REPORT OF THE

Virginia Coal and Energy Commission

TO THE GOVERNOR AND
THE GENERAL ASSEMBLY OF VIRGINIA

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Report of the
Virginia Coal and Energy Commission
to
The Governor and the General Assembly of Virginia
Richmond, Virginia
March 1989

To: Honorable Gerald L. Baliles, Governor of Virginia,
and
The General Assembly of Virginia

I. INTRODUCTION

Since 1979, it has been the charge of the Virginia Coal and Energy Commission to "study all aspects of coal as an energy resource and ... to stimulate, encourage, promote, and assist in the development of renewable energy resources..." (§ 9-145.1 of the Code of Virginia). This document constitutes the Commission's report regarding its activities during 1988.

The Virginia Coal and Energy Commission held four meetings in 1988. Testimony was received at these meetings regarding the following topics: acid rain, developments in federal electricity policy, cogeneration and independent power producers, transmission of electricity, updates on the Virginia coal industry and related topics, liquid coal and the bidding preference for Virginia-mined coal.

This report also discusses the deliberations of the Commission's Coal Subcommittee and Energy Preparedness Subcommittee.

II. 1988 COMMISSION DELIBERATIONS

A. ACID RAIN

At its first meeting of the year, the Commission received an update on the issue of acid rain. Testimony indicated that the acid rain issue continues to be politically troublesome because the major cause of acid rain originates in one portion of the country, while its effects are felt in another.

According to the Executive Director of the Virginia Department of Air Pollution Control, no further research on the causes and effects of acid rain is necessary. He indicated that prior research has already provided ample proof as to the causes and effects of acid rain, and that corrective measures can be taken based on the results of prior research.

The results of preliminary studies indicate that the Commonwealth is feeling the effects of acid rain. Although Virginia does not have as many lakes as do the northeastern states, results of a recent trout stream study conducted by the University of Virginia in cooperation with the National Wildlife Federation show that Virginia's trout streams are susceptible to acidification and that acidification is beginning to occur. Another study, recently conducted by the University of Virginia, found that two mountain streams in the Shenandoah National Park are becoming acidified. The United States Park Service has found that some of Virginia's more susceptible plants to acidification, such a milkweed, are showing signs of stress. Likewise, preliminary results of studies being conducted by the Tennessee Valley Authority indicate that frazier firs located on mountain tops are also showing signs of stress.

Commission members were provided with updates of three on-going studies authorized by the General Assembly several years ago. These studies were designed to determine the origin of acid rain in Virginia, its composition, and the potential effects of acid rain in Virginia. The studies, performed in cooperation with Virginia Polytechnic Institute and State University and the University of Virginia, are now in their final stages. The preliminary results of rain composition testing at the University of Virginia show that certain rain samples taken during the last decade were very acidic. Related studies have shown that the acidity levels of rain in the Commonwealth are nearly as high as those experienced in New England, where the impact has been much worse. Perhaps because Virginia's soil has a greater capacity for neutralizing acid rain, Virginia has not been as seriously impacted as other Northeastern states by the effects of acid rain. However, this neutralizing capability is limited, and at some point the soil's neutralizing capacity will be exhausted.

Testimony indicated that as the issues posed by acid rain are interstate in nature, Congress is the appropriate legislative body to address this problem. However, the Commission was told that the Commonwealth should be prepared to be a party in whatever solution Congress determines is appropriate.

According to Virginia Power's Washington, D.C. representative, during the fall of 1988 Congress considered a number of acid rain proposals. At the time he testified before the Commission, Congress was considering three different proposals: (i) Senator Byrd's compromise acid rain proposal, which was prepared by the United Mine Workers Association; (ii) the Peabody Compromise Proposal; and (iii) Senator Mitchell's compromise acid rain proposal.

Senator Byrd's compromise proposal emphasizes placing the burden on the "high emission" plants which are located in the midwest and which are considered by many to be the "heavy polluters." The proposal calls for reductions in pollutants emitted by these plants. Virginia Power's representative described this proposal as "commendable" from Virginia's point of view.

Senator Mitchell's proposal was described to the Commission as a "scrubber-oriented" bill which minimizes the options of using low sulfur coal. Testimony indicated that this bill would impact negatively upon coal producers and Virginia's electricity users, as consumers would eventually have to pay for these costly scrubbers. The Commission was told that any Clean Air Act legislation should provide utilities with the option of switching to low sulfur coals.

In response to discussion generated by these comments, the Commission unanimously agreed to forward identical letters to Representatives Bliley and Boucher and Senators Warner and Trible emphasizing the principles the Commission believes should be incorporated into any acid rain legislation. A copy of one of these letters is attached to this report as Appendix A.

B. DEVELOPMENTS IN FEDERAL ELECTRICITY POLICY

The Commission received an update from a spokesperson for Dominion Resources, Inc., regarding recent developments in federal electricity policy. In 1978, Congress passed the Public Utility Regulatory Policies Act (PURPA) in response to the energy crisis. The effects of this act were first felt when the Federal Energy Regulatory Commission (FERC) adopted rules and regulations under the act. By 1986, there was a "firestorm of complaints" regarding how the PURPA system was operating. In the spring of 1987, FERC held hearings and subsequently announced that it would consider allowing utilities to purchase power from qualifying facilities under PURPA through competitive bidding. Under PURPA there are two types of qualifying facilities: (i) cogenerators and (ii) small power producers (limited in the size of their plants and the types of fuels they can use).

The Commission was told that the problems encountered with the PURPA system revolved around administratively determined prices (avoided costs). Testimony indicated that administrative pricing does not work well because (i) it doesn't get the price right; (ii) it doesn't balance the supply and demand; (iii) it doesn't allocate capacity to the most efficient supplier; (iv) it doesn't give the customer the benefit of cost below the utility's; and (v) it impedes consideration of nonprice factors. FERC's notice for proposed rule making (NOPR) on administratively determined pricing provided for capacity payments only if capacity is needed, avoided costs on the basis of the least expensive alternative, and suggested a redetermination of avoided costs if offers exceeded need. Fuel diversity and other nonprice factors must also be considered. FERC has also prescribed that states may not require payments in excess of avoided costs. Under FERC's bidding NOPR, bidding would be legal under PURPA and optional to the states as an alternative to administrative pricing. Additionally, the bidding NOPR provides that nonprice factors must be considered.

States which currently utilize bidding processes include Maine, Massachusetts, California, Virginia, Connecticut, New York, Colorado, New Jersey, Vermont, and Florida. Illinois, Iowa, Michigan, Pennsylvania and Nevada are now considering the use of bidding processes.

C. COGENERATION AND INDEPENDENT POWER PRODUCERS

1. Cogeneration

According to testimony, Virginia Power attempts to plan five years in advance for capacity needs. However, as a result of a very cold winter last year and a hotter than usual summer, the company's predictions were lower than the actual needs. Part of this increased demand was also due to an influx of new customers into Virginia Power's service area.

Transmission limitations northwest of Virginia Power (i.e. power coming from West Virginia and Pennsylvania) also presented capacity projection problems for Virginia Power. During the summer of 1988, power purchased from areas northwest of Virginia Power could not be received by Virginia Power due to heavy loading of the transmission lines. As a result, Virginia Power plans to bring two small units back on line in Northern Virginia and to begin bringing in power from south of Virginia. The Commission was told that Virginia Power's most pressing need currently was for additional peeking capacity. On days when Virginia Power has its heaviest load, the peak load only exists for a few hours. As a result, testimony indicated that Virginia Power will seek approval from the State Corporation Commission to install four new turbines at the Surry site as well as additional turbines in Central Virginia.

Prior to the initiation of the competitive bidding process, Virginia Power signed a number of contracts to receive power from cogeneration projects around the state. A company can qualify as a cogenerator as long as it uses five percent of the steam for purposes other than generation of electricity. Currently, Virginia Power is receiving 317 MW in capacity from twenty-five cogeneration projects in operation in Virginia. Over and above this 317 MW, Virginia Power in 1987 predicted that at least an additional 700 MW would be necessary. However, as a result of increased demand, Virginia Power has already signed contracts to procure an additional 1200 MW of capacity.

According to a spokesperson for the State Corporation Commission, the SCC was the first state agency in the country to endorse "all supply source bidding" (a bidding process open to all independent power producers). While the SCC is "optimistic" regarding the future of nonutility generators, it does not plan to rely solely on nonutility power plants in the future because it believes this is a "risky proposition." The SCC favors a more balanced approach of purchasing power and building for capacity. When asked about the competitive bidding process and what importance was placed on nonprice factors (i.e. the importance of coal to the Virginia economy), the spokesperson indicated that about seventy percent of the decision will be based upon price and thirty percent of the decision will be based upon nonprice factors. The SCC is unsure at this time as to what the appropriate mix should be regarding cogeneration and building for new capacity.

The Commission discussed the advisability of extending the cogeneration tax credit currently available to cogenerators and small power producers who use Virginia-mined coal to other industrial users. According to written testimony received from the Director of the Virginia Coal and Energy Research Center, such an extension would be unwise because (i) the vast majority of current and projected utility and industrial coal markets in Virginia are covered by the existing utility and cogenerator tax incentives; (ii) administrative costs would be likely to increase while potential payoffs would be relatively small; and (iii) a recent survey found that smaller industrial coal users base their purchase decisions on such factors as haul distance, accessibility to railroads and coal quality, rather than price.

2. Independent Power Producers

The Commission was encouraged to endorse legislation which would exempt independent power producers (IPPs) from state regulation. IPPs are companies which sell electricity at wholesale to electric public service companies. The issue of IPP regulation has arisen due to Virginia's adoption of a formal competitive bidding system. The Commission was told that the trend currently is for utilities with power needs to purchase power because of the advantages to such companies' customers in terms of greater efficiency, lower cost, reduced rate-payer risks, diversity of supply and continued reliability in the provision of electric services. For example, during Virginia Power's most recent bidding solicitation, forty-one percent of the 14,600 megawatts in bids received were from IPPs. Of the bids awarded by Virginia Power, thirty-five percent were awarded to IPPs.

Testimony indicated that there are three major barriers to the development of the independent power industry: (i) the Federal Power Act, which requires cost-to-service pricing and other nonprice regulations; (ii) the Public Utility Holding Company Act, which creates entrance barriers to the electricity market; and (iii) utility-type regulation under state law.

Qualifying facilities are those cogenerators with minimal steam use for nonpower generation purposes. To be a qualifying facility under the Public Utility Regulatory Policies Act of 1978 (PURPA), a facility must use at least five percent of the steam it produces for nonpower generation purposes. Consequently, it is difficult for facilities using combustion turbines, which typically do not provide steam, to fit under the PURPA umbrella as a cogenerating facility. To do so, IPPs must purchase a steam host and contrive a steam use which may not make sense economically, but nonetheless serves as their ticket into the market. PURPA, according to testimony, was originally enacted by Congress because it was believed that by promoting cogeneration, electrical rates would drop due to higher efficiency. However, for IPPs that must obtain an expensive steam host, PURPA is having exactly the opposite effect.

PURPA exempts qualifying facilities from the traditional utility regulation of the Public Utility Holding Company Act and the Federal Power Act. The Federal Energy Regulatory Commission has already begun to remove some of the cost-to-service regulation. Additionally, in its next session Congress is expected to look into the regulation of IPPs under the Public Utility Holding Company Act.

With regard to state regulation, the Commission was told that IPPs are treated like public service companies. IPPs are subject to rate regulation by the State Corporation Commission and are only allowed to recover a certain amount of profit or return on their investment. However, the State Corporation Commission sets these rates after IPPs have already placed their bids. IPPs believe this is unnecessary, as competition in the bidding process serves as an effective price regulator. The State Corporation Commission also requires IPPs to submit financial reports, largely for purposes of determining what rates should be charged. A spokesperson representing IPPs stated that this requirement is unnecessary and expensive. He also explained that IPPs are placed at a disadvantage by having to obtain approval from the State Corporation Commission before issuing securities or selling assets. Testimony indicated that this requirement makes it difficult for IPPs to finance their projects, due to the expense and time involved in holding the required public hearings. Finally, the Commission was told that IPPs must currently obtain a certificate of public convenience and necessity from the State Corporation Commission. In order to do so, they must prove that the power is needed. IPP's believe that this burden should be placed upon the purchasing utility.

The Commission requested that the State Corporation Commission provide comments concerning the proposed deregulation of IPPs. A copy of the written response from the State Corporation Commission is attached to this report as Appendix B. As a result of this response, the Virginia Coal and Energy Commission took no position on this proposal.

D. ELECTRICITY TRANSMISSION PROBLEMS

The early 1920's marked the advent of electrical transmission lines. Prior to that time, generation plants were always located close to the areas of greatest demand: in the center of cities. The construction of electrical transmission lines now allows power companies to locate their generation facilities at more economically favorable locations. Despite the availability of power lines, adequate transmission still remains a problem as population, particularly in urban areas, continues to grow.

Electricity cannot be directed. It flows according to the laws of physics: towards the area of least resistance. As a result, some of the electricity destined for Canada and New York flows through Virginia Power's strong transmission lines. Testimony indicated that Virginia Power's transmission lines sometimes carry as much as twenty-five percent of the power destined for Pennsylvania and Maryland. Virginia Power's transmission system was initially designed and constructed to provide for the reliable transmission of electricity to Virginia Power's customers. The system was not designed to bring in large amounts of power on a daily basis, one quarter of which flows to other states' customers. As a result, the transmission capacity of these lines now prevents Virginia Power from bringing in the amount of power necessitated by the increased demand for electricity within the Commonwealth.

Virginia Power is not unique in its transmission problems. Because of rapid growth and development along the east coast of the United States, transmission problems are being experienced by many companies. North America is divided into geographical sectors called reliability councils, which work together to ensure the reliability of each transmission system. The Southeastern Reliability Council, of which Virginia Power is a member, is currently involved with the other reliability councils in a study of how best to strengthen the transmission systems so as to be able to bring in more power.

In an effort to increase transmission capability, the Commission discussed the possibility of connecting generation plants located in the coal fields of Southwest Virginia with eastern Virginia's transmission system. Testimony indicated that interests in the coal fields would like to build cogeneration plants, fueled by coal, and ship the power out to the eastern half of the state; however, Southwest Virginia is in the Appalachian Power Company's (APCO) service area. APCO has a 765,000 volt line running through the coal fields. Virginia Power's and APCO's transmission systems are currently interconnected only as far west as Cloverdale, Virginia. Testimony indicated that the most efficient means of moving power from Southwest Virginia to Virginia Power's transmission system would be to extend APCO's lines to the east. This would have the additional benefit of strengthening the interconnected transmission system as a whole.

E. AN UPDATE ON THE VIRGINIA COAL INDUSTRY

The Director for the Virginia Center for Coal and Energy Research provided the Commission with information on Virginia's coal industry taken from a number of recent summaries prepared by the Center. Copies of these summaries are attached to this report as Appendix C.

The first summary explains a recent system created by the Center entitled the "Virginia Coal and Energy Data System." According to the Director, this system will be useful for trend analysis and forecasting, identification of policy needs, and evaluation of existing programs of policy. He indicated that the data would be reported on an annual, semi-annual or quarterly basis. Data currently logged into the system cover such areas as coal production, oil and natural gas production, coal marketing, electricity, natural gas and petroleum product marketing, and energy consumption. The system also includes a directory of all licensed coal mines in Virginia. The Commission was informed that an analysis of the coal data from the system showed that 1988 would be a very bright year for the coal industry. The Director stated that Virginia's current coal production is about twenty percent ahead of last year's production. Should this trend continue, Virginia's 1988 production could exceed 50 million tons. Historical data on production trends indicate that the Virginia coal industry is quickly becoming a three-county industry, with Dickenson, Wise, and Buchanan counties producing 40 out of the 45 million tons mined annually in the Commonwealth.

The second summary, entitled "State Energy Policy to Enhance Coal Production: The Virginia Coal Incentive Acts," focuses on the Virginia Coal Employment and Production Tax Incentive Act of 1986. The summary indicates the act is having a positive effect on the economy of Southwest Virginia, but predicts that the benefits resulting from the act in 1988 would not be as positive as those in 1987 because the revenue loss is much greater due to the additional one dollar per ton tax credit offered in 1988. The 1988 legislation which offers a similar credit to cogenerators was also discussed. The Director indicated that he had surveyed a number of cogenerators who indicated that the $1 credit would have an effect on their decision to purchase Virginia coal. He predicted that the new bidding rules of the State Corporation Commission, in conjunction with the cogeneration tax credit, will enhance the prospects for Virginia coal-fired capacity in this and future competitive bidding solicitations by Virginia Power.

The third summary, entitled "Coal Use by Manufacturing Sector in Virginia," is a report from a study initiated to evaluate coal use in Virginia by the manufacturing sector. Results of the study demonstrate that the market for coal use in the manufacturing sector is substantial: between 3 and 3.7 million tons per year as compared with approximately 9 million tons used by the utilities sector. The results of the study also show that a few large firms dominate the tonnage of coal used by non-utility industries.

The fourth summary, entitled "Competition In The International Coal Market: Recent Trends And Prospects For U.S. Exports," outlines the trends and shifting patterns in the world coal market and comments on recommendations by the Federal Coal Export Commission for improving the competitiveness of the U.S. international coal trade. While the United States contributed more than forty percent to the world coal export tonnage in 1981, that percentage dropped to twenty-three percent in 1987. Figures for the first half of 1988 show an increase in total U.S. coal exports, but this is believed to be due to an overall expansion in the global market.

The Commission was told that Australia is the United States' largest competitor in the international coal market. Although Australia is cutting into Virginia's international coal markets, the United States is still the world leader in coal exports. Additionally, the Hampton Roads area is very important to the United States because it is the port from which more than one-half of all U.S. produced coal is shipped.

The fifth summary, entitled "The Revolution in Electric Utility Planning: Least-Cost Planning, Competitive Bidding, Transmission Access," describes the impact of the following issues on electrical power planning by utilities in the United States: least-cost, or integrated utility planning; competitive bidding for electricity supply; and transmission access, or wheeling of power.

F. LIQUID COAL TECHNOLOGY

The Commission received information regarding the current status of liquid coal technology. Liquid coal is created by separating all the liquids from the raw material. Two products are created by this process: liquid coal and char. The United Coal Company has developed a liquid coal diesel fuel which can be burned in current model diesel engine automobiles. No modifications to the engine are required before burning this type of fuel. The Commission was told that technology is currently being developed by which liquid coal can be blended with oil to produce a higher performance fuel than can be manufactured through the use of liquid coal or oil separately. The Commission was urged to endorse legislation which provides a tax incentive for the use of fuel which contains a certain percentage of liquid coal. It was suggested that this type of incentive would hasten the development of this technology. Although it is estimated that a gallon of liquid coal fuel might cost $100 to produce, the fact that the char could also be sold would make it cost effective to produce such fuel. Char is a desirable fuel because it burns at a higher B.T.U. than oil and creates virtually no smoke. The Commission was told that the cost of the liquid coal fuel would be competitive with the price of gasoline.

G. THE BIDDING PREFERENCE FOR VIRGINIA-MINED COAL

The Commission was informed that § 11-47.1 of the Code of Virginia, which provides a four percent preference in the competitive bidding process for the purchase of Virginia-mined coal for use in state facilities, is scheduled to sunset on June 30, 1989. This section was originally enacted during the 1987 Session of the General Assembly in an effort to stimulate the Virginia coal industry and the economy of Southwest Virginia.

Testimony by a spokesperson for the Department of General Services indicated that this legislation was having its intended effects. During fiscal year 1987/1988, the legislation accounted for additional expenditures by the state of $47,522 and $48,600 in fiscal year 1988/1989. Additional expenditures in fiscal year 1989/1990 are predicted to be the same as the previous year. However, coal awards by the Department of General Services for 1988/1989 totaled 70,400 tons of Virginia-mined coal out of 126,830 total tons purchased. This tonnage represents an increase of eight and one-half percent over coal awards made to Virginia producers in 1987/1988, a twenty percent increase in 1986/1987 coal awards, and a twenty-nine percent increase over coal awards made in 1985/1986. Testimony indicated that for every one million tons of coal purchased, 298 mining jobs are created.

After hearing the foregoing testimony, the Commission voted unanimously to endorse legislation which would extend indefinitely the bidding preference provided for in § 11-47.1 of the Code of Virginia. A copy of the proposed legislation is attached to this report as Appendix D.

III. SUBCOMMITTEE ACTIVITIES

A. THE COAL SUBCOMMITTEE

At its only meeting during 1988, the Coal Subcommittee received testimony regarding the United States Department of Energy's Clean Coal II Program. The Clean Coal II Program provides up to fifty percent funding for demonstration and innovative technologies which are capable of retrofitting or repowering existing facilities. The Clean Coal II Program therefore differs from the Clean Coal I Program, which was instituted in 1967 and for which only new technology projects qualified.

The Clean Coal II Program requires that technologies proposed must be: (1) capable of commercialization in the 1990's; (2) more cost-effective than current technologies; and (3) capable of achieving significant reductions of SO_2 and/or NO_x emissions from existing coal-burning facilities. The Clean Coal II Program also specifies that the government is to be paid back by the technology owner over a period of twenty years from a percentage of revenues from sales of any technology developed through the Program. Net funds available for award under this program totaled $536 million.

Fifty-four proposals, representing $5.3 billion worth of projects, were submitted to the Department of Energy (DOE) for the Clean Coal II Program. Of the fifty-four proposals received by DOE in Clean Coal II, thirty-four of these projects involve electric utilities. Testimony indicated that the response to Clean Coal II has been far greater than the response to Clean Coal I. To date only eight projects have been accepted by DOE under the Clean Coal I Program.

Subcommittee members were told that Virginia Power had proposed two projects for consideration by DOE under the Clean Coal II Program. The first project, entitled the Yorktown Demonstration Post Combustion Dry Sorbent Injection Project, was described to the subcommittee in detail. The project is intended to demonstrate three types of sulfur oxide emission control technologies as well as to reduce nitrous oxide emissions. Virginia Power's objective in this project is to reduce sulfur oxide emissions by fifty percent or more while providing technical, economic and operating data to market these technologies and make their use by Virginia Power royalty free. The total cost of the project will be $37 million, of which Virginia Power would contribute $11.6 million and EPRI would contribute $3 million. Funding from DOE was requested at the full fifty percent level.

Testimony indicated that the Commonwealth would benefit in a number of ways should DOE select this project. First, Virginia Power would be able to select the lowest cost emissions compliance strategy, thereby reducing the burden on electrical rate payers. Secondly, lower relative electric rates would help maintain Virginia's competitive position for economic development. Finally, these types of technologies could help protect Virginia's share of the coal market (a low surfur type coal) by providing environmentally acceptable and more economical alternatives to current emissions control technology (e.g. water scrubbers).

Virginia Power's second project, entitled the Mount Storm Integrated CFBC With Advanced Coal Cleaning Project, is proposed to be conducted at the company's plant in Mount Storm, West Virginia. The purpose of this project is also to provide a reduction in sulfur oxide emissions through technology other than extremely expensive water scrubbers.

The subcommittee agreed to endorse the Yorktown Project and a letter of support from the Commission was forwarded to Secretary of Interior John S. Herrington. A copy of this letter is attached as Appendix E. At its last meeting of the year, the Commission was informed that Virginia Power's proposed project at Yorktown had been accepted and that contract negotiations for funding had begun.

B. THE ENERGY PREPAREDNESS SUBCOMMITTEE

During 1988, the Energy Preparedness Subcommittee received updates on the following topics: oil overcharge funds, activities of the Department of General Services' energy team, state energy expenditures, and the Commonwealth's energy emergency plan.

1. Oil Overcharge Funds

The subcommittee received a description of some of the state programs which can be funded in part through the use of oil overcharge funds. Five of these programs can be funded with Exxon oil overcharge funds. Funding in 1988-89 for the Low Income Home Energy Assistance Program (LIHEAP) is estimated at $27 million from the federal government and $6,785,000 from Exxon oil overcharge funds. Testimony indicated that the federal government has been cutting its allocations to these programs and is looking to states to make up the difference with oil overcharge funds. For example, the federal allocation for LIHEAP in 1985 was $40 million. LIHEAP provides supplements of $230 in fuel costs to 109,685 households. The Weatherization Assistance Program (WAP), with approximately $7.5 million in funding, provided energy improvements of up to $1,600 for 4,563 homes in fiscal year 1987-88. Seventy-one percent of these homes were owner-occupied. The Institutional Conservation Program of DMME annually serves about twenty institutions and forty buildings, including schools and hospitals.

Stripper Well funds have enabled the state to enter into a partnership with Virginia Power and the Pacific Gas and Electric Company to study a photovoltaic demonstration project at Virginia Power's North Anna Nuclear Power Station. The total cost of the project is estimated to be $600,000; a $200,000 grant has been approved for 1988-89. United Coal Company utilized a $600,000 grant during 1987-88 for the development and testing of liquid coal fuels. The Department of Housing and Community Development (DHCD) began administering a $20 million energy improvement loan program for low and moderate-income families in July of 1988. The program, which was established by the 1988 Appropriations Act, offers forgivable loans over a four-year period.

Commission members were told that there will be a shortfall of oil overcharge funds in 1991-92. Only one large settlement remains undistributed. The settlement, in which Texaco has set aside about $1.25 billion to be paid over five and one-half years, would provide an estimated $17 million in funds for Virginia's programs. The Commission was told that disbursement of proceeds from this settlement will not begin until at least late 1989.

2. Department of General Services Energy Team

The subcommittee also received an update on the Department of General Services' (DGS) energy team. This team has historically received no general fund support and has been forced to rely upon funding by DMME from oil overcharge funds. In order to qualify for funding from the DMME, the DGS entered into a contract with DMME for the Energy Conservation Program. The DGS made seven specific agreements with DMME. First, the DGS agreed to prepare reports on energy use in all state facilities, including recommendations on reducing energy inefficiency where found. Secondly, the DGS is required to visit at least twenty state facilities and provide training to facilities' managers and operators on energy conservation measures. Preliminary results of these visits indicate that facilities have two general complaints: insufficient funding for energy needs and no incentive to save energy.

The DGS also agreed to review building designs and proposed energy systems for new construction and renovation projects to ensure maximum energy efficiency and the best fuel source. The DGS has developed energy standards and design criteria to be used in all new construction and renovation projects.

The DGS is also required to monitor the effects of demand rates in selected facilities and to assist users in reducing costs. To accomplish this task, the DGS evaluated more than 3,700 individual electric meters to determine under which of the two new rate schedules each of the accounts should be placed. The DGS has also conducted six seminars to educate facility managers on the effects of demand. Through these evaluations and seminars, the DGS has saved an estimated $2 to $3 million in energy costs.

DGS also agreed to identify and rank state facilities with the largest potential for cogeneration. Subcommittee members were told that the Medical College of Virginia and Virginia Commonwealth University are ranked first because both institutions now need to replace their boiler plants, they both have a distribution system in place and they both have a constant need for steam.

Additionally, DGS is required to assist facilities in the procurement of high efficiency energy equipment. DGS has contacted the Treasury Department and has worked out an agreement for facilities to request Treasury Board financing for the purchase of high efficiency energy equipment, which they will pay back through their savings. These loans are currently running at about eight percent, with state funds used as collateral. To date, the Department of Mental Health has been the only entity to take advantage of this opportunity, although other agencies have shown interest.

Finally, the DGS is required quarterly to prepare and submit financial information reports to DMME's Division of Energy.

3. State Energy Expenditures

Subcommittee members were also provided with information regarding the state's energy expenditures over the past year. Expenditures for energy in 1988 totaled $99 million, which represents almost a ten percent increase over 1987 expenditures.

State institutions have dramatically increased their use of oil and electricity, although most state facilities are designed to burn multiple fuels. Prior to the increase in oil prices it was financially advantageous to burn oil rather than coal because of the maintenance costs and manpower necessary to fire a coal boiler. Prisons have historically burned coal, utilizing prisoners for labor in their boiler plants. Testimony indicated that prisoners are no longer permitted to work in these plants and, as a result, almost all prisons now utilize oil.

In 1987-88, electricity costs accounted for approximately eighty percent of the Commonwealth's total energy expenditures. Electricity accounted for sixty-nine percent of the Commonwealth's energy expenditures in 1984. Electricity consumption in state facilities is currently growing each year by eight percent. Testimony indicated that one reason for increased electrical consumption is that almost every state employee now uses a computer. While these computers do not require an inordinate amount of energy, they generally must be used in an air conditioned environment, which does require a large amount of energy. Air conditioning has almost become standard in the construction of all state facilities, instead of the luxury item it was a decade ago. Because air conditioning is now given funding priority over items in the maintenance budget, the funding for energy automation systems, which control electrical consumption, has been cut.

It was predicted that if state facilities do not reduce their use of electricity, Virginia will be paying $100 million a year by 1990 for energy expenditures, eighty-seven percent of which will be for electricity. The subcommittee was told that the Commonwealth should re-educate state facilities' managers regarding the use of electricity, should provide them with incentives to help stop this trend, and should set reduction goals for state facilities.

4. The Commonwealth's Energy Emergency Plan

The subcommittee also received testimony regarding the status of Virginia's energy emergency plan. According to a spokesperson for the Department of Emergency Services, energy emergency responsibilities are shared by the Department of Emergency Services and DMME's Division of Energy.

The Department of Emergency Services is the entity with primary responsibility should a petroleum shortage occur. Until 1981, the federal government controlled the pricing and allocation of petroleum products. With the advent of de-regulation in 1981, the federal government now relies on free market factors to govern these matters.

In 1977, the federal government initiated the Strategic Petroleum Reserve Program. This program utilizes salt caverns in Louisiana and Texas as storage tanks for crude oil. With a total capacity of 545 million barrels, these caverns could provide the country with enough oil to function for ninety-five days. Should the United States be unable to import crude oil, the current federal plan authorizes the President to sell this stockpiled oil on the open market. This current plan represents a major change in policy as the old plan called for the use of the reserves as a last resort, when states' efforts to address the problem had failed. As currently written, the plan calls for a draw on the reserves as soon as a shortage is identified, meaning when allocations decrease by more than ten percent. Due to this change in federal policy, testimony indicated that the responsibility of dealing with petroleum shortages will have to be dealt with at the state level through the distribution of information to the public, conservation activities and interstate cooperation.

The legal authority for a state response to an energy emergency is found in § 44-146.18 of the Code of Virginia. Under that section, the Department of Emergency Services has developed its Emergency Operations Plan, which includes provisions for dealing with the emergency management of resources. While the plan assigns petroleum and coal shortage responsibilities to the Department of Emergency Services, the State Corporation Commission is given responsibility for dealing with shortages of natural gas and electricity.

The Emergency Operations Plan requires that the Departments of Emergency Services and Mines, Minerals and Energy track markets and supplies so that the extent and durations of potential shortages may be predicted. This information is gathered from the emergency services coordinator of each jurisdiction in the Commonwealth. Should a severe shortage occur, the plan requires the convening of the Resource Management Advisory Board, which is composed of industry leaders, and the Emergency Resources Committee, which is composed of state agency representatives. These two groups would then be responsible for providing the Governor with recommendations regarding the crisis.

If a shortage were to occur, voluntary conservation or mandatory restraint measures could be implemented. In addition to the Department of Mines, Minerals and Energy conducting an extensive public education campaign to encourage fuel-saving activities, the Department of Emergency Services could utilize an odd/even fuel sales program or other type of minimum purchase plan in order to manage available supply. In severe shortages, the Department of Emergency Services has the authority to institute mandatory restraint measures such as four-day work weeks, lower speed limits and mandatory temperature controls. The Department of Emergency Services also has the authority to implement a state set-aside program. This program would allow the Department to control up to three percent of the available petroleum imported into the state for purposes of offsetting regional or statewide supply imbalances. Should the shortage be statewide, this set-aside could be used to ensure supply to critical priority users, such as emergency crews, hospitals and fire departments.

Virginia, through the Department of Emergency Services, participates in the Tri-State Coordinating Agreement with Maryland and the District of Columbia. The Commonwealth also participates in the Mid-Atlantic Coordinating Agreement with Maryland, the District of Columbia, West Virginia, Delaware and Pennsylvania. These agreements ensure coordination before individual conservation actions are taken and require a forty-eight-hour notice to be given to other parties to the agreement before any action is taken.

IV. RECOMMENDATIONS OF THE COMMISSION

1. That the bidding preference contained in § 11-47.1 of the Code of Virginia for the purchase of Virginia-mined coal to be used in state facilities be extended indefinitely. A copy of legislation effectuating this recommendation is attached as Appendix D.

Respectfully submitted,

Daniel W. Bird, Jr., Chairman
A. Victor Thomas, Vice-Chairman
James F. Almand
John C. Buchanan
Charles J. Colgan
J. Paul Councill, Jr.
Cynthia J. Dahlin
John S. DiYorio, Ph. D.
Jerry D. Duane
Sandra E. Dysart
Virgil H. Goode, Jr.
W. Thomas Hudson
Glenn B. McClanan
Everard Munsey
Frank W. Nolen
Lewis W. Parker, Jr.
Ford C. Quillen
Alson H. Smith, Jr.
John Watkins
Richard A. Wolfe, Ph. D.
Donald A. McGlothlin, Sr., Ex-offico

APPENDIX A

COMMONWEALTH of VIRGINIA

COAL AND ENERGY COMMISSION
General Assembly Building
910 Capitol Street

POST OFFICE BOX 3-AG
RICHMOND, VIRGINIA 23208

IN RESPONSE TO
THIS LETTER TELEPHONE
(804) 786-3591

September 23, 1988

Honorable John W. Warner
The United States Senate
421 Russell Senate Office Building
Washington, D.C. 20510

Dear Senator Warner:

With the prospect that acid rain legislation may be considered by Congress during the remaining days of this session, the Virginia Coal and Energy Commission would like to re-emphasize certain principles that we believe should be incorporated in any acid rain legislation enacted by Congress.

First, the legislation should allow the utilities the flexibility to achieve mandated standards at the lowest possible cost. This requires that:

1. the legislation must not preclude or create a bias against the use of lower sulfur coals; and
2. utilities must have the option of meeting the emission standard over their system as a whole (under a "system bubble"), regardless of whether they use low sulfur coal or technological means of achieving the standard.

Second, the emissions standard should be a reasonable one which does not impose excessive costs in relation to the marginal benefits. This means that the standard for SO_2 emissions should not be lower than 1.2 lbs/MBTU. In many cases, use of low sulfur coal would be the least costly means of compliance if the emissions standard is 1.2 lbs/MBTU or more. A more stringent standard would prevent the use of coal switching and result in an increase in compliance costs that would be disproportionate to the value of the incremental emissions reductions.

Once an emissions standard is established by legislation, compliance should not be complicated by additional requirements for certain percentage reductions from a base. Those additional requirements are likely to prevent achievement of the standard in the most economical manner possible and unnecessarily increase costs to consumers.

Third, the approach suggested recently of giving priority attention to specific plants with high emissions levels seems reasonable. But if this is done as a first phase in emissions reductions, any second phase should adhere to the principles described above.

We believe these principles will serve the best interests of Virginia's coal producers and electricity customers. The Commission respectfully requests that you introduce or support amendments, as needed, to incorporate these principles in any acid rain bill that may be enacted by the 100th Congress.

Sincerely,

Daniel W. Bird, Jr. / JTH

Daniel W. Bird, Jr., Chairman
Virginia Coal and Energy Commission

cgw

APPENDIX B

Co[...]

ESTON C. SHANNON
CHAIRMAN
[...]MAS P. HARWOOD, JR.
COMMISSIONER
ELIZABETH B. LACY
COMMISSIONER

GEORGE W. BRYANT, JR.
CLERK OF THE COMMISSION
BOX 1197
RICHMOND, VIRGINIA 23209

STATE CORPORATION COMMISSION

January 17, 1989

The Honorable Daniel W. Bird, Jr.
Chairman, The Virginia Coal
and Energy Commission
525 W. Main Street
P.O. Box 628
Wytheville, Virginia 24382

Dear Senator Bird:

Thank you for your letter of January 10, 1989, seeking our comments on the draft legislation exempting independent power producers from regulation by the State Corporation Commission.

The Commission opposes this proposal. We do not feel it in the public interest of the citizens of Virginia to encourage the building and proliferation of these plants free of any current regulatory constraints. If enacted, this proposal would remove the control and oversight the Commission has traditionally exercised over the siting of generation plants, the determination of the public's need for such plants, their sizing, fuel mix, reliability criteria, operating characteristics, financial capabilities, etc. In short, there would remain no mechanism under Virginia law under which a statewide determination of the public interest for any such proposed plant would be assessed. The oversight and control of such projects would be relegated to local zoning and land-use restrictions, none of which can be expected to exercise a perspective of the overall worth of the plant to the state's utility grid and power generation system.

A few examples of the types of dangers inherent should such enterprises be given free reign in Virginia will illustrate our misgivings. There is nothing in the legislation which would prevent, for example, independent power producers from <u>building</u> in Virginia yet <u>selling</u> the power out of state. This fact alone could encourage plants to be built near Virginia's borders with other states, thus ensuring that the environmental problems would inure to Virginia, while the benefits of the power generated would be transferred to other states.

Secondly, the legislation would not prevent independent power producers from building transmission lines of whatever size desired. (We realize, of course, that such firms would not have the power of eminent domain, but assuming they could purchase suitable corridors, they would not be subject to the restraints of Va. Code § 56-46.1, which requires a full assessment of the public interest before transmission lines of greater than 150 kv can be constructed.)

Third, one of the objectives of the Public Utility Regulatory Policies Act of 1978 (PURPA) was to foster more efficient use of energy by encouraging cogenerators to make dual use of energy, first, at the industrial process level, and secondly, to generate electricity for sale off-site. Such a goal would not be furthered by the suggested legislation, since there is no requirement in the draft that such power producers be paired with an industrial host for any such complementary use of energy.

Fourth, the Federal Energy Regulatory Commission, not this Commission, would set the price for power produced by these plants, since it would be a wholesale transaction. Virginia ratepayers could thus be saddled with costs from plants built free from any effective state regulatory oversight.

Finally, on a related point, we must note that this draft legislation is tailor-made for certain of our utilities which have evidenced considerable recent interest in diversification outside their traditional sphere of regulated utility operations. For example, an article in the January 16, 1989, issue of the Richmond News Leader, page B1, copy enclosed, notes that Dominion Energy Inc., a subsidiary of Dominion Resources, is heavily involved in independent power production activities in other states. The article also reports that the same is true of Missions Energy Company, a subsidiary of Southern California Edison, and goes on to state:

> Oddly enough, Dominion is developing projects in California to sell electricity to Southern California Edison, and Missions Energy is part of a cogeneration venture in Hopewell that sells to Virginia Power.

Contrary to the newspaper, this situation does not seem odd to us at all, but is precisely the type of relationship which we would expect to see develop should Virginia opt for the total deregulation of such facilities. The chances of detrimental results to the public from having large utilities engaged in presumably mutually beneficial projects in each other's states would be substantially enhanced by this legislation.

In conclusion, this Commission is of the opinion that it needs regulatory oversight and control over independent power producers for the same public interest reasons that it is vested with control over similar generation facilities built by the state's regulated utilities. We would encourage the Coal and Energy Commission, and the General Assembly, not to endorse or support this proposed legislation.

Sincerely,

Preston C. Shannon
Chairman

PCS:sj
Enclosure

cc: John T. Heard, Staff Attorney,
Division of Legislative Services

VIRGINIA COAL AND ENERGY DATA SYSTEM (VACEDS)

A computerized data base for monitoring coal and natural gas production, distribution, and marketing; electricity generation, transmission, and sales; petroleum product sales; and energy consumption by fuel and by sector; and other information.

The system will be useful for trend analysis and forecasting, identification of policy needs, and evaluation of existing programs and policies. Data will be reported in annual, semi-annual or quarterly updates.

Data currently logged into the system include:

- **Coal Production**
  - Annual Virginia coal production by mining method, by county
  - Annual Virginia coal employment, payroll by county
  - Weekly Virginia coal production
  - Annual Virginia coal production by mine, by company

- **Oil and Natural Gas Production**
  - Annual natural gas production by county, by company
  - Annual oil production by field

- **Coal Marketing**
  - Monthly quantity cost and quality of steam coal deliveries to Virginia power plants by state of origin
  - Monthly quantity, cost, and quality of steam coal deliveries to out-of-state power plants using Virginia coal by state of origin

- **Electricity**
  - Monthly Virginia sales of electricity by sector
  - Monthly Virginia generation of electricity by fuel source
  - Monthly fuel consumption and generation at Virginia fossil fuel stations by plant
  - Monthly generation at Virginia nuclear and hydro electric stations by plant
  - Annual Virginia sales of electricity by utility

- **Natural Gas and Petroleum Product Marketing**
  - Monthly Virginia natural gas deliveries and average price by sector
  - Annual Virginia natural gas sales by company
  - Monthly Virginia sales of petroleum products for consumption
  - Monthly Virginia prices of petroleum products to end users

- **Energy Consumption**
  - Annual Virginia energy consumption by fuel type and by sector

Examples of data and data displays are given on the following pages.

VIRGINIA COAL PRODUCTION SUMMARIES: 1985/86/87

	1985	1986	1987
Number of Mines	681	656	606
Total Production	42,376,484	41,768,142	45,537,960
Surface Operations	13,905,302	12,348,832	11,649,994
Underground Mines	28,471,182	29,420,002	33,887,966
Cont. Miner	23,479,854	22,780,101	25,570,512
Longwall	4,991,328	6,639,901	8,317,454
Production Workers	12,621	13,107	13,648
Surface	2,949	3,434	3,207
Underground	9,672	9,673	10,441
Production Wages	$294,984,647	$303,365,551	$349,855,186

Source: Virginia Division of Mines, Big Stone Gap.

VIRGINIA COAL SHIPMENTS

1988			*	1987			
WEEK END	AMOUNT	TOTAL	*	WEEK END	AMOUNT	TOTAL	TOTAL % CHG
1/02	573	573	*	1/03	459	459	+24%
1/09	865	1,438	*	1/10	744	1,203	+20%
1/16	839	2,277	*	1/17	751	1,954	+17%
1/23	1,096	3,373	*	1/24	694	2,684	+26%
1/30	1,022	4,395	*	1/31	662	3,310	+33%
2/06	955	5,350	*	2/07	933	4,423	+21%
2/13	963	6,313	*	2/14	880	5,123	+23%
2/20	947	7,260	*	2/21	789	5,912	+23%
2/27	973	8,233	*	2/28	860	6,772	+22%
3/05	927	9,160	*	3/07	884	7,656	+20%
3/12	952	10,112	*	3/14	870	8,526	+19%
3/19	983	11,095	*	3/21	883	9,409	+18%
3/26	985	12,080	*	3/28	824	10,233	+18%
4/02	797	12,877	*	4/04	733	10,966	+17%
4/09	829	13,706	*	4/11	733	11,699	+17%
4/16	872	14,578	*	4/18	785	12,484	+17%
4/23	903	15,481	*	4/25	773	13,257	+17%
4/30	929	16,410	*	5/02	835	14,092	+16%
5/07	863	17,273	*	5/09	748	14,840	+16%
5/14	903	18,176	*	5/16	806	15,646	+16%
5/21	893	19,069	*	5/23	829	16,475	+16%
5/28	901	19,970	*	5/30	683	17,158	+16%
6/04	783	20,753	*	6/06	1,010	18,168	+14%
6/11	949	21,702	*	6/13	814	18,982	+14%
6/18	932	22,664	*	6/20	880	19,862	+14%
6/25	917	23,581	*	6/27	821	20,683	+14%
7/02	702	24,283	*	7/04	371	21,054	+15%
7/09	412	24,695	*	7/11	429	21,483	+15%
7/16	850	25,545	*	7/18	867	22,350	+14%
7/23	913	26,458	*	7/25	875	23,225	+14%
7/30	986	27,444	*	8/01	874	24,099	+14%
8/06	956	28,400	*	8/08	888	24,987	+14%
8/13	929	29,329	*	8/15	935	25,922	+13%
8/20	964	30,293	*	8/22	1,028	26,950	+12%
8/27	992	31,285	*	8/29	940	27,890	+12%
9/03	978	32,263	*	9/05	939	28,829	+12%

(All figures in thousands of tons)

Source: Weekly Statistical Summaries, National Coal Association

Virginia Center for Coal & Energy Research
Virginia Polytechnic Institute & State University
617 North Main Street, Blacksburg, VA 24060
Telephone: (703) 961-5038

FROM: 1988 VIRGINIA COAL MINE DIRECTORY (in press)

VIRGINIA POCAHONTAS CO	Mine: VP - # 2	Tons-1985: 0	Seam(s): POCAHONTAS # 3
Ken	Phone: 703-597-7426	Tons-1986: 0	Seam Ht.(s): 48/60
L	Type mine: DEEP	Tons-1987: 0	Equipment: CM, SC, RD, SCOOPS
OAKWOOD VA 24631	Mine ID: 05250		Coal Owner(s): BIG VEIN POCAHONTAS
BUCHANAN COUNTY	Employees: 3		Railroad: NS

VP-5 MINING CO	Mine: VP - # 5	Tons-1985: 616,964	Seam(s): POCAHONTAS # 3
Price, Ken	Phone: 703-498-4511	Tons-1986: 838,984	Seam Ht.(s): 50/72
Drawer L	Type mine: DEEP	Tons-1987: 1,255,094	Equipment: LW, CM, SC, RD, SCOOP
OAKWOOD VA 24631	Mine ID: 08776	LWall-1986: 478,773	Coal Owner(s): BIG AXE CO
BUCHANAN COUNTY	Employees: 259	LWall-1987: 875,945	Railroad: NS

WAHTAHSHI LAND & COAL CO	Mine: # 1	Tons-1985: 0	Seam(s): EAGLE
Slone, Jack	Phone: 703-597-7351	Tons-1986: 43,158	Seam Ht.(s): 96
Box 947	Type mine: DEEP	Tons-1987: 66,171	Equipment: LDR, SCOOPS, RD
VANSANT VA 24656	Mine ID: 13452		Coal Owner(s): SOUTHERN KY ENERGY
BUCHANAN COUNTY	Employees: 27		Railroad: NS

WARD BROTHERS INC	Mine: # 1	Tons-1985: 0	Seam(s): CLINTWOOD
Ward, James	Phone: NA	Tons-1986: 0	Seam Ht.(s): 40
Box 489	Type mine: SURFACE	Tons-1987: 0	Equipment: STRIP
JEMERIAH KY 41826	Mine ID: 13804		Coal Owner(s): HARMAN MINING CO
BUCHANAN COUNTY	Employees: 4		Railroad: NS

WELLABY COAL INC	Mine: # 2	Tons-1985: 0	Seam(s): LOWER BANNER
Horne, Roy	Phone: 703-935-7508	Tons-1986: 131	Seam Ht.(s): 60
Box 388	Type mine: DEEP	Tons-1987: 154,839	Equipment: CM, SC, RD, SCOOP
VANSANT VA 24656	Mine ID: 13536		Coal Owner(s): STANDARD BANNER COAL
DICKENSON COUNTY	Employees: 28		Railroad: NS

LMORE COAL CORP	Mine: # 9	Tons-1985: 0	Seam(s): CLINTWOOD
[illegible], Mark	Phone: 703-935-7521	Tons-1986: 2,418	Seam Ht.(s): 42
Box 901	Type mine: SURFACE	Tons-1987: 490	Equipment: STRIP
GRUNDY VA 24614	Mine ID: 12977		Coal Owner(s): UNITED COAL CO
BUCHANAN COUNTY	Employees: 2		Railroad: NS

WEST FORK ENERGY INC	Mine: # 1 TILLER	Tons-1985: 0	Seam(s): TILLER
Harris, William P.	Phone: 703-963-9288	Tons-1986: 0	Seam Ht.(s): 42
106 Suffolk Avenue	Type mine: DEEP	Tons-1987: 6,757	Equipment: CM, SC, RD, SCOOP
RICHLANDS VA 24641	Mine ID: 06291		Coal Owner(s): SEA B MINING
TAZEWELL COUNTY	Employees: 31		Railroad: NS

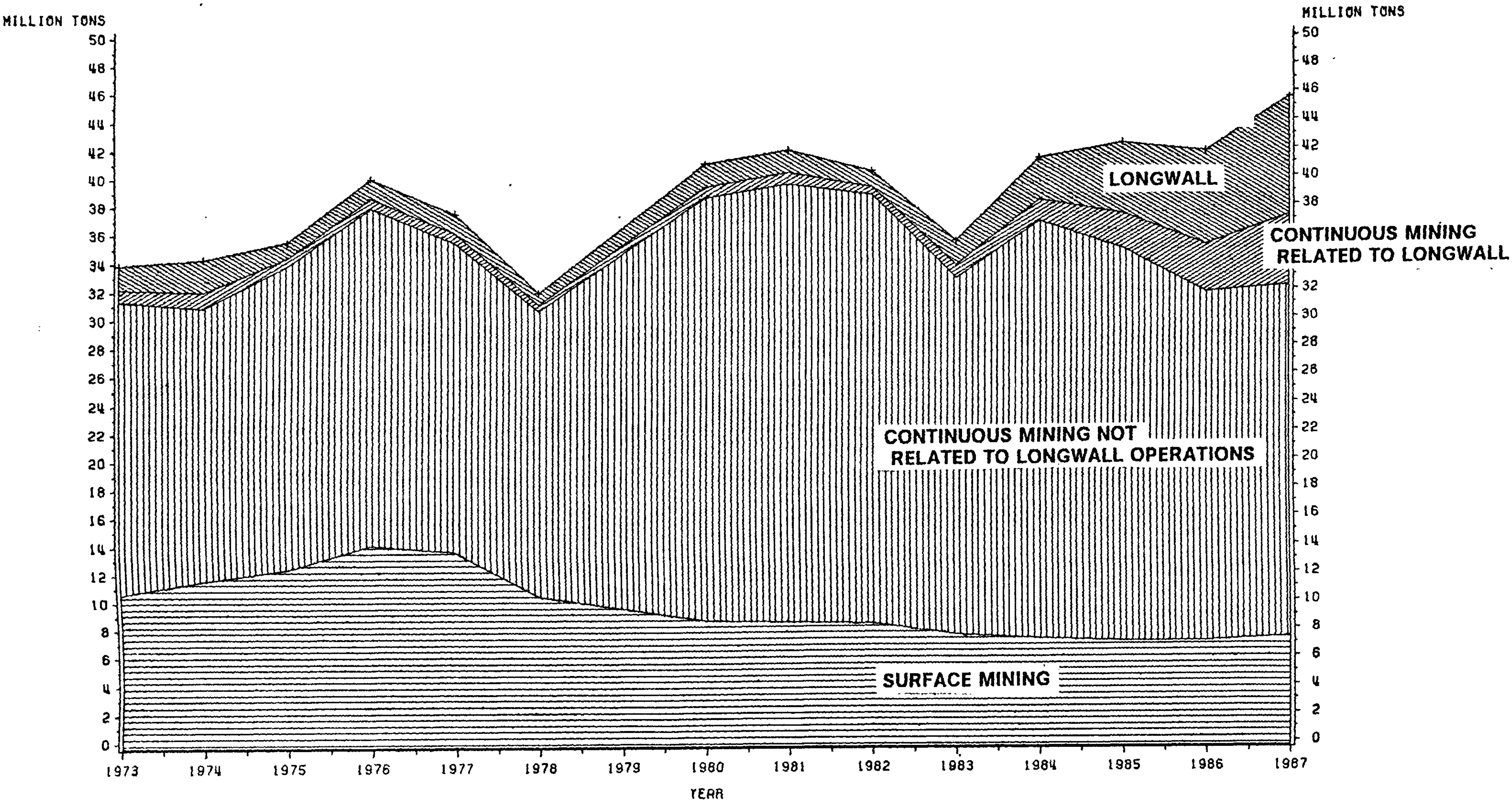
WESTMORELAND COAL CO	Mine: KS # 1	Tons-1985: 0	Seam(s): UPPER STANDIFORD
Taylor, R. E.	Phone: 703-523-4000	Tons-1986: 88,605	Seam Ht.(s): 50
Drawer A & B	Type mine: SURFACE	Tons-1987: 94,032	Equipment: AUGER
BIG STONE GAP VA 24219	Mine ID: 13384		Coal Owner(s): PENN VIRGINIA CORP
LEE COUNTY	Employees: 23		Railroad: NS

WESTMORELAND COAL CO	Mine: KS # 1	Tons-1985: 5,672	Seam(s): UPPER STANDIFORD
Taylor, R. E.	Phone: 703-523-4000	Tons-1986: 12,963	Seam Ht.(s): 50
Drawer A & B	Type mine: SURFACE	Tons-1987: 73,843	Equipment: STRIP
BIG STONE GAP VA 24219	Mine ID: 13379		Coal Owner(s): PENN VIRGINIA CORP
LEE COUNTY	Employees: 23		Railroad: NS

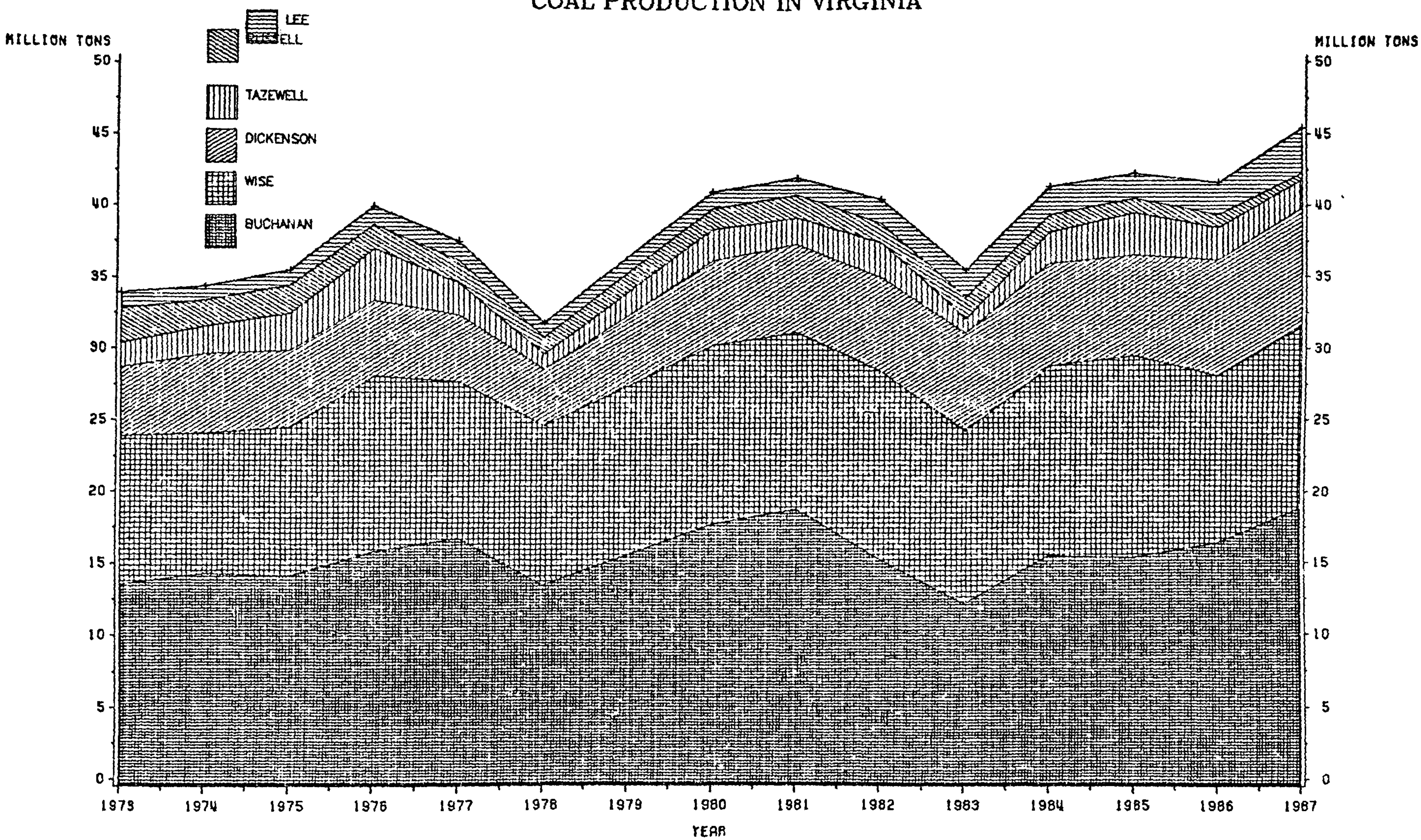
WESTMORELAND COAL CO	Mine: HOLTON	Tons-1985: 783,463	Seam(s): TAGGART
Taylor, R. E.	Phone: 703-523-4000	Tons-1986: 1,138,796	Seam Ht.(s): 48/54
Drawer A & B	Type mine: DEEP	Tons-1987: 1,499,765	Equipment: LW, CM, SC, RC, RD
BIG STONE GAP VA 24219	Mine ID: 09419	LWall-1986: 732,168	Coal Owner(s): PENN VIRGINIA CORP
E COUNTY	Employees: 205	LWall-1987: 307,043	Railroad: NS

FIGURE 1

COAL PRODUCTION IN VIRGINIA BY MINING METHOD, 1973–1987



COAL PRODUCTION IN VIRGINIA



ANNUAL DELIVERIES TO STATES FROM VIRGINIA,

DELIVERIES TO STATE	1987 QUANTITY DELIVERED (TONS)	1987 % OF TOTAL VIRGINIA DELIVERIES	1986 QUANTITY DELIVERED (TONS)	1986 % OF TOTAL VIRGINIA DELIVERIES
** TO_STATE DE ** Subtotal **	0.00	0.00	39.31	0.18
** TO_STATE FL ** Subtotal **	1172.73	4.95	810.25	3.73
** TO_STATE GA ** Subtotal **	3588.49	15.16	3508.38	16.14
** TO_STATE IN ** Subtotal **	369.10	1.56	0.00	0.00
** TO_STATE MA ** Subtotal **	1665.10	7.03	1438.73	6.62
** TO_STATE MI ** Subtotal **	651.00	2.75	678.30	3.12
** TO_STATE MS ** Subtotal **	164.85	0.70	0.00	0.00
** TO_STATE NC ** Subtotal **	4160.40	17.57	5386.70	24.78
** TO_STATE NJ ** Subtotal **	655.00	2.77	554.10	2.55
** TO_STATE OH ** Subtotal **	31.00	0.13	62.10	0.29
** TO_STATE SC ** Subtotal **	855.45	3.61	816.78	3.76
** TO_STATE TN ** Subtotal **	1447.23	6.11	1004.18	4.62
** TO_STATE VA ** Subtotal **	8653.00	36.54	7326.70	33.70
** TO_STATE WI ** Subtotal **	17.82	0.08	37.23	0.17
** TO_STATE WV ** Subtotal **	247.00	1.04		
** TO_STATE AL ** Subtotal **			7.12	0.03
** TO_STATE NH ** Subtotal **			70.80	0.33
*** Total ***	23678.17	100.00	21740.68	100.00

STATE ENERGY POLICY TO ENHANCE COAL PRODUCTION: THE VIRGINIA COAL INCENTIVE ACTS

John Randolph
Director, Virginia Center for Coal and Energy Research
Virginia Polytechnic Institute and State University
Blacksburg, Virginia 24060

Virginia's coal region in the southwest corner of the state has long been dependent on its coal resources for economic livelihood. While national and foreign energy demand has helped increase Virginia coal production modestly during the past ten years, improvements in productivity necessary for industry survival in a highly competitive market have caused a decline in mine employment.

This paper discusses Virginia General Assembly efforts to arrest declining mine employment by enhancing state coal production. The legislature passed laws in 1986 and 1988 providing tax credits for the use of Virginia-mined coal in state utility powerplants and cogeneration facilities. The paper describes the incentives and analyzes their impact on coal production and on the economy of the Virginia coal fields. The dilemma facing the coal fields is introduced below.

COMPETITIVE COAL MARKETS AND DECLINING EMPLOYMENT

Figure 1 shows the advance of the Virginia coal industry from 1900. Until 1950, the industry created opportunities for increased employment and population growth. However, after 1950, mine mechanization increased productivity, and mine employment declined while production increased. Though the shift from oil to coal prompted an increase in employment to more than 15,000 in 1977, further advances in mining productivity led once again to falling employment in the face of rising production. By the early 1980s, unemployment in the coal counties skyrocketed to nearly 20 percent.

Although the region has become accustomed to the booms and busts common to resource extraction industries, most analysts agree that coal industry productivity trends ndicate increasing mine employment in will not be forthcoming. While production increased by 20 percent between 1977 and 1987, mine employment declined by 12 percent. During the past two years, several commissions and studies have stressed the need for economic diversification to break the region's employment dependence on coal-based economy (SWVEDC 1987; Seltzer 1987; Knapp 1986). These reports have recommended a range of policies and programs to improve the prospects for new industry and sources of employment.[1] However, all studies and initiatives agree that diversification of the region's economy is a long-term prospect, and even if achievable will take decades.

In the meantime, far southwest Virginia continues its dependence on coal mining. With increasing productivity, coal production must increase simply to maintain current mine employment. Yet Virginia coal companies continue their struggle to maintain markets in an increasingly competitive industry. After achieving a 41 million tons in 1980, Virginia coal

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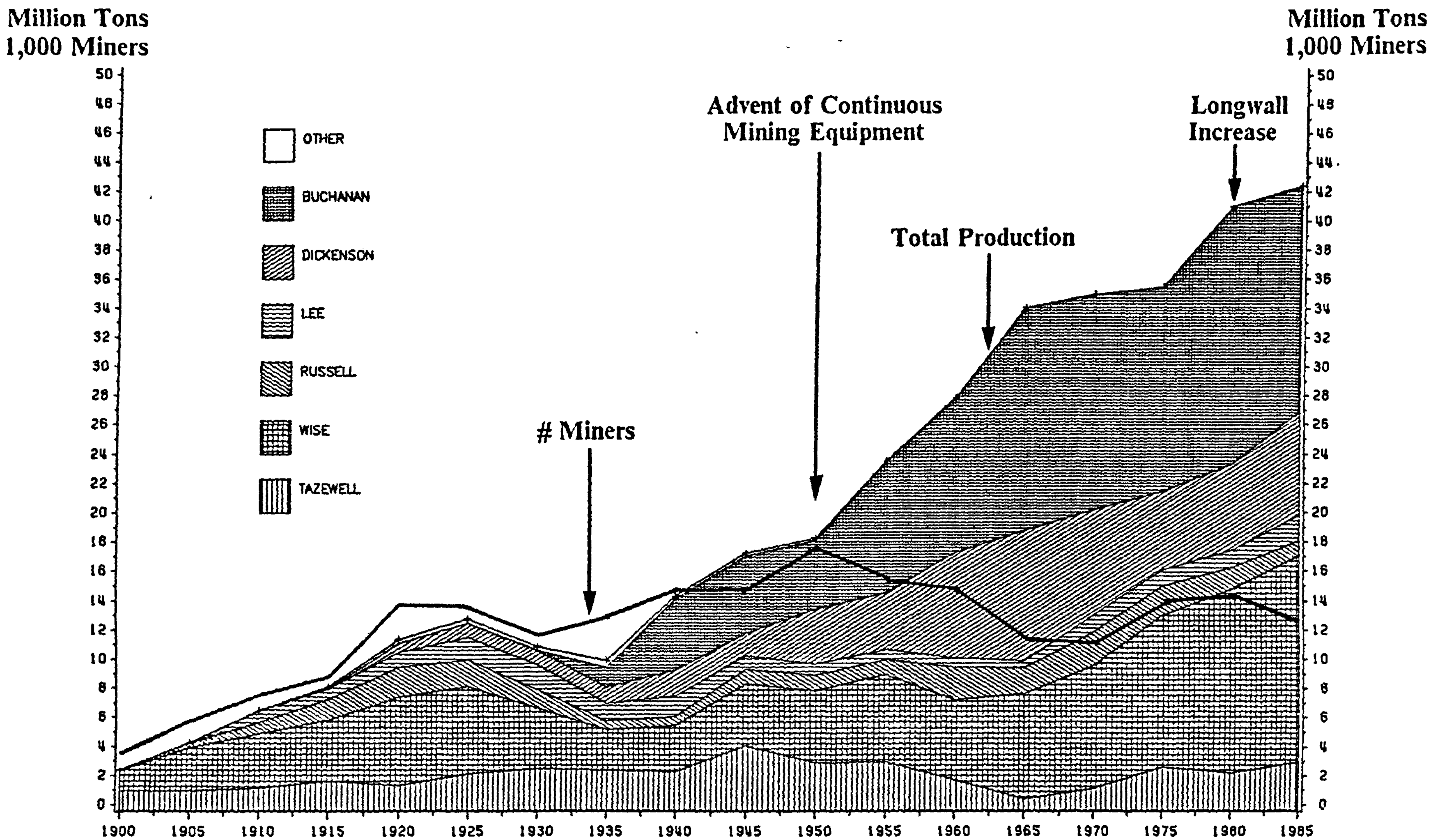
[1] One initiative, the Virginia Coal Fields Economic Development Authority, was established by the Virginia General Assembly in 1988. The Authority will use local coal severence tax proceeds to fund development projects other than coal mining that will add to basic employment (Code of Virginia, Title 15.1, chapter 40).

Figure I: Coal Production in Virginia By County, 1900 - 1985

Data Sources: Hibbard 1987; USGS 1900-1929; USBM 1930-1974; Virginia Division of Mines 1975-1985



production remained essentially stable through 1986, while national production rose by 8 percent.

Several factors have influenced the competitiveness of Virginia coal:

1. Virginia coal resources are estimated 10 percent more costly to mine than other Central Appalachian coal because of generally thinner and deeper seams.
2. Virginia coal has high quality characteristics (ie. low sulfur, low ash, high percentage of metallurgical grade). It has traditionally garnered a higher price on the domestic and foreign met coal market, but cannot maintain that price in steam coal markets.
3. The two traditional markets for Virginia coal (domestic steel and export from Virginia ports at Hampton Roads) have both declined in recent years.
4. Since 1984, decreasing world oil prices have eroded the price of coal, causing closure of many Virginia mines. The number of operating Virginia mines declined by more than 25 percent between 1981 and 1986.
5. Most Virginia mines are "captive" by a single railroad, Norfolk and Western (N&W), which serves almost 88 percent of remaining mines. Some analysts contend that N&W has not been as aggressive as other railroads (particularly CSX, which serves mainly Kentucky and West Virginia mines in central Appalachia) in reducing rail rates to in turn lower delivered coal price and capture additional markets (Hibbard 1986).

These factors have affected the ability of Virginia coal producers to compete in the only increasing coal market, steam coal for electric power generation. This became clear when a study of utility markets showed that Virginia mines were supplying only 20 percent of coal used by powerplants owned by the state's largest utility, Virginia Power Co. (Hibbard 1985). The study indicated that the delivered price of Virginia coal to these plants averaged $1 to $2 per ton higher than coal hauled from Kentucky and West Virginia. These higher prices were a result of higher production costs, higher rail rates, and the fact that some of the utility's powerplants were not located on N&W tracks and could not be easily supplied with Virginia coal.

In 1985, Virginia Power began experimenting with a number of coal supply options. It purchased a shipment of imported Colombian coal for test burning and tried barging coal to increase its transport alternatives. The latter activity enabled the utility to negotiate lower rail rates with CSX. However, it raised the ire of Virginia's coal field politicians, who saw further erosion of markets for state-mined coal.

THE VIRGINIA COAL INCENTIVE ACTS

In an effort to increase the competitiveness of state-mined coal to Virginia's utilities, Delegate Ford Quillen introduced the Virginia Coal Employment and Production Incentive Act in the 1986 General Assembly session. With extensive co-sponsorship, the bill passed easily and was signed into law on April 5, 1986.

Beginning in 1987, the law provided utilities a $1 credit against their state gross-receipts tax for every ton of Virginia-mined coal purchased in excess of 1985 deliveries. Beginning in 1988, an additional credit is provided, amounting to $1 per ton for **all** Virginia coal used. For 1988 and thereafter, Virginia utilities can receive a credit of $1 per ton on purchases equal to 1985 deliveries of Virginia coal, and $2 per ton on purchases above 1985 deliveries.

In late 1987, a preliminary assessment of the Quillen Act's impacts suggested positive effects on coal production and the coal field economy (Randolph and Hibbard 1987). Based on the apparent success of the Act, Delegate Quillen introduced a second bill in the 1988 General Assembly which offered a similar credit for cogenerators. Beginning in 1989, the Act provided a $1 income tax credit for each ton of Virginia coal used by "qualifying facilities" under the federal Public Utilities Regulatory Policy Act.[2] The credit doubles to $2 per ton in 1990.

The passage of the second bill was affected by the state's changing market for cogeneration. In 1987, Virginia Power experimented with a competitive bidding process for acquiring new generating capacity. Based on its success, the utility decided to get out of the business of building new powerplants. Instead, it will rely on competitive bidding to identify and contract with cogenerators and independent power producers to supply needed capacity. After its first solicitation for bids in 1987, the utility contracted with eight facilities, totalling 1,178 mw. More than 85 percent of this contracted capacity will be fueled by natural gas.

Before Virginia Power could proceed with a second solicitation, the Virginia State Corporation Commission (SCC) decided to provide the utility some regulatory guidance. One of the commission's concerns was that the bidding procedure could lead to extensive development of gas-fired capacity. They feared that future increases in the cost of gas could lead to escalation of electrical rates, or worse, a less reliable system if independent cogenerators failed in business. As a result, in its final rules the SCC required that the utility use an evaluation system which considers other factors in addition to bid price, including reliability *and* use of Virginia fuels.

In its second solicitation (March 1988), Virginia Power requested bids for 1,750 mw. In response to the SCC ruling, the utility told bidders that it would evaluate proposals on the basis of price and non-price criteria, including the use of Virginia coal. By the June 1, 1988 deadline, Virginia Power received bids for 96 projects totalling 14,000 mw, 60 percent coal-fired.

The utility will not complete its proposal evaluation until late summer 1988. It is likely that SCC rules in conjunction with the cogeneration tax credit will enhance the prospects for Virginia coal-fired capacity in this and future competitive bidding solicitations.

IMPACTS OF VIRGINIA COAL INCENTIVE ACTS

In assessing the impacts of the tax incentives two key questions must be addressed:

1. What are the purchases of Virginia coal compared to what they would have been without the laws?
2. What are the effects of any increased Virginia coal production on state revenues and local revenues, employment, and income?

The 1986 utility tax incentive has had a full year of implementation, and its effects on Virginia coal purchases are assessed in the following section. The 1988 cogeneration tax incentive will not begin until 1989, so actual data on its impacts will not be available for some time. However, a discussion of its potential impact on coal purchases is provided below. The paper concludes with an analysis of the economic effect of increased coal production.

Impact of the 1986 Incentive Act on Utility Coal Purchases

As discussed above, the 1986 bill responded to the coal purchase decisions of Virginia Power Co., but was meant to affect all coal-using utilities in the state. Appalachian Power Co. (APCO) operates two coal-burning powerplants in southwest Virginia. Being close to the Virginia coal fields and on the Norfolk & Western tracks, these plants have traditionally relied on Virginia coal for more than 90 percent of its purchases; and since 1982, APCO plants in the state have relied exclusively on Virginia coal (NCA 1988a). As a result, the incentive has

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[2] These include small power producers (which use at least 75 percent renewable energy such as wood) and cogenerators.

no effect on APCO's purchase decisions. Potomac Electric and Power Company (PEPCO) operates the coal-burning Potomac River plant in Alexandria, which has been an important market for Virginia coal (more than 500,000 tons of Virginia coal [50-70 percent of the plant's demand] have been used in each of the past three years [NCA 1988a]). However, PEPCO sold its Virginia service area to Virginia Power Co. in late 1986 and thus has no Virginia revenues. Because the law provides a credit to the tax bill on company revenues earned in the state, the utility has nothing on which to claim it. Thus, the credit will have no effect on PEPCO's coal purchases.

That leaves Virginia Power as the utility most affected by the Quillen Act. The utility operates five coal-burning powerplants in the state. Its Chesapeake Energy Center is served by N&W railroad, and has traditionally used a high percentage of Virginia coal. Because the utility's Bremo Bluff and Yorktown facilities are served by CSX railroad, they have used very little Virginia coal. Its large Chesterfield and the Possum Point plants are also on CSX tracks; coal from Virginia mines served by N&W can reach these plants, but requires short transfer hauls on CSX tracks (for which CSX charges a fee). CSX does serve a few Virginia mines in Dickenson and Wise Counties, but from there its tracks run into Kentucky and require a long, circuitous, and expensive haul to reach Virginia Power's plants. These transportation factors affect the delivered cost of Virginia coal and influence the utility's coal purchase decisions.

To determine the effect of the tax incentive on Virginia Power coal purchases, it is necessary to estimate the quantity of Virginia coal the utility would have bought in 1987 without the credit in place. Table 1 shows Virginia Power's coal deliveries at its state powerplants from 1979 through 1986. Coal use has grown dramatically as the utility completed conversion from oil to coal in 1981. Purchases from Virginia mines rose to 20 percent of total deliveries in 1983 and remained at that level through 1986. However, in early 1986 (at the same time the tax credit bill was being discussed and ultimately passed), the utility's purchase of Virginia coal was beginning to decline. Fourth quarter 1985 Virginia purchases were only 16 percent of the utility's total, and first quarter 1986 deliveries were well below the previous year. Nearly all Virginia coal deliveries from mid-1985 to mid-1986 were contract purchases. Many of these contracts were due to expire in late 1986 or early 1987. In 1986, CSX (in response to Virginia Power's experiments with Colombian coal and barge transport discussed earlier) lowered its haul rates for West Virginia and Kentucky coal. As a result, Virginia coal performed miserably on the spot market, with only 17 deliveries totalling 111,000 tons for all of 1986. It became apparent that as Virginia coal contracts expired, they would likely be replaced by contracts for West Virginia and Kentucky coal.

TABLE 1. VIRGINIA POWER COAL DELIVERIES, 1979-1986

	1979	1980	1981	1982	1983	1984	1985	1986	projected w/o credit 1987*
% KY	79	66	70	65	44	65	59	47	44
% WV	19	17	17	20	36	15	20	33	41
% VA	2	17	13	15	20	20	20	20	15
Total Tons	1812	1873	3242	3782	4194	5128	4119	4793	5000
VA Tons	43	312	436	578	846	1008	835	965	750

* projected in late 1986, see text
Sources: NCA (1988a), Randolph and Hibbard (1987).

Virginia Power expected their purchases of Virginia coal to decline in 1987. The trends and circumstances described above suggest that state coal would drop to 15 percent of total purchases, or 750,000 tons of the utility's *projected* 1987 deliveries of 5 million tons. This figure was confirmed by the utlity (Barbour 1987) and by a computer supply model of the Virginia steam coal market (Smith and Hibbard 1988). Therefore, the figure of 15 percent of total deliveries is used to estimate what the purchases of Virginia coal woulod have been in 1987 and later years **without the credit.**

The Virginia Coal Incentive Act for utilities was signed on April 5, 1986. The utility reevaluated its purchase options, and by early 1987, it had awarded two 3-year contracts and four 7-8 month orders for Virginia coal. Purchases of state coal reported by the utility to the U.S. Department of Energy and published by the National Coal Association (1987), indicated a dramatic increase in 1987. As shown in the first column of Table 2, not only did the proportion of Virginia coal deliveries increase to 30 percent, but total deliveries for the year jumped 29 percent to 6.2 million tons. The higher than anticipated total purchases resulted from heavy coal burning to make up for unexpected nuclear downtime and from some stockpiling in anticipation of a coal labor strike.

TABLE 2. VIRGINIA POWER COAL DELIVERIES, 1987

	1987 actual tonnage projected distribution w/o tax credit	1987 actual reported tonnage & distribution	1987 actual tonnage certified distribution	1987 impact of tax credit on purchases
% KY	44	36	41	- 3
% WV	41	34	36	- 5
% VA	15	30	23	+ 8
Total Tons	6200	6200	6200	-
VA Tons	920	1867	1400	+ 450

This increase in total purchases prompted an active spot coal market in which Virginia coal competed well. In 1987, there were 178 spot purchases of Virginia coal, totalling more than 1 million tons -- nearly ten times the tonnage for 1986 spot deliveries!

The increase in 1987 total purchases affects the estimate of Virginia coal purchases without the tax credit. The projected 750,000 tons assumed total deliveries of 5 million tons. Assuming the same 15 percent Virginia coal allocation of 1987 purchases, the expectation for state coal deliveries rises to 950,000 tons. This is shown in the second column of Table 2.

The reported Virginia purchases for 1987 of 1.87 million tons indicate tremendous growth from 1986 (0.97 mt) and 1985 (0.85 mt). This total includes all of Virginia Power's spot purchases, as well as contracts for deliveries from Virginia mines. However, when Virginia Power tried to certify these purchases as Virginia coal, the deliveries from a major contract for between 450,000 and 500,000 tons could not be certified. Although the contract specified "Virginia coal," apparently the vendor shipped coal from other states.

Therefore, although the utility should have purchased 1.87 mt, only 1.4 mt (or 23 percent of total purchases) could be certified Virginia coal, as shown in the third column of Table 2. The 1.4 mt are 450,000 tons greater than the 950,000 tons estimated without the tax credit. Thus, 450,000 tons is the net increase in production resulting from the credit. The amount of

Virginia coal purchased above 1985 levels is about 550,000 tons (1.4 mt minus 850,000 tons), and thus resulted in a $550,000 tax credit for Virginia Power.

In early 1988, Virginia Power projected the coming year's total coal deliveries at 5.2 mt, of which Virginia coal purchases would be 1.3 mt, or 25 percent. These projected deliveries of 5.2 mt are 16 percent lower than in 1987. The utility expected these lower purchases because its nuclear plants would be back in full operation, coal plant scheduled maintenance deferred from the fall would take place in the spring of 1988, and plans to use current stocks of coal. In fact, through May 1988, reported deliveries were 10 percent lower than in the same period in 1987. However, it is likely that the hot 1988 summer may have pushed deliveries above expectations.

Reported deliveries in the first five months of 1988 show Virginia deliveries to the utility are running at 30 percent of the total (NCA 1988b). Table 3 uses these figures and utility projections to estimate a range of impacts for the tax credit in 1988. The net increase in Virginia coal purchases above estimated deliveries without the credit (based on 15 percent), is given as 520-780,000 tons. Projected 1988 purchases of Virginia coal (1.3-1.56 mt) are 350,000 to 710,000 tons more than 1985 deliveries.

TABLE 3. PROJECTED VIRGINIA POWER COAL DELIVERIES, 1988

	1988 projected tonnage w/o credit	1988 projected tonnage w credit	1988 impact of tax credit on purchases
% KY	44	36	- 4-8
%WV	41	34	- 6-7
%VA	15	25-30*	+ 10-15
Total Tons	5200	5200	-
VA Tons	780	1300-1560	+ 520-780

* 25% projected by Virginia Power; 30% actual 1st 5 month deliveries, 1988.

Given these projections, the Virginia Power tax credit for 1988 would equal $2/ton for coal used above 1985 levels (or $700,000 to $1,420,000) plus $1/ton for deliveries up to 1985 levels (or $850,000). The total credit for Virginia Power would be $1.55 to 2.27 million. Adding to this the 1988 credit for Appalachian Power Virginia coal use of 1.7 million tons (equal to 1985 purchases), the total credit (or state revenue loss) for 1988 may be $3.26 to 3.98 million.

Table 4 summarizes 1987 and 1988 impacts of the tax credit in terms of net purchases of Virginia coal and tax credit claimed. The increased credit adds a substantial amount to total dollars claimed, because all utilities (including APCO) can claim $1 per ton on all Virginia coal purchases. The state revenue loss could approach $4 million.

TABLE 4. SUMMARY OF UTILITY TAX CREDIT ON COAL PURCHASES AND CREDIT CLAIMS		
	1987	**1988**
Net increase coal production with credit vs. without	450,000 t	420-780,000 t
Tax credit claimed	$550,000	$3.25-5.0 million

* assumed same purchases as 1988

The Potential Impact of the Cogeneration Tax Incentive

It is difficult to project what effect the 1988 tax credit for cogenerators will have on Virginia coal production. There are, however, two probable impacts:

1. Increased purchases of Virginia coal by existing coal-burning cogenerators in the state; and
2. new development of coal-fired cogeneration using Virginia coal.

Table 5 lists existing coal-fired cogenerators in Virginia and gives amounts and sources of coal used. In total, these facilities purchase 20 percent of their coal from Virginia mines. The 1.6 mt of coal bought from other states offers a substantial potential market for Virginia coal. In a survey of coal users, fuel purchasing managers for these facilities were asked if an income tax credit of $1 per ton of Virginia coal used would affect their use of state-mined coal. As shown in Table 5, four of the six responded "yes", while the others "didn't know."

TABLE 5. COAL USE BY EXISTING VIRGINIA COGENERATORS

	MW	TONS	% VA	VA Tons	Out of State	$1/TON credit have effect?
Cogentrix (2 plants)	220	800	0	0	800	DK
Chesapeake	57	140	70	100	40	Yes
Stone Container	56	110	20	22	88	Yes
Westvaco	34	450	1	45	405	Yes
Avtex Fibers	24	310	75	230	80	DK
Union Camp	19	230	3	7	223	Yes
TOTAL		2040	20%	404	1636	

Sources: Randolph (1988); Lewis (1987)

The most important impact of the cogeneration incentive, however, may come from new development. As discussed earlier, Virginia Power Co. is aggressively pursuing private power development through competitive bidding to supply its future capacity needs. Prompted by SCC rules and its own desire to foster fuel diversity, the utility is emphasizing coal in new development. In its current capacity solicitation, awards will be granted on the basis of bid price and other factors, including use of Virginia coal. With the cogeneration tax credit, coal-fired facilities can meet the Virginia coal criterion and still compete in bid price with plants using cheaper West Virginia and Kentucky coal.

The potential coal market in the 1750 mw solicitation is impressive. For example, if Virginia awards 75 percent of the capacity (or 1325 mw) to coal-fired facilities,[3] coal use in these plants will approach 5 mt, or the equivalent of nearly all coal purchases by Virginia Power Co. for its state power plants in 1988.

Effect of Increased Coal Production on State Revenues and the Economy of Southwest Virginia

The payoff from the net increase in Virginia coal purchases described above comes from positive effects created by a net increase in coal production. Effects include employment and income of miners, railroad workers, and support workers in Southwest Virginia; corporate income by coal companies and railroads; local coal severance taxes; and state revenues (which act to offset revenue losses from the tax credit). The "net increase" is emphasized because the incentive may cause an actual **increase** in production or a **retention** of production that would otherwise be lost. So the effects of the credit can't always be seen in gross figures for production, employment, or income.

An assessment of effects requires determining a number of multipliers and assumptions. Those used in this study are given in Table 6. Most are computed from existing conditions in the industry; some are assumed.[4]

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[3] 60 percent of the bids received are for coal-fired plants.

[4] Those assumed include support employment (of 1 support job for each mine job), taxable income of one-half worker income, and taxable sales on one-half of worker income. Support income multiplier of 1.0 is supported by the literature (C. B. Garrison, "The Impact of New Industry: An Application of the Economic Base Multiplier to Small Rural Areas" in *Land Economics*).

TABLE 6 MULTIPLIERS USED IN ANALYSIS	Effect of One Million Tons
• **Mine employment**: 298 miners/million tons	298 miners
• **Railroad employment**: 65 workers/million tons	65 workers
• **Support employment**: 1 support/1 miner	298 workers
• **Miner income**: $23,722/miner	$ 7.1 million
• **Railroad worker income**: $34,840/railroad worker	$2.3 million
• **Support income**: $1 indirect income/$1 direct (miner) income	$ 7.1 million
• **Coal revenue**: $24.40/ton	$24.4 million
• **Coal company profit**: 5% of revenue	$ 1.2 million
• **Railroad revenue**: $14.40/ton	$14.4 million
• **Railroad profit**: 5% of revenue	$720,000
• **Local severance tax rate**: 2% of coal revenues	$488,000
• **State corporate profit tax**: 6% tax on corporate profit	$116,000
• **State income tax**: 4% tax on 3/4 of worker income	$495,000
• **State sales tax**: 4 1/2% tax on 1/2 of worker income	$371,000
• **State unemployment tax**: $460/employee*	$304,000
• **Total state tax revenue:**	$1.29 million

*In addition to company payments (as a result of new jobs) to the state unemployment fund, the fund would incur savings if some of the new jobs went to unemployed who were receiving compensation. This savings is difficult to estimate and is not included.

Based on these multipliers, the effects of a million ton increase in Virginia coal production are also given in Table 6. Applying these figures to the net increase of 450,000 tons expected in 1987 as a result of the tax incentive, results in the effects given in Table 7.

TABLE 7 ESTIMATED EFFECTS OF NET INCREASE OF 450,000 TONS OF VIRGINIA COAL PRODUCTION

134 mine jobs
29 railroad jobs
134 support jobs
$3.2 million miner income
$1.0 million railroad worker income
$3.2 million support worker income
$11.0 million coal revenue
$540,000 coal profit
$6.5 million railroad revenue
$324,000 railroad profit
$220,000 local severance taxes
$52,000 state corporate taxes
$222,000 state income taxes
$167,000 state sales taxes
$137,000 state unemployment taxes
$578,000 total state tax revenue

The 1987 effects of the utility tax credit are quite positive. For a tax loss of $550,000, the state may realize $578,000 in tax income, in addition to economic effects benefiting Southwest Virginia. A summary of effects for 1987 includes:

$550,000 state revenue loss
$578,000 state revenue gain
$28,000 net state revenue gain
297 jobs
$17.5 million corporate revenues
$7.4 million payroll
$860,000 corporate profit
$8.26 million Southwest Virginia economic income benefits (payroll + profits)

Table 8 summarizes the effects of the utility tax credit for 1987 and 1988. The net coal production increase for 1988 is the middle of the range given in Table 4. The net revenue and economic effects are about the same as in 1987 ($8.3 million). However, the increase in net economic effects was achieved at the expense of a substantial increase in tax credit claimed. The estimated 1988 state net revenue loss of $2.8 million compares with $11.2 million in economic benefits. It should be noted that the $3.62 million in credit claimed includes $2.55 million paid for levels of 1985 production at $1 per ton -- a credit that provides no incentive for additional purchases of Virginia coal.

TABLE 8. UTILITY TAX CREDIT IMPACTS, 1987 and 1988

	1987	1988
Net production increase over 1985	550,000	530,000
Net production increase with incentive vs. without	450,000	600,000
State tax revenue lost	$550,000	$3.62 mill.
State tax revenue gain	$578,000	$772,000
Net state tax revenue	+$28,000	-$2,85 mill.
Net economic benefits	$8.26 mill.	$11.15 mill.
Net revenue and economic benefits	$8.29 mill.	$8.30 mill.

SUMMARY AND CONCLUSIONS

The Commonwealth of Virginia has taken initiatives to address the economic plight of the coal fields in the southwestern corner of the state. These include programs to improve the economic diversification of the region and to increase the marketability, and thus the production, of the region's coal.

The Virginia Coal Incentive Acts provide a tax credit for the use of state-mined coal in utility powerplants and cogeneration facilities in the state. The $1-2 per ton credit aims to cut the differential in the delivered price between Virginia and Kentucky/West Virginia coal. This differential results from the higher production and rail transport costs of Virginia coal.

The utility tax credit began in 1987, and the first year of implementation showed a number of positive impacts. First, purchases of Virginia coal by the state's largest utility turned from an expected decline to a substantial increase. These deliveries helped push Virginia coal

COAL USE BY MANUFACTURING SECTOR IN VIRGINIA

John Randolph, Director
Virginia Center for Coal and Energy Research
Virginia Polytechnic Institute and State University
Blacksburg, Virginia

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In analyzing coal markets and consumption, data are plentiful for purchases by electric utilities and the coke industry. However, there is little detailed quantitative information available on coal use by other industry, particularly manufacturing, and by the residential and commercial sector. While the latter sector uses little coal, the manufacturing sector represents a substantial market.

STUDY OBJECTIVES AND METHODS

This study was initiated to investigate coal use in Virginia by the manufacturing sector. Objectives were to determine market size, coal sources, delivery methods, price, and the possible effect of a tax incentive for use of Virginia-mined coal.

The last objective was included because the Virginia General Assembly has already enacted legislation providing tax credits for use of Virginia-mined coal by utility power plants (Code 1986) and cogeneration facilities (Code 1987). A recent study of the utility credit indicates that it has stimulated the use of Virginia coal, and that the economic effects of the credit appear to be positive.[1] The General Assembly may wish to extend the credit to non-power producing, industrial coal users if it can be shown that it will enhance the market for Virginia coal and produce positive economic impacts.

The method used to obtain this information was a mailed survey of non-utility industrial coal users in the Commonwealth. The list of users was determined from a State Air Pollution Control Board printout of all facilities permitted for burning coal in the state. Utility, coke plant, institutional, and commercial users were deleted from the list. Survey questionnaires were sent to the remaining 146 firms. Ten were returned by the post office and seventeen were returned by firms which in fact did not use coal. Of the remaining 119 recipients, 48 (or 40 percent) returned valid responses.

The questionnaire is included as Appendix A. It was designed short and simple to enhance the response rate. It included ten questions concerning the following information:

1. Quantity of coal used: 1986, 1987
2. Coal as percentage of combustion fuel: 1986, 1987
3. Other combustion fuel used

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[1] J. Randolph, "State Energy Policy to Enhance Coal Production: The Virginia Coal Incentive Acts," (Blacksburg, VA: VCCER), July 1988.

4. Method of coal delivery: rail, truck, barge
5. Contractor for coal deliveries: vendor, broker, mine
6. State of origin of coal and percentage: 1986, 1987
7. Average cost per ton of delivered coal
8. Delivered cost by state of origin
9. Would $1/ton tax credit for Virginia-mined coal affect use of Virginia coal? By how much?
10. Additional comments.

Before looking at the survey results, a brief presentation of available secondary data on industrial coal use in Virginia is given below.

INDUSTRIAL COAL USE IN VIRGINIA AS REPORTED BY U.S. EIA

The U.S. Energy Information Administration (U.S. EIA) collects distribution data from coal distributors on a quarterly basis.[2] Information is provided on amount of coal shipped by state of destination, consumer category, mine of origin, and method of transport. Tables 1 and 2 give 1987 data reported by U.S. EIA for Virginia destinations. Table 1 shows coal use in Virginia by sector for 1983 to 1987. Spurred by growth in the utility sector, coal use in Virginia increased by more than 30 percent during this period. Based on its survey of coal distributors, U.S. EIA estimates that "other industry" (i.e. manufacturing, agriculture, and mining) in Virginia purchased an estimated 3.66 million tons (or more than 25 percent of the total).

TABLE 1
COAL USE IN VIRGINIA BY SECTOR, 1983 - 1987
(thousand tons)

	Electric Utilities	Coke Plants	Other Industry	Res./Comm. Institut.	TOTAL
1983	6,593	903	3,083	253	10,832
1984	8,679	1,006	3,603	288	13,576
1985	7,426	884	3,264	271	11,845
1986	7,883	895	3,221	245	12,244
1987	9,322	942	3,657	325	14,246

Source U.S.EIA, *Coal Distribution*, January - December, 1987 (April 1988).

Table 2 gives the reported method of transport and sources of this coal. More than 85 percent of deliveries were made by rail. Nearly 90 percent originated in Coal Producing District 8. As described in the note and map given with Table 2, District 8 includes all eastern Kentucky mines, those in southwestern West Virginia, and most Virginia mines except some in Buchanan and Tazewell Counties. Because of the boundaries of these coal producing

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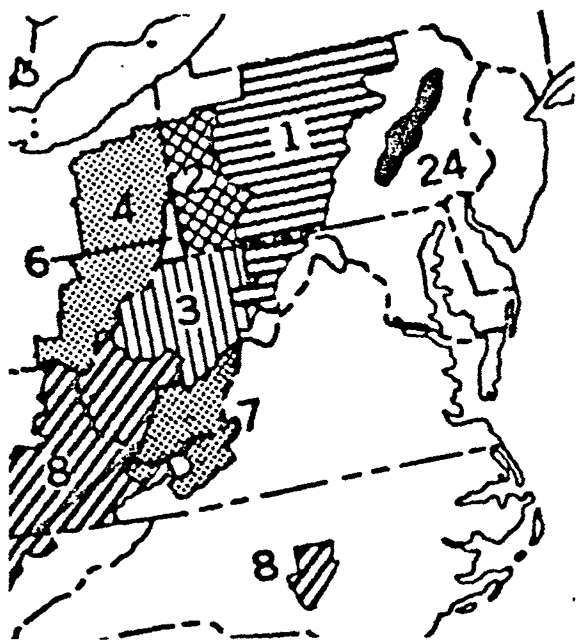
[2] U.S. Energy Information Administration, *Coal Distribution*, DOE/EIA-0125(year/quarter), published quarterly.

districts and the method of reporting by U.S. EIA, it is impossible to distinguish the specific state of origin of the distributed coal from this reference.

TABLE 2
DISTRIBUTION OF COAL TO VIRGINIA MANUFACTURING SECTOR, 1987
(Thousand Tons)

Source	Rail	Truck	Total
from District 8	3,165	165	3,270
from District 7	3	57	60
from District 3 & 6	30	252	282
from Others	-	44	44
TOTAL	3,138	510	3,649

Note--District 8: Mines in Eastern Kentucky, Tenessee, West Virginia, Virginia (All mines in Dickenson, Lee, Russell, Scott, and Wise Counties; all mines in Buchanan and Tazewell Counties except those in District 7). See Map.
District 7: Mines in West Virginia and Virginia (Buchanan County mines served by Richlands-Jewell Ridge branch of N&W, and in headquarters of Dismal Creek east of Lynn Camp Creek. Tazewell County mines served by Richlands-Jewell Ridge branch and Dry Fork branch to Cedar Bluff, from Bluestone Junction to Boissenan branch of N&W). See Map.
District 3 & 6: Mines in West Virginia.



SURVEY RESULTS

Forty-eight manufacturing firms using coal in Virginia responded to the mail survey. The tonnage used by these companies in 1987 totaled nearly 2.5 million tons; this is two-thirds of the "other industry" deliveries reported by U.S. EIA. Table 3 categorizes the respondents by quantity of coal used. More than half of the respondents (26) used less than 10,000 tons per year and in total consumed only 2 percent of the 2.5 million tons reported by all respondents. On the other hand, eight of the respondents (17 percent) consumed more than 100,000 tons each, totaling more than 75 percent of the 2.5 million tons reported. Clearly, the bulk of Virginia's non-utility coal market occurs in a few large industrial facilities.

TABLE 3
COAL USE BY 48 VALID RESPONDERS, 1987

Category	# Users	% of Responses	Total Tons	% of Total Tons
0 - 999 tons	14	29%	3,855	< 0.1%
1,000 - 9,999 tons	12	25%	56,949	2%
10,000 - 99,999 tons	14	29%	504,979	21%
> 100,000 tons	8	17%	1,883,334	77%
TOTAL	48		2,449,117	

Sources of Coal

What portion of this coal consumed by Virginia companies comes from Virginia mines? Table 4 shows that thirty-six of the respondents (including all of the largest users) knew the state of origin for their coal. Of the total coal used by this group, only 26 percent was mined in Virginia, while 42 percent originated in West Virginia, and 30 percent came from Kentucky.

TABLE 4
STATE OF ORIGIN OF COAL, 1987

User Category	Total # of Responses	Valid Responses	VA	WV	KY	Other
0 - 999	14	9	45%	22%	33%	0%
1,000 - 9,999	12	9	28%	30%	34%	8%
10,000 - 99,999	14	10	18%	45%	28%	10%
> 100,000	8	8	28%	41%	31%	0%
AVERAGE			26%	42%	30%	4%

Table 5 gives comments of several large users in Virginia (see Table 10 for their coal use data). These comments reflect the concerns of all of the users and the factors affecting their choice of coal source: the required specifications of their process (i.e., ash, sulfur, grind, etc.); reliability of supply; and most importantly, delivered price. The price depends on mine price and transport costs. Transport costs in turn are a function of distance from the mine, rail rates, and serving railroad. Many users are closer to mines in West Virginia, so transport costs tend to be less than from Virginia mines. Several large users in Virginia have access only to CSX railroad; CSX serves only a few Virginia mines, but a large number in West Virginia and Kentucky. Norfolk and Western (a subsidiary of Norfolk Southern) serves the vast majority of Virginia mines. As with Virginia utility markets, railroad service has an important effect on the use of Virginia coal by non-utility industry.

TABLE 5
SUMMARY OF COMMENTS OF TEN LARGEST USERS RESPONDING

USER	COMMENTS
Westvaco	Cost of conveyance to CSX main line shipping points. Truck coal (Virginia source) is too far away to be competitive.
Avtex Fibers	Contract with N&W for 75% of use. Specifications - grind, BTU, Sulfur.
Union Camp	Conformance to specification; service; performance as supplied.
DuPont (Richmond)	Virginia coal would have to be cost competitive and meet our specifications.
DuPont (Waynesboro)	We buy coal based on utilization cost (mine cost + freight + handling into boiler). If coal produced in Virginia are competitive in cost and meet our standards of requirement, we would be willing to consider Virginia coal.
Stone Container	The tax credit would certainly have some impact. Cannot determine tons/yr. at this time.
Dan River, Inc.	Good BTU value; low sulfur; low ash; good grind; good price.

Delivered Price

Table 6 shows the average delivered price of coal. As expected, larger users (having larger contracts and spot purchases) paid less per ton (on average). Question #8 in the survey attempted to compare the price of coal by state of origin, but very few firms had such information.

TABLE 6
DELIVERED COST OF COAL, 1987

User Category	# Users	Average $/Ton
0 - 999 tons	14	$56.23
1,000 - 9,999 tons	12	$47.09
10,000 - 99,999 tons	14	$31.36
> 100,000 tons	8	$30.48

Method of Delivery

U.S. EIA reports that 85 percent of industrial coal tonnage in Virginia is delivered by rail (Table 2). Table 7 shows that although every large user (> 100,000 tons per year) has access to rail service, most respondents receive truck deliveries. Of responding users with rail service, 17 are served by Norfolk Southern and 8 are served by CSX. Forty of 48 responding users contract with a coal vendor or broker. Only 7 firms contract with a mine; these are mostly small users close to the coal region.

TABLE 7
METHOD OF COAL DELIVERY

Category	# Users	# Truck	# Rail
0 - 999 tons	14	12	2
1,000 - 9,999 tons	12	10	4
10,000 - 99,999 tons	14	12	10
> 100,000 tons	8	4	8
TOTAL	48	38	24

Note: Some users have both truck and rail delivery.

Effect of $1 per Ton Tax Credit

Question #9 of the survey inquired whether a $1 per ton tax credit for use of Virginia-mined coal would affect the firm's purchases. As shown in Table 8, most small users indicated that it would not. However, most large users (> 10,000 tons) indicated either it would have an effect or they did not know.

TABLE 8
WOULD A $1/TON TAX CREDIT HAVE AN EFFECT ON PURCHASES OF VIRGINIA COAL

User Category	# Responding to Question	Yes	No	Don't Know
0 - 999 tons	10	0	7	3
1,000 - 9,999 tons	12	2	8	2
10,000 - 99,999 tons	14	3	5	6
> 100,000 tons	7	4	0	3
TOTAL	43	9	20	14

Table 9 looks more closely at the ten largest users responding to the survey. These ten firms purchased more than 2 million tons of coal in 1987. Nearly 1.5 million tons, or 70 percent of the coal used by these companies, came from West Virginia and Kentucky mines. Only those users served by Norfolk Southern tracks used Virginia-mined coal.

Five of the ten largest coal users indicated that a $1 per ton credit would affect their use of Virginia coal. The other five firms responded that they did not know if there would be an effect.

TABLE 9
TEN LARGEST COAL USERS RESPONDING TO SURVEY

User	1987 Coal Use (Tons)	%VA Coal	Railroad	$/Ton	$1/Ton Credit Effect?
Westvaco	453,000	1%	CSX	NA	Yes
Avtex Fibers	310,000	75%	NS	40	DK
Hoechest Celanese	300,000	45%	NS	31	DK
Union Camp	230,000	14%	NS,CSX	NA	Yes
DuPont (Richmond)	182,000	0%	CSX	45	DK
DuPont (Waynesboro)	160,000	0%	CSX	43	DK
Chesapeake Corp.	140,000	70%	NS	44	Yes
Stone Container	109,000	20%	NS	42	Yes
Dan River, Inc.	93,000	100%	NS	47	Yes
DuPont (Martinsville)	89,000	0%	Truck	38	DK
TOTAL	2,066,000	30%			

CONCLUDING COMMENTS

This study demonstrates that the market for coal use in the manufacturing sector is substantial: between 3 and 3.7 million tons per year. This compares to about 9 million tons in the utility sector. A few large firms dominate the tonnage of coal used in non-utility industry. Several of these large companies indicated in the survey that a $1 per ton tax credit would have some effect on their use of Virginia coal. Given this preliminary data, and the fact that the General Assembly has already provided tax credits for Virginia coal purchases by state utilities and cogenerators, The Assembly or the Coal and Energy Commission may wish to explore an extension of the cogenerator income tax credit to other industrial users. Any further study should consider that some of the industrial users responding to the survey (e.g. Westvaco, Avtex Fibers, Union Camp, Stone Container) are also cogenerators and thus are already eligible for the cogeneration credit.

COMPETITION IN THE INTERNATIONAL COAL MARKET: RECENT TRENDS AND PROSPECTS FOR U.S. EXPORTS

John Randolph, Director
Virginia Center for Coal & Energy Research
Virginia Polytechnic Institute and State University
Blacksburg, Virginia

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The world coal export market has become increasingly competitive as lower world oil prices have depressed the price of coal and new exporting countries have tried to grab a share of the action. The United States contributed more than 40 percent to world coal export tonnage during 1981, but that proportion dropped to 23 percent in 1987.

This paper describes trends in the world coal market, discusses reasons for shifting patterns, and comments on recommendations by the Federal Coal Export Commission for improving the competitiveness of the United States in international coal trade.

THE INTERNATIONAL COAL MARKET

World coal demand has remained strong since the oil price shocks of the 1970s. World production increased by 21 percent between 1976 and 1986. Table 1 shows that the United States, China, and the Soviet Union have dominated world production, accounting for 54 percent of total tonnage in 1986.

TABLE 1
WORLD COAL PRODUCTION 1976-1986
(Million Short Tons)

	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
China	586	606	681	698	684	683	734	788	870	931	959
United States	685	697	670	781	830	824	838	782	896	884	890
U.S.S.R.	784	796	798	792	790	776	792	789	785	798	825
East Germany	273	280	279	282	285	294	304	309	327	344	343
Poland	241	250	258	264	254	219	250	258	267	275	286
West Germany	247	229	228	239	239	241	247	236	233	231	222
Australia	109	111	114	119	116	130	140	146	153	186	210
South Africa	85	94	100	114	127	144	151	161	179	192	196
India	116	115	116	118	125	142	148	158	168	173	184
United Kingdom	137	135	136	135	141	138	137	127	55	104	115
Other	500	520	531	563	582	607	634	648	690	721	729
TOTAL	3,763	3,833	3,911	4,105	4,173	4,198	4,375	4,402	4,623	4,839	4,959

Source: U.S. EIA, *International Energy Outlook 1987*, (DOE/EIA-0484(87)), May 1988.

Coal Export Markets: Pacific Rim and Western Europe

Table 2 provides data on **gross** world coal trade in 1985, giving imports (in quadrillion BTU) by country and principal supply sources. Total gross imports of 9.99 quadrillion BTU include secondary products (e.g., coke and briquets) and also secondary exports (i.e., imported coal subsequently exported). As a result, there is some double counting in Table 2. An estimate of **net** world coal trade is slightly more than 300 million tons (mt) per year (Wampler 1988).

TABLE 2
WORLD COAL GROSS IMPORTS, 1985
(Trillion BTUs)

Importing Country		Principal Sources
Pacific Rim		
Japan	2,620	Australia (1,217), Canada (490), U.S. (415), South Africa (240)
S. Korea	476	Australia (212), Canada (110), U.S. (85)
Taiwan	357	Australia (260), U.S. (60), South Africa (40)
Western Europe		
Italy	609	U.S. (270), South Africa (165)
France	575	South Africa (170), West Germany (124), U.S. (118)
Netherlands	365	U.S. (168), Australia (97)
W. Germany	359	South Africa (94), Poland (88)
Belgium	352	U.S. (119), West Germany (113), South Africa (68)
Denmark	337	South Africa (94), Australia (62), Poland (58), U.S. (57)
United Kingdom	305	Australia (126), U.S. (70), Poland (39)
Spain	235	U.S. (92), South Africa (62), Australia (44)
Western Hemisphere		
Canada	442	U.S. (442)
Brazil	268	U.S. (156), Poland (54)
Other	2,690	Poland (690), U.S. (397), Australia (204), South Africa (94)
TOTAL	9,990	

Source: U.S. EIA, *International Energy Annual 1986* (DOE/EIA-0219(86)), October 1987.

Major markets for international coal trade are the Pacific Rim countries (principally Japan, but also South Korea and Taiwan) and Western Europe. Table 3 shows that in 1985 through 1987 there was a total market of about 235 mt per year in these two regions. Japan dominated with imports of 100 mt. Italy and France are the major European importers, each with about 20 mt annually. About two-thirds of the European market is for steam coal, while the Pacific Rim (dominated by Japan's steel-making requirements) imports three-fourths of its coal for metallurgical purposes.

TABLE 3
WORLD EXPORT MARKET
(Annual Net Imports Based on 1984-1987 Deliveries)

	Total (Mill Tons)	% Steam	% Met
Pacific Rim	**135**	**25%**	**75%**
Japan	10	23%	77%
Korea	20	71%	29%
Taiwan	15	NA	NA
Western Europe	**100**	**65%**	**35%**
Belgium	10	NA	NA
France	20	NA	NA
Italy	22	50%	50%
Netherlands	11	NA	NA
Spain	9	NA	NA
Sweden	6	NA	NA
UK	9	NA	NA

Sources: NCA, *International Coal*, 1985-87 Editions.

Table 4 shows the origin of Japanese coal imports from 1982 to 1987. All coal export countries have increased their tonnage except the United States. The 18 mt drop in imports from the United States was made up for by a 17 mt in purchases increase in purchases of Australian coal.

TABLE 4
ORIGIN OF JAPANESE COAL IMPORTS, 1982-1987
(Million Tons)

	1982	1983	1984	1985	1986	1987
Australia	35	40	41	45	42	51.6
Canada	12	12	16	18	18	18.5
United States	28	17	16	14	13	10.2
South Africa	7	7	7	8	8	7.4
U.S.S.R.	1	2	2	4	5	6.9
China	3	4	4	3	3	4.5
Other	1	-	1	1	1	0.8
TOTAL	87	82	87	93	90	99.9

Tables 5 and 6 give more detailed data on Pacific Rim and European markets. The tables show coal imports for the years 1982 through 1986, including market share and delivered price by exporting country. In the European market, the U.S. share of metallurgical (met) coal imports has maintained its level of 57-58 percent during the past five years (although this figure is well below the 1982 record of 72 percent). However, the U.S. share of the larger European steam coal market has dropped dramatically -- from 42 percent in 1982 to 18 percent in 1987! As in the previous example, Australian coal has made up this difference, rising

TABLE 5
EUROPEAN ECONOMIC COMMUNITY (EEC*)
COAL IMPORTS, MARKET SHARE, AND PRICE

	1982	1983	1984	1985	1986	1987	1988**
Steam Coal (Million Tons)	**47**	**44**	**50**	**57**	**63**	**63**	**NA**
Market Share (%)							
United States	42	29	22	15	24	18	NA
South Africa	35	36	37	37	34	31	NA
Australia	6	10	16	19	21	28	NA
Poland	13	20	26	16	10	12	NA
Steam Coal CIF Prices (US $/Ton)							
United States	61.8	54.3	50.3	52.6	47.6	45.3	46.3
South Africa	47.7	39.9	38.0	36.0	34.5	29.3**	NA
Australia	63.8	55.2	45.1	43.2	41.0	38.1	37.9
Poland	55.4	45.5	47.1	40.9	51.9	47.4**	NA
Coking Coal (Million Tons)	**25**	**20**	**32**	**30**	**35**	**34**	**NA**
Market Share (%)							
United States	72	58	58	57	57	57	NA
Australia	15	24	25	27	26	28	NA
Poland	10	14	10	10	9	9	NA
South Africa	1	3	2	3	2	1	NA
Coking Coal CIF Prices (US $/Ton)							
United States	69.1	61.0	56.8	56.2	54.2	49.8	50.7
Australia	65.5	55.2	53.3	52.1	51.3	48.3	47.3
Poland	68.3	56.0	55.1	63.3	54.9	49.3	NA
South Africa	65.9	50.8	38.9	41.5	35.6	31.6**	NA

*EEC - includes Belgium/Luxemboug, Denmark, France, West Germany, Ireland, Italy, Netherlands, Portugal, Spain, United Kingdom.
**First six months.
Sources: International Energy Agency, *Energy Prices and Taxes*, Second Quarter, 1987; NCA, *International Coal Review*, August 1988; NCA, *International Coal*, 1985-1987 Editions.

TABLE 6
JAPAN COAL IMPORTS, MARKET SHARE, AND PRICE

	1982	1983	1984	1985	1986	1987	1988*	
Steam Coal (Million Tons)	**15**	**15**	**17**	**20**	**20**	**26**	**12**	**(5 mo.)**
Market Share (%)								
Australia	47	55	65	65	65	69	69	
Canada	10	4	4	4	7	6	5	
United States	12	7	3	5	3	-	1	
South Africa	19	19	14	16	15	11	10	
USSR	2	3	4	5	4	4	4	
China	11	13	10	6	6	10	9	
Steam Coal CIF Prices (US $/Ton)								
Australia	59.0	50.8	46.5	40.4	40.4	39.7	36.2	
United States	65.2	60.5	54.3	51.6	50.1	49.0	51.3	
South Africa	55.9	47.2	41.3	41.6	40.9	37.6**	NA	
Canada	57.0	55.8	44.7	39.7	40.0	38.6**	NA	
Coking Coal (Million Tons)	**72**	**66**	**70**	**73**	**71**	**74**	**35**	**(5 mo.)**
Market Share (%)								
Australia	39	47	43	43	41	45	41	
Canada	15	17	22	24	24	23	26	
United States	37	25	23	19	17	14	16	
South Africa	5	5	7	6	7	6	7	
USSR	2	3	2	4	6	8	8	
China	3	4	3	3	3	3	2	
Coking Coal CIF Prices (US $/Ton)								
Australia	62.0	57.6	53.7	49.4	48.0	47.4	46.2	
United States	76.3	71.6	64.5	62.4	58.8	57.1	57.9	
South Africa	61.1	52.6	46.3	45.1	42.7	40.8	NA	
Canada	64.3	63.8	63.2	61.4	60.6	61.4	NA	

*First five months. Sources: International Energy Agency, *Energy Prices and Taxes*, Second Quarter 1987; NCA, *International Coal Review*, August 1988; NCA, *International Coal*, 1985-1987 Editions.

from 6 percent in 1982 to 28 percent in 1987, mirroring its rise to a 28 percent share of the met coal market during the same period.

Similar shifts in coal market share are apparent in Japanese coal demand. For coking coal, the export market shares of Australia, Canada and the Soviet Union to Japan each increased by 6-8 percentage points between 1982 and 1987, while the U.S. share dropped from 37 percent to 14 percent. During the same period, Australia's share of Japan's steam coal market increased from 47 to nearly 70 percent, at the expense of all other exporting countries. This is especially true for the United States, whose share dropped from 12 to 2 percent.

Coal Exporters: Australia, the United States and the Newcomers

Competition to deliver coal to the Pacific Rim and European markets is keen as a growing number of coal exporting countries are trying to obtain a share. Table 7 shows coal export tonnages of major producers. The United States dominated the international coal export market during the early 1980s, but has now been replaced by Australia as the largest coal exporter. Table 8 shows how Australian exports have grown. The nation's tonnage to its "local" market in the Pacific Rim grew by more than 60 percent between 1981 and 1987; more surprising, its exports to Western Europe **tripled** during the same period. With 1988 exports (through May) running 9 percent ahead of last year, Australia is on the verge of eclipsing the U.S. record for coal exports of 113 mt set in 1981.

TABLE 7
COAL EXPORTS OF SELECTED COUNTRIES, 1981-87
(Million Tons)

	1981	1982	1983	1984	1985	1986	1987
United States	113	106	78	81	93	86	80
Australia	52	52	61	73	91	97	111
South Africa	33	30	33	42	49	47	39
Poland	17	31	38	40	47	40	NA
Canada	17	18	19	28	30	29	27

TABLE 8
AUSTRALIAN COAL EXPORTS, 1981-1987
(Million Tons)

	1981	1982	1983	1984	1985	1986	1987
Japan	36	35	38	42	47	44	51.2
Korea	3	4	5	7	8	9	8.1
Taiwan	2	2	3	4	5	6	7.2
France	1	1	2	3	4	5	4.1
Netherlands	1	1	1	2	5	5	6.5
Other EEC	6	5	8	11	11	13	13.3
Other	3	4	4	4	11	14	20.5
TOTAL	52	52	61	73	91	97	111.0

Australia, however, is not alone in competing with the United States for coal export destinations. Other traditional coal exporters, South Africa and Poland, have maintained their share of the market. Concurrently, Canada has increased coal exports from its Vancouver terminal to the Pacific Rim. In coming years, China is expected to increase its coal export share in the Pacific Rim marketplace. With the help of Occidental Petroleum and its Island Creek Coal Subsidiary, China put its An Tai Bao mine into full production earlier this year. This operation will provide nine mt annually fc- export. In the Western Hemisphere, Colombia (with the help of Exxon) is also trying to captu. a share of the world coal market.

Delivered Coal Price, Freight Rates, and Currency Value

The most important determinant of the shifting international coal market is delivered price. Tables 5 and 6 compare delivered prices of coal by source country (in U.S. dollars) to Europe and Japan. While all prices have dropped dramatically since 1982 (affecting profitability of coal operations in all countries), U.S. coal continues to rank among the most expensive available to these two major markets. Two important factors influencing the relative value of the delivered prices shown are shipping rates and national currency value.

Table 9 illustrates the erratic nature of freight rates during the past four years. Rates dropped dramatically in 1986, but have since recovered. The cost to ship coal from Hampton Roads to Japan (on a 55,000 ton collier) increased from $8.75/ton (metric) in 1986 to $19.75/ton (metric) in 1988. Freight costs for coal from Australia and western Canada to Japan increased by only half as much during this period.

TABLE 9
COAL SHIPPING RATES (55,000 T Collier)
(U.S.$/Long Ton)

	June 1988	June 1987	June 1986	June 1985
Hampton Roads to Europe	8.50	7.00	4.25	9.25
Australia to Europe	13.75	11.50	9.25	11.50
South Africa to Europe	11.00	11.00	10.50	12.00
Hampton Roads to Japan	19.75	14.00	8.75	15.00
Australia to Japan	10.00	6.00	5.00	7.50
South Africa to Japan	11.25	10.00	9.00	12.00
Canada to Japan	10.50	6.00	5.00	9.00

The strength of the U.S. dollar compared to other currencies affects the competitiveness of U.S. coal. As the value of the U.S. dollar rises compared to Australian currency, for example, the relative cost of Australian coal will fall -- with no corresponding change in the price in Australian currency. Australian coal, therefore, becomes increasingly competitive with no price cutting by Australian producers.

Table 10 gives the exchange rates for U.S. dollars in Australia dollars and Japanese yen. The value of the U.S. dollar vs the yen peaked in 1982-1985 then fell in 1986 and 1987, effectively lowering the cost of U.S. coal delivered to Japan. But the real effect is seen in comparing the value of the U.S. dollar to the competition, namely Australia. U.S. and

Australia dollars were essentially of equal value in 1982, but by early 1987 the relative value of the U.S. dollar increased by more than 50 percent. In other words, 1982 saw Australian coal priced at $45 Aust/ton (FOB) selling for the equivalent $45 U.S./ton. By 1987, the same $45 Aust/ton sold for the equivalent of $30 U.S./ton, or a one-third cut in effective price on the international market. The effect of currency exchange rates guaranteed Australia an increasing share of the global coal export market.

TABLE 10
EXCHANGE RATES OF U.S. DOLLAR COMPARED TO AUSTRALIAN DOLLAR AND JAPANESE YEN

	1980	1982	1983	1984	1985	1986	Jan. 1987	June 1987	Jan. 1988	June 1988
Australian $	.88	.99	1.11	1.14	1.43	1.50	1.51	1.39	1.40	1.24
Japanese Yen	226	249	237	237	238	169	155	145	127	127
U.S. $	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Sources: U.S. EIA, *International Energy Annual 1986*; NCA, *International Coal Review*, monthly January 1987-August 1988.

However, the recent weakening of the dollar vs the Australian dollar has reversed this trend. In June 1988, the U.S. dollar was worth $1.24 (Australian), down from $1.51 in January 1987. This has contributed to a slight recovery in U.S. coal exports during 1988. As shown in Table 6, the U.S. share of the Japanese met coal market increased from 14 percent in 1987 to 16 percent during the first half of this year, while Australia's share dropped from 45 to 41 percent.

Global economic growth during the first half of 1988 also contributed to a recovery for U.S. coal exports. As shown in Table 11, global steel production was up 11 percent between January and June 1988 compared to the first half of 1987. This development has primarily increased the market for U.S. metallurgical coal.

TABLE 11
GLOBAL STEEL PRODUCTION FIRST HALF 1987, 1988
(1000's Metric Tons)

	Jan-June 1988	Jan-June 1987	% Change
U.S.	45.7	38.1	+20%
Japan	52.5	47.5	+11
West Germany	20.1	18.3	+10
Italy	12.0	11.8	+ 2
Brazil	11.9	10.4	+14
United Kingdom	9.8	8.7	+14
Other	81.9	75.8	+ 8
TOTAL	233.9	210.6	+11%

THE U.S. ROLE IN WORLD COAL TRADE

The United States has been a major player in international coal trade since World War II. Between 1946 and 1970, U.S. coal exports averaged 48 million tons. In 1957, the United States exported 76 million tons, the historic high until 1980.

Table 12 provides some data on U.S. coal production and exports from 1977 to 1987, with U.S. Department of Energy projections for 1988-1990. Although the U.S. coal industry achieved record production in 1987, exports dropped to the second lowest level since 1979. The surge in international coal use during the early 1980s (brought about by oil price increases and labor unrest in Poland), created tremendous growth in U.S. exports. In addition, the price of coal also reached record levels, bringing U.S. coal export value to nearly $6 billion per year in 1981 and 1982. However, recovery of Polish coal exports combined with increased competition from other exporters caused a dramatic decline in U.S. coal export tonnage during the past 5 years. With depressed coal prices, the value of U.S. coal export tonnage dropped by 44 percent between 1982 to 1987. While the U.S. Department of Energy forecasts considerable U.S. coal production growth in 1989 and 1990, it also predicts lower exports than in 1987.

TABLE 12
U.S. COAL EXPORT FACTS, 1977-1988

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
Production, Mill.Tons	697	670	781	829	824	838	782	896	883	890	917	914	932	962
Exports, Mill.Tons	54	41	66	92	113	106	78	81	93	86	80	74	76	79
% Exports of Production	8	6	8	11	14	13	10	9	11	10	9	8	8	8
Export Value, $ Billion	2.6	2.0	3.3	4.5	5.8	5.9	4.0	4.1	4.4	3.9	3.3	NA	NA	NA
Average FOB $/Ton	52	54	53	51	53	56	52	51	48	46	42	NA	NA	NA
% Steam Coal	22	24	22	30	41	39	35	30	34	35	31	NA	NA	NA

Sources: National Coal Association, *International Coal* 1985, 1986, 1987 Editions; *International Coal Review*, Monthly, 1985 through January 1988; U.S. EIA, *Short Term Energy Outlook*, Second Quarter 1988.

Table 13 shows the destination of U.S. exports between 1981 and 1988. Through 1987, major losses in coal trade have occurred in the Japanese market (from 26 mt in 1982 to 11 mt in 1987) and in Western Europe, especially to France and Spain.

Table 13 also shows, however, that U.S. exports experienced a slight recovery during the first half of 1987. As discussed above, factors contributing to this increase are improved currency exchange rates and increased world steel production. Exports to Japan, Italy, France, and the United Kingdom have all increased compared to the same period in 1988.

TABLE 13
DESTINATION OF U.S. COAL EXPORTS, 1981-1988
(Million Tons)

	1981	1982	1983	1984	1985	1986	1987	1988*
Canada	18	19	17	20	17	14	16.5	6.4
Japan	26	26	18	16	15	11	11.1	7.3
Italy	11	11	8	8	10	10	9.5	5.5
Brazil	3	3	4	5	6	6	5.8	2.2
Netherlands	7	6	4	6	6	6	4.1	1.8
Taiwan	2	2	2	3	3	4	4.8	2.4
France	10	9	4	4	4	5	2.9	2.1
Belgium	4	5	3	4	4	4	4.6	3.2
United Kingdom	2	2	1	3	3	3	2.6	1.6
Spain	6	6	3	2	3	3	2.4	1.0
Korea	2	2	2	2	3	3	4.0	1.9
Other	22	15	12	8	19	17	12.0	6.1
TOTAL	113	106	78	81	93	86	80.3	41.5

* 1st. 6 months

Tables 14 and 15 give data for major U.S. coal exporting ports. Hampton Roads ports (in the Norfolk Customs District) historically have moved about half of U.S. export tonnage. This coal is primarily high quality, metallurgical grade coal from Central Appalachia mines in Virginia, West Virginia, and Kentucky. Cleveland exports steam and metallurgical coal to Canada. New Orleans has become the nation's largest exporter of steam coal; Mobile moves mostly met coal; while Baltimore handles a mix.

TABLE 14
ORIGIN OF U.S. BITUMINOUS COAL EXPORTS, 1981-87
(Million Tons by Customs District)

	1981	1982	1983	1984	1985	1986	1987	1988*
Norfolk	52	58	41	36	43	39	37.3	20.1
Cleveland	18	18	17	20	16	14	15.7	6.1
New Orleans	14	8	6	5	8	9	7.7	5.3
Mobile	4	4	3	8	9	8	7.1	4.0
Baltimore	13	12	7	7	8	7	6.5	3.5
Other	9	5	3	5	7	7	4.0	1.6
TOTAL	110	105	77	81	91	84	78.4	40.6

* 1st. 6 months

TABLE 15
ORIGIN AND DESTINATION OF U.S. BITUMINOUS COAL EXPORTS, 1987
(Million Tons)

	Hampton Roads	New Orleans	Mobile	Baltimore	Other
Canada	0.1	--	--	--	1.57
Brazil	5.5	-	0.1	0.1	0.1
Italy	7.7	1.2	[illegible]	0.2	--
Netherlands	3.4	0.2	--	0.4	--
France	2.7	--	0.2	--	--
UK	1.9	1.2	0.5	--	--
Belgium	2.5	0.2	1.0	0.9	--
Spain	2.4	--	--	--	--
Japan	4.9	1.3	3.7	1.2	--
Taiwan	0.3	3.1	--	0.2	1.1
Korea	1.2	--	--	0.8	1.4
Other	4.7	0.5	1.1	2.7	1.5
TOTAL	37.3	7.7	7.1	6.5	19.8
Metallurgical	32.7	1.0	6.7	3.5	7.8
Steam	4.6	6.7	0.4	3.0	12.0

Tables 16 and 17 takes a more detailed look at Hampton Roads coal exports during the first half of 1988. Table 16 shows total exports are up 6 percent, spurred by increases to Western Europe. Table 17 shows the principal shippers of Hampton Roads coal. Pittston, Consolidation, and Island Creek provided nearly 40 percent of the port's export coal during the first seven months of 1988.

TABLE 16
HAMPTON ROADS COAL EXPORTS BY DESTINATION
JAN-JUNE 1987, 1988
(Million Tons)

	Jan-June 1988	Jan-June 1987	% Change
Italy	4.19	4.03	+4%
Japan	2.88	2.73	+5%
Brazil	1.98	2.41	-22%
France	1.90	1.49	+28%
Belgium	1.84	1.35	+36%
Netherlands	1.51	1.61	- 6%
United Kingdom	1.28	0.86	+49%
Spain	1.02	1.27	-20%
Korea	1.00	0.56	+79%
Other	2.52	2.74	- 8%
TOTAL	20.12	19.05	+ 6%

TABLE 17
JAN-JULY 1988 HAMPTON ROADS
COAL EXPORTS BY COMPANY
(Million Tons)

Pittston	3.46
Consolidation	3.19
Island Creek	2.29
Massey	1.95
Westmoreland	1.83
Peabody	1.80
Jno McCall	1.44
U.S. Steel	1.34
Other	5.59
TOTAL	22.89

PROSPECTS FOR U.S. COAL EXPORTS

The recent international coal market trends described above do not paint a rosy picture for U.S. coal exports. The decline in global coal prices have made it difficult for U.S. exporters to compete with those from other countries who are aggressively trying to capture a share of the market. Compared with other coal producing countries, U.S. costs of labor; safety and environmental requirements; and domestic transport are higher. The United States does not compete on an economically level playing field. Several countries subsidize their coal industry, lack comparable safety and environmental controls, and exploit their labor force with low wages. Australia, Colombia, and China will continue to fight for a larger share of the global market, while Poland and South Africa will try to maintain their exports. New steelmaking technologies are changing the market for metallurgical coal. Once dependent on high-quality met coal, found principally in the U.S., steel producers worldwide are now able to reduce their met coal requirements while fulfilling their needs with more plentiful "soft" coking coal available from a number of countries. U.S. competitiveness is further impacted by a strong U.S. dollar, which automatically makes U.S. coal more expensive compared to other currencies.

These factors contribute to a growing perception that the United States, once the dominant source of international coal exports, may be relegated to the role of "swing producer." U.S. exports may be sought less for base demand than for marginal demand bought during periods of high economic activity. As "swing producer", U.S. coal exports could collapse in periods of global recession.

Still, The United States has 29 percent of global coal reserves and will likely remain the most secure source of the highest quality coal in the world. Coal importers may be willing to pay for these benefits.

In 1985, the International Security and Development Cooperation Act established the Federal Coal Export Commission to identify opportunities for and impediments to expansion of the

U.S. share of the international coal market. The Commission released its final report in June 1988,[1] identifying a number of factors affecting U.S. coal exports (outlined in Table 18).

TABLE 18
OBJECTIVES FOR EXPANDING U.S. COAL EXPORTS IDENTIFIED BY THE FEDERAL COAL EXPORT COMMISSION, JUNE 1988

1. Expand Coal Use Worldwide

2. Increase competitiveness of U.S. coal by reducing costs
   a. mine mouth costs -- 50-75% of port FOB cost
   b. inland transportation cost -- 20-40% of port FOB cost
   c. port terminaling charges -- 5-10% of port FOB cost

3. Level the "playing field" of international coal trade
   a. promote fair trade
   b. promote reduction of coal industry subsidies
   c. promote equitable labor and environmental protection policies worldwide

Expansion of worldwide coal use may be the most important factor affecting the quantity, if not the market share, of U.S. coal exports. An expanding global economy (and in turn growing steel production) increases demand for high-quality U.S. metallurgical coal. Although newer technologies can utilize "soft" coking coal available from other countries, U.S. "hard" coking coal can increase steel productivity, necessary to an expanding industry. The return of high global oil prices will enhance steam coal demand and prices. However, higher oil prices may dampen global economic growth (as they did in the mid-1970s and early 1980s). Such a development could reduce growth in total energy consumption and coal-consuming steel production.

A second major goal cited by FCEC is to increase the competitiveness of U.S. coal by reducing costs. Mining costs have the greatest effect (50-75%) on export price. The Commission report cites recent improvements in efficiency and productivity of U.S. mines -- productivity increased by 5.9 percent per year between 1977 and 1986. The report also lauds improved labor relations in the coal industry, highlighted by the 1988 National Bituminous Coal Wage Agreement.

Domestic coal transport, primarily by rail and barge, contributes an estimated 20-40% to U.S. export price. The Commission report referred to the current controversy surrounding the 1980 Staggers Rail Act, which relaxed most economic regulations on the rail industry. However, this particular issue divided Commission members into "strongly opposing factions," resulting in no Commission consensus or position on the issue. The controversy stems from the fact that while the Staggers Act promoted competitive pricing of rail service

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[1] *Final Report of the Federal Coal Export Commission*, U.S. Department of Commerce, International Trade Administration, Washington, D.C., June 1988.

in regions served by more than one carrier, it allowed railroads to set confidential rates for coal mines served (or "held captive") by a single railroad. Congressional efforts to resolve this problem through legislation that would enhance the ability of captive mines to challenge rates (the so-called Consumer Rail Equity Act) appear to have stalled in 1988.[2]

Port terminal charges also affect coal export price, (5-10 percent of FOB price). One issue related to these charges is the recent change in cost-sharing by parties using federal improvements in ports and waterways (such as the current deepening of the Hampton Roads Channel). In 1986, the Water Resources Development Act transferred a substantial portion of these financial responsibilities from the general taxpayer to local ports, which in turn pass them on to port users, and are ultimately reflected in the price of commodities shipped. The Commission did not evaluate the effect of this legislation, but cautioned Congress to be aware that such policy changes can hinder the competitiveness of U.S. coal exports.

The third issue regarding expansion of U.S. coal exports involves leveling the playing field of international coal trade. Unfair trade practices by a number of countries impede U.S. coal competitiveness. The Commission recommends policies which promote fair trade, reduce national subsidies of coal industry in other countries, and encourage equitable labor and environmental protection policies in other coal-producing nations.

Unfortunately, the Commission's report lacks specific recommendations to expand U.S. coal exports. Rather, it identifies factors which may affect the international coal market and U.S. competitiveness. It appears that there is no simple cure-all for the U.S. coal export industry. The greatest advantages to the United States are (1) the quantity and quality of coal available for export; (2) the dependability of infrastructure, from mine to domestic transport to export terminal; and (3) political security of supply. These advantages will guarantee the United States a share of the world coal market for decades to come. However, current trends indicate that U.S. relative competitiveness has declined because of changes in the market, actions of other coal exporting countries, and the rising value of the dollar. If these trends continue, the U.S. role in the world market may change from dominant supplier to swing producer.

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[2] "Kiss Staggers Repeal Goodby?" *Coal Outlook* (August 22, 1988).

THE REVOLUTION IN ELECTRIC UTILITY PLANNING: LEAST-COST PLANNING, COMPETITIVE BIDDING, TRANSMISSION ACCESS

John Randolph
Director, Virginia Center for Coal & Energy Research
Associate Professor, Urban Affairs and Planning
Virginia Polytechnic Institute and State University
Blacksburg, Virginia 24061

Electric power planning in the United States is currently undergoing significant change. In past decades, utility planning involved simply projecting public power demand and scheduling generating facilities or power purchases from neighboring utilities to meet those projections. Although regulated by state commissions, utilities faced such consistent growth in demand and relatively low fuel and construction costs that both the planning task and regulatory oversight were straightforward.

However, the 1970s ushered in an era of uncertainty and planning complexity for electric utilities. Oil and other fuel prices increased dramatically, prompting a surge in inflation and economic recession. Electricity demand moderated, and many utilities found themselves in the midst of powerplant construction programs without foreseeable demand to use the power. After investing heavily in oil-fired capacity in response to air pollution regulations on coal, utilities found the tables turned as oil prices rose. Plans for nuclear capacity were particularly hard hit by declining demand growth, increasingly stringent regulations, and construction cost overruns, causing scores of project cancellations -- many in mid-construction.

To complicate matters for utilities, Congress passed the 1978 Public Utilities Regulatory Policy Act (PURPA), requiring them to interconnect qualifying, non-utility cogenerators and renewable power producers. Congress' intent was to stimulate development of these efficient facilities. PURPA also encouraged utilities and state commissions to consider energy conservation, and many states directed utilities to broaden their services with energy conservation programs.

All of these factors contributed to the planning and financial disarray of most utilities during the early 1980s. Yet, many resourceful utilities saw opportunities under the new operating conditions and rules. With uncertainties in future demand and increasing risk in capacity investment, some have embraced the development of smaller scale PURPA generating facilities financed by independent parties. Some utilities with high fuel costs or small capacity margins have found conservation programs an effective way to delay capacity additions and moderate rate increases.

These experiences have laid the groundwork for an emerging revolution in electric utility planning. Prompted by proposals of the Federal Energy Regulatory Commission and actions by several state commissions, utility planning is in the process of becoming far more comprehensive in terms of alternatives and impacts, and as a result, far more political. This planning revolution involves three separate but related issues: least-cost, or integrated utility planning; competitive bidding for electricity supply; and transmission access, or wheeling of power.

This paper first describes these three issues, then discusses how they are related and what implications they may have on our future electric power system.

TABLE 1
SUMMARY OF LEAST-COST PLANNING PROGRAMS BY STATE

STATE	PROGRAM	STATE	PROGRAM	STATE	PROGRAM
Alabama	no	Louisiana	no	Ohio	**statewide**
Alaska	no	Maine	**utility**	Oklahoma	**utility**
Arizona	considering	Maryland	developing	Oregon	no
Arkansas	no	Massachusetts	see note 1	Pennsylvania	**utility**
California	yes	Michigan	developing	Rhode Island	developing
Colorado	considering	Minnesota	considering	South Carolina	no
Connecticut	**utility**	Mississippi	no	South Dakota	no
Delaware	**utility**	Missouri	considering	Tennessee	no
Florida	**statewide**	Montana	no	Texas	**statewide**
Georgia	no	Nebraska	see note 2	Utah	developing
Hawaii	no	Nevada	**utility**	Vermont	**statewide**
Idaho	considering	New Hampshire	see note 2	Virginia	**utility**
Illinois	developing	New Jersey	see note 3	Washington	**utility**
Indiana	yes	New Mexico	developing	West Virginia	see note 4
Iowa	developing	New York	**statewide**	Wisconsin	**statewide**
Kansas	no response	North Carolina	developing	Wyoming	no
Kentucky	developing	North Dakota	no	Dist. of Col.	**utility**

1. Aspects of least cost-planning incorporated in facility siting process.
2. All public power; no state body with rate-making authority.
3. Aspects of least-cost planning incorporated in conservation program.
4. Least-cost planning incorporated in rate cases.

statewide = statewide perspective approach
utility = utility planning approach

Source: Berry (1988) based on Arizona Corporation Commission Staff Survey, April 1987.

LEAST-COST UTILITY PLANNING

Least-cost utility planning programs involve the integrated analysis of both supply options and demand-side alternatives, such as conservation and load management (C&LM), in deciding how future electricity needs will be met. While utility executives maintain they have always taken a least-cost approach (PUF 1988a), few have consistently analyzed demand-side options and integrated them with traditional supply-side planning.

Least-cost planning increases the scope and comprehensiveness of traditional utility planning by putting supply- and demand-side options for meeting electrical needs on equal footing. The method rests on the premise th. electric utilities should provide energy services (i.e. not just electricity but the end-use functions of that energy) at the least possible cost (Wellinghoff 1988).

Least-cost planning has proven quite popular among state legislatures and regulatory commissions. As shown in Table 1, as of April 1987 eighteen states had adopted a least-cost planning program, three incorporated least-cost principles in other programs, and fourteen others were developing or considering least-cost planning. Only 15 states were not pursuing least-cost planning (Berry 1988).

Berry (1988) indicates that existing state-regulated, least-cost planning programs are of two basic types. In the "utility planning" approach, state commissions require utilities to prepare specific information on supply/demand forecasts and options by setting up detailed reporting requirements. The commission can then use this information in a variety of ways, including rate cases and applications for plant construction or conservation programs. Although this approach depends heavily on the utilities for data and analysis, it gives them a sense of ownership of their plans (once approved). Thus, they may be more apt to implement them. Table 1 shows that eight states and the District of Columbia use this approach.

The second approach which Berry calls the "statewide perspective," involves commission development of a statewide analysis of electricity supply and demand. The commission can then use this analysis to review utility construction applications, plans, and rate requests. Six states in Table 1 use this statewide perspective.

Despite the widespread acceptance of least-cost planning by state regulatory commissions, the debate goes on over the merits and implementation of the approach. (See Lovins [1985], Wellingkoff and Mitchell [1985], Schneider [1986], Morkowitz [1986], Cavanaugh [1986], Puff [1988], Steigelmann [1988], Whittaker [1988], Woyclink [1988], Wellingkoff [1988]).

Major concerns include:

- how to provide incentives to utilities so that they will truly treat demand and supply side programs on a comparable bases;
- how to assure that demand-side investments maximize efficiency;,
- how to protect ratepayers, especially non-participants, in demand-side programs;
- how to deal with the uncertainty and reliability questions of demand-side programs.

The first concern is perhaps the most fundamental. Why should investor-owned utilities get involved in demand-side programs which diminish electricity sales -- and profits? Most utilities have done so only in response to regulatory commission rules developed for the public benefit. If utilities do not see a vested interest in demand-side programs by sharing in the energy and cost savings they provide, then these programs will never receive the equal consideration that least-cost planning requires.

Ruff (1988) goes so far as to suggest that utilities may not be the logical party to provide demand-side programs:

> *Determining how to supply power in the "least-cost" way should be the utilities sole responsibility. It is undeniably true that the economy should be organized so that someone, somewhere, compares the cost of saving kwh with the cost of producing*

kwh and saves the kwh whenever this is cheaper; but it does not at all follow that the cost comparisons need be made within utility planning or that C&LM actions need be undertaken as utility programs... Customers and firms who specialize in serving them can be trusted to decide how to use electricity in a "least-cost" way, with the results reflected in the demand for utility services, with no need for the utility to evaluate all downstream options and second-guess customers' decisions.

Whittaker (1988) acknowledges that there may be a place for investor-owned utilities in demand-side programs, but for such programs to be successful, utilities must be rewarded in terms of their ultimate goal: greater profits. Whittaker argues that this can be accomplished by allowing utilities to charge customers, not only for kwh sold, but also for kwh saved as a result of conservation measures installed or financed by the utilities. Further, he recommends that rates for sold and saved kwh be the same. He argues that such a program would stimulate a great deal of conservation activity. Although consumers would pay for the electricity saved by the utility program, they would not pay more for the actual services performed (e.g., a cool house in summer) than before. Whittaker believes that once such a program is started, consumers would likely exploit "their own conservation resources for profit before the local utility does so." While Whittaker's approach is novel, it raises questions about incentives for consumer participation, how savings from utility conservation measures can be separated from lifestyle effects, and a number of administrative issues.

Wellinghoff (1988), of the Nevada Attorney General's Office, agrees that utilities can and should provide demand-side programs, but argues that adequate incentive can be provided through conventional cost-recovery mechanisms. He offers a cost-recovery formula for demand-side options that not only provides such an incentive, but also addresses the second and third concerns cited above (i.e., maximizing efficiency of demand-side investments and protecting ratepayers). The annualized demand-side cost recovery is:

$$\frac{DE + CC + (AC - DE) \cdot Z}{AP}$$

where:
- DE = Demand-side measure Expenditures
- CC = Carrying Ccharges
- AC = system Avoided Cost = system cost of supply avoided by demand-side measure
- Z = administratively set incentive factor between 0 and 1, defining the level of benefit sharing between ratepayers and utility shareholders
- AP = Amortization Period equivalent to life of demand-side measure

With this formula, the utility is able to recover (over the lifetime of the demand-side measure) the cost of the measure, plus carrying charges, plus a profit incentive ([AC - DE]*Z) based on the cost effectiveness of the measure. This incentive is maximized in the most cost effective measures (i.e., high AC, low DE). It reduces to zero and turns negative as the costs of measures approach and exceed the costs of avoided supply.

Woychik (1988), of the California PUC, proposes a standard practice approach to evaluate supply and demand options on a common basis. It involves a "with/without analysis" to test for cost effectiveness and rate impacts, and a "reliability adjustment factor" to explicitly consider uncertainties involved in both supply and demand options. The cost effectiveness test compares total system, net-present-value (NPV) costs with and without the supply- or demand-side resource being analyzed. The resource is cost effective if the NPV is less with the resource than without it. Likewise, the rate impact measure (RIM) compares NPV of total utility revenue requirements with and without the resource in question, then divides the difference by system sales to show net rate change with the resource.

The above discussion indicates that although least cost utility planning remains controversial, the revolutionary method is being adopted by most state utility regulatory commissions. Planning methods required for effective integration of supply- and demand-side alternatives are evolving.

COMPETITIVE BIDDING FOR FUTURE GENERATING CAPACITY

The 1978 Public Utilities Regulatory Policy Act (PURPA) required electric utilities to interconnect certain "qualifying" non-utility generators and to purchase from them their excess power at reasonable rates. According to the Federal Energy Regulation Commission's (FERC) implementing rules for PURPA, these rates must be based on the energy and capacity costs the utility avoids by purchasing the power. Since these "avoided costs" vary from utility to utility, so do their purchase rates.

By providing a guaranteed market for sale of electricity, PURPA encouraged the development of "qualifying facilities" (QFs). They include (a) any size cogeneration facilities which produce both electricity and useful thermal energy at a total efficiency of more than 42 percent (at least 5 percent thermal); and (b) "small power production" facilities which are less than 80 megawatts (mw) in capacity and use renewable energy (e.g., municipal wastes, hydro, wind, wood, solar, geothermal) for at least 75 percent of their energy input.

During its first 10 years, PURPA has prompted a great deal of QF development. A 1988 profile of qualifying facilities lists 1,808 operating QFs totaling 24,833 mw, with another 38,345 mw in various stages of development and considered likely to be realized. Of the total "active" capacity of 63,178 mw, 74 percent is cogeneration and 26 percent small power production; 44 percent of active cogeneration is fueled by natural gas (RCG Hagler, Bailley, Inc. 1988). Estimates of annual QF generation exceed 100 million mwh or more than 4 percent of utility production (Edison Electric Institute 1987).

In utility service areas with relatively high "avoided costs" (i.e., high fuel costs or projected capacity needs), cogeneration and small power developers have been very active. Indeed, generation requests by QFs have in many cases exceeded the utility's forecasted demand growth. This has prompted several utilities, and state regulatory commissions overseeing them, to adopt a market-based approach to new electricity supply. Some now require proposed suppliers to engage in a competitive bidding system. Lowest-cost bidders (who also meet other criteria established by commission or utility) are then awarded contracts. Through the bidding system, avoided costs are determined by competitive market forces rather than merely the utility's generation options.

As of March 1988, utility commissions in six states had issued rules for competitive bid solicitations by utilities. On March 16, FERC issued proposed rules which would give states the right to allow competitive bidding under PURPA and provide guidelines for such systems. Hearings on the proposal are scheduled for July.

The provisions of the existing state rules and the FERC proposal are summarized in Table 2. A number of factors are described for each, including:

- What size supply block is included in the bid request? Is the block based on a long-term supply plan? Is a ceiling price provided?
- Which facilities are qualified to bid, which are exempt, what price is paid to these exempt facilities, and are certain facilities given special consideration?
- What is the selection criteria, and what price will be paid to winning bidders?
- What transmission access or wheeling provisions are included in the rules?

All approaches provide bidding for a specified supply block based on a long-range plan. The plan ranges from 6 years in Virginia to 30 years in Maine. In most states, it is a "least-cost" plan based on demand- and supply-side options available to the utility. The supply block for bid is either administratively set or determined by the utility (Virginia), or by both the utility and the regulatory commission (Connecticut, Texas). In Maine and Massachusetts, the block is a percentage of the utility's current peak demand; in California, it is based on an "avoidable" utility generating plant. Some states set a ceiling price in the bid request that is based on the utility's generating options.

Regarding qualifications, most states' rules provide for only QF involvement in the bidding process. However, Virginia and the FERC proposal provide "all source" bidding, allowing

COMPETITIVE BIDDING SYSTEMS FOR NON-UTILITY POWER GENERATION

Factor State	Texas	Maine	California	Massachusetts	Virginia	Connecticut	FERC
Date	1984	1986	1986	1986	1988	1987	1988 Proposed
Long Term Plan	yes	30 year	12 year	20 year	6-10 year	20 year	yes
Supply Block for Bid	PUC determined	10% peak demand	avoidable plant	5% peak demand	utility determined	utility, PUC	based on plan
Ceiling Price	no	avoided cost of supply block	avoidable plant	utility least-cost mix	no	no	based on plan
Qualified Bidders	QFs > 100 kw	QFs > 1 mw	QFs	QFs (proposed: all source & conservation)	all source > 3 mw (QFs, IPP, non-host utilities)	QFs (cogen. > 20% thermal)	all sources
Exempt from Bidding	QFs < 100 kw	QFs < 1 mw	-	QFs < 1 mw	QFs < 3 mw	QFs < 1 mw; renew. < 5 mw MWtE < 10 mw	QFs < 1 mw
Price for Exempted	avoided energy cost	full avoided cost	-	weighted ave of winning bids	avoided energy cost	-	based on winning bids
Special Consideration	renewable, MWtE	-	-	-	-	-	-
Evaluation Criteria	lowest price	lowest price, reliability	lowest fixed cost	sum of weighted price and non-price factors	price, VA fuel, societal benefits	sum of weighted price and non-price factors	price and non-price factors
Price for Winning Bidders	bid price	bid price	lowest losing bid price	bid price	bid price	bid price	bid price
Transmission Access	wholesale for QF; retail for renewable < 10 mw	case by case	-	intrastate	intrastate	-	participating utility: wheel in/wheel out

Abbreviations: PUC = Public Utility Commission; QF = qualifying facility; mw = megawatt; kw = kilowatt, MWtE = municipal waste-to-electricity.

Sources: Meade (1987); Nagelkout (1988); Virginia SCC (1988); Connecticut DPUC (1987); Massachusetts DPU (1986); California PUC (1986); Maine PUC (1987); Texas PUC (1984).

participation of non-QF independent power producers (IPP) and other utilities. This opens up the bidding system and may lead to lower-priced bids. To improve the prospects for IPPs, FERC has issued a companion rule proposal which would relieve much of the regulatory burden on these less efficient producers. In Virginia, bidders are restricted to supply-side generators. FERC's March 16 proposed rules are vague in their definition of "all source," but the Commission is considering making offset payments of full marginal cost for demand-side reductions an element of its capacity bidding rules (Hines 1988a). In Maine (and proposed in Massachusetts), demand-side services do qualify for the bidding process. Users and energy service companies can submit bids for conservation programs intended to absorb a portion of the supply block up for bid. The implications of promoting IPPs and demand-side bidding are discussed later in this paper

All states (except California) and FERC's proposal exempt smaller QFs from the bidding process. The maximum size of exempt facilities ranges from 100 kw in Texas to 3 mw in Virginia. In Connecticut, the following facilities are exempt: cogenerators (with more than 20 percent thermal output) less than 1 mw; renewable energy facilities less than 5 mw; and municipal waste-to-electricity facilities less than 10 mw. These exempt facilities need not compete in the bidding system and are still guaranteed a market. However, the bidding system will affect the price they are paid for their power. In most states, exempt QFs will not compete for capacity and will not be paid a capacity fee. They will only receive a rate based on avoided energy cost. This is likely to reduce revenues available to these facilities below what they would receive without competitive bidding. In Maine, however, exempt facilities are paid full avoided costs. In Massachusetts, exempt QFs are paid the weighted average price of winning bids. FERC's proposal calls for rates, terms, and conditions for exempt QFs (< 1 mw) determined by the bidding program.

In Texas, renewable power and municipal waste-to-electricity are given special consideration. When a utility requires added capacity, these facilities must be considered first. In addition, utilities are required to provide <u>retail</u> wheeling for renewable power facilities under 10 mw. Thus, these facilities can sell their power over utility transmission wires to end-users under contract. FERC's proposed rules would allow states to withhold a portion of a utility's planned capacity needs from bidding, but QFs must be given an opportunity to satisfy the capacity withheld.

In most states, selection criteria for winning proposals is based on more than bid price. It is not simply an auction. Utilities obviously have an interest in factors other than price, including reliability, fuel used, location, etc. State regulators have required that certain criteria fulfilling their interests be part of the evaluation of proposals. For example, while the Virginia State Corporation Commission (SCC) has given utilities a great deal of flexibility in implementing the bidding process, it has suggested consideration be given to use of Virginia fuels and manpower; high percentage of steam and electricity used by the host firm; and economic and societal benefits to the people of Virginia (Virginia SCC 1988). Massachusetts and Connecticut call for a detailed evaluation procedure that produces a rating score for each bid based on a sum-of-weighted price and non-price criteria. Using this method, factors other than price play an explicit role in deciding among proposals.

The utility ultimately negotiates contracts with winning bidders. In all but California, contracted purchase rate is based on the bid price. In California, bids are only for a capacity supply block based on an "avoidable" utility power plant. Winning bidders (those with lowest fixed cost) are awarded a capacity fee based not on their bid but on the lowest losing bid.

To open up the bidding system as much as possible, most states allow intrastate "wheeling" of power from one utility service area to another. This gives a firm in one utility service area the option to bid on a request-for-proposals from another utility in the state. If successful in its bid, the firm can transmit power over one utility's lines to another. FERC has hesitated to address the wheeling question, but has asked for comments on a proposed requirement that a utility participating in competitive bidding allow wheeling in and out of its service area.

TRANSMISSION ACCESS AND WHEELING

The question of "wheeling," or transmission access, is the third major issue affecting utility planning. As mentioned above, wheeling of power is the use of a utility's transmission lines (for a fee) by a cogenerator (for example) to transmit power for sale to another utility (wholesale wheeling) or an end user (retail wheeling). Some analysts have argued for mandatory wheeling, particularly in competitive bidding systems; this would require utilities to wheel power for certain generators. FERC Chairman Martha Hesse has stated that competitive bidding can achieve a free market "only if the potential power suppliers have adequate transmission access" (Hesse 1987). Without wheeling, competition would be restricted to potential generators within the soliciting utility's service area.

Indeed, some states (Texas, Massachusetts, Virginia) involved in competitive bidding require intrastate wholesale wheeling to increase competition in the bidding system. Under their programs, if utility A solicits competitive bids for capacity, a cogenerator planning to locate in neighboring utility B's service area can submit a bid. If his bid is successful, he will be guaranteed the right to wheel his power over utility B's lines to utility A. As mentioned above, Texas requires retail wheeling for small producers ($<$ 10 mw) using renewable energy. Such generators can wheel power to end-users and sell their power at contracted rates.

Despite this apparent movement toward transmission access for non-utility generators, the current legal basis for mandatory wheeling is unclear. Under present FERC regulations, wheeling of cogenerator power by utilities is voluntary, not mandatory. FERC countered Florida's attempt to require intrastate wheeling of power produced by PURPA qualifying utilities. On an appeal by Florida Power and Light, FERC asserted exclusive jurisdiction over rates, rules, and conditions of interstate wheeling, which it ruled, includes **intra**state wheeling if **one** utility has interstate connections (FERC 1987).

Although sections 211 and 212 of the Federal Power Act allow FERC to order wheeling on behalf of an electric utility under certain conditions, the Commission has thus far been reluctant to use this authority.

Still, there is an ongoing debate over the merits and consequences of opening transmission access. (See Chalker [1988]; Anderson and Pace [1988]; Radford [1987]; Romo [1988]). On one hand, most agree with FERC Chairman Hesse's statement that competitive bidding will be constrained and limited if some kind of transmission access if not provided. Another FERC Commissioner, Charles Stalon, has stated that the lack of mandatory wheeling is "a major barrier" to cogeneration and independent power development.

On the other hand, few support mandatory retail wheeling. Chalker (1988) argues it would lead to "cream skimming" that would benefit a few non-utility generators and some large customers at the expense of the utilities and their ratepayers. Although the Electricity Consumers Resource Council (which represents large power users who might benefit from retail wheeling) argues that state regulators should have the authority to order wheeling -- including retail wheeling -- on a case-by-case basis, it does not advocate mandatory wheeling across-the-board (Anderson and Pace 1988).

Despite actions by some states that appear to violate FERC's existing rules and the importance of the wheeling issue to competitive bidding systems, the Commission has taken little action to resolve the issue. However, as mentioned above, FERC has requested comment on a policy requiring that a utility soliciting competitive bids allow wholesale wheeling <u>into</u> its service area by outside generators and wheeling <u>out</u> to neighboring utilities by generators located in its service area. FERC also asked for public comment on pricing of transmission services (EUN 1988). Chairman Hesse has indicated that proposed rules dealing with transmission access will be initiated by the end of 1988 (Hines 1988b).

IMPLICATIONS OF THE REVOLUTION IN UTILITY PLANNING

Changes in global energy markets and innovations in both utility-operated conservation programs and non-utility generation have fueled a revolution in electric utility planning in the United States.
Yet, the implications of widespread use of least-cost planning and competitive bidding coupled with transmission access have not been fully addressed. Some analysts argue that FERC and some state commissions have rushed headstrong into a new era of utility planning without adequately assessing the effects on our electric power system (Ruff 1988; Pace 1988; Chalker 1988; Studness 1988). While some concerns about this movement were discussed above, it is helpful to elaborate on possible consequences. A thorough consideration of potential impacts can improve the effectiveness of these emerging changes in electric power planning.

Issues in Least-Cost Planning

The rationale for equal consideration of supply- and demand-side options in planning new electricity supply is based on the success of many utilities in offering conservation programs and the substantial opportunities for conservation and load management. Some, however, look upon utility conservation services as limited because of the overall ineffectiveness of the federally mandated Residential Conservation Service (RCS). In its first ten years, the program cost $660 million (most integrated into utilities' rate bases), but will achieve energy savings estimated at only 7.4 trillion BTU in 1989. The program is scheduled to expire in mid-1989 (U.S. DOE 1988).

However, in six states (Michigan, Massachusetts, New York, Wisconsin, California, and Illinois) the RCS program has been far more effective than for the nation as a whole. Most of the nationwide audits and two-thirds of the energy savings have occurred in these states. One reason is that utilities in these states complement the RCS information program with financial incentive schemes offering low interest loans or rebates for conservation and load management (C&LM) investments. The Conservation Service Reform Act of 1986 scheduled the end of RCS, but gave state commissions increased flexibility to implement different types of conservation programs that meet state-specific needs (Sponseller 1988). As a result, the involvement of commissions and utilities in such incentive programs has increased dramatically across the nation during the past few years, despite lower energy prices. In a survey of utility C&LM programs, *Energy Users News* reports that the number of utilities offering commercial and industrial rebates has grown from less than 10 five years ago (mostly on the West Coast) to about 60 today, in nearly all regions of the country (Fore 1988). Utility experience in conservation, particularly in the Pacific Northwest,[1] has convinced many analysts and regulatory commissions that utility programs will be the principal mechanism for implementing energy efficiency in buildings and industry during the next decade (ORNL 1987; Flavin and Dunning 1988; Alliance to Save Energy 1988).

Still, the principal concerns about least-cost planning and utility demand-side programs discussed earlier must be addressed if such initiatives are to be successful. These issues include (1) providing profit incentives to investor-owned utilities for demand-side programs; (2) assuring that demand-side investments maximize efficiency; (3) protecting ratepayers who do not participate in utility C&LM programs; and (4) consideration of the uncertainties of demand-side programs and impacts on system reliability. As discussed earlier, researchers

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[1] Despite having the lowest electricity rates in the nation, utilities serving Washington, Oregon, Idaho, and Montana have established the model of utility-least cost planning and conservation services. With the assistance of Bonneville Power Administration and the federally established Northwest Power Planning Council, utilities have implemented a wide range of programs designed to offset future capacity needs (PNUCC 1987; NPPC 1987). For example, Seattle City Light, a municipal utility, operates loan and grant programs which aim to retrofit all electrically heated residences with cost-efficient conservation measures over 10 to 20 years. Puget Sound Power and Light, an investor-owned utility, has cut its electricity demand by 200,000 mwh per year (23 average mw) through its rebate program (Fore 1988).

and commissions are developing policies and methods which address these concerns. For example, Wellinghoff's method of cost recovery for demand-side programs may prove effective in stimulating utilities to engage in cost-effective initiatives while protecting rates.

Issues in Competitive Bidding and Wheeling

By stimulating competition in electricity supply with the goal of lowering cost of new generation, competitive bidding can be viewed as a component of least-cost planning. The current experience of state commissions and FERC suggests two approaches to integrating least-cost planning and competitive bidding. The first, and that adopted by states most involved, calls for competitive supply bidding only after some type of integrated supply- and demand-side planning has identified generation capacity needs.

The second approach makes competitive bidding a more integral part of least-cost planning by including in the bidding process both supply-side and demand-side options for meeting or offsetting future capacity needs. This method has been advocated by a number of energy analysts (Lovins 1985; Flavin and Dunning 1988), and Central Maine Power Company has included C&LM in its bid solicitation. However, proposed FERC rules (which do not exclude demand-side options) have generated a great deal of discussion about the merits of the approach.

Several analysts have suggested that demand-side bidding may result in kwh savings that total twice the cost of supply, thus actually increasing rates and discriminating against customers who do not participate in the demand-side program (Ruff 1988; Hines 1988). They argue that paying customers or independent energy service companies for energy saved an amount equal to avoided costs (i.e., marginal cost of supply), will cost the utilities (and their ratepayers) twice: first in the payment for saved energy, and second in the reduced revenues of lower electricity sales. The second component may actually drive rates higher, as existing fixed costs have to be covered by reduced sales.

However, there are certain flaws to this argument. It is true that rates may increase if payments are made for conservation when the utility has excess capacity, the fixed costs of which must be covered by lower sales. But realistically, utilities with excess capacity will not engage in competitive bidding for new supply if they don't need new capacity.[2]

On the other hand, for those utilities likely to implement competitive bidding (i.e., those needing new capacity), demand side measures will not <u>reduce</u> sales and revenues needed to cover existing fixed costs, they will <u>offset</u> future demand growth and the capacity the utility needs to provide it. In this case, demand-side C&LM may provide effective options in the bidding process.[3]

However, cost-effectiveness is not the only issue affecting the viability of demand-side C&LM in competitive bidding systems. The Virginia State Corporation Commission, in excluding

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[2] Steigelmann (1988) argues that for utilities with excess capacity, "least-cost" planning should involve the promotion of economic development and increased demand, so that existing fixed costs can be covered by larger sales reducing the cost per kwh. For the most part this is true, because most demand-side opportunities (such as retrofitting existing buildings with insulation) will still be available when existing excess capacity is consumed and the utility explores ways of meeting new demand. However, some cost-effective demand-side opportunities may be available only today (such as the design of buildings built today) and utilities may wish to explore such options to mitigate long-term demand. In fact, the Northwest Power Planning Council and BPA have done exactly that. With excess capacity in the region, the Council has decided to suspend its major retrofit program and concentrate its efforts on conservation opportunities that would be foregone if not implemented today. These include incentives for efficient design and construction of new buildings (NPCC 1987b).

[3] Even for utilities with excess capacity, some investment in, or payment for, conservation may make sense (i.e., encourage conservation and protect rates of non-participants), as long as the cost to the utility of each kwh saved is less than the variable cost of supply (fuel cost for generation or wholesale rates for its purchases from another utility).

C&LM from its bidding rules, expressed concern about reliability and necessary interaction with utility customers by outside parties:

> *Theoretically a solicitation of new capacity should encompass all means of either increasing capacity or decreasing load in order to accomplish the goals of achieving the least cost to ratepayers and an economic allocation of resources. Practical and administrative considerations, however, may exclude certain options from the bidding process, including conservation and load management... Even though conservation and load management bidding options reduce load and reduce capacity needs, these options require interaction between the bidders and a utility's franchised customers. This, coupled with the fact that expected reduction in load is difficult to measure and compare with the supply-based bids makes it impractical to include load reduction in the solicitation process* (VSCC 1987).

There are some broader implications of the movement toward competitive bidding coupled with transmission access. One is the problem of risk and system reliability. By developing independent generating facilities over which the utility has far less control, competitive bidding may foster higher risk and less reliability of its electrical system. However, it was the perception of risk that pushed Virginia Power Co. to become the nation's utility leader in competitive bidding. After developing 13,000 mw of generating capacity, Virginia Power has decided to get out of the business of building new powerplants. Faced with 8-10 percent annual demand growth, it will meet all future needs through all-source competitive bidding. Virginia Power's finance vice-president James Rhodes indicates that utility building programs are risky business, particularly with such high demand growth, and they "earn at best a modest regulated return." To maximize the utility's profits, it abandoned its construction program, passing on some of the financial risk to developers of non-utility power. To ensure system reliability, the utility expects to sign contracts for 30 percent more power than it needs, assuming some projects will fail (Hines 1988c). After its first solicitation in 1987, the utility contracted for 1,178 mw from bids totaling more than 5,000 mw. In its second solicitation (March 1988), Virginia Power requested bids for 1,750 mw. After receiving inquiries for projects totaling 27,000 mw, the utility received complete bids for 86 projects totaling nearly 14,000 mw.

Primarily because of currently attractive natural gas prices, gas-fired cogenerators competed well in Virginia Power's first solicitation, commanding 85 percent of contracted capacity. However, considering the volatility of gas prices, reliance on these sources raises some question about the long-term cost effectiveness of this option. From Virginia Power's perspective, greater risks of this venture fall more on the rate payers than on the utility. Still, in its second solicitation, the utility sought increased fuel diversity by contracting more coal-fired capacity. Coal comprised 60 percent of the bid capacity (Virginia Power 1988).

Thus, the question of uncertainty and reliability depends on who bears the risks. In its current regulatory situation, Virginia Power has pursued a course in which the utility's financial risk is actually minimized even though the total risk of rate hikes and reliability problems borne by its customers may be substantial.

Another implication of competitive bidding, wheeling, and the improved status of non-QF independent power producers (IPP) concerns the ability of qualifying facilities to compete. PURPA singled out efficient cogenerators and renewable power producers as socially desirable because they conserve conventional fuels. PURPA guaranteed these QFs a market and assured them of buy-back rates based on the purchasing utility's cost of producing new power or buying it from the regional grid.

As discussed previously, QFs have proliferated as a result of PURPA. However, competitive bidding and easing the regulation of IPPs is likely to reduce the opportunities for QFs. While certain cogenerators may compete well in a bidding system due to their revenues from sale of steam, renewable power producers may not. Although most existing and proposed bidding programs exempt small QFs from the process, thus guaranteeing access, rates paid to them generally amount to avoided energy costs. Some provision such as Texas' "set-aside" capacity for QFs, or exemption with rates based on average or highest bid, may be necessary to continue to promote efficient QFs, particularly beneficial community-based facilities such as waste-to-energy plants.

The status of IPPs is also likely to affect continued development of cogeneration. Proposed FERC rules would remove most of the present regulatory burden on IPPs, essentially putting them on equal footing with cogenerators in the bidding process (FERC 1988). If the rules are approved as expected, some believe that most entrepeneurial development will shift from cogeneration to IPP. The reason is that the number of steam hosts for large cogenerators is limited. Cogeneration attorney Norman Pedersen indicates that many developers are "tired of hasseling with the steam host problem." "You won't see so many greenhouses being build," a popular option for developers without hosts to use the minimum 5 percent thermal energy and qualify as a cogenerator (Hines 1988d). If IPPs dominate in the competitive bidding system, improved efficiency of future power production will be foregone. In Virginia Power's latest solicitation (the first opened to IPPs), over 40 percent of the bidded capacity came from planned independent power producers (Virginia Power 1988).[4]

Finally, there is concern that competitive bidding may alter the fuel mix used in electric generation. During the past fifteen years, there has been a major shift in energy sources for utility generated power in the U.S. Between 1973 and 1987, coal-fired generation jumped from 45 to 57 percent of total utility production; nuclear has grown from 4 to 18 percent, while petroleum has dropped from 17 to 5 percent, and natural gas has fallen from 18 to 10 percent (U.S. EIA 1988). Also, electricity has been the dominant choice of consumers shifting from oil and gas, and thus has been instrumental in reducing oil consumption in buildings and industry. Electricity's proportion of primary energy consumption has grown from 27 percent in 1973 to 36 percent in 1987, and is expected to rise to 44 percent by 2000 (Studness 1988).

The concern is that if much of the needed electricity growth in the next decade comes through competitive bidding programs favoring oil- and gas-fired IPPs, we may be recreating an inefficient electricity generating system based on fuels with high price volatility and limited supply.

Competitive bidding programs should be tailored to develop a system not only of low cost power today, but also of efficiency and fuel diversity to assure lower rates in coming years. State commissions must establish decisionmaking criteria for bidding programs so that such a desirable generating system will result.

[4] Yet another issue affecting cogeneration development is the emergence of "anti-cogeneration" contracts. While certain utilities such as Virginia Power are encouraging non-utility power, many others wish to discourage it to preserve their sales. They offer customers who are contemplating cogeneration reduced rates in exchange for postponement or cancelation of their cogeneration plans. At least four state commissions (California, Indiana, Arkansas, and Illinois) have approved such contracts; only Michigan has rejected an anti-cogeneration rate, but on grounds unrelated to PURPA. The Cogeneration Coalition of America has filed a petition to FERC arguing that such utility and state commission action violates Congress' intent in PURPA (Bain 1988).

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LD5755105 APPENDIX D DF

D 12/29/88 Heard T 12/30/88 DF

SENATE BILL NO. .... HOUSE BILL NO. ....

A BILL to repeal the third enactment clauses of Chapters 81 and 91 of the 1987 Acts of Assembly, relating to the sunsetting of the priority given to use of Virginia coal in state facilities.

Be it enacted by the General Assembly of Virginia:

1. That the third enactment clauses of Chapters 81 and 91 of the 1987 Acts of Assembly are repealed.

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COMMONWEALTH of VIRGINIA

JOHN A. BANKS, JR
DIRECTOR

DIVISION OF LEGISLATIVE SERVICES
General Assembly Building
910 Capitol Street

POST OFFICE BOX 3-AG
RICHMOND, VIRGINIA 23208

IN RESPONSE TO
THIS LETTER TELEPHONE
(804) 786-3591

September 21, 1988

The Honorable John S. Herrington
Secretary of Energy
1000 Independence Avenue
Washington, D.C. 20585

Re: Demonstration Program for Post-Combustion Dry Sorbent Injection Technology

Dear Secretary Herrington:

On September 12, 1988, engineers from Virginia Power briefed the Coal Subcommittee of the Virginia Coal and Energy Commission on a proposed clean coal project which would be sited at their power station in Yorktown, Virginia. This proposed project would evaluate the application of dry sorbent injection technologies as a means of reducing SO_x emissions. As chairman of the Commission, I would like to convey to you the Commission's endorsement of this proposal and encourage the Department of Energy to provide matching funds to the maximum extent possible for the support of this activity.

The Commission believes that this project, proposed by Combustion Engineering in cooperation with Virginia Power and the Electric Power Research Institute, holds the promise of substantially reducing SO_x emissions at a fraction of the cost of wet scrubbing. If proven, this technology would be readily transferable to other coal-fired generating units across the nation. Additionally, the Commission understands that coals typical of the central Appalachian region would be utilized in these tests, thereby protecting the market for this coal should this technology be implemented on a large scale.

In summary, the Commission is favorably impressed with the design of the proposed project and believes that it conforms to the intent of your clean coal technology program. The Commission requests that the merits of this proposal be given full consideration in your selection and negotiation process.

Thank you for your consideration.

Sincerely,

Daniel W. Bird, Jr., Chairman
Virginia Coal and Energy Commission

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