Economic Feasibility of Transporting Western Coal on the New York State Barge Canal System

JAMES E. VITALE

The results of a comparative economic study of the feasibility of transporting western coal to New York State utilities via the barge canal system are presented. Three coal-supply regions are delineated: southwestern Pennsylvania and northern West Virginia and Montana. Site-specific projections of potential coal consumption developed for coal from each region are presented. A costing framework that includes all unit operations in the mine-to-stack coal-use cycle is used in making economic comparisons of the use of the three coals at new generating stations. This framework is designed to account for major expenditures that vary as a function of the characteristics of coal quality, including (a) extraction costs, (b) distribution costs, (c) flue-gas-desulfurization system investment and operating costs, and (d) balance-of-plant investment expenditures. The methodology is applied to a comparison of the economics of using the three coals at a future mid-Mohawk River Valley generating facility.

In recent years, commercial traffic on the New York State barge canal system has steadily decreased. To ascertain the causes of this decline and estimate future traffic volumes, the New York State Department of Transportation engaged Roger Creighton Associates, Inc., to conduct a market study of the canal system. Cargo potentials and transportation cost savings resulting from the use of the canal were estimated for two situations: (a) continued operation of the existing facilities and (b) operation of an improved and modernized canal that could accommodate larger barges and tows.

A major component of the market study was an assessment of the economic feasibility of transporting western coal to New York State utilities via the canal system. It was felt that emerging federal policies on energy resources and environmental quality might create pressures for increased use of western coal in the state. This potential demand for western coal, coupled with the construction of a proposed transshipment facility at the Port of Buffalo, might in turn lead to significantly increased traffic on the canal system. Thus, western coal was considered to be the bulk commodity that had the greatest potential for large-volume, long-term shipment via the canal.

The primary purpose of this paper is to report and update the coal-related portion of the market study. It also serves to illustrate the importance of using a total systems approach in estimating future levels of coal traffic on waterways and rail lines and through ports.

GENERAL METHODOLOGY

A comparative economics approach was used in the study to assess the feasibility of transporting western coal to New York State utilities via the canal system. This methodology consisted of four major components, each of which is discussed in this paper:

1. Three coal-supply regions were delineated: southwestern Pennsylvania and northern West Virginia (coal A), northern Wyoming (coal B), and Montana (coal C). There are major differences in physical characteristics and free-on-board (FOB) mine prices for coals produced in these regions. Moreover, northeastern utilities either use or have considered using coal produced in these areas.

2. Site-specific projections of potential coal consumption (for coal from each region) were developed. These estimates were derived from the announced plans of New York State utilities (1) and interviews with personnel of the New York State Public Service Commission.

3. A costing framework that included all unit operations in the mine-to-stack coal-use cycle was developed and quantified. Since this analytic construct was to be used to compare the economics of using alternative coals at new generating stations, it was designed to account for all major expenditures that vary as a function of coal quality.

4. This framework was applied to all potential supply-demand pairs, and estimates of future western coal traffic on the canal system were made. Rational economic behavior on the part of potential coal consumers was assumed; that is, it was assumed that the source of coal supply and the transportation mode or route configuration for which total annual costs would be lowest would always be chosen.

COAL-SUPPLY REGIONS

For the purposes of this inquiry, one eastern and two western coal-supply regions were delineated. It was assumed that eastern coal would originate from mines located in southwestern Pennsylvania and northern West Virginia, a region that has large quantities of untapped reserves and excellent access to New York State markets via the existing rail system.

The boundary between the states of Wyoming and Montana was used to divide the Powder River Basin into two supply regions. This strategy was dictated by differences in quality characteristics and FOB mine prices of coals produced in these states as well as differences in the accessibility of these...
regions to eastern markets via major transportation corridors.

The physical characteristics of the coals used in this study are given in Table 1 (2). It should be noted that characteristics such as heat and sulfur content vary both within and between coal seams. Thus, the information given in Table 1 is considered to be "typical".

**POTENTIAL DEMAND FOR WESTERN COAL**

For the purposes of this study, I have focused exclusively on the use of western coal as a fuel to fire new steam electric generating stations. It has been assumed that all plants in the state that currently burn eastern coal will continue to do so. It has also been hypothesized that generating stations that might reconvert from oil to coal would fire eastern coal. Use of western coal at such facilities could require extensive expenditures for boiler modifications, rehabilitation or expansion of coal-handling equipment, and acquisition of new (or enlarged) storage areas. Moreover, use of western coal at such facilities would result in a substantial reduction in the generating capacities of the plants.

It has been assumed that five new coal-fired power plants with a combined capacity of 6650 MW will come on-line before the year 2000. The locations, gross generating capacities, and target service dates of these facilities are given in Table 2. All information given on the three known stations reflects the expansion plans of member utilities of the New York Power Pool for the next 15 years. Interviews with New York State Public Service Commission personnel revealed that two additional 1700-MW coal-fired stations—a Lake Ontario plant northeast of Oswego and a facility in the mid-Mohawk River Valley—might be constructed before the year 2000. It was optimistically assumed that this additional base-load capacity would come on-line in accordance with the schedule given in Table 2.

### Table 1. Average characteristics of coals A, B, and C.

<table>
<thead>
<tr>
<th>Source</th>
<th>Designation</th>
<th>Heat Content (Btu 1000s)</th>
<th>Sulfur Content</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Per Pound</td>
<td>Per Ton</td>
</tr>
<tr>
<td>Pennsylvania and</td>
<td>A</td>
<td>12 24000</td>
<td>2.3</td>
</tr>
<tr>
<td>West Virginia Powder</td>
<td>B</td>
<td>8.3 16600</td>
<td>0.5</td>
</tr>
<tr>
<td>Powder River Basin</td>
<td>C</td>
<td>8.8 17600</td>
<td>0.85</td>
</tr>
<tr>
<td>Wyoming</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Montana</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Table 2. Projected additions to generating capacity.**

<table>
<thead>
<tr>
<th>Location</th>
<th>Facility</th>
<th>Operating Company</th>
<th>Capacity (MW)</th>
<th>Target Service Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pomfret</td>
<td>Lake Erie Generating</td>
<td>NMPC</td>
<td>1700 (two units at 850 MW each)</td>
<td>Unit 1, 1988; unit 2, mid-1989</td>
</tr>
<tr>
<td></td>
<td>Station (LEGS)</td>
<td></td>
<td></td>
<td>November 1983</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>November 1984</td>
</tr>
<tr>
<td>Niagara County</td>
<td>Somerset</td>
<td>NYSEG</td>
<td>850</td>
<td>Unit 1, 1993; unit 2, mid-1995</td>
</tr>
<tr>
<td></td>
<td>700 Fossil</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Arthur Kill</td>
<td></td>
<td>PASNY</td>
<td>700</td>
<td></td>
</tr>
<tr>
<td>Lake Ontario northeast of</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oswego</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Canajoharie (mid-Mohawk</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>River Valley)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Note: NMPC = Niagara Mohawk Power Commission; NYSEG = New York State Electric and Gas; PASNY = Power Authority of New York State.

a New York Power Pool Planning Committee (1, p. 218).

b Targets of this site suggested by Weber of the New York State Public Service Commission during an interview conducted on April 12, 1978.

c Declared the most probable configuration for new coal-fired plants by Swanson of the New York State Public Service Commission during March 3, 1978, meeting.

d Use of this site suggested by Swanson, Hausgaard, and Cummings of the New York State Public Service Commission during March 3, 1978, meeting.

Site-specific and total estimates of potential coal demand are given in Table 3. Two points regarding these projections are worthy of note. The first is that the volume of coal required to generate 1 kWh of electricity is a function of (among other factors) coal heat content. I have therefore reported three different estimates of potential coal demand by assuming the use of coal produced in the supply regions described above. The second point is that all site-specific coal requirements have been derived from the demand forecasts developed for the Niagara Mohawk Power Corporation’s proposed Lake Erie Generating Station (2). Here it is assumed, in effect, that the heat rates (heat input required to generate 1 kWh of electricity) and capacity factors (proportion of time that a unit is on-line) of all facilities given in Table 3 will be identical to those for the Lake Erie station. The impact of these assumed parameter values on potential annual demand for the three candidate coals studied is illustrated by the data given in Table 4.

**ANALYTIC FRAMEWORK**

A sequential, integrated construct was used to assess the feasibility of transporting western coal to New York State utilities by way of the canal system. Since this framework was developed for the purpose of comparing the total economics of using alternative coals at new generating stations, it was designed to account for major expenditures that vary as a function of the characteristics of coal quality, including (a) extraction costs, (b) distribution costs, (c) flue-gas-desulfurization (FGD) system investment and operating costs, and (d) balance-of-plant (BOP) investment expenditures (for equipment such as boilers and coal-handling and storage facilities).

It should be noted that, whenever possible, procedures and cost estimates developed by personnel of the Public Service Commission and utility industry consultants were used in an attempt to render the analyses as realistic and meaningful as possible.

**Extraction Costs**

The FOB mine prices used in the study are given in Table 5 (2). It was assumed that Appalachian coal would originate from large underground mines in which continuous mining equipment and the room-and-pillar mining plan are used. All Powder River Basin coal was assumed to originate at large surface mines.

As Table 5 indicates, two FOB mine prices for Appalachian coal were used in all analyses. This strategy was dictated by a lack of consensus among coal producers as to the most appropriate contract...
Table 3. Potential annual coal demand.

<table>
<thead>
<tr>
<th>Location</th>
<th>Facility</th>
<th>Coal A</th>
<th>Coal B</th>
<th>Coal C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Niagara</td>
<td>Somerset</td>
<td>1 861 083</td>
<td>2 834 518</td>
<td>2 637 784</td>
</tr>
<tr>
<td>Arthur Kill</td>
<td>700 Fossil</td>
<td>1 532 602</td>
<td>2 334 226</td>
<td>2 172 715</td>
</tr>
<tr>
<td>Pomfret</td>
<td>LEGS</td>
<td>1 861 083</td>
<td>2 834 518</td>
<td>2 637 784</td>
</tr>
<tr>
<td>Sackets</td>
<td></td>
<td>1 861 083</td>
<td>2 834 518</td>
<td>2 637 784</td>
</tr>
<tr>
<td>Harbor</td>
<td></td>
<td>1 861 083</td>
<td>2 834 518</td>
<td>2 637 784</td>
</tr>
<tr>
<td>Canajoharie</td>
<td></td>
<td>1 861 083</td>
<td>2 834 518</td>
<td>2 637 784</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>14 560 183</td>
<td>22 175 852</td>
<td>20 636 703</td>
</tr>
</tbody>
</table>

Table 4. Operating parameters for one Lake Erie Generating Station 850-MW coal-fired unit.

<table>
<thead>
<tr>
<th>Coal Type of Mine</th>
<th>Quotation</th>
<th>Production Costs ($/ton)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A New underground</td>
<td>Avg from several producers or sales agents</td>
<td>24.76</td>
</tr>
<tr>
<td>B Surface</td>
<td>Consolidation Coal Company</td>
<td>29.52</td>
</tr>
<tr>
<td>C Surface</td>
<td></td>
<td>7.50</td>
</tr>
</tbody>
</table>

Table 5. Extraction costs for coals A, B, and C.

<table>
<thead>
<tr>
<th>Coal Type of Mine</th>
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<td>29.52</td>
</tr>
<tr>
<td>C Surface</td>
<td></td>
<td>7.50</td>
</tr>
</tbody>
</table>

Note: Costs are in 1977 dollars.

As noted above, it was assumed that western coal is transported from Buffalo to New York State utilities by either the rail mode or the canal system, depending on relative modal costs (shipments are always assigned to the least-cost mode or route configuration). It was further assumed that all eastern coal would originate at Pittsburgh and be transported directly to the consumption sites. Since rail rates for coal shipments between most of the origin-destination pairs analyzed do not exist, the following strategy was used.

Unless otherwise noted, all estimates of unit train rates were derived from a regression equation that expresses rates (in dollars per ton) as a function of length of haul. Data from the New York State Public Service Commission on existing rates for 13-unit train shipments from Pennsylvania and West Virginia mines to New York State generating stations were used to calibrate this equation (all rates were applicable to shipments of bituminous steam coal, effective as of November 30, 1977). Since short-line rail distances were not reported, they were estimated from 1976 state transportation maps of New York, Pennsylvania, and West Virginia, which were prepared by the U.S. Geological Survey.

The calibrated relationship is

\[ U = 3.771 + 0.0122X \]

where

- \( U \) = unit train rate ($/ton),
- \( X \) = length of haul (miles), and
- \( R^2 \) = proportion of variation in rates accounted for by distance.

Differential capability (kW) 9450 Base
Net station heat rate (Btu/kW·h) 9410 9795
Average annual capacity factor (%) 69 69
Annual burn - coal heat content. 2 637 784
Transportation Research Record 763

Coal destined for inland plants would then be loaded into hopper cars or barges for final delivery via rail or the canal system. It has been assumed that all western coal destined for inland plants passes through the proposed Buffalo transshipment facility. Thus, all such consumers face identical FOB Buffalo prices for Montana and Wyoming coals. The unit costs included in these prices (2) are given below (the rail rate is for unit train shipments from mine to midwest energy terminal; rail car costs are amortized, assuming 10 000-ton unit trains and a five-day round-trip time):

<table>
<thead>
<tr>
<th>Item</th>
<th>Coal B (Wyoming)</th>
<th>Coal C (Montana)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost per ton ($)</td>
<td>7.50</td>
<td>9.00</td>
</tr>
<tr>
<td>Rail</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Rate</td>
<td>9.75</td>
<td>7.00</td>
</tr>
<tr>
<td>Car costs</td>
<td>1.50</td>
<td>1.50</td>
</tr>
<tr>
<td>Transshipment at</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Midwest energy</td>
<td></td>
<td></td>
</tr>
<tr>
<td>terminal</td>
<td>1.50</td>
<td>1.50</td>
</tr>
<tr>
<td>Great Lakes vessel</td>
<td></td>
<td></td>
</tr>
<tr>
<td>to Buffalo</td>
<td>4.10</td>
<td>4.10</td>
</tr>
<tr>
<td>Transshipment at</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Buffalo</td>
<td>1.15</td>
<td>1.15</td>
</tr>
<tr>
<td>Total</td>
<td>25.50</td>
<td>24.25</td>
</tr>
<tr>
<td>Total cost per million Btu ($)</td>
<td>1.54</td>
<td>1.38</td>
</tr>
</tbody>
</table>

As noted above, it was assumed that western coal is transported from Buffalo to New York State utilities by either the rail mode or the canal system, depending on relative modal costs (shipments are always assigned to the least-cost mode or route configuration). It was further assumed that all eastern coal would originate at Pittsburgh and be transported directly to the consumption sites. Since rail rates for coal shipments between most of the origin-destination pairs analyzed do not exist, the following strategy was used.

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The calibrated relationship is

\[ U = 3.771 + 0.0122X \]

where

- \( U \) = unit train rate ($/ton),
- \( X \) = length of haul (miles), and
- \( R^2 \) = proportion of variation in rates accounted for by distance.
Transportation costs for shipment via the canal system were estimated for two scenarios: (a) continued operation of existing facilities and (b) operation of an improved and modernized canal. Currently, lock chambers on the canal constrain vessel and tow size to a maximum width of 43.5 ft and a maximum length of 300 ft. Effective drafts are 13 ft on the Oswego Canal and the Erie Canal west of Three Rivers, New York, and 11 ft on the remainder of the system. In the second scenario, which assumed a canal system expanded and modernized to handle specially constructed, self-unloading barges, lock chambers were assumed to be 1000 ft long and 110 ft wide and to have a depth over sill of 27 ft.

Distribution costs were estimated for each scenario. Individual components included in these cost estimates were variable and fixed operating costs, profits, transit times, loading and terminal times, and inventory costs.

An in-depth discussion of the method used to estimate costs for transportation via the canal system is given elsewhere (2).

Flue-Gas-Desulfurization Costs

It has been assumed that all generating stations included in this analysis will use limestone FGD systems. Capital and operating costs for such systems depend on several factors, including the maximum allowable rate of sulfur dioxide (SO2) emissions, the sulfur content and heating value of the coal, boiler size and capacity, boiler status (new or retro), and replacement power requirements (4). The complex manner in which many of these factors interact, and thus affect costs, dictated the use of generic cost estimates. However, to assess the impacts of recently promulgated environmental standards on the costs resulting from the use of eastern and western coal, estimates were developed for two sets of SO2 emission limitations.

The Clean Air Act Amendments of 1970 required the U.S. Environmental Protection Agency (EPA) to develop primary and secondary national ambient air quality standards for sulfur dioxide (although emission limitations for particulates and nitrogen oxide were also established, sulfur dioxide regulations had the greatest impact on coal production and distribution patterns). In December 1971, EPA responded to that mandate by establishing New Source Performance Standards (NSPS), which limited emissions from new electric generating stations to 1.2 lb SO2/million Btu of heat input.

It is important to note that utilities could comply with those regulations by either (a) direct combustion of low-sulfur (primarily western) coals or (b) use of high-sulfur coals in conjunction with FGD systems. The actions of many major utilities indicate that use of low-sulfur western coal was considered to be the most economical and technologically workable alternative. The attractiveness of this compliance strategy is demonstrated by the fact that in 1976 more than 11 million tons of western coal were consumed in Illinois, a state endowed with large quantities of high-sulfur coal reserves (5).

In accordance with the Clean Air Act Amendments of 1977, EPA issued modified NSPS in June 1979. These revised standards require all new coal-fired power plants to install and continuously operate FGD systems, regardless of coal sulfur content. Thus, as a direct result of these regulations, the cost associated with use of western coal will increase.

Statistics on requirements for the removal of sulfur dioxide for the coal-supply options considered in this analysis are given in Table 6 for the 1971 and 1979 NSPS. As the data given in that table indicate, direct combustion of the Wyoming coal would have been permissible under the provisions of the 1971 standards. The revised NSPS allow use of this coal only if scrubbers are installed and one-half of the uncontrolled SO2 emissions are re-
moved from all flue gases.

The generic capital cost estimates used in this study for installation of FGD waste stabilization and disposal systems, assuming use of coals A, B, and C at a 1700-MW generating station, are given in Table 7 for the original and revised NSPS.

The study performed by Ebasco Services, Inc. (2), was also used as the basis for estimates of FGD system operating costs. Supplemental data on the impacts of alternative SO2 removal requirements on annual operating costs were provided by Weber of the New York State Public Service Commission. Table 8 gives generic estimates of FGD system annual operating costs for two 850-MW units.

Balance-of-Plant Investment Costs

BOP comparative investment costs include expenditures for major items that are dependent on the quality characteristics of a particular coal. Such items include steam generators, electrostatic precipitators, and all requisite concrete, structural steel, and electrical equipment. All BOP cost estimates used here are, again, derived from work performed by Ebasco Services, Inc. (2). Table 9 gives these comparative investment costs for two 850-MW units. Expenditures for items common to both units are assessed to unit 1.

Illustrative Application

To facilitate the reader's comprehension of the methodology used in this study, the procedures have been applied to assessing the comparative economics of coals A, B, and C at the proposed mid-Mohawk River Valley generating facility. Three points about this illustrative application are worthy of note:

1. FGD system investment and operating cost estimates have been computed for SO2 removal efficiencies that would have been required to comply with the 1971 NSPS.

2. The following escalation and amortization parameters were used in all calculations:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual fixed capital charge rate (%)</td>
<td>18</td>
</tr>
<tr>
<td>Discount rate (%)</td>
<td>11.5</td>
</tr>
<tr>
<td>Escalation rate (%)</td>
<td></td>
</tr>
<tr>
<td>Fuel (per year)</td>
<td>5</td>
</tr>
<tr>
<td>Materials</td>
<td>6</td>
</tr>
<tr>
<td>Labor</td>
<td>8</td>
</tr>
<tr>
<td>Operations and Management</td>
<td>5</td>
</tr>
<tr>
<td>Plant life (years)</td>
<td>30</td>
</tr>
</tbody>
</table>

   Escalation rates for materials, labor, and operations and management are from Ebasco Services, Inc. (2). The other parameters given above are recommended by the New York State Public Service Commission.

3. To provide insight on the impacts of eastern coal prices on overall comparative economics, the two FOB mine prices for this fuel given in Table 4 were included in the analyses.

Computations of total delivered prices for the three types of coal at the mid-Mohawk River Valley location are given in Table 10. It was assumed that western coal destined for this inland plant would pass through the proposed Buffalo transshipment facility. Transportation costs were estimated by assuming shipment from Buffalo to the plant via the existing canal, an expanded and modernized canal, and unit trains. Eastern coal was assumed to be shipped directly from mines to the consumption site in unit trains.

It is of interest to note the effects that coal heat contents have on total delivered prices (Table 10). Assuming massive reconstruction of the canal system, the delivered price of eastern coal (with an
Table 11. Fuel charges for unit 1, proposed Canajoharie facility.

<table>
<thead>
<tr>
<th>No.</th>
<th>Item</th>
<th>Coal A</th>
<th>Coal B</th>
<th>Coal C</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Min</td>
<td>Max</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Annual Fuel Charge</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>Fuel escalation rate (%/year)</td>
<td>5</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>2</td>
<td>Fuel cost as of operation date ($/million Btu)</td>
<td>3.61</td>
<td>4.09</td>
<td>4.14</td>
</tr>
<tr>
<td>3</td>
<td>Levelized fuel cost ($/million Btu)</td>
<td>5.66</td>
<td>6.41</td>
<td>6.49</td>
</tr>
<tr>
<td>4</td>
<td>Net generating capacity (kW)</td>
<td>785 350</td>
<td>785 350</td>
<td>794 800</td>
</tr>
<tr>
<td>5</td>
<td>Level station heat rate (Btu/kW·h)</td>
<td>9410</td>
<td>9410</td>
<td>9795</td>
</tr>
<tr>
<td>6</td>
<td>Average operating time (h/year)</td>
<td>6044</td>
<td>6044</td>
<td>6044</td>
</tr>
<tr>
<td>7</td>
<td>Annual burn (Btu x 10^{12})</td>
<td>44.666</td>
<td>44.666</td>
<td>47.053</td>
</tr>
<tr>
<td>8</td>
<td>Levelized annual fuel charge (no. 3 x no. 7) ($000s)</td>
<td>252 810</td>
<td>286 309</td>
<td>305 374</td>
</tr>
</tbody>
</table>

Energy Charge for Equivalent Generation

<table>
<thead>
<tr>
<th>No.</th>
<th>Item</th>
<th>Coal A</th>
<th>Coal B</th>
<th>Coal C</th>
</tr>
</thead>
<tbody>
<tr>
<td>9</td>
<td>Differential capability (kW)</td>
<td>9450</td>
<td>9450</td>
<td>Base</td>
</tr>
<tr>
<td>10</td>
<td>Average charge (no. 3 x no. 5 x no. 6)</td>
<td>322</td>
<td>365</td>
<td>Base</td>
</tr>
<tr>
<td>11</td>
<td>Energy charge (no. 9 x no. 10) ($000s)</td>
<td>3043</td>
<td>3449</td>
<td>0</td>
</tr>
<tr>
<td>12</td>
<td>Total annual fuel charge for this unit (no. 8 + no. 11) ($000s)</td>
<td>255 853</td>
<td>289 758</td>
<td>305 374</td>
</tr>
</tbody>
</table>

* Sensitivity alternatives.

Table 12. Fuel charges for unit 2, proposed Canajoharie facility.

<table>
<thead>
<tr>
<th>No.</th>
<th>Item</th>
<th>Coal A</th>
<th>Coal B</th>
<th>Coal C</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Min</td>
<td>Max</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Annual Fuel Charge</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>Fuel escalation rate (%/year)</td>
<td>5</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>2</td>
<td>Fuel cost as of operation date ($/million Btu)</td>
<td>3.98</td>
<td>4.51</td>
<td>4.57</td>
</tr>
<tr>
<td>3</td>
<td>Levelized fuel cost ($/million Btu)</td>
<td>6.24</td>
<td>7.07</td>
<td>7.16</td>
</tr>
<tr>
<td>4</td>
<td>Net generating capacity (kW)</td>
<td>785 350</td>
<td>785 350</td>
<td>794 800</td>
</tr>
<tr>
<td>5</td>
<td>Net station heat rate (Btu/kW·h)</td>
<td>9410</td>
<td>9410</td>
<td>9795</td>
</tr>
<tr>
<td>6</td>
<td>Average operating time (h/year)</td>
<td>6044</td>
<td>6044</td>
<td>6044</td>
</tr>
<tr>
<td>7</td>
<td>Annual burn (Btu x 10^{12})</td>
<td>44.666</td>
<td>44.666</td>
<td>47.053</td>
</tr>
<tr>
<td>8</td>
<td>Levelized annual fuel charge (no. 3 x no. 7) ($000s)</td>
<td>278 716</td>
<td>315 789</td>
<td>336 899</td>
</tr>
</tbody>
</table>

Energy Charge for Equivalent Generation

<table>
<thead>
<tr>
<th>No.</th>
<th>Item</th>
<th>Coal A</th>
<th>Coal B</th>
<th>Coal C</th>
</tr>
</thead>
<tbody>
<tr>
<td>9</td>
<td>Differential capability (kW)</td>
<td>9450</td>
<td>9450</td>
<td>Base</td>
</tr>
<tr>
<td>10</td>
<td>Average charge (no. 3 x no. 5 x no. 6)</td>
<td>355</td>
<td>402</td>
<td>Base</td>
</tr>
<tr>
<td>11</td>
<td>Energy charge (no. 9 x no. 10) ($000s)</td>
<td>3355</td>
<td>3799</td>
<td>0</td>
</tr>
<tr>
<td>12</td>
<td>Total annual fuel charge for this unit (no. 8 + no. 11) ($000s)</td>
<td>282 071</td>
<td>319 588</td>
<td>336 899</td>
</tr>
<tr>
<td>13</td>
<td>Total 1996 annual fuel charge for this unit ($000s)</td>
<td>255 847</td>
<td>289 876</td>
<td>305 577</td>
</tr>
<tr>
<td>14</td>
<td>Total annual fuel charge for all units ($000s)</td>
<td>511 700</td>
<td>579 634</td>
<td>610 951</td>
</tr>
</tbody>
</table>

* Sensitivity alternatives.

Table 13. Investment cost summary for Canajoharie facility under 1971 NSPS.

<table>
<thead>
<tr>
<th>No.</th>
<th>Item</th>
<th>Coal A</th>
<th>Coal B</th>
<th>Coal C</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>BOP construction costs</td>
<td>818 219</td>
<td>965 341</td>
<td>965 341</td>
</tr>
<tr>
<td>2</td>
<td>Coal-receiving equipment and cooling-tower make-up and blow-down lines</td>
<td>17 085</td>
<td>7 593</td>
<td>7 593</td>
</tr>
<tr>
<td>3</td>
<td>Indirect costs, contingencies, and fees for no. 2</td>
<td>4 784</td>
<td>2 126</td>
<td>2 126</td>
</tr>
<tr>
<td>4</td>
<td>Total BOP comparative investment costs</td>
<td>840 088</td>
<td>975 060</td>
<td>975 060</td>
</tr>
<tr>
<td>5</td>
<td>FGD system</td>
<td>484 274</td>
<td>0</td>
<td>422 078</td>
</tr>
<tr>
<td>6</td>
<td>Total comparative investment costs (no. 4 + no. 5)</td>
<td>1 324 362</td>
<td>975 060</td>
<td>1 397 138</td>
</tr>
<tr>
<td>7</td>
<td>Annual capital charge (no. 6 x 0.181)</td>
<td>239 709</td>
<td>176 486</td>
<td>252 882</td>
</tr>
</tbody>
</table>

Note: Costs in 1996 dollars.

Table 14. Comparative economics for Canajoharie facility under 1971 NSPS.

<table>
<thead>
<tr>
<th>Item</th>
<th>Coal A</th>
<th>Coal B</th>
<th>Coal C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Amount ($000s)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Annual capital charge</td>
<td>239 709</td>
<td>239 709</td>
<td>176 486</td>
</tr>
<tr>
<td>Annual fuel charges</td>
<td>511 700</td>
<td>579 634</td>
<td>610 951</td>
</tr>
<tr>
<td>Annual operating charges</td>
<td>35 134</td>
<td>35 134</td>
<td>23 613</td>
</tr>
<tr>
<td>Annual revenue requirements</td>
<td>786 543</td>
<td>854 477</td>
<td>787 437</td>
</tr>
</tbody>
</table>

Note: Figures are in 1996 dollars.

FOB mine price of $24.76/ton is approximately $6/ton higher than that of Montana coal. However, when the heating values of the coals are used to convert these delivered prices to equivalent prices per million Btu, eastern coal enjoys a slight cost advantage. Thus, dollar-per-ton cost comparisons of...
coals with different heat contents can be quite misleading.

Tables 11 and 12 give the annual fuel-charge computations for units 1 and 2 of the proposed generating station. Only the delivered prices of western coals that assume shipment via the minimum-cost mode and route configurations are subjected to further analysis. As data given in Table 11 show, 1977 delivered prices (in dollars per million Btu) are converted to corresponding 1996 prices (the target service date for unit 1) by assuming an escalation rate of 5 percent/year. The resultant figures are then levelized to account for the present worth of price increases (at a rate of 5 percent/year) over the 30-year plant life (all fuel supply analyses conducted by New York State utilities used levelized fuel cost estimates). The levelization factor (LF) was calculated from the following formula:

\[ LF = \frac{1}{1 - \left(\frac{i}{r}\right)} \times \frac{e^{(1 - r)n}}{-\left(\frac{i}{r}\right) e^{(-rn)} - 1} \]  

where

- \( i \) = escalation rate (5 percent),
- \( r \) = discount rate (11.5 percent), and
- \( n \) = plant life (30 years).

Levelized fuel costs are determined by multiplying fuel costs (in dollars per million Btu) by the levelization factor. These costs are then multiplied by the projected annual burn (the product of net generating capacity, net station heat rate, and operating time) to obtain estimates of levelized annual fuel charges. Total annual fuel costs are equal to levelized annual fuel costs plus energy charges for differences in net generating capacities. The method used to compute energy penalties is presented in Table 11. Total annual fuel charges for unit 2 are calculated in a similar manner. Those costs are then converted to equivalent 1996 dollars and added to unit 1 charges to obtain total annual fuel charges for the plant (Table 12).

A summary of required investment expenditures for the proposed generating station is given in Table 13. These investment costs are amortized and added to annual fuel charges to determine the estimated revenue requirements given in Table 14.

Examination of that table reveals that the comparative economics of eastern and western coals at this hypothetical generating station are extremely sensitive to assumptions regarding the FOB mine prices of eastern coal. Use of the lower price ($24.76/ton in 1977 dollars) yields results that suggest that eastern coal would be the preferred fuel-supply option. If, however, comparisons are based on the higher price ($29.52/ton), the eastern coal alternative would be the most costly.

RESULTS AND CONCLUSIONS

Table 15 summarizes the comparative economics of eastern, Wyoming, and Montana coals at the five proposed New York State generating stations. Several points regarding the information displayed in Table 15 warrant discussion.

It should be noted that annual revenue requirements for the Montana and Wyoming (B and C) coal options were estimated by assuming the existence of a transshipment facility at the Port of Buffalo and an expanded and modernized canal system. (The locations of the Lake Erie Generating Station and the Somerset facility rendered shipment via the canal infeasible. In addition, direct delivery of western coal to the Lake Erie Generating Station was less costly than shipment through the Port of Buffalo.) In the absence of such facilities, delivered prices (and consequently annual revenue requirements) would be significantly higher.

Table 15 provides insight into the effects of the 1979 NSPS on the competitive position of western coal in New York State. As the table shows, the increases in total annual costs attributable to those standards are substantial, particularly for the Wyoming coal option.

The impacts of the assumed FOB mine prices for eastern coal on the costs related to its use at new coal-fired plants are significant. I am of the opinion that the annual revenue requirements based on the lower estimate ($24.76/ton in 1977 dollars) most accurately reflect prevailing coal market conditions. According to Coal Week, as recently as October 1979, 12 800-Btu/lb, 2.5 percent sulfur coal produced in southwestern Pennsylvania could be purchased under long-term contract for $27.00/ton FOB mine. When escalated (at 5 percent/year) to 1979, the minimum FOB mine price is $27.30/ton.

A comparison of the revenue requirements for coals A (minimum), B, and C in Table 15 for the revised NSPS scenario reveals that eastern coal is the preferred fuel supply option for all of the proposed generating stations. Thus, no large-volume shipments of western coal can be expected to traverse the canal system, even if it is modernized to deep-draft standards.

REFERENCES

Foreign Trade Zones and Inland Ports: A Question of Size

JOHN J. DA PONTE, JR.

Although all domestic ports of entry are "entitled" to establish foreign trade zones under federal law upon meeting certain technical and economic requirements, the volume of international trade at inland ports is often marginal in terms of the need for zone services. Since many of these communities wish to use zones as a means of helping to attract new international-trade-related operations, their zone projects are often conceived for a small amount of activity at the outset and with an uncertain medium- and long-term outlook. The requirements of federal law and how they have been interpreted with regard to smaller zone projects are discussed. Recent interpretations and practices of the Foreign Trade Zones Board and the U.S. Customs Service are discussed in terms of how they affect the feasibility of zones in inland areas that have an inherently smaller "zone-use base". A general analysis is presented of the first few inland zones. Some methods of structuring smaller zones to reduce and spread capital and operating costs are suggested. It is concluded that, whereas current federal requirements of federal law and how they have been interpreted with regard to smaller zones intensified efforts, some communities should be mindful of the financial risks involved.

Although foreign trade zones have constituted a chapter in U.S. customs laws for some 45 years, it has not been until the past decade that they have become widely available in the United States. Congress coined the term "foreign trade zone" when the law that authorized these facilities—the Foreign Trade Zones Act—was enacted in 1934. In this paper, the term is used interchangeably with the general terms "free trade zone" and "customs-free zone". All are limited versions of the historic "free port".

Before 1970, fewer than 10 U.S. cities had foreign trade zones, all of them ocean or Great Lakes ports. By the end of the decade the number had increased to 50, and several of the new projects were bringing international trade service to U.S. inland ports of entry for the first time.

Although the inland ports have always been eligible as sites for foreign trade zones, only recently have the agencies concerned with economic development in these areas taken an interest in making zones a part of their public services. The traditional association of customs-free zones with seaports, and major seaports at that, has undoubtedly been a psychological factor. Were it not for the provision in the U.S. Constitution that prohibits legislation favoring the ports of one state over those of another, the Foreign Trade Zones Act might well have perpetuated this stereotype. The fact that Congress did not find this narrower view appropriate and made all U.S. ports of entry eligible for zones gave the concept wider currency in the United States (there are more than 300 customs ports of entry in the United States, about 25 percent of which are involved with commercial shipments). This provided the legal foundation for the present growth in the U.S. zone program.

The spread of zones to inland U.S. ports has not been just a matter of overcoming a mental block. The very definition of a port has broadened in a dramatically changing world economy. International trade, direct investment, and transportation technology are weaving a new trade network. Most of the world's larger seaports retain their prominence but, throughout the network, inland centers of trade are growing and new ones are emerging. These communities, although smaller in size, are taking on the trappings of true port cities.

The products of modern technology are also affecting the role of inland ports. Multinational firms that produce and market these products have an unparalleled range of choices in the siting of plants and distribution centers. Industries are no longer as tied to certain locations as they once were. Mobility and flexibility are the rule. This places new and complex demands on port communities, including inland ports, which have become increasingly sensitive to the need for improved public services and facilities (1,2).

U.S. ZONES FROM 1934 TO 1970

The first U.S. foreign trade zones were, as expected, established as seaports. Through the late 1940s, New York, Mobile, New Orleans, San Francisco, Los Angeles, and Seattle were the only U.S. cities that were authorized zones. New York's zone was sponsored by the city government, which contracted the operation of its facility to a private firm. The other zones were from the outset owned and operated by seaport authorities, some of whom eventually took on private firms as zone operators. Both Los Angeles and Mobile closed their zones after a short time, apparently finding that customs-bonded facilities served their needs.

Even after the 1934 act was amended in 1950 to permit manufacturing, another decade passed before there were further zone efforts. During the 1960s, new zones were approved for Toledo, Ohio; Bay County, Michigan; Mayaguez, Puerto Rico; and Honolulu, Hawaii. All of these facilities were tied to ocean or Great Lakes ports.

EXPANSION WAVE OF THE 1970s

Interest in foreign trade zones intensified with the international economic developments of the