ECONOMIC CONSIDERATIONS IN CONVERTING FROM OIL/GAS FIRING TO COAL

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ABSTRACT

Economic considerations involved in fuel conversion such as from oil and/or gas firing to coal include investment costs for new facilities and equipment (including air pollution control equipment), operation and maintenance costs, and purchased fuel costs. This paper presents an analytical approach to assessing the cost effectiveness of fuel conversion in terms of the annual net cost of conversion, the equivalent annual number of barrels of oil saved, and the internal rate of return of the conversion investment. Illustrative numerical examples are presented for typical utility boilers and industrial boiler facilities. A further consideration addressed deals with the impacts of these costs on the overall financial structure of the firm and the ability of the firm to raise the necessary investment capital.

I. OVERVIEW OF COAL CONVERSION ACTIVITIES

By coal conversion in this paper we mean the switching from either oil and/or gas as the primary fuel(s) to coal as the primary fuel in a combustor (boiler, burner, furnace or kiln). Historically, fuel switching has generally tended to be in the other direction, namely, oil/gas conversion. For example, during the late 1960's and early 1970's, while coal-fired powerplants were being converted to oil, utilities were also building new plants to burn oil. Initially, utilities converted to oil for economic reasons; however, more recently, the principal reason for converting to oil has been the requirement to meet strict sulfur emission regulations which the utilities were unable to do using coal. Most of these conversions took place on the East Coast at plants with easy access to ocean and river barge transport.

In 1970, it is estimated (Ref. 1) that only 40 of new boiler orders provided for coal-firing capability. In 1974, however, in response to the natural gas shortages and increased price of oil, 97 of new boiler orders provided for coal-firing capability. Consequently, we see a trend occurring back to coal conversion. It is noteworthy that, according to Reference 2, about 80 of the boilers which were converted from coal to oil can, in time, be re-converted to coal.

The current impetus for coal conversion is caused by the legislative requirements of the Energy Supply and Environmental Coordination Act (ESECA) of 1974 (Public Law 93-319), as amended by the Energy Policy and Conservation Act (EPCA) of 1975 (Public Law 94-163). It is intended that ESECA, by providing the Department of Energy (DOE) with the authority to require the use of coal by existing and future electric utility powerplants and other major fuel burning installations (IBFIs), will result in a significant decrease in the use of petroleum and natural gas and an increase in the use of our most abundant domestic energy resource.

Collectively, ESECA and EPCA provide DOE with the statutory authority to issue a Prohibition Order to an existing facility for the purpose of prohibiting the further use of oil and/or gas as the primary fuel(s). Before such an order can be issued, DOE must determine that the powerplant or NFBI possessed the necessary equipment and capability to burn coal on June 22, 1974, or acquired it thereafter. DOE must assess the existence of certain necessary coal handling facilities and appurtenances such as adequate facilities for the storage of coal, and equipment such as a boiler, unloaders, conveyors, crushers, pulverizers, scales, burners, stack blowers, and special coal burning instrumentation and controls. In addition, DOE must also find that:

1. the burning of coal at the facility is practicable and consistent with the purposes of ESECA;
2. coal and coal transportation facilities will be available for the period the order is in effect; and
3. in the case of a powerplant, the order will not impair the reliability of service in the area served by the converting powerplant.

Prohibition Orders were issued in 1975 affecting 74 powerplant units and were issued in 1977 affecting 18 powerplant units and 27 NFBI combustors.

DOE is also provided with the statutory authority to require powerplants or NFBI's in the early planning process to be designed and constructed so as to be capable of using coal as the primary energy source. This is accomplished through the issuance of a Construction Order. No such order may be issued if DOE finds that (a) in the case of a powerplant, such order is likely to impair the reliability or adequacy of service, or (b) an adequate and reliable supply of coal is not expected to be available. Furthermore, in considering the desirability of issuing such an order, DOE must consider the existence and effects of any contractual commitment for the construction of such facility, and the ability of the owner to recover any capital investment made as the result of a Construction Order. Orders of this type were issued in 1975 affecting 74 new powerplants and were issued in 1977 affecting 18 new powerplants and 27 new NFBI combustors.

II. CONSIDERATIONS AND FACTORS IN COAL CONVERSION INVESTMENT

Major considerations of significance in assessing the willingness and/or overall acceptance of coal conversion include the following:

1. the difficulties industry will experience with environmental and facility siting regulatory problems
2. the aversion industry has to using coal
due to the difficulties of handling coal at the plant, the extra personnel required, etc.

(3) the higher rate of return some firms require on a discretionary investment (assuming no DOE order is issued) - especially one which may neither enhance output nor protect production.

(4) the added risks associated with reliability of coal supply to the plant.

Of particular importance are those factors which have a direct effect on costs such as:

(1) combustor size affects costs since costs of coal equipment as well as pollution control equipment are characterized by economies of scale.

(2) capacity utilization determines how quickly capital costs are recovered as the result of fuel price savings.

(3) coal capability is a factor because, if the unit was designed originally to fire coal, the capital costs of conversion will, most likely, be less than the cost differential between a new gas/oil-firing and a new coal-firing unit.

(4) remaining useful life of facilities determines the period of time over which the conversion investment, can be amortized and thus affects the rate of return on the investment.

(5) regional location affects costs primarily through delivered fuel prices.

(6) environmental controls imposed through state regulations and Federal New Source Performance standards affect the costs of the pollution control equipment necessary, which in many cases is the most significant capital cost.

(7) new versus existing units for conversion involves the tradeoff between new capital equipment and thus longer amortization period versus modification of used and existing units with perhaps a shorter amortization period.

(8) fuel type as determined by sulfur content required, percent ash required, etc. and the means for transportation affects the corresponding fuel price differential.

III. BREAK-EVEN FORMULATIONS FOR COAL CONVERSION INVESTMENT

In terms of analyzing an annual basis the investment by a company in coal conversion, there are three basic quantities to be considered, namely:

(1) annualized investment cost, which is defined to be

\[
\text{Total investment} \times \text{Capital recovery factor or fixed charge rate}
\]

(2) annual fuel cost differential, which is defined to be

\[
\text{Fuel cost differential} \times \text{Heat rate in BTU's/\text{hr}} \times \text{Size in kw}
\]

(3) annual operation and maintenance cost differential, which is defined to be

\[
\text{(OM cost differential)} \times \frac{\text{Size in kw}}{8760 \text{ hrs}} \times \text{Average capacity factor}
\]

In the formulation of the annualized investment cost, multiplying the total investment cost by either the capital recovery factor, defined to be

\[
\frac{1}{(i + 1)^N} - \frac{1}{i}
\]

where \( i \) is the annual discount rate which reflects the worth of capital and \( N \) is the number of years over which the investment is amortized, or by the annual fixed (or levelized charge) rate has the effect of amortizing the investment over a specified period of time (generally the remaining useful life of the facility). Typically, the choice of the discount rate is based on the weighted cost of capital as determined according to the sources of capital. For example, consider the following computation:

<table>
<thead>
<tr>
<th>Capital Source</th>
<th>Capitalization Cost (%)</th>
<th>Capital Weighted Cost (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mortgage Bonds</td>
<td>50</td>
<td>8.1</td>
</tr>
<tr>
<td>Preferred Stock</td>
<td>15</td>
<td>8.3</td>
</tr>
<tr>
<td>Common Equity</td>
<td>35</td>
<td>15</td>
</tr>
<tr>
<td></td>
<td></td>
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</tr>
</tbody>
</table>

Therefore, the discount rate used would be 10.55% based on a weighted average cost of new capital.

Another approach would be to use a fixed (or levelized) charge rate as is done by utility companies to compute the annualized investment cost. This rate is chosen as a measure to describe the revenue which must be raised annually to earn a reasonable return on the capital used to purchase equipment, to amortize the equipment over its productive life and to pay requisite income taxes, property taxes, and insurance. This rate depends upon the consideration of many factors including the following: the capital structure of the company; the required return on debt, common and preferred stock; the useful life of the equipment and its scrap value, if any; the formulas used in computing actual and tax depreciation; whether tax savings from depreciation and the investment tax credit are normalized or allowed through; the effective tax rate (combined federal and state); the property taxes. Typically, fixed charge rates range from 20-40%, depending upon the relative importance of the above factors.

In order for the investment in coal conversion to break even the following must be true:

\[
\text{Annualized investment} \times \text{Annual fuel cost differential} \times \text{Annual OM cost differential}
\]
The right-hand side of this equation represents the net gain due to fuel price savings.

As an illustration, consider the conversion of 2,800-megawatt boilers requiring flue gas desulfurization (FGD). This conversion is estimated to take place in 1980 at a cost of $680/MW, These boilers are assumed to be operated at 70% capacity over their remaining 20 years of useful life, and have a design heat rate when coal-fired of 9,700 BTU/s/kw. Assuming a 11% discount rate, this implies a capital recovery factor equal to

\[
\frac{(1.11^{20} - 1)}{1.11^{20}} \times 12557 = .00909
\]

or, equivalently, a fixed charge rate of approximately 12.6%. Therefore,

\[
\text{Annualized investment} = \frac{1,169,000}{\text{ktwr}} (\$304 \text{ per kw})
\]

\[
x \times (12557) = \$12,557,556
\]

\[
\text{Annual fuel cost differential} = \frac{9,700}{\text{BTU/s/kw}} x \times (1.11) = (95,040,540)
\]

\[
\text{Annual O&M cost differential} = \frac{1,400,000}{\text{kw}}
\]

\[
x \times (8,760 \text{ per hr}) = (9,811,200)
\]

\[
\text{Reproducibility of the original page is lost.}
\]

For breakeven we must then have

\[
12,557,556 = \frac{95,168,640}{\text{fuel cost differential}} + \frac{1,400,000}{\text{O&M cost differential}} + \frac{9,811,200}{\text{O&M cost differential}}
\]

Figure 1 provides a plot of fuel cost differential vs. O&M cost differential using this linear relationship for breakeven. Assuming a 1.4 mill/kwh O&M cost differential, this implies a fuel cost differential of approximately $1.94 per 106 BTU's. An estimated 1930 coal price (Source: Pacific Gas & Electric Co.) is $1.49 per 106 BTU's. This implies that in 1930 for breakeven the price of oil must be at least $3.33 per 106 BTU's or, approximately $20.31 per barrel, which is comparable to DOE estimates of the 1930 range of oil prices.

IV. OVERALL METHODOLOGY FOR EVALUATION OF COAL CONVERSION ECONOMICS

In the evaluation of the overall reasonableness of coal conversion by utility companies, the Department of Energy (formerly the Federal Energy Admin-
With regard to the Income Statement, investment costs would impact the income taxes paid based on the amount of investment tax credit claimed and, as a result, would affect the firm's net profit after taxes. Both the operation and maintenance costs and the fuel costs would impact the cost of goods sold category and, as a result, the firm's gross profit. Fixed charges would affect the operating expenses, other expenses and income taxes categories and, as a result, would also have a direct effect on the firm's net profit after taxes.

Other considerations which affect the capital aspect of a firm's financial structure are as follows:

(1) growth rate of future sales

The future growth rate of sales is a measure of the extent to which the earnings per share of a firm are likely to be magnified by leverage. In some cases, financing by debt with limited fixed charges should magnify the returns to owners of the stock. On the other hand, the common stock of a firm whose sales and earnings are growing at a favorable rate commands a high price in which case equity financing is desirable. A firm must weigh the trade-offs between leverage against the opportunity of broadening its equity base when it chooses between future financing alternatives.

(2) stability of future sales

Sales stability and debt ratios are directly related. With greater stability in sales and earnings, a firm can incur the fixed charges of debt with less risk than it can when its sales and earnings are subject to periodic declines; in the latter instance it will have difficulty in meeting its obligations.

(3) competitive structure of the industry

Debt-servicing ability is dependent upon the profitability as well as the volume of sales; hence, the stability of profit margins is as important as the stability of sales. The ease with which new firms may enter the industry and the ability of competing firms to expand capacity will influence profitability. A growth industry promises higher profit margins, but such margins are likely to narrow if the industry is one in which the number of firms can be easily increased through additional entry.

(4) asset structure of the industry

Asset structures influence the sources of financing in several ways. Firms with long-lived fixed assets use long-term mortgage debt extensively. Firms whose assets are mostly receivables and inventory whose value is dependent on the continued profitability of the individual firm (for example, those in wholesale and retail trade) rely less on long-term debt financing and more on short-term.

(5) control position and attitudes toward risk of owners and management

The management attitudes that most directly influence the choice of financing are those concerning (1) control of the enterprise and (2) risk. Large corporations whose stock is widely owned may choose additional sales of common stock because they will have little influence on the control of the company. In contrast, the owners of small firms may prefer to avoid issuing common stock in order to be assured of continued control. Because they generally have confidence in the prospects of their companies, and because they can see the large potential gains to themselves resulting from leverage, managers of such firms are often willing to incur high debt ratios.

(6) lender attitudes toward firm and industry

Regardless of management's analysis of the proper leverage factor for their firms, lenders' attitudes are frequently the most important determinant of financial structure. When management uses leverage beyond norms for the industry, lenders may be unwilling to accept such debt increases. They will emphasize that excessive debt reduces the credit standing of the borrower and the credit rating of the securities previously issued.

Traditionally, corporations have had three sources of capital for investment in property, plant, and equipment:

(1) Reserves for depreciation, depletion and amortization are essentially deductions from operating income which can be used for new investment.

(2) Long-term and short-term debt may be increased through the sale of debentures and other debt instruments.

(3) Equity capital may be raised through the issuance of preferred or common stock.

With regard to reserves, they are generally short-term and, in many cases, not sufficient in amount. Both long- and short-term debt are constrained by the lending institutions' desired capitalization profile for a firm. For example, long-term debt for utility companies is typically on the order of 45-55, and debt greater than 55 could lead to a lowering of bond ratings. In many cases, there are mortgage indenture coverage requirements in times-interest-earned before new debentures can be issued. For equity capital, preferred stock typically represents 10-15 of total capitalization and common stock 30-40 for utility companies. There are in many cases coverage requirements on both interest and dividends before new equity capital can be raised.

This discussion points out that, even though it may be technically feasible for a company to convert from using oil and/or gas to the use of coal as its primary fuel, the financial impact of the firm must be considered as well as the sources of the needed capital. The ability to attract capital is promoted by a demonstrated ability to provide investors with a fair and reasonable return on their investment, to maintain a balanced capitalization structure, and to generate a reasonable amount of capital requirements internally.


4. Executive Office of the President, Energy Policy and Planning, Replacing Oil and Gas with Coal and Other Fuels in the Industrial and Utility Sectors, 2 June 1977


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**Fig. 1. Fuel Cost Differential Versus O&M Cost Differential for Break-even**

*Table 1. Illustrative Site Characteristics and Fuel Prices*

<table>
<thead>
<tr>
<th>Site Characteristics</th>
<th>Beer Unit</th>
<th>Megawatt Capacity</th>
<th>Remaining Life</th>
<th>Operating Capacity Before</th>
<th>Operating Capacity After</th>
<th>Derating Percent</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number 1</td>
<td>351.0</td>
<td>20</td>
<td>.550</td>
<td>.550</td>
<td>0.000</td>
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</tr>
<tr>
<td>Number 2</td>
<td>107.0</td>
<td>20</td>
<td>.550</td>
<td>.550</td>
<td>0.000</td>
<td></td>
</tr>
</tbody>
</table>

**FUEL PRICES (IN DOLLARS PER MILLION BTU'S)**

<table>
<thead>
<tr>
<th>Before Conversion</th>
<th>After Conversion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>0.0000</td>
</tr>
<tr>
<td>Oil</td>
<td>1.9130</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>1.5500</td>
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</tbody>
</table>
### Table 2. Illustrative Cost Data

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Min. Ash Pollution Control Equipment Investment Cost</td>
<td>$0.00</td>
</tr>
<tr>
<td>Min. Ash Pollution Control Equipment Investment Cost</td>
<td>$0.00</td>
</tr>
<tr>
<td>Total Investment Cost</td>
<td>$1552000.00</td>
</tr>
<tr>
<td>Total Investment Cost per KWh</td>
<td>90.23</td>
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</table>

### Amortization Period Data

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Time to Complete Conversion in Years</td>
<td>5</td>
</tr>
<tr>
<td>Average Remaining Useful Life in Years</td>
<td>20</td>
</tr>
<tr>
<td>Investment Amortization Period in Years</td>
<td>15</td>
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</tbody>
</table>

### Annual Cost Data

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Min. Ash Pollution Control Equipment Annual</td>
<td>$236000.00</td>
</tr>
<tr>
<td>Operation and Maintenance Cost Differential</td>
<td>$76000.00</td>
</tr>
<tr>
<td>Min. Ash Pollution Control Equipment Annual</td>
<td>$0.00</td>
</tr>
<tr>
<td>Operation and Maintenance Cost Differential</td>
<td>$0.00</td>
</tr>
<tr>
<td>Amortized Min. - Investment Cost</td>
<td>$0.00</td>
</tr>
<tr>
<td>Annual Fixed Charge - Cost</td>
<td>$24307.5</td>
</tr>
<tr>
<td>Annual Fuel Charge Differential</td>
<td>$0.00</td>
</tr>
<tr>
<td>Total Annual Cost Differential</td>
<td>$24307.5</td>
</tr>
<tr>
<td>Total Operation and Maintenance Cost Differential</td>
<td>$0.00</td>
</tr>
<tr>
<td>Cost Differential per KWh</td>
<td>$0.00</td>
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</table>

### Table 3. Illustrative Fuel Consumption Data and Values of Coal Conversion Measures

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Annual Oil Consumption in Barrels Before Conversion</td>
<td>1259005.00</td>
</tr>
<tr>
<td>Average Annual Natural Gas Consumption in Mcf Before Conversion</td>
<td>62947.5</td>
</tr>
<tr>
<td>Average Annual Coal Consumption in Tons Before Conversion</td>
<td>0.0</td>
</tr>
<tr>
<td>Average Annual Plus After Conversion (in Million-Millions)</td>
<td>8.0098</td>
</tr>
<tr>
<td>Average Annual Plus After Conversion (in Million-Millions)</td>
<td>8.0098</td>
</tr>
<tr>
<td>Average Annual Coal Consumption in Tons After Conversion</td>
<td>556075.00</td>
</tr>
<tr>
<td>Equivalent Annual Barrels of Oil Saved as a Result of Conversion</td>
<td>1355005.00</td>
</tr>
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</table>

### Coal Conversion Measures

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual Cost per Equivalent Barrel of Oil Saved</td>
<td>1.95</td>
</tr>
<tr>
<td>Change in Cost per KWh-Million of Electricity Generated</td>
<td>0.005472</td>
</tr>
<tr>
<td>Internal Rate of Return on Coal Conversion Investment (Percent)</td>
<td>6.061</td>
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<tr>
<td>After Taxes Rate of Return on Coal Conversion Investment (Percent)</td>
<td>3.209</td>
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