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Project Summary

Development of the Fuel Choice Module in the Industrial Combustion Emissions Model

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The Industrial Combustion Emissions (ICE) Model is one of four stationary source emission and control cost forecasting models developed by EPA for the National Acid Precipitation Assessment Program. The ICE Model projects air pollution emissions (sulfur dioxide, sulfates, nitrogen oxides, and particulate matter), costs, and fuel mix for industrial fossil-fuel-fired (natural gas, distillate and residual fuel oil, and coal) boilers by state and year (1980 baseline, 1985, 1990, 1995, 2000, 2010, 2020, and 2030).

The ICE Model was originally developed from the Industrial Fuel Choice Analysis Model (IFCAM), which relies on a life-cycle cost-of-fuel logic. Two reports describe the development of an updated forecast model (i.e., ICE) which relies on a broader range of factors shown to be relevant to the industrial boiler fuel choice decision. These reports describe the development and basis for the improved fuel choice decision logic used in the ICE Model (Version 6.0).

This Project Summary was developed by EPA's Air and Energy Engineering Research Laboratory, Research Triangle Park, NC, to announce key findings of the research project that is fully documented in two separate reports of the same title (see Project Report ordering information at back).

Introduction

The Industrial Combustion Emissions (ICE) Model is one of several emission forecasting models developed by EPA for use by the National Acid Precipitation Assessment Program (NAPAP). The ICE Model (Version 6.0) projects air pollution emissions (sulfur dioxide, sulfates, and nitrogen oxides), costs, and fuel mix for industrial fossil-fuel-fired (natural gas, distillate and residual fuel oil, and coal) boilers by state (excluding Alaska and Hawaii) and year (1980 base year, 1985, 1990, 1995, 2000, 2010, 2020, and 2030). The ICE Model does not include projections related to the combustion of LPG, municipal or agricultural solid waste, or non-purchased, self-generated by-product fuels (i.e., wood, black liquor, coke oven gas, blast furnace gas, refinery off-gas, and refinery still gas).

Background

The ICE Model is a disaggregated process engineering model. Models of this type simulate the effects of specific policies on technical alternatives for new and existing equipment. The ICE Model is designed to assess the impact of several factors on industrial boiler fuel choice decisions and air pollution emissions, including local and Federal air pollution emissions regulations, fuel price forecasts, and capital and annual operating and maintenance (O&M) costs of firing alternative fuels or retrofitting pollution control equipment.

The ICE Model projects the distribution of industrial boiler characteristics (e.g., new versus existing, boiler size and capacity utilization rate) and selects the fuel type and pollution control compliance strategy for each unit. An important model feature is the approach chosen in the ICE Model to select the fuel type for new industrial boilers.

One option is to estimate the life cycle costs for each fuel type (including boiler and pollution control equipment capital, O&M, and fuel expenses) and select the low-cost alternative. This cost comparison can be performed on an after-tax basis because, in the past, Federal income tax laws treated investments in coal and alternative fuel-firing boilers differently than investments in oil- and gas-fired boilers. Specifically, the regular investment tax credit was denied for investments in industrial oil- and gas-fired boilers.

Many analysts recognize that actual decisions by industrial firms consider a broader range of factors than just capital, O&M, and expected fuel costs. These other considerations include: reliability of fuel supplies, risks of operating disruptions, uncertainty regarding future fuel prices, capital budgeting constraints, and whether purchasers have past experience with coal.

Some analysts believe that a decision framework which considers only expected costs is an unreliable predictor of fuel choice decisions for new industrial boilers. They are further concerned that the use of this narrow approach in industrial energy demand analyses conducted in the past has resulted in unreasonably high or low forecasts of the market share for coal in new industrial boilers and, as a result, this procedure is biased.

EPA decided that a more comprehensive evaluation of the factors affecting the boiler fuel choice decision was required to eliminate this bias in the forecasted results. A qualitative review identified several important factors in addition to life-cycle costs of capital investment and annual operating expenses. Recent new industrial boiler sales data showed that the fuel choice decision was not based solely on the comparison of readily quantifiable life-cycle costs for alternative fuels.

Fuel Choice Module Development

Data on new industrial boiler sales were evaluated as a function of expected cost (boiler and pollution control equipment capital, O&M, and fuel) differences and other factors in three statistical analyses (Phases I, II, and III). The initial and final statistical analyses (Phases I and III) were performed by EEA. Additional insights were gained from an additional statistical analysis (Phase II) by Joel L. Horowitz and Thomas Cook.

The data base analyzed includes over 400 orders for new industrial coal, oil, and gas boilers between 1977 and 1983. The probability of selecting coal was estimated from this data base as a function of boiler size, region, previous experience with firing coal on-site in existing boilers (yes or no), and expected cost differences.

Prior to the late 1970s, the market share of coal in new boilers since World War II was so low (approximately 5%) that there was no real experience to analyze which showed any variability in fuel choice. In general, natural gas was underpricing other fuel sources due to price controls; therefore, that premium fuel was the overwhelmingly dominant fuel choice.

However, in the late 1970s and early 1980s the coal market share (as a percent of fossil fuel capacity) for new boilers rose to 15-30%. Even though this period was characterized by sudden shifts in incentives (e.g., oil embargo, changes in tax laws), at least the coal versus oil/gas market's share changed substantially. This study was initiated with the hope that analysis of new boiler orders during that period would shed new light on the determinants of fuel choice decisions.

The market share of coal in new boiler orders was found to be a strong function of boiler size. Almost 75% of the large boilers were ordered with coal-firing capability, in comparison with approximately 50% of the medium-sized boilers and 11% of the small boilers.

The impact of fuel choice decisions of having previous coal experience also was apparent in the data. For both medium and large boilers, the very large majority of decisions were made for coal when previous coal experience was a factor. A much lower percentage of small boiler orders chose coal with prior coal experience, but on a *relative basis* this lower market share still greatly exceeded that observed for small units without experience.

Plant location was also important. New industrial boilers built at plants without previous coal experience in Federal Regions 4 (South Atlantic) and 5 (Midwest) are, on the average, more likely to choose coal than plants without coal experience located elsewhere. More than half of U.S. coal consumption is accounted for by these two regions. Apparently close proximity to coal supplies and the demonstrated reliability of coal boilers in other plants in the same area may also be important considerations.

In addition to boiler size, location, and previous coal experience, there are other important factors. However, the data base on new industrial boiler orders does not include information on plant-specific equipment costs, fuel price expectations, perceptions of fuel supply reliability, equipment reliability, capital budget constraints, or the costs of lost production due to steam supply disruption. Therefore, this study summarizes the *distribution* of fuel choice decisions as a function of the available data (fully recognizing the data limitations) to capture the effects of these less readily quantifiable effects on the fuel choice decision by industrial plant managers.

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***Larry G. Jones** is the EPA Project Officer (see below).*
The complete report consists of two volumes, entitled "Development of the Fuel Choice Module in the Industrial Combustion Emissions Model:"
"Volume 1. Phases I and III," (Order No. PB 88-198 577/AS; Cost: $14.95)
"Volume 2. Phase II," (Order No. PB 88-198 585/AS; Cost: $14.95)
The above reports will be available only from: (costs subject to change)
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