VIRGINIA CENTER FOR COAL
AND ENERGY RESEARCH

ASSESSMENT OF VIRGINIA COALFIELD REGION CAPABILITY TO SUPPORT AN ELECTRIC POWER GENERATION INDUSTRY

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VCCER REPORT NO. 94-1

Virginia Tech
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VIRGINIA CENTER FOR COAL AND ENERGY RESEARCH

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Report No. 94-1

January, 1994

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Executive Summary

The economy of southwestern Virginia's coal-mining region suffers from lack of industrial development, and a corresponding lack of employment opportunities. This study was conducted to assess the potential of southwestern Virginia's coal mining region to support an electric power generation industry. Information was gathered via a survey of major land and energy resource owners, other business interests, and economic development agencies, and from auxiliary sources. The Virginia coalfield consists of three southwestern counties (Buchanan, Dickenson, and Wise) where the majority of the state's coal mines are located, and adjoining portions of four neighboring counties (Lee, Scott, Russell, and Tazewell).

Of surveyed firms and agencies, only one had conducted a thorough study of the suitability of a specific site for an electric power generation venture greater than 100 MW in size: Coastal Corporation has advanced a well-publicized proposal to establish an integrated gasification combined cycle (IGCC) "clean coal technology" facility at Toms Creek in Wise County, in partnership with Tampella Power Co. None of the other parties reported having conducted serious power development investigations. Lack of marketing opportunities, complicated by present transmission constraints, was the major factor identified which has prevented other firms from investing the resources required to conduct such investigations.

The region's major advantage as a potential locus for electric power production is local availability of fuel. It appears that locally produced coal and gas, and non-traditional fuel resources such as waste heat, coal refuse, and low-Btu coalbed methane, could be made available to power generation facilities. The nature of the region's fuel resources, and its location relative to potential markets, are better suited to baseload power than peaking power production.

Conventional Coal-Fired Generation:

Limitations of surface-water resources place a serious constraint on the potential for conventional coal-fired power development. Economies of scale dictate that these plants attain minimum sizes of at least a few hundred megawatts in order to produce power at competitive prices. These minimum competitive sizes are close to the maximum sizes that the best coalfield locations appear capable of supporting. Environmental restrictions in some southwestern Virginia rivers also limit power plant siting opportunities. Abandoned coal mines may harbor substantial volumes of water, but no information on quantities or legal constraints is available. Water-conserving heat rejection systems are commercially available, but are more costly to install and operate than conventional cooling systems. The coalfield region's capacity to support conventional coal-fired generation is estimated at 400 to 600 MW, based on the results of an Apco - Virginia Power study (Sargent and Lundy, 1991) which considered a variety of economic and environmental factors, including surface water availability.

Gas-fired Generation:

The region's gas resources could provide power development options, should marketing opportunities improve. Producers report that the region's gas resources are not being fully utilized due to pipeline and market capacity limitations. Some producers reported being forced to sell on spot markets despite a preference for long term contracts. Producers reported that marketing difficulties and restrictions are slowing gas resource development.

In many areas of the country, gas-fired combined cycle units are producing baseload power in unit sizes which are smaller than many conventional coal-fired plants. Gas-fired combined cycle facilities require only 1/3 to 1/4 of the water per MW of capacity, compared to conventional steam units. Survey participants report that available gas resources (*i.e.* currently developed or under active development, and non-contracted) could support approximately 600 MW of combined-cycle generation, if competitively priced power markets were available and accessible. This is a lower-bound estimate, as one major gas producer did not participate in the study. Participating gas producers reported that, if local markets were available at prices near current market levels, sufficient quantities of coalbed methane could be developed in a short time period to at least double the above estimate. Gas producers would look favorably on opportunities to serve local electric power generation markets paying competitive prices, because such markets would require gas on a year-round basis, and because service to such markets would not be dependent on long-distance pipeline transport. Gas-fired power generation, however, would bring fewer economic benefits to host locations than would coal-fired plants using locally mined coal.

Gas-fired combined cycle units established at locations with access to coal would have the option of converting to coal in the future, if IGCC technology costs decline to commercially viable levels. Some IGCC technologies can reduce per-MW water consumption by one-half or more, compared to conventional steam units. IGCC scale economies are consistent with those of gas-fired combined cycle power production. Continued development of water-conserving IGCC technologies, such as the Tampella process proposed for for Toms Creek in Wise County, will be necessary if Virginia producers are to employ IGCC on a commercial scale.

Non-traditional Fuels:

Non-traditional fuels (low-Btu coalbed methane, waste heat, coal processing fines, coal refuse) could also be made available, although they are not as abundant as traditional fuels. Currently, the non-traditional fuels are not being used for economically valued purposes; the most easily developed non-traditional fuel resource appears to be waste heat. Approximately 40 to 60 MW of electric power generation could be developed from this resource, in the short term, if reasonably-priced markets for this power were available. One coal producer reported an opportunity to burn the fine-particle waste stream from a coal processing facility to produce 15 to 40 MW of electric power.

TABLE ES-1. COALFIELD REGION GENERATING CAPACITY ESTIMATES

Fuel	Conservative Estimate	Liberal Estimate	Source
	(- - - - - MW	- - - - -)	
Coal	400	600	Apco-VP study (1991)
Gas (short term)	600	600	Fuel availability
Gas (long term)	-	600	Potential fuel availability
Waste Heat	40	60	Company study
Coal slurry fines	15	40	Company study
Total	1055	1900	

1. Estimates are not comprehensive, do not include proposed TAMCO facility (Wise County), other potential sites for coal-fired plants which may exist in the coalfield region, or potential sites for coal-fired plants identified by Apco-VP study (Sargent and Lundy, 1991) located outside of coalfield. Gas availability estmates are based on company reports.

Results of Capability Assessment:

Thus, a lower-bound estimate of the coalfield region's capability to support electric power generation facilities at this time is 1055 MW (Table ES-1). This estimate is preliminary and approximate, and is based on a review of available information; it is not based on site-specific study. Major factors limiting the accuracy of this estimate include imperfect information on mine-cavity water, gas availability, and coal-fired plant siting opportunities.

Additional southwestern Virginia sites suitable for conventional coal-fired generation may be present outside of the coalfield area. An Apco - Virginia Power study (Sargent and Lundy, 1991) identified, and recommended for further evaluation, potential 400 MW sites in Scott, Smyth, and Washington Counties, and a potential 800 MW site in Wythe County. These potential sites are not included in the above-cited 1055 MW lower-bound estimate.

Future Prospects:

Short-run prospects for establishing power generation facilities in the coalfields are not bright at present, primarily due to lack of power market opportunities. However, economic and societal changes over the next ten years could change the situation. As water resource utilization and air emissions restrictions imposed on U.S. society become more stringent, as economic growth increases regional baseload power demands, and as IGCC technology becomes commercialized, the competitive position of coalfields as a power generation location may improve. However, improvements to the electric power transmission system, both locally and regionally -- allowing power generated within the Virginia coalfield to be marketed in faster growing areas -- will be required if southwestern Virginia is to take advantage of future opportunities.

Introduction

The economy of the Virginia coalfield region suffers from lack of industrial development, and a corresponding lack of employment opportunities. Large quantities of natural resources (coal, natural gas, and timber) are produced within the region, but the majority are shipped to other locations as raw materials. The regional economy would benefit if local "value-added" industries, utilizing locally-produced resources, could be developed.

Fossil fuels -- such as coal and natural gas -- are consumed in substantial quantities by the generation of electric power. Per capita consumption of electrical energy -- in total, and as a proportion of total energy use -- are increasing with time, both in Virginia (Randolph, 1991) and in the U.S. as a whole.

A reliable supply of electricity is available at most Virginia locations at competitive prices. Currently, Virginia's citizens and businesses consume more electric power than is generated within the state. The Virginia Center for Coal and Energy Research (VCCER) estimates that, in 1990 and 1991, approximately $800 million per year of electrical energy expenditures by customers of Virginia's two major utilities (Appalachian Power Co. and Virginia Power) supported costs required to generate electricity out of state for consumption in Virginia.

Objective

This paper describes the results of research conducted to assess the capacity of the Virginia coalfields to support electric power generation facilities. The research also addressed potential economic impacts of power generation facilities.

Method

The research was conducted by gathering information from a variety of sources.

The primary source of information was a survey of major land and energy resource owners, other business interests, and economic development agencies serving Virginia's coal-producing region. The purpose of the survey was to gather information on the availability of resources necessary to support power generation facilities, and on the perceptions of individuals associated with the region's principal industries and agencies. The survey was conducted via personal interviews with principal parties associated with these business interests and agencies.

Auxiliary sources of information were used to pursue study objectives. These included discussion with knowledgeable parties and reference to literature.

Previous Research

Randolph *et al.* (1990) surveyed coal and natural gas producers to assess fuel availability. They found area coal producers willing to dedicate coal resources to power generation facilities in amounts sufficient to support 1,575 MW of power generation. At that time, natural gas producers were not willing to commit resources to the long-term contracts that would be required to establish power production facilities. However, the Randolph *et al.* (1991) study did not seek to assess the availability of resources other than fuels.

Background Information

Over ninety percent of Virginia's electrical energy is provided by two major utilities, through direct service to their own customers or indirectly, through power supplied to the state's rural electric coops and municipal utilities. The state's major utilities are Appalachian Power Company (Apco) and Virginia Power (Figure 1).

Virginia Power

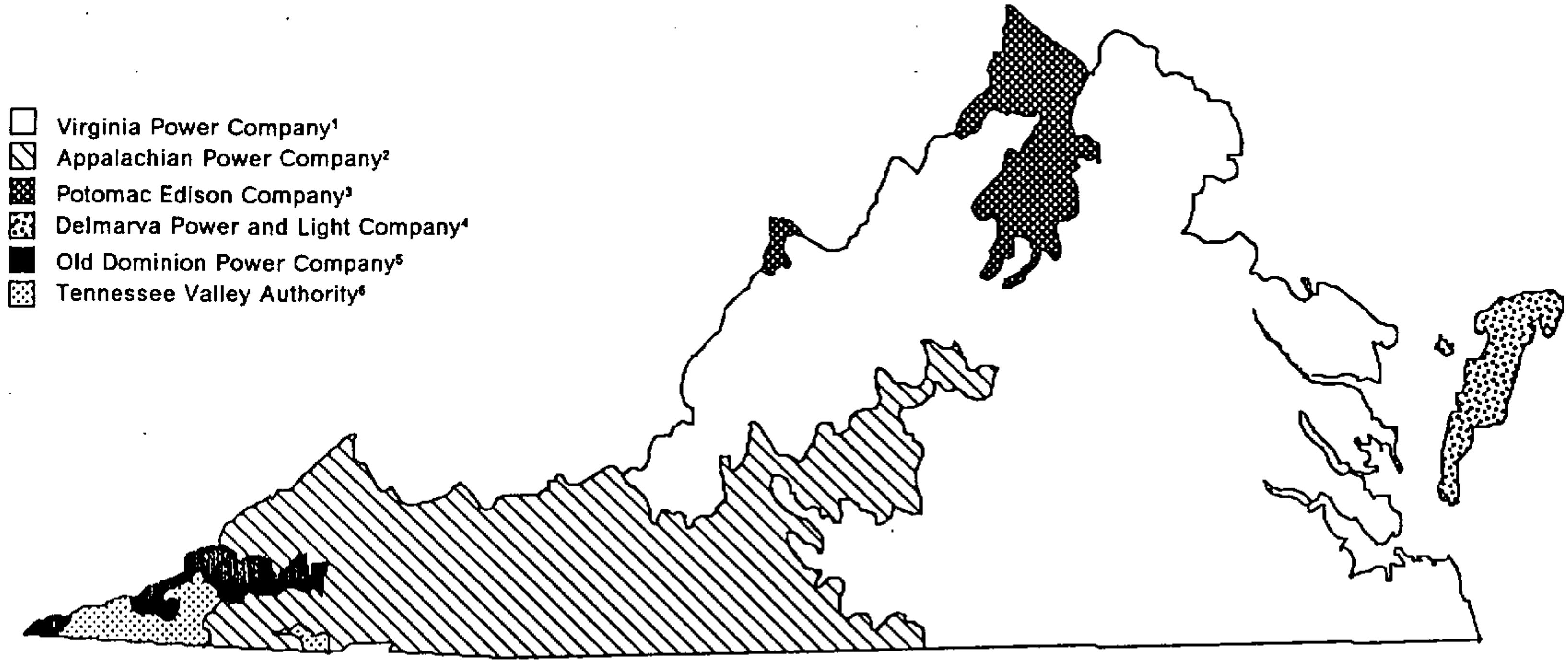
Virginia Electric and Power Company (VEPCO) is a subsidiary of Dominion Resources, Inc. VEPCO is an investor-owned utility which operates as Virginia Power in Virginia, and North Carolina Power in North Carolina. Dominion Resources is also the parent company of Dominion Energy, a non-utility subsidiary which develops independent power production facilities and natural gas reserves.

Virginia Power serves nearly 65 percent of Virginia's land area, and over 80 percent of Virginia's population. North Carolina Power provides service to customers in 20 northeastern North Carolina counties, an area adjacent to its Virginia service region. The Virginia Power load is much larger than the North Carolina Power load. Most of the VEPCO system's power sources are closely integrated with Virginia Power.

Virginia Power's service region includes northern and eastern Virginia areas which grew rapidly during the 1970s and early-to-mid 1980s, including Richmond, Tidewater, and District of Columbia suburbs. Throughout this period of rapid growth, VEPCO has developed new power supplies, including purchases from other utilities, to meet steadily increasing demands. In the late 1980s, Virginia Power embraced non-utility generation as a means to develop needed capacity. A series of solicitations for non-utility power supplies were issued in the late 1980s. Successful bidders began coming on line in the early 1990s. Virginia Power also obtains electricity from non-utility cogenerators and small power producers that have located within its service territory in compliance with the Public Utility Regulatory Policies Act (PURPA). In 1991, nearly 10 percent of the energy provided by Virginia Power to its customers was generated by non-utility units.

Economic and power-demand growth in the Virginia Power service region slowed considerably during the late 1980s and early 1990s. A number of the non-utility and company-owned capacity additions contracted by VEPCO are scheduled to come on line during the mid 1990s.

VEPCO projects that new capacity, in addition to projects already contracted or under construction, will not be required until the late 1990s (Dominion Resources, 1993). Beginning in 1997, 1998, or 1999, VEPCO plans to add 600 - 750 MW of peaking power capacity over a 3-to-4 year period. The exact dates of these additions will depend on factors such as the rate of economic growth over the interim. For system-planning purposes, VEPCO is assuming that these additions will constitute a mix of off-system purchases and company-built units. Current plans call for VEPCO to acquire 3000 - 5000 MW of additional baseload capacity between the years 2000 and 2012. These long-term plans may be modified as needed to respond to changes in outlook during the intervening period.



[1] Includes service areas of municipal utilities (Blackstone, Culpepper, Elkton, Franklin, Harrisonburg, Iron Gate, Manassas, Wakefield) and co-ops (BARC, Central Virginia, Craig-Botetourt, Mecklenberg, Northern Neck, Northern Virginia, Prince George, Rappahanock, Shenandoah, Southside) which purchase power from Virginia Power.

[2] Includes service areas of municipal utilities (Bedford, Danville, Martinsville, Radford, Richlands, Salem, Virginia Tech) which purchase power from Appalachian Power.

[3] Includes service areas of municipal utility (Front Royal) which purchases power from Potomac Edison.

[4] Includes the service area of electric co-op (Accomack-Northampton) which purchases power from Delmarva.

[5] Purchases all power from Kentucky Utilities.

[6] Service provided by Powell Valley Co-op and Bristol Utilities which purchase all power from TVA.

Figure 1: Service territories of Virginia's major electric utilities.

VEPCO is currently purchasing power on long-term contracts from AEP (500 MW) and from Hoosier Energy Rural Electric Cooperative (400 MW). Both contracts are scheduled to terminate in 1999. Both VEPCO and AEP have stated publicly that the AEP contract will not be renewed.

Appalachian Power:

Appalachian Power Company (Apco) is one of seven operating companies comprising the American Electric Power (AEP) System, which services parts or all of seven states (Virginia, West Virginia, Kentucky, Ohio, Indiana, Michigan, and Tennessee). Apco's service region includes areas in southern West Virginia (44.5% of customer sales in 1991) and southwestern Virginia (55.5% of customer sales in 1991). Apco also provides power to Kingsport Power, an AEP operating company serving the Kingsport, Tennessee, area.

The majority of Apco's generation consists of coal-fired units in the Kanawha and Ohio Valleys of West Virginia which utilize the abundant coal and water resources found in those areas. Apco also takes advantage of the generating capacity surpluses of other utilities in the AEP system, purchasing power as needed to supplement its own generation.

AEP invested in capacity additions during the 1970s and 1980s. Because economic growth over the interim period did not match earlier projections, AEP's current capacity to generate electricity exceeds the demands of customers within its service region. Therefore, AEP has entered into long-term power-supply agreements with other utilities, including Virginia Power and Carolina Power and Light.

AEP plans to renew capacity expansion in the late 1990s, when it will begin adding peaking-power units to its system (Apco, 1991; Apco, 1992). According to current plans, these units are expected to begin coming on-line in the year 2001. The next baseload units projected are two 910 MW pulverized coal units (one in Apco territory) in 2009. AEP has received a pressurized fluidized bed unit, which has received a Department of Energy Clean Coal Technology grant to install a 340-MW pressurized fluidized bed unit at the Philip Sporn plant, located at New Haven, West Virginia. This project's timing is uncertain.

A map of Apco's generation and transmission system is included as Figure 2.

Ownership and Marketing Options:

The majority of the southwestern Virginia study region is located within Apco's service territory, although the far southwestern portion is located in areas served by Old Dominion Power Company and the Tennessee Valley Authority.

Potential developers could include either of the state's major utilities or non-utility interests. However, neither Apco nor Virginia Power is actively pursuing power development opportunities in southwestern Virginia's coalfields at this time. Therefore, most of the following discussion assumes that the most likely developers of southwestern Virginia's electric power generation resources would be non-utility interests.

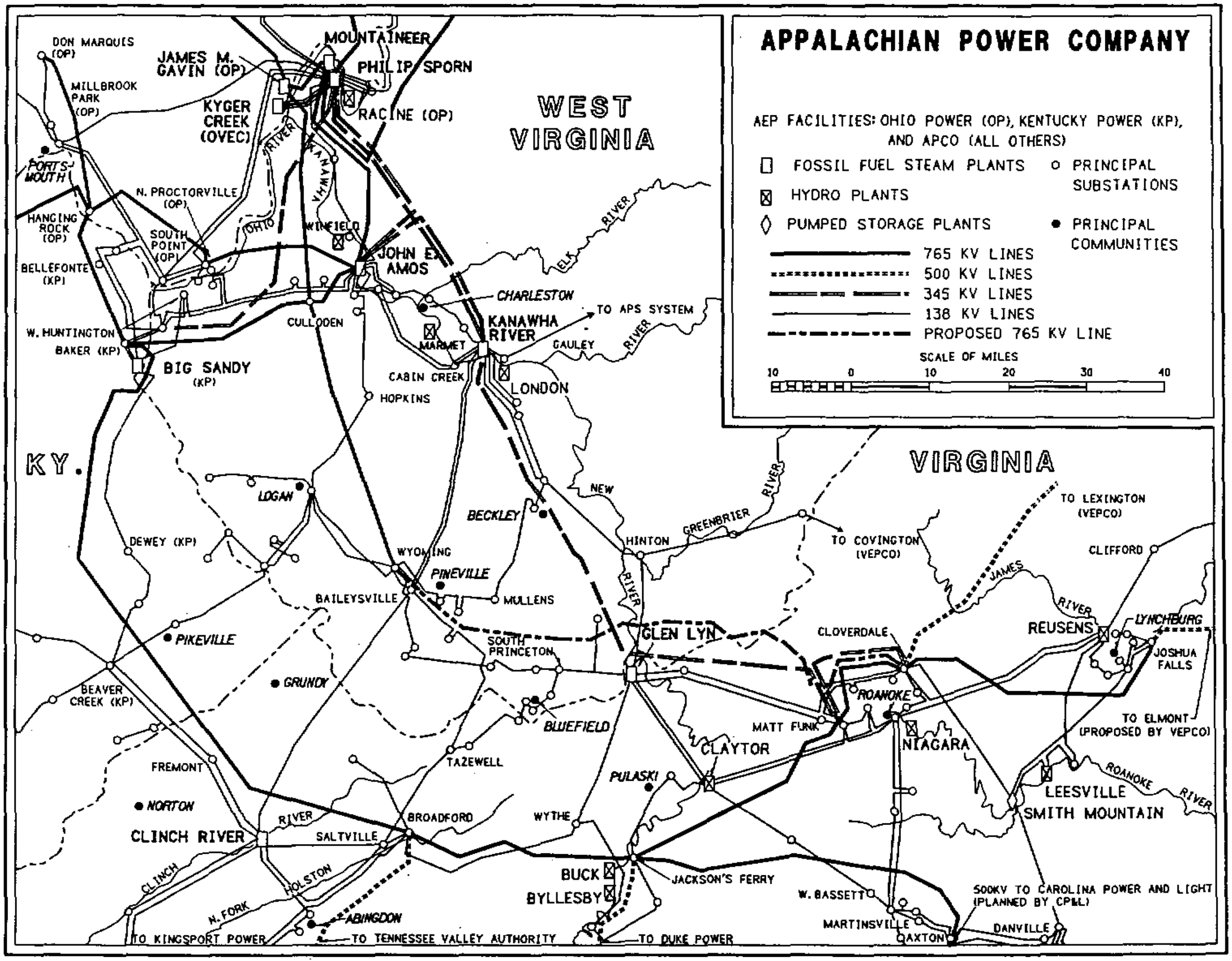


Figure 2: Appalachian Power Company - Selected generation and transmission facilities, adjacent AEP facilities, and principal interconnections. (Figure prepared by Appalachian Power Company).

As a result of changes in federal law, non-utility firms are becoming more important as suppliers of electricity nationwide. In order for a non-utility firm to successfully develop an electric power facility, a market for that power must be contracted.

Under the federal Public Utility Regulatory Policies Act of 1978 (PURPA), certain non-utility generators (called "qualifying facilities," or QFs) are exempt from federal and state utility regulation, and are guaranteed the right to sell power to the local electric utility. QFs include cogeneration facilities (which produce both electricity and useful thermal energy), and small power producers (SPPs), defined as facilities which utilize renewable energy or wastes to generate electricity.

Under PURPA, an electric utility must purchase power from QFs at rates which reflect the costs which such purchase enables the utility to avoid ("avoided costs"). Utilities are required to publish a schedule of avoided costs for reference by potential QFs. Typically, such schedules are based on two separate rate components:

1. "Energy Costs," which include the variable costs borne by the utility in producing electrical energy, such as fuel and labor, and

2. "Capacity Costs," which include the fixed charges of capacity construction and/or ownership.

Non-utility power plants which do not qualify as cogenerators or SPPs under PURPA are called independent power producers (IPPs). Utilities are not required to purchase power from IPPs. Nonetheless, such facilities are becoming increasingly important to the nation's electrical generation capacity. Some utilities (including Virginia Power) have chosen to invite IPPs to submit bids for constructing and operating new capacity. The resulting proposals are evaluated by the utility, as a part of the process of determining the most cost-effective means of providing reliable service.

The IPP industry was given an added boost by the Energy Policy Act of 1992. The Act established a category of exempt wholesale generators (EWGs). These include IPPs, utility affiliates, and others engaged in the wholesale generation of electricity. When certified by the Federal Energy Regulatory Commission, EWGs operate free of regulation as a utility. The Act also requires electric utilities to wheel power from IPPs to contracted purchasers, if transmission capacity is available, for a price which reflects the actual cost of of owning and operating that transmission system.

The Virginia Coalfield Region:

Virginia's primary coal-mining region is located in the far southwestern portion of the state. Buchanan, Wise, and Dickenson counties are the state's primary coal producers. Coal is also mined in adjoining sections of Lee, Scott, Russell, and Tazewell counties. The coalfield region differs from other Virginia counties, both topographically and economically. Coal mining is the only major industry, while lands suitable for agriculture and industrial development are scarce. A map designating the coalfield region is included as Figure 3.

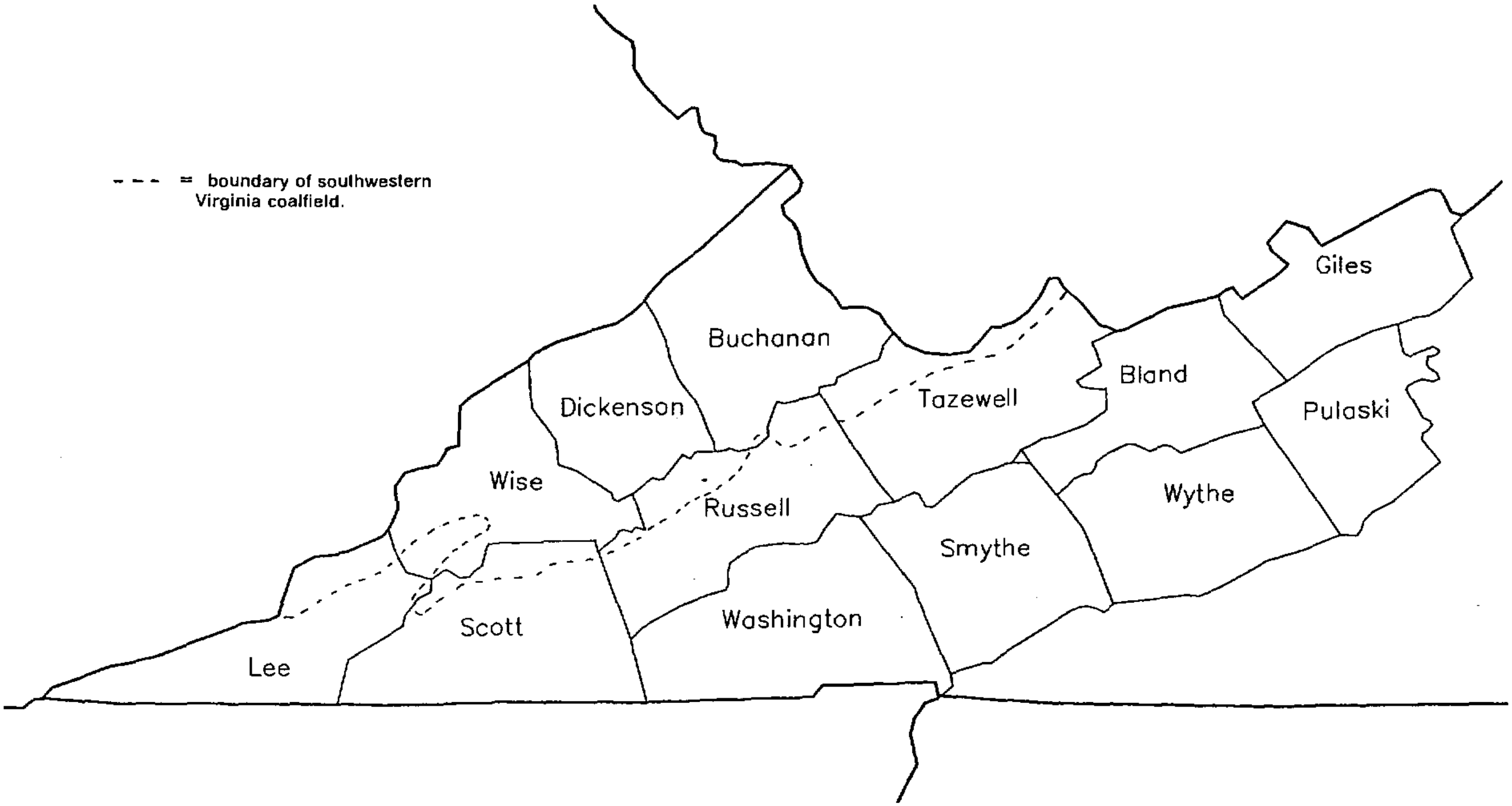


Figure 3: The location of the Virginia coalfield region, relative to the 13-county Sargent and Lundy (1991) study area.

TABLE 1. INDICATORS OF ECONOMIC CONDITIONS IN SOUTHWESTERN VIRGINIA'S COAL PRODUCING COUNTIES

County	Unemployment[1]	Per-Capita Income[2]	Poverty[3]
Buchanan	13.5 %	$9,621	21.9 %
Dickenson	17.3	8,067	25.9
Lee	12.6	7,837	28.7
Russell	11.0	8,753	22.5
Scott	7.5	9,100	20.9
Tazewell	11.3	9,995	19.0
Wise	13.2	9,392	21.6
State Average	6.4 %	$15,713	10.2 %

1. Annual average, 1992. Source: Virginia Employment Commission.
2. $/year, 1990. Source: U.S. Bureau of Census.
3. Percentage of population. Source: U.S. Bureau of the Census.

The southwestern Virginia coalfield region is suffering economically compared to the rest of the state. The major reasons for the region's economic problems include the facts that coal-industry employment has declined over the past two decades, while non-coal employment opportunities remain limited.

A recent VCCER study of the coalfield region's economic impacts (Zipper *et al.*, 1993) reviewed Virginia Employment Commission (VEC) data, showing the coal industry to be directly responsible for 19 percent of total employment in Virginia's seven southwestern coal-producing counties.

Looking only at the three primary coal-producing counties (Wise, Dickenson, and Buchanan), the industry's impacts are even greater. VEC data show coal mining to be directly responsible for 30 percent of the three-county region's jobs, and the VCCER study estimates that at least 50 percent of the region's jobs are supported by the mining of coal.

Because of this dependency on the coal industry, the local economy reflects the fate of the industry. Southwestern Virginia lags behind the rest of the state economically (Table 1). An important factor in the industry's (and, therefore, the region's) poor economic performance has been declining real-dollar market prices for coal (Table 2). To remain competitive and retain market share, the industry has increased labor productivity but reduced overall employment.

TABLE 2. AVERAGE VIRGINIA MINE PRICES FOR COAL (CURRENT AND 1980 DOLLARS), COAL PRODUCTION, AND COAL MINING EMPLOYMENT, 1975-1991

Year	Avg. Mine Price		Produc-tion	Employ-ment
	(Curr.$)	(1980 $)	(10^6 tons)	
1975	$30.46	$44.01	35.5	14,231
1980	34.58	34.58	41.0	14,399
1985	30.16	23.18	42.4	12,621
1990	28.05	17.75	46.5	10,265
1991	27.45	16.78	42.3	9,755
1992	27.55	16.30	42.5	9,099

Sources: Average Mine Price from U.S. Energy Information Administration, adjusted for inflation using consumer price index. Other data from Virginia Department of Mines, Minerals and Energy.

Findings: Survey Results

Fuel Availability

Coal:

Previous work (Randolph, *et al.* , 1990) focused on the potential availability of Virginia coal to non-utility generating units, and concluded that coal would be available. Producers participating in that study indicated a willingness to commit coal reserves sufficient to support 1575 MW of electrical power generation. A review of available data by Milici and Campbell (1991) estimated that 2 to 4 billion tons of original reserves have yet to be mined.

Because of these results, coal availability did not constitute a primary focus of the current study. Six coal producers participated in the current survey. No comments received indicated Randolph's conclusion to be in error, although developments since that time have sharpened producers' concerns regarding price.

Most companies contacted indicated that the coal reserves sufficient to support power generation are available to be mined. The reservations of study participants regarding commitment of coal reserves to power generation hinged on price. Those companies which devote substantial production to the metallurgical market indicated that they would not be willing to dedicate metallurgical-grade coals to an electric power generation venture because they can obtain higher prices on the metallurgical market. Continuing erosion of steam-coal prices is likely to remain a concern to Virginia producers, due to Virginia's status as a high production-cost state.

At current coal prices, additional production is not seen as the answer to the industry's economic problems. While market prices decline, costs continue to rise. Producers have attacked mining costs aggressively, through investments in mechanization and productivity. However, costs over which producers have no control, such as wage rates, taxes, and insurance, continue to rise. Companies currently producing for the spot market indicated that they were able to do so only because of remaining capacity at existing mines; some stated an expectation that they would not be able to develop new underground mines at current market prices. Producers also expressed significant concern that a number of long-term steam-coal contracts are due to expire in the mid-1990s. Because these contracts were negotiated years ago, producers have been receiving price premiums for coals produced under these older contracts. Producers are not optimistic about their opportunities to compete with new contracts for Virginia operations under current market conditions.

The above concerns dampened coal producers' enthusiasm for electric power generation ventures. The general opinion seemed to be that only a venture which minimized transportation costs (such as a mine-mouth plant) would be likely to yield prices that would allow production to be expanded under a long-term commitment.

Natural Gas:

Five gas producers participated in the survey. These companies included both conventional natural gas and coalbed methane producers. Three of these producers expressed a willingness and ability to commit reserves to a power production facility, while two others stated that current contracts would not allow them to take on additional commitments at this time. One additional gas producer was approached but declined to participate in the study.

The state's major gas producers are well acquainted with the electrical generation market. One producer is already marketing approximately 40 percent of production to various non-utility electric power projects.

Some gas producers reported marketing difficulties. In some cases, potential production is not being brought on line due to lack of pipeline access or capacity. There are times when the region's pipeline network is unable to accept local gas produced from currently developed wells. Pipeline capacity problems include inadequate pipeline infrastructure connecting the coalfields' gas producing regions to regional pipelines supplying northeastern markets, and capacity limitations on the regional pipelines themselves during peak gas-demand periods.

Much of the gas currently being produced within the region is being sold on spot markets or under term contracts covering periods of two years or less, in spite of producer preferences for longer-term contract sales. Producers would be willing dedicate production to longer-term contracts only if prices were indexed to broader market price indicators. Producers also stated that local electric power markets would provide two major non-price benefits that are not available through many existing markets: a more constant year-round gas demand, and reduced dependency on regional pipeline carriers for market access.

Producers indicate that the region's gas reserves would be more appropriate to baseload generation than peaking uses. According to these respondents, the conventional gas-yielding formations are most responsive to a steady rate of withdrawal, and do not respond well to changes in the rate of withdrawal. That is, a sporadic withdrawal pattern would be expected to increase the period of time required to fully utilize reserves, and may decrease overall yield. Because natural gas production economics are front-loaded and capital intensive, the producer's interest is to utilize reserves as fully and as rapidly as possible. Gas producers also reported that the region's geology does not, for the most part, lend itself to temporary underground storage in permeable geologic formations.

Participating producers report an ability to dedicate on the order of 100 million cubic feet (mcf) per day of gas (both conventional and coalbed methane) to local markets, if contract terms are agreeable. This estimate includes only gas that could be produced from currently developed reserves, and from proven reserves currently under active development. It includes current production that could be diverted from existing spot and term-contract sales, as well as production capacity with no current market outlet. This quantity of gas would be sufficient to support approximately 600 MW of baseloaded combined-cycle generation.

Virginia Division of Mineral Resources recently completed a study of gas reserves in Wise, Dickenson, and Buchanan Counties (Jacobeen, 1992). Comparison of cumulative production to date to the Division's estimates of original reserves shows that more than 80 percent of original, producible reserves remain in the ground. The study only considered conventional, deep gas reserves; it did not consider coalbed methane. These results confirm producers' expectations that southwest Virginia's remaining gas reserves are adequate to support electric power facilities.

Coalbed Methane:

The state's coalbed methane resources offer a challenge to electrical generation potential. Where these resources are being drawn out ahead of a coal mining operation, the economics of coal mining dictate the rate of gas withdrawal. Such production, which includes a significant proportion of the state's current coalbed methane capacity, would be best suited to baseload power production.

Producers report that, under improved price and marketing conditions, considerable quantities of coalbed methane could be developed and put into production within a relatively short period of time. Producers reported a capacity to develop at least 100 mcf per day in potential production capacity which is not included in the estimate of developed resources under "Natural Gas" above. This additional gas production would be capable of supporting an additional 600 MW of generation, if suitable sites were available. Other producers own the rights to additional undeveloped capacity, but they did not specify producible quantities. Producers stated that the major problem hindering additional coalbed methane development is market volume capacity, not price.

Inconsistent quality of coalbed methane presents a major problem for effective utilization. One producer candidly discussed the fact that variable quality is causing considerable quantities of low-Btu (below pipeline quality) methane to be vented to the atmosphere. Apparently, 20 to 50 million cubic feet per day are being vented. This volume is comparable to that producer's pipeline-quality gas production. On some days, the amount of low-Btu gas vented approaches 80 million cubic feet. In the current price environment, available technologies do not allow conversion of that methane to pipeline quality. In the absence of an alternative use, venting to the atmosphere is the only option available.

In the early 1980s, this producer attempted to set up an experimental combustion turbine, in an effort to convert low-Btu methane to electrical energy. The variable quality of the gas caused problems in the operation of the turbine, and the experiment was abandoned. According to National Independent Energy Producers, no commercial technology currently exists to allow variable-quality methane to be used for electrical generation. The amount of energy contained in the methane being vented by this single producer would be sufficient to run a baseload power plant in the 100-to-200 MW size range, if it could be harnessed cost-effectively. At current market prices (*i.e.* energy costs of approximately $0.02/kWhr), these releases would be valued at 20 to 30 million dollars per year, if they could be transformed into marketable electric power.

Coal Refuse:

Considerable quantities of coal refuse occur throughout the coalfield region. Some of the older refuse piles have a substantial energy content. Three of the coal producers participating in this study made specific reference to refuse as a potential source of fuel. One of these producers mentioned the existence of 2 million tons of high-Btu refuse (energy content up to 8,000 Btu/lb.). Another producer mentioned that testing indicated a refuse Btu content in the 2,000 - 5,000 per pound range. Typically, such refuse could be co-fired with fresh coal, with the co-firing rate determined by refuse Btu content. Although these producers have performed preliminary assessments of this refuse as a potential fuel, lack of a reasonable use has prevented in-depth investigations. As well as providing economic benefits, refuse-fired electric power production could provide environmental benefits when older refuse piles, currently acting as environmental hazards, are used as a fuel source.

Coal-Processing Fines:

Slurries produced by conventional coal-cleaning processes often contain fine coal particles which may constitute a potential source of fuel for power generation. Because of the costs involved in separating the coal fines from other small particles, slurries disposed in coal refuse facilities often retain a considerable energy content.

One coal producer reported a feasibility study, conducted in the late 1980s, which assessed the potential to burn a segment of the fine waste stream from a 1.5 million ton-per-year coal processing facility. Fine-sized reject from this plant was determined to have an average energy content of 5000 Btu per dry ton. The study also showed variations in energy content among the fine waste streams contributed by various coal cleaning processes. An electric power generation facility was proposed to utilize these higher-Btu waste segments, so no co-firing with fresh coal would be required. Various plant sizes, from 15 to 40 MW, were investigated, and all looked promising. A fluidized bed combustion process would be utilized.

Due in part to the proposed plant's small size, cooling water availability was not considered to be a problem at the study location. A significant proportion of the plant's cooling requirements could have been met through processes required to de-water and dry the slurry so as to produce a burnable fuel.

The plant was not built because of power marketing problems. The plant was approved by FERC as a small power producer under PURPA. However, the avoided cost payments available from the host utility, which would not have included a capacity cost component, were not sufficient to justify needed investment. Transmission to a potential customer located outside of the region was not available on terms satisfactory to that customer.

Waste Heat:

Another potential energy source is waste heat from the coke ovens at Jewell Smokeless in Vansant, Buchanan County. The company has actively investigated the potential to utilize this heat as a source for electrical generation. These investigations indicate that waste heat from current operations is sufficient to support 40-to-60 MW of generation. They also believe that access to sufficient water is available to make such a project feasible. Jewell Smokeless personnel state that lack of an accessible electric power market paying reasonable prices is the only factor preventing the company from from developing this resource.

Other Factors

Water and Sites:

These two factors are being discussed together, because cooling water availability is essential to the suitability of sites for power generation.

In the late 1970s and early 1980s, there was an effort by several private companies to evaluate southwest Virginia for power generation. These early efforts produced a flurry of activity, but no concrete results.

With the exception of Coastal Corporation's proposed Tom's Creek facility, none of the parties participating in this study was able to identify specific sites that had been investigated recently and found suitable for establishment of a coal- or gas-fired generation facility. All of the economic development agency representatives contacted believe that sites exist near both coal and natural gas reserves that would be suitable for small power plants, but none had access to hard data that would substantiate this belief. No recent investigations of water availability were reported. Several companies indicated that they could come up with a suitable location for a power plant, if the economics worked, again with the caveat that water availability remained an open question. No one interviewed was predicting a large plant; most were talking in the range of less than 100 MW.

Persons participating in the study were aware of the fact that the coalfield region lacks significant water sources, and that this deficiency constrains the potential for power development in the region. Many persons suggested that the existence of mine water may constitute a solution to that problem. Extensive volumes of mined cavities underlie much of the region, and many of these cavities have been filled with water. No study participants reported recent studies of mine water availability or suitability for power plant use.

Regardless of source, study participants perceived the need to permit surface water withdrawals as a significant problem. They voiced an expectation that permit applications would be opposed by environmental interests. The energy industry has numerous environmental regulations to contend with, and industry representatives look warily upon any projects which open them to additional regulation, and even more warily on projects which present a potential for environmental conflict. Mine-water withdrawals are viewed in a similar light, although with even greater skepticism, due to numerous uncertainties.

All of the coal companies interviewed believed that a mine-mouth site would be the best location for a power-generating facility because it would reduce costs. The need to establish rail facilities to serve a non-mine-mouth location was not viewed as a problem for any reason other than cost.

Cogeneration:

A variety of economic factors, including economic conditions in the coalfields, is perceived to hamper cogeneration power opportunities. Currently, there is adequate power available to industrial customers in the coalfields, at reasonable cost, and the avoided cost payments that a cogeneration facility could expect to receive selling power to Apco under PURPA are quite low.

On the other side of the cogeneration question, none of the study participants was able to suggest uses for the heat energy that might be produced by a cogeneration facility, other than drying coal. The poor economic conditions in the coalfield counties were perceived as a barrier to opportunities for attracting an industrial steam host from outside the region.

One of the coal companies participating in this study has a new cogeneration project outside of the state of Virginia. They chose an area other than the Virginia coalfield for this investment because they perceive economic opportunities in the Appalachian area to be poor.

Expertise:

Of the companies participating in this study, only Coastal Corporation has in-house expertise in the power generation area. None of the economic development agencies has such expertise on their staffs.

This lack of expertise was discussed as a logical response to current conditions. The coal industry is occupied by its attempts to retain market share in a declining price environment. Most companies are downsizing, and staff positions are disappearing, which places additional demands on remaining personnel. Economic survival (*i.e.* cost cutting and improving productivity) is much more important to these companies than the possibility of generating power. Economic development agencies have chosen to concentrate their efforts on opportunities which they believe to have a higher potential for success.

Other Barriers:

The fact that the local utility (Apco, a subsidiary of American Electric Power) does not provide a potential market creates a major impediment to power plant development, according to study participants. Assuming the Wyoming-Cloverdale 765-kV transmission line is completed as planned, successful power plant development will still require contract negotiation with at least two major parties: Apco as a supplier of transmission, and a power purchaser.

Coal industry interests were frank in discussing their perception that it might not be in their interest to attempt power plant development, even if market conditions were more favorable. American Electric Power is a major coal purchaser throughout the Appalachian region, as is the utility which is viewed as the most likely power purchaser: Virginia Power. Coal interests perceive that, if they were to enter the electric power business, disagreements could arise in essential negotiations with the major utilities. Coal interests believe that, if such disagreements were to occur, the consequences could have a negative influence on their ability to sell coal to Apco and/or Virginia Power.

The problems of TAMCO's Toms Creek venture had a negative effect on many survey respondents' attitudes towards power development. They, and other interested parties, observed with great interest the experience of the project, as it offered a demonstration of the prospects for power development in the coalfields.

TAMCO, a partnership of Coastal Corporation and Tampella Power Company, proposed an integrated gasification combined cycle (IGCC) facility at Toms Creek in Wise County. The project had several major advantages: (1) substantial financial support, in the form of a $95 million U.S. Department of Energy grant; (2) plans to utilize IGCC, a low-water consumptive technology believed to be well suited to the Virginia coalfield's water-short conditions; and (3) considerable political backing.

A major problem for the Toms Creek proposal resulted from the need to reach agreements with both a provider of transmission (Apco) and a power purchaser (Virginia Power). Virginia Power's position is that it will enter into a power purchase contract only if Coastal would be able to supply power at a cost comparable to the cost of power available from other sources. TAMCO's response was that this could be accomplished only by scaling up the plant to reduce per-kWhr costs. Apco would agree to provide transmission service for the Toms Creek facility only under contract terms allowing for interruption of that service when required to maintain reliability to internal customers and pre-existing contractual commitments. Due to current transmission system demands, larger plant sizes would result in a greater likelihood of transmission curtailment or interruption. As of this writing, no agreement has been reached. The need to reach essential agreements with two separate parties, and TAMCO's problems in doing so, has reinforced fears of coal interests regarding power development. If the Toms Creek venture does fail, it will deal a serious blow to prospects for establishing new power facilities in the coalfields.

Findings: Auxiliary Information

Current Status of Non-Utility Generation Industry

Nationally, the non-utility generation (NUG) industry has enjoyed substantial growth in recent years. In 1991, approximately one-half of the U.S. new electrical generation capacity was developed by non-utility sources. Table 3 shows, however, that the majority of those non-utility additions occur as cogeneration. It also shows that natural gas is the most common source of energy utilized, while coal is used by only a small minority of NUG developers.

Reasons for coal's failure to capture a larger share of the non-utility generation market include the higher capital costs and greater environmental permitting difficulties (and, hence, longer lead times) required by coal-fired plants, relative to plants which rely on natural gas (Drzemiecki and Augustini, 1993). Higher capital costs result in longer cost-recovery periods. Increased environmental permitting requirements mean that increased permitting costs must be borne further in advance of the planned revenue stream. Taken together, these two factors combine to create a higher level of financial risk for coal-burning plants, relative to plants using gas or oil. Where gas is available, gas-fired plants are easier to site than plants using coal, because they do not require areas for coal loading, coal storage, or ash disposal, and their water requirements are often less.

Table 4 shows that a majority of active coal-fired non-utility units were established as cogeneration facilities. It also shows that some developers have had success in developing power generation units to burn coal refuse. A large number of the coal refuse-burning facilities (over 10) are located in Pennsylvania. Individ-

TABLE 3. SUMMARY OF SELECTED U.S. NON-UTILITY ELECTRIC GENERATION INDUSTRY CHARACTERISTICS

Project Type	Number of Projects		Capacity	
	(No.)	(%)	(MW)	(%)
Active Projects				
Coal-Fired	219	5	16,735	15
Gas-Fired	1,458	32	51,040	47
Cogeneration	2,153	48	73,163	67
Total	4,523	100	108,804	100
Active Projects > 100 MW				
Coal-Fired	57	24	12,440	19
Gas-Fired	141	58	35,677	56
Total	242	100	63,939	100

Active project category includes operating plants plus plants under development. Totals, and the "cogeneration" category, include coal-fired plants, gas-fired plants, and plants utilizing other energy sources.

Source: RCG Hagler-Bailey, Inc. (1992). As of December 31, 1991.

TABLE 4. SUMMARY OF ACTIVE SOLID-FUEL-FIRED NON-UTILITY GENERATION PROJECTS GREATER THAN 1 MW IN SIZE, BY FUEL TYPE AND PURPA CATEGORY

Fuel/Category	Number of Projects		Capacity	
	(No.)	(%)	(MW)	(%)
Coal:				
SPP	-	-	-	-
IPP	9	4	2,543	15
Cogeneration	200	96	14,188	85
Total	209	100	16,731	100
Waste Coal				
SPP	22	56	1,235	50
IPP	-	-	-	-
Cogeneration	17	44	1,229	50
Total	39	100	2,464	100

Source: RCG Hagler-Bailey, 1992.

uals in Pennsylvania who are close to this development could not point to specific state actions responsible for stimulating this activity. The refuse-burning plants were established as small power producers under PURPA. The critical ingredient, according to these sources, was local utilities that were willing to deal and whose avoided cost rates were sufficient to cover the cost of development. The technology for burning high-Btu coal refuse is available, and environmental regulations did not cause any insurmountable problems. The financing was helped by eligibility of refuse-burning facilities to issue tax-free bonds, as solid-waste disposal facilities. Most of these facilities are burning older refuse piles, and mitigating environmental problems in the process. One factor in the success of these ventures in Pennsylvania has been a lack of close proximity to areas classified as Class I air quality zones; it is more costly to achieve effective air emissions control for refuse-burning facilities than for conventional coal-fired units.

Siting

Sargent and Lundy Study:

Virginia Power and Apco jointly sponsored a southwestern Virginia site availability study, conducted by Sargent and Lundy during 1991. This study utilized topographic maps, aerial photos, and site visits to identify sites suitable for coal-fired electric power generation in southwestern Virginia. Potential sites were screened for suitability using 43 criteria related to a wide variety of economic and environmental characteristics, including terrain, water, emissions permitting, coal transportation, and environmental factors such as presence of wetlands and proximity to documented threatened and endangered species habitats.

The study was conducted in three phases. Phase I consisted of an initial screening of 31 southwestern Virginia counties utilizing topographic map data. Fifty to 60 potential sites were identified. Most of these were located in the eastern portion of the study area.

At the conclusion of Phase I, Appalachian Power Company joined Virginia Power as study sponsor. Realizing that the initial screening may have missed potential sites in the western portion of the study area, the sponsors directed that Phase II should focus on 13 counties in closer proximity to the state's coal resources, an area extending from Giles and Pulaski Counties to Washington, Scott, and Lee (Figure 3). The Phase II study area included the entire southwestern coalfield area. The Phase II study relaxed some of the topographic criteria of the Phase I screening, and utilized aerial photos to supplement the topographic map base. Initially, 47 sites were identified as candidates for power generation facilities. Further screening reduced this number to 25 potential sites, in 12 of the 13 counties (Table 5).

In Phase III, these 25 sites were subjected to further economic and environmental analysis, including site visits. The layout of proposed facilities on each site was mapped, and capital costs were estimated.

Ten of these sites, representing 2800 MW of potential generation, were selected as having the highest potential for supporting generation. The authors were clear in stating that this was a site screening study only -- that more detailed investigations would need to be conducted before concluding that these sites would actually be suitable for establishing generation. Study sponsors indicated that the study did not exhaust the inventory of potential sites.

All sites were categorized as being suitable to support a plant sized at 100, 200, 400, or 800 MW. Criteria for identifying 1600-MW sites were utilized in the study, but no such sites were identified.

Average capital costs for the 25 sites chosen in Phase II are summarized in Table 6. The maximum variation within each category was 13 percent. The table clearly shows per-MW capital costs to be more expensive for the smaller sites. A primary reason is that certain costs must be borne, regardless of the plant's size. For example, the costs of providing water intake, air pollution control, solid waste storage facilities, and environmental permitting will not vary in direct proportion to the size of the facility planned for a given site.

The criterion utilized by Sargent and Lundy to evaluate surface water availability was .025 cfs/MW, with no withdrawals when flow volumes are less than 30 percent of average annual flow. Of the 25 sites most intensively studied in Phase III, only five were planned to rely on direct withdrawals. The other 20 sites would require construction of on-site reservoirs. Only two of the final 25 sites chosen for study proposed to make use of the Clinch River. According to Virginia Power, the reason for avoiding the Clinch is the documented occurrence of threatened and endangered aquatic species.

Typically, proposed plant sites were located at some distance from the water sources. Only five of the 25 Phase III sites were located 1 mile or less from the potential water source. For the remaining sites, distances over which water must be

TABLE 5. SUMMARY OF 25 PHASE III SITES STUDIED INTENSIVELY BY SARGENT AND LUNDY (1991)

Site No.	Plant Size	County	Water Source	Adequacy[1]	Piping Distance	Rail Access
	(MW)				(Miles)	(Miles)
A01[2]	100	Bland	Walker Crk.	2	2	>20
A04	100	Tazewell	Bluestone R.	1	1.5	>20
B01[2]	200	Dickenson	Pound R.[3]	2	2	4-8
B02[2]	200	Dickenson	Russell Fk.[4]	5	2	8-12
B03	100	Dickenson	Clinch R.	3	9	<4
B05[2]	100	Giles	New R.[4]	5	<1	4-8
B07	200	Lee	Powell R.	3	<1	>20
B08	100	Lee	Powell R.	3	9	16-20
B10	100	Lee	Powell R.	3	3	>20
B11	200	Pulaski	Claytor Lake[4]	5	2	>20
B13[2]	100	Russell	N.F. Holston	1	6	>20
B23	100	Washington	N.F. Holston	1	9	<4
B25	200	Wise	Pound R.[4]	2	4	<4
B26	200	Wythe	Reed Crk.	2	4	<4
B28	200	Wythe	S.F. Holston	1	4-8	3
B29[2]	200	Wythe	New R.	2	1	>20
C02[2]	400	Scott	Clinch R.	3	3	12-16
C03[2]	400	Smythe	N.F. Holston	1	5	8-12
C04[2]	400	Washington	N.F. Holston	2	4	<4
C05	400	Washington	S. Holston Lk.[4]	5	2	>20
C09	400	Washington	S.Holston Lk.[4]	5	2	>20
C10	400	Wythe	Reed Crk.	2	2	<4
D01	800	Wythe	New R.	3	11	4-8
D02[2]	800	Wythe	New R.	4	4	16-20

1. Water Source Adequacy, rates on scale of 1-5, with a 1 representing least adequate." Factors influencing adequacy rating are:
   - Required reservoir capacity (primary factor)
   - Drainage area of water source
   - Difficulty of reservoir development
2. The ten sites selected by Sargent and Lundy as most feasible, totaling 2800 MW.
3. Below North Fork reservoir.
4. Sites proposed to utilize direct water intake. All other sites expected to require storage reservoirs. Site B02 would draw water from the proposed Haysi Reservoir.

pumped ranged up to 11 miles. Piping distances and reservoir construction costs were considered in preparing the capital-cost estimates of Table 6.

Only one of the 25 Phase III sites studied intensively by Sargent and Lundy was described as "mine-mouth," suitable for conveyer transportation; all other sites relied on trucks or rail for coal transportation. No sites were located along the

TABLE 6. AVERAGE CAPITAL-INVESTMENT ESTIMATES BY SARGENT AND LUNDY (1991) FOR 25 PHASE III SITES

Site Capacity	Number of Sites	Avg Capital Investment Total ($ million)	Avg Capital Investment Per 100 MW ($ million)	Variation[1]
100 MW	6	$403	$403	13%
200 MW	10	514	257	4%
400 MW	7	889	222	6%
800 MW	2	1,542	193	1%

1. Increase in investment required to develop the most costly site, vs. the least costly site.

Levisa Fork in Buchanan County, presumably due to topographic constraints to plant siting.

Conventional Coal-fired Plant Scale Economies:

Conventional coal-fired baseload power plants are subject to economics of scale. Significant costs associated with rail-loadout facilities, water withdrawal and storage facilities, and environmental permitting are independent of plant size. Thus, larger plants can be desirable, from a per-kWhr cost standpoint, because they allow the fixed costs of establishing these facilities to be spread out over a larger number of kWhrs. At the other end of the scale, certain factors limit allowable plant size. Two significant plant-size-limiting factors are the water source, and the airshed capacity to receive emissions. Smaller plants can also provide an economic advantage, relative to larger-sized units, in locations where the transmission system would require major modification to receive production from a larger plant.

Independent power industry sources contacted during this study stated that the optimal size for a non-cogeneration conventional coal-fired baseload power plant, today, is the 250 - 400 MW size range, and that it would be very difficult for a non-cogeneration coal-fired baseload plant smaller than 200 MW to compete for contracts successfully.

The 1993 *Power Engineering* survey of utility baseload power plant construction included 79 coal-fired units that are planned or under construction, with an average size of 375 MW (Smock, 1993). The Hagler-Bailey (1992) survey of non-utility generation (Table 4) showed the average size of non-cogeneration coal-fired units to be 280 MW.

Two major factors that are not operable along the eastern seaboard will influence the optimum size of coal-fired baseload plants in southwestern Virginia. The first is the potential to establish a mine-mouth plant, where coal delivery facilities could be constructed at lower cost than a typical rail loadout, which would affect scale economies by allowing a smaller plant. The second is the fact that a southwestern-Virginia plant would be connected to the AEP transmission system. Thus, in the absence of any cost incentives unique to southwestern Virginia, it would essentially be competing with plant sites in other parts of the AEP system where cooling water resources do not limit plant size, and which are also close to mine sites.

Environmental Permitting

Surface-Water Withdrawals:

Surface-water withdrawals would require a Virginia Water Protection Permit from the Virginia Department of Environmental Quality (DEQ), in a program administered jointly with Army Corps of Engineers. Permits are reviewed on a case-by-case basis. In addition to DEQ, five Virginia agencies (Departments of Health, Agriculture, Game and Inland Fisheries, and Conservation and Recreation; and the Marine Resources Commission) review and comment on the permit application. Permits for water withdrawals are generally issued with conditions to protect existing beneficial uses, including in-stream uses such as aquatic life and recreation.

Generally, permits are issued with the restriction that no withdrawals may take place when the volume of flow in the river is less than some percentage of mean annual flow. This limit is set on a case-by-case basis.

Threatened and Endangered Aquatic Species:

Assessment of the adequacy of water resources, relative to cooling-water demands, is complicated by the presence of threatened and endangered (T&E) species.

The Clinch River is the primary potential water source within or adjacent to the coalfields. The Clinch River has been identified as one of the world's premier habitats for mussels; many of the Clinch's mussels are listed as threatened or endangered at either the federal or state level. Occurrences of T&E fish and aquatic plant species have also been documented in the Clinch. According to U.S. Fish and Wildlife Service personnel, it would be virtually impossible to site a power plant on the Clinch River without encountering the need to comply with the Endangered Species Act, due to potential impacts on T&E species.

The situation in the lower Powell is similar to that in the Clinch. In the upper Powell basin (above Pennington Gap), T&E species are not known to be present. Any development on the upper Powell would be scrutinized, however, for potential impacts on T&E species downstream. Although there are T&E species in the Holston, Big Sandy, and New River basins, documented occurrences are not as dense as in the Clinch and lower Powell.

Attempting to site a power plant on a water body where T&E species are known to occur opens the applicant to potential costs and risks that are not present in non-T&E species areas. Under Section 7 of the federal Endangered Species Act, all federal agencies must ensure that their actions do not jeopardize the continued existence of T&E species. Federal agencies would be involved in a power plant development, as federal permits are required for air emissions and for surface water withdrawals and discharges. The application for any federal permit would be sufficient to trigger an Endangered Species Act review.

If this review found a potential for the proposed power plant to jeopardize continued existence of T&E species, an environmental impact statement (EIS) would be required. The EIS would assess indirect effects of the proposed plant (such as increased coal mining or residential development) on the T&E species, as well as direct effects (such as a water withdrawal or discharge).

If the EIS were to find that plant development would jeopardize the continued existence of T&E species regardless of control measures, no permit would be issued. If the facility were to remain eligible for a permit at the conclusion of the EIS process, the presence of T&E species would be likely to increase operating and/or capital costs. A permit issued in a T&E species area might include conditions designed to minimize impacts on T&E species' survival, such as establishment of effluent limits at lower levels than might otherwise be required; additional water quality and biological monitoring, both above and below the plant; and additional constraints upon the timing and manner of water withdrawals. Any permittee in a T&E species area would also face potential readjustment (tightening) of permit conditions at a future date, if scientific research and/or monitoring data were to find the original permit conditions to be insufficient to protect the T&E species.

Independent power industry sources confirm that, at present, they would not consider attempting to site a power plant on a water source harboring T&E species, unless no other options were available.

<u>Air Emissions:</u>

Air-emissions permitting requirements constitute a substantial hurdle for any effort to establish a power plant, regardless of location. Any point source likely to emit any criteria pollutant in amounts exceeding 250 tons per year will be subject to requirements designed to prevent significant deterioration (PSD) of air quality. Criteria pollutants emitted by a coal-fired electric power plant would include NOx, SOx, particulates, and carbon monoxide. The primary pollutant of concern for a gas-fired plant would be NOx, but an application would also be scrutinized for carbon monoxide and unburned hydrocarbons.

According to Virginia Department of Environmental Quality, Division of Air Pollution Control staff, preparation of an air-emissions permit under the PSD criteria would probably require at least 18 to 24 months. The permit would include data on background concentrations of various air pollutants, a comparison of the costs of controlling emissions at various levels using available technologies; and analysis of the environmental impacts of expected emissions. Another 18 to 24 months, including public hearings and U.S. EPA involvement, would be consumed by the permit review process.

The permit application procedures described above would have to be endured regardless of the plant's proposed location. There do not appear to be any major permitting difficulties likely to be encountered specifically because of a southwestern Virginia location.

The nearest PSD Class I areas are the Linville Gorge wilderness area of North Carolina, the Great Smoky Mountains of North Carolina, and James River Face in Jefferson National Forest, Virginia. The federal land managers of these areas have requested notification of any PSD application within the state of Virginia. Thus, these land managers could respond to a power plant air-emissions application from southwestern Virginia by requesting an analysis of air-emissions impacts on the protected facilities. However, an application from elsewhere in the state would likely meet with the same response.

The only area of southwestern Virginia that is classified under the Clean Air Act as a non-attainment area is Whitetop Mountain at elevations greater than 4500 feet, due to high ozone concentrations caused by regional transport. Assuming a southwest Virginia power plant could be located so as to avoid significant impact on ozone in this area, no pollutant offsets would be required.

There are numerous locations throughout the state that are non-attainment areas for ozone, where offsets would be required for VOC and NOx emissions. New sources would also be required to obtain CO offsets in some of these areas. Most of the state's non-attainment areas are located in the northern Virginia, Richmond, and Tidewater areas. From an air emissions permitting standpoint, there would be advantages to locating an electric power plant in southwestern Virginia, relative to such areas.

There is one air permitting problem that might be encountered in southwestern Virginia due to terrain. In some cases, the terrain could cause air emissions to concentrate in "pockets" downwind from the plant. Such problems can be remedied through use of existing technologies, but at a cost.

From an air-emissions permitting standpoint, the major advantage of a gas-fired plant (relative to coal) is that fewer pollutants are emitted, so the permitting process would be simplified accordingly.

Cooling Water Requirements and Availability

Steam Turbines, Conventional Cooling:

Sargent and Lundy (1991) estimated water utilization of a pulverized-coal steam-turbine plant using cooling towers to be .025 cfs/MW. This estimate is in agreement with other sources. For example, in a study commissioned by Electric Power Research Institute (EPRI), Mitchell (1989) states that "typical" evaporative losses from coal fired plants range from 0.45 to 0.55 gallons per kWh, equivalent to 0.017 to 0.020 cfs per MW while the plant is in operation. Mitchell estimates that blowdown (the need to provide makeup water to limit cooling-cycle salt concentrations) and drift will typically add another 20 to 50 percent, resulting in a total cooling water use estimate that is very much in line with the Sargent and Lundy (1991) estimates. The use of gas or other fuels to fire a conventional steam turbine (as opposed to coal) will not alter the water requirements.

Conventional cooling system costs can vary widely between installations. The actual cooling tower equipment can constitute between 1 and 3 percent of the plant's total capital costs, but the complete cooling system cost can be considerably more. Typically, the cooling system is responsible for 5 to 10 percent of capital. In addition to tower material and construction, major variables include whether or not reservoir storage needs to be constructed, the difficulties of that construction, and the distance over which cooling water needs to be piped. In some cases, capital requirements of cooling can range up to 15 percent of the plant total (Elliott, 1990).

Mine Water Availability:

Study participants suggested that the availability of water in abandoned underground mines could potentially provide a source of cooling water. Preliminary calculations on potential underground mine yields (Table 7) demonstrate that it is unlikely that an underground mine cavity alone could provide water for a large power plant. A mine cavity remaining from production of nearly 80 million tons of coal would be required to hold the amount of water required to cool a 200 MW conventional steam plant for 40 years.

In reality, the fact that water would be percolating into the mine over time means that a smaller mine cavity would be adequate. If a mine cavity was being resupplied by rainfall percolation from the land surface at a rate of 10 inches per year, approximately 4,000 acres of surface infiltration would be required to supply the needs of a 200 MW conventional steam plant.

Water Conserving Cooling System Designs:

In recent years, water-conserving cooling systems have generated attention. The two main types of water-conserving systems are dry cooling systems, air-cooled systems that do not consume water, and wet-dry (or dry-wet) systems, which couple a traditional wet-cooling unit with a dry-cooling unit by placing the two in series or in parallel.

In the U.S., dry cooling systems were installed at 12 locations between 1988 and 1991 (Guyer and Bartz, 1991). The largest of these is a 665 MW non-utility installation at Doswell, Virginia, powered by three gas-fired combined cycle units.

Manufacturers estimate that the capital cost of dry cooling can range from 5 to 7 times that of conventional wet cooling. To compare total costs, however, factors in addition to equipment must be considered. One is that the total cost of a conventional wet cooling system generally exceeds that of the cooling equipment by a considerable margin, but a dry cooling system is mostly self-contained. Therefore, the cost advantage held by a conventional wet cooling system will generally be less than the factor of 5 to 7 for which the equipment alone is responsible.

Dry cooling systems also impose operating penalties on the generating unit of at least 1 to 2 percent (Bartz, 1992). Because dry cooling systems rely on the atmosphere for a heat sink, their efficiency is further reduced in hot weather (Von Cleve, 1985). Decreased cooling efficiency in hot weather would impose a greater-than-proportionate economic penalty where power is being generated for a hot-weather-peaking load.

TABLE 7. ANALYSIS OF UNDERGROUND MINE SURFACE AREA AND VOLUME REQUIRED TO PROVIDE COOLING WATER TO A COAL-FIRED POWER PLANT (WATER REQUIREMENT: 0.025 CUBIC FT/SEC PER MW)

		Annual Requirement		Lifetime Requirement[2]	
Plant Size	Water Req.	Water Volume	Surface Area[1]	Water Volume	Mined Coal[3]
(Mw)	(cfs)	(Ac. Ft.)	(Acres)	(Ac. Ft.)	(10^6 tons)
100	2.5	1,807	2,170	72,280	37.6
200	5.0	3,614	4,340	144,560	75.2
400	10.0	7,228	8,680	289,120	150.4
800	20.0	14,560	17,360	578,240	300.8

1. Assuming 10 inches of rainfall per year percolates through ground to infiltrate mine cavity, and that infiltrating water volume is sufficient for use in plant.
2. 40 years.
3. Assuming bank density of unmined coal = 2,150 lb/cubic yard, and that water stored in cavity will be sole source of water used in plant.

Dry cooling systems can offer the advantages of greater siting flexibility and reduced environmental permitting. In areas where obtaining a surface water withdrawal permit would be likely to require a lengthy time period, dry cooling could also have a positive cost impact by speeding plant construction. Dry cooling installations allow generating units to achieve zero-discharge operation.

A dry cooling system exerts less back pressure on the generating turbine than does a conventional wet cooling system. Thus, the turbine installation must be designed to accommodate the dry system.

Mitchell (1989) reviewed studies of dry-cooling economics for Electric Power Research Institute. Eleven such studies were located, three from 1985 and the rest from 1980 or earlier; none of the studies considered dry-cooling siting economies. The three 1985 studies found that dry cooling increased cooling system capital costs by factors ranging from 1.1 to 2.6, relative to conventional wet cooling, while total cooling costs (including capacity penalties, operating costs, makeup water costs, and similar factors) were determined to increase by factors ranging from 1.9 to 3.8 through use of dry cooling. Primary factors identified as favoring dry cooling were expensive water, inexpensive energy, and environmental restrictions. Mitchell was clear in stating that, regardless of the above factors, conventional wet cooling systems would be preferred in virtually any location where that option is available.

Mitchell (1989) also reviewed economic studies of wet-dry cooling systems; these can be more expensive to install than totally dry systems but they do reduce hot-weather operating penalties. The only post-1980 study reviewed (a coal-fired installation in southern Colorado) found that dry-wet systems, capable of reducing plant water consumption to levels that were 10 to 35 percent of the conventional wet cooling "base case," increased cooling-system capital requirements by factors ranging from 3.4 to 4.8, total plant capital requirements by 4 to 6 percent, and the cost of delivered energy by 1 to 7 percent. The conditions of this installation were favorable water-conserving cooling, as both expensive water and inexpensive energy were present.

Compared to dry cooling, far fewer wet-dry cooling systems have been installed for commercial operation.

Surface Water Resource Constraints on Coal-fired Plants:

Cooling water is widely reputed to be a constraint to plant size in the coalfield region. Table 5 contains information on water sources considered in the Sargent and Lundy (1991) plant-siting study, and Table 8 summarizes water flow information for southwestern Virginia's major streams. (See also Figure 4). Comparison of the two tables illustrates the nature of that constraint. The only southwestern Virginia locations suitable for plants as large as 800 MW, according to Sargent and Lundy, use the New River (the region's largest water resource) as a cooling source. Water intakes for the 800-MW sites identified by Sargent and Lundy are located on the New River between the Galax and Allisonia monitoring stations.

Seven potential 400 MW sites were located by Sargent and Lundy. The two 400 MW sites where water availability appears to be most restricted are the North Fork Holston site in Smythe County, which is located near the Saltville water monitoring station, and the Reed Creek site in Wythe County, which is located near the Graham's Forge water monitoring station. A comparison of the minimum, maximum, and average volumes available at these two stations to other water bodies listed in Table 8 indicates that there may be other locations near and within the coalfields where similar amounts of water would be available. Flow volumes in the Clinch below Richlands exceed those at Saltville and Reeds Creek, according to these figures, while flow volumes in the Levisa Fork below Grundy, the Russell Fork near Haysi, and the Powell below Big Stone Gap are slightly less.

In conducting this study, we did not perform a detailed analysis of water availability. Presumably, the water available at Saltville and Reed Creek would be close to the minimum amount required to support a 400 MW generation venture, as Sargent and Lundy (1991) gave both sites low ratings for adequacy of water source. Greater volumes of water would need to be stored at such sites, relative to sites with greater flows, which would increase site development costs unless a supplementary water source (such as groundwater or municipal wastewater) were available.

Estimating Conventional Coal-fired Capacity:

Given the above factors, it seems logical to conclude the following:

1. Coal-fired plants smaller than 200 MW should not be considered as economically feasible.
2. The presence of threatened and endangered aquatic species are likely to effectively prevent power plants from being sited on the Clinch River or on the lower Powell.

TABLE 8. SUMMARY OF FLOW DATA FROM SOUTHWEST VIRGINIA'S MAJOR RIVERS (CUBIC FEET PER SECOND)

Monitoring Point	Daily Maximum	Daily Average	Daily Minimum	7Q10	Drainage (mi^2)	Period of Record
Big Sandy Basin						
Levisa Fork, Grundy (Buchanan Co.)	13,600	288	0.3	1.4	235	1941-87
Levisa Fork, Big Rock (Buchanan)	24,800	377	5.1	11.1	297	1967-91
Russell Fork, Haysi (Dickenson)	30,600	331	0.2	1.5	286	1926-91
N.F. Pound R., Pound (Wise)	1,170	28	0.04	0.2	19	1961-87
Pound R. George's Fork[1] (Dickenson)	5,090	120	1.7	4.0	83	1963-87
Pound R, Haysi (Dickenson)	4,450[2]	275	0.1	1.1	221	1926-91
Cranesnest R., Clintwood (Dickenson)	8,000	80	0.7	2.1	67	1963-91
Clinch River Basin						
Richlands (Tazewell)	7,000	190	8.8	15.7	137	1945-89
Cleveland (Russell)	27,800	709	37	53.0	528	1929-91
Speer's Ferry (Scott)	42,500	1593	77	99.7	1,126	1920-81
Guest R., Coeburn (Wise)	4,000	141	1.6	2.1	87	1949-81
Powell River						
Big Stone Gap[3] (Wise)	7,860	202	5.0	7.3	112	1944-81
N. Fork, Pennington Gap (Lee)	6,360	130	0	1.0	71	1944-81
Jonesville (Lee)	35,000	537	18	24.5	319	1931-91
Holston Basin						
S. Fork, Riverside (Smythe)	4,040	112	8.0	19.0	N/A	1920-91
S. Fork, Damascus (Washington)	12,800	476	40	72.9	301	1931-91
M. Fork, 7 Mile Ford (Smythe)	5,990	163	20	26.6	132	1942-89
N. Fork, Saltville (Smythe)	10,900	298	2.0	23.5	222	1920-91
N. Fork, Gate City (Scott)	36,700	905	36	58.5	672	1931-81
New River						
Galax (Grayson)	86,200	1,896	265	395	1,131	1930-91
Allisonia (Pulaski)	95,000	3,685	453	723	2,202	1929-91
Radford	105,000	3,873	550	912	2,748	1907-91
Eggleston (Giles)	108,000	3,937	635	884	2,941	1914-76
Glen Lyn (Giles)	126,000	5,006	787	1,091	3,768	1927-91
Reeds Cr., Graham's Forge (Wythe)	10,600	268	22	N/A	247	1927-92

1. Below North Fork reservoir.
2. Since construction of Flanagan Dam in 1965.
3. One mile above confluence with South Fork.

Source: Virginia Water Resources Center. 7Q10 is an estimate of 7-day, 10-year low flow.

3. Opportunities to develop conventional coal-fired generation are confined to a small number of locations; surface water resources at these locations are capable of supporting plants only in the 200 - 300 MW size range.

4. Water-conserving cooling technologies should not be considered to be a feasible means of extending the range of available sites for conventional coal-fired plants at this time, due to cost considerations.

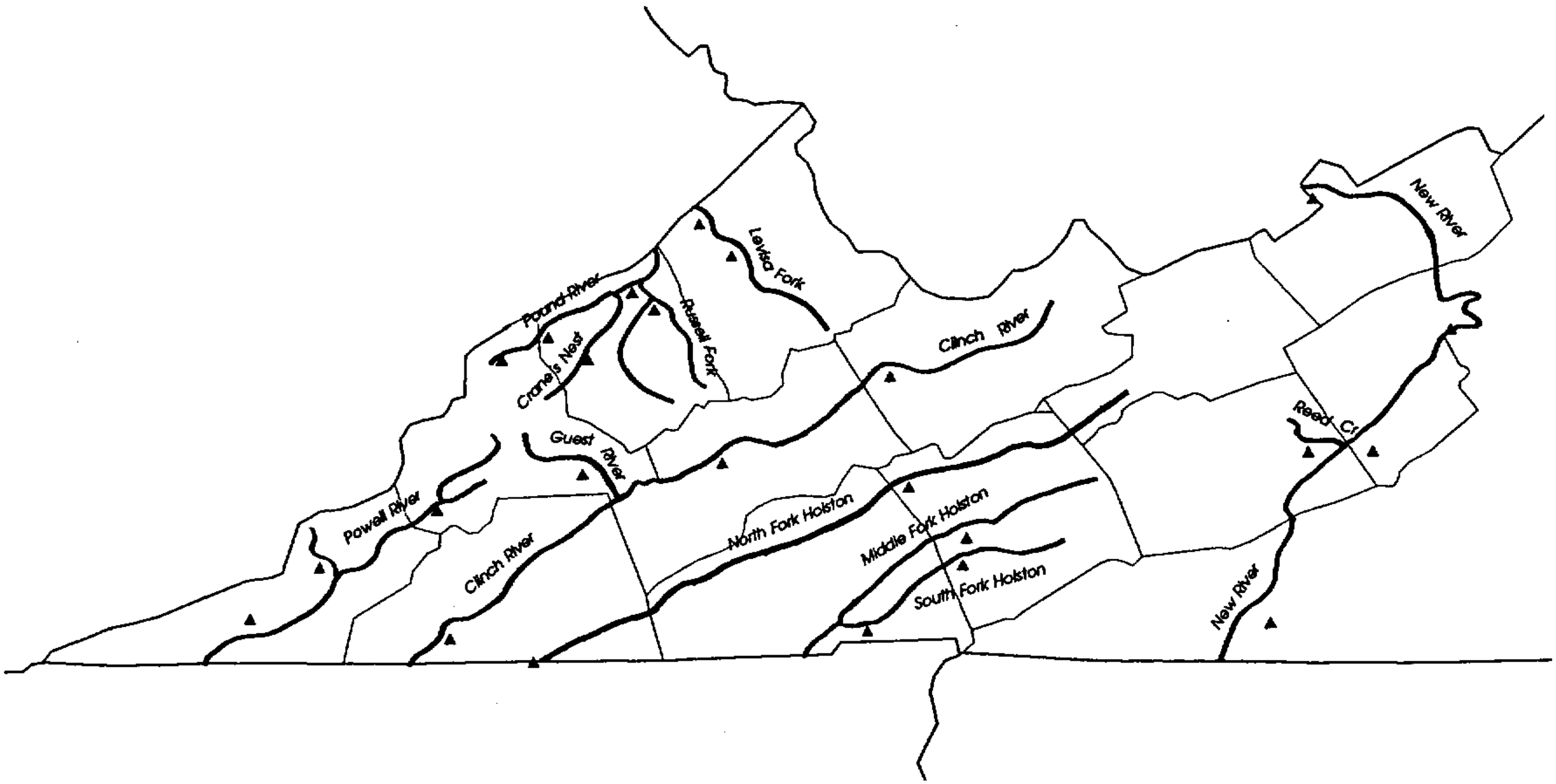


Figure 4: Major rivers of southwestern Virginia, and the locations of the flow monitoring points listed in Table 8.

Given the above, we used the Sargent and Lundy (1991) study as a basis for estimating the coalfield region's potential to support conventional coal-fired generation. Two 200-MW coalfield sites (B01 and B02) were among the ten most feasible sites identified by this study, while one additional coalfield site (B25, also rated as suitable for a 200-MW plant) was listed among the 25 most feasible (Table 5). Thus, the best available estimate of the coalfield region's capacity to support conventional coal-fired generation is 400 to 600 MW.

Sargent and Lundy (1991) were clear in stating that water resources and economic feasibility would need to be evaluated on a site-specific basis before concluding that the sites they identified would be suitable for power development. The Sargent and Lundy study was not presented as an exhaustive inventory of all potential sites; however, it is the only plant siting study available. Other suitable coalfield sites may exist, but none were called to our attention in conducting this study.

Sargent and Lundy also located potential sites in the Holston and New River basins (Table 5), which were not included in the 400 - 600 MW coalfield capacity estimate. These included 400 MW sites in Scott, Smythe, and Washington Counties, and an 800 MW site in Wythe County, all of which are located outside of the coalfield region.

Gas-fired Combined Cycle:

Gas-fired combined cycle power plants use considerably less water than conventional steam turbines. Two separate generating systems comprise combined cycle facilities: a gas turbine, and a heat recovery steam unit which generates additional electric power from the turbine's exhaust heat. Typically, the gas turbine produces two-thirds to three-quarters of the total energy. The gas turbine does not require a cooling system installation, whereas the steam unit must be cooled as would a conventional steam-fired unit. The only process water generally required by the gas turbine is steam injection to increase power output and/or suppress NOx emissions. Steam-injection water requirements are typically on the order of five percent of the amount of water that would be consumed in cooling a conventional steam generator to produce a similar amount of power.

In addition to reduced water consumption, combined cycle units offer other advantages relative to conventional steam plants. Capital-cost requirements are lower (Table 9). Modular construction is possible, allowing the turbine component to be installed and running in less than one year (Collins, 1993). Combined cycle units are typically sized smaller than coal-fired steam plants: the thirty combined cycle units reported to the *Power Engineering* utility baseload survey averaged 210 MW (Smock, 1993); six of the thirty units were 100 MW or smaller.

Because combined cycle cooling requirements are much lower than those of conventional coal-fired generation, dry (or wet-dry) cooling can be installed in water-short areas without imposing as great an economic penalty, relative to conventional steam plants. One major disadvantage of gas-fired combined cycle is uncertainty regarding future costs of fuel. Another is the fact that the gas turbine unit's power output suffers at higher air temperatures; approximately 1 percent of the gas turbine power output is lost for every 10°F in temperature above 60°F.

TABLE 9. TWO ESTIMATES OF AVERAGE ELECTRIC POWER PLANT CAPITAL COST, AND TYPICAL HEAT RATES, FOR VARIOUS TECHNOLOGIES

Technology Type	Fuel	Capital Cost Estimates ($/kW) (1)	(2)	Heat Rate (Btu/KWhr)	Water Use[3] (cfs/kW)
Combustion Turbine	Gas	350	430	11,500	.001
Combined Cycle	Gas	620	680	7,150	.010-.015
Steam Coal	Coal	1,500	1,650	9,580	.02-.03
IGCC	Coal		1,700	8,950[4]	.010-.025

1. Median costs in 1990 dollars reported from a 1992 General Electric Co. survey of 150 utility planners.
2. Electric Power Research Institute Technical Assessment Guide values.
3. Approximate; water use varies with cooling system as well as generating technology. These figures represent typical water consumption by conventional wet cooling and other necessary plant processes.
4. 8,240 Btu/kWhr is the projected hear rate for TAMCO's proposed Toms Creek facility, which will use advanced turbine technologies.

Source: Kaupang *et al.* (1993).

Integrated Gasification Combined Cycle (IGCC):

This technology uses gasified coal as feed to a combined cycle unit. Water requirements of the combined cycle component are no greater than they would be if the feed fuel were conventional natural gas. The coal-gasification component does require some process water; the amount is dependent on the gasification process used.

With some gasification technologies, process water requirements are sufficiently great to virtually eliminate any water conservation advantage held by IGCC over conventional coal-fired generation. Other gasification technologies do not require extensive use of water. Coastal Corporation personnel report that total water utilization (including process water and steam-generator cooling) by the Tampella IGCC process planned for use at TAMCO's Toms Creek project is on the order of one-half that of a similarly-sized conventional coal generating unit. U.S. Department of Energy (DOE) funding, through the Clean Coal Technology program, has been a major impetus to continued development of IGCC technology. However, many other technologies are also competing for these funds; only 6 of 46 DOE Clean Coal Technology grants to date have been for IGCC technology demonstrations. According to a DOE official,[1] reduced water consumption is not defined as an objective of the Clean Coal Technology program. Therefore, if TAMCO's

1 Richard W. Lynch, Program Manager, Advanced Power Systems.

problems result in loss of the DOE grant, the result could be a setback for the development of an important water-conserving IGCC technology.

In addition to water conservation, the major advantage of IGCC over conventional coal technologies is in air emissions. IGCC is capable of SO_2, NOx, and particulate emissions that are substantially less than those of conventional steam plants with state-of-the-art emissions controls. Many expect that the tightening of clean air laws will hasten the commercialization of IGCC (Smith, 1992).

Major advances in IGCC technology have occurred over the past decade. Some expect that the time when the technology will be fully commercialized is not far away (Smith, 1992; Smock, 1991). Scale economies vary with technology; most of the non-pilot-scale installations to date have been in the 100 - 250 MW size range, although some have been as large as 440 MW. According to DOE, scale economies of most IGCC technologies are consistent with those of gas-fired combined cycle technology, as transportation constraints effectively confine unit sizes to the order of 200 MW.

Some utilities have hedged against uncertainties in future natural gas prices by planning gas-fired combined cycle installations in a manner that would allow future conversion to IGCC technology, if needed. Coal consumption per kWhr is less for IGCC than for conventional coal-fired steam generation by factors of 5 to 20% (Table 9).

Market Opportunities

<u>Potential for an IPP to Compete for Local Contracts:</u>

It would be very difficult for a new non-utility baseload plant to compete with Apco for local contracts based on price. Apco is one of the nation's lowest-cost electricity suppliers, in part because most of AEP's generation capacity is in large coal-fired units located on major rivers, constructed years ago. Any non-utility plant locating in southwestern Virginia to serve a non-local customer would need to transmit power to potential markets over the Apco system and would be required to pay a wheeling fee.

<u>Apco and Virginia Power "Avoided Cost" PURPA Power Buyback Rates:</u>

At present, Virginia Power's avoided costs make it an attractive customer for QFs, relative to Apco. Because Virginia Power is actively expanding power production capacity, its avoided cost schedules consider the deferred need for plant construction that results when QFs come on line. Documentation filed by Virginia Power with its PURPA-buyback rates state that the levelized cost of a baseload coal unit for a 25-year period beginning in 1993 is \$261/kW-year.[2]

On the other hand, Apco (as a part of the AEP System) is not facing a need to construct new capacity in the near future. Thus, the capacity component of Apco's

[2] Notice of Proceeding to Amend Schedule 19, Case No. PUE920060. Filing of Virginia Electric and Power Company with Virginia State Corporation Commission. October 7, 1992.

avoided-cost rate schedule is very low because it reflects only the fixed costs of operating current capacity. Depending on whether or not a prospective supplier of capacity is prepared to utilize time-of-day metering, Apco's PURPA buyback capacity rates will range from $1.05 - $2.52 per kW-month ($12 - $30 per kW-year). The main cost factor considered in calculating Apco's avoided cost is energy. At approximately $.0184 to $.0224 per kWhr (1993),[3] Apco's base-level energy cost rates are generally 10 to 20 percent less than the corresponding rates filed by Virginia Power.[4]

The combination of low capacity and energy costs make Apco an unattractive customer for companies intending to establish facilities to generate power for sale to a utility under PURPA. Recently constructed non-utility coal-fired baseload capacity costs are running in the $300-to-$350 per kW-year range, far above levels that could be economically justified under the Apco avoided cost schedule. Currently, there are no non-hydro non-utility power generating plants (PURPA-regulated or otherwise) selling power to Apco.

Non-Virginia Markets:

The Kentucky Power service territory lies west of southwestern Virginia. Kentucky Power is an AEP operating company, so it presents no opportunities to an entity that is unable to compete with Apco.

There may be market opportunities associated with utilities located west of the Kentucky Power service territory. Apco officials state that transmission capacity to the west is not constrained, as it is to the east, and that significant AEP short-term and economy sales are currently being made to midwestern utilities. Power production costs in midwestern areas are being increased by clean air legislation, due to the relatively high sulfur contents of midwestern coal reserves.

Three utilities are located to the south: Tennessee Valley Authority (TVA), Carolina Power and Light (CP&L), and Duke Power. TVA expects its capacity to keep pace with load growth over the next decade, as five nuclear units (with a combined capacity of 5000 MW) are scheduled to come on line between 1993 and 1999 (TVA, 1991).

Both CP&L and Duke Power project that their only capacity additions during the 1990s will be combustion turbines to serve peaking needs. Neither utility plans to add baseload capacity until after the year 2000.

The plans by regional utilities conform with patterns observed nationally. The *Power Engineering* survey of utility baseload power plants revealed that most of the U.S. utilities' "in process" baseload capacity is planned for the late 1990s or thereafter (Smock, 1991). The same article reported a 1991 survey of utility plans for coal-fired baseload construction, which showed that only 18 percent of total planned capacity is scheduled to come on line prior to the year 2000.

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3 Virginia State Corporation Commission Tariff N. 14, Schedule Cogen/SPP. Filed by Appalachian Power Company. Effective August 1, 1991.

4 Schedule 19 - 1992/93. Filed by with Virginia State Corporation Commission by Virginia Electric and Power Company. Effective 01-24-92.

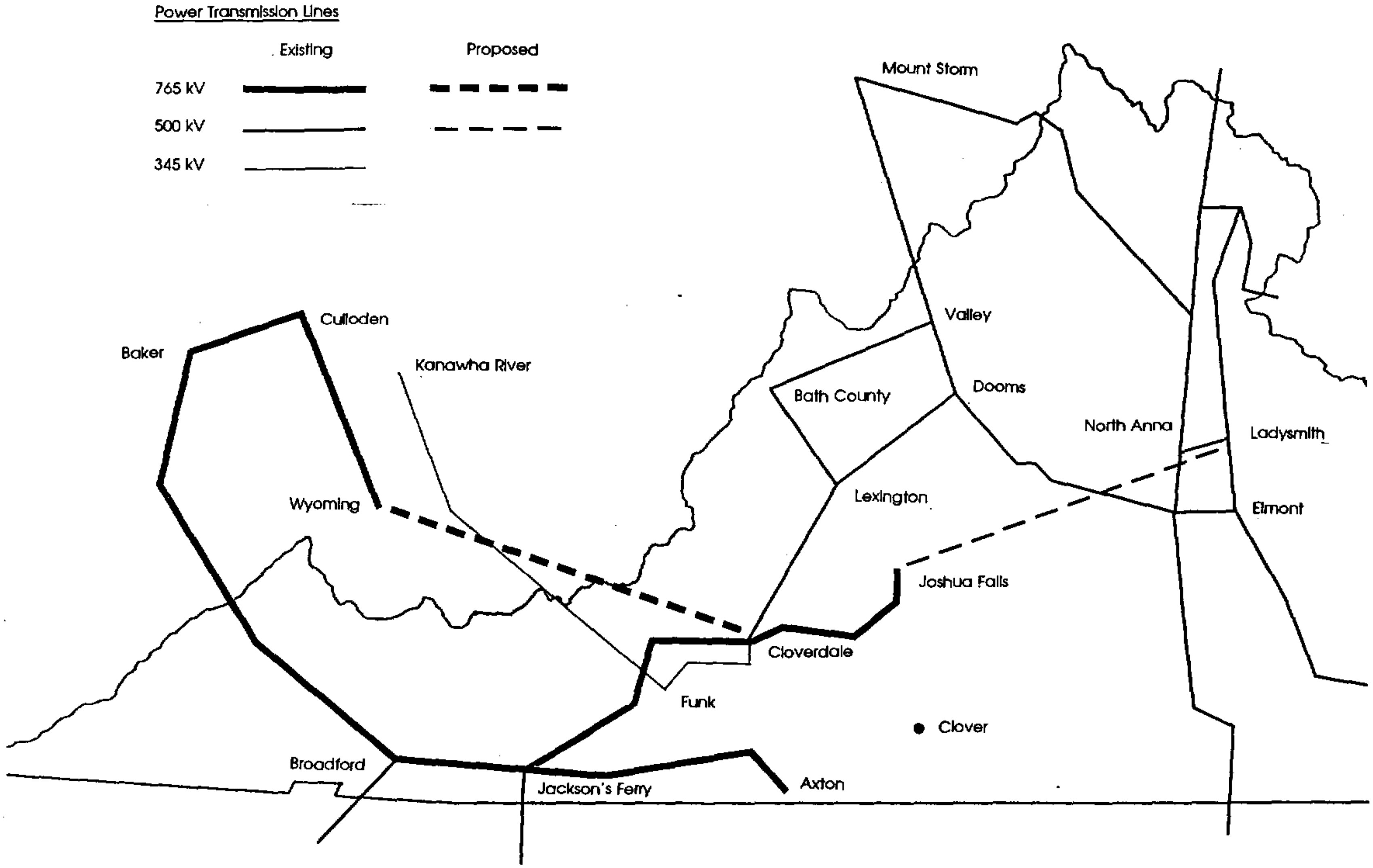

Figure 5: Major existing and proposed transmission facilities in Virginia and southern West Virginia.

Transmission:

Power transmission constraints are a major factor affecting the potential for power plant development in far southwestern Virginia. Most individuals contacted during this study consider primary power-market opportunities to be located northeast of the Apco system, in areas such as eastern Virginia and other eastern seaboard areas north of Washington, D.C.

Both Apco and Virginia Power have prepared transmission reinforcement proposals. Apco has proposed a 765-kV connection from Wyoming, West Virginia, to Cloverdale, Virginia, while Virginia Power has proposed to extend a new 500-kV connection from Joshua Falls to the east (Figure 5). The two utilities see these proposals as complementary.

At present, Apco maintains that it would be unable to provide a guaranteed, long-term transmission contract to a non-utility generating unit located in southwestern Virginia, to enable service to Virginia Power or other customers to the northeast, unless the Apco-Virginia Power transmission enhancement program is completed. A recent study confirmed Apco's contention that long-term west-to-east wheeling on the Apco system will not be possible unless the existing transmission system is upgraded (SCC, 1991).

If the proposed Apco-Virginia Power transmission reinforcements are approved and constructed, Apco has committed itself to providing 500 MW of transmission capacity to "wheel" power for non-utility generators in southern West Virginia and southwest Virginia. Under certain conditions, Apco would be willing to consider increasing the 500-MW limit (Simmons, 1993). Those conditions include wheelage to a power purchaser located to the north or west of the non-utility generating unit, in a location which would allow power to be transferred in a direction contrary to the prevailing direction of current power flows, or if the power supply facility were to connect with the Apco 765-kV system at Jacksons Ferry.

According to Apco, if the proposed Wyoming-Cloverdale 765 kv line is not completed, transmission enhancements would be required in order for new generation in the coalfields to transmit power to Apco's Virginia load centers (Roanoke and Lynchburg) or the Apco interface with Virginia Power. The length of new transmission from the coalfields to the Roanoke area would approach or exceed that of the proposed Wyoming-Cloverdale 765-kV line. No formal studies have been performed to assess the technical or economic feasibility of such an arrangement. Routing of such a line would be complicated by southwestern Virginia's environmental amenities, which include National Forests, Mount Rogers National Recreation Area, wilderness areas, and the Appalachian Trail.

Transmission Costs:

One factor influencing the economic feasibility of locating an IPP facility in southwestern Virginia is the cost of transmission from the IPP to the power purchaser.

Power-wheeling rates on the AEP system are determined by the "embedded cost" concept (Zipper *et al.*, 1991), and are subject to FERC approval. The current FERC-approved Apco rate for transmission of power from Hoosier Energy is \$2.00

per kW-month, plus $.001 per kWhr delivered, plus 2% compensation for power losses. If the supplying unit were a baseload generating unit operating at 80% of capacity, the equivalent charge would be $.0045 per kWhr delivered. If the supplying unit were a peaking turbine, operating at 10 percent of capacity, the equivalent charge would be approximately $0.03 per kWhr.

American Electric Power has submitted an initial rate schedule for open access wholesale transmission service with the Federal Energy Regulatory Commission[5] which the Commission has not yet acted upon. If this schedule is approved, the basic capacity charges for transmission and ancillary services on the AEP system would be $2.96 per kW-month, which is equivalent to $0.0052 per kW-hr for a baseload plant operating at 80 percent of capacity. No current studies which compare AEP's transmission charges to those of other utilities is available.

AEP's transmission rates are generally applied as a set fee, independent of path or distance, which is consistent with common electric utility practice. If a non-utility generator in southwestern Virginia required transmission service by a non-AEP utility other than the power purchaser in addition to transmission by AEP, that utility's charge for transmission services would be added to the rate charged by AEP.

The cost of moving baseload power to eastern or northern Virginia markets compares favorably to costs of moving an equivalent amount of energy to those markets from southwestern Virginia as raw fuel. Survey participants representing gas producers indicated that the cost of transporting gas to northern Virginia via pipeline, at current rates, is $0.60 - $0.80 per thousand cubic feet, with an additional $0.30 per thousand cubic feet required to guarantee delivery during peak use periods. This translates to about $.011 per kWhr at heat rates typical of single-cycle gas turbines, which would typically be used to provide peaking capacity, and to about $.007 per kWhr at heat rates typical of combined cycle plants (Table 9). Coal can be moved for slightly less expense per equivalent electrical energy unit than gas on guaranteed contract. Typical rail transport costs from the coalfield region to eastern and northern Virginia range from $12 to $15 per ton, which is equivalent to $.005 to $.006 per kWhr of electricity generated at a conventional coal-fired steam turbine.

Economic Benefits

If an electric power generation industry were to become successfully established in southwestern Virginia, numerous economic benefits would result (Table 10).

The plants themselves would have a favorable impact on the local economy by providing employment, purchasing inputs from local suppliers, and contributing to the local tax base. Plant construction would also have a major economic impact on the local economy. Expenditures of salary and wage income by construction workers and plant employees would also provide economic benefits to the local area.

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[5] American Electric Power Service Corporation, FERC Docket N. ER93-540-000, filed April 5, 1993.

TABLE 10. SUMMARY OF ESTIMATED ANNUAL ECONOMIC BENEFITS PER 100 MW OF OPERATING COAL-FIRED ELECTRICAL GENERATION[1]

Benefit	Direct	Indirect[2]	Ref[3]
Plant Construction (4 years)			
Jobs	150	52	(B)
Payroll	$3,750,000	$1,300,000	(B)
State Income Tax on Payroll (4% on 3/4 of Amount)	$110,000	$39,000	(A)
State Sales Tax (4.5% on 1/2 of payroll)	$85,000	$29,000	
Plant Operation (40 years)			
Jobs	40	40	(A,B)
Payroll	$1,300,000	$1,000,000	(A,B)
Local Property Tax[4]	$900,000		
State Income Tax on Payroll	$39,000	$30,000	(A)
State Sales Tax on Payroll Expenditures	$29,000	$22,500	(A)
Coal Production (40 years)			
Tons[3]	262,500		(C)
Revenues (@ 28.05/ton)	$7,363,000		(C)
Jobs	67	61	(C)
Payroll	$2,500,00	$1,500,000	(C)
State Income Tax on Payroll	$75,000	$45,000	(A)
State Sales Tax, on Payroll Expenditures	$56,000	$33,000	(A)
Coal Severance Tax (2%)	$147,400		
Other State & Local Taxes by Coal Industry	$62,000		(C)

1. All benefits expressed in 1990 dollars.
2. Refers to "spinoff" benefits, such as jobs in support industries and jobs supported by local employee expenditures.
3. References: (A) Randolph *et al.*, 1990; (B) Apco, 1992; (C) Zipper *et al.*, 1992.

A primary input purchased locally would be fuel. If the new plant were to utilize locally produced coal, additional impacts would occur through economic impacts of the coal mining firms.

Table 11 presents consolidated totals of the economic benefit figures in Tables 10. Only those impacts which can be quantified have been considered. Therefore, the economic benefits of Tables 10 and 11 represent conservative, lower-bound estimates.

The property tax figures of Tables 10 and 11 are among the highest tax-revenue benefits noted. Methods of dealing with property taxes on the plant structure would vary widely between counties. The figures utilized were prepared

TABLE 11: TOTAL ESTIMATED ANNUAL ECONOMIC BENEFITS (DIRECT PLUS INDIRECT) PER 100 MW OF COAL-FIRED ELECTRICAL GENERATION CAPACITY, DURING PLANT CONSTRUCTION AND OPERATION PHASES.

Phase/ Benefit Type	Benefit Estimate
Plant Construction (4 Years)	
Jobs	202
Annual Payroll	$5,000,000
Annual State Taxes	$263,000
Plant Operation and Coal Production (40 Years)	
Jobs	208
Annual Payroll	$6,300,000
Annual State & Local Taxes	$1,440,000

Note: Benefit estimates represent totals derived from Table 10, expressed in 1990 dollars.

with the assistance of personnel at Coastal Corporation, based upon Wise County rates.

Tables 10 and 11 refer to the economic impacts of a coal-fired baseload plant, in the 100 - 200 MW size range, based on the results of available studies. Larger baseload plants will employ fewer people per 100-MW capacity, but the coal purchase benefits will be unchanged. Apco's 705-MW Clinch River plant, for example, employs 176 people, an average of 25 per 100-MW capacity.

No comparable studies are available to allow estimation of the economic impacts of gas-fired facilities. The impacts of constructing the plant could be estimated relative to the benefits of constructing a conventional coal-fired plant, roughly in proportion to total capital costs.

Local economic benefits of gas-fired plant operation would be less than those cited in Tables 10 and 11. Again, no published studies are available for reference. An air-cooled 665-MW gas-fired combined cycle at Doswell, Virginia, employs less than 50 people for plant operation and maintenance, an average of 7 per 100 MW. The primary local economic benefits of locally produced natural gas fuel utilization would during exploration and development, rather than during the gas production phase.

State Involvement:

Some survey respondents suggested that state assistance might be considered as a means of establishing a power generation industry in southwestern Virginia. Presumably, any such commitment by the state would need to be justified, based upon the level of benefits likely to result.

TABLE 12. NET PRESENT VALUE OF EXPECTED ECONOMIC BENEFITS, PER 100 MW OF GENERATION, AT VARIOUS DISCOUNT RATES

Discount	Benefit Type	
Rate	Payroll	Taxes
6%	$181,000,000	$38,000,000
8%	128,000,000	26,000,000
10%	95,000,000	18,700,000
12%	74,000,000	14,000,000

Note: Benefits estimated in current dollars using Table 11 totals, and assuming total payroll and taxes escalate by 4% per year (i.e. keeping pace with inflation).

Table 12 contains estimates of the net present values of two distinctly different types of benefits that would occur from conventional coal-fired power plant development. Taxes represent financial benefits to the state, while wages represent one measure of economic benefits that would accrue to citizens of the area. Tax benefit calculations do not include consideration of the increased costs of providing state and local government services that would be required because of a power plant development.

Table 12 includes net present values of expected future benefit streams at various interest rates, assuming 4 percent per year future inflation.

Review of Key Findings

The purpose of this study was to assess the potential of the Virginia coalfield region to support an electric power generation industry.

General Findings

The major asset of the Virginia coalfield region as a potential location for electric power generation facilities is the local availability of fuel.

If marketing opportunities were available, the coalfield's resource base would appear to be capable of supporting at least 1055 MW of power generation capacity (Table 13). This is a lower-bound estimate, developed as follows:

- *Waste Heat:* Officials at Jewell Smokeless believe that waste heat from the coke ovens could be used to produce 40 - 60 MW electricity without any problem, if markets paying prices sufficient to justify the required investment were available.

- *Conventional Coal-Fired Generation:* Limitations of the region's surface water resources present constraints to location of conventional coal-fired power plants. The largest conventional coal-fired plants that could be reasonably considered would appear to be in the 200 - 300 MW size range; only a small number of coalfield locations have the potential to supply surface water in volumes required to support such plants. The Sargent and Lundy (1991) power plant siting study identified coalfield sites capable of supporting 400 to 600 MW of capacity within the coalfield region, as well as other sites outside of the coalfields. Site-specific studies would be needed to confirm this estimate. No additional siting studies are available.

- *Gas:* The region's gas producers indicated an ability and willingness to commit gas resources to long-term power supply contracts, if reasonably priced contract opportunities were available. Per-MW cooling-water demands and typical unit sizes of gas-fired combined cycle plants are generally less than those of coal-fired plants, so it seems reasonable to expect that suitable locations should be available. Gas producers report a potential availability of currently developed supplies, and resources under active development, sufficient to support approximately 600 MW of combined cycle capacity. Producers also report that, if local markets paying competitive prices were available, quantities of additional gas sufficient to at least double this capacity could be developed as coalbed methane within a relatively short time period. National data on the non-utility generation industry show that gas is a preferred fuel.

- *Coal-Processing Fines:* One coal producer reported a potential to produce up to 40 MW of electric power from the fine waste stream of a 1.5 million ton-per-year processing facility.

- *Refuse:* Older coal refuse piles could also be available for use in power generation. However, no information on the water sources that would be accessible to such development is available, The proximity of the Virginia coalfield region to Class I air quality areas is a factor that may constrain this development.

TABLE 13. COALFIELD REGION GENERATING CAPACITY ESTIMATES

Fuel	Conservative Estimate	Liberal Estimate	Source
	(- - - - - MW	- - - - -)	
Coal	400	600	Apco-VP study (1991)
Gas (short term)	600	600	Fuel availability
Gas (long term)	-	600	Potential fuel availability
Waste Heat	40	60	Company study
Coal slurry fines	15	40	Company study
Total	1055	1900	

1. Estimates are not comprehensive, do not include proposed TAMCO facility (Wise County), other potential sites for coal-fired plants which may exist in the coalfield region, or potential sites for coal-fired plants identified by Apco-VP study (Sargent and Lundy, 1991) outside of coalfield region. Gas availability estimates are based on company reports.

- *Low-Btu Coalbed Methane:* Methane that does not meet pipeline quality standards is being vented to the atmosphere in quantities sufficient to support a baseload plant in the 100 - 200 MW size range. At this time, however, technologies to convert this resource to electrical energy are not available.

The above estimate does not include TAMCO's Tom's Creek facility, proposed at 135 MW, because the economic feasibility of that plant depends upon a Department of Energy grant.

Electric power development in the coalfield area would provide economic benefits, including increased employment and tax revenues, to the coalfield region.

A primary economic benefit would result from operation and construction of the plants themselves. Additional benefits would result if plants burned a locally produced fuel. The economic benefits of mining coal, to supply a coal-fired plant, would be likely to equal or exceed the benefits of of operating the plant itself. The economic benefits of gas-fired plant operation and fuel procurement were not estimated.

Barriers

In spite of potential availability of fuel resources within the coalfield region, there are a number of factors present which present barriers to electric power development opportunities. These include:

- Lack of market access:

  Local power market opportunities are limited; transmission to potential eastern seaboard markets is not available; and there is no indication that utilities located south of the coalfield region (TVA, Carolina Power and Light, Duke Power) will provide baseload power market opportunities prior to the year 2000.

As a result of these limitations, there has been very little effort extended to investigate power development opportunities in the coalfield region, and most of the companies and agencies participating in the study did not have the expertise required to conduct such investigations on their staffs.

- Lack of cogeneration opportunities:

  National data show that 67 percent of total non-utility electric generation capacity (Table 3) and 85 percent of coal-fired non-utility electric generating capacity (Table 4) are cogeneration plants, able to derive revenues from supplying waste heat in addition to revenues derived from sales of electric power. Due to poor economic conditions in the Virginia coalfield region, cogeneration opportunities appear to be limited.

- A resource base which appears to be best suited to baseload-power generation, while anticipated needs of regional utilities in the near future will be for peaking power:

  Coal is the most plentiful resource; conventional coal-fired plants are suitable for baseload applications. The region's gas resources were reported to be better suited to baseload than peaking applications. The region's primary non-traditional fuel resources -- coal refuse and waste heat -- would also be best suited to baseload applications. A non-utility generator's per-kWhr transmission costs would be substantially less for baseload power than for power produced only to meet peak needs.

- A resource base which appears to be best suited to an industry of smaller facilities, dispersed throughout the region:

  Limitations of the region's water resources, coupled with the high capital and operating expenses of water-conserving cooling technologies, would appear to prevent establishment of conventional coal-fired plants larger than 200 to 300 MW in size. Non-utility interests state that coal-fired plants smaller than 200 MW should not be considered as economically feasible. Only a limited number of sites appear to be capable of supporting conventional coal-fired plants.

  Generally speaking, smaller plants may suffer cost disadvantages if forced to compete for contracts with larger plants in other areas. Generating technologies requiring large site and infrastructure development costs -- such as conventional coal -- will suffer the greatest economic penalties if local water resources limit plant size. Such penalties will tend to offset whatever economic advantages may be derived from reduced fuel transportation costs of plants in coalfield locations.

Fuels other than coal -- including gas, coal-processing fines, coal refuse, and waste heat -- are potentially available at a number of locations; plants using such fuels are generally constructed in smaller-sized units than typical conventional coal-fired units.

- Problems being experienced by TAMCO's proposed Toms Creek facility:

  TAMCO's proposed Toms Creek project is important to the coalfield region's potential to support future power development. The TAMCO IGCC technology emphasizes water conservation, but U.S. Department of Energy does not consider water conservation to be an objective of its clean coal technology development program. Therefore, if TAMCO loses its DOE grant, there is no guarantee that the DOE funds currently committed to TAMCO would otherwise be spent to develop a water-conserving IGCC technology.

Opportunities

New information, new technology, and economic change over the next decade may improve prospects for electric power generation in the Virginia coalfield region:

- The potential availability of water in mine cavities is an unknown factor which could have a positive influence on power development opportunities.

  Conventional coal-fired plant siting opportunities, in particular, appear to be limited by availability of cooling water supplies. If available in adequate quantities, mine cavity water could be used as an emergency supplement to a surface water supply, thus allowing a plant to locate where surface waters are only marginally adequate to meet cooling needs, or as a primary source of cooling water for a water-efficient plant. Underground cavities may also prove suitable for use as cooling water storage reservoirs. However, there are considerable uncertainties regarding the volumes of water potentially available from mine cavities, and regarding the legal implications of using this water for cooling purposes.

- The region's gas resources are a potential fuel source for electric power generation that have not been widely recognized.

  Survey respondents reported the existence of substantial coalbed methane and conventional natural gas quantities which could become available to local electric power facilities, if power market opportunities were to improve.

- When commercialized, integrated coal gasification combined cycle (IGCC) technologies may be be better suited to the coalfield resource base than conventional coal-fired power plants.

  Per-MW water requirements of some IGCC technologies are substantially less (on the order of 50 percent lower) than those of conventional coal. Individual

IGCC units can be effectively constructed at sizes smaller than conventional coal units, which effectively limits individual unit water requirements. If water-conserving water-conserving IGCC technologies are successfully commmercialized over the next decade, prospects for coal-fired electric generation in the coalfield region will be improved.

- The availability of both local gas and coal resources would appear to provide an opportunity for power plant developers, when IGCC technologies become available.

  Location of a gas-fired combined cycle plant close to a potential source of coal could provide a developer with some protection against the possibility of future gas price increases. A gas-fired combined cycle plant could be sited and designed to accommodate future conversion to coal-fired IGCC, as the IGCC technology becomes commercialized.

A number of current trends, if continued over the next decade, may improve the region's competitive position as a potential power producer:

- Continued development of IGCC and water conservation cooling technologies.
- Increased water resource constraints in other areas. Power production opportunities in southwestern Virginia are already constrained by these factors; if potential competing areas are similarly affected, the southwestern Virginia's competitive position may be improved.
- Increased needs for baseload power by regional utilities beyond the year 2000.
- Increases in Apco's avoided cost rates, as the AEP system approaches the time when new baseload capacity will be needed.

Regardless of these developments, adequate transmission access to potential markets will remain a factor that is critical to the region's ability to take advantage of future power development opportunities.

Conclusions

Fuel resources are plentiful in southwestern Virginia's coalfield area. However, the region does not appear to offer many other advantages as a location for electric power production. Limitations of water resources place a serious constraint on the potential for coal-fired power plant development. The low-cost power currently available locally through Appalachian Power, and the low rates that would be paid by that utility to firms offering to sell power to Apco under PURPA, are barriers to potential power plant developers. Lack of available transmission from southwestern Virginia to eastern seaboard areas presents a marketing barrier.

If marketing prospects were to improve, the coalfield resource base would appear to be better suited to a number of smaller plants, dispersed throughout the region, than one or two large plants, and better suited to baseload power than to peaking power production. The region's coal resources are plentiful, and are best suited to baseload generation. However, limitations of the region's surface water resources appear to limit opportunities for establishing conventional coal-fired plants. The region possesses non-traditional fuel resources -- coal refuse, coal processing fines, and waste heat -- which could potentially be converted to electric power if marketing opportunities were available. Another non-traditional fuel resource -- coalbed methane that does not meet pipeline quality standards -- is being vented to the atmosphere in considerable quantities, due to lack of technology and opportunity for conversion to useful product.

The region's gas resources would appear to provide an opportunity for power production, should marketing opportunities improve. Gas producers report a willingness and a capability to devote developed capacity to local power supply contracts, if prices were right and opportunities were available. The water requirements of gas-fired combined cycle technologies are a better match to the region's water resources than is conventional coal-fired generation. Appropriately designed gas-fired combined cycle units established on suitable sites at near-mine-mouth locations would have the option of converting their operations to burn gasified coal if gas prices were to rise and/or the cost of using IGCC technology declined to commercially viable levels. Gas-fired facilities, however, would bring less in the way of economic benefits to host locations than would coal-fired plants buying locally mined coal.

If markets for power were available and accessible, a lower-bound estimate of the coalfield region's electric power generation capacity at this time is 1050, including 400 MW of conventional coal-fired capacity, 600 MW of gas-fired capacity, 40 to 60 MW that could be developed from waste heat, and at least 15 MW that could be developed to burn fine-particle reject from a single 1.5 million ton-per-year coal processing facility. The coal-fired generation capacity estimate is based on a 1991 site availability study sponsored by Virginia Power and Apco; site-specific studies would need to be conducted to confirm its validity. The 600 MW gas-fired capacity estimate is based upon producers' estimates of gas availability; it includes currently developed production capacity, and proven reserves under active development, that are not obligated to buyers under current long-term contracts. Producers state that as much as 600 MW of additional gas could become available if local markets were present. Estimates of potential gas availability are incomplete, because one of the region's producers declined to participate in the study. Additional opportunities to burn coal-processing fines may be available, as well, as no unique attributes of the coal processing facility in question were identified as being responsible for its potential to act as an electric power fuel source.

The above estimate includes only generation opportunities positively identified by study participants within that area of southwestern Virginia known as the coalfield region (Figure 3). Lack of information on availability of mine-cavity water, and on possible legal constraints to its use, are significant unknowns.

Prospects for establishing power generation facilities in the coalfields do not appear to be bright, at present, primarily due to limited marketing opportunities. However, economic and societal changes over the next decade could cause those prospects to improve. As water resource constraints affect other regions, southwest Virginia's competitive position as a water-constrained power-producing region would improve. Economic growth which increases baseload power demands on regional utilities could also create marketing opportunities. Technological advances to decrease the costs of water-conserving cooling and IGCC technologies, and air emissions constraints to provide further incentive for use of IGCC, could improve southwestern Virginia's competitive position as a potential power producer. Improvements to the transmission system, both locally and regionally, will be required if the Virginia coalfield is to become a major electric power producing region.

Acknowledgements

This study was funded by Equitable Resources Co., Appalachian Power Co., Virginia Power, and Virginia Tech. The authors offer their sincere appreciation to all parties who contributed information to this study. Figure 2 was prepared by Appalachian Power Company, and originally appeared in Simmons (1993).

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