ILLINOIS POLLUTION CONTROL BOARD
July 7, 1977

IN THE MATTER OF)
) R71-23
EMISSION STANDARDS)

OPINION OF THE BOARD (by Mr. Goodman):

Regulations controlling emissions of sulfur dioxide, nitrogen oxides, carbon monoxide, hydrocarbons, and particulate matter were adopted by the Board in its Order and Opinion of April 13, 1972, in the regulatory proceeding R71-23 Emission Standards. These regulations are Part II of Chapter 2 of its rules and regulations. Commonwealth Edison subsequently filed a petition in the First District Appellate Court of Illinois seeking review of several of Chapter 2 rules, among those being:

> Rule 203(g)(1) Particulate Emission Standards and Limitations for Fuel Combustion Emission Sources Using Solid Fuel Exclusively,
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> Rule 204(a)(1) Sulfur Dioxide Emission Standards and Limitations for New Fuel Combustion Emission Sources with Actual Heat Input Greater than 250 Million BTU per Hour, Solid Fuel Burned Exclusively, and
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> Rule 204(c)(1)(A) Sulfur Dioxide Emission for Existing Fuel Combustion Sources Located in the Chicago, St. Louis (Illinois), and Peoria Major Metropolitan Areas, Solid Fuel Burned Exclusively.

The Appellate Court in Commonwealth Edison Company v. Pollution Control Board, 25 Ill.App.3d271, 323 N.E.2d 84 (1975), reversed the adoption of Rules 203(g)(1), 204(a)(1), and 204(c)(1)(A) and remanded them to the Board for further consideration, with instructions either to validate them in accordance with Section 27 of the Environmental Protection Act or to prepare proper rules as substitutes. In its opinion the Appellate Court stated, "...we are unable to state that the Board took into account the technical feasibility of these rules", and, "we further hold that there is no evidence that the Board took

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The Board expresses its appreciation for the excellent work done in this matter by Ms. Donna Farley and Ms. Roberta Levinson, Technical Assistant and Administrative Assistant to the Board, respectively.

into account the economic reasonableness of these rules for a substantial number of the generating units in this state." The Court concluded that the regulations were not promulgated in accordance with Section 27 of the Act and were, therefore, arbitrary and unreasonable. The Court also observed, however, that further scientific evidence may have been developed since the original Board order and opinion, and its remand instructed the Board to review any new evidence for the purpose of validating or modifying the rules. In addition, the Court held that the Board's enactment of Rule 303, which is designed to prevent degradation of existing ambient air quality which is better than the air quality standards, was void.

The Appellate Court decision was appealed by the Board to the Illinois Supreme Court. Commonwealth Edison Company v. Pollution Control Board, 62Ill.2d494, 343 N.E.2d 459 (1976). The Supreme Court, rather than reviewing the record and Board Opinion to determine whether the Board had complied with Section 27 of the Act in promulgating the regulations, declined "to determine the validity of Rules 203(g)(1), 204(a)(1) and 204(c)(1)(A) on the basis of evidence adduced at hearings held in 1970, 1971, and 1972 and the Board's opinion of April 13, 1972." It affirmed the Appellate Court reversal and remand for further consideration, citing the Appellate Court's reference to the "wealth of new information" that has been gathered in the Board's inquiry hearings (R74-2) and hearings on Board (R74-2) and Agency (R75-5) proposals to amend Rule 204. The Supreme Court, however, reversed the Appellate Court's holding on Rule 303 and upheld the Board's enactment of that Rule.

The Appellate Court stated that the record showed there were only two possible options for simultaneous compliance with both the sulfur dioxide and particulate standards. The first of these was the use of low-sulfur coal, with modification of the particulate emissions control system to compensate for the adverse effect the reduction of sulfur dioxide in the flue gas would have on collection efficiency. The second option was the use of high sulfur coal with particulate removal designed to comply with Rule 203, followed by sulfur dioxide removal processes to comply with Rule 204. Thus, according to the Court, the technical feasibility and economic reasonableness of obtaining low-sulfur coal and modifying particulate removal systems is at issue in the first option, and that of sulfur dioxide removal processes is at issue in the second option.

On April 8, 1976, the Board entered an Order in R71-23, reopening the record for the purpose of validating Rules 203(g), 204(a)(1) and 204(c)(1)(A). The Board also ordered the record in its current consolidated proceedings, R74-2 and R75-5, and the record in R71-23 to be mutually incorporated. Two subsequent hearings were held on R75-5 and R74-2, consolidated, in May, 1976.

It is the Board's position that further hearings are unnecessary in order to comply with the Supreme Court's mandate. The Supreme Court specifically declined to review the record in R71-23 but invited the Board to validate the regulations in question in light of information gathered at the many hearings held subsequent to the original proceedings. After the Supreme Court's decision and the Board's mutual incorporation of the records in its sulfur dioxide proceedings, two hearings were held in R75-5. In order to facilitate validation of the rules in response to the Supreme Court's remand, an abstract was prepared by Marder and Associates under contract to the Illinois Environmental Protection Agency. The abstract consists of a review of the record of three proceedings before the Board, R71-23, R74-2, and R75-5, which contain information pertinent to the remanded regulations. The Board has reviewed the abstract together with testimony and exhibits in the three proceedings. Based on analysis of the information available in these records, and taking into consideration the issues identified by the Courts, we hereby validate Rules 203(g)(1), 204(a)(1) and 204(c)(1)(A) as adopted in 1972.

There is indeed a "wealth of information" in the record before the Board. The Marder abstract organizes the information by subject, summarizes testimony and exhibits, and identifies where each item is found in the record. It thereby served as a useful aid during our study of the record. It did not, however, serve as an analysis of the merits of the information itself. That responsibility is ours, and we herein present our findings on this matter.

Need for the Regulations

Particulates and sulfur dioxide are criteria pollutants for which ambient air quality standards have been adopted by the U.S. Environmental Protection Agency (USEPA) under the Clean Air Act Amendments of 1970, and by the Board by its authority under Section 10 of the Illinois Environmental Protection Act (the Act). The ambient standards established for each pollutant are set at levels which are intended to protect the health of the general public (primary standards) and prevent damage to property, vegetation, or other components of our welfare (secondary standards). The levels set are based on air quality criteria, with a margin of safety included for the primary (health related) standards. (See the Board opinion in R72-7 Air Quality Standards, July 10, 1975, for discussion of the criteria.)

Under the Clean Air Act the State of Illinois was required to prepare a State Implementation Plan (SIP) containing a control strategy for attaining the ambient air quality standards by July 3, 1975. An important part of the SIP is Part II of the Board's Air Pollution Control Regulations, which sets forth the emission standards for each of the criteria pollutants. Air quality modeling was used to estimate existing and projected ambient air pollutant concentrations, based on emission rates from Illinois sources. Modeling was performed for the Chicago, St. Louis (Illinois), and Peoria major metropolitan areas (MMA's), all of which had monitored concentrations of pollutants in violation of the air quality standards. Using the Air Quality Display Model (AQDM), several alternative emission control strategies were developed and evaluated for the MMA's, and the most feasible options for attaining the ambient standards were identified. The MMA emissión standards adopted by the Board were derived from the outcome of that analysis. Emission standards for the rest of the State were designed to provide reasonable continuous emission control in order to keep the air as clean as possible based on available technology and economic costs of control. These standards allow for growth while protecting the air quality standards in these cleaner, areas. (R71-23, April 13, 1972, Opinion of the Board; R71-23, pp.15-62, 146-165, 173-185, Ex. 2, 6, 8).

Thus, the emission standards for particulates and sulfur dioxide are directly related to the documented health and welfare effects on which the air quality standards are based. It is noted that though there is some margin of safety built into the primary ambient standards, that margin is used to compensate for variability in human susceptibility to the various pollutants and to take into account gaps in the available medical information. This does not mean it is a margin that allows "safe" violation of the air quality standards. The standards as adopted by the Board are "...standards designating maximum tolerable levels for various air contaminants..." (p.4 of Board Opinion in R72-7).

The Board is required by the Act to consider many factors when adopting regulations, including the technological feasibility and economic reasonableness of measuring or reducing a particular pollutant. These are the issues with which we are concerned in this matter, in response to the Courts' findings and remand of Rules 203(g)(1), 204(a)(1) and 204(c)(1)(A). It is noted that the need for emission standards designed to attain and protect ambient air quality standards is an important component of the assessment of economic reasonableness. Requirements for removal of hazardous contaminants from the air we breathe will necessarily tolerate a higher price tag than will control of less harmful pollutants.

Particulate Emissions Control Technology

There is substantial documentation in the R71-23 record that technology to control particulate emissions is well established. The four principal control devices are cyclones, wet scrubbers, electrostatic precipitators (ESP), and fabric filters (or baghouses). These devices can be used alone or in combination to attain the desired removal efficiencies (Ex. R71-23-32). When burning coal with a 10% ash content and 10,000 BTU/lb heat content, removal efficiencies of 90% to 99% are required for compliance with the 0.1 lb/million BTU (MMBTU) heat input emission standards, depending on the type of boiler being used. (R71-23, R.295-303, Ex. 11).

The most widely used technology for particulate control on large boilers is ESP (Ex. R71-23-32). The removal process involves passing the flue gas through an electric corona as it flows through the precipitator, placing a charge on the ash particles and pulling them out of the gas to collect on plates in the precipitator. The collected dust is periodically rapped off the plates. Collection efficiency of an ESP depends on, among other factors, the resistivity of the ash being collected, the temperature of the flue gas, and the velocity of the flue gas through the precipitator. ESP's are able to achieve more than 99% removal in utility operations (R71-23, Ex. 32, 33, 34, 35).

Testimony of representatives of utilities and industry verified their ability to achieve the particulate emission standards (R71-23; pp.2074-82, 3842-43, 2285-6, 2308-10, 2465-66). Existing sources would require modification of already operating ESP's to comply with the regulation, and continued compliance over time would require proper operation and maintenance of the equipment. Degradation of collection efficiencies with age can be prevented by proper maintenance. An example of potential ESP life and efficiency is that of a unit built in 1929 by Commonwealth Edison at a design removal efficiency of 82-83%. This unit in 1971 was running close to 98% efficiency as a result of several rebuildings (R71-23, pp.3867-68).

Recognizing the sophistication of particulate removal technology, the next question to be addressed is that of simultaneous compliance with both the particulate and sulfur dioxide emission standards. Testimony was given that if a facility burned low sulfur coal (less than 1% sulfur content) as a means to comply with the SO_2 emission standard, its ESP collection efficiency would drop substantially because of the higher resistivity of fly ash from low sulfur coal.

A test conducted by Commonwealth Edison showed that particulate emissions increased from 0.16 to 0.26 lb/MMBTU when the coal sulfur content was reduced from 2.0% to 0.8% (R71-23 pp.2079-80). The experiences of several other facilities were described in other testimony (R71-23, pp.1705-10), relating their attempts to control particulates while burning low sulfur coal. Approaches taken included sulfuric acid injection, liquid SO_3 injection, backfitting fabric filters, increasing precipitator size and surface area, and complete ESP replacement. These modifications were applied to both existing and new ESP equipment with various degrees of success.

Further information on this subject is presented in the R74-2 record, Exhibit 115, part of which is the entire record of PCB 74-16 Commonwealth Edison v. Environmental Protection Agency. A table given on page 13 of the Board Opinion in that case details the experience of the Edison Waukegan #8 unit (an existing unit) when burning coals with varying sulfur contents. Efficiency of particulate removal dropped from 98.6% efficiency with 2.79% sulfur coal to 88.1% with 0.45% sulfur coal. The options being considered to solve the problem were the retrofit of a "hot" precipitator located before the air preheaters, or the conditioning of flue gas by injection of SO_3.

Mr. Andrew Bhan, testifying for the Illinois Environmental Protection Agency in R75-5, discussed the difference in resistivities between high and low sulfur coals. The generally accepted theory for this difference is that sulfur trioxide (SO_3) in the flue gas reduces fly ash resistivity, and that SO_3 is virtually absent from the low sulfur coal flue gas. A comparison of flue gas concentrations shows 50 ppm SO_3 from 3.5% sulfur coal and 5 ppm SO_3 from 0.5% sulfur coal (R75-5, p.539-42).

The total record reviewed in this matter shows that for facilities with existing ESP equipment there are four general techniques available for simultaneous compliance with particulate and SO_2 emission standards. These are: 1) enlarge precipitator collection area, 2) retrofit "hot" precipitators, 3) conditioning of flue gas by addition of an electrolyte, and 4) use of ESP in combination with other particulate control devices. We note with interest that the fourth option, though discussed as a means of particulate reduction to reach stringent standards, is not considered nor costs evaluated for its use in achieving simultaneous compliance with particulate and SO_2 standards. The first three options are fully reviewed, however, providing us a valuable perspective on their effectiveness and costs.

Several attempts have been made to enlarge precipitator collection area to allow more time and surface area for collection. This approach has not been successful on existing units, either technologically or economically, but it can become a part of the design for new units under development (R75-5 pp.543-47, Ex. 26(18)).

The use of a "hot" precipitator, located before the preheater, takes advantage of the decrease in resistivity of the fly ash with temperature. At high enough temperatures, the ash resistivity would be essentially independent of SO_3 content. A hot precipitator would operate at about 700°F rather than the 300-400°F at which "cold" precipitators operate (R75-5, pp.547-48, Ex. 26(15)). Like the former option, however, retrofit of a hot precipitator can be difficult and expensive due to site limitations. For example, Edison spent $13 million on a retrofit hot ESP for the Waukegan #7 unit, in comparison to the $3.4 million estimated cost for a new ESP (R75-5, p.549). Use of a hot ESP is better suited to new installations or installations in which an existing ESP is being replaced anyway for reasons other than fuel switching. The hot ESP is an accepted technology. Over 81 orders had been let for 20,000 megawatts (MW) at the time the testimony was given, and the units on Edison's Will County #3 boiler had a tested efficiency of 99.8% (R75-5 p.550).

The third option, that of flue gas conditioning, is an available and feasible technology. It is based on the principle of decreasing the resistivity of fly ash by adding an electolyte that will improve the ability of the ash to take an electric charge. The most successful flue gas conditioning systems have been those which injected SO_3, thus replacing the actual chemical that was missing from the gas (R75-5, pp.550-52). The quantities of SO_3 injected are small, and most of it is removed with the particulate, so flue gas conditioning does not add to sulfur oxide emissions.

The four methods available for SO_3 flue gas conditioning are use of H_2SO_4, liquid SO_2, sulfur burning, or liquid sulfur trioxide. The preferred method is sulfur burning. For example, Commonwealth Edison has ordered eight such units for use on power plant units that burn low sulfur coal. Because the conditioning process handles a small volume of gas, its hardware is relatively small. The result is much lower capital costs than for the other methods discussed, as well as greater ease and reduced costs in installation and operation on site (R75-5, pp.552-61).

The information presented to the Board readily allows us to conclude that particulate control technology is very well developed, and it is capable of achieving simultaneous compliance with particulate and sulfur dioxide emission standards. The "worst case" for simultaneous compliance is when an existing facility in one of the three major metropolitan areas (MMA's) is switched from high (3.5%) to low (less than 1%) sulfur coal to comply with the 1.8 lb/MMBTU SO_2 standards. Flue gas conditioning is available for use in these cases, and can be installed within fairly short time periods and with modest costs, installation, and operating requirements. Hot precipitators may also be used, depending on site design and costs involved.

We also note that there are many sources which do not face the worst case conditions. Simultaneous compliance for smaller existing sources may not be a problem if they are not using an ESP for particulate control, but rather are using another device not affected by changes in ash conductivity. New facilities burning low sulfur coal will be able to design their particulate control systems using the available removal devices as necessary to comply with the standard. Large sources outside of the MMA's are subject to a 6 lb/MMBTU sulfur dioxide standard, for which they would probably use washed coal. The change in ash resistivity would be small at the sulfur content of washed coal, with a similarly small effect on ESP efficiencies. There may also be sources using a low sulfur coal which has a low ash content, such that even at lower ESP efficiency there would be less ash to remove from the gas, with no net change in emissions.

These situations are pointed out for two reasons. First, Rule 203(g)(1) pertains statewide to new and existing sources of all sizes. The remand, therefore, has called into question particulate control under all of the conditions discussed above, though the main focus of the question of simultaneous compliance is the large sources in the MMA's. Having concluded that simultaneous compliance is feasible for the large urban sources, we also conclude that compliance is yet more feasible for the other classes of particulate sources. Secondly, there are not in fact only two mutually exclusive options available for simultaneous compliance. Reduction of SO_2 emissions may be accomplished by washing, scrubbing, blending, or any combination of these methods, as is discussed below. Particulate control requirements may vary widely, depending on the SO_2 control technique with which they will be operated. The record shows that the particulate technology is sufficiently advanced and flexible to allow simultaneous compliance under such a range of conditions.

<u>Flue Gas Desulfurization Technology</u>

There are three general methods to reduce sulfur dioxide emissions for a coal combustion source. The source may burn a low sulfur fuel (oil, gas, or low sulfur coal), it may remove the sulfur from the coal prior to combustion, or it may remove the sulfur dioxide from the flue gas after combustion. For a coal with 10,000 BTU/lb heat value and 3.5% sulfur content, a sulfur dioxide removal of 75% would be required to comply with the 1.8 lb SO_2/MMBTU heat input emission standard, and an 83% removal would be necessary for the 1.2 lb SO_2/MMBTU standard.

Because of limited supplies and high costs of alternate fuels, many facilities in Illinois have taken the position that the only way that all sources will be able to meet the emission standards will be by use of flue gas desulfurization (FGD). They further claim that FGD is not an available technology, and therefore they will be unable to comply. The record verifies that supplies of oil and gas are limited and low sulfur coal is expensive and sometimes difficult to obtain in sufficient quantities (Ex. R74-2-55A, 56A). Accepting the need to rely on technology to remove sulfur dioxide from the flue gas, does adequate technology exist?

The process of SO_2 removal involves a chemical reaction of SO_2 in the flue gas with a reactant, followed by removal of the chemical product in either liquid or solid state. Some systems are "throwaway" systems which discard this product. Others are designed to recover a sulfur byproduct, usually as sulfur or sulfuric acid, and regenerate the reactant, which then is recycled for further SO_2 removal.

Flue gas desulfurization (FGD) is recognized to be a new and rapidly evolving technology, and a wide range of theoretical approaches has been explored over the past 10 to 15 years. The information presented in the record provides descriptions of the viable technologies and an assessment of their status and applications on existing facilities.

Processes described in R71-23 include lime or limestone injection, the Reinluft process, alkalized alumina, lime or limestone scrubbing, the DAP-Mn process, sodium hydroxide, catalytic oxidation, magnesium oxide, Wellman-Lord, and the Stone and Webster ionics method (Exhibits 15, 32, 37, 57, 73). Of these, the lime or limestone scrubbing, sodium hydroxide, magnesium oxide, catalytic oxidation, Wellman-Lord, and adsorption processes had been identified as the most promising (R71-23, pp.674-78, 1795-1800, Ex. 57, 57A, 73). Both the lime injection and alkalized alumina had been determined to be unworkable, after some extensive demonstration work (R71-23, pp. 1797, 2276, Ex. 57A). The wet lime or limestone scrubbing process was considered to be the most developed and demonstrated process at that time (R71-23, pp.681, 1799, Ex. 48, 57).

An interesting example of how FGD technology had been developing is given in testimony by Dr. Engdahl. He cited a 1969 Federal report that listed limestone injection, catalytic oxidation, and alkalized alumina sorption as the most promising processes. In contrast to that list, he then cited limestone wet scrubbing, catalytic oxidation, and alkaline scrubbing as the most promising technologies at the time of his testimony in 1972 (R.2275-77). Both limestone injection and alumina sorption had been eliminated, and a number of new processes had been introduced.

Another witness, Dr. Lowell, said that "SO_2 control technology is advanced to the point that they can be designed if preceded by the required process development steps" (R71-23, p.1800). A report prepared by Radian Corp. (Ex. R71-23-73) stated that throwaway systems have more flexibility and are more readily understood than the regenerative systems. The report also stated that no process had yet been demonstrated for full-scale, long-term reliability on a coal-fired power plant.

A 1970 report by the National Research Council (NRC) (Exhibit R71-23-48), though optimistic about development of SO_2 control technology, concluded it was not yet commercially proven and that only the limestone scrubber had been installed in full size power plants. The NRC felt that limestone scrubbing processes would be available by 1971-1973, and other processes by the mid-70's to early 80's, if "there is positive commitment on an urgent basis by government agencies, utilities, fuel suppliers, and vendors to support the orderly development and timely application of these processes" (Ex. R71-23-48, p.31). The NRC definition of proven industrial scale acceptability (commercial demonstration) was that of satisfactory operation on a 100 MW or larger unit for more than one year. (Ex. R71-23-48).

Several different interpretations of availability were introduced into the R71-23 record. The differences between the definitions became one of the areas of disagreement as to the status and, therefore, feasibility of FGD. The NRC definition given above was supported consistently by industry representatives. Dr. Engdahl used the term "commercial availability", saying that availability would exist when the seller guarantees the efficiency and performance of the process (R71-23, pp.2278-79). Dr. Stukel, testifying for the Illinois Environmental Protection Agency, defined availability as successful completion of pilot plant tests, i.e. a process should be ready for demonstration on greater than 100 MW units (R71-23, pp.673-74, 681, 3485). He also agreed that the offer of a guarantee is a strong argument for availability.

The fourth definition was given by Mr. Walsh of the U.S. Environmental Protection Agency. The USEPA assesses availability when it sets its New Source Performance Standards (R71-23, pp.2702-2707). The USEPA Administrator determines what technology is available and what degree of emission control it can attain considering the history of the technology and the need for control. Mr. Walsh's testimony implies that he considers pilot plant operation to be an adequate demonstration of availability for the USEPA definition.

In the context of these various definitions, and with recognition of the speed with which SO_2 control technology has been evolving since 1970, we have reviewed the complete record before us. In the review we have studied the various facilities with FGD, the capacity and performance of the units, and changes over time in application of the various technologies.

At least twelve facilities were cited in the R71-23 record. Of these, four had demonstration FGD units in operation. Two facilities, the Union Electric Meramec plant (125 MW unit) and the Kansas City Power and Light Lawrence plant (125 and 430 MW units) used limestone injection into the furnace. Both plants, after extensive testing with variable success, shut down their units (R71-23, pp. 308-331, 1633-35, 2289-2294, Ex. 46, 83). The TVA Shawnee plant (175 MW) attempted application of a dry limestone injection, which was also shut down because of low efficiency and increased requirements for ESP capacity (R71-23, pp.326-7, 2274-2284). The fourth plant was the Commonwealth Edison Will County unit #1 (163 MW), on which a limestone slurry scrubber was installed. Testimony in R71-23 was limited to startup, early operating experience, and shutdowns for design modifications (R.321-324, 2082-2087, 3828-29). Later operating experience for this unit is described in R74-2 and R75-5.

There were an additional six units over 100 MW in size (i.e. demonstration units) which were either under construction or in the design phase. These were (R71-23, pp.327, 630-37, 2277, 2960-64, Ex. 15, 48):

1. Mitsui, Japan - 155 MW, carbide lime scrubber, 2.2% sulfur coal

2. Boston Edison Mystic - 155 MW, magnesium oxide, 2% sulfur oil

3. Arizona P.S. Cholla - 125 MW, limestone scrubber, 0.4% sulfur coal

4. Illinois Power Wood River - 100 MW, catalytic oxidation, 3% sulfur coal

5. Duquesne Light Phillips - 307 MW, lime scrubber, 2% sulfur coal

6. Kansas City La Cygne - 820 MW, limestone scrubber, 5.2% sulfur coal

Commonwealth Edison was installing a 25 MW pilot unit at its State Line plant, to use the Sulfoxel process (R71-23, pp.324-25, 2082-87). In addition, a 70 MW unit was being constructed at the Louisville Electric Paddy's Run plant, which is a peaker unit (R71-23, pp.2741-43 All of these units indicate that extensive work had been underway through the pilot plant stage and into demonstration units at that point in time.

The most common problems cited in operation were excess scaling, corrosion, plugging, and vibration of various components of the FGD units. Shutdown and system modifications tended to yield subsequent improvements in operation, though the problems were still apparent throughout the R71-23 record.

Moving into the R74-2 record, we are again reminded of the rapid evolution of FGD technology. Testimony by Mr. McCarthy of the USEPA lists lime/limestone scrubbers, double alkali, magnesium oxide, and Wellman-Lord as demonstrated processes (R74-2, pp.630-636, Ex. 38). Mr. Orem, of the Industrial Gas Cleaning Institute, identified lime/limestone, double alkali, magnesium oxide, and catalytic oxidation, thus closely matching Mr. McCarthy's testimony (R74-2, pp.1637-38, Ex. 69). We note that both statements refer to the processes as "available" or "demonstrated", in contrast to testimony in R71-23 which described the various technologies as "promising". Mr. Orem confirms this observation with his statement that "...SO_2 removal technology has been adequately demonstrated and is available now." (R74-2, p.1614).

In addition, several years of experience with the lime/limestone scrubber have yielded new scrubber designs, including open spray towers, mobile bed scrubbers, and multigrid scrubbers. These designs yielded varying removal efficiencies, but each design improved scrubber reliability by reducing scaling and plugging of the system (R74-2, pp.411-12. 1289-90), thereby contributing to the development of the technology.

The concept of modular installation had also been introduced. In several facilities a series of 100-150 MW units had been installed in parallel to scrub a single large flue gas stream. Excess scrubber capacity was provided so that each module in the series could be shut down for cleaning on a regular schedule without interrupting scrubber availability (R.649-50, 1281-82, Ex. 40, 42).

Given the development of the various technologies, we now look at their performance records on full scale facilities. The units described as either planned or under construction during R71-23 had been put in operation by the time of the R74-2 hearings, as had several additional units. Testimony was given in R74-2 on the status of various plants by Mr. Elder of the TVA (R.418-25), Dr. Hesketh of Southern Illinois University (R.474-85), Mr. McCarthy of the USEPA (R.630-653), Mr. Slack for TVA (R.1276-81), Mr. Orem of the Industrial Gas Cleaning Institute (R.1617-51), and Mr. Fancher of Commonwealth Edison (R.2338-43). Their testimony was fairly consistent in identifying what were generally considered to be successfully operating FGD units and in describing problems that occurred and actions taken to resolve them.

Six facilities were listed by almost all these witnesses. They were the Mitsui, Phillips, Mystic, Cholla, Paddy's Run, and Mohave systems. All of them were assessed as having viable FGD systems. Five of these facilities were among those identified in the R71-23 record, and although all had had problems in startup and design modification, they had generally proved to have good reliability (70-90%) and high removal efficiency (80-90%). The La Cygne facility was also listed as successful by several of the witnesses. La Cygne has a modular system, as do Cholla and Paddy's Run, which are smaller units.

The Southern California Edison Mohave scrubber is a 165 MW cross flow limestone scrubber which had been running on 0.4% sulfur coal at 83% reliability at the time of testimony in R74-2 (R.423, 484). This unit had not been mentioned in the R71-23 record. Wellman-Lord was also still considered a viable system, as evidenced by several other facilities using or planning to use it, including the Chiba facility (75 MW) in Japan and a Northern Indiana Public Service plant (R74-2, pp.630-653).

The Will County and Wood River plants had continued to experience operating problems. The Wood River catalytic oxidation system was started up close to schedule, but because of design problems, it had to be shut down for an extended time. During that time it rusted out, resulting in a need for major repairs (R74-2, pp.1357-62, Ex. 52).

The Will County unit was continuing to have trouble with scaling, plugging, and corrosion, as described by Mr. Fancher of Commonwealth Edison (R74-2, pp.2332-34). According to his testimony, they were making progress in increasing scrubber reliability, but it was very slow and costly. Mr. Saleem of Peabody Engineering Systems attributed the Will County problems to low liquid to gas ratios, inadequate pH control, and incorrect retention time in the scrubber (R.445). Dr. Hesketh (R.500-02) listed the cramped installation space, the old and ineffective facility on which the scrubber was installed, the lack of precision in scrubber operation, and some basic design problems as contributors to the limited success of the scrubber.

At least four additional facilities were being planned in 1974. These were a 170 MW limestone scrubber on 4% sulfur coal at the Detroit Edison St. Clair station, a 550 MW limestone scrubber on 3.7% sulfur coal at the TVA Widow's Creek plant, a 100 MW magnesium oxide scrubber on 2.0% sulfur coal at the Potomac Power and Light Dickerson plant, and a 120 MW magnesium oxide scrubber on 2.5% coal at the Philadelphia Electric Eddystone station (R74-2, pp.402-05, 409, 639-48).

In reviewing the R74-2 testimony, we observe that the industry positions on the status of FGD technology differ from those expressed in R71-23. Mr. Dodge contrasted the term "available" with "merchantable" (R74-2, pp.975-88), with reference to the characteristics of a business decision needed to commit to the purchase of such a system. His position was that merchantable systems, defined as commercial quality, suitable for sale, and acceptable to buyers, did not then exist (R74-2, pp.983-4). Under that definition a system could be considered a reasonable risk and merchantable only if it had a proven design and long term reliability, resulting from orderly process development through several generations of equipment. Therefore, available technology under any of the definitions presented in R71-23 would not be merchantable systems. The key factor in this concept was that of an acceptable financial risk, a concept which was also supported by the Illinois Coal Operators Association (Ex. R74-2-55) and the TVA (R74-2, pp.1296-98).

Virtually all the vendors of SO_2 removal systems offered guarantees on their equipment for removal efficiency, but they were less consistent in coverage for other aspects of installation and performance. One vendor (R74-2, pp.394-99) said they had a long-term reliability guarantee, but would not describe it due to their competitive position in the market. Another vendor (R74-2, pp.404-5) offered guarantees on utilities and raw materials consumption and capital costs, but it would not guarantee reliability. Both vendors, however, said their systems were expected to have a reliability equivalent to that of the boiler involved.

In January, 1974 a USEPA hearing panel published a report on hearings held to review the status of power plant compliance with SO_2 regulations (Ex. R74-2-40). In the report the panel noted that "...guarantees for FGD systems are similar to those offered for such other major equipment purchased by utilities as boilers, turbines, and electrical equipment", but that "...no vendor is willing to assume all risks during the lifetime of the FGD system by guaranteeing its reliable operation at all times because the vendor rarely has control over the operation and maintenance of the system after an initial performance test" (p.43-4). The hearing panel found that guarantees offered by vendors were "generally appropriate" (p.44).

By 1975 when hearings for R75-5 began, experience with SO_2 control technology had expanded even further. Under contract to the USEPA the consulting firm PEDCo-Environmental Specialists, Inc. had been preparing monthly summary reports of the status of FGD technology. Several PEDCo reports were submitted as exhibits in R75-5. According to the December 1975 PEDCo report (Ex. R75-5-58), there were installations totalling over 3000 MW capacity operating with catalytic oxidation, lime or limestone scrubbing, double alkali, lime injection, magnesium oxide, sodium carbonate scrubbing, or Chiyoda Thoroughbred 101 processes. In addition various systems totalling over 7000 MW capacity were under construction and were projected to use those processes plus activated carbon and Wellman-Lord/Allied Chemical. Reported sulfur dioxide removal efficiencies averaged from 70% to over 90%. At a 70% efficiency a source could comply with the 1.8 lb/MMBTU standard while burning coal with 3% sulfur content and with the 1.2 lb/MMBTU standard while burning 2% sulfur coal. (Ex. R75-5-58, Table 3).

Lime/limestone scrubbing was the process used for 88% of the operating FGD systems as well as for 96% of the ones under construction. This information, along with testimony in the record, highlights the status of lime/limestone scrubbing as the most demonstrated system. It was attaining high reliability in long term operation on a number of facilities, where the systems had had time for design modification and correction of problems as part of process development. Problems remaining for this process were corrosion and plugging when used on high sulfur coal, limited ability to operate a closed loop system, derating of the facility due to scrubber energy demands, and handling and disposal of sludge wastes (R75-5, pp.321-24, 1101-1316, 1329-60, Ex. 11, 58).

Summary data from two PEDCo reports for May and December of 1975 (Exhibits 11, 58) provide additional perspective on the experience at that time with FGD technology. They are presented in the following table, which can be compared to the much smaller list of 6 to 10 units in operation at the time of R74-2.

FGD unit status	Number of units (MW capacity)	
	May 1975	December 1975
Operating	21(3344)	22(3828)
Under Construction	23(7550)	20(7026)
Planned	73(35,736)	60(31,306)
	117(46,630)	109(42,160)

This experience is accompanied by a diversification in the technologies being used, as users moved toward regenerative rather than throwaway FGD systems. Costs and degree of demonstration of the throwaway systems had resulted in their domination of the early market, but in 1975 it appeared that FGD technology had evolved to the point where process refinement and further development of more efficient processes was underway. This is shown in the December, 1975 PEDCo report wherein the lime/limestone scrubber share of the existing FGD market (88% of operating megawatts and 96% of those under construction) is much higher than its share of 44% of the total FGD capacity being planned for future control technology (Ex. R75-5-58, Table 10). This difference is particularly great considering that 10,854 MW's were in operation or under construction, while 31,306 MW's were listed as planned control capacity.

Many of the facilities discussed in R74-2 were again reviewed in the R75-5 record, though testimony on the status of FGD technology was much more limited than in the earlier hearings. The primary concerns expressed were those given by Commonwealth Edison (R75-5, pp. 1101-13). Their criticism of limestone scrubbing, based on their Will County unit, focused not on availability but on energy demands, closed loop operation, sludge disposal, and use on high sulfur coal, as described above. They also expressed doubt about the future viability of sodium-based scrubbing systems, because of the technical failure and economics of the sodium-based Sulfoxel process tested on their State Line facility (R75-5, pp.1113-16).

The history of FGD processes presented in the three records clearly shows that it is a relatively young and rapidly evolving technology. Flue gas desulfurization involves not just one technology, but a variety of throwaway or regenerative systems. The processes are in various stages of development, but several of them, e.g. limestone scrubbing, Wellman-Lord, and magnesium oxide scrubbing, have been demonstrated as viable processes with acceptable reliabilities. Technology availability is verified in the record by several observed patterns over time. These include the increasing reliability with experience for individual units, the growth in the number of units operating and projected for operation, the shift of engineering efforts from troubleshooting scrubber problems to process refinement and development of new generations of processes, and the gradual change in users' concerns from early questioning of scrubber availability to later criticism of its energy and environmental impacts and economic costs.

We conclude that flue gas desulfurization technology is available and feasible and that long-term reliability equivalent to that of a boiler can be maintained by proper design and careful operation and maintenance of the unit. The problems with the lime/limestone scrubber cited in the R75-5 record are being overcome by further design modification, and will eventually be eliminated as new and more efficient processes mature and replace the throwaway lime/limestone processes. In the meantime feasible processes do now exist for use by new and existing SO_2 emission sources for complying with the emission standards in Rules 204(a)(1) and 204(c)(1)(A).

Combinations of Methods for Particulate and SO_2 Control

As discussed above, the Court decisions identified only two options that could be taken to simultaneously control particulate and SO_2 emissions from coal burning combustion sources. The first option was the use of low sulfur coal plus upgrading of the flue gas particulate removal process; the second one was the serial operation of particulate and SO_2 removal systems on the flue gas stream. We have found that both options are technologically feasible.

However, the record also demonstrates that other options are available for simultaneous control of the two pollutants. These options take advantage of the washability of coal at relatively low, cost, to reduce both sulfur and ash contents of the coal. By use of coal washing for high sulfur coal, followed by either blending with low sulfur coal or flue gas removal technology, particulate and SO_2 emission standards can be met while requiring less flue gas emission control capacity. The use of these combinations of control methods would result in a need for smaller FGD capacity and in a net reduction in costs incurred for use of low sulfur coal or flue gas control processes.

The coal washing (beneficiation) process is described in testimony (R71-23, pp.657-68; R74-2, pp.1478-1521, 1556-58) and several exhibits (R71-23, Ex. 56c; R74-2, Ex. 59,84; R75-5, Ex. 19). The basic steps are crushing of the coal, followed by gravity separation of coal from pyrite impurities and dewatering of the washed coal. Sulfur in coal is either in the form of organic sulfur in the coal molecule itself, or an inorganic impurity in pyrite, or free sulfur. The crushing and washing process frees the pyritic forms from surrounding coal molecules, with the pyrite settling out in gravity separation because of its higher specific density. The washability of any coal will depend on how much of its sulfur content is pyritic and how closely the pyrite intermingles with the coal. Ash content will also be reduced by gravity separation, and some loss of coal (and therefore heat value) will also occur.

Extensive testing has been done on Illinois coal to assess its washability. Results show that an average of 38% (range of 5% to 65%) of the sulfur in Illinois coals can be removed at 80% coal recovery.

Expressed in terms of the total sulfur content, the content would be reduced an average of 1.5%, e.g. from 4% to 2.5% sulfur content (R71-23, pp.657-68, Ex. 56c; R74-2, p.1478-1521). Assuming a heat content of 10,000 BTU/lb of coal, a 4% sulfur coal would require 85% SO_2 emission reduction while a 2.5% coal would require 76% reduction to meet the 1.2 lb SO_2/MMBTU standard for new sources. Following washing, either less low sulfur coal for blending or lower technology removal capacity would be needed to attain compliance with the standard. It is noted also that the reduction in ash should enhance capability of compliance with the particulate standard, as well as lessening the impact of burning low sulfur coal on ESP efficiencies. Another relevant factor, however, is that of the burnability of the washed coal, which must also be assessed in determining the feasibility of this method for any given facility (R74-2, pp.1556-58, Ex. 59).

Costs of Compliance with Emission Standards

The combined records of R71-23, R74-2, and R75-5 have provided a perspective of the evolution of processes for simultaneous control of SO_2 and particulate emissions. The experience accumulated during that period also yielded estimates of capital and operating costs for the various control methods used.

Cost estimates increased substantially over the time between 1971 and 1975, due to both inflationary forces and higher actual costs resulting from problems in the startup and operation of demonstration FGD systems. Because costs cited in the R75-5 record are the most recent estimates and are derived from a fairly wide base of experience, they must be considered the most reliable figures available to us. They are expected to be more practical cost estimates, reflecting knowledge of FGD hardware and operating requirements. They should also take into account technical lessons learned from earlier demonstration problems for streamlining subsequent systems, thereby minimizing future problem-related cost increases.

In response to the Court's remand we have evaluated the economic reasonableness of simultaneous compliance with particulate and SO_2 emission standards. Both the Appellate Court and Supreme Court discuss Rule 203(g)(1) solely in the context of the problems associated with simultaneous compliance. We have therefore limited the analysis herein to costs required above and beyond those for compliance with just the Rule 203(g)(1) particulate standards. For example, costs for ESP upgrade to comply with Rule 203(g)(1) are not included, but any ESP upgrade necessary to counteract effects of burning low sulfur coal is included in costs for simultaneous compliance. Similarly, particulate removal equipment in series with an SO_2 removal system is not considered part of the simultaneous compliance cost because it is needed anyway for Rule 203(g)(1). The only relevant costs in this option would be those related to the SO_2 system installation and operation.

For existing sources, the conversion to low sulfur coal and ESP upgrade involves an increase in operating cost for low sulfur coal supplies, capital costs for modifications of boilers and purchase of equipment to transport the coal, and capital and operating costs for ESP modification or flue gas conditioning systems. Exhibit R75-5-70 (Appendix B) gives 1974 costs for Illinois and western coals. The average delivered coal costs for one utility, Commonwealth Edison, were calculated from that data to be 82.6 cents/MMBTU for western coal and 68.4 cents/MMBTU for Illinois coal, the incremental cost being 14.2 cents/MMBTU (about 21%) more than Illinois supplies. As an example, applying this cost to the Commonwealth Edison 1232 MW Kincaid 1 and 2 station, which burns 3 million tons of coal per year (Exhibit R75-5-37, Table I), the incremental operating cost of purchasing western coal would be $8.3 million per year, 1974 dollars, assuming 10,000 BTU/lb coal heat value. Assuming costs are proportional to size, the cost of coal for a 500 MW plant would be about $3.4 million per year. The costs cited here do not include new equipment, such as railroad cars for transporting coal, or costs resulting from adjustments made in the boiler and/or combustion process to compensate for differences in the burning characteristics of high and low sulfur coals. (See R75-5, pp.1116-1119 for discussion of this issue.) Neither do the costs reflect expected price increases resulting from limited supplies coupled with greatly increased demand for low sulfur western coal.

Costs for each of four flue gas conditioning systems were given in exhibit R75-5-26A. Capital costs ranged from $1.1-2.6/kw for 250 MW plants ($275,000-650,000) to $0.9-2.0/kw for 500 MW plants ($450,000-1 million), showing some efficiency of scale. Operating costs ranged from .06-0.15 mills/kwh.

The costs associated with replacement or modification of an ESP would be substantially higher, and such an approach would not be expected to be selected by an existing facility solely as a means for simultaneous compliance. The decision to install a hot precipitator would require a need to serve other purposes as well, and the bulk of the costs for the system would then be attributed to that purpose rather than to the compensation for burning low sulfur coal.

New sources would be expected to have similar costs for purchase and transport of low sulfur coal, as well as some incremental costs for particulate control. They will not, however, require modification of existing boilers to burn the coal, so their total costs should be lower than existing facilities.

Flue gas desulfurization costs were presented in a number of exhibits in R75-5 (Exhibits 11, 12, 31(4), 58), as well as in testimony by a variety of witnesses. The most comprehensive and consistent data were found in Exhibit 12, a PEDCo report entitled "Flue Gas Desulfurization Process Cost Assessment", in which capital and operating costs for several model plants were estimated for lime/limestone scrubbers and the Wellman-Lord system. Listed in Table 6.1 of Exhibit 12 were capital costs for both new and retrofit FGD systems, cited by the utility industry in response to a survey questionnaire. PEDCo adjusted the industry cost estimates to January, 1975 dollars, deducted particulate control costs included in the total, adjusted indirect charges (usually upward), adjusted sludge disposal costs to include disposal only of SO_2 sludge (not fly ash) over the entire lifetime of the FGD system, and deducted any replacement power costs. The resulting costs represent actual operating experience, adjusted and reported on a consistent base. The costs can be compared to each other and to estimates generated by the PEDCo models, thereby providing us fairly extensive information on the magnitude and ranges of costs to industry for FGD.

A total of 19 lime/limestone scrubber systems were reported by the industry, with adjusted costs averaging $70/kw with a range of $50-88/kw. Three magnesium oxide scrubbers had reported costs of $113, $137, and $144/kw (average of $131/kw), and five Wellman-Lord systems had an average cost of $106/kw with a range of $95-117/kw. The PEDCo model plant cost estimates were $70/kw for limestone and $114/kw for Wellman-Lord for a 500 MW retrofit FGD on 3.5% sulfur coal, and $58/kw for limestone and $90/kw for Wellman-Lord for a new 500 MW FGD system, closely matching the industry estimates. For the model plant with retrofit FGD, total capital expenditures would be $35.1 million for limestone and $56.9 million for Wellman-Lord. It is noted that these costs do not include replacement power costs for power necessary to run the control system, for which a range of $2.70-14.00/kw was estimated.

Annualized costs for the 500 MW retrofit FGD model plant, which included operation and maintenance, fuel and electricity, and fixed costs (including capital), were estimated at 4.27 mills/kwh ($11.2 million/yr) for limestone scrubbing and 5.83 mills/kwh ($15.3 million/yr) for Wellman-Lord. (One mill equals one-tenth of a cent.) Annualized costs for new FGD were 15-20% lower than for retrofit systems.

These costs to SO_2 emission sources are seen to involve large quantities of money. In order to put them into perspective, we may observe the effect they will have on the utility bills paid by the consumer. The League of Women Voters submitted a report (Exhibit

R75-5-41) that estimated a 10% increase in utility rates as a result of SO_2 and particulate control. A major portion of that increase would be expected to be for SO_2 control because its costs are higher than those for particulate control. A utility report (Exhibit R75-5-35) estimated a nationwide utility bill increase of 7.59% to pay for new and existing SO_2 scrubbers. A third study (Exhibit R75-5-38), prepared by Argonne National Laboratory, reported an expected 10% increase in utility bills.

The use of coal washing combined with SO_2 scrubbing was identified above as a potentially less costly method to comply with emission standards. Exhibit R75-5-31(6) reports the results of a study that compared the capital and operating costs for simultaneous SO_2 and particulate control for unwashed coal and washed coal at two different levels of cleaning. Costs were given as ranges because of uncertainty in some estimates and in recognition of site-specific factors that could influence costs. Costs for scrubbing unwashed coal were given as \$64-119/kw capital costs and 3.94-6.20 mills/kwh operating costs. Scrubbing cleaned coal (at 95% thermal recovery) would cost \$53-84/kw capital and \$2.89-4.22/kwh operating costs. The costs for scrubbing washed coal at 90% thermal recovery were similar to the 95% recovery coal. Use of the combined methods results in a reduction in costs for emission control systems and sludge disposal and an increase in costs for coal beneficiation facilities and operation, with a net reduction in total cost (Exhibit R75-5-31(6), Table I). The ranges of the costs overlapped, however, indicating that in some facilities the washing/scrubbing combination may not yield a savings. Thus, as always, a decision on which method to use would depend on conditions at any given location.

When considering the emission control costs presented in the record, compared to the magnitude of operation of the source facilities, we estimate that emission control costs for all sources (both new and existing) amount to around 8% to 10% of their total operating budgets. This amount is obtained from the estimated utility bill increases of 8% to 10%, assuming all control costs are passed on to the consumer. With costs for new sources being 15-20% lower than for retrofit control capacity, as discussed above, their costs would be expected to be 7% to 8% of their operating budgets. These moderate increases are the price paid for attainment and protection of the SO_2 ambient air quality standards. As such the expenditures will yield a return in dollars, as well as in other less quantifiable benefits resulting from reduction of the health and welfare effects of SO_2 air pollution. We find, therefore, that the control costs are economically reasonable, and the consumer who will ultimately pay the bill for pollution control will also reap substantial benefits from the reduction of ambient SO_2 to levels which will protect health, welfare, vegetation, and property.

In conclusion, we find, based upon information originally developed in the R71-23 proceedings and later expanded upon in the subsequent R74-2 and R75-5 proceedings, that the Rules in question are technologically feasible and economically reasonable. Therefore, in accordance with the option specifically detailed by the Courts in the Commonwealth Edison decision, we hereby validate Rules 203(g)(1), 204(a)(1) and 204(c)(1)(A), subject to a 45-day public comment period.

Mr. James Young dissented.
Mr. Nels Werner abstained.

I, Christan L. Moffett, Clerk of the Illinois Pollution Control Board, hereby certify the above Opinion was adopted on the 7th day of July, 1977 by a vote of 3-1.

Christan L. Moffett

Christan L. Moffett, Clerk
Illinois Pollution Control Board