of November 15, 1990, that meets the following requirements:

- ❑ The identity of the electrical purchaser does not change, or
- ❑ The identity of the steam purchaser and the planned location of the facility do not change, and
- ❑ The cost of compliance with the acid rain regulations are not allowed to shift to the purchaser.

See 40 CFR 72.2.

Retired Unit: A unit that has ceased operation and certified that it will not recommence operation. See 40 CFR 72.8.

Simple Combustion Turbine: A unit that is a rotary engine driven by a gas under pressure that is created by the combustion of any fuel. This includes combined cycle units without auxiliary firing and combined cycle units with auxiliary firing that did not use auxiliary firing in 1985 through 1987 and will not use auxiliary firing at any time after November 15, 1990. See 40 CFR 72.2.

Solid Waste Incineration Unit: A distinct operating unit of any facility that combusts any solid waste material from commercial or industrial establishments or the general public. This does not include most materials recovery facilities, qualifying small power production facilities, or air curtain incinerators. See Clean Air Act, Section 129(g)(1).

Source: Any governmental, institutional, commercial, or industrial structure, installation, plant, building, or facility that emits or has the potential to emit any regulated air pollutant under the Clean Air Act. See 40 CFR 72.2.

Substitution Units: An affected unit that is designated as a Phase I unit in a substitution plan under 40 CFR 72.41. See 40 CFR 72.2.

Total Nameplate Capacity: The sum of the nameplate capacities to which a unit is headered.

Unaffected Unit: A unit that is not subject to any acid rain emissions reduction requirement or acid rain emissions limitation.

Unit: A fossil fuel-fired combustion device. See 40 CFR 72.2.

Utility: Any facility, company, or person that sells electricity. See 40 CFR 72.2.

Utility Unit: A unit owned or operated by a utility that serves a generator that produces electricity for sale. This includes, in some instances, electrical generating equipment owned or operated by entities that are not public utilities, such as manufacturers and independent power producers. This does not include units that did not serve a generator in 1985 or on or after November 15, 1990. This also does not include most cogeneration units. See 40 CFR 72.2.

Appendix A
Selected Acid Rain Regulations and Documents

The Acid Rain Program regulations and documents have been produced as a series and include those listed below:

Auctions, Direct Sales, and Independent Power Producers Written Guarantee
40 CFR 72
Final December 17, 1991, 56 FR 65592
Additional materials located in EPA Air Docket A-91-32.

Acid Rain Program: General Provisions and Permits, Allowance System, Continuous Emission Monitoring, Excess Emissions, and Administrative Appeals
40 CFR 72, 73, 75, 77, and 78
Final January 11, 1993, 58 FR 3590
Additional materials located in EPA Air Dockets A-90-38 (for permits-related materials), A-91-43 (for allowance systems), A-90-51 (for continuous emission monitoring), A-91-68 (for excess emissions), and A-91-69 (for the general docket).

Acid Rain Allowance Allocations and Reserves
40 CFR 72, 73, and 75
Final March 23, 1993, 58 FR 15634
Additional materials located in EPA Air Docket A-92-06.

Acid Rain Provisions: Notice of Availability of the National Allowance Data Base
Revised Final Data Base, version 2.11, March 23, 1993, 58 FR 15720
Additional materials located in EPA Air Docket A-92-07.

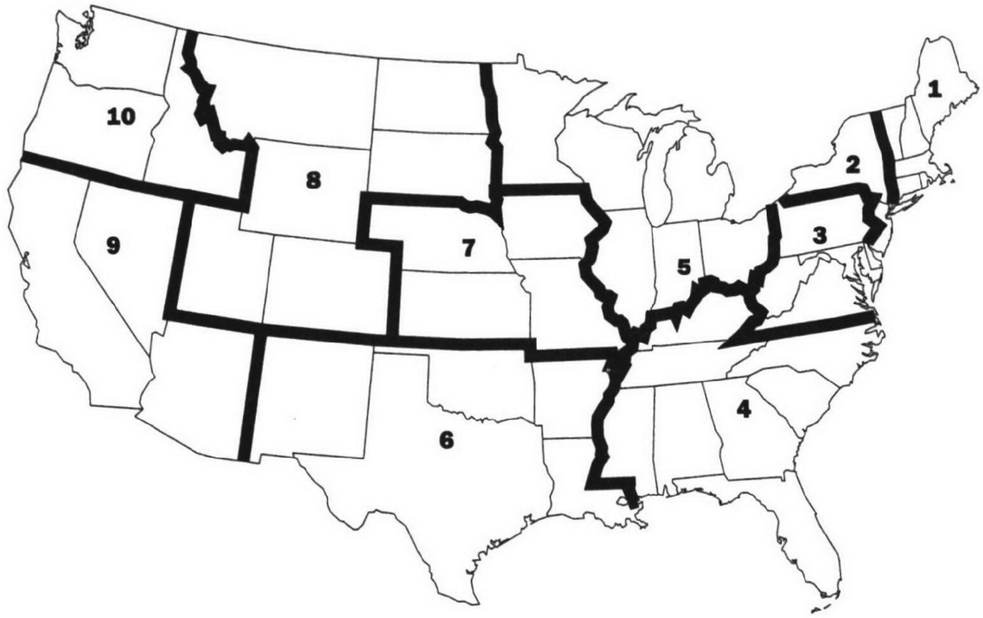
Acid Rain Program: Nitrogen Oxides Emission Reduction Program
40 CFR 76
Proposed November 25, 1992, 57 FR 55632
Additional materials located in EPA Air Docket A-92-15.

Acid Rain Program: Permits and Allowance System (Opt-In)
40 CFR 74
Proposed September 24, 1993, 58 FR 50087
Additional materials located in EPA Air Docket A-93-15.

Acid Rain Program: Permits and Allowance System (Substitution & Compensating Units)
40 CFR 72 and 73
Proposed November 18, 1993, 58 FR 50949
Additional materials located in EPA Air Docket A-93-40.

To obtain a copy of any of these documents, call the ***Acid Rain Hotline*** at **(202) 233-9620.**

Appendix B: EPA Regional and State Office Addresses



EPA Regional Contacts

Region 1

JFK Building
One Congress Street
Boston, MA 02203
(617) 565-3800
FAX#: (617) 565-4939

Region 2

Jacob K. Javitz Federal Building
26 Federal Plaza
New York, NY 10278
(212) 264-2301
FAX#: (212) 264-7613

Region 3

841 Chestnut Building
Philadelphia, PA 19107
(215) 597-9390
FAX#: (215) 597-3156

Region 4

345 Courtland Street, NE.
Atlanta, GA 30365
(404) 347-3043
FAX#: (404) 347-3059

Region 5

77 West Jackson Boulevard (A-18J)
Chicago, IL 60604
(312) 353-2212
FAX#: (312) 353-1661

Region 6

First Interstate Bank Tower
1445 Ross Avenue (MC6T-AN)
Dallas, TX 75202-2733
(214) 655-7200
FAX#: (214) 655-2164

Region 7

726 Minnesota Avenue
(ARTX/ARBR/PERM)
Kansas City, KS 66101
(913) 551-7404
FAX#: (913) 551-7065

Region 8

999 18th Street, Suite 500 (8ART)
Denver, CO 80202-2466
(303) 293-0946
FAX#: (303) 294-7559

Region 9

75 Hawthorne Street (A-3-1)
San Francisco, CA 94105
(415) 744-1219
FAX#: (415) 744-1076

Region 10

1200 Sixth Avenue (AT-082)
Seattle, WA 98101
(206) 553-4152
FAX#: (206) 553-0110

State Contacts

Alabama

Environmental Management Department
1751 Congressman W.L. Dickinson Drive
Montgomery, AL 36130
(205) 271-7706
FAX#: (205) 271-7950

Arizona

Environmental Quality Department
3033 N. Central Avenue
Phoenix, AZ 85012
(602) 207-2300
FAX#: (602) 207-2218

Arkansas

Department of Pollution Control and Ecology
P.O. Box 9583
Little Rock, AR 72219
(501) 570-2130
FAX#: (501) 562-4632

California

California Air Resources Board
P.O. Box 2815
Sacramento, CA 95812
(916) 445-4383
FAX#: (916) 322-6003

California Environmental Protection Agency
555 Capitol Mall, Suite 235
Sacramento, CA 95814
(916) 445-3846
FAX#: (916) 445-6401

Colorado

Office of Environment
Colorado Department of Health
4300 Cherry Creek Drive South, OE-B2
Denver, CO 80222-1530
(303) 692-3099
FAX#: (303) 782-4969

Connecticut

Department of Environmental Protection
79 Elm Street
Hartford, CT 06106
(203) 566-2110
FAX#: (203) 566-7932

Delaware

Natural Resources and Environmental Control
P.O. Box 1401
89 Kings Highway
Dover, DE 19903
(302) 739-4403
FAX#: (302) 739-6242

District of Columbia

Department of Consumer and Regulatory Affairs
Environmental Regulation Administration
2100 Martin L. King, Jr. Avenue, SE
Washington, D.C. 20020
(202) 404-1136
FAX#: (202) 404-1141

Florida

Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400
(904) 921-9717
FAX#: (904) 487-4938

Georgia

Department of Natural Resources
205 Butler Street, S.W., Suite 1252
Atlanta, GA 30334
(404) 656-4713
FAX#: (404) 656-0770

Idaho

Division of Environmental Quality
1410 N. Hilton Street
Boise, ID 83720
(208) 334-0502
FAX#: (208) 334-0417

Illinois

Illinois Environmental Protection Agency
2200 Churchill Road
P.O. Box 19276
Springfield, IL 62794
(217) 782-3397
FAX#: (217) 782-9039

Indiana

Indiana Department of Environmental Management
100 N. Senate, Room 1301
Indianapolis, IN 46204
(317) 232-8162
FAX#: (317) 232-8564

Iowa

Environmental Protection Division
Iowa Department of Natural Resources
Wallace State Office Building
Des Moines, IA 50319
(515) 281-6284
FAX#: (515) 281-8895

Kansas

Department of Health and Environment
900 S.W. Jackson, Suite 901
Topeka, KS 66612-1290
(913) 296-0461
FAX#: (913) 296-6231

Kentucky

Natural Resources and Environmental Protection Cabinet
5th Floor, Capital Plaza Tower
Frankfort, KY 40601
(502) 564-3350
FAX#. (502) 564-4245

Louisiana

Department of Environmental Quality
P.O. Box 44066
Baton Rouge, LA 70804
(504) 765-0639
FAX#: (504) 765-0746

Maine

Department of Environmental Protection
State House Station 17
Augusta, ME 04333
(207) 287-2812
FAX#: (207) 287-7826

Maryland

Department of Environment
2500 Broening Highway
Baltimore, MD 21224
(410) 631-3084
FAX#: (410) 631-3888

Massachusetts

Department of Environmental Protection
One Winter Street
Boston, MA 02108
(617) 292-5856
FAX#: (617) 556-1049

Environmental Affairs Executive Office
One Winter Street
Boston, MA 02108
(617) 727-9800
FAX#: (617) 727-2754

Michigan

Department of Natural Resources
Box 30028, Steven T. Mason Building
Lansing, MI 48909
(517) 373-2329
FAX#: (517) 335-4242

Minnesota

Minnesota Pollution Control Agency
520 Lafayette Road, 6th Floor
St. Paul, MN 55155-3898
(612) 296-7303
FAX#: (612) 296-7923

Mississippi

Department of Natural Resources
Box 10305
Jackson, MS 39289-1305
(601) 961-5000
FAX#: (601) 354-6965

Missouri

Department of Natural Resources
205 Jefferson Street, P.O. Box 176
Jefferson City, MO 65102
(314) 751-4422
FAX#: (314) 751-7627

Montana

Environmental Sciences Division
Department of Health and Environmental Science
Cogswell Building
Helena, MT 59620
(406) 444-3948
FAX#: (406) 444-1374

Nebraska

Environmental Control
P.O. Box 98922
Lincoln, NE 68509
(402) 471-2186
FAX#: (402) 471-2909

Nevada

Environmental Protection Division
Nevada Department of Conservation and
Natural Resources
333 West Nye Lane
Carson City, NV 89710
(702) 687-4670
FAX#: (702) 687-5856

New Hampshire

New Hampshire Department of Environmental Services
Hazen Drive, P.O. Box 95
Concord, NH 03301
(603) 271-3503
FAX#: (603) 271-2867

New Jersey

Department of Environmental Protection and Energy
401 East State Street - CN 402
Trenton, NJ 08625
(609) 292-5617
FAX#: (609) 984-3962

New Mexico

Department of Environment
P.O. Box 26110
Santa Fe, NM 87503-0968
(505) 827-2850
FAX#: (505) 827-2836

New York

Environmental Conservation Department
50 Wolf Road
Albany, NY 12233
(518) 457-3446
FAX#: (518) 457-6996

North Carolina

Environmental Protection
North Carolina Department of Environment, Health and Natural Resources
P.O. Box 27687
Raleigh, NC 27611-7687
(919) 715-4140
FAX#: (919) 715-3060

North Dakota

Environmental Health Section
1200 Missouri Avenue, Box 5520
Bismarck, ND 58502-5520
(701) 221-5150
FAX#: (701) 221-5200

Ohio

Ohio Environmental Protection Agency
P.O. Box 1049
1800 Watermark Drive
Columbus, OH 43266-0149
(614) 644-2782
FAX#: (614) 644-3184

Oklahoma

Oklahoma Department of Environmental Quality
1000 N.E. 10th Street
Oklahoma City, OK 73117-1299
(405) 271-8056
FAX#: (405) 271-7339

Oregon

Department of Environmental Quality
811 S.W. Sixth Avenue
Portland, OR 97204-1334
(503) 229-5395
FAX#: (503) 229-6124

Pennsylvania

Department of Environmental Resources
400 Market Street
Harrisburg, PA 17105-2063
(717) 787-5028
FAX#. (717) 783-8926

Rhode Island

Department of Environmental Management
9 Hayes Street
Providence, RI 02908
(401) 277-2771
FAX#: (401) 277-6802

South Carolina

Environmental Quality Control
Department of Health and Environmental Control
2600 Bull Street
Columbia, SC 29201
(803) 734-5360
FAX#: (803) 734-5199

South Dakota

Department of Environment and Natural Resources
523 E. Capitol Avenue
Pierre, SD 57501
(605) 773-5559
FAX#: (605) 773-6035

Tennessee

Department of Environment and Conservation
21st Floor, L & C Tower
401 Church Street
Nashville, TN 37243-0435
(615) 532-0109
FAX#: (615) 532-0120

Texas

Texas Natural Resource Conservation Commission
1700 North Congress, Room 123
Austin, TX 78701
(512) 463-7901
FAX#: (512) 475-2332

Utah

Department of Environmental Quality
168 North 1950 West
P.O. Box 144810
Salt Lake City, UT 84116-4810
(801) 536-4400
FAX#: (801) 538-4401

Vermont

Vermont Agency of Natural Resources
103 S. Main Street, Building 1-South
Waterbury, VT 05676
(802) 241-3600
FAX#: (802) 244-1102

Virginia

Department of Environmental Quality
9th Street Office Building
Richmond, VA 23219
(804) 786-0044
FAX#: (804) 371-8333

Washington

Department of Ecology
P.O. Box 47600
Olympia, WA 98504-8711
(206) 407-7001
FAX#: (206) 493-9495

West Virginia

Natural Resources Department
800 Washington Street
Charleston, WV 25305
(304) 558-2754
FAX#: (304) 348-2768

Wisconsin

Wisconsin Department of Natural Resources
P.O. Box 7921
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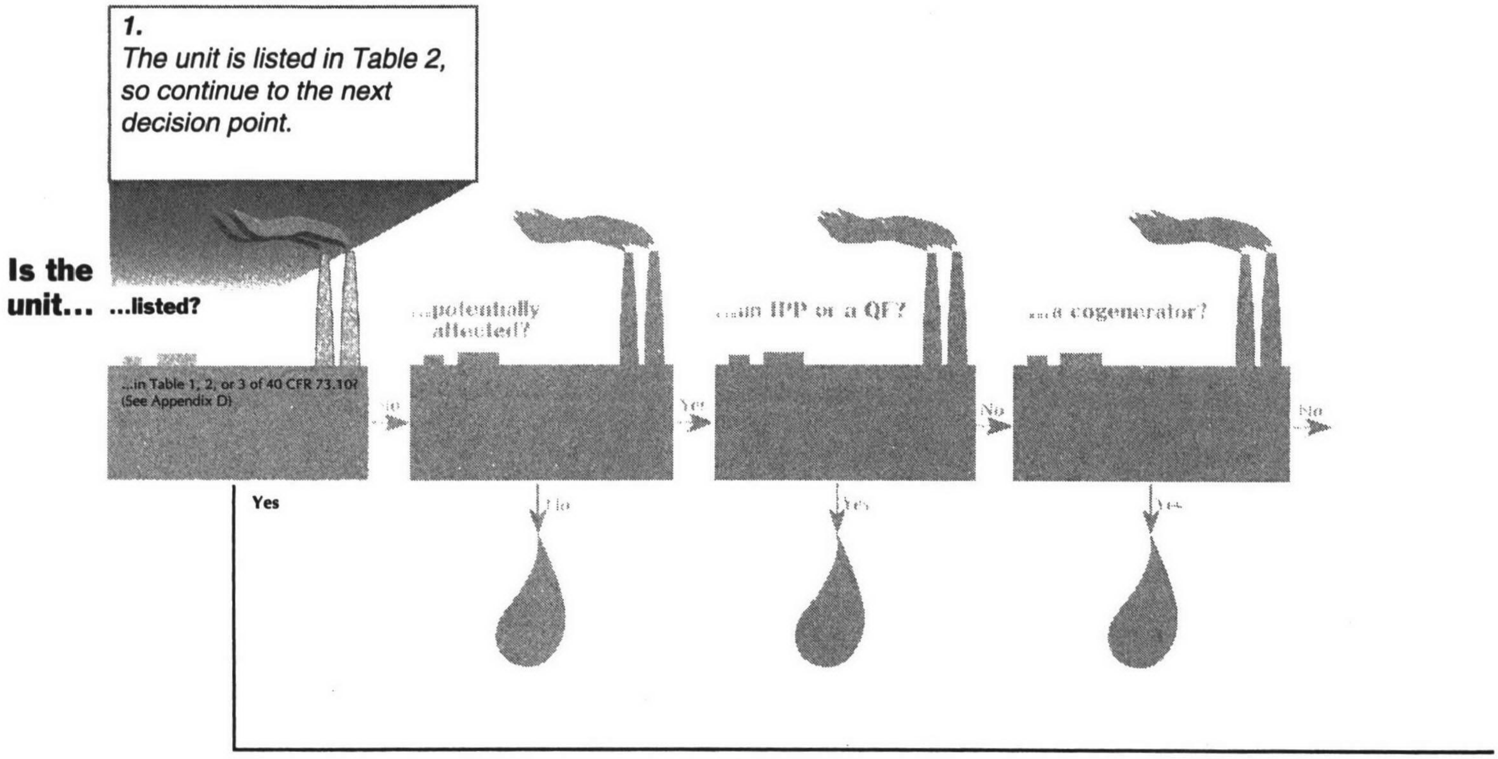
Appendix C Applicability Determination Examples

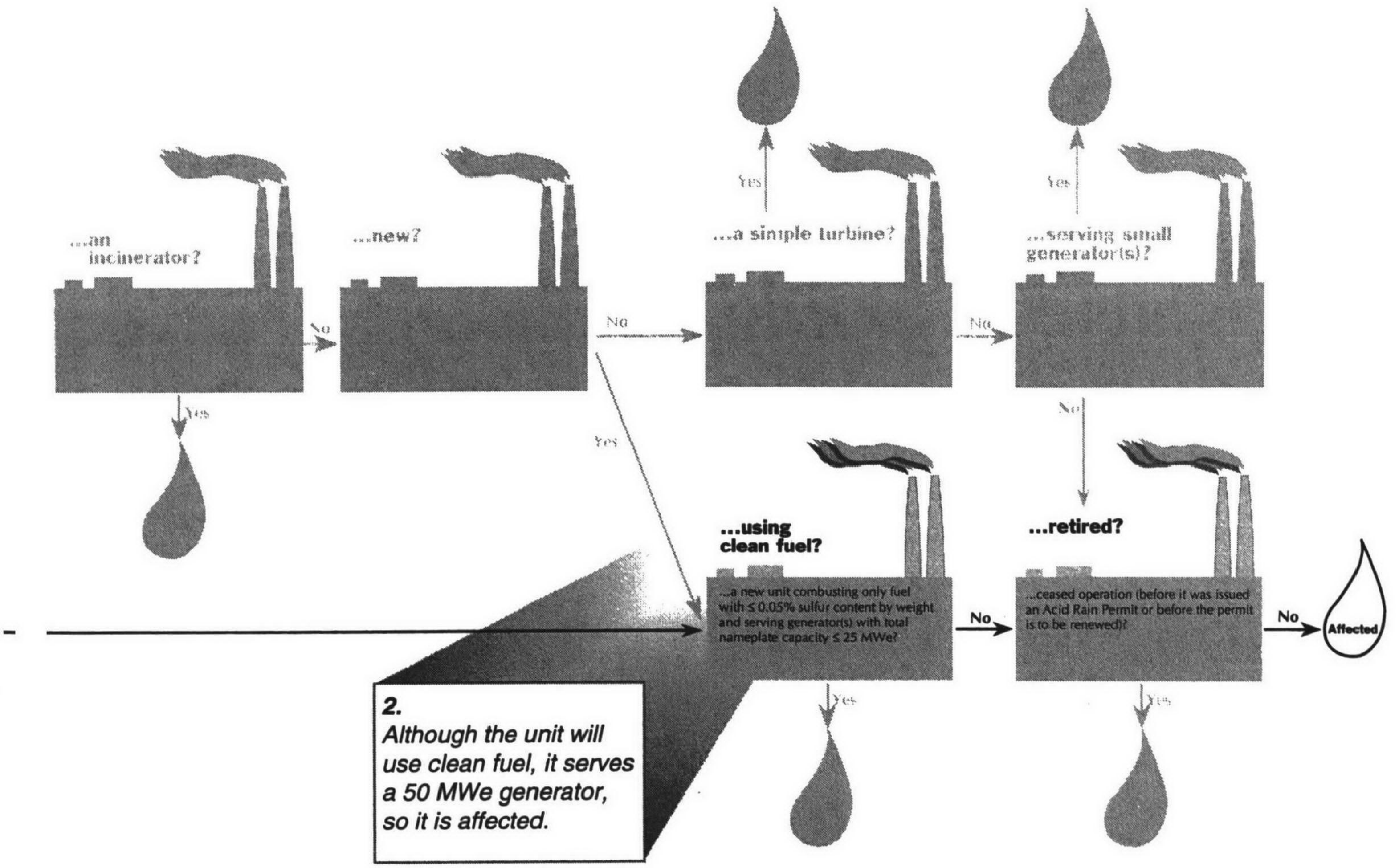
This appendix provides examples illustrating how to work through the flow chart to determine applicability of the Acid Rain Program to a specific unit. Each example includes facts about a hypothetical unit, the applicability decision for that unit, and an annotated flow chart.

Example 1: Listed Unit

Facts: This unit is listed in Table 2 of 40 CFR 73.10 (Exhibit 2 of *Appendix D*). A prospective owner wants to buy the unit and convert it to burn only non-fossil fuels. The unit will continue to supply steam to a 50 MWe capacity generator that sells electricity.

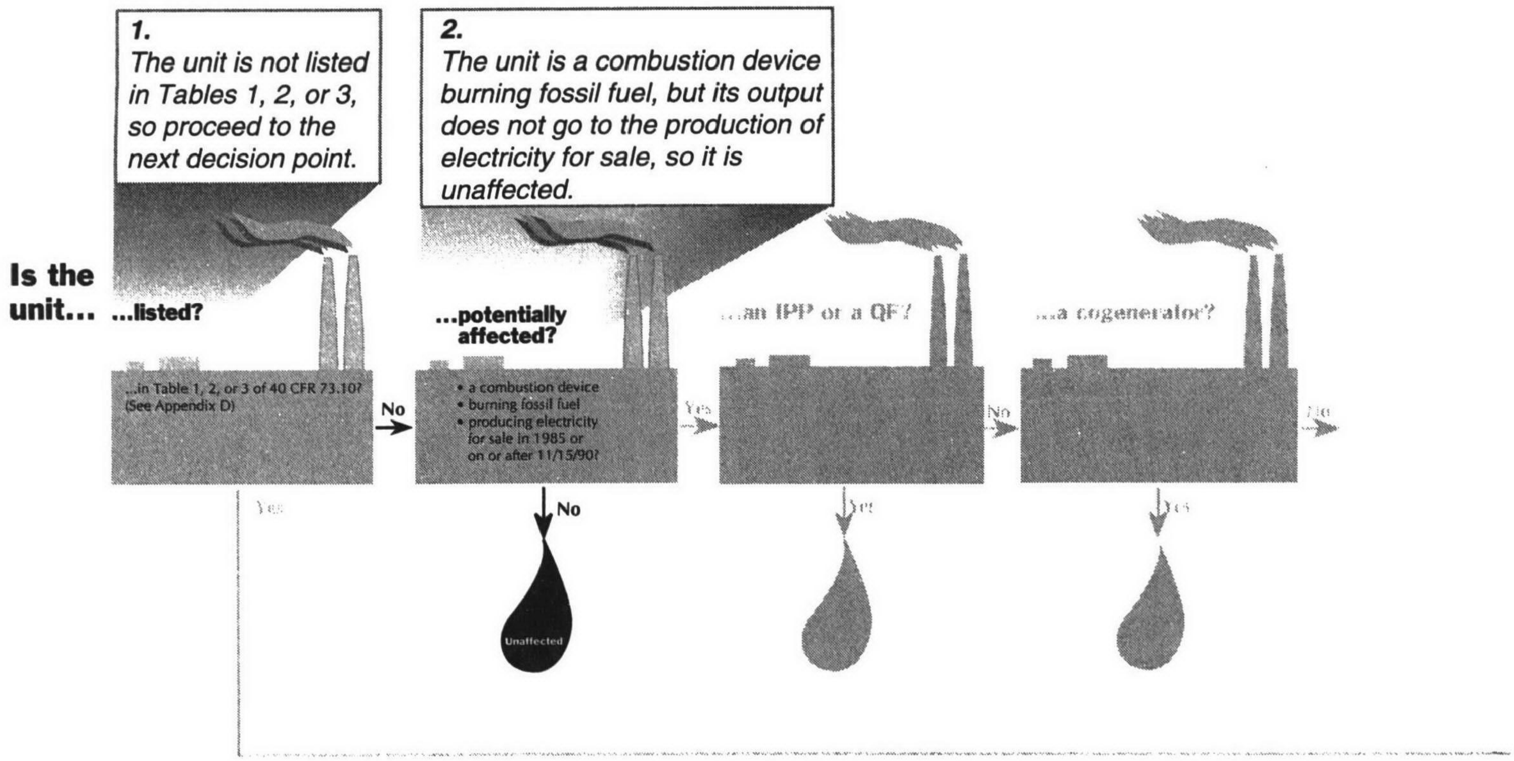


Decision: The unit is affected even if it is converted to consume non-fossil fuels. Note that the unit will retain its allowance allocation even though it uses non-fossil fuels.

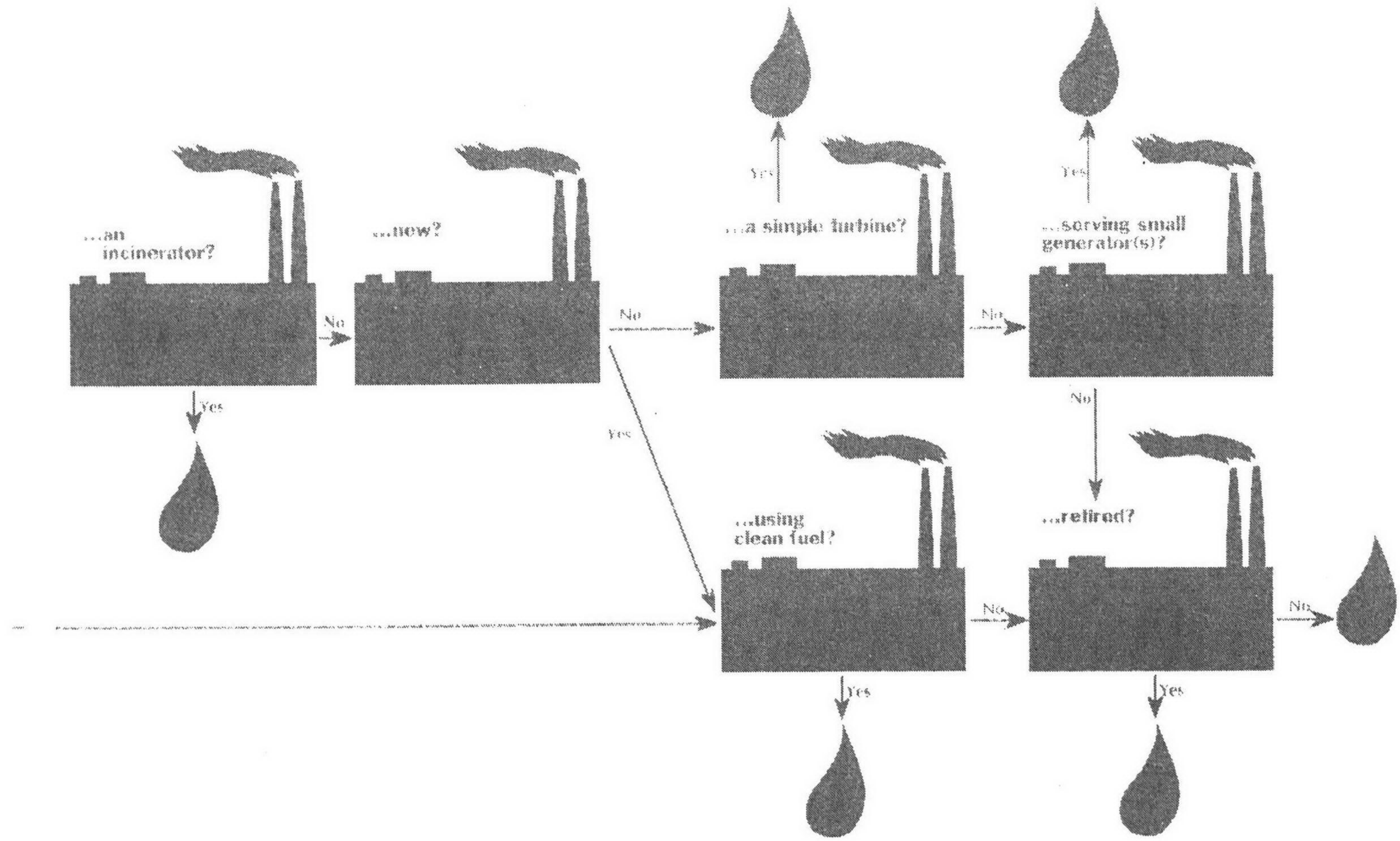


Example 2: Cogenerator Not Selling Electricity

Facts: This unit is not listed in Tables 1, 2, or 3 of 40 CFR 73.10 (Exhibits 1, 2, or 3 of *Appendix D*). The cogenerator commenced commercial operation in 1988 and burns primarily coal, but also some wood waste and natural gas. The cogenerator was constructed to supply steam to an industrial facility. Neither the cogenerator nor the industrial facility has sold any electricity since the commencement of operations.

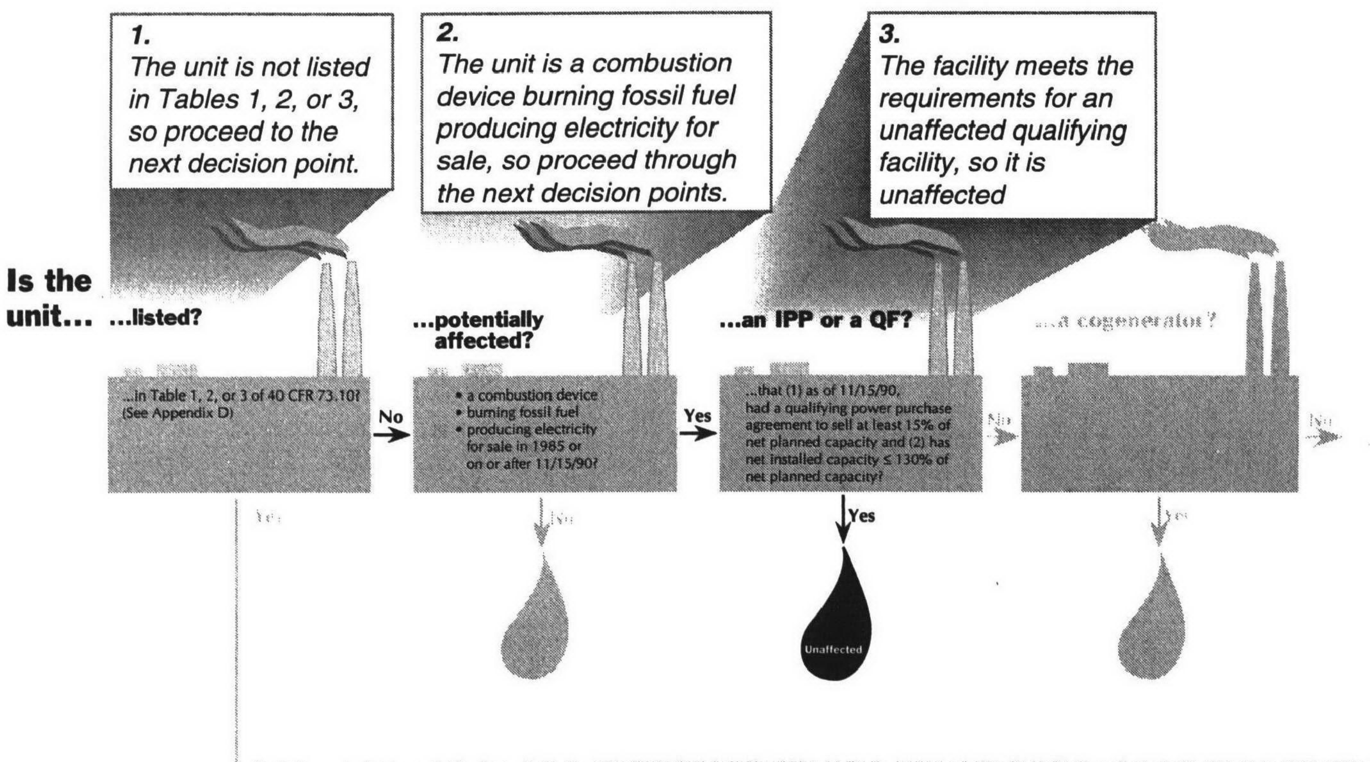


Decision: **The unit is unaffected,** because its output does not go to the production of electricity for sale. If the industrial facility buying the steam was using it to produce electricity that was then sold to the public utility grid, then one would have to continue through the flow chart to determine whether the unit is affected.



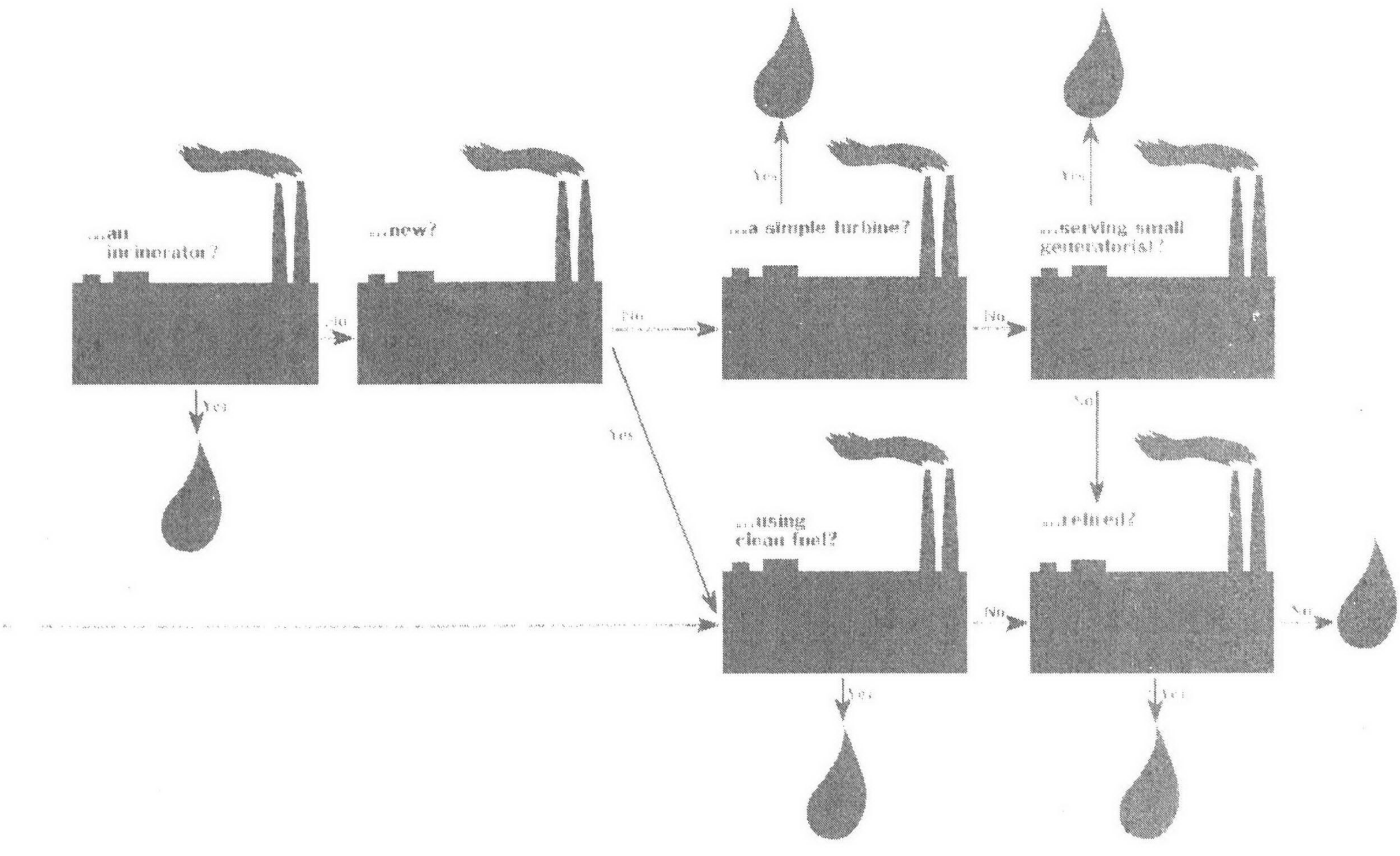
Example 3: Qualifying Facility

Facts: There are two oil- and gas-fired boilers headered to one generator at this facility. In 1986, during the planning of the facility, the facility owners filed for self-certification of qualifying cogeneration facility status with the Federal Energy Regulatory Commission (FERC). The facility is the subject of a power sales agreement, executed in 1987, for 40 MWe with a utility. The facility's construction contract specifies a generator of 50,000 kVA at a power rating of 85% (equivalent to 42.5 MWe). The facility also has a steam sales agreement with a local prison. The facility was completed and commenced operation in 1992 with a 43 MWe nameplate capacity generator. The power sales agreement has not been changed or amended. The unit is not listed in Tables 1, 2, or 3 of 40 CFR 73.10 (Exhibits 1, 2, or 3 of *Appendix D*).



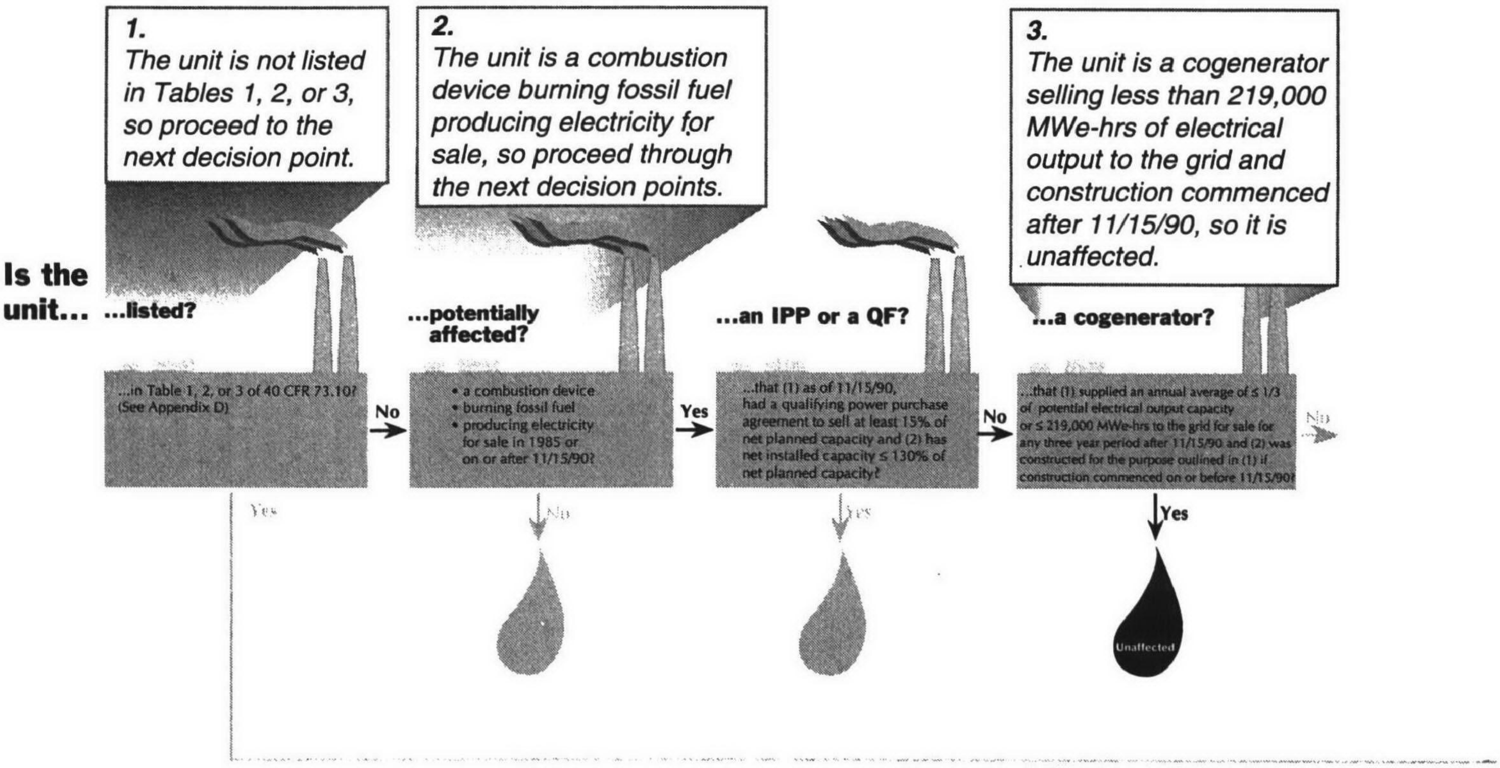
Decision: **Neither boiler at this facility is affected.** The facility meets the requirements for an unaffected qualifying facility:

- ❑ It meets the definition of a qualifying facility;
- ❑ It had a qualifying power purchase commitment as of November 15, 1990; and
- ❑ It has installed capacity less than or equal to 130% of its planned net capacity.



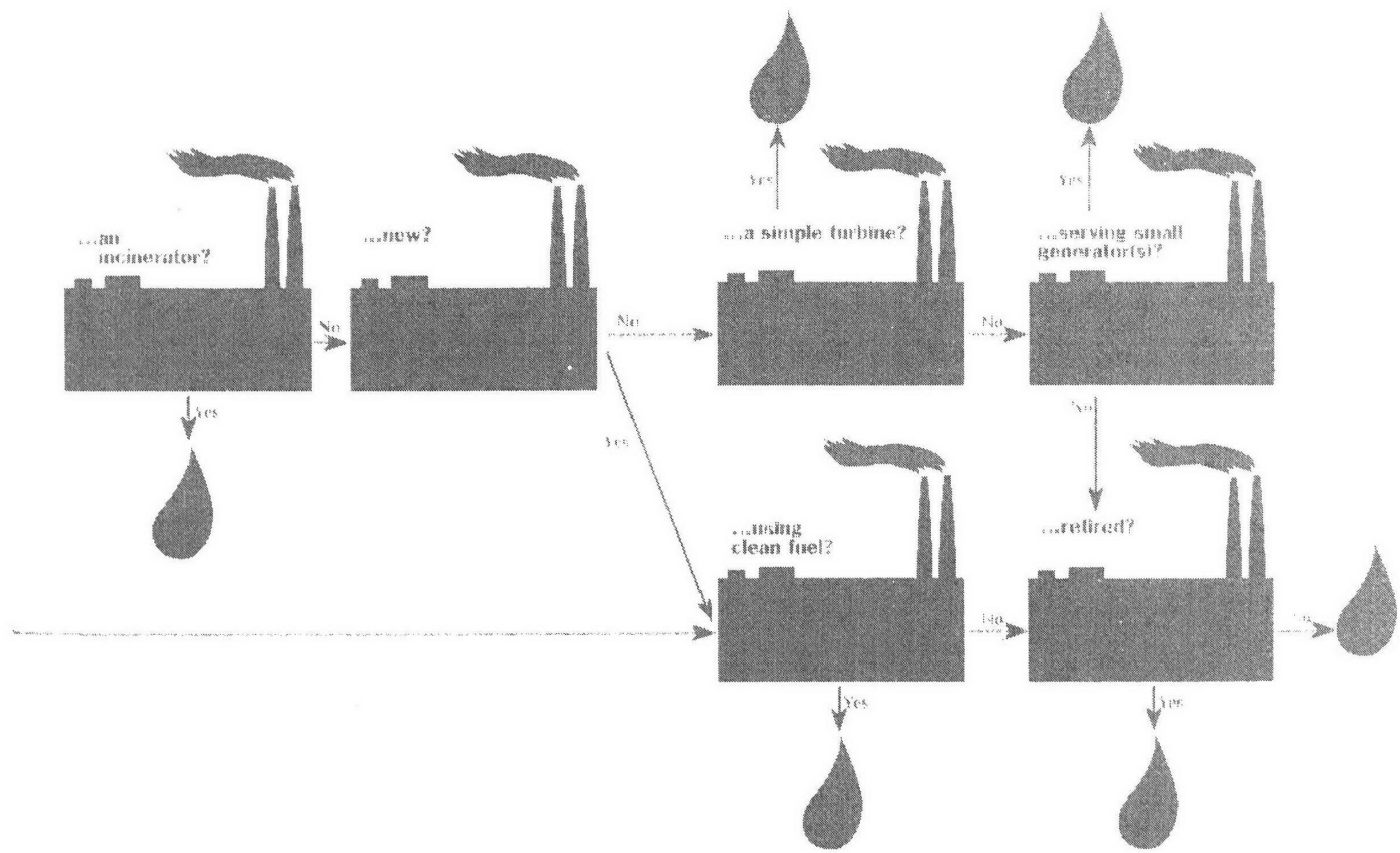
Example 4: Cogenerator Selling Electricity

Facts: An industrial company built a cogeneration facility to serve the company's adjacent manufacturing plant. The facility commenced commercial operation with a single boiler-generator pair in 1991. The boiler has a maximum design heat input of 1,024 mmBtu/hr (which calculates to potential electrical output capacity of 100 MWe), and the generator has a nameplate capacity of 75 MWe. When the needs of the manufacturing plant are low, the industrial company sells the excess power to a public utility. The amount of electricity sold to the public utility (gross sales) in any one year has not exceeded, and is not expected to exceed, 200,000 MWe-hrs. The unit is not listed in Tables 1, 2, or 3 of 40 CFR 73.10 (Exhibits 1, 2, or 3 of *Appendix D*).



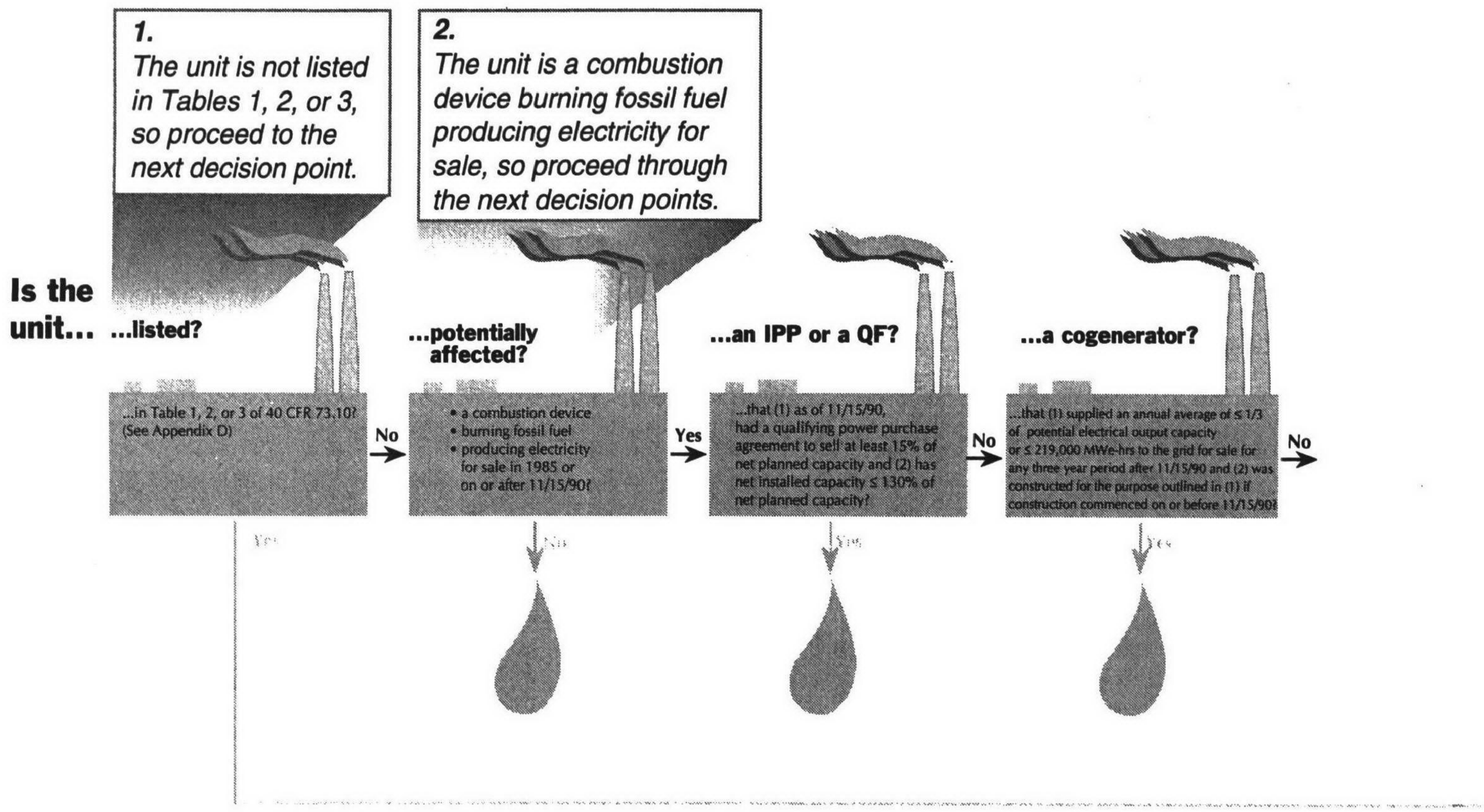
Decision: **The unit (boiler) is unaffected** because it meets the requirements for an unaffected cogenerator. The gross annual electricity sales are less than or equal to one-third of the potential electrical output capacity or less than or equal to 219,000 MWe-hrs.

First, calculate the potential electrical output capacity (100 MWe), then compare this to the generator nameplate capacity. In this example, 75% of the boiler's capacity can be used to generate electricity. Because this level (75%) is greater than one-third, calculate the maximum number of MWe-hrs that could be sold at one-third potential electrical output capacity. This figure is 292,000 MWe-hrs (see Example of Cogenerator Determinations on page 14 of *Section 1*). Since 200,000 MWe-hrs (the amount of the unit's gross electricity sales) is below both the 292,000 MWe-hrs and 219,000 MWe-hrs criteria, the boiler is unaffected.

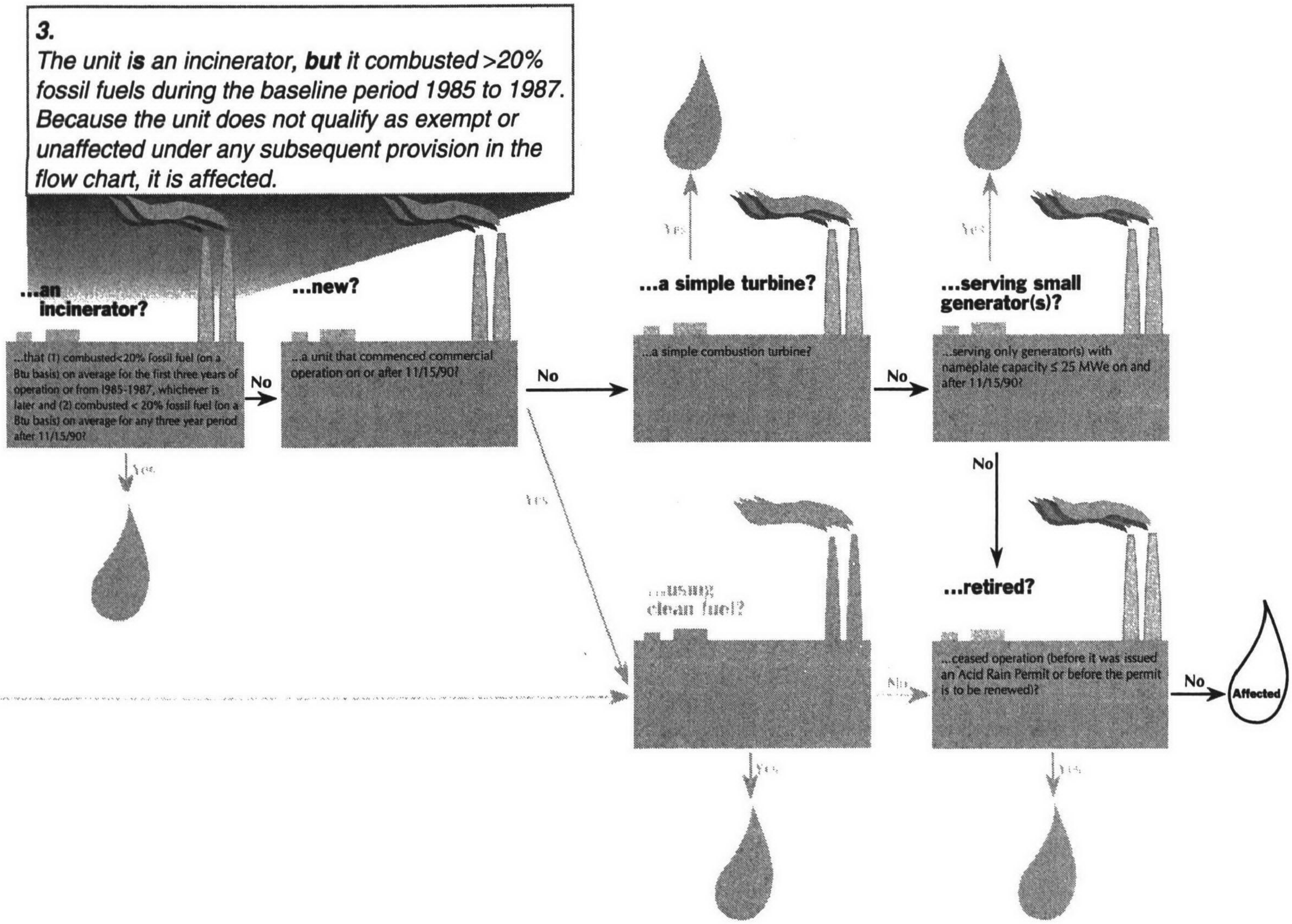


Example 5: Solid Waste Incinerator

Facts: A solid waste incinerator commenced operation in the 1970s and generally consumes 25 to 30% of its fuel in the form of number 2 diesel fuel. By 1995, the facility expects to consume less than 20% fossil fuels by burning more consumer waste. It is not listed in Tables 1, 2, or 3 of 40 CFR 73.10 (Exhibits 1, 2, or 3 of *Appendix D*).

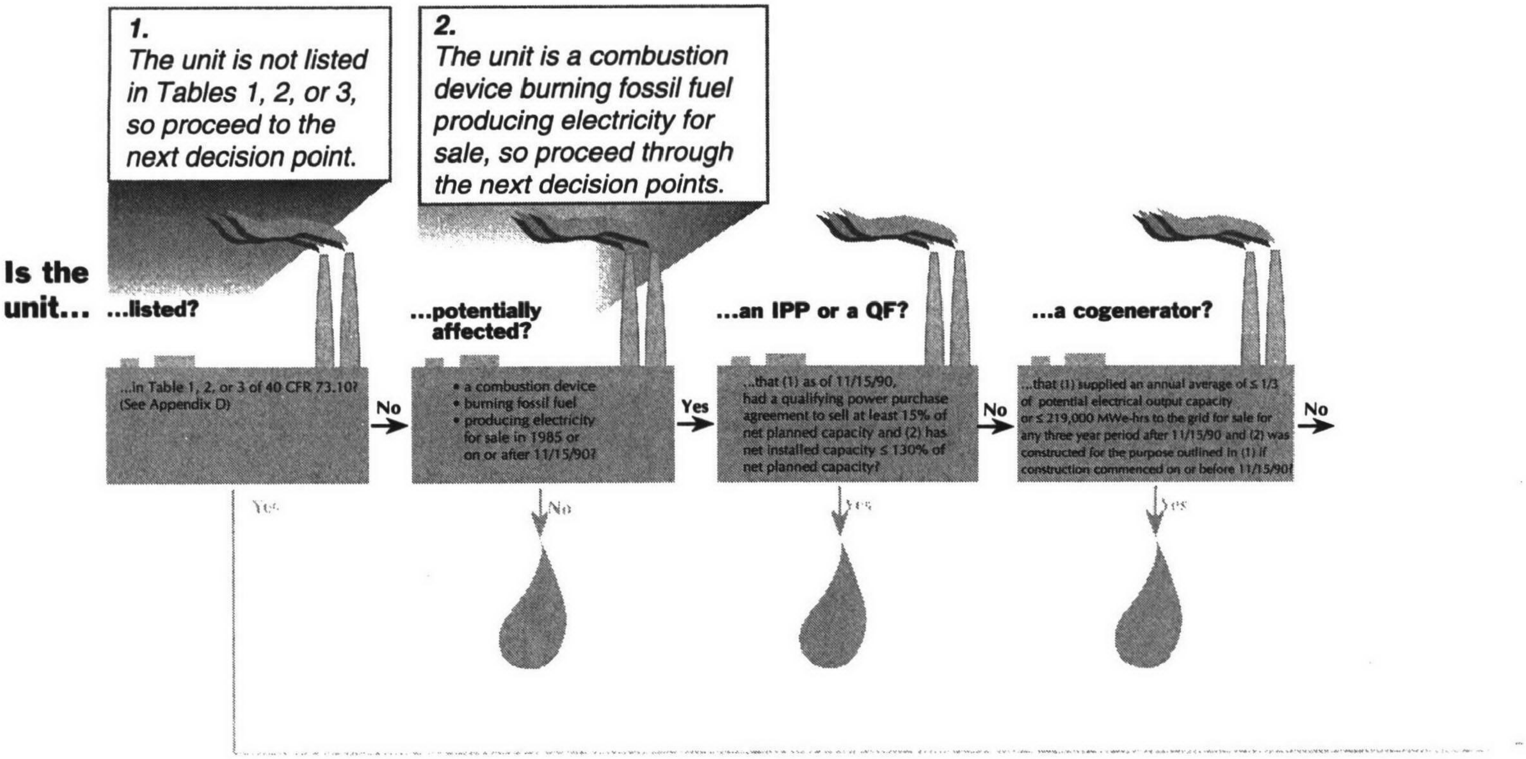


Decision: **The facility is affected** because it consumed greater than 20% fossil fuels during the baseline period, 1985-1987. The current and future consumption rates are irrelevant in this case.

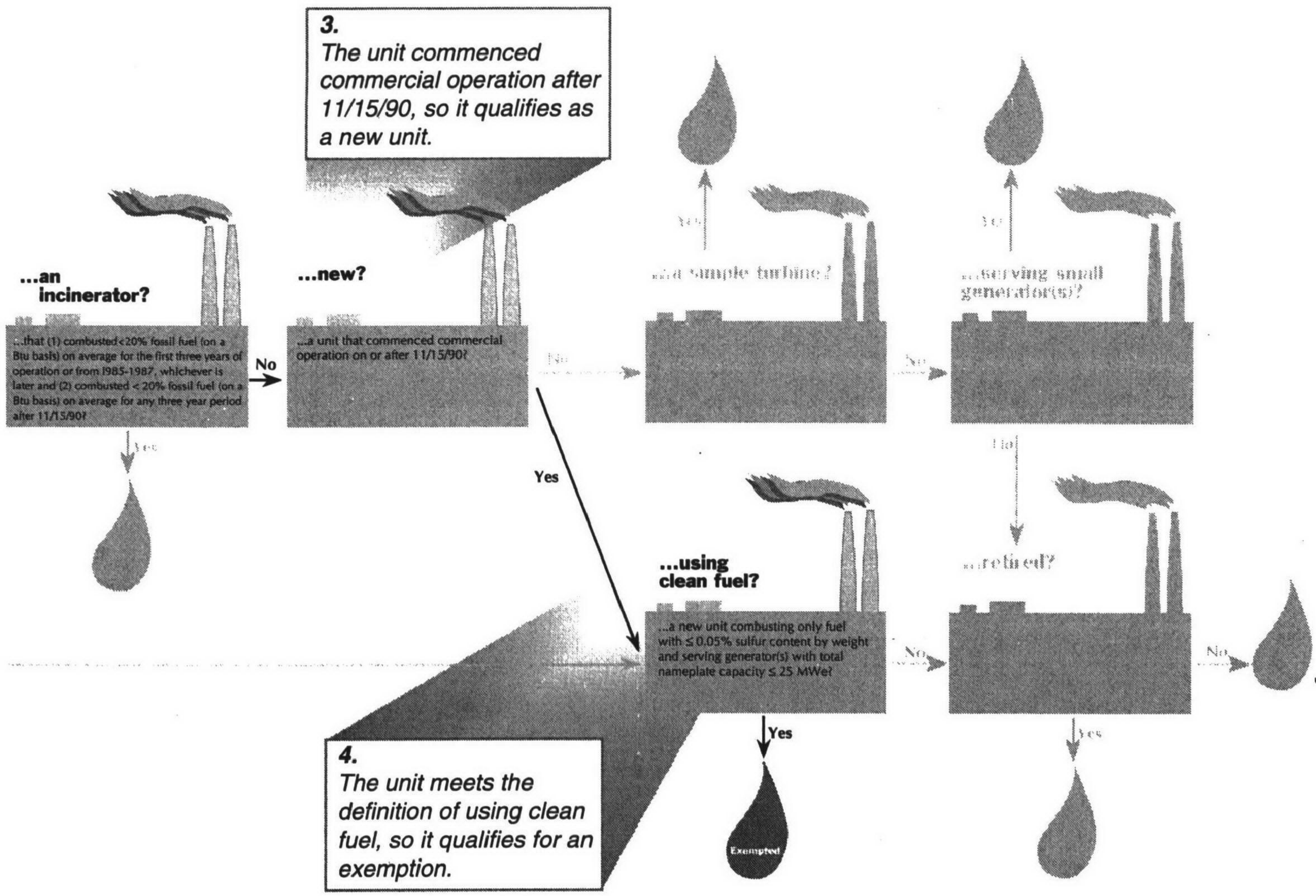


Example 6: New, Small, Clean Unit

acts: A unit is planned to commence commercial operation in March 1998. It is not listed in Tables 1, 2, or 3 of 40 CFR 73.10 (Exhibits 1, 2, or 3 of *Appendix D*), nor is it listed in the National Allowance Data Base (NADB). It is planned to consume at least 90% natural gas, so its fuels average sulfur content will be below 0.05% by weight. The boiler will serve one generator with nameplate capacity of 15 MWe.

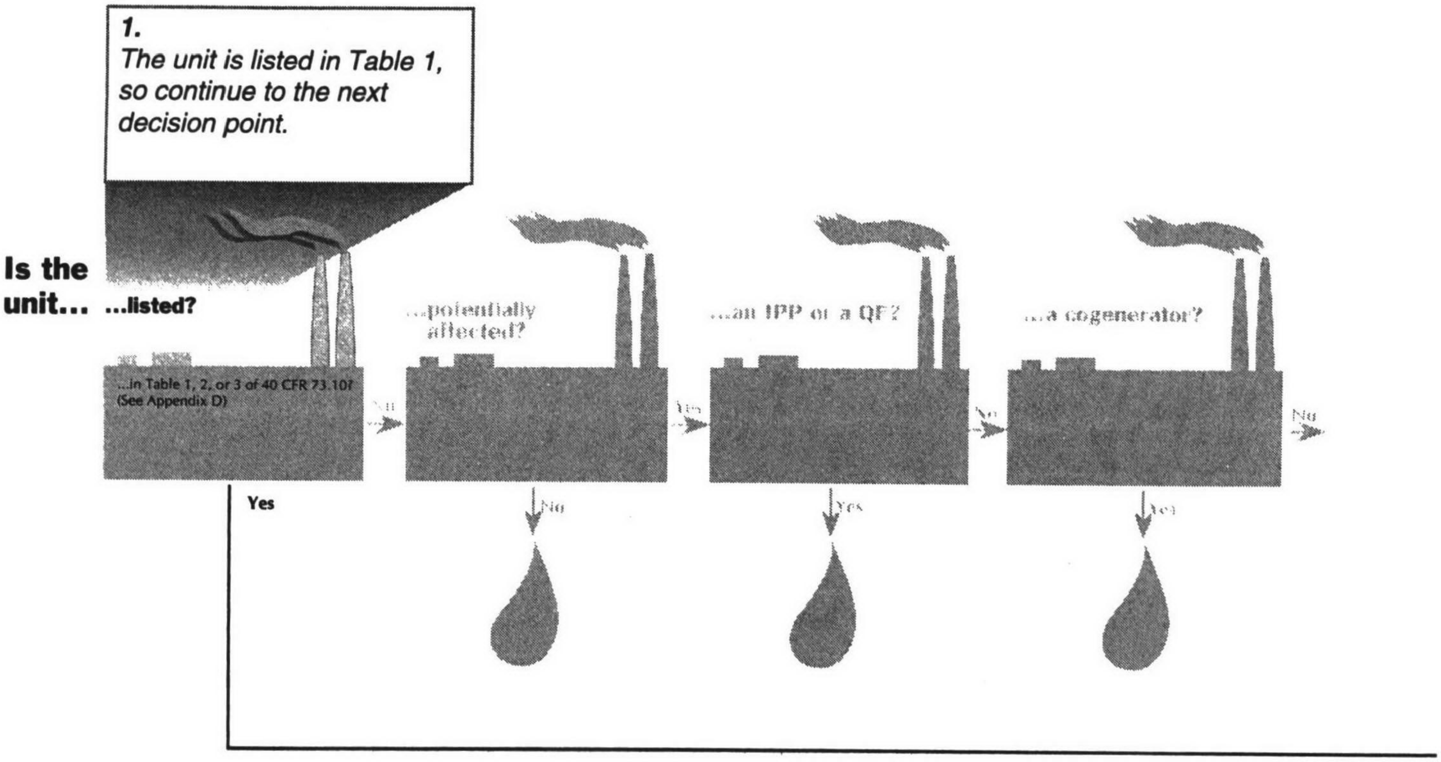


Decision: **The unit is eligible for the exemption** as a small, new unit burning clean fuels. It received no allowance allocation initially, so it does not need to forfeit allowances. The unit may be able to avoid the requirements to install and test CEMS by receiving its exemption before January 1, 1998. Without this exemption, the unit would be required to install and certify CEMS within 90 days of the unit's commencement of commercial operation (see *Compliance Timelines*) in June 1998. If the unit files for and receives its exemption in 1997, the exemption goes into effect January 1, 1998, in time to avoid the requirements to install and certify CEMS (see 40 CFR 72.7(c) and 75.4(b)(1)).

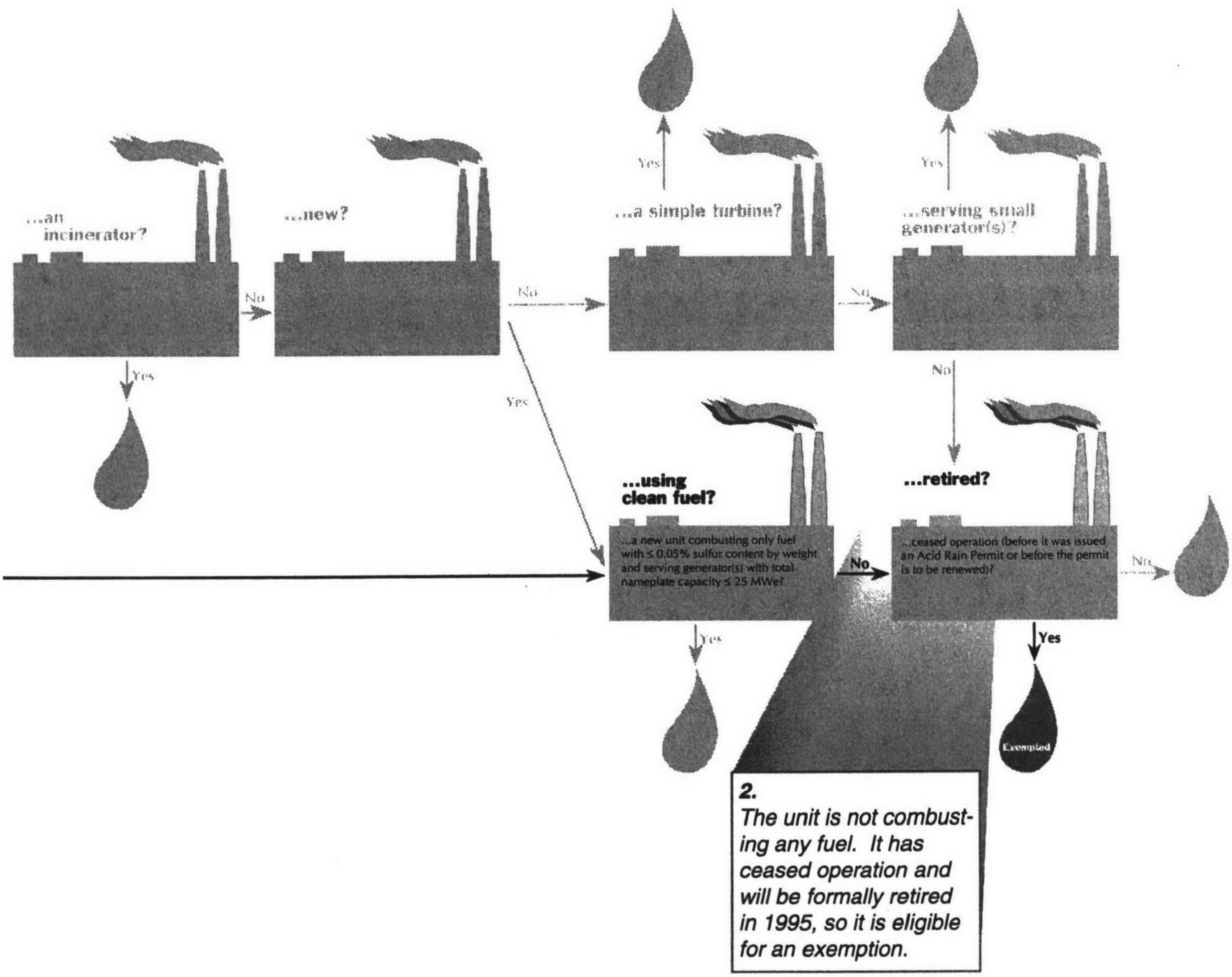


Example 7: Retired Unit

Facts: A unit is listed in Table 1 of 40 CFR 73.10 (Exhibit 1 of *Appendix D*). The unit is presently on "cold standby" status; that is, it is not immediately operable but could be brought on-line within 6 months. The owners have decided to formally retire the unit in 1995.

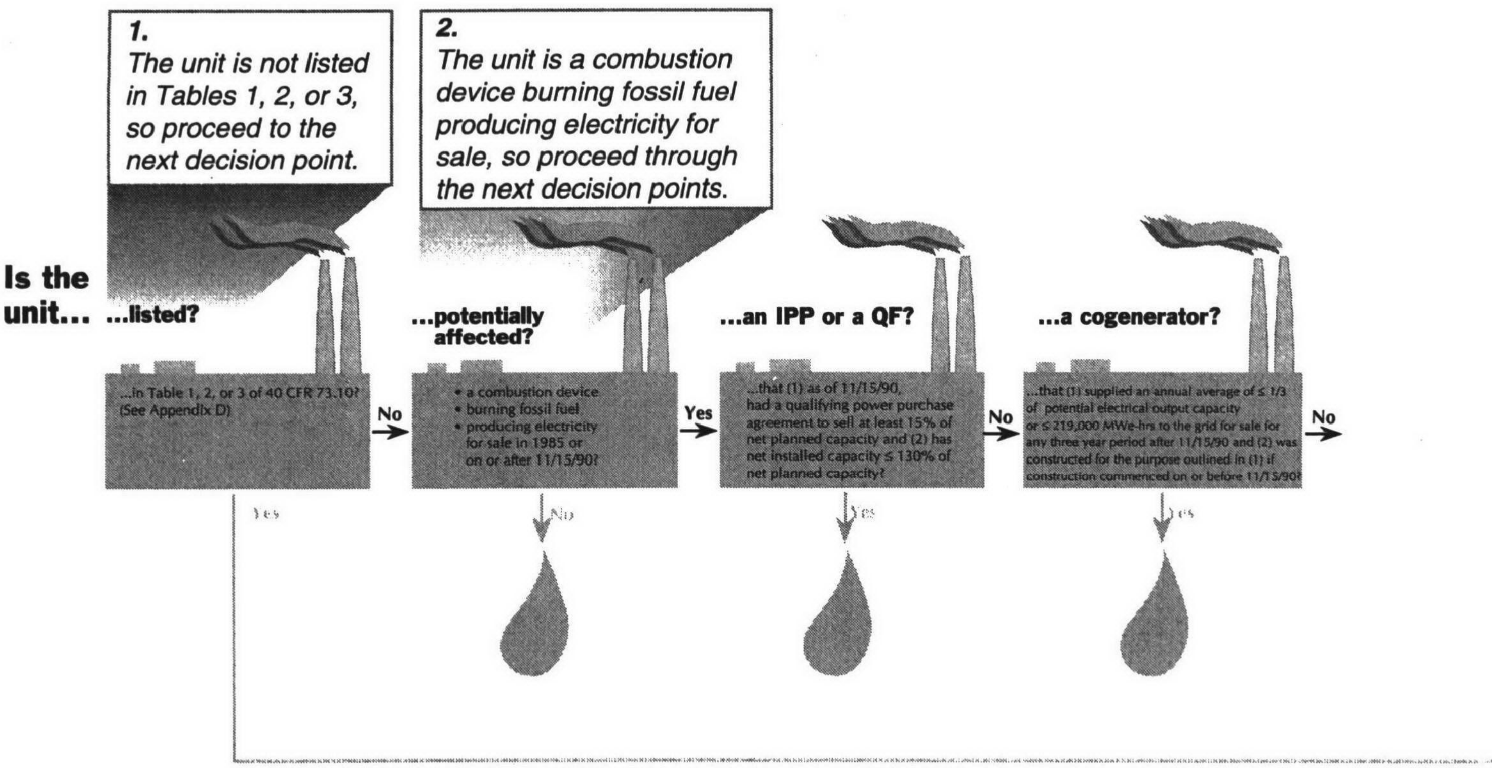


Decision: **The unit is eligible for the retired units exemption** of 40 CFR 72.8. Because it is a Phase I affected unit, it must meet all applicable Acid Rain Program requirements until January 1 of the year after the unit is granted its exemption. Applicable acid rain requirements include holding sufficient allowances to cover its annual SO_2 emissions (for emissions in 1995 and thereafter), obtaining an acid rain permit, having a Designated Representative, and installing and operating systems to monitor emissions, as required by 40 CFR 75.

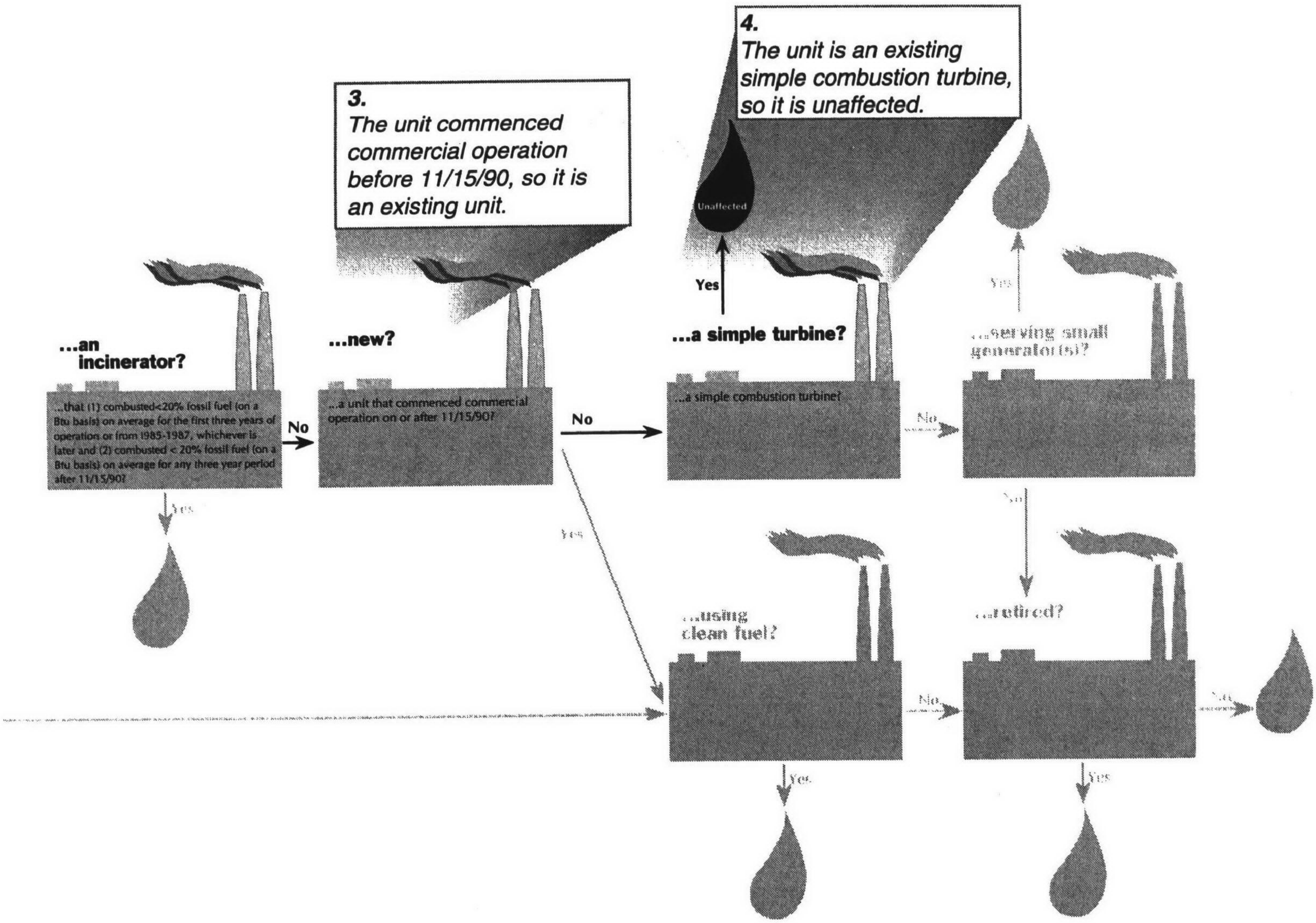


Example 8: Existing Simple Combustion Turbine

Facts: A unit is a simple combustion turbine that is not listed in Tables 1, 2, or 3 of 40 CFR 73.10 (Exhibits 1, 2, or 3 of *Appendix D*). It commenced commercial operation in 1983 and does not have auxiliary firing. The owner plans to sell it to another utility. That utility plans to move the turbine, refurbish it, and rename it. The turbine is listed in the National Allowance Data Base (NADB) with the 1983 on-line date.

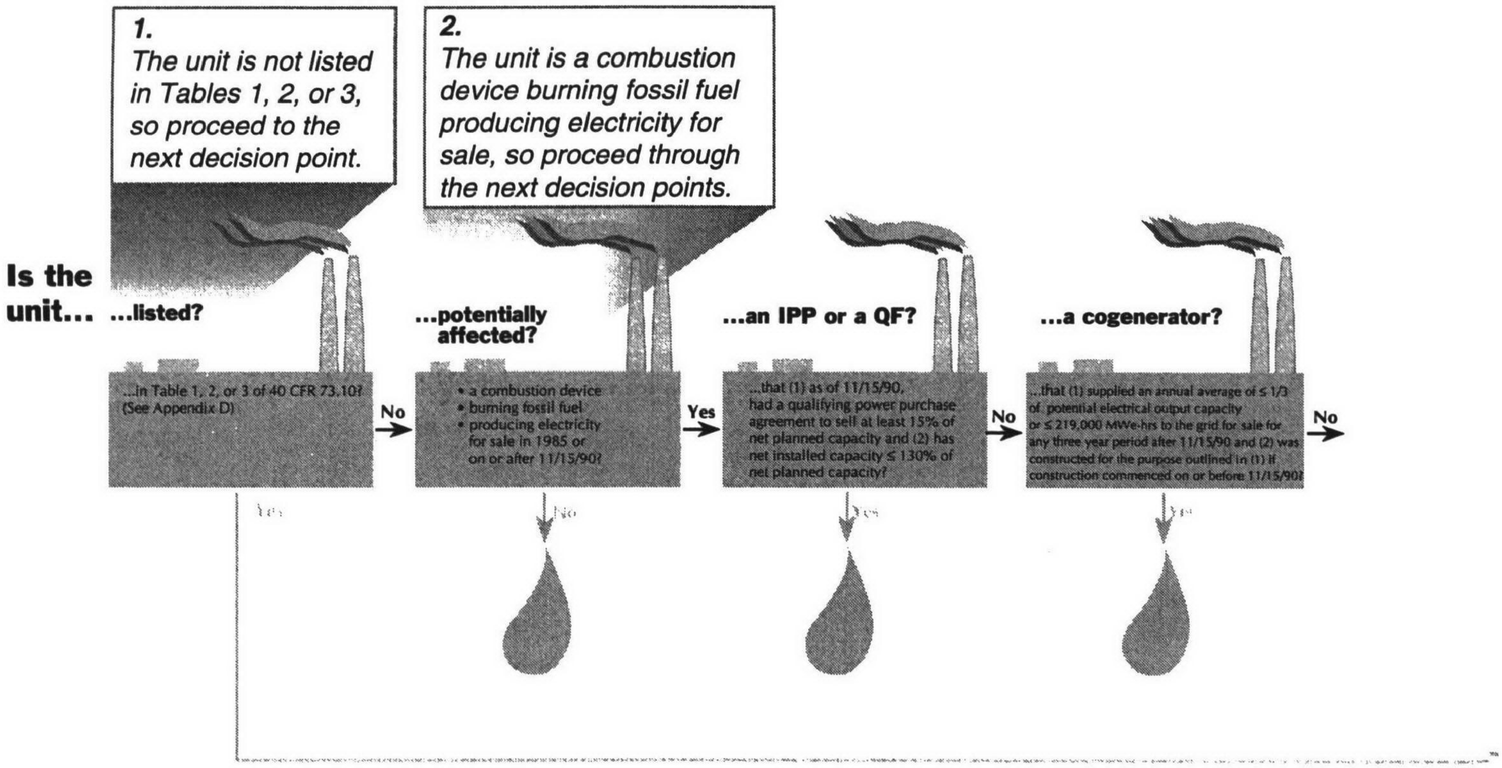


Decision: **The turbine is unaffected** as an existing simple combustion turbine. The new owner should not change the name of the turbine and should ensure that future submittals to the Energy Information Administration (EIA) do not change the on-line date to avoid becoming affected as a new unit.

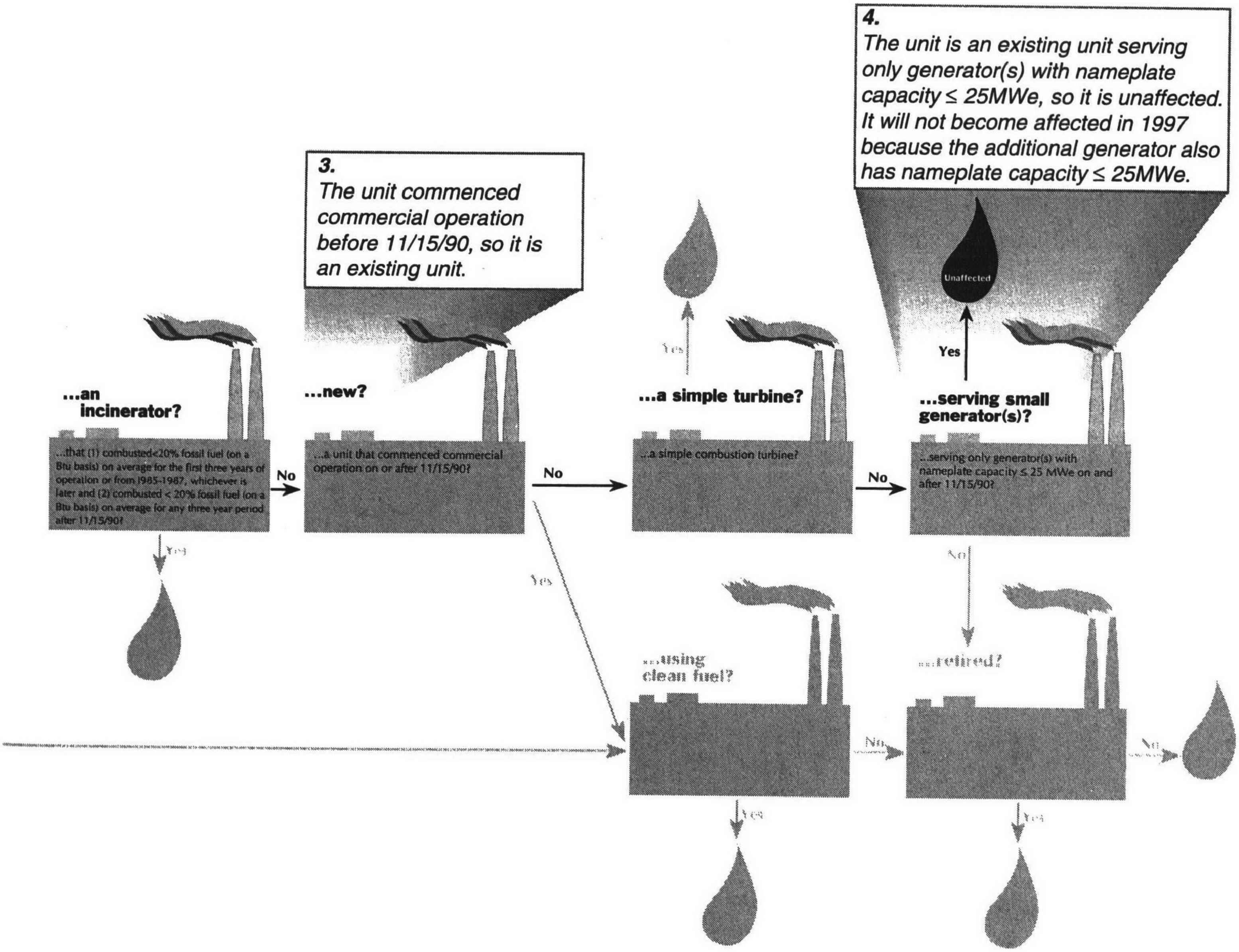


Example 9: Existing Unit Serving A Small Generator

Facts: A boiler presently serves a generator with nameplate capacity of 18 MWe and, in 1985, served only this generator. The boiler commenced operation in 1963 and sells electricity and steam for industrial process use. Because of increased electrical demand at the industrial site, the owner of the boiler plans to add a generator with nameplate capacity of 8 MWe in 1997.



Decision: **The unit is currently unaffected and would remain unaffected if it adds the 8 MWe generator.** The boiler is an existing unit, and all current and planned generators served by it have nameplate capacities of less than 25 MWe (i.e., the statutory cutoff; see Section 402(8) of the Clean Air Act). However, if the boiler owner replaces the 18 MWe (nameplate) generator with a generator of greater than 25 MWe nameplate capacity, the boiler would become affected, according to 40 CFR 72.6(a)(3)(ii), which affects existing units that serve, on or after November 15, 1990, generators with nameplate capacities greater than 25 MWe.



Appendix D: Selected List of Units Affected by the Acid Rain Regulations

Exhibit 1: Units listed in Table 1 of §73.10 (40 CFR 73)

State Name	Plant Name	Boilers
ALABAMA		
	Colbert	1, 2, 3, 4, 5
	E C Gaston	1, 2, 3, 4, 5
FLORIDA		
	Big Bend	BB01, BB02, BB03
	Crist	6, 7
GEORGIA		
	Bowen	1BLR, 2BLR, 3BLR, 4BLR
	Hammond	1, 2, 3, 4
	Jack McDonough	MB1, MB2
	Wansley	1, 2
	Yates	Y1BR, Y2BR, Y3BR, Y4BR, Y5BR, Y6BR, Y7BR
ILLINOIS		
	Baldwin	1, 2, 3
	Coffeen	N01, 02
	Grand Tower	09
	Hennepin	2
	Joppa Steam	1, 2, 3, 4, 5, 6
	Kincaid	1, 2
	Meredosia	05
	Vermilion	2
INDIANA		
	Bailly	7, 8
	Breen	1
	Cayuga	1, 2
	Clifty Creek	1, 2, 3, 4, 5, 6
	Elmer W Stout	50, 60, 70
	F B Culley	2, 3
	Frank E Ratts	1SG1, 2SG1
	Gibson	1, 2, 3, 4
	H T Pritchard	6
	Michigan City	12
	Petersburg	1, 2
	R Gallagher	1, 2, 3, 4
	Tanners Creek	U4
	Wabash River	1, 2, 3, 5, 6
	Warrick	4
IOWA		
	Burlington	1
	Des Moines	11
	George Neal	1
	Milton L Kapp	2
	Prairie Creek	4
	Riverside	9
KANSAS		
	Quindaro	2
KENTUCKY		
	Coleman	C1, C2, C3
	Cooper	1, 2
	E W Brown	1, 2, 3
	Elmer Smith	1, 2
	Ghent	1
	Green River	5
	H L Spurlock	1
	HMP&L Station 2	H1, H2
	Paradise	3
	Shawnee	10
MARYLAND		
	C P Crane	1, 2
	Chalk Point	1, 2
	Morgantown	1, 2
MICHIGAN		
	J H Campbell	1, 2
MINNESOTA		
	High Bridge	6
MISSISSIPPI		
	Jack Watson	4, 5
MISSOURI		
	Asbury	1
	James River	5
	Labadie	1, 2, 3, 4
	Montrose	1, 2, 3
	New Madrid	1, 2
	Sibley	3
	Sioux	1, 2
	Thomas Hill	MB1, MB2
NEW HAMPSHIRE		
	Merrimack	1, 2
NEW JERSEY		
	B L England	1, 2
NEW YORK		
	Dunkirck	3, 4
	Greenridge	6
	Milliken	1, 2
	Northport	1, 2, 3
	Port Jefferson	3, 4
OHIO		
	Ashtabula	7
	Avon Lake	11, 12
	Cardinal	1, 2
	Conesville	1, 2, 3, 4
	Eastlake	1, 2, 3, 4, 5
	Edgewater	13
	Gen J M Gavin	1, 2
	Kyger Creek	1, 2, 3, 4, 5
	Miami Fort	5-1, 5-2, 6, 7
	Muskingum River	1, 2, 3, 4, 5
	Niles	1, 2
	Picway	9
	R E Burger	5, 6, 7, 8
	W H Sammis	5, 6, 7
	Walter C Beckjord	5, 6
PENNSYLVANIA		
	Armstrong	1, 2
	Brunner Island	1, 2, 3
	Cheswick	1
	Conemaugh	1, 2
	Hatfield's Ferry	1, 2, 3
	Martins Creek	1, 2
	Portland	1, 2
	Shawville	1, 2, 3, 4
	Sunbury	3, 4
TENNESSEE		
	Allen	1, 2, 3
	Cumberland	1, 2
	Gallatin	1, 2, 3, 4
	Johnsonville	1, 2, 3, 4, 5, 6, 7, 8, 9, 10
WEST VIRGINIA		
	Albright	3
	Fort Martin	1, 2
	Harrison	1, 2, 3
	Kammer	1, 2, 3
	Mitchell	1, 2
	Mt Storm	1, 2, 3
WISCONSIN		
	Edgewater	4
	Genoa	1
	Nelson Dewey	1, 2
	North Oak Creek	1, 2, 3, 4
	Pulliam	8
	South Oak Creek	5, 6, 7, 8

Exhibit 2: Units listed in Table 2 of §73.10 (40 CFR 73)

State	Plant Name	Boiler
ALABAMA		
	Barry	1, 2, 3, 4, 5
	Charles R Lowman	1, 2, 3
	Chickasaw	110
	Colbert	1, 2, 3, 4, 5
	E C Gaston	1, 2, 3, 4, 5
	Future Fossil	**1
	Gadsden	1, 2
	Gorgas	5, 6, 7, 8, 9, 10
	Greene County	1, 2
	James H Miller Jr	1, 2, 3, 4
	Mcintosh-Caes	**1, **2
	Mcwilliams	**CT1, **CT2, **CT3
	Widows Creek	1, 2, 3, 4, 5, 6, 7, 8
ARIZONA		
	Agua Fria	1, 2, 3
	Apache Station	1, 2, 3
	Cholla	1, 2, 3, 4, **5
	Coronado	U1B, U2B
	De Moss Petrie	4
	Gila Bend	**GT1, **GT2, **GT3, **GT4
	Irvington	1, 2, 3, 4
	Kyrene	K-1, K-2
	Navajo	1, 2, 3
	Ocotillo	1, 2
	Saguaro	1, 2
	Springerville	1, 2
	West Phoenix	4, 6
	Yuma Axis	1
ARKANSAS		
	Carl Bailey	01
	Cecil Lynch	1, 2, 3
	Flint Creek	1
	Hamilton Moses	1, 2
	Harvey Couch	1, 2
	Independence	1, 2
	Lake Catherine	1, 2, 3, 4
	Mcclellan	01
	Na 2 — 7246	**1
	Robert E Ritchie	1, 2
	Thomas Fitzhugh	1
	White Bluff	1, 2
CALIFORNIA		
	Alamitos	1, 2, 3, 4, 5, 6
	Avon	1, 2, 3
	Broadway	B1, B2, B3
	Contra Costa	1, 2, 3, 4, 5, 6, 7, 8, 9, 10
	Cool Water	1, 2
	El Centro	2, 3, 4
	El Segundo	1, 2, 3, 4
	Encina	1, 2, 3, 4, 5
	Etiwanda	1, 2, 3, 4
	Glenarm	16, 17
	Grayson	4, 5
	Harbor Gen Station	1, 2, 3, 4, 5
	Haynes Gen Station	1, 2, 3, 4, 5, 6
	Highgrove	1, 2, 3, 4
	Humboldt Bay	1, 2
	Hunters Point	3, 4, 5, 6, 7
	Huntington Beach	1, 2, 3, 4
	Kern	1, 2, 3, 4
	Magnolia	M4
	Mandalay	1, 2
	Martinez	1, 2, 3
	Morro Bay	1, 2, 3, 4
	Moss Landing	1, 2, 3, 4, 5, 6, 7, 8, 6-1, 7-1
	Oleum	1, 2, 3, 4, 5, 6
	Olive	01, 02
	Ormond Beach	1, 2
	Pittsburg	1, 2, 3, 4, 5, 6, 7
	Potrero	3-1
	Redondo Beach	5, 6, 7, 8, 11, 12, 13, 14, 15, 16, 17
	San Bernardino,	1, 2
	Scattergood Gen Sta	1, 2, 3
	Silver Gate	1, 2, 3, 4, 5, 6
	South Bay	1, 2, 3, 4
	Valley Gen Station	1, 2, 3, 4

State	Plant Name	Boilers
COLORADO		
	Arapahoe	1, 2, 3, 4
	Cameo	2
	Cherokee	1, 2, 3, 4
	Comanche	1, 2
	Craig	C1, C2, C3
	Hayden	H1, H2
	Martin Drake	5, 6, 7
	Nucla	1
	Pawnee	1, **2
	Rawhide	101
	Ray D Nixon	1, **NA1
	Valmont	5, 11, 12, 13, 14, 21, 22, 23, 24
	Zuni	1, 2, 3
CONNECTICUT		
	Bridgeport Harbor	BHB1, BHB2, BHB3
	Devon	3, 6, 7, 8, 4A, 4B, 5A, 5B
	English	EB13, EB14
	South Meadow	11, 12, 13
	Middletown	1, 2, 3, 4
	Montville	5, 6
	New Haven Harbor	NHB1
	Norwalk Harbor	1, 2
DELAWARE		
	Edge Moor	3, 4, 5
	Hay Road	**3
	Indian River	1, 2, 3, 4
	Mckee Run	3
	Vansant	**11
DISTRICT OF COLUMBIA		
	Benning	15, 16
FLORIDA		
	Anclote	1, 2
	Arvah B Hopkins	1, 2
	Avon Park	2
	Big Bend	BB01, BB02, BB03, BB04
	C D Mcintosh Jr	1, 2, 3
	Cape Canaveral	PCC1, PCC2
	Crist	1, 2, 3, 4, 5, 6, 7
	Crystal River	1, 2, 4, 5
	Ct	**1, **2, **3, **4
	Cutler	PCU5, PCU6
	Debary	**7, **8, **9, **10
	Deerhaven	B1, B2, **NA1, **NA2
	F J Gannon	GB01, GB02, GB03, GB04, GB05, GB06
	Fort Myers	PFM1, PFM2
	G E Turner	2, 3, 4
	Henry D King	7, 8
	Higgins	1, 2, 3
	Hookers Point	HB01, HB02, HB03, HB04, HB05, HB06,
	Indian River	1, 2, 3, **C
	J D Kennedy	8, 9, 10
	J R Kelly	JRK8
	Smith	1, 2
	Larsen Memorial	7, **8, **9
	Lauderdale	PFL4, PFL5
	Manatee	PMT1, PMT2
	Martin	PMR1, PMR2
	Na 1 — 7238	**1
	Northside	1, 2, 3
	P L Bartow	1, 2, 3
	Port Everglades	PPE1, PPE2, PPE3, PPE4
	Putnam	HRSG11, HRSG12, HRSG21, HRSG22
	Riviera	PRV2, PRV3, PRV4
	S O Purdom	7
	Sanford	PSN3, PSN4, PSN5
	Scholz	1, 2
	Seminole	1, 2
	Southside	1, 2, 3, 4, 5
	St Johns River Power	1, 2
	Stanton Energy	1, 2
	Stock Island	1
	Stock Island D 1	**NA1, **NA2
	Suwannee River	1, 2, 3
	Tom G Smith	S-3, S-4
	Turkey Point	PTP1, PTP2
	Vero Beach Municipal	3, 4, **5
GEORGIA		
	Arkwright	1, 2, 3, 4
	Atkinson	A2, A3, A4, A1A, A1B,
	Bowen	1BLR, 2BLR, 3BLR, 4BLR
	Hammond	1, 2, 3, 4

State	Plant Name	Boilers
	Harllee Branch	1, 2, 3, 4
	Jack Mcdonough	MB1, MB2
	Mcintosh	1
	Mcmanus	1, 2
	Mitchell	3
	Port Wentworth	1, 2, 3, 4
	Riverside	12
	Scherer	1, 2, 3, 4
	Wansley	1, 2
	Yates	Y1BR, Y2BR, Y3BR, Y4BR, Y5BR, Y6BR, Y7BR,
ILLINOIS		
	Baldwin	1, 2, 3
	Coffeen	01, 02
	Collins	1, 2, 3, 4, 5
	Crawford	7, 8
	Dallman	31, 32, 33
	Duck Creek	1
	E D Edwards	1, 2, 3
	Fisk	19
	Grand Tower	07, 08, 09
	Havana	1, 2, 3, 4, 5, 6, 7, 8, 9
	Hennepin	1, 2
	Hutsonville	05, 06
	Joliet 29	71, 72, 81, 82
	Joliet 9	5
	Joppa Steam	1, 2, 3, 4, 5, 6
	Kincaid	1, 2
	Lakeside	7, 8, GT2
	Marion	1, 2, 3, 4
	Meredosia	01, 02, 03, 04, 05, 06
	Newton	1, 2
	Powerton	51, 52, 61, 62
	R S Wallace	9, 10
	Venice	1, 2, 3, 4, 5, 6, 7, 8
	Vermilion	1, 2
	Waukegan	7, 8, 17
	Will County	1, 2, 3, 4
	Wood River	1, 2, 3, 4, 5
INDIANA		
	A B Brown	1, 2, **4
	Bailly	7, 8
	Breed	1
	Cayuga	1, 2
	Clifty Creek	1, 2, 3, 4, 5, 6
	Dean H Mitchell	4, 5, 6, 11
	Edwardsport	6-1, 7-1, 7-2, 8-1
	Elmer W Stout	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 50, 60, 70
	F B Culley	1, 2, 3
	Frank E Ratts	1SG1, 2SG1
	Gibson	1, 2, 3, 4, 5
	H T Pritchard	1, 2, 3, 4, 5, 6
	Merom	1SG1, 2SG1
	Michigan City	4, 5, 6, 12
	Na 1 — 7221	**1, **2, **3
	Na 1 - 7228	**4, **5
	Noblesville	1, 2, 3
	Petersburg	1, 2, 3, 4
	R Gallagher	1, 2, 3, 4
	R M Schahfer	14, 15, 17, 18
	Rockport	MB1, MB2
	State Line	3, 4
	Tanners Creek	U1, U2, U3, U4
	Wabash River	1, 2, 3, 4, 5, 6
	Warrick	4
	Whitewater Valley	1, 2
IOWA		
	Ames	7, 8
	Burlington	1
	Council Bluffs	1, 2, 3
	Des Moines	**5, 10, 11
	Dubuque	1, 5
	Earl F Wisdom	1
	Fair Station	2
	George Neal	1, 2, 3, 4
	Graettinger	**5
	Grinnell	**2
	Lansing	3, 4
	Lime Creek	**1, **2
	Louisa	101
	Maynard Station	1
	Milton L Kapp	2
	Muscatine	8, 9
	Na 1 — 7230	**2
	Ottumwa	1
	Pella	6, 7, 8
	Prairie Creek	3, 4
	Riverside	9
	Sixth Street	1, 2, 3, 4, 5
	Streeter Station	7
	Sutherland	1, 2, 3
KANSAS		
	Arthur Mullergren	3
	Cimarron River	1
	Coffeyville	4
	East 12Th St	4
	Garden City	S-2
	Gordon Evans	1, 2
	Holcomb	SGU1
	Hutchinson	1, 2, 3, 4
	Jeffrey Energy Centr	1, 2, 3
	Judson Large	4
	Kaw	1, 2, 3
	Kingman	**9
	La Cygne	1, 2
	Lawrence	2, 3, 4, 5
	Mcpherson 2	1
	Mulvane	**7, **8
	Murray Gill	1, 2, 3, 4
	Nearman Creek	N1
	Neosho	7
	Quindaro	1, 2
	Ripley	**2, **3
	Riverton	39, 40
	Russell	**11, **12
	Tecumseh	9, 10
KENTUCKY		
	Big Sandy	BSU1, BSU2
	Cane Run	3, 4, 5, 6, **12, **13
	Coleman	C1, C2, C3
	Cooper	1, 2
	D B Wilson	W1
	Dale	3, 4
	E W Brown	1, 2, 3
	East Bend	2
	Elmer Smith	1, 2
	Ghent	1, 2, 3, 4
	Green River	1, 2, 3, 4, 5
	H L Spurlock	1, 2
	Henderson I	6
	Hmp&L Station 2	H1, H2
	J K Smith	1
	Mill Creek	1, 2, 3, 4
	Na 1 — 7220	**3, **4, **5
	Paradise	1, 2, 3
	Pineville	3
	R D Green	G1, G2
	Robert Reid	R1
	Shawnee	1, 2, 3, 4, 5, 6, 7, 8, 9, 10
	Trimble County	1
	Tyrone	1, 2, 3, 4, 5
LOUISIANA		
	A B Paterson	3
	A B Paterson	4
	Arsenal Hill	5A
	Big Cajun 1	1B1, 1B2, 2B1, 2B2, 2B3
	Coughlin	6, 7
	D G Hunter	3, 4
	Doc Bonin	1, 2, 3
	Dolet Hills	1
	Houma	15, 16
	Lieberman	3, 4
	Little Gypsy	1, 2, 3
	Louisiana 1	1A, 2A, 3A
	Louisiana 2	10, 11, 12
	Michoud	1, 2, 3
	Monroe	11, 12
	Morgan City	4
	Natchitoches	10
	Ninemile Point	1, 2, 3, 4, 5
	Opelousas	10
	R S Nelson	1, 2, 3, 4, 6
	Rodemacher	1, 2
	Ruston	2, 3
	Sterlington	10, 7AB
	Teche	2, 3
	Waterford 1 & 2	1, 2
	Willow Glen	1, 2, 3, 4, 5

State	Plant Name	Boilers
MAINE		
	Graham Station	5
	Mason Steam	3, 4, 5
	William F Wyman	1, 2, 3, 4
MARYLAND		
	Brandon Shores	1, 2
	C P Crane	1, 2
	Chalk Point	1, 2, 3, 4, **GT3, **GT4, **GT5, **GT6
	Coal Gas Cc 1	**CT1, **CW1
	Coal Gas Cc 2	**CT3, **CT4
	Dickerson	1, 2, 3
	Easton 2	**26, **27
	Gould Street	3
	Herbert A Wagner	1, 2, 3, 4
	Morgantown	1, 2
	Nanticoke	**ST1
	Perryman	**52, **61, **62
	R P Smith	9, 11
	Riverside	1, 2, 3, 4, 5
	Vienna	8
	Westport	3, 4
MASSACHUSETTS		
	Brayton Point	1, 2, 3, 4
	Canal	1, 2
	Cannon Street	3
	Cleary Flood	8, 9
	Kendall Square	1, 2, 3
	Mount Tom	1
	Mystic	4, 5, 6, 7
	New Boston	1, 2
	Salem Harbor	1, 2, 3, 4
	Somerset	1, 2, 3, 4, 5, 6, 7, 8
	Waters River	**2
	West Springfield	1, 2, 3
MICHIGAN		
	B C Cobb	1, 2, 3, 4, 5
	Belle River	1, 2
	Conners Creek	15, 16, 17, 18
	Dan E Karn	1, 2, 3, 4
	Delray	7, 8, 9, 10, 11, 12
	Eckert Station	1, 2, 3, 4, 5, 6
	Endicott Generating	1
	Erickson	1
	Greenwood	1
	Harbor Beach	1
	J B Sims	3
	J C Weadock	7, 8
	J H Campbell	1, 2, 3
	J R Whiting	1, 2, 3
	James De Young	5
	Marysville	9, 10, 11, 12
	Mistersky	5, 6, 7
	Monroe	1, 2, 3, 4
	Presque Isle	2, 3, 4, 5, 6, 7, 8, 9
	River Rouge	1, 2, 3
	Shiras	3
	St Clair	1, 2, 3, 4, 5, 6, 7
	Trenton Channel	16, 17, 18, 19, 9A
	Wyandotte	5, 7
	491 E. 48Th Street	**7, **8
MINNESOTA		
	Allen S King	1
	Black Dog	1, 2, 3, 4
	Clay Boswell	1, 2, 3, 4
	Fox Lake	3
	Future Base	**1
	High Bridge	3, 4, 5, 6
	Hoot Lake	2, 3
	M L Hibbard	3, 4
	Minnesota Valley	3
	Na 1 — 7237	**2
	Northeast Station	NEPP
	Riverside	6, 7, 8
	Sherburne County	1, 2, 3
	Silver Lake	4
	Syl Laskin	1, 2
MISSISSIPPI		
	Baxter Wilson	1, 2
	Delta	1, 2
	Gerald Andrus	1
	Jack Watson	1, 2, 3, 4, 5
	Moselle	1, 2, 3, **6, **7
	Natchez	1
	R D Morrow	1, 2
	Rex Brown	3, 4, 1A, 1B
	Sweatt	1, 2
	Victor J Daniel Jr	1, 2
	Wright	W4

State	Plant Name	Boilers
MISSOURI		
	Asbury	1
	Blue Valley	3
	Chamois	2
	Columbia	6, 7, 8
	Combustion Turbine 1	**NA4, **NA5, **NA6, **NA7
	Combustion Turbine 3	**3
	Empire Energy Center	**4, **NA2, **NA3
	Grand Avenue	**7, **9
	Hawthorn	5
	Iatan	1, **2
	James River	3, 4, 5, **GT2
	Jim Hill	**1
	Labadie	1, 2, 3, 4
	Lake Road	6
	Meramec	1, 2, 3, 4
	Montrose	1, 2, 3
	Na 1 — 7223	**1, **2, **3
	Na 1 — 7226	**1
	New Madrid	1, 2
	Rg 1 & 2	**1, **2
	Rush Island	1, 2
	Sibley	1, 2, 3
	Sikeston	1
	Sioux	1, 2
	Southwest	1
	Thomas Hill	MB1, MB2, MB3
MONTANA		
	Colstrip	1, 2, 3, 4
	Frank Bird	1
	J E Corette	2
	Lewis & Clark	B1
NEBRASKA		
	Bluffs	4
	C W Burdick	B-3
	Canaday	1
	Gerald Gentleman Sta	1, 2
	Harold Kramer	1, 2, 3, 4
	Hastings Energy Ctr	1
	Lon Wright	8
	Na 1 — 7019	**NA2
	Nebraska City	1
	North Omaha	1, 2, 3, 4, 5
	Platte	1
	Sheldon	1, 2
NEVADA		
	Clark	1, 2, 3
	Fort Churchill	1, 2
	Harry Allen	**1, **2, **3, **4, **GT3, **GT4
	Mohave	1, 2
	North Valmy	1, 2
	Reid Gardner	1, 2, 3, 4
	Sunrise	1
	Tracy	1, 2, 3
NEW HAMPSHIRE		
	Merrimack	1, 2
	Newington	1
	Schiller	4, 5, 6
NEW JERSEY		
	B L England	1, 2, 3
	Bergen	1, 2
	Burlington	7
	Butler	**4
	Deepwater	1, 3, 4, 5, 6, 8, 9
	Gilbert	01, 02, 03, 04, 05, 06, 07
	Hudson	1, 2
	Kearny	7, 8
	Linden	2, 4, 11, 12, 13
	Mercer	1, 2
	Na 3 — 7141	**1, **2
	Na 4 — 7142	**1
	Na 5 — 7217	**1, **2
	Na 6 — 7218	**1, **2
	Sayreville	02, 03, 05, 06, 07, 08
	Sewaren	1, 2, 3, 4, 5
	Werner	04
NEW MEXICO		
	Cunningham	121B, 122B
	Escalante	1, **2
	Four Corners	1, 2, 3, 4, 5
	Maddox	**3, 051B
	North Lovington	S2
	Person	3, 4
	Reeves	1, 2, 3
	Rio Grande	6, 7, 8
	San Juan	1, 2, 3, 4

State	Plant Name	Boilers
NEW YORK		
	Albany	1, 2, 3, 4
	Arthur Kill	20, 30
	Astoria	10, 20, 30, 40, 50
	Bowline Point	1, 2
	C R Huntley	63, 64, 65, 66, 67, 68
	Charles Poletti	001
	Danskammer	1, 2, 3, 4
	Dunkirk	1, 2, 3, 4
	E F Barrett	10, 20
	East River	50, 60, 70
	Far Rockaway	40
	Glenwood	40, 50
	Goudey	11, 12, 13
	Greenidge	4, 5, 6
	Hickling	1, 2, 3, 4
	Jennison	1, 2, 3, 4
	Lovett	3, 4, 5
	Milliken	1, 2
	Northport	1, 2, 3, 4
	Oswego	1, 2, 3, 4, 5, 6
	Port Jefferson	1, 2, 3, 4
	Ravenswood	10, 20, 30
	Rochester 3	1, 2, 3, 4, 7, 8, 12
	Rochester 7	1, 2, 3, 4
	Roseton	1, 2
	S A Carlson	9, 10, 11, 12
	Somerset	1
	Waterside	41, 42, 51, 52, 61, 62, 80, 90
	59Th Street	110
	74Th Street	120, 121, 122
NORTH CAROLINA		
	Asheville	1, 2
	Belews Creek	1, 2
	Buck	5, 6, 7, 8, 9
	Cape Fear	3, 4, 5, 6
	Cliffside	1, 2, 3, 4, 5
	Dan River	1, 2, 3
	G G Allen	1, 2, 3, 4, 5
	L V Sutton	1, 2, 3
	Lee	1, 2, 3
	Marshall	1, 2, 3, 4
	Mayo	1A, 1B
	Riverbend	7, 8, 9, 10
	Roxboro	1, 2, 3A, 3B, 4A, 4B
	W H Weatherspoon	1, 2, 3
NORTH DAKOTA		
	Antelope Valley	B1, B2
	Coal Creek	1, 2
	Coyote	B1
	Dakotas	**1
	Leland Olds	1, 2
	Milton R Young	B1, B2
	R M Heskett	B2
	Stanton	1, 10
OHIO		
	Acme	9, 11, 13, 14, 15, 16, 91, 92
	Ashtabula	7, 8, 9, 10, 11
	Avon Lake	9, 10, 11, 12
	Bay Shore	1, 2, 3, 4
	Cardinal	1, 2, 3
	Conesville	1, 2, 3, 4, 5, 6
	Dover	**6
	Eastlake	1, 2, 3, 4, 5
	Edgewater	11, 12, 13
	Gen J M Gavin	1, 2
	Gorge	25, 26
	Hamilton	9
	J M Stuart	1, 2, 3, 4
	Killen Station	2
	Kyger Creek	1, 2, 3, 4, 5
	Lake Road	6
	Lake Shore	18, 91, 92, 93, 94
	Miami Fort	6, 7, 8, 5-1, 5-2
	Muskingum River	1, 2, 3, 4, 5
	Niles	1, 2
	O H Hutchings	H-1, H-2, H-3, H-4, H-5, H-6
	Picway	9
	Poston	1, 2, 3
	R E Burger	1, 2, 3, 4, 5, 6, 7, 8
	Refuse & Coal	001, 002, 003, 004, 005, 006
	Richard Gorsuch	1, 2, 3, 4
	Tidd	**1
	Toronto	9, 10, 11
	W H Sammis	1, 2, 3, 4, 5, 6, 7
	W H Zimmer	1
	Walter C Beckjord	1, 2, 3, 4, 5, 6
	Woodsdale	**GT1, **GT2, **GT3, **GT4, **GT5, **GT8, **GT9, **GT10, **GT11, **GT12,

State	Plant Name	Boilers
OKLAHOMA		
	Anadarko	3
	Arbuckle	ARB
	Comanche	7251, 7252
	Conoco	**1, **2
	Grda	1, 2
	Horseshoe Lake	6, 7, 8
	Hugo	1
	Inola	**1
	Mooreland	1, 2, 3
	Muskogee	3, 4, 5, 6
	Mustang	1, 2, 3, 4
	Na 1 — 5030	**1, **2, **3
	Northeastern	3301, 3302, 3313, 3314
	Ponca	2
	Riverside	1501, 1502
	Seminole	1, 2, 3
	Sooner	1, 2
	Southwestern	8002, 8003, 801N, 801S
	Tulsa	1402, 1403, 1404
OREGON		
	Boardman	1SG
PENNSYLVANIA		
	Armstrong	1, 2
	Bruce Mansfield	1, 2, 3
	Brunner Island	1, 2, 3
	Cheswick	1
	Conemaugh	1, 2
	Cromby	1, 2
	Delaware	71, 81
	Eddystone	1, 2, 3, 4
	Elrama	1, 2, 3, 4
	F R Phillips	1, 2, 3, 4, 5, 6
	Front Street	7, 8, 9, 10
	Hatfield'S Ferry	1, 2, 3
	Holtwood	17
	Homer City	1, 2, 3
	Hunlock Power	6
	Keystone	1, 2
	Marcus Hook Refinery	1
	Martins Creek	1, 2, 3, 4
	Mitchell	1, 2, 3, 33
	Montour	1, 2
	New Castle	1, 2, 3, 4, 5
	Portland	1, 2
	Richmond	63, 64
	Schuylkill	1
	Seward	12, 14, 15
	Shawville	1, 2, 3, 4
	Southwark	11, 12, 21, 22
	Springdale	77, 88
	Sunbury	3, 4, 1A, 1B, 2A, 2B
	Titus	1, 2, 3
	Warren	1, 2, 3, 4
	Williamsburg	11
RHODE ISLAND		
	Manchester Street	6, 7, 12
	South Street	121, 122
SOUTH CAROINA		
	Canadys Steam	CAN1, CAN2, CAN3
	Cross	1, 2
	Dolphus M Grainger	1, 2
	H B Robinson	1
	Hagood	**4, HAG1, HAG2, HAG3
	Jefferies	1, 2, 3, 4
	Mcmeekin	MCM1, MCM2
	Na 4 — 7210	**ST1
	Urquhart	URQ1, URQ2, URQ3
	W S Lee	1, 2, 3
	Wateree	WAT1, WAT2
	Williams	WIL1
	Winyah	1, 2, 3, 4
SOUTH DAKOTA		
	Big Stone	1
	Huron	**2A, **2B
	Mobile	**2
	Pathfinder	11, 12, 13
TENNESSEE		
	Allen	1, 2, 3
	Bull Run	1
	Cumberland	1, 2
	Gallatin	1, 2, 3, 4
	John Sevier	1, 2, 3, 4
	Johnsonville	1, 2, 3, 4, 5, 6, 7, 8, 9, 10
	Kingston	1, 2, 3, 4, 5, 6, 7, 8, 9
	Watts Bar	A, B, C, D

Do the Acid Rain Regulations Apply to You?

State	Plant Name	Boilers
TEXAS		
	Barney M Davis	1, 2
	Big Brown	1, 2
	Bryan	6
	C E Newman	BW5
	Cedar Bayou	CBY1, CBY2, CBY3
	Coleto Creek	1, **2
	Collin	1
	Concho	2, 4, 5, 6, 7
	Dallas	3, 9
	Dansby	1
	Decker Creek	1, 2
	Decordova	1
	Deepwater	DWP1, DWP2, DWP3, DWP4, DWP5, DWP6, DWP9
	E S Joslin	1
	Eagle Mountain	1, 2, 3
	Forest Grove	**1
	Fort Phantom	1, 2
	Generic Stat	**1, **2
	Gibbons Creek	1
	Graham	1, 2
	Greens Bayou	GBY1, GBY2, GBY3, GBY4, GBY5
	Gt 98	**1, **2
	Gt 99	**1, **2, **3
	Handley	2, 3, 4, 5, 1A, 1B
	Harrington Station	061B, 062B, 063B
	Hiram Clarke	HOC1, HOC2, HOC3, HOC4
	Holly Ave	1, 2
	Holly Street	1, 2, 3, 4
	J K Spruce	**1, **2
	J L Bates	1, 2
	J T Deely	1, 2
	Jones Station	151B, 152B
	Knox Lee	2, 3, 4, 5
	La Palma	7
	Lake Creek	1, 2
	Lake Hubbard	1, 2
	Laredo	1, 2, 3
	Leon Creek	3, 4
	Lewis Creek	1, 2
	Limestone	LIM1, LIM2
	Lon C Hill	1, 2, 3, 4
	Lone Star	1
	Malakoff	**1, **2
	Martin Lake	1, 2, 3
	Mission Road	3
	Monticello	1, 2, 3
	Morgan Creek	3, 4, 5, 6
	Mountain Creek	2, 6, 7, 8, 3A, 3B
	Na 1 — 7216	**1, **2
	Na 1 — 7219	**1, **2
	Na 2 — 4274	**NA1
	Neches	11, 13, 15, 18
	Newman	1, 2, 3, **4
	Nichols Station	141B, 142B, 143B
	North Lake	1, 2, 3
	North Main	4
	North Texas	3
	Nueces Bay	5, 6, 7
	O W Sommers	1, 2
	Oak Creek	1
	Oklaunion	1
	P H Robinson	PHR1, PHR2, PHR3, PHR4
	Paint Creek	1, 2, 3, 4
	Parkdale	1, 2, 3
	Permian Basin	5, 6
	Pirkey	1
	Plant X	111B, 112B, 113B, 114B
	Powerlane Plant	2, 3
	R W Miller	1, 2, 3
	Ray Olinger	BW2, BW3, CE1
	Rio Pecos	5, 6
	River Crest	1
	Sabine	1, 2, 3, 4, 5
	Sam Bertron	SRB1, SRB2, SRB3, SRB4
	Sam Seymour	1, 2, 3
	San Angelo	2
	San Miguel	**2, SM-1
	Sandow	4
	Seaholm	9
	Sim Gideon	1, 2, 3
	Spencer	4, 5
	Stryker Creek	1, 2
	T C Ferguson	1
	T H Wharton	THW1, THW2
	Trip One	U1, U2, **3, **4
	Tolk Station	171B, 172B
	Tradinghouse	1, 2
	Trinidad	7, 8, 9
	Twin Oak	1, 2
	V H Braunig	1, 2, 3
	Valley	1, 2, 3
	Victoria	5, 6, 7, 8
	W A Parish	WAP1, WAP2, WAP3, WAP4, WAP5, WAP6, WAP7, WAP8
	W B Tuttle	1, 2, 3, 4
	Webster	WEB1, WEB2, WEB3
	Welsh	1, 2, 3
	Wilkes	1, 2, 3
UTAH		
	Bonanza	1-1
	Carbon	1, 2
	Gadsby	1, 2, 3
	Hale	1
	Hunter (Emery)	1, 2, 3
	Huntington	1, 2
	Intermountain	1SGA, 2SGA
VERMONT		
	J C Mcneil	1
VIRGINIA		
	Bremo Bluff	3, 4
	Chesapeake	1, 2, 3, 4
	Chesterfield	3, 4, 5, 6, **8A, **8B
	Clinch River	1, 2, 3
	Clover	1, 2
	Glen Lyn	6, 51, 52
	Possum Point	1, 2, 3, 4, 5
	Potomac River	1, 2, 3, 4, 5
	Yorktown	1, 2, 3
WASHINGTON		
	Centralia	BW21, BW22
	Kettle Falls	1
	Shuffleton	1, 2, 3
WEST VIRGINIA		
	Albright	1, 2, 3
	Fort Martin	1, 2
	Harrison	1, 2, 3
	John E Amos	1, 2, 3
	Kammer	1, 2, 3
	Kanawha River	1, 2
	Mitchell	1, 2
	Mountaineer (1301)	1
	Mt Storm	1, 2, 3
	Phil Sporn	11, 21, 31, 41, 51
	Pleasants	1, 2
	Rivesville	7, 8
	Willow Island	1, 2
WISCONSIN		
	Alma	B4, B5
	Bay Front	1, 2, 3, 4, 5
	Blount Street	3, 5, 6, 7, 8, 9, 11
	Columbia	1, 2
	Combustion Turbine	**2
	Commerce	25
	Edgewater	3, 4, 5
	Genoa	1
	J P Madgett	B1
	Manitowoc	6, 7, 8, 9
	Na — 7222	**1
	Na 1 — 7203	**CT3, **CT4
	Na 1 — 7205	**1, **2, **3
	Na3	**1
	Na4	**1
	Nelson Dewey	1, 2
	North Oak Creek	1, 2, 3, 4
	Pleasant Prairie	1, 2
	Port Washington	1, 2, 3, 4, 5
	Pulliam	3, 4, 5, 6, 7, 8
	Rock River	1, 2
	South Oak Creek	5, 6, 7, 8
	Stoneman	B1, B2
	Valley	1, 2, 3, 4
	West Marinette	**33
	Weston	1, 2, 3
WYOMING		
	Dave Johnston	BW41, BW42, BW43, BW44
	Jim Bridger	BW71, BW72, BW73, BW74
	Laramie River	1, 2, 3
	Naughton	1, 2, 3
	Wyodak	BW91

Exhibit 3: Units Listed in Table 3 of §73.10 (40 CFR 73)

State	Plant	Boiler
ALABAMA		
	Mcwilliams	**4
ARIZONA		
	Springerville	3
CALIFORNIA		
	Harbor Gen Station	**10, **10A, **10B
FLORIDA		
	G W Ivey	**22
	Indian River	**D
	Intercession City	**7, **8, **9, **10
	Lauderdale	**4GT1, **4GT2, **5GT1, **5GT2
	Martin	**3ST, **4ST, **3GT1, **3GT2, **4GT1, **4GT2
ILLINOIS		
	Lakeside	GT1
INDIANA		
	Na 1 — 7228	**1, **2, **3
IOWA		
	Na 1 — 7230	**1
KANSAS		
	Wamego	**NA1
MARYLAND		
	Coal Gas Cc 1	**CT2
	Easton 2	**25
	Perryman	**51
MINNESOTA		
	Na 1 — 7237	**1
MISSISSIPPI		
	Moselle	**4, **5
MISSOURI		
	Combustion Turbine 1	**1
	Combustion Turbine 2	**2
	Empire Energy Center	**3
	Lake Road	**8
NEBRASKA		
	Na 1 — 7019	**NA1
NEVADA		
	Clark	**9, **10
	Harry Allen	**GT1, **GT2
NEW JERSEY		
	Butler	**1, **3
	Na 1 — 7139	**1
	Na 2 — 7140	**1
OHIO		
	Dover	**7
	Woodsdale	**GT6, **GT7
PENNSYLVANIA		
	Trenton Cogen Proj	**1
SOUTH CAROLINA		
	Na 1 — 7106	**GT1
	Na 2 — 7107	**GT2
	Na 3 — 7108	**GT3
SOUTH DAKOTA		
	Ct	**5
TEXAS		
	R W Miller	**4, **5
	Twin Oak	2
UTAH		
	Bonanza	**2
VIRGINIA		
	Clover	1, 2
	East Chandler	**2
WISCONSIN		
	Combustion Turbine	**1
	Concord	**1, **2, **3, **4
	Na 1 — 7203	**CT1, **CT2
	Na2	**1
	Paris	**1, **2, **3, **4

Appendix E
Certificate of Representation

A Certificate of Representation with instructions is attached.

Acid Rain Program
Instructions for Certificate of Representation (40 CFR 72.24)

Under the Acid Rain Program (at 40 CFR Subpart B), the owners and operators for each affected source must designate a representative, and may designate an alternate, to act on their behalf. The owners and operators must choose the representative through a process that ensures that all owners and operators have notice regarding the selection. All affected units at a source must have the same designated representative.

Type or complete this form using black ink. If you need more space, photocopy the pertinent page. When you have completed the form, indicate the page order and total number of pages (*e.g., 1 of 4, 2 of 4, etc.*) in the boxes in the upper right hand corner of each page.

You must submit one Certificate of Representation form with original signatures and three photocopies. Remember that under 40 CFR 72.21, the designated representative must notify each owner and operator of all Acid Rain Program submissions.

If you need assistance, call the Acid Rain Hotline at (202) 233-9620.

STEP 1 NADB is the National Allowance Data Base for the Acid Rain Program. To obtain the database on diskette or in hard copy, call the Acid Rain Hotline. This data file is in dBase format for use on an IBM-compatible PC. It requires 2 megabytes of hard drive memory.

STEP 2 The designated representative must be a natural person and cannot be a company. Please enter your firm name and address as you would like it to appear on all correspondence.

STEP 5 See 40 CFR 72.2 for the definitions of "owner" and "operator." You may enter a person's or a company's name.

Identify each unit at this source that is owned or operated by the named party by providing the boiler identification number listed for the unit in the NADB. For new units not listed in NADB, use the boiler number you have assigned.

The state or local regulatory authority means the Public Utility Commission or other rate-making authority.

As designated representative, you are responsible for all submissions and allowance transactions relating to the units at that source. You and the alternate designated representative are liable for acts or omissions within the scope of your responsibilities under the Acid Rain program.

EPA will not issue an Acid Rain permit or record an allowance transaction until it has received a complete Certificate of Representation.

Submission Instructions

Mail this form to:

U.S. Environmental Protection Agency
Acid Rain Program (6204J)
Attention: Designated Representative
401 M Street, SW.
Washington, D.C. 20460

For Phase II sources, submit this form by November 17, 1994. If you wish to participate in the annual auctions and sales of allowances prior to that date, submit the form earlier. EPA will not issue proceeds from auctions or sales to a unit until it receives a complete certificate of representation.

Submit a revised Certificate of Representation when any information changes. EPA must be notified of changes to owners and operators within 30 days.

Paperwork Burden Estimate

The burden on the public for collecting and reporting information under this request is estimated at 35 hours per response. Send comments regarding this collection of information, including suggestions for reducing the burden, to: Chief, Information Policy Branch (PM-223), U.S. Environmental Protection Agency, 401 M Street, SW, Washington, D.C. 20460; and to: Paperwork Reduction Project (OMB#2060-0221), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503. ***Do not send your forms to these addresses; see the submission instructions above.***

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0221
Expires 6-30-95

EPA

Certificate of Representation

For more information, see instructions and refer to 40 CFR 72.24

This submission is: ☐ New ☐ Revised

STEP 1
Identify the source by plant name, State, and ORIS code from NADB

Plant Name	State	ORIS Code

STEP 2
Enter requested information for the designated representative

Name	
Address	
Phone Number	Fax Number

STEP 3
Enter requested information for the alternate designated representative (optional)

Name	
Address	
Phone Number	Fax Number

STEP 4
Complete Step 5, read the certifications and sign and date

I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the affected source and each affected unit at the source.

I certify that I have given notice of the agreement, selecting me as the designated representative or alternate designated representative, as applicable for the affected source and each affected unit at the source identified in this certificate of representation, daily for a period of one week in a newspaper of general circulation in the area where the source is located or in a State publication designed to give general public notice.

I certify that I have all necessary authority to carry out my duties and responsibilities under the Acid Rain Program on behalf of the owners and operators of the affected source and of each affected unit at the source and that each such owner and operator shall be fully bound by my actions, inactions, or submissions.

I certify that I shall abide by any fiduciary responsibilities imposed by the agreement by which I was selected as designated representative or alternate designated representative, as applicable.

I certify that the owners and operators of the affected source and of each affected unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected unit, or where a utility or industrial customer purchases power from an affected unit under life-of-the-unit, firm power contractual arrangements, I certify that:

> I have given a written notice of my selection as the designated representative or alternate designated representative, as applicable, and of the agreement by which I was selected to each owner and operator of the affected source and of each affected unit at the source; and
>
> Allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement or, if such multiple holders have expressly provided for a different distribution of allowances by contract, that allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in accordance with the contract.

The agreement by which I was selected as the alternate designated representative includes a procedure for the owners and operators of the source and affected units at the source to authorize the alternate designated representative to act in lieu of the designated representative.

Plant Name (from Step 1)

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Signature (designated representative)	Date
Signature (alternate)	Date

STEP 5
Provide the name of every owner and operator of the source and each affected unit at the source. Identify the units they own and/or operate by boiler ID# from NADB. For owners only, identify each state or local utility regulatory authority with jurisdiction over each owner

Name					☐ Owner	☐ Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#
Regulatory Authorities						

Name					☐ Owner	☐ Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#
Regulatory Authorities						

Name					☐ Owner	☐ Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#
Regulatory Authorities						

Name					☐ Owner	☐ Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#
Regulatory Authorities						

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