The Potential for Coal Use in New England

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The large rise in oil prices has occasioned a reexamination of alternative sources of energy. Great interest is centered on the vast coal resources of the United States. Legislation being considered in the Congress would make it mandatory to burn coal in all new fossil fuel plants.[1] The Federal Energy Administration has recently ordered the conversion of existing oil plants where feasible to the use of coal.[2] In short, there is a great deal of optimism about the ability of the U.S. coal reserves to play a larger role in satisfying U.S. energy demands.

At one time in New England coal supplied an important proportion of electric utility fuel needs. As recently as 1966 about 10 million tons of coal were burned annually in the six states of New England. By 1973 this had declined to 1.3 million tons, the great bulk of which supplied one power plant in New Hampshire.[3] This steady decline in coal consumption was due to the availability of cheap imported fuel oil and to increasingly strict environmental regulations. It was cheaper to comply with sulfur regulations by burning oil than by burning coal. Has this situation now been reversed by the actions of the cartel of oil-producing nations? Will coal now be favored in New England power plants? It is this issue that we will address in this paper.

If coal is to make a contribution to solving the energy problems of New England, it will be because it is a less costly fuel than its competitors. The costs of coal must also include the environmental costs of production and use since society has demonstrated a willingness to pay for a cleaner environment.

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[1]See *Coal Age*, July 1975, p. 22.

[2]*Coal Age*, August 1975, p. 25.

[3]National Coal Association, *Steam-Electric Plant Factors*, 1974.

In what follows, we concentrate on the use of coal in electric power plants. This is the dominant use for coal today. Economies of scale in handling, transport and purchasing make it more costly to use coal in smaller quantities. If the potential for coal use proves to be limited here, it is unlikely to prove a satisfactory fuel for most industrial uses.

The Irrelevance of Reserve Statistics

The great optimism with regard to potential coal use that is reflected in public statements of government and industry officials stems from the vast coal resources distributed through major areas of the United States.[4] Total resources are truly staggering and could supply the entire United States with its energy needs for years to come. However, this is not really the issue. Coal "reserves" measure only what is in the ground and not how much it costs to mine and deliver. The important question is how costly will it be to use coal. The answer will differ from region to region of the United States since each region relies on different supplying areas and will have to pay different transport charges.

Dimensions of Price

The price of coal is not easy to estimate. Coal differs by sulfur content, heating value, ash content, and volatile matter. Furthermore, prices observed in the marketplace are for contracts of various time periods, and for delivery ranging from immediate delivery to three or even five years from the contract date. The latter contracts are the truly long-term contracts for they allow the development of new mining capacity. Unanticipated shocks in supply and demand would have no effect on the price of these long-term contracts. These are all important distinctions to bear in mind. A great deal of confusion arises because people, with different purposes, quote a "price" of coal.

In 1973 the spot price of coal increased dramatically. The sudden increase in the price of oil together with the embargo greatly increased the demand for coal. This was an unexpected development, one for which the coal industry was eager but unprepared. In face of the limited capacity in the industry for quick output expansion the increased demand led to a dramatic rise in prices of coal for immediate delivery as well as for contracts that specified delivery within a year or two. The price of coal in the short run was a poor guide to the future price. The direction of future prices was clear, however — the price would decline as new expansion took place as the industry adjusted to increased levels of demand. To be sure, prices, after the dust settled, might be higher than they were before the surge in demand but they would be lower than what was being earned by the coal industry in the period immediately after the embargo. Price developments since that period bear this scenario out. Prices have declined, both spot and contract, from their record high levels of 1974.[5]

The long-run price is the relevant price for decisions about new capacity. The utility building a new plant has adequate time to sign a contract that stipulates initial delivery in four or five years. This is adequate for a coal company to develop an entirely new reserve and dedicate it to the power plant. This is not the case for the power plant required by the Federal Energy Administration to begin burning coal as soon as possible. In the latter case the utility must enter the spot market. It can, of course, sign contracts for coal deliveries in future years, but for the next few years it will be forced to buy coal at spot prices.

The time element is not the only dimension of price. Of particular importance is the sulfur content of coal. Low-sulfur coal earns a substantial premium over higher-sulfur coal. Here again one should not be misled by the large "reserves." There is a lot of low-sulfur coal in the ground. However, it is in thinner seams and lies deeper in the ground than does the high-sulfur variety. This fact simply reflects geology and the working of economic processes. Since low-sulfur coal was valued by users for its noncorrosive, nonpolluting aspects, coal mining companies sought it out. This selection, coupled with a niggardly nature meant that mining proceeded more rapidly into deeper and thinner and consequently, more expensive-to-mine seams.

[4]See, for example, the optimism expressed in *Newsweek*, January 22, 1973, p. 53.

National Policies Affecting Coal Prices

New England is a small purchaser of coal. Even if present use of coal expands dramatically, total New England purchases will amount to only a small fraction of U.S. output. In short, with respect to the national coal industry, New England will have no effect on coal prices.

There are, however, important national policies that can have a significant impact upon coal prices faced by New England. The most important of these deal with strip mining and with air pollution controls.

Strip mining is a mining technique whereby coal is obtained by removing the overburden material above a coal seam with large shovels, draglines or bulldozers. Then, using smaller shovels, coal is removed. Strip mining occurs in all three major coal-producing regions — Appalachia, the Middle West and the Far West. However, its environmental impact is different in each of the areas. In much of Appalachia the terrain is hilly and strip mining is very disruptive of the contour of the land. Reclamation is possible, but expensive. In the Middle West the land is flat and the restoration of the original contour is easily and relatively cheaply accomplished. In the Far West the problem is different. The land is flat and arid. The contour of the land is easy to restore, but the vegetation presents a problem. It is unclear at present how easily or how cheaply the

Coal Week, July 28, 1975.

original vegetation can be restored once the delicate balance has been disturbed. A recent report by the National Academy of Sciences indicates that ten inches of rainfall is enough to allow restoration.[6] Many of the coal areas in the west receive this amount of rainfall, yet mining prohibitions are still hotly contested.

President Ford has twice vetoed legislation that would limit strip mining, but some form of control is likely to emerge eventually. Depending upon the restrictiveness of the law, it can have an important effect on the cost of strip mining and thus on the price of coal.

The other piece of environmental legislation that impacts upon the cost of coal is the Clean Air Act of 1967 and its amendments of 1970. This act set antipollution standards. The various states and municipalities then established standards on particulate and sulfur emissions. The regulations regarding particulates can be satisfied, in most cases, with the use of some form of mechanical control device at the power plant. Technology for the control of sulfur dioxides, however, is not as well developed. At present, the status of stack-gas scrubbing devices is subject to much controversy. Scrubbers are costly devices with no history of proven effectiveness and reliability.[7] In the absence of a mechanical control, in order to comply with air pollution standards, particularly the more stringent standards for new plants, a utility would have to burn low-sulfur coal.

These two environmental goals interact with each other. Major supplies of low-sulfur coal lie west of the Mississippi River, much of it available only through strip mining. Legislation that restricts strip mining will then have the effect of diminishing the supply of low-sulfur coal. There is a tradeoff that the United States must make between these two valid environmental objectives, for the stricter strip mining controls are, in the absence of a low-cost scrubbing technology, the higher the cost of reducing sulfur dioxide emissions. Clean air in the cities at low cost comes at the expense of strip mining in less urbanized areas.

With this as background, we can now turn to an examination of the options for New England.

FOB Prices

High-Sulfur Coal. It is difficult to estimate a relevant price of coal today. We don't have any estimate of truly long-run contracts. Reliable

[6]National Academy of Sciences, *Rehabilitation Potential of Western Coal Lands: A Report to the Energy Policy Project of the Ford Foundation* (Cambridge, Mass.: Ballinger Publishing Company, 1974)

[7]This, of course, can change over time. A recent article indicates technical success with scrubbers for six months on a power plant in Kansas. *New York Times*, September 7, 1975, p. 21.

statistics are not collected, and we can only trace out likely prices based on cost studies of the Bureau of Mines and reports of recently signed contracts.

In 1973, before the coal market was thrown into the chaos described above, high-sulfur (about 2 percent) eastern coal was selling for $8.75 per ton in West Virginia.[8] This represents the last observation on prices in a period when supply and demand were close to long-run equilibrium. As such, it represents the best base for estimation of what high-sulfur coal prices will be once the industry has had a chance to adjust to the higher levels of demand. Of course, significant changes have occurred to drive up the long-run price in 1975. About 40 percent of the 1973 price represented labor costs. These costs have risen significantly with the new union contract of 1974. Estimates place the increase at about $2-$3 per ton, which together with the 1973 labor cost of $3.50 yields a labor cost of $5.50-$6.50 per ton.[9] The remaining costs we escalate by 44 percent to reflect increases in the cost of mining machinery and equipment as recorded in the wholesale price indices. This yields a price of about $14 per ton at the mine mouth.

This cost is below the price for new contracts signed by the TVA in the Middle West. These contracts were in the $15-$16 per ton range, but these contracts can be expected to reflect the recent market tightness.[10] Expectations of the TVA are for a further decline in contract prices.[11] Depletion, that is the movement to costlier seams, has been ignored in this estimate since our own research indicates that depletion in high-sulfur coal has been small.[12]

Low-Sulfur Coal. The situation with low-sulfur coal is more complicated. For coal with less than 1 percent sulfur, depletion has been significant. The supply of low-sulfur coal is not as elastic as the supply of the high-sulfur product. The air pollution regulations in various states and municipalities have forced the use of coal low in sulfur content. The cost of mining this coal at the margin, or what is the same thing, the cost of expanding production, is much greater than for high-sulfur coal. This coal earns a premium relative to high-sulfur coal. Furthermore, much of the low-sulfur coal available in the eastern states is of metallurgical quality

[8]See M.B. Zimmerman, "Long-Run Mineral Supply: The Case of Coal in the United States." Ph.D. Diss., MIT, August 1975. This is also corroborated by R.L. Gordon, *The Competitive Setting of the U.S. Coal Industry (1940-1980)*, 1975.

[9]See, for example, *Coal Age*, January 1975, p. 57. Total cost over three years was estimated as $4.6 billion. Expected production is about 1.8 billion tons so that a per ton cost is $2.55. For relative importance of labor costs, see U.S. Bureau of Mines, Information Circular 8632, 1974.

[10]*Coal Week*, May 12, 1975.

[11]*Coal Week*, July 21, 1975.

[12]Zimmerman, *op. cit.*, p. 195.

suitable for making coke. The need for this low-sulfur, low-ash coal is forcing some eastern utilities into the metallurgical coal market and a similar situation would face New England utilities seeking supplies of coal low in impurities. The highest quality metallurgical coal sells on long-term contract for $50 per ton.[13] These are coals low in sulfur and ash as well as volatile matter. The latter quality is important in coke production.

While no firm price information exists for lower-quality metallurgical coal, there is evidence that it is in the $30 per ton range.[14] There is another important source of low-sulfur coal — the states west of the Mississippi River. This coal is low in heating value but also low in sulfur. It occurs in large deposits close to the surface so that mining costs are low. Its disadvantage is its location, which when coupled with its low heating value, makes transport cost per heating unit quite expensive. Nevertheless the high prices of eastern low-sulfur coal make it an attractive alternative to some eastern utilities. American Electric Power, for example, has contracted for large quantities to be used in its plants in Indiana, and now it will be moving into plants in the Ohio coal fields.[15] This is the American equivalent of "hauling coals to Newcastle."

The price of western coal delivered to a New England utility sets an upper limit on the price it would have to pay for low-sulfur coal in the long run. Western coal, because of its low heating value might not be compatible with existing boilers designed for high-quality eastern coal. For the new plant, where the boiler design is still flexible, it represents a real alternative.

Currently, western coal is selling for $6 per ton at the mine mouth in Montana.[16] This price also reflects short-run capacity constraints imposed by limited government leasing, uncertainty with regard to the future course of legislation dealing with strip mining and environmental suits that are holding up the issuance of mining permits. Were these obstacles to be removed, price could be expected to decline. Recent engineering estimates of the costs of mining put the cost, including a 12 percent after tax rate of return, of new western strip mines at about $4 per ton.[17] New

[13] *Coal Age*, May 1975, p. 30 and February 1975, p. 22.

[14] *Ibid.* Contract prices are mentioned as $20-$25 for coal with about 1.5 percent. We have therefore assumed 1 percent sulfur coal at a cost of $30.

[15] For American Electric Power purchases see *Wall Street Journal*, Sept. 24, 1972, p. 11, Nov. 5, 1973, p. 8, and Aug. 15, 1974, p. 14. The shipment into the area of Ohio will be announced soon. Information was provided by an executive of the railroad that will haul the coal.

[16] A recent contract for coal with 19.2 million Btus per ton was signed at a price of $7 per ton. Converting it to a per-ton cost for coal with 17-million Btus per ton yields $6. *Coal Age*, December 1974, p. 21. A contract for $5.26 per ton was announced in early 1975, *Coal Age*, February 1975, p. 22.

[17] This figure comes from U.S. Bureau of Mines, *Basic Estimated Capital Investment and Operating Costs for Coal Strip Mines*, IC 8661, 1974. The costs were presented as of 1973 and, adjusting for inflation in the mining machinery and equipment index, yields $3.83.

taxes in western states together with expectation of more stringent reclamation requirements suggest a price of about $5 per ton at the mine mouth for a long-run contract.

Transport Costs and Delivered Prices

Transport costs comprise a significant fraction of the delivered costs of coal. The most efficient means for transporting coal when water transport is unavailable is shipment by unit train. These are trains that are dedicated to hauling coal between a mine and a power plant. The cost of switching cars is avoided and administrative costs are reduced considerably. Further, the cars and locomotive are in almost constant use, greatly increasing utilization rates.

Rates are not set exclusively by the cost of the haul. Railroads in the past have been able to discriminate, charging utilities with higher cost alternative fuels and no alternative to rail transport more than utilities with less costly alternatives for a haul of any given distance.[18] Consequently, the rate pattern differs from area to area.

The best estimate of probable unit-train rates for new shipments from Appalachia to New England is the rate on the large-volume train shipment with fast loading and unloading to the Merrimack Plant in Concord, New Hampshire. In railroad-owned cars, the rate is $7.85 per ton or about 8.9 mills per ton-mile from Pennsylvania.[19] In reality, this represents a low estimate for new rates, since it was agreed upon when the real price of oil was far below what it is today. If past history is a guide, the higher prices of alternative fuels, in this case oil, could well lead to higher unit-train rates.

Western transport rates are even more complicated. Western coal is now moving into the Ohio Valley, but midwestern roads, in an effort to protect their local markets, appear to be establishing high rates for their portion of the haul.[20] A similar situation could arise in shipments further east, but it is too early to tell. The lowest rate likely to emerge for western shipments is 7 mills per ton-mile to the midwest and 8.9 mills per ton-mile for the continuation to the east. The 7 mill figure represents the low end of rates on shipments originating in the west.

Water shipment offers an alternative to New England coastal stations. This would involve an initial shipment by rail and transloading at the port. Some savings could be realized here, but the more circuitous route and transloading make costs about the same for an all-rail shipment at

[18] Zimmerman, *op. cit.*, ch. 3.

[19] The Pennsylvania and Lake Erie tariff specifies 4 hours loading, 10 hours unloading, 9,000 tons per train and a minimum of 900,000 tons per year.

[20] Zimmerman, *op. cit.*, ch. 3.

Table 1

A. Transport Costs to New England
($ per ton)

Source	Destination Hartford	Destination Concord
Northern Appalachia	$ 5.34	$ 7.85
Southern Appalachia	7.12	9.97
West	19.89	22.56

B. Mine Mouth and Delivered Costs

	Mine Mouth Cost Per Ton	Delivered Btu Content (mm)	Hartford Delivered Cost Per Ton	Hartford Delivered Cost Per Million Btus ($)	Concord Delivered Cost Per Ton	Concord Delivered Cost Per Million Btus ($)
Northern Appalachia (2% sulfur)	$14	(24)	$19.34	($ .81)	$21.85	($ .91)
Southern Appalachia (1% sulfur)	30	(25)	37.12	(1.48)	39.97	(1.59)
Metallurgical Coal	50	(25)	57.12	(2.28)	59.97	(2.40)
West	5	(17)	24.89	(1.46)	27.56	(1.62)

Source: Text. Transport costs are all-rail rates. Mileage from Rand McNally, *Handy Railroad Atlas*, 1973.

the rates cited above.[21] Water transport can be important though as a competitive tool for keeping rail rates low. We return to this point below.

Table 1 summarizes the above information. It shows that the cost of coal per million Btus delivered to New England ranges from 80¢-90¢ for high-sulfur coal and $1.40-$1.60 for low-sulfur coal. Low-sulfur Eastern coal would most likely come from southern Appalachia so that in addition to a higher mine mouth price, the transport cost would also be greater.

These costs probably represent the minimum New England would have to pay. Transport costs, depending upon the outcome of bargaining between railroads and utilities, could in fact be much higher. Further, real wages in coal mining have been escalating rapidly. A continuation of this process could increase costs significantly. It is instructive to compare these minimum estimates to alternative fuel prices.

Coal as a Base-Load Fuel

At present, oil delivered on new contracts in Massachusetts is in the neighborhood of $1.80 per million Btus. This is much higher than high-sulfur coal costs and comes close to the delivered cost of low-sulfur coal.

Electric power generated by nuclear plants is more capital intensive than alternative generation methods, but fuel costs are insignificant. The difference between the total costs of nuclear power and the nonfuel costs of coal sets an upper limit on the amount utilities will pay for coal before turning to nuclear power. Table 2 presents the implied limit on coal prices for various differences in the capital costs of nuclear and coal plants. The figures were generated by first calculating the additional cost per kwhr implied by the capital cost differential. This cost differential was converted to a cost per million Btus input equivalent. The latter figure is the result of multiplying the cost per kwhr by the number of Btus required to produce a kwhr.[22] This yielded an equivalent price per Btu which was multiplied by one million to yield cost per million Btus. Differences in operating and maintenance costs were also taken into account.[23]

Table 2 suggests it would take a price difference of at least $250 per kw between a coal and nuclear plant to justify the building of a coal plant in New England, since delivered cost of coal is at least 81¢ per million

[21]It is difficult to get an estimate of cost of large-scale bulk transport since coastwise coal shipments to New England ceased a number of years ago. Rough estimates for a coastal bulker on a run to New Haven suggest little or no savings. In more northern sites, water transport might provide some moderate savings.

[22]This is the "heat rate," assumed here to be 9,000 Btus.

[23]These come from the Federal Energy Administration *Project Independence Report*, Nuclear Volume, p. V-22 and Facilities Volume, p. VII-144-210. Operating and maintenance cost for a coal plant assumes no scrubbers and is the cost of burning low-sulfur coal.

Btus for *high-sulfur* coal. This is below the estimated difference of $150 per kw in late 1974 of the Federal Energy Administration for a coal plant without scrubbers. If the cost of the scrubbers is included, the FEA has the difference narrowing to only $80.[24]

These numbers are highly conjectural. They do not consider the total costs of unexpected delays in licensing nuclear plants since they ignore the costs of using an inefficient plant mix during the period when the nuclear plant would have been operating. Nevertheless, Table 2 suggests that in the absence of a dramatic reversal in the comparative costs of nuclear and coal plants, the base load alternative in New England will be nuclear.[25]

One event could drastically change this panorama — a nuclear moratorium. Then coal would obviously be used, but at cost levels above those estimated here. In this case, increased demand for coal would drive up prices and all bets are off as to how high the price of coal would go.

Table 2

Allowable Cost of Coal for Various Capital Cost Differentials (in cents per million Btus)

Advantage of Coal Plant in Capital Cost per Kw	Capacity Factors for Both Plants .65	.75
$ 50	25.6	23.4
100	42.2	37.7
150	58.8	52.1
200	75.4	66.5
250	92.0	80.9

Source: See text.

Notes: Assumes 17 percent annual capital charge. Adjustment for differential O & M costs as described in text. Assumes no scrubbers and therefore no additional operating and maintenance cost due to their use, a bias in favor of coal plants. The table assumes no difference in capacity factors for the plants. Available data are confusing on this issue and there appears to be no presumption that one plant will achieve a higher factor than the other, particularly if coal plants must use scrubbers which will reduce their availability somewhat. See source cited in footnote 24.

[24] *Ibid.* A recent report indicates a differential of $150 per kw between a nuclear plant and a coal plant with scrubbers in early 1975. Arthur D. Little, Inc., *Economic Comparison of Base Load Generation Alternatives for New England,* report prepared for New England Electric Systems, January 1975.

[25] Gordon reaches a similar conclusion for the United States, Gordon, *op. cit.*

Other Roles for Coal in New England

Eliminating coal from new base-load generation is saying a great deal, but it does not mean that coal resources have no role to play in New England. There are potentially three areas in which coal can provide an important part of New England's fuel supply.

(a) Coal plants, because of the shorter lead time in construction than nuclear plants, will provide capacity where demand has been underestimated. In light of recent cancellations of new orders and great uncertainty about future electric demand, this could prove important. The advantage of coal over oil capacity depends upon whether low- or high-sulfur coal may be burned. We return to this issue below.

(b) Coal conversion. The Federal Energy Administration recently estimated that over 3,300 MW of capacity could physically be converted to coal.[26] This capacity represents one-third of New England's fossil capacity and 36 percent of its fossil generation. These figures overstate somewhat the oil savings that can be realized in the future. As nuclear capacity comes on stream, the older fossil fuel plants will be pushed up the load curve. That is, they will be used to satisfy demands for electricity other than base load and their operating rates will go down. Nevertheless, in the period until the nuclear capacity comes on stream, coal can substitute for substantial quantities of oil.

(c) Finally, for new, intermediate load plants that must be constructed, coal offers an alternative to oil.

Policy Choices Involved in the Use of Coal

A. *The Environment Trade-off*

In all the cases described above, coal can substitute for oil. This serves the goal of limiting New England's dependence on oil. But it does not guarantee a lower-cost fuel. The costs of low-sulfur oil and low-sulfur coal discussed above are almost equal. When the costs of conversion for oil-fired plants are added, the difference could disappear for many existing plants. Furthermore, real oil prices could go down in the future. Voluntary conversion to coal will occur only if sulfur-in-fuel standards are relaxed. The present .5 percent standard in Connecticut and 1 percent in Massachusetts, where the bulk of the electric load is, insures this result.

The conclusion is not modified even if scrubbers are proven reliable in the near future. They represent an equivalent cost of 55¢ per million Btus in a new plant.[27] The costs of low-sulfur coal or high-sulfur coal plus

[26] *Federal Energy Administration Factsheet,* "Breakdown of Power Plants Being Considered for Conversion," May 9, 1975.

[27] This allows for a $75/kw cost of a scrubber and additional operating and maintenance costs. The additional O & M costs come from comparing a coal plant burning low-sulfur lignite and a plant using high-sulfur bituminous with scrubbers. Costs are from *Project Independence Report,* Nuclear Volume, p. V-22.

scrubbing are therefore roughly equivalent. If scrubbers are to be put on old plants with shorter lifetimes, scrubbing costs will be greater than low-sulfur coal costs.

This is a policy choice that each state must make. Coal will substitute for oil only at the cost of relaxed pollution standards. Low-sulfur coal can be burned and reduce dependence on oil, but it will not significantly lower costs and in many cases could raise them. Each state must determine its tradeoff between pollution, power costs, and the unreliability of oil supply. Table 1 indicates that a 1 percent sulfur-in-fuel standard will add 60¢ per million Btus burned when compared to coal with roughly 2 percent sulfur. If it is decided that pollution standards can be relaxed, they must be permanently eased for those power plants in question. If costs are to be low, assurance must be provided to allow a long-term contract and unit-train transport. Temporary variances will not be effective. There is some flexibility since not all plants need lower standards. Where plants are unable to take advantage of lower-cost coal, standards need not be relaxed. Low-sulfur oil can continue to be required.

B. *Should Conversions be Forced?*

The implication of Table 1 is that conversion, under current sulfur standards, will not be voluntary. This raises the issue of whether it should be forced. If utilities are forced to convert, dependence on potentially unreliable sources can be lessened. The FEA has opted for this route. There is, however, a danger in forcing conversion. As described above, coal transportation costs are affected by the alternatives available to a utility. The price of oil sets an upper limit on the delivered cost of coal a utility is willing to pay. If oil is eliminated by fiat, this upper limit is removed. Oil, at present, is a high cost alternative, but an upper limit nevertheless. If oil prices move down, this would be even more important.

Furthermore, it is not clear that conversion to coal is insurance for New England against the disruptions of embargo. During the period of rapid rises in coal prices, many utilities complained of nondelivery on coal contracts as supplies were allegedly shifted to the temporarily more profitable spot market.

Measures for Reducing Costs

If coal is used, an important area for keeping costs down is transport cost. One way to keep down transport costs is to explore the use of water transport for coastal plants as a means of promoting competition for the railroads. In the past, a great deal of the coal used in New England came through tidewater shipments. The coal originates on a rail line and there will still be a lack of competition at the origin, but by looking widely for coal and increasing the number of railroads that can originate tonnage, some competition there can be introduced. Unit-train rates are substantially less expensive than other forms of rail transport. Small plants often will not consume enough coal to justify large scale unit-train shipments and long-term contracts. In those cases, an alternative might be to combine fuel purchasing on a regional level. A single mine could supply a group of plants. A unit-train need service only one plant per trip, but service several destinations on a regular schedule.

Coal Conversion

Coal can be converted to high and low Btu gas. Work is proceeding on synthetic oil technologies. At present, these technologies are very high cost sources of energy. It is estimated that high Btu gas costs are now $4 per million Btus at the site of manufacture.[28] We might eventually turn to this source for space heating, but it is a future more to be feared than welcomed. Low Btu gas could be produced at New England sites for about $2.10 per million Btus.[29] Since the latter product is low in heat content, transport cost per heating unit is expensive and the gas would be produced at the site of consumption. There are economies of scale in coal conversion and this cost is attainable only for large plants producing about 250 billion Btus per day. It would therefore be a base load alternative, but a high cost one. It might eventually prove more valuable as an industrial fuel where industries are grouped together and collectively use this quantity of gas. In the next ten years, coal conversion offers small promise.

Summary

The original reason for the movement away from coal in New England is still with us. The OPEC cartel has not changed that fact. The costs of using coal depend importantly upon the sulfur standards set by each state and the Environmental Protection Agency. Short of a modification on the permissible levels of sulfur emissions, coal will not voluntarily be burned in significant amounts in New England's boilers. If the choice is made to relax these standards, attention must be paid to promoting competition as much as possible. Present conversion technologies also appear to be of limited value to New England.

[28] *Coal Age*, June 1975, p. 36.

[29] Capital and operating costs from M.I.T. Energy Laboratory Policy Study Group, *The FEA Project Independence Report: An Analytical Review and Evaluation*, Energy Lab Report No. MIT-EL-75-017, May 1975, p. 8-2. Coal cost from Table 1. Capital cost escalated from 1973 prices by construction machinery price index and operating cost by the wholesale price index.

Discussion

Guy W. Nichols*

When Frank Morris asked me to present a critique of Dr. Zimmerman's paper I was deeply concerned, because of my long-time affiliation with MIT and my fear that I would be in violent disagreement with an academician's approach to the use of coal in New England.

My concern was not justified. In fact, I have no criticism of Dr. Zimmerman's paper — it is excellent. I would, however, like to respond to his suggestion that we range widely for our coal so as to present our U.S. suppliers with adequate competition. Within the last year and a half, we in New England have burned coal from South Africa, Australia, and Poland. I don't think we can range much further than Australia. That's all behind us now, however, because we were not able to convince either Congress or the Administration to modify their environmental rules to permit us to burn coal past June 30 of this current year.

I would like to expand on three points that are covered in Dr. Zimmerman's paper:

1. Western coal may not be compatible with existing boilers designed for eastern coal.
2. Unless the Environmental Protection Agency (EPA) modifies permissible sulfur emissions, New England public utilities will not voluntarily burn coal in significant amounts.
3. In the absence of a dramatic reversal in the comparative costs of nuclear and coal plants, the base-load alternative in New England will be nuclear.

To provide background for my remarks I would like to review some tables with you.

Table 1 shows present Massachusetts sulfur regulations for plants located outside the Boston metropolitan area. For existing units the standards permit the emission of no more than 0.55 lbs. of sulfur per million Btus of heat generated. For eastern coal with a heat value of approximately 13,600 Btus per pound this is equivalent to an allowed sulfur content of 0.74 percent by weight. For western coal the standard permits only

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Table 1

CURRENT MASSACHUSETTS SULFUR REGULATIONS
(OUTSIDE BOSTON METROPOLITAN AREA)

	Existing Units 0.55 lbs. of Sulfur/MMBtus	New Units 0.40 lbs. of Sulfur/MMBtus
Equivalent to sulfur Content by Weight for:		
Oil	1.00%	0.73%
13,600 Btus/lb. Coal	0.74	0.54
8,000 Btus/lb. Coal	0.44	0.32

Note: The existing units at the Brayton Point plant were designed for 13,600 Btus/lb. coal with 1.8 lbs. of sulfur/MMBtus. MMBtus = 1,000,000 Btus.

0.44 percent sulfur because of this fuel's much lower heat value. To appreciate the severity of these regulations one must realize that our Brayton Point plant, our largest and most modern plant capable of burning coal, was designed to burn coal with 13,600 Btus per pound and a sulfur content of 2.4 percent. The standards for new plants are even more stringent.

Can we meet these environmental standards in our existing plants? The coal most readily available to us that can meet existing regulations is western coal, which has a sulfur content of approximately 0.4 percent. Unfortunately this coal averages about 8,000 Btus per pound — far less than the 13,600 Btus per pound of coal our boilers were designed to use. We cannot physically burn enough western coal per hour to permit us to get the full capacity out of our existing plants. In fact, our best engineering estimates indicate a 25 percent reduction if we use western coal.

For a plant the size of Brayton Point this means a reduction of some 280,000 kilowatts. This is base-load capacity that would need to be replaced at a cost in excess of $150 million. This capacity penalty rules out western coal.

Eastern coal, while it has an acceptable heat value, can only meet the sulfur standards if it is high quality metallurgical coal or if scrubbers are installed. However, metallurgical coal is eliminated from consideration by a price of $50 per ton.

Table 2 outlines the capital costs that we may have to incur if we burn coal at our Brayton Point plant. The extent of these expenditures will be determined in part by the type of coal available and by the dictates of the then environmental authorities.

Flue gas desulfurization facilities account for more than half of the total costs of conversion, or $120 per kilowatt. The cost of these scrubbers

Table 2

POTENTIAL INCREMENTAL CAPITAL COSTS TO BURN COAL

90% COAL FIRING

Brayton 1-2-3 Only

Pulverizers	$ 15 Million	
Ash Handling	10 Million	
New Coal Receiving and Handling	15 Million	
Balanced Draft Work on No. 3 Other Boiler Work	10 Million	
Miscellaneous Dual Firing Station Service Flue Gas Conditioning	8 Million	
Precipitators	57 Million	
Sub Total	$115 Million =	$100./kw
Capital Costs — Scrubbers	$138 Million =	$120./kw
Total Capital Costs	$253 Million =	$220./kw
Original Plant Cost		$135./kw

more than offsets the economic advantages of burning eastern high sulfur coal and re-enforces the point that "unless the EPA modifies permissible sulfur emissions, New England public utilities will not voluntarily burn coal in significant amounts."

On the subject of sulfur regulations, I would like to emphasize our industry's commitment to meeting the SO_2 standards that have been set by our Federal environmental protection authorities. As you may remember, these are ambient standards and not plant emission standards. They address themselves to the ambient air, the air we breathe, and they set standards that this ambient air must meet. To be exact, they set primary standards sufficient to protect public health, and more severe secondary standards to protect public welfare as well as public health.

Our industry is committed to the attainment of both of these standards. We do ask, however, that we be allowed to attain these standards by the least expensive methods that we can devise. Our proposed methods include fuel switching, the use of tall stacks and, in some cases, the use of scrubbers.

We are not anti-scrubber. Although they are inefficient and largely untested, in some areas we anticipate their use will be required to meet our objectives.

The environmental bureaucracy of this Nation, both state and Federal, would, almost uniformly, like to have us go beyond the attainment of these Federal standards and achieve the even higher standards set forth in many of the various state implementation plans — and they would like to have us meet these standards without resorting to fuel switching, tall stacks and the like.

I have three tables that describe the difference in the results of the industry plan and what the government officials would like. The latter I have referred to as the EPA plan. Table 3 points out the differences in capital costs between the two plans. Under the utility plan 1980 capital costs for the industry are estimated to be $156 billion, of which $6 billion would be for equipment needed solely to meet the environmental standards. However if the government refuses to accept the industry's methods of meeting these standards this environmental component would more than double, raising the total capital requirements to $164 billion.

Converting plants from oil to coal increases costs under both plans, but particularly under the EPA version because of the higher sulfur content of most coal. If all plants were converted to coal, a step required in order to meet project independence goals by 1985, it would increase capital requirements $28 billion under the industry plan and $38 billion with the EPA version.

Table 4 lists the wasted annual costs of electrical production if we are forced to go the EPA route. And Table 5 describes the impact on coal demand and scrubber equipment demand if the utility approach is used — as compared with the impact if the EPA approach is used.

I am very pleased to report that there has been a very recent change in the thinking of the EPA at the Federal level. Roger Strelow, Assistant Administrator for Air and Waste Management, has recently indicated his support of fuel switching, tall stacks, etc. (the industry's recommended approach) for coal-burning plants through the year 1985. This is the first "crack in the door." It would be a little illogical for EPA to recommend this, and not recommend it for oil-fired plants as well — particularly when you realize that the oil-fired plants tend to be in those parts of the country with relatively clean air.

The third point of Dr. Zimmerman's that I would like to emphasize is "in the absence of a dramatic reversal in the comparative costs of nuclear and coal plants the base-load alternative in New England will be nuclear." I agree completely. There are obvious problems with all forms of energy production and energy conversion. Coal has some problems that do not

Table 3

ESTIMATED 1980 CAPITAL COSTS
(Billions of 1980 Dollars)

	Industry Plan	EPA Plan
No Conversions		
Environmental	5.8	13.5
Conversion	—	—
New Capacity	150.0	150.0
Total	155.8	163.5
FEA Recommended Conversions		
Environmental	5.8	17.1
Conversion	0.6	0.6
New Capacity	150.0	150.0
Total	156.4	167.7
All Plants Convert[1]		
Environmental	7.2	25.2
Conversion	26.5	26.5
New Capacity	150.0	150.0
Total	183.7	201.7

[1]Required to meet project independence goals.

Table 4

WASTED ANNUAL COSTS
OF ELECTRICAL PRODUCTION IN 1980
UNDER THE EPA PLAN[1]
(1980 Dollars)

No Conversions		
	$ Billions	5.3
	Millions/kwh	1.7
	$/Household	66.0
FEA Recommended Conversions		
	$ Billions	6.3
	Millions/kwh	2.0
	$/Household	76.0
All Plants Convert		
	$ Billions	8.8
	Millions/kwh	2.9
	$/Household	111.0

[1]The wasted cost of electrical production is attributable to the additional capital cost and reduced capacity caused by the EPA plan.

Table 5

1980 COAL DEMAND
AND SCRUBBER EQUIPMENT DEMAND
(Scrubber Equipment Demand in MW)

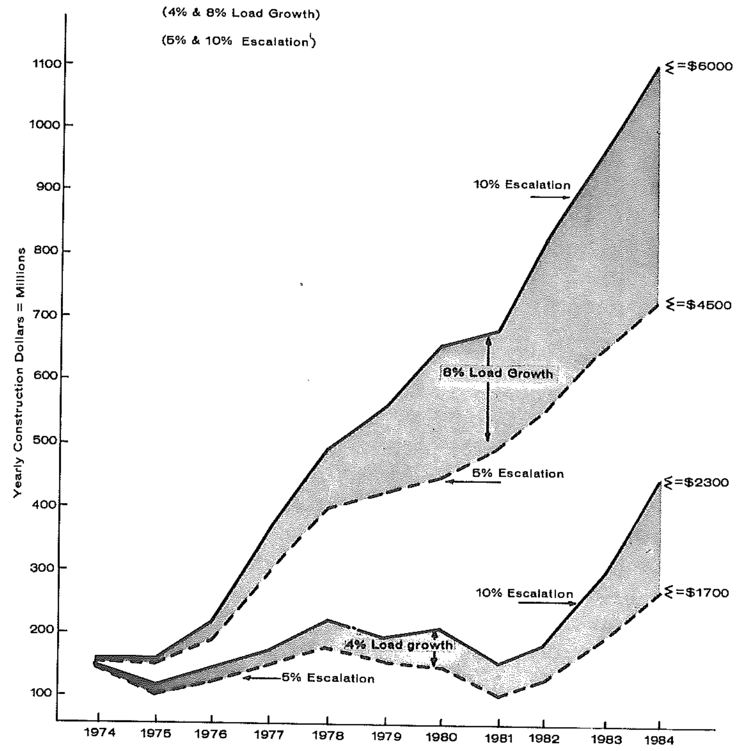
(Coal in Millions of Tons)

	Industry Plan	EPA Plan
No Conversions		
Total Coal	584	583
Low Sulfur[1] Coal	105	173
Required Scrubber Capacity	38,015	93,421
FEA Recommended Conversions		
Total Coal	622	622
Low Sulfur[1] Coal	105	173
Required Scrubber Capacity	38,015	116,480
All Plant Convert		
Total Coal	922	909
Low Sulfur[1] Coal	184	311
Required Scrubber Capacity	42,992	164,706

[1] Less than 1% sulfur.

Figure 1

NEES' 10-YEAR CONSTRUCTION FORECAST



get much attention — it is labor intensive. The British have learned, to their sorrow, of the control exerted by the coal miners. In fact, some of you may have visited London during a period when the British were forced into blackouts due to lack of coal brought about by labor strikes.

The problems of handling coal ash are often overlooked and probably deserve more attention than we have given them today. Dumping fly ash at sea is an obvious solution, but one that is quickly vetoed by environmental authorities. Utilization of coal ash in building materials and road construction is meeting with increasing resistance. In fact, in Massachusetts, fly ash is now considered a refuse material and can only be placed in approved landfill operations. These are very difficult to find and increasingly expensive.

In conclusion, there are two myths about utilities that I would like to clear up. The first of these concerns our supposed penchant for nuclear power. I am afraid many people think that the electric utility industry in New England is wedded to nuclear power and refuses to consider other alternatives. This is not the case. Nuclear power is more capital intensive than coal and/or oil-fired facilities. My life as a utility executive would be much easier if our industry could plan on less capital intensive sources of base-load generation. As previous speakers have indicated, the attraction of capital to the energy industries of New England is a critical problem. The reason the utility industry reluctantly selects nuclear for base-load generation is simple. It is the lowest-cost source of electric power of all the options that are available to us. In fact, nuclear power offers the only energy solution that will bring New England's electric energy costs into a competitive position with other parts of our country.

The second myth that I would like to correct concerns growth. I fear many people believe that electric utility executives strongly favor electric energy growth and only reluctantly pursue conservation of energy. This is not the case. Figure I will, I hope, convince you that rapid growth brings real problems to our industry. The bottom band on this figure indicates NEES' annual construction budget with 4 percent load growth. It implies annual expenditures of $170-230 million per year over the next 10 years. The upper band shows the same information if consumption grows at an 8 percent rate. With 5 percent inflation annual capital needs would average $450 million, with 10 percent inflation, $600 million. Obviously if we grow at 4 percent our capital needs are significantly lower than at 8 percent and we will escape the capital attraction problems associated with the difference.

In addition, every time we add a new unit of capacity, we raise our average costs. Unfortunately, the economies of scale that were so significant through the 1960s no longer offset the impact of inflation. This means the faster we grow, the higher our average costs and the greater the need for rate increases. In addition, the faster we grow, the more common equity we have to sell. And, unfortunately, if the above points were not enough (and they are), our common equity is now selling below book

value. Selling below book value results in a reduction in the earnings potential of existing shares. Under this situation everybody loses. The customers lose because the faster the growth the faster the rates go up, and the investors lose because the faster the growth the faster earnings decline.