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MASTER

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MASTER

INDUSTRIAL SECTOR TECHNOLOGY USE
MODEL (ISTUM): INDUSTRIAL ENERGY
USE IN THE UNITED STATES, 1974-2000

VOLUME 1. PRIMARY MODEL DOCUMENTATION

BOOK 1:

CHAPTERS I, II, and III

Prepared for:

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PREFACE

This report presents the current status of the Industrial Sector Technology Use Model (ISTUM), an analysis and projection of the use of energy in the industrial sector. ISTUM is an extension of the work done by the Industrial Working Group as part of ERDA's (now the Department of Energy) Market Oriented Program Planning Study. Under the direction of William B. Williams and Cyril W. Draffin of the Industrial Working Group, a preliminary version of the ISTUM model was developed by Warren P. Heim, Robert O. Reid, and Roger E. Bohn of Energy and Environmental Analysis, Inc.

Subsequent funding* by the Division of Fossil Energy and the Office of Industrial Conservation permitted significant extensions and refinements of the original version of ISTUM. These volumes describe the results of this work.

It is anticipated that the ISTUM model will become an important tool in the evaluation of industrial energy use patterns. It is important to emphasize that the model does not provide the ultimate truth about future energy consumption in the industrial sector; rather, it is a means of developing insights on industries and technologies.

This report contains four volumes:

- Volume 1 - Primary Model Documentation
- Volume 2 - Results of the Base Case
- Volume 3 - Appendix on Service and Fuel Demands
- Volume 4 - Appendix on Technologies

This documentation is currently (April, 1978) in draft form. The authors feel that there are several areas where

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useful improvements can be made in the documentation, to more fully explain the workings of ISTUM and to better highlight the implications of its results. All conclusions are tentative.

The efforts reflected in these documents represent a great deal of work accomplished in a remarkably short period of time. The project management owes a debt of gratitude to the people on the staff and sub-contractors who were willing to make significant sacrifices in order to meet the project goals.

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CHAPTER I

PROJECT OVERVIEW

A. Introduction

The Industrial Sector Technology Use Model (ISTUM) is designed to predict the commercial market penetration of various energy technologies in the industrial sector out to the year 2000. The model represents the refinement and further development of the Industrial Sector Model developed for the Market Oriented Program Planning Study task force in 1977^{1/}. Improvements were made to both the model logic and the many data inputs required for such broad analysis of the industrial sector.

The model assesses the comparative economic competitiveness of each technology. It then uses these assessments to project each technology's anticipated market penetration. Careful accounting of total industrial energy demand forecasts assumes that the total market for all energy technologies is not overstated. Each technology's success is a function of its comparative economics and the total demand for the energy service it provides. All technologies are treated equally with regard to fuel prices and other macro-economic factors. The procedures used to compete the technologies against each other were designed to give an accurate reflection of corporate decision making. In all aspects EEA's

^{1/} "Market Oriented Program Planning Study - Final Report of the Industrial Sector Working Group", prepared for DOE by Energy and Environmental Analysis, Inc. November 30, 1977, unpublished.

strategy was to provide a realistic framework within which energy technologies could be objectively appraised.

Because of the uncertainty that exists in many of the model inputs, the model was designed to allow maximum flexibility in testing alternative scenarios. For example technology costs are broken down into their major components so that if the cost or necessity of one particular component is in doubt it can easily be changed. Or if an alternative fuel price scenario is of interest each or all fuel price vectors can easily be replaced.

In its present state of development, ISTUM is a valuable tool for evaluating:

- The commercial viability of energy technologies in the industrial sector.
- The impact of various macro-economic forecasts and fuel price projections on energy use patterns in the industrial sector.
- The consequences of various environmental regulatory policies.
- The aggregate fuel mix of the industrial sector between now and the end of the century under various economic and policy scenarios.
- The commercial potential for certain technologies within specific industries -- e.g., synthetic gas in the petroleum refining industry.

Because of the many dimensions in the ISTUM model this list of possible use for the model is virtually endless.

The primary value of the ISTUM model will be in its systematic use to evaluate either broad economic/policy scenarios or investigation of the factors which determine the commercial potential of emerging energy technologies.

A broad overview of the model will be provided in the next two sections of this chapter. Section B will deal with the input requirements of the model; Section C will discuss the solution of the model. The remainder of this volume will include an in-depth discussion of the topics which are briefly described in this chapter. The purpose of this chapter is to give the reader a quick familiarization with the ISTUM model logic and its special terminology.

B. Key Model Inputs

There are three key sets of inputs to the ISTUM model:

Each of these sets of inputs are discussed in general terms in this section. For more in depth discussion refer to Chapters II, III, V and VI of this volume.

1. Technologies

ISTUM competes over 100 energy technologies. These fall in six primary categories: conventionals, fossil/energy, conservation, cogeneration, solar and geothermal.

a. Conventional Technologies

Generally these are the technologies which are currently meeting the energy demands in the industrial sector such as conventional oil, gas or coal steam generation. There are a few technologies which are of a conventional nature but are as yet untried. In ISTUM all such cases are direct coal firing applications in some direct heat industrial use.

b. Fossil Energy Technologies

These technologies are those which are being developed or studied by the Fossil Energy Division of the Department of Energy. The ISTUM fossil energy technologies are not an exhaustive sample of the DOE portfolio. The primary technologies are atmospheric fluidized bed combustion (AFB), Low Btu gasification (LBG), and medium Btu gasification (MBG). Each of these technologies actually appears several times depending on how many different service sectors it can compete in. Service sectors are described later in this chapter.

c. Conservation Technologies

These technologies were all selected from DOE's portfolio of industrial conservation technologies which are currently

being developed or studied. The ISTUM conservation technologies were chosen according to how well they fit ISTUM logic, how complete their economic and performance data was, and their potential for significant energy savings.

d. Cogeneration Technologies

ISTUM's portfolio of cogeneration technologies actually includes several self-generation technologies along with various topping and bottoming cycles. These technologies are strictly tied to industrial applications which precludes such utility applications as district heating. There are many intricate dimensions to modeling the commercial penetration of cogeneration in the industrial sector. These are discussed in detail in Chapter II of this volume.

e. Solar and Geothermal Technologies

There is much controversy surrounding the commercial potential of these technologies. In the case of solar technologies in the industrial sector this stems from uncertainty over technology cost, and questions about the applicability of solar in high temperature or high capacity factor uses. In the case of geothermal the uncertainty is related more to the spatial location of industrial demand as well as the opportunity for using geothermal resources for central station electric power generation instead of industrial uses.

For all technologies, costs were developed in a systematic way using a framework that allowed breakdown of the technologies into key component costs.

In the case of technologies where there was an abundance of data, costs were broken down into the following major components:

- Site preparation and power house
- Primary system and controls
- Fuel handling
- Environmental controls and waste handling
- Utility and feedwater systems
- Indirect capital costs
- Installation costs are included in each component with a separate set of indices to capture regional variability in construction labor costs.

These capital cost components are in turn broken down into subcases which reflect variability in the component cost due to factors such as sub-surface conditions, multiple unit installations, etc. These subcases are assigned probabilities of occurrence which sum to 1.0 for all subcases within a component. The technology cost inputs are then processed into cumulative frequency distributions which are used in the competition for market shares.

A great deal of time and effort went into the methodology of developing technology costs and the specifications of particular component costs. Due to variability in the amount and quality of the data available, a coding system was set up to grade each technology's inputs. The system gives grades from "A" to "D", with "A" representing a technology with sufficient reliable data to allow a detailed specification of all relevant components. On the other end of the range, a "D" technology is based on sketchy or unsubstantiated data on a technology which presently has no proven commercial

applications. In some cases a low grade was also applied to a technology which had economic factors that were not easily modeled in the ISTUM framework. Chapter II of this volume and the Technology Appendix volume combine to give extensive detail on all the technologies modeled in ISTUM. This documentation is designed in such a way as to allow the reader to recreate every technology cost used as an input to the model.

2. Energy Demand

This facet of the model actually has three important sub-dimensions:

- Industries
- Equipment sizes (measured in million Btus per hour)
- Equipment load factors (measured in hours of operation per year)

Chapter III is an extensive discussion of all the factors relating to the energy demand base used in ISTUM. The primary data for ISTUM's energy demand data base comes from the Energy Consumption Data Base (ECDB) which was completed in 1977 for the Department of Energy (FEA) under the management of EEA. The data base is a comprehensive accounting of energy consumption in the industrial sector in 1974.

Considerable effort went into translating the ECDB data base into ISTUM's energy demand data base. Much of this involved allocating the Btus of energy consumption into industry classifications used in ISTUM, and allocating the same energy demands into the sizes and load factors used in the model. Additional effort went into converting fuel consumption quantities into "service demand" quantities. A service demand is a unit of energy which facilitates the modeling

of comparative energy economics. It is defined as the amount of useful energy product required by an energy using industrial process. Thus a boiler with an 80 percent efficiency will convert 100 MMBtu/hr. of fuel into 80 MMBtu/hr. of service demand - in this case in the form of steam. By converting energy consumption into service demand, technologies with different costs and conversion efficiencies can compete equitably for a given amount of service demand even though they don't use the same fuel/capital-equipment mixes to satisfy the demand.

ISTUM allocates energy demand into 23 different service sectors such as steam, indirect heat, machine drive, etc. Thirteen of these service sectors are actually competed to determine which technologies will "win" the service demand. The other service sectors are maintained to keep accurate accounting of energy consumption. These include such service sectors as natural gas feedstocks, miscellaneous lubes and waxes, etc. Table I-1 is a complete listing of the service sectors used in ISTUM.

In each of the 13 service sectors where technology competition takes place it is necessary to specify sizes and load factors in order to calculate the economics for each technology on a \$/MMBtu basis. For example in the steam service sector 2 sizes and 2 load factors were chosen giving a total of 4 size/load factor combinations. The sizes were 50 and 250 MMBtu/hr. of service demand; the load factors were 4000 and 7000 hours/yr. Different technologies will dominate different size/load factor cells. Capital intensive technologies will do better with high load factors; technologies with significant economies of scale will do better in large installations.

TABLE I-1

SERVICE SECTORS USED IN THE ISTUM MODEL

1. Steam*
2. Direct Heat - (Intermediate)*
3. Direct Heat - (Dirty)*
4. Indirect Heat - (coal capable)*
5. Machine Drive*
6. Electrolytic*
7. Liquid Feedstock
8. Natural Gas Feedstock
9. LPG Feedstock
10. Metallurgical Coal
11. Miscellaneous Energy and Lubes
12. Space Heat*
13. Indirect Heat - (not coal capable)*
14. Calcining*
15. Glass Melting*
16. Brick and Clay Firing*
17. Ironmaking*
18. Steelmaking
19. Steel Reheating*
20. Internal Generation
21. Captive Electricity
22. Captive Direct Heat
23. Coke Consumption

* indicates service sectors in which technologies compete in ISTUM. The remaining service sectors are maintained to keep an accurate accounting of total energy consumption in the industrial sector.

ISTUM divides energy demand among 26 different Standard Industrial Classifications (SIC's). Twenty-two of these are industrial SICs at the two, three or four digit level depending on energy consumption patterns. The other four SICs represent mining and agricultural energy uses. Growth rates of future energy demand are forecast for each SIC. These forecasts were obtained from Data Resources, Inc. most recent "Trendlong" solution of their macro-economic model of the U.S. economy.

3. Fuel Prices

The third key input to the model is fuel prices. Fuel price inputs for the model were also provided by Data Resources, Inc. They correspond to the same solution of DRI's "Trendlong" macro forecast for the U.S. economy and a coordinated solution of the DRI energy model which actually forecasted the basic fuel prices. The fuel prices were forecast for 13 different regions from which a distribution of national prices for each fuel was generated. Prices were calculated in this fashion out to the year 2000 to match the models solution horizon. In the actual technology competition these fuel prices were levelized to give a more accurate decision analysis.

C. Solution of the Model

With these three key inputs set, the model is ready for solution to determine the commercial market shares of the competing technologies. There are three key aspects to a solution of the ISTUM model:

- Nominal Market Shares
- Actual Market Shares
- Capital Stock Growth and Retirement

1. Nominal Market Shares

Nominal market shares are calculated assuming rational economic decision making behavior in the private sector. Every decision maker is assumed to always pick the lowest cost technology to meet his energy needs.

Since both the technology cost inputs and the fuel price inputs are ranges (they are inputted as distributions of possible prices rather than single point estimates), the solution of nominal market shares requires a statistical integration procedure to determine how often any given technology will be the lowest cost choice. Thus with Figure I-1 below, there are four hypothetical technologies competing for the service demand in this particular competitive cell. A competitive cell is a certain size and load factor of energy

FIGURE I-1

HYPOTHETICAL TECHNOLOGY COST DISTRIBUTIONS

demand in a certain service sector (steam, indirect heat, etc.) in a given year. The distribution for each technology represents the probability of its total cost (capital, fuel and O&M) equaling any given \$/MMBtu price. The area under a technology's cost distribution represents the total fraction of that particular competitive cell for which that technology can compete. Thus Technology "A" has the lowest cost distribution of the four, but the fact that the area under "A"'s distribution is relatively small indicates that it is getting

blocked out of a part of the market. To do this ISTUM uses what is termed a maximum market fraction. If a particular technology for technical or other reasons can only compete for half of a given market it will receive a maximum fraction of .50. Examples of maximum fraction constraints would include:

- ① Process stream requirements in some cases are at higher temperatures or load factors than a solar system can provide
- ② A conservation technology applicable to one, but not all, direct heat applications in particular industry.
- ③ Non-attainment regulations effectively blocking coal combustion in some geographical area.

Maximum fractions for all technologies are listed along with the other technology data in the Technology Appendix.

Returning to the example in Figure I-1, the competition between these four technologies is accomplished by a statistical procedure to determine how much nominal market share each technology will get. In this example Technology "A" can be expected to get the majority if not all of its maximum market share. Technology B will get the next strongest share with "C" next. It is possible that by the time "A", "B" and "C" have taken their shares the entire market will be satisfied and Technology "D" will get no share of the market at all. On the other hand, if technologies "A", "B", and "C" have small maximum market fractions there would still be market available to technology "D".

This competitive procedure takes place in each of about 360 competitive cells in the model. The results of this

step of the model solution are the nominal market share for every technology, in every service sector in every industry, in every year of the model. The next step involves determining actual market shares.

2. Actual Market Shares

For emerging technologies it is assumed that not all industrial energy decisions reflect precision economics. There is great uncertainty surrounding the commercial introduction of new technologies. Some more "risk-prone" decisions makers will be likely to respond to the economics of an emerging technology sooner than others. This phenomenon introduces a lag to the commercial acceptance of a new energy technology, causing its actual market share to be somewhat less than its nominal market share in early years. ISTUM has a behavioral lag logarithm that captures this phenomenon with new energy technologies. It is discussed in detail in Chapter IV of this volume.

Although most analysts agree that a behavioral lag phenomenon exists, no one has developed substantial data to quantify or predict this phenomenon parametrically. This subject is discussed in some length in Chapter IV and the appendix to Chapter IV.

3. Capital Stock Growth and Retirement

Once actual market shares are calculated for all service sectors and years, it is necessary to determine the size of the service sector demands which apply to these actual market fractions. These demands for energy technologies are a function of two factors -- retirement of existing capacity and new growth. Data Resources, Inc. provided assistance in developing both of these dimensions.

The projections of retirement are based on past capital stock turnover rates in each of the industries we modeled. By looking at historical stocks, we developed a capital stock retirement model based on the philosophy that the amount of retirement of energy stock in any year is a function of the age of the equipment in the stock. In each period in the model the age of the existing capital stock is tracked and coefficients (estimated from historical data) are applied to retire an appropriate portion of the capital stock.

The amount of predicted growth in each industry is then added to this retirement factor to come up with the total incremental demand of energy capacity in each industry in each year. This demand, in turn, is allocated to the appropriate sizes and load factors in each of the service sectors. At this point the energy demands and the actual market shares for all the technologies are on the same basis and the final results are easily calculated.

At their most disaggregated level the model results are measured in annual Btus of service demand consumption by technology, by industry, by service sector, by fuel, by size by load factor, and by year. Given the many useful ways of sorting and displaying these outputs, the model is capable of generating vast quantities of results. Figure I-2 is a schematic representation of the ISTUM model.

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D. Strengths and Limitations of the Model

Through the development of ISTUM and the original work done on the MOPPS task force industrial sector model, many areas of energy technology commercial evaluation have been greatly enriched. However, problems associated with modeling in as many dimensions as the ISTUM model, persist - some ultimately soluble - others not. The following is a candid discussion of what EEA sees as the major strengths and limitations of the ISTUM model.

1. Strengths

The strengths of the ISTUM model can be discussed on two planes. There are some general attributes of the modeling approach used in ISTUM that distinguish it from other efforts. There are also several specific areas of the model that got focused attention for strategic reasons that should enhance use of the model.

a. General Attributes of the Model

Perhaps the most salient feature of the model is the consistency with which it treats a wide spectrum of energy technologies. This was seen as the most crucial aspect of the model's development. The technology costing system allows for consistent technology costing; all technologies face the same primary fuel prices and macro-economic scenario. The nature of the technology competition in the model assures each technology fair access to the particular energy markets it serves.

The many dimensions factored into the ISTUM model allows it to produce many types of results. It can be used to indicate

broad industrial trends in fuel consumption or technology use patterns; or it can be used to specifically evaluate the commercial prospects of a single technology.

The model was structured in such a way as to allow relatively easy extensions in its scope or detail. More technologies or service sectors can be added without interrupting the model's structure. Similarly as additional data becomes available on technologies included in the model, this too, can be easily incorporated.

The primary model logic is constructed to directly reflect decision procedures used in private industry. The essence of the decision logic is a discounted cash flow framework that escalates fuel and capital costs on a commensurate basis. Fuel costs are levelized, allowing accurate reflection of a decision maker's anticipation of price escalation. By using this decision modeling framework it is possible to make adjustments to inputs and have the result reflect the actual change in the comparative economics of the technologies. This precludes unrealistic relationships between parameters that can evolve from econometric or linear programming solutions of issues that involve the aggregate effect of many individual corporate decisions. The combined effect of the nominal market share calculation, the actual market share calculation, and the capital stock model causes realistic penetration pattern for emerging technologies responding to gradual or step changes in energy economics in the future.

b. Specific Attributes of the Model

Some of the more specific strengths of the model are listed below:

- Technology evaluation system
- Technology cost inputs
- Energy demand specifications
- Cogeneration
- Capital stock model
- Environmental factors

Each will be discussed in turn.

i. The Technology Evaluation System

The technology evaluation system in ISTUM was developed to allow consistent treatment of technology cost inputs. Its essence is a system of "building block" components that were costed out in some detail including the application - specific factors that can cause variability in technology costs. If different technologies share some components the same building block data is used to assure consistency in the cost specifications. The system allows for easy identification of the cost makeup of any technology and easy modification of mix or costs of components of a technology if additional data becomes available. For example, the data EEA gathered showed sizes and load factors where in the case of LBG/steam generation applications it was more economical to combust the uncleaned LBG gas and use stack gas clean up equipment instead of cleaning the LBG gas prior to combustion. This equipment configuration gave a stronger market position to LBG in future years. If it is determined that the uncleaned LBG gas could not be combusted in these applications it is a simple straightforward process to change the "pollution

equipment" component of all LBG technologies and calculate their revised market shares. Although EEA was diligent in developing reliable technology costs, our highest priority went to the development of a technology input system that allows for consistent treatment of technologies and easy modifications of component arrangements or costs.

ii. Technology Cost Inputs

In applying this technology evaluation system to the 100⁺ technologies in ISTUM, EEA endeavored to use the most current data available from DOE program offices or the most recent studies available elsewhere. For conventional technologies EEA surveyed several construction engineering companies to gain insights into component costs and variabilities. This rigorous, systematic approach could not correct the fact that many technologies are still in their conceptual phases and precise costing data is simply not available. To account for the fact that the data available on some technologies is much stronger than what is available on others, a data quality coding system was developed to roughly rank the confidence one could have in the costing of any particular technology. This quality coding system should be useful in identify areas where more technical data would be most valuable. For example a technology with a poor quality code but a high nominal market share, would be a good place to get more technical data to validate the result.

Detailed discussion of the technology evaluation system is contained in Chapter II of this volume. A detailed listing of all technology data is included in the Technology Appendix which is a separate volume.

iii. Energy Demand Specifications

The energy demand specifications in ISTUM were also developed with attention to systematic consistency. The foundation for ISTUMs demand base comes from the Energy Consumption Data Base (ECDB) maintained by DOE. It is the most current and detailed data base available dealing with industrial energy use patterns. Where valuable, additional data or insights were gained from other data bases or sources. Details of the ISTUM data base and how it was developed are given in Chapter III of this volume. Detailed listing of the energy consumption data is given in the Service and Fuel Demand appendix which is a separate volume.

iv. Cogeneration

Another strong feature of the ISTUM model is its treatment of cogeneration technologies. The comparative economics of cogeneration technologies are complicated by many factors. The relation to the primary system decision in the case of a topping unit requires the use of conditional logic that says in essence that a topping cycle can exist only where a primary system exists to support it. For all industrial cogeneration (and self-generation systems) there are difficult issues of modeling the option to purchase electricity due to the variabilities caused by regional factors and rate structures. ISTUM contains a comprehensive cogeneration logic which captures many of these factors which determine the commercial potential of cogeneration technologies. A detailed discussion of ISTUM's treatment of cogeneration technologies is included in Chapter II of this volume.

v. Capital Stock Model

Much of the potential of new energy technologies will be determined by capital stock factors in the industrial sector. The capital stock model in ISTUM was developed to capture these aspects of commercial penetration modeling. With the contributions of Data Resources, Inc. This piece of the model was built with information from historical capital stock retirement patterns from specific industries. This information combined with industry-specific production forecasts from DRI's macro model of the U.S. economy, allows ISTUM to generate credible forecasts for energy demand in the industrial sector to the year 2000. Detailed discussion of these aspects of the model is included in Chapters IV and VI of this volume. An additional strength of the model is the consistent set of fuel prices that were generated from DRI's energy model. By linking the service demand forecasts with the fuel prices that are derived from a coordinate run of the DRI energy model, the model inputs are generated on an "equilibrium" basis.

vi. Environmental Factors

Great care went into the treatment of environmental factors in the model. Environmental regulatory policy will have much to do with the future mix of fuels and energy technologies in the industrial sector. It is impossible to predict what every aspect of this policy will be. The strategy in ISTUM was to set a consistent baseline of environmental assumptions from which environmental regulatory policy could be readily evaluated. This strategy should allow ISTUM to become a strong tool in the future evaluation of environmental policy in the industrial sector. Discussion of environmental factors in the model is included in Chapter V of this volume.

This is not intended to be an exhaustive list of what EEA feels are the strengths of the ISTUM model. Many of the strengths we feel will become self evident as the model gains use to evaluate various technologies, programs or policies.

2. Limitations of the ISTUM Model

It is logical that any model that deals with as many dimensions and at as aggregated a level as does ISTUM, will give only approximate solutions. The relationships between parameters in the model can all be expected to move in the correct directions, but there are limits to the accuracy of their absolute values. There is a natural trade off in the development of a model such as ISTUM between getting enough aggregation to yield useful results but not losing too much validity due to the loss of precision inherently involved in such aggregation. We feel that ISTUM is a logical balance between these two constraints. Some of the limitations listed below represent carefully considered decisions to not attempt to capture something that we did not feel the model logic was suited for. By not trying to answer too many questions with this model, we feel that we have answered many questions better.

Within the model itself, we see the following key limitations and shortcomings.

- Interdependencies between parameters
- Heterogeneous service sectors
- Broad differences in economic logic of many technologies
- Supply side technologies

- Retrofit modeling
- Changes in the composition of energy demand within an SIC
- Behavioral lag modeling
- Non-equilibrium solutions.
- Technical Uncertainty

a. Interdependencies Between Parameters

The issues of interdependencies has several facets. Each technology is specified in the model as a distribution of possible costs. The solution of the model implicitly assumes that these distributions are independent. In reality some of the distributions are completely independent; some are not. Regional variability is one factor which could cause some interdependencies between technology costs -- especially fuel prices. Two coal-based technologies would also be to some extent interdependent. A maximum fraction constraint placed on two technologies for the same reason, might not have the desired effect in the aggregate solution. It is not known how much inaccuracy is caused by problems of interdependencies. Solutions are available, but none could be completed in the time available for ISTUM's development. The component system used for technology cost specifications in ISTUM will facilitate solution of part of the interdependency problems. There is additional discussion of this issue in Chapter IV.

b. Heterogeneous Service Sectors

This is a problem correlated to the heterogeneity of the applications in any given service sector. For example

the steam and brick firing service sectors produce a product or involve an energy service that is easily modeled due to the homogeneity of the application. To a great extent steam is steam regardless of its ultimate use. However, if a service sector includes applications that are highly variable, the economic modeling becomes more approximate. By far the best examples of this are the "intermediate direct heat" and "dirty direct heat" service sectors. These include a wide range of processes that have to be modeled as some hybrid applications to allow the technologies to compete on a consistent basis. The solution to this problem is clear and was to some extent accomplished in ISTUM. Service sectors 14 through 19 (calcining, glass melting, brick firing, iron-making, steelmaking and steel reheating) are examples of industry direct heat applications that were split out of the more aggregated direct heat service sectors. If this process of splitting out the industry specific direct heat applications continued the heterogeneity problem would diminish at the price of a larger and larger model -- again the tradeoff.

c. Broad Differences in Economic Logic of Many Technologies

On the technology side there was a problem of broad differences in the economic logic of many technologies. This is particularly the case with conservation technologies, many of which are very application specific and often offer non-energy and sometimes non-economic benefits. To fit some of these technologies with the ISTUM framework in some cases required some "bending" of the economic factors involved. The broadly applicable technologies such as coal-fired boilers or recuperators didn't suffer from this problem. In many

cases, outside-the-model calculations allow adequate corrective factors for some of these technologies which can be included in their model inputs. In other cases they are poorly modeled and received low grading factors as a result. These issues are discussed on a case by case basis in the Technology Appendix.

d. Supply Side Technologies

A related technology problem involves modeling "supply-side" technologies in what is in essence a "demand-side" model. The difference between the two categories is whether or not the product of the technology is used directly in the production process or sold over the fence. Medium Btu gasification and geothermal are the two best examples in this model of "supply-side" technologies. A coal fired-boiler that converts fuel to steam which is then consumed on site is an example of a "demand side" technology. The difficulties with "supply-side" technologies arise from estimating the cost of delivering the energy product to the ultimate end user. An MBG plant needs economies of scale to be competitive, but this requires knowing what the spatial distribution of demand for the MBG gas will be and how much it will cost to pipe the gas to all end users. High Btu coal gasification, coal liquefaction and oil shale are also examples of "supply-side" technologies. Whereas MBG in some cases could be end-user-owned, these technologies in all cases produce intermediate energy products that are sold over the fence. To accurately model these technologies the focus would be on macro-level supply logic that would probably treat end-user behavior with econometrics instead of decision logic without losing too much precision. No attempt was made to model these "supply-side" technologies

in ISTUM with the exceptions of MBG and geothermal. These issues are discussed on a case by case basis in the Technology Appendix.

e. Retrofit Modeling

ISTUM is not a retrofit model. The modeling of decision economics for retrofit technologies is radically different from modeling incremental demand (the sum of growth and retirement). Technologies that rely heavily on retrofit markets are therefore not given access to their primary markets in ISTUM. This seems to apply mostly to some conservation technologies. This issue is discussed in Chapter II of this volume and the Technology Appendix.

f. Changes in the Composition of Energy Demand
Within an SIC

As energy economics change many conservation projects will simply involve more meticulous operating procedures which reduce the ratio of primary fuel to product. Process changes over time will likely have the same effect of making the industrial sector more energy efficient. The production growth forecasts used in ISTUM do not account for these efficiency improvements. The solution obviously involves detailed industry specific analysis which was not within the scope of this modeling effort.

g. Behavioral Lag Modeling

The issue of modeling behavioral lags in new technology commercial acceptance is currently open ended. Many people feel there are significant delays in the acceptance of new technologies in the industrial sector due to differing risk

attitudes of decision makers and information transfer factors. There is little substantiated empirical data to quantify this effect. ISTUM contains a relatively simple behavioral lag algorithm which is discussed in Chapter IV. An appendix to that chapter discusses other methods which have been used to model these behavioral phenomenon. We feel that these other methods have even more serious shortcomings.

h. Non-equilibrium Solutions

ISTUM is not an equilibrium model. As mentioned earlier the production growth inputs and the fuel price inputs resulted from coordinated solutions of DRI's macro-economic and energy models, but the ultimate fuel mixes which result from solution of the ISTUM model do not necessarily reflect equilibrium between fuel prices and demands. An equilibrium check between the base case solution of the ISTUM model and the DRI energy model has been discussed and will probably be undertaken in the future.

i. Technical Uncertainty

With many emerging energy technologies there is uncertainty concerning the actual performance of the technology. Conversion efficiencies, heat transfer properties, and reliability are all examples of areas where unproven technologies are more uncertain than existing conventional technologies. ISTUM does not capture this technical uncertainty. The cost distributions in the model represent variability due to application specific factors e.g., differing sub-surface conditions, or redundant primary systems. There is no reflection of the uncertainty of performance with an emerging technology. To do the comparative economic analysis correctly it is necessary to ignore this dimension of uncertainty. All technologies have

to be specified consistently on the basis of what their most likely operating characteristics will be. If technical uncertainty were included the results of the model would be difficult to interpret. For example if two technologies shared a 50/50 split of a market, it would be possible to interpret this as a 50/50 chance of either technology getting 100 percent of the market. If technical uncertainty and application-specific variability were both included in the inputs it would be infeasible to determine which was causing how much of the result-making interpretations impossible. It is possible to gain information on the issue of technical uncertainty on a technology by rerunning the model with the operating characteristics of that technology changed to other plausible values. By noting the change in economics and the resulting shift in market share, it is possible to determine how sensitive the technology is to its performance characteristics.

Again this is not an exhaustive list of the shortcomings and trade-offs involved in the ISTUM model. Most of the key problems listed here result from decisions to keep the model manageable in size and cost. It is not felt that the cumulative error that results from the issues listed above precludes use of the ISTUM model as a valuable tool for analyzing energy issues in the industrial sector.

E. Further Development of the ISTUM Model

It is logical that the ISTUM model itself will point the way to useful areas of further development. The results obtained from evaluation of various technologies or energy/environmental policy issues will be the best indicator of where more careful development of model inputs or logic will be most useful.

Large scale analysis of industrial energy issues are on the drawing boards at DOE and within several private companies and institutions. It is hoped that ISTUM might provide useful logic and inputs to these efforts.

The remainder of this volume is an in-depth discussion of the model inputs and logic. Separate volumes deal with base case results of the model and technology and energy demand data. The documentation in total is intended to provide comprehensive insights into the model logic, inputs, and results. Questions which are not answered in this documentation can be directed to:

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CHAPTER II

TECHNOLOGIES

A. Introduction

The characterization of energy technologies in the ISTUM model is based upon the construction of a cost frequency distribution for each technology. This distribution reflects the fact that the costs associated with a specific energy technology will vary among the different sites and applications occurring within a service sector. Some factors causing this variability are listed in Table II-1. Normally when costing out a technology, the technology is being considered for an application where there is a reasonable expectation that the technology will be economically viable. This procedure normally leads to examining a biased sample, and consequently a restricted range of costs. The ISTUM model must consider the costs associated with all the potential applications of a technology within a service sector. This may include obtaining costs for a particular energy technology in applications where it is usually rejected, a priori, as being too expensive and is normally not even considered. By considering costs for an entire population of potential applications, a much wider range of costs are obtained.

The methodology used to estimate a technology's cost frequency distribution involved separating the costs into cost components. Each component had an estimated cost and frequency distribution. The components were then combined to give costs for entire plants. The methodology devised has the following advantages:

TABLE II-1

PARTIAL LIST OF SOURCES OF TECHNOLOGY COST VARIABILITY

A. Application Related Variability

1. Specific process requirements. These may vary within a service sector. For example some direct heat applications may require more uniform heat distribution, which is accomplished by increasing the number of burners resulting in higher costs. Another example is steam, where pressure and temperature requirements vary with application.
2. Turndown requirements. Batch processing or discontinuous shipments of raw materials may call for equipment that can respond to rapidly changing loads.
3. Reliability requirements. Some industries place a high premium on reliability. The value of lost output due to equipment failure may make it economic to have complete backup systems.

B. Site Related Variability

1. Available Space. A lack of available space can greatly increase the cost of certain technologies, particularly solar where collector space is needed, and coal where room for coal handling is required.
2. Local variables. Such as the cost of the land, costs of obtaining required permits and costs related to environmental restrictions.

TABLE II-1 cont.

3. Weather. Harsh weather increases coal handling costs, and amount of sunlight (insolation) is important for solar costs.
4. Terrain - Rugged, sloped or marshy land can increase construction costs.
5. Auxiliary costs. Some technologies require considerable water and/or electricity. Their cost and availability varies from site to site. Boiler feedwater and electricity for coal handling equipment are examples.
6. Labor wages and productivity variability. Wage rates and labor productivity vary from site to site.

C. Firm Related Variability

1. Cost of Capital. Different firms have different financial structures.
2. Operator and maintenance skill levels.
3. Familiarity with technology being installed. Do they have past experience with this type of system?
4. Planning Horizon and general organization.

Note: Technical uncertainty is not incorporated into the cost variability. It is a separate issue. ISTUM assumes for example, that any technical barriers preventing the use of an energy technology are overcome, and at reasonable cost.

- 1) It is general enough to apply across most technologies.
- 2) Estimation of the costs and frequencies of the underlying components is easier than determining the costs and frequencies of plants. It is hard for a person to conceive of all the possible plant combinations that can occur.
- 3) It allows for a more explicit statement of the assumptions.
- 4) It provides information on the interdependence between technologies by identifying the components that technologies have in common.
- 5) It makes for easy cost sensitivity analysis by compartmentalizing the costs.

The complete characterization of the energy technologies in the ISTUM model requires the following inputs for each technology in each service sector:

- A specification of the technology's capital cost distribution, and its annual operating and maintenance expenses.
- A determination of the applicable market for that technology. Factors such as size and temperature restrictions, the form of the energy produced, environmental regulations and other application specific items were considered.

- An estimate of when the technology will be sufficiently developed to be considered available for general commercial use.
- The fuel efficiency of that technology.
- An estimate of the construction period and life of the physical equipment.

B. Estimation

In devising a methodology for determining the cost frequency distributions, the following goals were considered to be important:

- To portray the costs associated with an energy technology as accurately as possible.
- The methodology should be general enough to allow for a consistent and systematic application across different technologies.
- It should provide information on the interdependencies among the different technologies^{1/}.

The estimation procedure used tries to break down the costs of a particular energy technology into independent components or combinations of components. For example the costs of installing a conventional coal-fired steam system in an industrial plant could be divided into:

^{1/} At this time (April, 1978) the model does not take into account the interdependencies between technologies. However, the methodology for handling these interdependencies has been worked out and this cost estimation procedure is an integral part of the final formulation.

- A. Site Preparation and Power House Costs;
- B. Boiler Equipment and Control System Costs;
- C. Coal Handling Costs;
- D. Environmental Control and Waste Handling Costs;
- E. Utility and Feedwater System Costs;
- F. Installation Variability Indices
- G. Indirect Capital Costs

Included in cost components A through E is the capital cost of the relevant equipment, the costs of installation and the costs of operation and maintenance. Component F, installation indices, is used to adjust for regional variations in construction costs. Component G, indirect direct capital costs, includes items that are normally estimated as a percent of capital cost like engineering and design, contingency costs, and startup costs. Components A through E are additive components, where as components F and G are multiplicative. That is, the cost of a particular boiler system is the sum of components A through E. This sum is then multiplied by the product of F and G.

The industrial plants that incur the above categorized costs can be divided into three cases:

1. Case 1 - New Plant:

Case 1 exists when the energy technology under consideration is being installed in a new plant. A new plant can take advantage of construction economies of scale by building the power system at the same time as the rest of the plant. The men and the majority of the equipment are already at the site, and the leveling and grading for the power system can be done at the same time as the rest of the plant. A new plant will also face fewer constraints than an existing plant. For example, a new plant is less likely to be locked

into a particular site. Favorable conditions for the installation of an energy technology are more likely to exist when starting from scratch.

2. Case 2 - Existing Plant, Different Technology

Case 2 occurs when an existing plant is installing an energy technology different from what is currently being used. An example would be when a plant using oil or gas fired boilers installs coal-fired boilers. This plant will face different constraints than those faced by an entirely new plant. An existing plant whose power system is being expanded or replaced by a different technology will usually face more severe site restrictions and will have higher installation costs.

3. Case 3 - Existing Plant, Same Technology

Case 3 exists when a plant expands or replaces its power system, with the same technology it is currently using. An example would be where a plant currently using coal produced steam adds more coal boilers. The past experience of this firm can be used to help reduce costs. The plant may also be able to take advantage of its foresight if the expansion is a planned expansion. However, if the expansion was not adequately planned for, when the plant was first built, the plant may find itself having severe site restrictions.

These technology cost components and plant type cases make for a two-tiered system of cost determination. To capture cost variation resulting from factors other than plant type one more subdivision needed. Table II-2 illustrates the final generalized form. The structure in Table II-2 is drawn out completely for cost category A only. The other categories, B through H, would be similar.

TABLE II-2
GENERALIZED TECHNOLOGY COST STRUCTURE

A. Site Preparation and Power House Construction

Case A1 - New Plant

<u>subcase A1a</u> - Best conditions (low cost).....	Freq	Cost
<u>subcase A2b</u> - Moderate conditions	Freq	Cost
<u>subcase A1c</u> - Difficult to worst conditions (high cost).....	Freq	Cost

Case A2 - Existing Plant, Different Technology

<u>subcase A2a</u> - Best conditions (low cost).....	Freq	Cost
<u>subcase A2b</u> - Moderate conditions.....	Freq	Cost
<u>subcase A2c</u> - Difficult to worst conditions (high cost).....	Freq	Cost

Case A3 - Existing Plant, Same Technology

<u>subcase A3a</u> - Best conditions	Freq	Cost
<u>subcase A3b</u> - Moderate conditions.....	Freq	Cost
<u>subcase A3c</u> - Difficult conditions.....	Freq	Cost
<u>subcase A3d</u> - Worst conditions.....	Freq	Cost

B. Energy Technology Specific Equipment - in the case of boilers this would be the firing system, the boilers, fans, economizers, etc.

Case B1 - New Plant

<u>subcase B1a</u> - Best (low cost).....	Freq	Cost
<u>subcase B1b</u> - Moderate.....	Freq	Cost
<u>subcase B1c</u> - Difficult.....	Freq	Cost
<u>subcase B1d</u> - Worst (high cost).....	Freq	Cost

Case B2 - Existing Plant, Different Technology

Case B3 - Existing Plant, Same Technology

C. Fuel Handling Costs

Cases C1 through C3

D. Environmental Controls and Waste Removal

E. Auxiliary Systems (an example would be a boiler feed water system)

F. Installation Variability Indices

G. Indirect Capital Costs

In early work on ISTUM the frequencies of each subcase was viewed as a discrete probabilities. It was found that estimates of discrete events and costs were difficult to obtain and often resulted in biased estimates. The final methodology obtained frequency estimates as points on a cumulative cost distribution for each component. To help facilitate the exposition and to avoid the use of complicated math an example will be worked out using discrete probabilities. The changes required to convert the discrete frequency estimates to the cumulative, continuous case are presented after the example.

The use of discrete frequency and cost estimates allows us to construct numerous hypothetical plants by combining the different subcases. The estimated costs and frequencies of the subcases can be used to give us estimated costs and frequencies of entire plants. To make this clearer, a portion of the cost breakdown for coal-fired boilers is extracted without explanation and in abbreviated form. For a full explanation of these subcases see the Technology Appendix. The plant costed out is sized at 100 MMBtu/hr and all costs are in thousands of 1977 dollars.

Case A1 - New Plant

- subcase Ala -- Freq - .3, cost - 320: minimal site preparation, straightforward construction of power house.
- subcase Alb -- Freq - .6, cost - 380: site is on sloped or rugged terrain, significant amount of grading and leveling.
- subcase Alc -- Freq - .1, cost - 500: several site difficulties, unstable soil, rugged and sloped terrain.

Case A2 - Existing Plant, Different Technology

- subcase A2a -- Freq - .3, cost - 340: Expansion planned site preparation done in advance, expansion of power house required.
- subcase A2b -- Freq - .5, cost - 390: Expansion unplanned, moderate grading, no special problems.

subcase A2c -- Freq - .2, cost - 550: Expansion unplanned steeply sloped or rugged site; or possibly a lack of available space.

Case A3 - Existing Plant, Same Technology

subcase A3a -- Freq - .4, cost - 300: Expansion planned, site prep. done, extend power house.

subcase A3b -- Freq - .4, cost - 350: Expansion unplanned, site prep. needed, extend power house.

subcase A3c -- Freq - .1, cost - 500: Expansion unplanned, significant site difficulties, may need to remove the old boilers.

Component B - Technology Specific Equipment - Boiler Related Equipment

Case B1 - New Plant

subcase B1a -- Freq - .3, cost - 1,000: No redundancy, one boiler provides the addition to total capacity.

subcase B1b -- Freq - .4, cost - 1,700: Two boilers

subcase B1c -- Freq - .3, cost - 2,400: Three or more boilers.

Case B2 - Existing Plant, Different Technology (same subcases as B1)

subcase B2a -- Freq - .5, cost - 1,000: one boiler.

subcase B2b -- Freq - .4, cost - 1,700: two boilers.

subcase B2c -- Freq - .1, cost - 2,400: Three or more boilers.

Case B3 - Existing Plant, Same Technology

subcase B3a -- Freq - .5, cost - 1,000: One boiler

subcase B3b -- Freq - .4, cost - 1,700: Two boilers

subcase B3c -- Freq - .1, cost - 2,400: Three or more boilers.

If we were to assume that these two components are independent and that they completely define the expansion of coal burning capacity either by the construction of a new plant, or the expansion of facilities in an existing plant; then we could use this information to construct a series of hypothetical plants by combining the listed subcases. The plant frequency and cost would be determined by the estimated frequency and cost of each subcase. The calculations for three hypothetical plants and the possible combinations for all new plants are shown in Table II-3.

Similar tables can be constructed for the other two cases, i.e., Existing Plants Different and Same Technology. New plants will probably exhibit less variability than the other two cases due to their construction economies of scale and their comparative flexibility.

When the frequency and costs are specified for the other cost components a full complement of hypothetical plants can be costed out with their estimated frequency of occurrence. For this procedure to work the cost components must be independent. In most cases there will be a significant amount of interdependence among the components, but most of the interdependence can be handled by restricting the combinations of subcases, or by combining two interdependent components into one larger component. In the previous example for coal fired boilers, subcase Alc, severe site difficulties, might preclude the installation of three or more boilers. One could then specify that subcases Alc and Blc could never occur simultaneously. If one thought that whenever severe site difficulties occurred, only one boiler would be installed one could specify that Alc and Bla always be combined together. To better understand this type of

TABLE II-3

HYPOTHETICAL PLANT COST CALCULATIONS

New Plant 1 - subcases Ala, Blb: freq = $(.3)(.2) = .06$

cost = $320 + 1,000 = 1,320$

New Plant 2 - subcases Ala, Blb: freq = $(.3)(.4) = .12$

cost = $320 + 1,700 = 2,020$

New Plant 3 - subcases Ala, Blc: freq = $(.3)(.3) = .09$

cost = $320 + 2,400 = 2,720$

All New Plants

New Plant #	Subcases	Cumulative Freq.	Total Cost ($\times 10^3$ dollars)
1	Ala, Bla	.09	1,320
2	Alb, Bla	.27	1,380
3	Alc, Bla	.30	1,820
4	Ala, Blb	.42	2,020
5	Alb, Blb	.66	2,080
6	Alc, Blb	.70	2,520
7	Ala, Blc	.79	2,720
8	Alb, Blc	.97	2,780
9	Alc, Blc	1.00	3,220

restriction please see the technology appendix concerning estimation of the cost frequency distribution for coal fired boilers and how the interdependencies were handled in that case.

In the final application of this methodology it was found to be more appropriate to express the frequency estimates as a cumulative distribution for each cost component. For example, assume our cost and frequency estimates are:

Case A1 - New Plant - Site Preparation and Power House
subcase Ala -- Freq. - .4, cost 320
subcase Alb -- Freq. - .4, cost 380
subcase Alc -- Freq. - .2, cost 500
subcase Ald -- Freq. - .0, cost 625

This implies that the lowest possible cost for the power house and site preparation is \$320,000 and that forty percent of the plants will have a cost between \$320,000 and \$380,000. Another forty percent will incur costs between \$380,000 and \$500,000 and finally twenty percent of the plants will have a cost between \$500,000 and \$625,000.

This method results in continuous distributions for each cost component. The distribution of total technology cost is then calculated by the convolution operation^{1/}. It was felt that this continuous distribution approach yielded better frequency estimates, and it anchored the distribution around a base cost that was more accurately estimated.

This methodology has several advantages. The cost components "A" through "G" in Table II-2 and the three cases New Plant, Existing Plant Different Technology, and Existing Plant Same Technology, are general enough to apply across

^{1/} See Chapter IV.B.

most technologies. However, not every cost component will be applicable to each technology. For example, solar technologies would not have any fuel handling costs, therefore all 1's would go in the frequency slots and 0's in for the costs.

It is also easier to estimate the costs and frequencies of the underlying cost components represented by the subcases than to determine costs and frequencies of plants representing an aggregate of these assumptions. One reason for this is that it is hard for a person to imagine all the possible plants that should be considered. If discrete frequencies are used then seven cost components each with three subcases allows us to obtain frequency and cost information on a possible 2,187 hypothetical plants.

This systematic approach to the determination of the ISTUM cost distributions allows for a more explicit statement of the assumptions, and it makes for easy cost sensitivity analysis by compartmentalizing the costs.

The ISTUM cost estimation procedure can be viewed as a four stage procedure:

- Stage 1 - The identification of the significant cost components of a particular energy technology
- Stage 2 - The arrangement of the cost components into independent combinations.
- Stage 3 - Estimation of the frequency of occurrence of each of the independent component combinations.
- Stage 4 - The construction of hypothetical plants by combining the cost components. Each hypo-

thetical plant will have an estimated frequency of occurrence and an estimated cost. These points are then used to determine the final cost frequency distribution.

This procedure was the basis for the capital cost estimates in each service sector. Available time and to a larger extent available data somewhat limited its application in many service sectors. This formulation in its complete form was used to estimate the costs of oil, gas and coal power systems in the steam sector. Of interest is that all three cases (New Plant, Old Plant) generated nearly the same distribution (See Table II-4). This resulted from each of the cases having offsetting cost advantages and disadvantages. This tended to make each final cost distribution very similar. For example, the new plant case obtained construction economies of scale, but this savings was offset by a higher mean equipment cost since they were more likely to require redundant equipment for increased reliability. (Old plants would probably be able to place old equipment into backup mode, obviating the need to construct a backup system from scratch.) This allowed us to simplify the calculations by examining only one case in the remaining service sectors. The new plant case was chosen since it seemed to be the most representative^{1/}.

C. Determination of a Technology's Market

In delineating the market in which a technology can compete on a technical basis the major segmentation is by service

^{1/} For some technologies the distinction among plant cases is probably more important. This is true for solar, which old plant sites are unlikely to have enough room for. In any case, there is not data available on the relative frequency of the three cases, implementing the three cases will require an extensive data and modeling effort.

TABLE II-4

CUMULATIVE FREQUENCY DISTRIBUTIONS FOR 100 MMBtu/hr. COAL STEAM SYSTEM USING DISCRETE FREQUENCY ESTIMATES

I. New Plants ^{1/}		II. Existing Plants				III. Total of All Three ^{4/}	
Cumulative Frequency	Capital Cost (x 10 ³)	Different Technology ^{2/}		Same Technology ^{3/}		Cumulative frequency	Capital Cost (x 10 ³)
		Cumulative Frequency	Capital Cost (x 10 ³)	Cumulative frequency	Capital Cost (x 10 ³)		
0.03	6,124	0.06	6,291	0.09	6,029	0.02	6,121
0.07	6,503	0.14	6,657	0.16	6,197	0.08	6,363
0.12	6,595	0.22	6,775	0.27	6,449	0.11	6,559
0.15	6,781	0.30	6,969	0.32	6,551	0.16	6,723
0.23	7,022	0.34	7,082	0.38	6,688	0.23	6,882
0.26	7,080	0.39	7,221	0.45	6,780	0.26	7,004
0.30	7,133	0.46	7,333	0.49	6,957	0.31	7,082
0.37	7,327	0.49	7,450	0.52	7,041	0.35	7,221
0.47	7,435	0.53	7,552	0.56	7,137	0.42	7,340
0.51	7,569	0.57	7,617	0.62	7,300	0.49	7,442
0.53	7,601	0.63	7,725	0.66	7,381	0.52	7,528
0.55	7,682	0.67	7,897	0.69	7,467	0.56	7,608
0.63	7,879	0.69	8,001	0.71	7,538	0.59	7,718
0.68	7,925	0.72	8,074	0.74	7,646	0.64	7,863
0.74	7,995	0.74	8,133	0.79	7,779	0.71	7,944
0.78	8,151	0.78	8,211	0.82	7,887	0.75	8,054
0.79	8,231	0.84	8,447	0.85	7,997	0.77	8,148
0.82	8,454	0.86	8,588	0.86	8,102	0.80	8,263
0.87	8,492	0.88	8,672	0.89	8,229	0.83	8,447
0.90	8,567	0.89	8,753	0.91	8,366	0.89	8,547
0.93	8,756	0.92	8,913	0.93	8,502	0.91	8,716
0.95	9,073	0.96	9,159	0.95	8,715	0.93	8,913
0.97	9,158	0.96	9,383	0.97	8,964	0.96	9,143
0.99	9,699	0.99	9,813	0.99	9,346	0.98	9,600
1.00	10,688	1.00	10,923	1.00	10,957	1.00	10,923

1/ 25 plants are displayed out of a total 324 plants.

2/ 25 plants displayed out of 324 total.

3/ 25 plants displayed out of 648.

4/ 25 plants out of 1296.

sector. A service sector groups together applications which require a similar energy form, for example, steam or clean direct heat. If a technology is capable of supplying the appropriate energy form it is allowed to compete in that service sector. A further breakdown is achieved by subdividing the service sector into two digit SIC's. A technology may compete in one or all of the industries. For example, black liquor and bark boilers compete in the steam sector, but are restricted to the paper industry. When appropriate the service sector is also divided into size and load factor categories.

For some technologies this market segmentation was inadequate. To incorporate other limiting factors a maximum market fraction is used. Factors that could result in a maximum market fraction less than one are geographical and climatological considerations, technical characteristics such as reliability requirements or temperature limitations, and environmental constraints. A good example is coal boilers where two factors, environmental restrictions and lack of available land for coal storage, result in a maximum fraction of .7. The maximum market fraction is also used to limit the market for conservation technologies. For example, if a conservation technology improves the efficiency of a process by ten percent then even if all applications adopt this conservation technology it would only supply ten percent of that service sectors energy demands. Therefore its maximum market share is placed at ten percent.

D. Other Technology Data

To complete the technology characterization estimates of the date of commercial availability, fuel efficiency, the

construction period and the life of the physical equipment are needed.

The "date of availability" is defined as the year in which a technology is fully available for commercialization. This requires the following sequence to have occurred.

- a. Appropriate pilot plants must have been built and successfully operated, to prove technical feasibility.
- b. At least one full scale demonstration plant must have been built and operated under field conditions. It must have been operated for a year, or long enough to give some indication of reliability.

In the case of certain technologies, the basic principles are well established but particular applications have not been proven. An example is low Btu gas. The technology for its production is well known, but its use for various direct heat applications has not been proven.

- c. After a demonstration plant has been built and operated, further time must elapse in which to build units with solely private funding.

For the base case run in this report, the year of availability was assessed optimistically. A full Department of Energy pilot and demonstration plant program was assumed.

The fuel efficiency of a technology is expressed in terms of Btu's of fuel in to Btu's of service demand out. These may include several stages each with a different efficiency. For

medium Btu coal gasification in the steam sector you have the gasifier with a fuel efficiency of .90, the distribution system with an efficiency of .94 and the gas boiler with an efficiency of .82. The overall fuel efficiency of the technology is then $(.90)(.94)(.82) = .69$.

For the estimates of construction time and the life of physical equipment, conventional industrial estimating procedures were used.

E. Discussion of Technology Groups

This section provides an overview of the technologies that compete in the ISTUM model. The model encompasses many diverse energy technologies. Some fit well into the model logic, others presented significant problems. The major assumptions, issues and possible biases are presented in this main report, while the detailed derivation of the cost frequency distributions are contained in the technology appendix.

To help with the interpretation of the results the technologies have been grouped in the following manner:

- Conventional Technologies (proven) - This classification includes technologies that are "proven" on a technical basis and are currently being used commercially.
- Conventional Technologies (unproven) - These are technologies based on conventional firing systems which may be feasible in new applications. They also are not part of any DOE research or demonstration program. The major examples are the use of direct coal combustion to provide direct heat.

- Fossil Energy Technologies - this classification includes the new fossil fuel technologies that are in DOE's research, development and demonstration program.
- Conservation Technologies - this includes a wide spectrum of technologies that are a part of DOE's industrial conservation program. They primarily are involved with using or reducing waste heat, but no one generalization covers all the technologies in this group.
- Cogeneration, Self-generation Technologies - all of the technologies in this classification are involved with in-plant generation of electricity. Cogeneration technologies generate steam in addition to electricity.
- Solar-Geothermal Technologies - these include all the technologies directly driven by solar or geothermal energy.

1. Conventional Technologies

The conventional technologies are, in general, the best documented in the model. They are technologies that are currently being used or, if they are unproven, are new applications of basically conventional techniques. Given adequate time, enough data should exist to allow for very accurate estimation of the economic and operating characteristics of these technologies. The ISTUM time constraint only allowed a thorough cost formulation in the steam and space heat service sectors. For the indirect and direct heat applications our technology characterizations are largely based on work previously done by EEA on non-boiler applications in

support of the National Energy Plan. Often this data was not in a form compatible or consistent with ISTUM. To compensate for this, the data was normalized using natural gas costs as a baseline, but the incremental differences between coal, oil and gas technologies were maintained. Other small adjustments in these cost estimates were made to maintain a consistent set of assumptions, but generally these cost estimates were not broken out in the same level of detail as the costs generated for the steam technologies. This tended to limit the application of the cost component methodology in the indirect and direct heat service sectors.

a. Conventional Coal Technologies

In the ISTUM model the coal technologies are divided into two categories, proven coal applications and unproven applications. The proven technologies are primarily boiler related applications while the unproven technologies are direct heat and indirect heat applications. In the past actual industrial use of coal in non-boiler uses has been limited to only a few applications, primarily in the stone, clay and glass industry. The use of coal in other non-boiler applications is still unproven.

There are several technical problems for coal to overcome before it can be widely used in the indirect and direct heat applications. While natural gas can be used to fuel any size burner and will produce a clean and even flame, coal requires a larger burner to allow for sustained combustion. This can cause problems by not providing adequate flame control and by not allowing for appropriate heat distribution. Other problems are related to fuel contaminants.

Vanadium and sulfur can accelerate corrosion of metallic furnace parts. Coal ash can cause product contamination, corrosion, lining refractory walls and plugging.

As a result of these technical problems the date of availability for these coal applications is assumed to be 1982. Two exceptions are brickfiring, assumed to be available in 1980, and low temperature coal capable indirect heat, with an availability date of 1981. There is another indirect heat service sector which is considered coal incapable. This service sector includes indirect heat applications such as the production of ammonia and ethylene where the extremely high temperatures cause even very small amounts of ash and sulfur to be highly corrosive^{1/}.

b. Conventional Oil Technologies

The use of conventional oil appears as a technology in every service sector. They are all assumed to be proven and currently available. The only limitation placed on the oil technologies is the assumption that the Energy Supply and Environmental Coordination Act (ESECA) will effectively prohibit the use of oil in boilers larger than 100 MMBtu/hr. Additional information on the effects of ESECA is contained in Chapter V.

The ISTUM model makes no distinction between residual and distillate oils. The use of residual oil is the basis for all capital costs. This aggregation of distillate and residual oils together presents problems in two service

^{1/} Much of this information was obtained from: "The Potential for Natural Gas Substitution" prepared by Energy and Environmental Analysis for the Department of Commerce, Dec. 20, 1977.

sectors, the intermediate direct heat service sector and the coal incapable indirect heat service sector. The capital costs for oil in intermediate direct heat includes an air to air heat exchanger to avoid product contamination. If distillate oil is used there is no need for a heat exchanger. It can be burned directly resulting in lower capital costs and a higher efficiency. In the coal incapable indirect heat service sector the high temperatures require the removal of the trace metals and sulfur from residual oil to prevent furnace corrosion. Distillate oil doesn't contain these contaminants and can be burned directly.

c. Conventional Natural Gas Technologies

Natural gas is the most convenient fuel. There are no technical limitations to its use in any size or application. Natural gas is currently the most widely used industrial fuel and this makes available a large amount of data. As a result the costs associated with natural gas were used as a baseline cost for the indirect and direct heat service sectors. The costs of the other technologies were calculated by the increment in which they were expected to exceed the natural gas costs.

The use of natural gas in new applications was limited as the result of two factors. Like oil, it was assumed that the Energy Supply and Environmental Coordination Act would prevent the use of natural gas in boiler applications larger than 100 MMBtu/hr. It is also assumed that federal regulation of natural gas will be phased out, with complete deregulation occurring in 1986. Consistent with this regulatory scenario, supply shortfalls of natural gas are assumed in 1980 and 1985. In the period 1976 to 1980, only 25 percent of all

industries that want natural gas hookups are assumed to be able to obtain them. In 1981-85 this restriction is reduced to 50 percent and in 1986-90, with the deregulation of natural gas, there is no limitation placed on the number of new gas hookups.

d. Other Conventional Technologies

Several additional conventional technologies are allowed to compete for new energy demand in specific service sectors. In the steam service sector, black liquor and wood burning boilers compete in the paper industry. An electric heat pump is included in the space heat service sector and a captive gas technology is competed in the steel reheat service sector.

2. Fossil Energy Technologies

There are three technologies in this grouping, atmospheric fluidized bed combustion, low Btu coal gasification and medium Btu coal gasification. All of these technologies are currently supported by DOE's research, development and demonstration program.

a. Atmospheric Fluidized-Bed Combustion

Fluidized-bed combustion is currently the subject of much research and development. A DOE supported pilot plant is now in operation, but atmospheric fluidized-bed combustion is not assumed to be commercially available for industrial use until 1982.

The basic design of the system calls for the bed to be comprised of crushed limestone or dolomite and large ash particles. The bed is "fluidized" by a stream of air rising

through a supporting grid beneath the bed. The gas velocity and pressure^{1/} are set to keep the particles suspended, without blowing them away. The bed is then heated up to combustion temperature and coal is fed into the bed. The resulting mixture has properties similar to a boiling liquid. The bed turbulence produces very good heat transfer by continually replacing the cooled particles around the tubes or heating surface with particles at actual bed temperature. Boiler tubes submerged in the bed remove heat at a very high rate which allows for low combustion temperatures, smaller furnace volume and less required tube surface. The smaller combustion equipment needed and the use of modular beds should allow for shop fabrication of the major boiler equipment. This cost savings may be offset by the need to use more expensive alloys to withstand the higher surface temperatures resulting from the higher heat-transfer rates, and to prevent erosion of the submerged tubes by the bed particles.

The main advantage claimed for atmospheric fluidized bed is that it allows for the combustion of the coal in contact with a chemically active sulphur capturing agent, usually limestone or dolomite. This process makes effective SO₂ control possible without having to resort to a wet scrubber. However, a wet scrubber can achieve sulphur absorption efficiencies of 95 percent where fluidized-bed incurs prohibitively high sorbent related costs at efficiencies above 90 percent. In our baseline case only an 80 percent SO₂ standard was enforced, resulting in competitive fluidized-bed costs. One possible disadvantage to the use of fluidized-bed is that limestone and dolomite from different sources

^{1/} For atmospheric fluidized bed the pressure is about one atmosphere.

vary in their ability to reduce sulfur emissions and resist size degradation to avoid being blown out of the bed.

Another potential problem for fluidized-bed is the design of an operational coal feed system. Good operation of fluidized-bed requires uniform distribution of the bed material. If the coal is introduced at one spot uniform distribution cannot occur. An estimated 40 feedpoints would be required for a 250 MMBtu/hr unit. The coal would need to be crushed, divided equally into 40 streams and then fed uniformly into the furnace.

To achieve good temperature control and turndown a compartmentalized bed system is being proposed. To meet different load requirements, a different number of bed cells are fluidized. Multiple beds require additional duct work, dampers and other mechanical equipment to control and deliver the air to each cell. This air control system and the coal feed system tend to make the fluidized bed boilers considerably more complicated than a conventional boiler.

The atmospheric fluidized-bed combustion technology was allowed to compete in four service sectors: steam, space heat and the two indirect heats. It was not considered applicable in the direct heat service sectors. Technically it is very hard to design a fluidized bed unit that would allow materials, such as steel ingots, to pass through it and still maintain the appropriate aerodynamics. If heat exchangers are used then it must be excluded from all direct heat applications where radiant energy is required. In addition, our environmental scenario requires no sulphur removal by the direct heat service sectors and this negates much of the economic advantage that fluidized-bed may have.

There are several uncertainties still associated with this technology, primarily the design of the coal feed system and availability of suitable limestone. To the extent that these are unresolved, there remains some significant uncertainty concerning the prospective costs of fluidized bed units. The costs used in the model are favorable in that they assume no significant technical problems are encountered.

b. Low Btu Gasification

The use of low Btu gas produced from coal competes as a technology in every service sector. Different methods of producing low Btu gas are available and some components of the production process have been used for decades. There is not much technical uncertainty associated with the production of the gas, although reliability may pose some concern.

The LBG production process assumed in the model is a fixed bed system. This technology has been available for over two decades and is the one most often considered for industrial applications due to the small sizes available, high reliability, and simplicity of operation.

i) Production and Use

In calculating the costs associated with the use of LBG the cost of the gasifier and required gas cleanup was determined, then the costs of the conventional natural gas combustion system were added to these. The assumption is that the cost of a natural gas combustor is a good estimate of a combustor capable of utilizing LBG. These combustor estimates are probably slightly low. LBG has different combustion properties than does natural gas. LBG may require

larger combustion volumes, different burners, larger flues, bigger recuperators or preheating of the gas. In many applications the differential costs are minimized by using preheated gas or the hot, raw gas along with preheated air since this combination combusts more like natural gas. Also, LBG is known for a "lazy" flame which produces even heat. In applications where even heat is desired the use of LBG may result in simpler burner configurations than those required for natural gas.

The production of low Btu gas, even though the gas is produced on site, is still a fuel supply technology rather than a final use technology. This can be a problem for the model methodology. For example, one large low Btu gasifier could be built at a petrochemical plant with the low Btu gas being used to fuel all of the plant's process applications. These process uses may cut across the service sector divisions. The gas can be used in indirect heaters, in direct heat applications, or to produce steam, all at the same plant. The model methodology sizes the low Btu gasifier to meet the demands of the specific process represented by the service sector in which it is competing. To the extent that economies of scale are significant, this procedure may overstate the capital costs for low Btu gas production in certain industries. However, most economies of scale are exhausted at relatively small gasifier sizes, say 150 MMBtu/hr. Therefore the bias is probably slight.

ii) Cleanup

Other considerations concern the gas cleanup required. The product gas may either be used in its raw form with any impurities conveyed to the burner, or the gas may be cleaned.

The cleaner the gas, the fewer problems associated with using the gas. There are three cleanup options. One is to burn the hot raw gas directly. Extreme care must be taken to keep the gas hot to prevent the tars and oils from condensing out and clogging the pipes or burners. This prohibits transporting the gas for more than a few hundred feet. In this arrangement the production of the hot raw gas normally has an efficiency around 90 percent.

The second option is to remove the tars and oils from the gas. A water wash and electrostatic precipitator are used to condense and remove the tars and oils. Essentially no sulfur is removed by this process. The removal of the tars and oils makes the gas more transportable and reduces the risk of clogging. With tar and oil removal the coal to gas efficiency is around 76 percent.

The third option is to produce a "clean" gas where the oils, tars and sulfur are removed. The process assumed for this is to water wash the raw gas, run it through a precipitator, chemically wash it to remove hydrogen cyanide and then use a Stretford system to remove the sulfur. The hydrogen cyanide must be removed for the Stretford system to be effective. The coal to gas efficiency is usually around 74 percent, or nearly the same as the detarred-deoiled gas. The major loss of efficiency is due to the tar and oil removal.

In each service sector the gas cleanup system chosen reflects what was assumed to be the most favorable system economically, subject to the technical and environmental requirements of that service sector. For example, in the steam sector where 80 percent sulfur removal is required

two options were available. The sulfur can be removed before combustion providing a clean gas for use, or the hot raw gas can be combusted and the resulting flue gases scrubbed to remove the SO_2 . The capital cost of the two systems are virtually the same, but the reduction in efficiency from 90 percent for the raw gas to 75 percent for the clean gas results in a significant increase in fuel costs over the lifetime of the equipment. The most favorable economics for low Btu gas in the steam sector occurs when the hot, raw gas is used with its resulting higher efficiency. To meet the SO_2 removal requirement a flue gas scrubber is used. However, not all steam applications are capable of burning the hot, raw gas. Some plants may not be able to locate the gasifier close enough to the boiler house to prevent the tars and oils from condensing out. In addition, industries that place a high premium on reliability may be averse to using the raw gas with its danger of clogging. To compensate for these factors a maximum fraction of .5 was assigned to low Btu gas in the steam sector. Little information is currently available regarding the reliability of combusting the hot, raw gas and industry's willingness to assume that risk.

The gas cleanup systems that were assumed for each service sector are as follows:

- Steam and Space Heat - the raw gas is burned in the boiler with the fuel gases being scrubbed to remove the SO_2 . In each service sector a .5 maximum fraction adjusts for applications where use of the raw gas is infeasible. (Since LBG would not be competitive for steam if raw gas cannot

be directly combusted, this technology combination was not considered).

- Intermediate Direct Heat - Clean gas is burned. The tars, oils and sulfur are removed to prevent product contamination.
- Indirect Heat/Coal Incapable - To prevent corrosion at the high temperatures which these processes require, the gas must be detarred and deoiled. As long as this process condenses out all the vanadium oxides there is no need for additional sulphur removal. Sulphur will present corrosion problems only when acting in combination with vanadium.
- All Other Service Sectors - in all of the other direct and indirect heat applications it was assumed that the hot, raw gas could be combusted directly.

c. Medium Btu Coal Gasification

The MBG production process is very similar to LBG. The only difference is that oxygen is fed into the gasifier instead of air. This substitution removes the diluting nitrogen, resulting in a gas with a higher energy density (more Btu's per standard cubic foot). The requirement of an on-site oxygen generating facility greatly increases the capital costs of coal gasification. This causes MBG to be viable only at large sizes. An LBG unit is more economic in the production of gas up to a size of 36 trillion Btu's per

year^{1/}. However, the greater Btu/ft³ content makes MBG cheaper to transport.

MBG's most economic application is probably as a retrofit technology. The combustion properties of medium Btu gas allow it to be burned in conventional natural gas boilers with only slight equipment modification. An MBG plant could either be built on-site for large plants, or in an industrial park for several plants and fuel processes formerly using natural gas, or fuel oil. If the economics favor a switch from natural gas and oil to coal fueled systems, it may be cheaper to use medium Btu gas rather than replace their existing equipment with direct coal capable or low Btu gas capable combustors. Since the present version of ISTUM does not deal with retrofit applications the potential market for MBG is considerably understated.

To determine the potential market for on-site production and use of MBG in grass roots industrial plants an estimate of the number of new plants that could use 36 trillion Btu's per year of medium Btu gas is needed. There are five industries that have existing plants with a total energy consumption of 36 trillion Btu's per year (Table II-5). Further examination of these five industries, steel, ethylene, petroleum, chlorine and aluminum led to the conclusion that there was no significant market for on-site production and use of MBG among new grass roots plants. Most of these plants that currently exist at the required size were the result of one or more expansions and were not originally built at a size greater than this MBG

^{1/} Estimate from "Production and use of Low and Medium Btu Gas" presented at the 5th Energy Technology Conference, by Gilbert Associates, February 27, 1978.

TABLE II-5

TOTAL ENERGY USAGE IN INDIVIDUAL INDUSTRIAL PLANTS^{1/}(10¹² BTU/yr)

Industry	Total Number of Plants	Number of Plants in Each Range					
		<10	10-20	21-35	36-50	51-80	>80
Steel	187	124	9	13	12	7	22
Ethylene	33	7	2	10	4	6	4
Petroleum Refining	258	171	44	23	7	7	6
Ammonia	85	60	20	5	0	0	0
Chlorine	64	53	10	0	0	1	0
Carbon Black	34	29	5	0	0	0	0
Styrene	14	10	2	2	0	0	0
Cement	172	171	1	0	0	0	0
Paper	727	714	13	0	0	0	0
Aluminum	<u>31</u>	<u>6</u>	<u>14</u>	<u>7</u>	<u>1</u>	<u>3</u>	<u>0</u>
TOTAL	1605	1345	120	60	24	24	32

^{1/} Fuels and Feedstocks included, except for exclusion of feedstocks in petroleum refining. Non-fossil fuels in the paper industry excluded.

SOURCE: "Data Sources and Methods for Industrial Energy Analysis", prepared by Energy and Environmental Analysis, Inc., for the Division of Fossil Energy, ERDA, January 31, 1977.

threshold.

The steel industry is an unlikely candidate for a new grass roots plant capable of using an on-site MBG facility since it is currently undergoing little growth. Also, two thirds of the total energy used by the steel industry is in the form of metallurgical coal and its process by-products, coke and captive gas.^{1/} For a steel plant to require 36 trillion Btu's of medium Btu gas per year, it would have a total energy demand of around 108 trillion Btu's per year. It is unlikely that a grass roots steel plant of this size will be constructed in the next twenty years.

Ethylene production is not a potential market for on-site MBG production since all new ethylene plants will use either naphtha, fuel oil or desulfurized crude oil as the feedstock instead of LPG. The use of these feedstocks will furnish enough process by-products to supply all the fuels required for energy needs in these plants.

Petroleum refining is a potential application of on-site MBG production, however most refineries have combustible by-products and few new grass root refineries are being constructed. The current industry growth is primarily the result of the expansion of existing refineries.

In the production of chlorine and aluminum it is unlikely that many new plants will be built at the size required for economic on-site production of MBG. In addition, the fuels consumed in these industries are used primarily for the production of electricity. It is likely that conventional coal

^{1/} Energy Consumption Data Base, by Energy and Environmental Analysis, Inc. for the Federal Energy Administration, June, 1977. See also Volume III.

boiler steam turbine combinations will prove more efficient than MBG fueled boilers and turbines at large sizes.

With little or no market existing for the on-site production and use of MBG, the most likely scenario for the MBG facility involves supplying gas for an industrial park comprised of several plants. This considerably complicates the investment decision process. It would involve several industrial customers working together to decide on the size, design and location of the facility. This presents many potential areas of conflict. Also, the plants would have to coordinate their planned maintenance and production to correspond to the MBG plants scheduled maintenance. To be successful this type of industrial consortium would need stable industries with high, even load demands.

Even under the best conditions a consortium may fail due to management not wanting to increase the number of variables outside their control. Each industry would be dependent upon the others buying their share of gas and not having financial difficulties. Users would have to commit themselves to long-term contracts for fixed amounts of gas. They may not want to make a twenty year commitment in a changing technological and economic environment. These issues are complex and varied. A more complete discussion can be found in papers by Energy and Environmental Analysis^{1/} and SRI International^{2/}.

1/ Market Potential for Low and Medium Btu Gas, by Energy and Environmental Analysis, Inc., October 27, 1977.

2/ Market Opportunities for Low and Intermediate Btu Gas from Coal, by Stanford Research Institute, October 1977.

The approach taken in ISTUM involved the construction of a series of hypothetical industrial parks which could be fueled by an MBG plant. Since our costing procedure assumes a "normal" return on equity which is constant across industries, it makes no difference to the analysis whether the MBG plant is viewed as a "producer-user" who makes gas for its own use in addition to selling to other users, or as a plant devoted exclusively to selling gas to end users. However, if utility financing assumptions are used rather than standard industrial financing procedures then the costs may be different.

Three sizes of MBG plants were costed out, 50 billion Btu/day, 100 billion Btu/day and 250 billion Btu/day. The 50 billion Btu/day plant proved not to be competitive and was dropped in the final run. At each of these sizes three distribution systems were costed out. Distribution costs were a significant portion of total MBG costs and they were also subject to wide variation. If the gas pipelines are to be installed in developed areas the cost may be very high. Streets may have to be torn up and repaved, or other underground pipes and cables cut or avoided at additional expense. Also, obtaining the necessary right of ways for the pipelines may prove difficult and expensive.

Once production and distribution costs are obtained, a decision must be made concerning how these costs are to be apportioned among the final users. Several options are available. Industrial plants farther away from the MBG producer could be charged more for a unit of gas, reflecting the increased distribution costs, or each user could be charged the same rate for each cubic foot of gas. There are many items to be considered before an efficient pricing scheme can be devised. What is best in one case, may be inequitable in another. For

the ISTUM model, the simplest pricing method was chosen. Each industrial customer was charged for whatever proportion of total gas output they consumed. For example, if the MBG plant produces 100 billion Btu/day and the industrial user consumes 10 billion Btu/day then the user incurs one tenth of all costs associated with the MBG production regardless of location. To obtain the final cost distribution, the cost of the conventional natural gas combustor in the same service sector was added on to the MBG production and distribution costs.

Recall that the incorporation of low Btu coal gasification into ISTUM presented a problem by having instances where the same gasifier could supply combustors that are in different service sectors, but still at the same plant. Since ISTUM sizes the gasifier to meet the fuel requirements of each combustor, economies of scale that could be obtained were neglected in estimating the cost of the gasifier. This does not present a problem for MBG due to the pricing scheme. By distributing the MBG costs proportional to the amount of gas consumed, there are no economies of scale for individual industrial plants in an industrial park.

In all cases the medium Btu gas produced was clean gas with tars, oils and sulphur removed. For an MBG plant to supply two streams of gas, one clean and one dirty, would be uneconomic since it would require much duplication of the distribution system. The clean gas guarantees that the MBG plant could meet the specific fuel requirement of any customer, and since there are economies of scale associated with gas cleanup, the cleanup is done at the MBG plant. Also, it is assumed that MBG is commercially available in 1983, one year later than most LBG applications. This reflects the larger size and longer construction time required for MBG.

3. Conservation Technologies in ISTUM

A portfolio of 33 conservation technologies was developed for the ISTUM base case. The majority of these technologies compete in the steam, intermediate direct heat, dirty direct heat, calcining or steel reheating service sectors.

These conservation technologies, as a group, present a severe test to any comprehensive industrial energy model. Unlike new fossil technologies or ISTUM conventional energy systems the conservation strategies are typically designed for a specific process within a single industry. Many of the conservation technologies incorporate difficult to evaluate but significant non-energy factors, related to environmental control, production capacity, and institutional relationships. In addition, only a handful of conservation technologies were supported by outside documentation. These factors made the specification of conservation technologies in a form compatible with ISTUM very difficult.

The conservation portfolio, listed in Table II-6, was selected with three guiding criteria. First, conservation technologies had to be reasonably compatible with ISTUM model logic. Second, only DOE projects that were well defined and based upon "hard" data were accepted. Finally, in the limited time available for technology specification, EEA endeavored to include proposals with the potential for major energy impact. The ISTUM conservation portfolio is therefore representative of DOE sponsored industrial conservation projects, but includes only a part of the entire federally funded program.

Incompatibilities with ISTUM model logic caused some technologies to be removed from the conservation portfolio. For

TABLE II-6
CONSERVATION TECHNOLOGIES IN ISTUM

<u>Service Sector</u>	<u>Technology</u>	<u>ISTUM I.D.</u>
Steam	Boiler Air Fuel Controls	2.11
	Heat Pump for Steam	2.21
	Poultry Process Modification	2.31
	Blast Furnace Conversion for MBG (Steam)	2.41
	Headbox for Paper	2.51
	Pulp Paper Characterization	2.61
	Hyperfiltration	2.71
	Low Level Heat Pump for Steam	2.81
	Foam Fiber Technology	2.91
Clean/Intermediate Direct Heat	Heater Air/Fuel Controls	2.12
	Coal in Aluminum Remelt	2.22
	High Temperature Recuperators	2.32
	Heat Pump - Brayton Cycle	2.92
Dirty Direct Heat	Heater Air/Fuel Control	2.13
	High Temperature Recuperators	2.33
	Paper Pulp Sludge Drying	2.43
Electrolytic	Direct Reduction of Aluminum	2.46
	Aluminum Smelter Modification	2.56
Liquid Feedstocks	Lube Oil Recovery	2.57
Non-Coal Indirect Heat	Heater Air/Fuel Controls	2.113
	Polypropylene Waste to Fuel	2.413
Calcining	High Temperature Recuperators	2.413
	Refuse Derived Fuel in Cement Kilns	2.414
	Blended Cement	2.514

TABLE II-6 cont.
CONSERVATION TECHNOLOGIES IN ISTUM

<u>Service Sector</u>	<u>Technology</u>	<u>ISTUM I.D.</u>
Glass Melting	High Temperature Recuperators	2.315
	Glass Conglomerates	2.415
	Flat Glass Energy Reduction	2.515
Brick Firing	Cement Block Drying	2.516
Iron Making	High Temperature Recuperators	2.317
	Cupola Furnace Modification	2.417
Steel Reheating	Blast Furnace Conversion for MBG (Steel Reheat)	2.219
	High Temperature Recuperators	2.319
	Moving Beam Furnace	2.419

example, Petroleum Refinery Energy Audits, a non-hardware DOE demonstration, could not be accurately modeled. The proposed Sterile Fluid Milk technology claimed energy benefits outside of the industrial sector (energy savings in retail and wholesale facilities) and was not suitable for ISTUM, an industrial sector model. The lack of appropriate competitive technologies prevented the inclusion of the Coal to Acetylene.

Numerous other DOE conservation proposals are in an early stage of development and lack adequate technical specification for ISTUM. DOE proposals for Waste Tire Energy Recovery, CO Conversion to Methanol, and Freeze Crystallization are some of the technologies that were not included in the ISTUM base case for this reason.

Table II-7 identifies the conservation technologies not included in the ISTUM base case, and the reasons why they were not modeled. Future development and refinement of the ISTUM model, coupled with the ongoing EEA research in technology specification and project evaluation will strengthen the conservation portfolio of the continuing ISTUM analysis.

a. The Conservation Retrofit Issue

The previous formulation of the MOPPS industrial sector model evaluated incremental demand (a combination of growth and normal capital retirement) and included a crude algorithm for estimating the pure retrofit applications of conservation technologies. Because of limited time and resources and the weakness of the original retrofit analysis, EEA limited the development of the ISTUM model to incremental demand. The lack of a retrofit algorithm understates the potential impact of conservation technologies.

TABLE II-7

MAJOR CONSERVATION TECHNOLOGIES NOT INCLUDED IN ISTUM^{1/}

<u>Reason for Omission</u>	<u>Technologies</u>
Insufficient technical data because proposal is being redefined or is in pre- liminary stages	O ₂ Enrichment CO Conversion to Methanol N ₂ Based Carberrization CO as Feedstock Freeze Crystallization Irrigation Water Conservation Waste Heat from Slag
Non-hardware project, incompatible with ISTUM	Refinery Energy Monitor
Current ISTUM technology port- folio lacks appropriate competitors	Coal to Acetylene Heat Pump Grain Drying High Efficiency Arc Welding
Non-industrial energy savings are not compatible with ISTUM model structure	Sterilized Fluid Milk
Data quality of technology docu- mentation is marginal, or technology could not be accurately specified in limited time	Electric Arc Furnace Glass Composite Pipes Slot Forge Furnace Textile Process Modification Food Sterilization (GASPAK) Low Energy Fluid Food

^{1/} This list is representative of the projects omitted from the ISTUM base case. Many relatively new conservation proposals will not appear on either this page or in Table 1.

The importance of this ISTUM limitation is illustrated by Figure II-1. At time T_0 , all service demand is satisfied by the ongoing capital stock. Future service demand in the ISTUM model, at T_1 , is composed of three categories. The first is new demand (region A on Figure 1) required by industrial growth. The second demand category (Region B) is created by the normal retirement of old capital equipment. The remaining service demand is supplied by the ongoing capital stock (Region C) until time T_j when all capital equipment existing at time T_0 has been replaced. Under the current ISTUM model structure, technologies may only compete for incremental demand, the sum of regions A and B on Figure II-1. The ISTUM model provides no information for Region C which represents the potential market for retrofit technologies or premature retirement.

Normal retirement of old capital stock in ISTUM is determined by the capital turnover function described in Chapter IV. Premature retirement is the additional early replacement of existing equipment because of the availability of an economically superior technology. The superior technology shifts forward the optimal replacement age for the older combustion equipment. The current ISTUM model structure does not evaluate the potential market from premature retirement.

Since old industrial plants incur only variable costs once the capital investment has been paid, firms have an incentive to keep an existing plant in operation. This economic barrier is strong enough to minimize error in ISTUM projections of most major combustion equipment markets. However, a positive case can be made for retrofit applications of some conservation technologies. The excellent economics of Boiler Air/Fuel Controls combined with the simple "bolt on" character of these devices is stimulating retrofit applications. Because this

FIGURE II-1
COMPONENTS OF ISTUM SERVICE DEMAND

Region A = Service Demand From New Growth

Region B = Service Demand From Normal Retirement

Region C = Service Demand Satisfied by Ongoing
Capital Stock (the potential retrofit
market)

} ISTUM
Incremental
Service
Demand

monitoring technology operates virtually parallel to primary combustion equipment, the retirement economics of the existing capital stock may be only a minor influence on the retrofit investment decision. Other technologies with good economics, but with stronger links to the special characteristics of a particular production process, such as High Temperature Recuperators, still may have some potential as retrofit applications. ISTUM provides no clues as to the extent of the bias against these and other conservation technologies. Resolution of the premature retirement or conservation retrofit issue must wait for the planned extension of the current model.

b. Conservation Technology Specification --
Capital Cost Variability

The capital cost specifications of the conservation technologies was almost invariably weaker than the specifications of new and conventional technologies. None of the conservation proposals included detailed breakdowns of equipment components or the capital cost distributions essential for ISTUM technology specifications. EEA was supplied with only point estimates for capital costs of each conservation technology, generally based up on a proposer's preliminary estimate of the technology's lowest cost in an ideal application.

To specify the conservation technologies in the ISTUM format, EEA constructed a single primary equipment building block with a probability distribution based up on three points. The lowest capital cost represents the ideal application, generally assumed to be the proposer's point estimate. Two additional capital cost estimates and a probability distribution were added by EEA staff. The three points and probability distribution, in combination, express the subjective assessment of the equipment cost variations of all technically possible applications of the conservation device.

Since none of the conservation technologies were specified for different service demand sizes, linear multipliers were employed to scale the capital cost distributions up and down to correspond to ISTUM levels. The final cost distribution incorporated the installation variability index and indirect capital costs (components "I" and "H", common to all ISTUM technologies), which are explained in detail in the Technology Appendix.

The simple "bolt on" technologies, such as Boiler Air/Fuel Controls, Blended Cement, and Pulp Paper Characterization, may have been reliably modeled by this method of capital cost specification. For these technologies, the expected cost distributions are fairly narrow. Some of the more complicated process modifications, such as Direct Reduction of Aluminum, Moving Beam Furnace, or Paper Pulp Sludge Drying, could not be modeled accurately by capital cost distributions supported only by a point estimate. The available technology data for these complex conservation systems provided little insight as to the cost range for potential applications. In addition the lack of detailed component breakdown increased the possible errors from partial or inconsistent specification of the primary combustion equipment costs of the technology.

c. Conservation Maximum Market Fractions

The maximum market fraction represents the potential service demand share for which conservation technologies may compete. Although ISTUM service demand is segmented by industry and service sector, additional factors provide technical bounds for conservation technologies. The maximum market fraction for conservation strategies is limited by the maximum service

displacement of the technology, such as the 2 percent average energy savings of Boiler Air/Fuel Control. The availability of suitable waste heat (such as restricting high temperature recuperators) or waste material (limiting lube oil recovery) are additional factors which may constrain maximum market fractions. Conservation proposals that are technically applicable to a process subcategory within a single industry (such as Poultry Process Modification) are subject to a restriction based upon the ratio of the applicable process service demand to the service demand for the entire industry.

Multiple technical limits of the maximum market fraction for conservation strategies are common. For example, the Refuse Derived Fuel in Cement Kilns technology is restricted by three factors. First, the service demand displacement is limited for technical reasons to 30 percent, the maximum substitution of refuse fuel for conventional energy sources in the Portland Cement process. In addition, EEA estimates that only half of the cement plants in the United States could secure an adequate supply of waste fuel because of geographic or institutional reasons. Finally, the Portland Cement process is only a little more than half of the service demand in calcining service sector. The multiplicative combination ($.30 \times .50 \times .52$) of the three restrictions - maximum service demand displacement, limited availability of waste fuel, and service sector subcategory - yields a maximum market fraction of .078 for Refuse Derived Fuel in Cement Kilns.

Due to the generally favorable economics of many conservation technologies, the accurate calculation of a maximum market fraction is extremely important. If the cost distribution

for a conservation proposal is below the range of new and conventional technologies, the maximum market fraction is the only reason why the technology gets less than a 100 percent market penetration. Although this component of technology specification is important, the data supporting the calculations was often weak. For most conservation technologies, the proposer's data on technical limits or potential applicable units were the principle sources for maximum market calculations. Only limited number of calculations were supplemented by outside documentation and technical evaluations by EEA staff. Continued effort by EEA in this area will yield improved maximum market data for the entire conservation portfolio for use in subsequent refinements of the ISTUM model. Complete documentation of maximum market fractions for each conservation proposal can be found in the Technology Appendix.

d. Size and Load Factors

Other factors that constrained the applicability of conservation technologies were size and capacity utilization specifications. Typically size or load ranges were restricted when scale-up or scale-down factors were not known or did not seem reasonable. For example, Poultry Processing Modification was restricted to the 50 MMBtu/hr and 4000 Hr/Yr size and load factor categories because USDA documents indicated that virtually no plants operated beyond these limits. Headbox for Paper was restricted to the largest size and load factor in the steam sector, the only applicable paper making processes according to the proposers of this technology. These restrictions may actually improve the ISTUM market projection for a technology by placing the entire maximum market fraction in the logical model subcategory,

which is probably the best market for the technology.^{1/}
Distortions of ISTUM market projections from inappropriate competition amongst non-compatible technologies are thereby eliminated.

e. Data Quality Codes

The data quality codes for conservation technologies in ISTUM are low for two reasons, weak technology documentation and conflicts with ISTUM model logic. As noted above, much of the technology specification for conservation proposals is based upon proposer data. Often the technology is in an early stage of development and neither "bench scale" tests or engineering calculations have been completed. As a result of prior experience, EEA has concluded that the proposer data, especially estimates of expected capital costs, energy savings and potential markets, for technologies are generally very optimistic. Conservation technology specifications that were not based upon existing hardware development or could not be verified by EEA review or outside sources, received low data quality codes.

The "D" quality code is related to the second major technology specification problem, conflicts with ISTUM model logic. The current formulation of ISTUM was designed to accomodate major conservation or combustion equipment. The conservation portfolio includes several technologies with environmental

^{1/} The maximum market fraction of a conservation technology that is restricted by size or load will shift upward to compensate for reduced service demand for which it will compete. The size of the shift is based upon the size and load specifications of the particular service sector. Full explanations of these calculations for a specific technology can be found in the Technology Appendix.

control credits, material savings, production capacity changes and other non-energy related characteristics. Although some technologies were not included in the conservation portfolio because of significant conflicts with ISTUM model logic, EEA included a number of technologies with a "D" quality code to assure reasonable representation of conservation for the base case.

4. Cogeneration

a. Introduction

This section describes the manner in which industrial cogeneration and self-generation technologies were integrated into ISTUM. The section discusses the major prospects for internal electricity generation for industrial uses, thus excluding such non-industrial technologies as district heating. The section includes discussions of the special modeling problems associated with certain of the technologies and the trade-offs required to fit cogeneration into ISTUM. The section ends with a discussion of the electricity prices used in ISTUM.

Several cogeneration and self-generation technologies were considered as potentially significant energy suppliers to the industrial sector:

- 1) Steam turbine topping
 - a. coal-based
 - b. oil-based
 - c. gas-based
 - d. atmosphere fluidized bed (AFB) based
 - e. low Btu gas based (LBG)
- 2) gas turbine with waste heat boiler (export/no export)
- 3) diesel engine with waste heat boiler (export/no export)
- 4) gas turbine with organic rankine cycle system
- 5) diesel engine with organic rankine cycle system
- 6) organic rankine cycle system
- 7) self-generation
 - a. coal-based
 - b. oil-based
 - c. gas-based
 - d. AFB-based
 - e. LBG-based

Of these, preliminary analyses suggested that we exclude the organic rankine cycle system. The analyses demonstrated that, in effect, no waste heat will be available in the future to supply organic rankine cycle systems. The waste heat required to run the technology can be used by pre-heaters at a higher investment return rate than it can by organic rankine cycle systems (more will be said on this in the text). Thus the system was excluded from ISTUM.

The following will document how each of the cogeneration technologies was integrated into the ISTUM logic.

b. Steam Turbine Topping

In plants where steam is required, the boiler (or boilers) may be designed to generate higher energy steam (in Btu's per pound -- enthalpy) than demanded by its processes. The higher energy steam is expanded through a turbine, generating electricity. The steam exhausting from the turbine (the back pressure) contains the same energy content as that required for the plant processes.

To determine the electricity generation potential, three factors must be known - steam flow rate (in pounds of demand per hour), incremental enthalpy (in Btu's per pound), and turbine efficiency (dimensionless). The product of the three defines the electricity potential per plant in Btu's per hour. Because of technical and economic criteria, turbine efficiency and incremental enthalpy have limits. Thus, steam flow rate determines the quantity of electricity that can be generated per plant.

Because steam is required for the plant anyway, the costs charged for electricity generation are the incre-

mental costs of generating electricity. These include the incremental capital costs of a boiler generating higher enthalpy steam, the turbine-generator capital costs, the incremental fuel required for the higher enthalpy steam, and the incremental operating and maintenance costs. One other cost charged to electricity production is the electric utility demand charge for standby power which will be discussed below.

The sum of these costs comprise, in effect, the cost of a specific electricity generating technology, steam topping cogeneration. The total costs divided by the electricity produced via the turbine-generator constitutes the cost of steam topping in dollars per energy unit. In the ISTUM framework this technology competes in the machine drive sector with other electricity supply technologies.

As noted, the electricity generation potential per plant depends on steam flow. Turbine efficiency - the conversion of steam Btu's to electricity Btu's - is approximately 70 percent. Enthalpy increases will vary by boiler size but will be limited as follows:^{1/}

- Boilers up to 50,000 lbs per hour commonly produce steam at 1220 Btu/lb, which can be increased to 1370 Btu/lb for cogeneration (an increase from roughly 150 psi/350°F to 600 psi/700°F).
- Boilers ranging from 50,000 lbs/hr to 150,000 lbs/hr normally produce steam at 1270 Btu/lb, which can be increased to 1400 Btu/lb for cogeneration (an increase from roughly 250 psi/500°F to 900 psi/800°F).

¹ Values derived from cogeneration equipment vendor; values were reported in pressure units - a 1.58 entropy was assumed to convert from pressure to enthalpy.

- Boilers exceeding 150,000 lbs/hr normally generate steam at 1370 Btu/lb, which can be increased to 1450 Btu/lb (an increase from 600 psi/700°F to 1250 psi/950°F).

In the two smaller size ranges, the limits are caused by boiler technical constraints; in the larger size range, the limit is caused by turbine technical constraints.

Thus, for each plant size, a certain amount of electricity can be generated. Because the technology incurs economies of scale, reaching the limit in increases in enthalpy is always desirable. Therefore, a certain enthalpy increase (and thus electricity potential) can be estimated for each plant with some steam demand.

The preceding analysis sets the stage for determining a maximum market fraction for steam topping in the machine drive sector. Incremental industrial steam demand will be met by conservation and steam-generating technologies. The five relevant steam generating technologies for steam topping are coal-fired, oil-fired, gas-fired, AFB and LBG-based gas-fired boilers. The extent to which each of these boiler types penetrates the steam sector in each ISTUM size category will determine the maximum market fraction for steam topping cogeneration.

The dynamics are as follows. The steam sector market shares are "run" before the machine drive sector. Using coal-fired boilers as an example, suppose coal-fired boilers "win" 20 percent of the steam sector market in 1985.

The 20 percent market penetration for coal-fired boilers can be translated into a total amount of steam produced by coal-fired boilers by taking 20 percent of the total steam demand. The value obtained is divided by the normal (non-cogenerating) enthalpy (1370 Btu/lb) to determine the aggregated steam flow rate and then multiplied by the incremental enthalpy and turbine efficiency (80 Btu/lb and .7 respectively) to obtain the maximum quantity of electricity that could be generated via coal fired boilers. The resulting value is divided by the total incremental machine drive (mostly electricity) service demand to determine the maximum market fraction for coal-fired steam topping in 1985. The appendix provides a more in-depth example of ISTUM's treatment of steam topping.

The above presumes that the option to cogenerate will not affect the mix of new boilers. Boiler type decisions are driven hardest by firing rate - the larger the firing rate, the more likely coal will be used over oil and gas. The discussion below suggests that firing rates will not be significantly affected by the decision to cogenerate. Thus, the mix of new boilers is not likely to change significantly when cogeneration is considered - the maximum market fraction calculation should be considered valid in this sense.

Given the internally-determined maximum market fraction, the cost effectiveness of steam topping is determined in the same way as any other technology. The following describes the costs of steam topping categorized as follows:

- 1) incremental boiler capital costs
- 2) turbine generator capital costs
- 3) combined operating and maintenance costs
- 4) demand charges
- 5) fuel costs

1) Incremental Boiler Costs

To increase the enthalpy output of a boiler in general requires the use of higher quality metals for the tubes and also requires more expensive equipment to achieve greater degrees of super heating. After a series of interviews with boiler manufacturers,^{1/} a range of boiler costs of different sizes and enthalpy designs was determined from which costs for specified sizes and enthalpies could be interpolated.

Given the average enthalpies and enthalpy increases for different boiler sizes as outlined above, Table II-8 shows incremental boiler costs for different boiler sizes and types.

There is scarce data on costs for AFB and no data on incremental costs for enthalpy increases. However, it is judged that the incremental costs for AFB are roughly parallel to those of coal-fired boilers since the major costs are for more substantial tubes in both cases. Thus, AFB incremental costs were assumed equal to those of coal-fired boilers..

Oil and gas-related incremental capital costs were similar enough to be considered equal.

As can be observed, capital costs for enthalpy increases for coal-fired boilers exceed those for oil-fired boilers at smaller sizes but the reverse is true at larger sizes. This is due to a combination of design factors which include the interaction of temperature, pressure, and fuel impurities and the specifications of metallurgy and tube wall thickness.

¹ Babcock & Wilcox Co., Industrial and Marine Division,
North Canton, Ohio.
E. Keeler Co., Danville, Pennsylvania.
Foster Wheeler Energy Corp., Livingston, N.J.

TABLE II-8

INCREMENTAL BOILER CAPITAL COST FOR
STEAM TOPPING COGENERATION

<u>Type</u>	<u>Size</u>	
	<u>50 MMBtu/hr</u>	<u>250 MMBtu/hr</u>
Approximate flow rate (lbs/hr)	40,000	180,000
Increased Enthalpy (Btu/lb)	150	80
Increased Capital Costs		
Coal	\$150,000	\$430,000
Oil	\$140,000	\$480,000
Gas	\$140,000	\$480,000
AFB	\$150,000	\$430,000
LBG	\$140,000	\$480,000

It is unlikely that the decision to cogenerate steam and electricity rather than simply generate steam will significantly affect boiler support costs, such as scrubbing, fuel handling, feedwater and other costs. Most of these boiler support costs depend on the firing rate of the boiler, i.e., the greater the firing rate, the greater the costs. Steam topping cogeneration, however, does not increase the firing rate enough to justify increased boiler support costs.

To demonstrate this, it is best to consider the largest boiler size assumed here, since most cogeneration topping is likely to be drawn from large boilers. The largest boiler considered, generating 180,000 lbs/hr, is assumed to normally generate steam at 1370 Btu/lb and can cogenerate up to 1450 Btu/lb. With feedwater entering the boiler at approximately 100 Btu/lb, the boiler normally adds 1270 Btu to each pound of steam generated. When cogenerating, the boiler adds 1350 Btu/lb of steam generated, a 6 percent increase in the firing rate. The small difference in the firing rate when cogenerating is considered to have inconsequential impacts on boiler support costs.

2) Turbine-Generator Capital Costs

Capital costs for turbine generator systems were derived from the 1977 Price Handbook published by the General Electric Industrial Steam Turbine division. Table II-9 presents the installed capital costs for the two turbine sizes selected for ISTUM. The turbine sizes are those that would be used to cogenerate off of the two boiler sizes in the steam sector, 50 MMBtu/hr and 250 MMBtu/hr. A .25 installation cost factor was assumed for these turbines which are non-condensing units and require much less space than do condensing units.

TABLE II-9

Installed Capital Costs for Industrial Turbine-Generators

Machine Drive Demand	20MMBtu/hr	100MMBtu/hr
Turbine Size	2 MMBtu/hr	10 MMBtu/hr
Associated MW capacity	.6 MW	3 MW
Installed Capital Costs	\$160,700	\$714,300

3) Operating and Maintenance Costs

System vendors offered the following as typical operating and maintenance costs for steam topping systems:^{1/}

\$100,000 plus $(.01) \times (\text{turbine-generator capital costs plus incremental boiler capital costs})$

The \$100,000 pays for one system operator around the clock seven days a week - maintenance costs comprise the rest.

4) Demand Charge

Industrial plants obtain insurance against cogenerating facility failures by contracting with their electric utility company for reserve capacity. Most utilities have set cost guidelines for such arrangements. Conversations with several utility representatives reveal guidelines fairly consistent

¹ Thermo-Electron Corp., Waltham, Mass.

among utilities. A typical set of guidelines is presented below:^{1/}

<u>Capacity</u>	<u>Monthly Rate</u>
First 2700 KW	\$11,877
Next 12600 KW	\$3.40 per KW
Additional KW	\$3.09 per KW

Using these rates, the annual demand charge associated with a 2 MMBtu/hr turbine is \$142,500; for a 10 MMBtu/hr turbine it is \$154,800 annually.

5) Fuel Costs

ISTUM calculates fuel costs by multiplying the inverse of the fuel efficiency by the fuel price. The fuel efficiency of electricity generation by steam topping is the product of the boiler and turbine efficiencies. Given a 70 percent turbine efficiency and an 82 percent boiler efficiency, the combined fuel efficiency is 57 percent. The fuel price multiplied by the efficiency inverse equals the cost in dollars per energy unit for fuel.

It should be noted here that the fuel efficiency of steam topping causes it to be more economical than self-generation. When self-generating, the steam exiting the turbine must be condensed to pump the water into the boiler again. The energy lost when condensing (cooling) the steam

¹ Actual rates for Monongahela Power Company. A distribution around these rates, distributed by the frequency distribution of electricity prices, was entered into ISTUM.

decreases the system efficiency from around 57 percent to 33 percent. In cogeneration, the steam is used for normal process needs after exiting the turbine. The condensing efficiency penalty is allocated totally to the process economics since the topping system did not add to this energy loss. This fuel cost differential causes steam, topping cogeneration to be more economic than straight self-generation schemes.

6) Industrial Markets For Steam Topping

The markets for industrial cogeneration are likely to occur where large steam and electricity demands coincide on a per plant basis. After examining the industrial sector, it was concluded that steam topping should compete only in the machine drive sector and not the electrolytic sector - where steam and electricity demands coexist, the electricity demands are almost always of the machine drive type.

Noting the discussion of the internally - generated maximum market fractions discussed above, the primary consideration for cogeneration penetration is the number of new boilers expected (since retrofitting old boilers is technically and economically infeasible). The second consideration is the existence of machine drive demands. The coexistence of these occur to a significant degree in the following industries:

Coexistence of Significant Steam and Electricity Needs

<u>Industry</u>	<u>SIC Code</u>
Food	20
Textiles	22
Paper	26
Chemicals	28
Petroleum Refining	29
Rubber	30
Steel	331

Thus, steam topping will compete for machine drive demand primarily in the industries listed above.

There is much discussion of the role for exports in cogeneration. Exports are assumed negligible for steam topping primarily because industrial plants cannot produce enough electricity to warrant exports. Given the per plant steam demands, feasible enthalpy increases, and turbine efficiencies, electricity supply from topping rarely approaches the per plant electricity demand. On average, the ratio of steam to electricity produced by steam topping is approximately 20:1. Given that only one industry (Textiles) has a steam to electricity ratio approaching that (12.5) and most have ratios considerably less (many less than one), at least from an aggregate perspective, exports seem unlikely.

Furthermore, the major industrial consumers of steam and electricity have fairly constant load demands. This suggests that it will be rare that demands will be so uncoordinated that the need to export will arise.

7) Modeling Limitations

Preliminary analysis suggests that steam topping is competitive with purchased electricity. The major barrier preventing topping taking up the entire machine drive sector is the steam demand limitations. The tool used in ISTUM to represent this barrier is an endogenously-determined maximum market fraction. As noted, the maximum market fraction is determined by dividing the electricity generating potential for new boilers in a given year by the machine drive demand.

Thus, a major consideration in a plant-specific analysis of cogeneration is the ratio of steam demand to electricity demand. Within a given industry, however, the ratio may

vary over a wide range. There is no reason to believe that the steam to electricity ratio for each plant in as fragmented an industry as the Food Industry even closely approximates that of the entire industry. Ideally, industries where topping has the most potential should be disaggregated further than the 2-digit SIC level - maybe to the 4-digit level or even further. It would be useful to perform sensitivity analyses to determine the penetration effect when steam to electricity ratios are varied over a representative range.

Steam to electricity ratios will vary even more across industries and, as a result, maximum market fractions should vary as well. Table II-10 presents the approximate maximum market fractions for all SIC's and shows the variation in these fractions by industry. These fractions were calculated by assuming the same steam and electricity demand growth rates for each industry and a 20:1 ratio of steam to electricity production from steam topping.

In its present form, ISTUM cannot differentiate maximum market fractions by industry. Thus, one value must be chosen to represent the industrial market for topping. To maximize accuracy, a relatively large maximum fraction will be assumed for each industry but only certain industries will be included.

Thus, seven industries were selected as potential consumers of steam topping: Food, Textile, Paper, Chemicals, Petroleum Refining, Rubber and Steel. Even for these seven industries, however, note the variability in the maximum market fractions, ranging from .71 in the Textile Industry to .11 in the Steel Industry.

TABLE II-10

Variability in Maximum Market Fractions Across Industries

SIC		Approximate Maximum Market Fraction
20	Food*	.27
21	Tobacco	0
22	Textiles*	.71
23	Apparel	.06
24	Lumber	.17
25	Furniture	.01
26	Paper*	.34
27	Printing	.01
28	Chemicals*	.19
29	Petroleum Refining*	.24
30	Rubber*	.13
31	Leather	0
32	Stone, Clay, Glass	0
331	Steel*	.11
3334	Aluminum	0
334	Other Primary Metals	.01
34	Fabricated Metals	.02
35	Nonelectrical Machinery	.02
36	Electrical Machinery	.01
37	Transportation Equipment	.04
38	Instruments	.04
39	Misc. Manufacturing	.03

* Steam topping cogeneration was considered a potentially significant energy supplies in these industries for ISTUM.

ISTUM calculates in effect a weighted average maximum market fraction by aggregating all new boilers in the industries studied, assessing the electricity generation potential from these new boilers, and dividing by total incremental machine drive demand in the industries studied. ISTUM will calculate accurately the overall industrial penetration of steam topping by way of a weighted average maximum fraction. It will not calculate accurately the penetration for each particular industry.

c. Gas Turbine with Waste Heat Boiler

This cogeneration system produces both steam and electricity. The gas turbine is fueled with either natural gas or distillate fuel oil.^{1/} The turbine-generator produces electricity and exhausts substantial amounts of waste heat. The waste heat boiler acts as a heat exchanger, converting this waste heat to steam.

A gas turbine has a heat rate of approximately 11,000 Btu/KWh (31 percent efficiency) and exhausts 2.22 Btu's of waste heat for each Btu of electricity generated. With a waste heat boiler efficiency of 55 percent, the system produces one Btu of steam for each .819 Btu of electricity. The gas turbine costs approximately \$200/kw installed, the waste heat boiler approximately \$10/lb/hr installed. Annual operating and maintenance costs are five percent of total capital costs^{2/}.

The system is modeled to fulfill either the steam demand or the electricity demand of a particular industrial

¹ For ISTUM, gas turbines are assumed fueled by distillate fuel oil.

² Thermo-Electron Corp., Waltham, Mass.

user. On average, industrial electricity demand is only 40 percent of industrial steam demand. Thus, two technologies are considered by ISTUM. The first is a system which fulfills steam demand and exports electricity to the neighboring utility. The second is a system which fulfills the electricity demand but not the steam demand and thus does not have excess electricity for export into the grid. In this case, a conventional back-up boiler is assumed to satiate the residual steam demand. The discussion that follows describes the manner in which the technologies were fitted into the ISTUM logic and the costs associated with each of the two cases described.

1) Gas Turbine Modeling Logic

The combined gas turbine/waste heat boiler technology (GTWB) must compete in either the steam or machine drive sectors to fit into the ISTUM logic. Because the analysis for steam topping requires that the steam sector be determined before the machine drive sector, the GTWB is considered a steam supply technology for modeling purposes. The value of electricity generated is credited to the technology cost; revenues from exports are credited the same way.

The value of electricity credits is the product of electricity demand and electricity price. Electricity demand is dependent on the size category being studied, equalling either 20 MMBtu/hr or 100 MMBtu/hr. The electricity price varies by region. As elsewhere in ISTUM, the regional variations are approximated by a frequency distribution, rather than re-solving the model explicitly for each region. The product of the two is subtracted from total annual costs to determine the total costs credited to

steam production. The remainder is divided by total steam produced to determine cost per energy unit for steam production. Table II-11 presents the credit values for different sizes and load factors.

The revenues collected from utilities depend on the size of the electricity and steam demands (and thus the size of exports) and the variable cost of producing electricity at the utility importing the electricity. It is assumed that the utility would be willing to pay for imports up to but not more than its variable cost (operating, maintenance and fuel costs) of running the last increment of capacity. The utility is no better or worse off financially whether it runs this capacity or pays for imports at the cost of running that capacity.

Typical utility generating characteristics were determined to assess the weighted average of the variable cost of the last increment of capacity in operation. The variable cost of the three typical generating units and the fraction of time that the unit is the last increment of capacity in operation are listed in Table II-12.

The overall weighted average variable cost that an industrial plant would assume when calculating the benefits of investing in in-plant generation is \$4.04/MMBtu in 1977.

A gas turbine/waste heat boiler designed to meet the steam needs of 250 MMBtu/hr plant demand will produce 204.75 MMBtu/hr of electricity. On average, electricity demand for a plant this size is 100 MMBtu/hr. Thus, 104.75 MMBtu/hr. will be exported with revenues equal to this value multiplied by \$4.04/MMBtu. Revenues, like credits, are subtracted

TABLE II-11

Annual Credit Values for Internal Generation of Electricity
(assuming price of electricity equal to \$6.76/MMBtu)

(1977)

<u>Load Factor</u>	<u>Size</u>	
	<u>20 MMBtu/hr</u>	<u>100 MMBtu/hr</u>
4000	\$540,800	\$2,704,000
7000	\$946,400	\$4,732,000

TABLE II-12.

Weighted Average Variable Costs for Utility Electricity Generation
(1977)

Generating Unit	Weight	Variable Cost
Nuclear	.25	\$1.41/MMBtu ^{1/}
Coal	.25	\$3.01/MMBtu
Oil-Fired Boiler/ Turbine Generator	.38	\$5.80/MMBtu
Gas Turbine	.12	\$6.07/MMBtu ^{2/}
TOTAL	1	\$4.04/MMBtu

^{1/} Mitre Corp., Nuclear Power Issues and Choices, Ballinger Publishing Co. Cambridge, Mass. 1977 p. 126.

^{2/} National weighted average natural gas price was used to calculate this.

from total system costs to determine the total costs attributed to steam production.

Because the economics of the system vary depending on whether the system is sized to meet electricity or steam demand, two separate technologies are considered in the model. One technology fulfills the steam demand, exporting power to utilities. The other technology fulfills the electricity demand, requiring a conventional boiler to fulfill the steam demand residual of the particular industrial user. For the larger steam demand, the residual is 130 MMBtu/hr; for the smaller steam demand, the residual is 25 MMBtu/hr. The export and no export cases compete against each other as well as with the other technologies in the steam sector.

The credits and revenues are calculated by ISTUM on a dollar per million Btu of steam basis. To calculate these, ISTUM's efficiency factor for electricity was used to reflect the impact of electricity prices on the credit and revenue values. The value of the credit will equal, on a dollar per million Btu of steam basis, the following:

$$\left(\frac{X \text{ MMBtu of electricity demand}}{Y \text{ MMBtu of steam demand}} \right) \left(\frac{\$}{\text{MMBtu of electricity}} \right)$$

As one can see, the first term can be modeled as an efficiency factor to marry the credit calculation with ISTUM's tools. Since ISTUM multiplies the inverse of the efficiency factor by the electricity price, the negative inverse of the first term was entered into ISTUM as an efficiency factor to calculate the credit.

When revenues from exports are considered as well, both the amount of electricity produced and the electricity "price" are different than for credits alone. In the "export" cases,

the value of the electricity produced will equal, on a dollar, per million Btu of steam basis, the following:

$$\left(\frac{M}{N}\right)\left(\frac{(A)(E_1) + (B)(E_2)}{M}\right)$$

where M = total electricity produced (= A + B)
 N = total steam demand
 A = electricity consumed
 B = electricity exported
 E₁ = electricity purchase price
 E₂ = weighted average variable cost of electricity generation (revenue from export value)

This is equivalent to:

$$\left(\frac{AE_1 + BE_2}{NE_1}\right) E_1$$

which once again is an electricity price multiplied by an "efficiency factor." Once again, the negative inverse of the first term was entered into ISTUM as an efficiency factor to ascertain in dollars per million Btu of steam demand the value of electricity production.

d. Diesel Engines With Waste Heat Boilers

This system was integrated into ISTUM in the same way as the gas turbine system. The differences lie in the costs, heat rates, and electricity to steam supply ratios. Diesel engines cost approximately \$300/kw installed, have heat rates of approximately 8500 Btu/KWh, and generate 1.05 Btu's of electricity for each Btu of steam produced. The resulting fuel efficiency (for producing steam) is 38 percent.^{1/}

Because of different steam to electricity ratios, the size of exports (in the export case) and the size of the

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Thermo Electron Corp., Waltham, Mass.

residual steam demand (in the non-export case) differ from those associated with the gas turbine systems. Table II-13 presents each case.

Both the gas turbine and diesel engine systems will require associated demand charges. As noted, a 250 MMBtu/hr steam demand is associated with a 100 MMBtu/hr machine drive demand and a 50 MMBtu/hr with a 20 MMBtu/hr demand. Thus, the corresponding demand charges for each steam demand size are as follows:

Associated Demand Charges for Steam Demand Sizes
for Gas Turbine and Diesel Engine
Cogeneration Systems
(1977)

	<u>50 MMBtu/hr</u>	<u>250 MMBtu/hr</u>
Electricity Demand	20 MMBtu/hr	100 MMBtu/hr
Annual Demand Charge	\$285,987.84	\$1,290,599.5

The demand charge is included as an annual cost of cogenerating with these technologies.

After ISTUM calculates the actual penetration of technologies, it subtracts the electricity supplied by these technologies from the machine drive sector before the machine drive sector is "run". The amount of electricity subtracted from the machine drive sector will reflect only that amount consumed in-house and will exclude the amount exported (since it is not fulfilling machine drive demands).

Electricity demand is, on average, 40 percent of steam demand. Thus, the total steam produced by each of the technologies (the actual share multiplied by the total steam

TABLE II-13

Exports and Steam Demand Residuals by
Plant Size Using Cogeneration Technologies

<u>System/Case</u>	<u>Size</u>	
	50 MMBtu/hr	250 MMBtu/hr
	<u>Size of Residual Steam Load</u>	
Gas Turbine/ No Export	25 MMBtu/hr*	130 MMBtu/hr*
Diesel Engine/No Export	30 MMBtu/hr*	155 MMBtu/hr*
	<u>Size of Exports of Electricity</u>	
Gas Turbine/Export	20 MMBtu/hr	105 MMBtu/hr
Diesel Engine/Export	32 MMBtu/hr	160 MMBtu/hr

*An oil-fired boiler is assumed to meet this residual demand in ISTUM. The boiler is sized to meet the entire steam demand in case of diesel engine or gas turbine failures. The oil-fired boiler runs at partial capacity when the waste heat boiler is operating and runs at full capacity when the waste heat boiler is not operating. The excess capacity is considered as steam supply insurance much as the demand charge is considered electricity supply insurance.

demand) multiplied by .40 yields the amount of electricity to be subtracted from the machine drive sector. This structure remains intact even for the "no export" cases since ISTUM treats the technology plus the residual boiler as one technology. The appendix provides an example of ISTUM's treatment of gas turbine-waste heat boiler cogeneration.

e. Modeling Problems with Gas Turbines and
Diesel Engines with Waste Heat Boilers

Both of these technologies supply both the steam and machine drive sectors. ISTUM is not set up to have technologies compete in two service sectors simultaneously. In fact, a model would have to calculate an overall rate of return on investment for each technology and compare those to treat such technologies accurately.

Instead, these technologies must be considered either steam or machine drive demand suppliers and credited for production in the other service sector. Because steam topping necessitates that the steam sector be determined before "running" the machine drive sector, the gas turbine/diesel engine - waste heat boiler technologies are considered steam supply technologies and compete in the steam sector.

One problem with this method is determining the value of the credits earned through electricity production. For ISTUM, the value of the credits is determined by multiplying the electricity price by the electricity supplied (for revenues from exports, utility variable costs are considered instead). However, the electricity price accurately represents the opportunity cost of cogeneration only if purchased electricity is the only technology in the machine drive sector. To the extent other technologies (say, steam topping) are

less expensive than purchased electricity, the credit is overstated. Simultaneity problems precluded a more accurate representation of the value of the credit. The problem might not distort the results, however, since purchased electricity is expected to supply a major portion of the machine drive service sector anyway.

Sensitivity analyses were completed suggesting that the number of demand sizes in a given service sector does not change the results of ISTUM significantly. However, an important consideration for cogeneration is not so much the independent demand sizes as much as it is the ratio of electricity demand to steam demand. This ratio varies by industry (and within an industry) and may affect significantly the economics of these cogeneration technologies. This poses problems for ISTUM since costs for a given technology cannot vary across industries. The following discusses the problem.

The economics of the cogeneration technologies are affected by the portion of electricity production valued as credits and the portion valued as export revenues (since the revenue price is roughly half the electricity price). In effect these ratios are determined by the assumed electricity to steam ratios since the larger the ratio the smaller the exports. Given the tremendous variance in the electricity to steam ratios by industry (see Table II-14), the costs could vary significantly by industry.

A weighted average ratio was used to maximize the accuracy of the analysis (given the constraint). Once again, the results will be more accurate for the entire industrial sector than for any particular industry.

TABLE II-14
Electricity to Steam Demand Ratios by Industry*

SIC Code	Electricity to Steam Demand Ratios
Total Industry	.40
20 Food	.20
22 Textiles	.08
23 Apparel	.90
24 Lumber	.35
25 Furniture	6.61
26 Paper	.16
27 Printing	4.35
28 Chemicals	.29
29 Petroleum Refining	.23
30 Rubber	.44
331 Steel	.51
334 Other Primary Metals	7.82
34 Fabricated Metals	3.21
35 Nonelectrical Metals	3.63
36 Electrical Metals	5.23
37 Transportation Equipment	1.29
38 Instruments	1.41
39 Misc. Manufacturing	2.12

* Source: ISTUM's data base for 1975.

Many of these modeling problems that result from the aggregated nature of ISTUM could be to a large extent remedied by decoupling the cogeneration logic from the general ISTUM framework and doing the analysis on an industry by industry basis. This would be in effect establishing a separate industrial sector cogeneration model that uses logic formats and dimensions similar to ISTUM but is capable of modeling the commercial prospects of cogeneration in more detail.

f. Organic Rankine Cycle System

The organic rankine cycle system (ORCS) converts waste heat to electricity. The organic fluid collects the waste heat and is expanded through a turbine, thereby generating electricity. The vapor is then condensed and pumped to the waste heat source to continue the cycle.

As noted in the introduction, it has been concluded that organic rankine cycle systems driven off of industrial waste heat will not penetrate the market and therefore have not been entered into ISTUM. Its exclusion does not stem from its inability to compete with other electricity supply technologies but with its inability to "win" waste heat from air preheaters.

A typical ORCS has been selected to demonstrate the economics of ORCS versus air preheating.^{1/} The system uses a benzene fluid and converts waste heat with temperatures above 600°F to electricity at a 22 percent efficiency. The system costs approximately \$400/kw installed.

^{1/} System being developed by Sundstrand Energy Systems, Rockford, Illinois.

An air preheater collects waste heat and returns it to the system to preheat incoming combustion air. The preheater operates at an 80 percent efficiency and costs \$24/kw. Table II-15 provides an example of the economics given a 100 MMBtu/yr waste heat supply for a given plant and demonstrates that the low efficiency of ORCS relative to preheaters is the main hindrance to ORCS's penetration.

Both the much lower capital costs and much higher efficiency for the air-preheater will persuade plant managers to invest in air preheating rather than ORCS. The fact that ORCS's can accept temperatures only as low as 500°F yet new air preheaters will reduce waste heat temperatures to 200-300°F suggests a lack of a significant market for ORCS in combination with industrial waste heat streams.

g. Gas Turbine With ORCS

The waste heat given off by gas turbines normally approximates 900°F. Gas turbines cannot use preheaters. It is also unlikely that transporting waste heat to processes requiring preheated combustion air will be economically feasible. Thus, gas turbines with ORCS are potentially viable electricity suppliers.

Combining the typical gas turbine with the typical ORCS as described in previous sections, Table II-16 presents the characteristics of the system assumed for ISTUM.

Combining these systems, the overall system efficiency is 46 percent and the cost is \$266.3/kw. The gas turbine will produce two-thirds of the electricity generated, the ORCS one-third.

TABLE II-15

Assumptions for ORCS/Air Preheater Comparative Economics

	<u>ORCS</u>	<u>Air Preheater</u>
Waste Heat Available	100 MMBtu/yr	100 MMBtu/yr
Annual Costs (Capital O&M)	\$93,786.6	\$28,852.8*
Load Factor (hrs/yr)	5500	5500
Capital Recovery Factor	.15	.15
Efficiency	.22	.80
Price of Fuel Replaced	\$7/MMBtu	\$2.50/MMBtu
Value of Annual Energy Savings	\$154,000	\$200,000
Net Annual Savings	\$60,13.4	\$171,147.2

* American Iron & Steel Institute, "Energy Conservation in the Steel Industry", p. 148.

TABLE II-16

Typical Characteristics of a Gas Turbine/ORCS

	<u>Gas Turbine</u>	<u>ORCS</u>
Capital Cost (Installed)	\$200/kw	\$400/kw
Heat Rate (Btu/kWh)	11,000	15,500
Operating & Maintenance Costs	(.05) (Capital Costs)	(.05) (Capital Costs)

The system competes in both the machine drive and the electrolytic sectors. Its installation will effect annual demand charges as follows:

Demand Charges for Different Electricity Demand Groups

Service Sector	Size (MMBtu/hr) *		
	20	100	600
Electrolytic	--	--	7,320,599.4
Machine Drive	\$285,987	\$1,290,599	--

* Sizes correspond to ISTUM service sector sizes.

The ORCS system does not incur significant economies of scale (except for demand charges) and thus, given the economies of scale of purchased electricity and other electricity generating technologies, is more likely to compete successfully in the smaller size ranges.

h. Diesel Engine with ORCS

This system is designed in much the same way as the gas turbine with ORCS. Using the same diesel design as described in preceding sections, the overall cost of the system is approximately \$325/kw. The electricity to waste heat ratio for the diesel is .67 and the fuel efficiency is 53 percent. The diesel engine will generate 75 percent of the overall electricity produced, the ORCS generating 25 percent. The system competes in the machine drive and the electrolytic sectors and of course requires the same demand charges. It also does not incur significant economies of scale and thus will fare better in the smaller sizes.

i. Self-Generation

Self-generation differs from steam topping cogeneration in that the steam exiting the turbine is condensed and pumped into the boiler to continue the cycle. Because of the much lower system efficiency that results, cogeneration always will be less expensive on a per million Btu basis than self-generation. However, the latter does not require coincident steam demands.

Self-generation will compete in both the machine drive and electrolytic sectors. Its contribution is likely to be limited to the aluminum, chemical, and steel electrolytic demands which can take advantage of its economies of scale.

The technology requires a steam generator and a condensing turbine. The condensing turbine costs more than a non-condensing turbine per unit capacity, both to design and to install. The steam generator can be coal-fired, oil-fired, gas-fired, LBG-fired or AFB. Each of these systems competes against the others and with the rest of the electricity supply technologies.

As noted, self-generation will compete in both the machine drive and electrolytic sectors. The costs associated with each of the sizes represented are in Table II-17.

As noted, fuel efficiencies are low for self-generation (33 percent) because of the need to condense the steam exiting the turbine. This fuel efficiency will tend to make more expensive fuel forms uneconomic at any size. Oil, gas and LBG-fired systems are less likely to win significant market shares than coal and AFB.

TABLE II-17

Estimated Costs of Self-Generation
(\$10³)

	<u>Sizes (MMBtu/hr)</u>		
	<u>Machine Drive</u>		<u>Electrolytic</u>
	20	100	600
Boiler Capital Costs ^{1/}			
Coal	2611.6	9,033.9	40,171.9
Oil	820.6	2,707.7	14,153.0
Gas	593.5	2,092.6	11,243.2
AFB	3,325.7	10,366.9	52,815.2
LBG	2,887.6	12,300.7	70,599.2
Turbine Capital Costs	1,953.0	5,533.5	\$16,401.0
O&M Costs	6 to 11 percent of Capital Costs		
Demand Charge	\$286.0	\$1,290.6	\$ 7,320.6

^{1/} Boiler sizes are 50 MMBtu/hr, 250 MMBtu/hr, and 1500 MMBtu/hr to fulfill electricity demands of 20 MMBtu/hr, 100 MMBtu/hr, and 600 MMBtu/hr respectively. Costs are slightly higher than those entered into ISTUM for steam production due to higher enthalpies for electricity generation. The costs presented are those most likely for each boiler type and size according to ISTUM's frequency distributions.

Electric Utility Rate Structures

This subsection discusses the probable future electric utility rate structures. Many of the technologies studied by the ISTUM group, particularly those competing in the machine drive and electrolytic sectors, may be highly dependent on the structure of these rates. The rate structures of several utilities were studied to determine a base line case from which predictions for future rate structures could be justified^{1/}. It is concluded that the most likely scenario will be a slightly downward sloping pricing schedule due to:

- the declining rate structure for the demand charge
- the flat rate structure for the energy charge holding load factor constant
- the declining rate structure for the energy charge allowing load factor to increase.

The following rationalizes these conclusions and elaborates on them.

Table II-18 presents the eight utilities studied, the structures of their energy and demand charges, and the year for which these rates correspond. In each case, the demand charge per kw declines with increased capacity. In all cases except Monongahela Power Co. of West Virginia, however, the energy charge is flat - the dollar per million Btu for the energy charge is constant with increased demand. However, in each of these cases, increasing the load factor while maintaining the same demand for capacity reduces the

^{1/} The results of the rate structure were not included in ISTUM's 4/6/78 base case run due to time limitations. DRI's average price estimates were used instead.

TABLE II-18

SURVEY OF ELECTRIC UTILITY RATE STRUCTURES

<u>Utility</u>	<u>State</u>	<u>Energy Charge</u>	<u>Demand Charge</u>	<u>Year</u>
Detroit Edison	Michigan	On-Peak, Off-Peak	Declining	1976
Southern California Edison	California	Flat	Declining	1977
Pacific Gas and Electric	California	Flat	Declining	1977
Monongahela Power	West Virginia	Declining	Declining	1977
VEPCO	Virginia	Flat*	Declining	1977
CON ED	New York	Flat	Declining	1977
Cincinnati Gas & Electric Co.	Ohio	Flat	Declining	1977
Ohio Edison	Ohio	Flat	Declining	1977

* This utility's energy charge rate reaches its asymptote short of the size demands studied here.

energy charge per million Btu consumed. The following explains why.

For most utilities, the energy charge is structured to capture the ratio of the electricity consumed to the amount of capacity contracted for - in other words, the energy charge per unit consumed is affected only by the consumer's load factor. A typical energy charge would be one where the first 250 Kwh per kw reserved is priced at a higher rate than the remainder consumed per kw reserved. Thus, regardless of capacity demand, equal load factors will render equal energy charges per energy unit consumed. However, because a lower rate is charged when consuming more electricity per unit capacity, high load factors reap lower energy charges per energy unit consumed.

For illustrative purposes, the energy charge for Monongahela Power Company and Pacific Gas and Electric Company are presented below.

<u>Monongahela (1977)</u>	<u>Pacific Gas and Electric (PGE) (1977)</u>
Energy Charge (monthly)	Energy Charge (monthly)
First 5.118 MMBtu — \$4.25/MMBtu	First 4.1 MMBtu per 3412 Btu/hr demand — \$3.48/MMBtu
All Additional Btu's — \$3.88/MMBtu	Next 8.2 MMBtu per 3412 Btu/hr demand — \$2.13/MMBtu
	All additional Btu's — \$1.55/MMBtu

Monongahela clearly has a declining rate schedule, charging less per Btu with increased consumption. PGE's structure is more complicated and can be analyzed best by using specific cases.

First, assume two different size demands with the same load factor: 20 MMBtu/hr and 100 MMBtu/hr each with a 4000 hr/yr load factor. Table II-19 presents the energy charges associated with each part of the rates structure.

TABLE II-19
EXAMPLE OF ENERGY CHARGE CALCULATION

	20 MMBtu/hr	100 MMBtu/hr
Load Factor	4000 hrs/yr	4000 hrs/yr
Yearly Demand	8×10^{10} Btu	4×10^{11} Btu
Yearly Btu's subject to first block	288,393.9 MMBtu	1,441,969.5 MMBtu
Yearly Btu's subject to second block	576,787.8 MMBtu	2,883,939.0 MMBtu
Yearly Btu's subject to remainder	79.999×10^9 Btu	399.966×10^9 Btu

Since, in each case, the Btu's subject to a given block in the 100 MMBtu/hr size are five times that of the 20 MMBtu/hr size, the energy charge per MMBtu is the same for different size demands with equal load factors.

However, when maintaining capacity constant at 20 MMBtu/hr and allowing the load factor to increase to 7000 hrs/yr, the energy charge per MMBtu is reduced. In this case, the same number of Btu's are subject to a given block except for the last block (the remainder). For the larger load factor, more Btu's will be supplied at the lowest price. Thus, the energy charge decreases on a unit energy basis as load factors are increased.

The electricity price is determined for a given customer by adding the demand and energy charges together. With a constant load factor, the electricity price decreases moderately with capacity increases due to a declining demand

charge and constant energy charge. Both the demand charge and energy charge are reduced with increased load factors. The result is a sharper drop when increasing load factors than when increasing reserved capacity and maintaining constant load factors.

Figures II-2 - II-4 illustrate the demand, energy, and total charges for the several utilities studied. Except for Cincinnati Gas and Electric (whose rate drops precipitately), all utilities allow slightly declining block rates across the range studied. Monongahela's rates approximate the mean. The demand rates vary significantly; VEPCO charges roughly six times as much as Southern California Edison for reserved capacity in the range studied.

As noted above, energy charges are generally flat for constant load factors - capacity increases do not reduce the energy charge per unit consumed. Monongahela is the only exception yet, in the range studied, it too has nearly flat rates for the high load factor and for the low load factor when demand exceeds 100 MMBtu/hr. The two lowest sets of rates, those for Pacific Gas and Electric (PGE) and Cincinnati Gas and Electric (CGE), probably reflect the large amounts of hydropower and coal respectively used by each (approximately 35 percent and 94 percent respectively).

Data Resources Inc. (DRI) calculated the average industrial price for electricity in 1977 at \$6.70/MMBtu (2.3¢/kwh). Given that the average plant load factor is between the 4000 hrs/yr and 7000 hrs/yr load factors used here, it is likely that the electricity price for plants running at 4000 hrs/yr would exceed DRI's price and that the price for plants running at 7000 hrs/yr would undercut DRI's price. Using approximate energy charges of \$4.30/MMBtu for a 4000 hrs/yr load factor and \$3.90/MMBtu for a 7000 hrs/yr load factor,

FIGURE II-2

ELECTRIC UTILITY DEMAND CHARGES (INDUSTRIAL)

1977

FIGURE II-3

ELECTRIC UTILITY ENERGY CHARGES
(INDUSTRIAL)

1977

06-II

\$/MMBtu

FIGURE II-4

ELECTRIC UTILITY RATE
STRUCTURES 1977
(INDUSTRIAL)

TABLE II-20

Projected Regional Electricity Prices for Select Years
(1977 dollars)

	1977	1980	1985	1990	1995	2000
National	5.702	7.213	8.152	9.630	11.4	13.4
New England	10.589	11.747	13.651	15.473	18.27	21.59
Mid Atlantic	3.632	9.094	9.999	11.613	13.71	16.20
South Atlantic	7.612	8.179	8.850	10.392	12.27	14.50
East North Cent	5.827	7.170	7.986	9.566	11.31	13.35
West North Cent	7.318	7.354	7.636	8.553	10.10	11.93
East South Cent 1	4.675	4.886	5.330	6.431	7.60	8.97
East South Cent 2	6.471	6.082	7.007	8.716	10.30	12.17
West South Cent 1	6.515	7.812	9.227	9.051	10.69	12.63
West South Cent 2	6.096	7.600	8.834	10.061	11.88	14.04
Mountain 1	7.009	6.810	7.145	7.705	9.11	10.66
Mountain 2	4.559	5.689	5.961	7.282	8.60	10.16
Mountain 3	6.846	6.496	7.395	8.353	9.86	11.65
Pacific	5.254	5.552	7.191	9.131	10.79	12.74
Standard Deviation	1.3	1.4	1.6	1.7	2.0	2.4

Source : Data Resources Inc.

and assuming the Monongahela demand charge, Table II-21 presents the approximate average electricity prices at the relevant sizes and load factors.

Electricity prices vary significantly by region. Table II-20 presents DRI's regional electricity prices for select years from 1977 to 2000. The standard deviations for each year are presented as well. The standard deviations were applied to the prices listed in Table II-21 to incorporate the regional price variability into the size and load factor-related electricity price analysis. DRI's electricity price growth rates were incorporated into the analysis as well.

There has been some discussion of the possibility of flat rates in the future, defined as a structure where all consumers (residential, commercial, & industrial) pay the same rate for electricity. A flat structure is being considered as a policy alternative to promote conservation. Figure II-5 presents the residential electricity rates for several utilities and, when compared to the industrial rates (Figures II-2 - II-4), demonstrates a significantly higher rate for small consumers. While Federal or State regulatory policy may mandate flat rates in the future, there is no evidence of such a utility policy at present.

The 1977 weighted average flat rate, calculated by dividing total U.S. utility revenues by total U.S. utility electricity generation, would have been \$9.02/MMBtu. The decision to use flat rates rather than declining block rates (compare \$9.02/MMBtu to \$6.70/MMBtu) should make the cogeneration technologies significantly more attractive.

As one of its policy alternatives, ISTUM will be run with either declining block rates or flat rates for electricity

TABLE II-21

1977 ELECTRICITY PRICES FOR DIFFERENT SIZES & LOAD FACTORS
 (\$/MMBtu)

Load Factor (hrs/yr)	Size (MMBtu/hr)		
	20	100	600
4000	\$7.88	\$7.50	--
6500*	--	--	\$6.26*
7000	\$5.94	\$5.73	--

* This value was determined by calculating the 4000 hr/yr and 7000 hr/yr price for this size and weighting it to 6500 hrs/yr.

FIGURE II-5

RESIDENTIAL ELECTRICITY RATES 1977

prices. For the latter, the DRI growth rates will be used. The standard deviations derived from DRI's regional electricity prices will be incorporated into the flat rates as well.

Chapter Appendix

This appendix presents examples to demonstrate ISTUM's treatment of cogeneration. Three examples are used:

- 1) coal-fired steam topping
- 2) gas turbine-waste heat boiler with export
- 3) diesel engine-waste heat boiler without export

The numbers used are for explanatory purposes only and do not reflect actual results.

1. Coal-Fired Steam Topping

a. General Data

- (1) Technology Name: COAL TOPP COG
- (2) Technology I.D.: 5.45
- (3) Applicable Industries: Food, Textiles, Paper, Chemicals, Petroleum Refining, Rubber, Steel
- (4) Service Sector: Machine Drive
- (5) Year: 1985

b. Technology Data

- (6) Average Percentage Enthalpy Increase: 10 percent
- (7) Turbine Efficiency: 70 percent
- (8) New Coal-Fired Boiler Penetration in 1985 in the Seven Specified Industries: 50×10^{12} Btu/yr.
- (9) Total Incremental Machine Drive Demand in 1985* in the Seven Specified Industries: 15×10^{12} Btu/yr.

* The value is the remainder after the electricity produced by gas turbines and diesel engines have been subtracted - see next examples.

(10) Maximum Market Fraction: .23

$$\frac{(6) \times (7) \times (8)}{(9)} = .23$$

c. Cost Data**

Incremental Boiler Capital Cost:	\$100,000
Turbine Cost:	\$300,000
O&M Cost:	\$103,535
Capital Recovery Factor:	.14
Demand Charges:	\$600,000
Fuel Price (Coal):	\$1.50/MMBtu
Fuel Efficiency:	.57
Cost of Producing Electricity via COAL TOPP COG (60 MMBtu/hr; 5500 load factor):	\$4.93/MMBtu

This value competes against a frequency distribution of electricity prices and against other electricity generating technologies with a maximum penetration in 1985 of 23 percent of the market.

2. Gas Turbine - Waste Heat Boiler with Export

a. General Data

- (1) Technology Name: GASTURB WHB EX
- (2) Technology ID: 5.61
- (3) Applicable Industries: All except Tobacco, Leather, Aluminum
- (4) Service Sector: Steam
- (5) Year: 1985

** Weighted by size and load factor.

b. Cost & Technology Data

- (6) Ratio of Electricity to Steam Demand: .4
- (7) Ratio of Electricity to Steam Supply: .82
- (8) Ratio of Exports to Steam Demand: .42 $((7) - (6))$
- (9) Ratio of Export Value to Electricity Purchase

Price: .60

(10) Total Value of Electricity Production: $(.65) \times$
Electricity Price*

$$((8) \times (9)) + (6) = .65$$

(11) Capital Costs for Technology I.D. 5.61: ** \$16,000,000

(12) Capital Recovery Factor: .14

(13) O&M Costs: \$810,000

(14) Demand Charge: \$1,000,000

(15) Fuel Price (Distillate): \$2.50/MMBtu

(16) Fuel Efficiency: .40

(17) Total Costs for Tech ID 5.61: \$11.16/MMBtu of steam

(18) Value of Electricity Production: \$5.20/MMBtu of steam

(19) Total Cost including Credits and Revenues: \$5.96/

MMBtu of steam

This technology competes in the steam sector with all other steam technologies. For this example, if the technology produced 25×10^{12} Btu/yr of steam in 1985, 10×10^{12} Btu/yr (40 percent) of electricity would be subtracted from the machine drive service sector in 1985 since machine drive demands are assumed 40 percent of steam demands.

* Assume \$8.00/MMBtu here.

** Assume 150 MMBtu/hr Steam Demand; 5500 load factor

3. Diesel Engine with Waste Heat Boiler - No Export

a. General Data

- (1) Technology Name: DIES ENG WHB NEX
- (2) Technology ID: 5.51
- (3) Applicable Industries: All except Tobacco, Leather, Aluminum
- (4) Service Sector: Steam
- (5) Year: 1985

b. Cost and Technology Data

- (6) Ratio of Electricity to Steam Demand: .4
- (7) Electricity Price: \$8.00/MMBtu
- (8) Credit Value = (6) x (7): \$3.20/MMBtu of Steam
- (9) Ratio of Electricity to Steam Supply: 1.05
- (10) Ratio of Conventional Oil Boiler Supply to Steam Demand: .62

$$1 - \left(\frac{1}{.9} \times (6) \right)$$

- (11) Capital Costs for Technology ID 5.51*: \$10,000,000
- (12) Capital Recovery Factor: .14
- (13) O&M Costs: \$700,000
- (14) Demand Charge: \$1,000,000
- (15) Fuel Price (Distillate): \$2.50/MMBtu
- (16) Oil-fired Boiler Efficiency = .82
- (17) Diesel Engine-Waste Heat Boiler Efficiency: .38
- (18) Fuel Efficiency: .57
- (19) Total Costs for Tech ID 5.61: \$8.15/MMBtu
- (20) Total Costs including Credit: \$4.94/MMBtu of Steam

* Assume 150 MMBtu/hr Steam Demand; 5500 load factor - includes Diesel Engine, Waste Heat Boiler, and conventional boiler.

This technology competes in the steam sector and its electricity production is subtracted from the machine drive sector before the machine drive sector is run (assumed 40 percent of steam production). Technology ID 5.61 includes the oil-fired boiler as an integral part of the technology for both steam production and cost calculations.

5. Solar

a. Introduction

The ISTUM model was developed for the Department of Energy as a policy tool that could simultaneously compare many DOE technologies and project their acceptance and use by the industrial market. The great majority of the technologies modeled are conventional fossil fired energy conversion systems. ISTUM's logic is best designed to analyze these conventional technologies, and due to size constraints common to all models, cannot fully integrate into its logic many of the unique features of solar thermal energy systems. Analysis of solar energy applications in the industrial sector raises technical and economic issues that are only partially accounted for in the ISTUM results. The purpose of this section is to discuss those issues and provide some insights into the prospects of solar thermal energy systems in the industrial sector in a manner complementary to the model results.

The analysis presented below hopes to identify three things; what characteristics unique to solar technologies inhibit a complete assessment of ISTUM; what factors are critical in assessing the costs (and therefore the acceptance) of solar energy; and in what areas further investigation should be initiated in order to furnish the data necessary for a major modeling effort.

There are several non-economic factors that inhibit the acceptance of solar by industrial uses. The most important of these factors is reliability. One must assume that a user of process steam cannot afford to have an interruption in energy supply due to extensive and long lasting

cloud cover. Fossil fired back up (residual, distillate or natural gas) is necessary in order to insure an uninterrupted supply of steam to a manufacturing facility. This is an expensive but necessary ingredient to a solar system. With the capital cost of a fossil back-up included in the costs of solar system, the cost effectiveness of solar can be measured with a simple equation; solar is cost effective when the discounted total cost of the solar system is less than the equivalent cost of a system that was totally fossil fired.

Even this simple economic analysis has a major ambiguity; how does industry measure the cost of fuel for twenty years (the life of a solar system)? Many studies that demonstrate the economic viability of solar thermal energy answer this question by using life cycle costing in a very liberal fashion.^{1/} The discounted cost of fuel is added up for the twenty year life of a system, and should that discounted fuel cost be greater than the discounted capital and operating costs of a solar system (minus its fossil fired backup component), solar becomes a more cost effective energy supply system. Payback usually occurs in the tenth or twelfth year of operation. The problem with this accounting system is that industry does not practice that type of life cycle costing. A ten or twelve year pay back period is usually unacceptable, and basing a large capital investment decisions on twenty years of fuel price predictions is not considered

^{1/} Intertechnology Corporation, Analysis of the Economic Potential of Solar Thermal Energy to Provide Industrial Process Heat, for the Energy Research and Development Administration, February, 1977 and Amory Lovins, Soft Energy Paths, Cambridge, Mass. Ballinger Publishing Co., 1977 are two good examples.

prudent. Therefore, solar may actually be more cost effective over a twenty year period but industry does not perceive it as such.

Another issue associated with reliability is the unwillingness of solar vendors to extend warranties for any considerable period of time. A typical warranty for concentrating collectors is one year, with some flat plate vendors offering three year warranties.^{1/}

ISTUM integrates many of these problems into the cost distribution and the maximum market shares. However, other parts of ISTUM's logic exacerbate these problems and create new ones. ISTUM models two size systems; 50 MMBtu/hr and 250 MMBtu/hr. These sizes are larger than existing real world solar systems. ISTUM uses load factors that demand a certain amount of fuel usage, regardless of yearly insolation in a given area. ISTUM cannot completely account for the significant variations in insolation across regions, and though these differences are folded into a continuous cost distribution ISTUM cannot pinpoint the regional markets where solar would be most cost effective. Other technologies, where costs do not vary significantly across regions, do not need to be located in regional energy markets to show their cost effectiveness.

The main application of solar discussed in this report is industrial process heat, especially in the form of steam. It is assumed that solar technology will be "plugged" into existing manufacturing processes as a source of energy and

^{1/} Sales literature supplied by Ed Rossiter of AEROTHERM-ACUREX Corporation.

will not require process changes. Solar energy is treated as a primary source of power; no hybrid systems are discussed, although the issue of solar powered preheat is discussed as a special topic in section e. These assumptions are necessary in order to make the conclusions of this report consistent with ISTUM logic.

b. Issues Unique to Solar Thermal Energy Systems

1) Temperature

The temperature requirements of industry are the major factor in determining the technical applicability and ultimate costs of solar technology. The maximum market fraction is limited by solar's ability (or inability) to meet industry temperature requirements. The original MOPPS model set the highest attainable temperatures for solar systems at 650°F (350°C), and this was lowered to 600°F in ISTUM. This makes the maximum market fraction large, (e.g., 60 percent for direct steam). However, cost variations between 300°F and 600°F were incorporated into the cost distribution, shrinking the nominal market share considerably.

The best available data concerning temperature requirements comes from Batelle Columbus Laboratories (BCL) Survey of the Applications of Solar Thermal Energy Systems to Industrial Process Heat.^{1/} This is the data base used by the

^{1/} Batelle Columbus Laboratories, Survey of the Applications of Solar Thermal Energy Systems to Industrial Process Heat, for the Energy Research and Development Administration, January, 1977

MITRE Corporation in its SPURR/METREK solar model.^{1/} BCL broke out temperature requirements into three ranges; below 100°C, 100°C to 177°C (350°F), and above 177°C, a temperature they consider to be the practical limit for solar thermal energy systems. BCL concluded that roughly 35 percent of all industrial demand for process heat falls into temperature ranges below 177°C. The Inter-Technology Corporation (ITC) conducted a similar study which arrived at roughly the same conclusions, with one major exception.^{2/} ITC included potential demand for solar preheat (which is discussed as a separate, special topic in section e) in its calculations.

One advantage these three temperature ranges offer is a higher degree of specificity in identifying what industrial applications of solar are more likely to find solar thermal energy economically attractive. BCL established that possible applications of solar in the less than 177°C range cut across most industries and regions, and did not try to regionalize the data and include weather variations. They also concluded that the major processes requiring heat above 177°C were found in fuel fired direct heaters in petroleum refining, in metallurgical furnaces, and in kilns. All these applications are considered to be beyond the realm of solar thermal technology. However, solar concentrating collectors can generate temperatures up to 600°F. This expands the market available to solar technologies, but limits the use of BCL data to determine the exact size of the data, for they only specify how much steam is required above 177°C (350°F) rather than 600°F.

^{1/} The Mitre Corp., Metrek Division, Systems Descriptions and Engineering Costs for Solar-Related Technologies, V. 1, for the Energy Research and Development Administration, April, 1977.

^{2/} Intertechnology Corporation, op. cit.,

Both BCL and ITC concluded that a considerable (but, as of yet, unquantified) amount of process heat is used at temperatures greater than the actual manufacturing process requires. This leads to possibility that the maximum market share for solar would be greater if estimated by manufacturing process requirements rather than actual application requirements. The data needed is extremely site and process specific, and generating such data would probably require several separate analyses. However, such data would probably increase the number of markets where solar thermal energy is technically applicable.

2) Insolation

Insolation can be defined as the amount of solar radiation reaching the earth, and is measured in Langley/days. It is one of the most important factors that drives the cost of solar systems. Insolation (combined with temperature, load factor, and collector efficiency) determines the amount of collector footage, storage, and backup needed by a solar system.

Data on insolation is available and sophisticated techniques are available to convert average daily sunlight to figures reflecting average collector efficiency. Daily insolation in the United States runs from about 275 to 525 Langley days, with the national mean about 400 Langley/day.^{1/} The two areas critical to a proper integration of insolation into cost distributions and the ISTUM model are its relationship to collector footage and its variability across regions. This latter problem can escalate the cost of solar

^{1/} Ibid, v. 2, p. 77.

systems by more than a factor of two. Inter-Technology Corporation (ITC) in its Analysis of the Economic Potential of Solar Thermal Energy to Provide Industrial Process Heat, divides the country into six regions. Average daily and yearly regional insolation was calculated using weather data gathered from 90 cities. ITC developed a precise relationship between collector costs and insolation, using a multiplier to escalate a "base cost" for a specific collector in the region with the greatest amount of yearly insolation. This method solves both problems, for it defines the relationship between insolation and collector footage (given certain assumptions) and utilizes this relationship to specifically define insolation variability across regions.

Although ITC conducted analyses of data from ten different collectors, these multipliers are based on a flat plate, single glazed collector with a selective coating that has an emissivity of 0.4. The collector provides 50 percent of the energy required to heat 1000 gallons/day from 60°F to 140°F.

ISUTM integrates regional variation in costs due to different levels of insolation by construction a cost distribution that includes multipliers similar to those specified above. For example, if the base cost distribution for region VI is \$4.00 to \$10.00 per ft² of collector, the national distribution would have to be from \$14.00 to \$26.00, using the largest multiplier (region I) to calculate the upward range.

One problem not addressed in depth by ITC is seasonality, or the changes in ambient air temperature and of cloud cover

through the different seasons and across regions. This is an issue especially important to an accurate assessment of solar space heat potential. ISTUM uses two sizes of space heat service demand combined with different load factors to establish a potential space heat market. This demand is not broken out regionally or on a seasonal basis. The space heat system modeled integrates regional insolation differences into its cost distribution, but is otherwise unable to better incorporate seasonality into the model. A certain amount of storage (5 days) is assumed to be necessary for all regions. While this does not completely integrate the many differences seasonality into the model, it is not on overly optimistic or pessimistic assumption. A much more detailed model would be necessary in order to fully assess the effect of seasonality on the costs of and demand for solar technologies.

3) Timing of Demand

Timing of demand is basically the question of when process heat is in demand and how this timing affects the use of solar technologies. The ISTUM assumption that is explicitly related to this question is the choice of load factors. In ISTUM process steam load factors will be modeled at 4000 and 7000 hours per year; space heat will be 2500 hours per year. The technology characterizations used in the original ISTUM model costed solar systems that had several hours of storage -- enough to bring them up to 12 hours per day operation. Thus, they were not applicable in two and three shift per day operations. However, many energy consuming industries operate most of their plants on two of three shift per day basis; therefore, solar technologies without back-up were excluded from the majority of the industrial market.

ISTUM assumes fossil back-up, and will be modeled at both 4000 and 7000 hours per year. This allows for an expanded maximum market fraction that includes many energy intensive industries. This does not mean that solar is ideally suited to operate at either load factor. Most applications or planned applications of solar by industry are for low load factor processes; one can washing facility uses its solar system to supply 3×10^9 Btus to heat water. This is the amount of energy used annually by 30 homes located in the northeastern United States.^{1/}

Even at the 7000 hour load factor, solar is the primary source of supply when the sun is shining; fossil fuel when it is not. The two systems are not a hybrid that supply energy simultaneously. This issue is further discussed in the special topic treatment of hybrid energy systems to be found in section 3.

4) Collectors

Solar energy technology is still in an early stage of development and there are a large number of collectors at different prices on the market or in the planning stage. Collectors range in complexity from a simple solar pond to a concentrating collector, such as a dual axis parabolic trough.^{2/} Costs also vary widely, depending on the insolation of the region and the temperature requirements of

^{1/} William C. Dickinson, "Solar Energy for Industrial Process Heat", Solar Age, August, 1977, pps. 29-33.

^{2/} Intertechnology Corporation, op. cit., pps. 87-260.

the industry in question. For low temperature applications (less than 100°C), a flat plate, double glazed collector made of aluminum or copper is the most efficient. A parabolic trough concentrator is best suited for the 100°C - 177°C and greater than 177°C range. Even though only two types of collectors are in question the cost per square foot (installed) can vary by as much as a factor of 5. These costs range from \$4.00 to \$14.00 per ft² for a flat plate collector and \$12.00 to \$21.00 per ft² for a parabolic trough.^{1/} Cost ranges this broad are contested by certain sources, most notably the cost figures used by MITRE for the SPURR/METREK model. According to MITRE, costs range (for all types of collectors) from 12.90 to 31.20 per square foot during the initial stage of production, and from 4.00 to 10.40 under mass production.^{2/} These economies of scale have been disputed by solar energy engineers and scientists. They cite material and not production or installation costs as being the driving force behind overall collector costs, and do not envision a significant price decrease when mass production of collectors is initiated. Aden and Marjorie Meinel of the University of Arizona Optical Sciences center appearing before a House subcommittee contested the assumption that solar costs will drop, either through mass production

1/ The MITRE Corp., op. cit., p. 86. Intertechnology Corp., op. cit., pps. 82-260 and United States Congress Office of Technology Assessment, Application of Solar Technology to Today's Energy Needs (Prepublication Draft), June, 1977, pps. II/4-II/24.

2/ The Mitre Corporation, op. cit. p. 86.

of collectors or due to a learning curve phenomenon.^{1/} The reasons they presented are simple; the cost of materials used in solar collectors is as low as it will be, and these costs are the greatest portion of collector costs. Another problem cited by the Meinels is the amount of middlemen involved in the manufacturing and retailing of solar equipment. The Meinels opinions concerning materials costs were not once disputed by any of the solar vendors contacted in the course of conducting this study.^{2/}

The possibility of solar collectors undergoing price reductions due to a learning curve phenomenon is disputed by the opinions stated above and the fact that solar flat plate collectors have been available for many years. The only area where this phenomenon might take place would be in the area of instrumentation; computer control of tracking systems is in an infant state and may become less expensive over time.

It is important to note that the driving force behind solar system cost is not simply collector cost by the square foot. Insolation, heat requirements and load factors, as well as the efficiency of a specific type of collector drive the costs by determining how much footage is actually needed.

5) Microgeography

Microgeography is another factor that contributes to determining the maximum market share for solar systems. Land

1/ McGraw Hill Publications, Inside DOE, February 27, 1978 pps. 12-13.

2/ The vendors interviewed about materials costs in general asked to remain unspecified. However, ACUREX-AEROTHERM and SUNPOWER SYSTEMS did not foresee any price reductions for their collectors.

is not an unlimited resource, and should the footage requirements of a collector system be too great, land serves as an effective constraint on the technical applicability of a given solar system. It also helps determine the nominal market share by having land costs integrated into the cost distribution of solar energy. Adjacent land is the only place appropriate for the collector systems in question, for in most cases the roof of a manufacturing plant is not large enough to hold the amount of collector area needed to produce process heat. Rooftop systems invariably can only supply space heat.^{1/}

It is an intuitively appealing notion that land will be less available (and more costly) in the older, more developed manufacturing areas of the United States, such as the northeast, than in newer industrial areas such as the sunbelt. Again, ISTUM is unable to include these types of regional differences due to a lack of specific data. It is best to assume unlimited variability and assign higher overall costs to those systems that require more collector area and hence higher land costs. In this manner the maximum market share is made as large as is reasonable.

6) Retrofits

The issue of retrofits is an interesting one, and is directly related to the issue of preheat, which will be dealt with as a special topic in section e. The current ISTUM formulation is targeted at new or incremental technology demand. Retrofit markets will be further developed

^{1/} United States Energy Research and Development Administration, Solar Industrial Process Heat Workshop, College Park, Md., June 28-29, 1976. pp. 24-27.

for the ISTUM framework in the future. The retrofit market, which is important not only to solar systems but to several conservation technologies, is not a critical factor in assessing the prospects of the great majority of ISTUM technologies. As with several other ISTUM constraints, the lack of a retrofit market hurts solar more than most other technologies, for solar is well suited as a supplemental source of power to be used when the sun is shining. The cost calculations are simple -- when the cost of installing and operating a solar system is equal to or less than the cost of fuel needed to supply additional power to a more conventional system, solar systems can be retrofitted to provide the necessary power. This oversimplified analysis assumes that solar can be plugged in and used as part of a hybrid power system, as is happening in several manufacturing concerns at present, and requires no significant process changes. It should not be assumed, however, that the lack of a retrofit market shrinks the actual use of solar systems by a significant amount. Solar technologies competing in such a market will have the same economic advantages and disadvantages as they have in the new facilities market.

It may be possible to create several hybrid energy supply technologies that do not use one source of power exclusively and which would be well suited for a retrofit market. At the moment, specifications for such a system are quite tentative, and little data is available from which cost distributions can be generated. Should hybrid supply systems using some form of solar thermal energy be included in the ISTUM model, the retrofit market for solar energy could become quite large. The typology system used to

generate ISTUM's cost distributions would be an excellent method to develop definitive hybrid system costs. It is ideally suited to multi-component technologies.

Microgeography, however could offset this possible gain, for land constraints may be critical for retrofit applications. Little data is available to either corroborate or disprove whether land is available for retrofit applications of solar. More work needs to be done in this area.

c. Solar Costs

The nominal market share of a given technology in ISTUM is a concept which combines maximum market shares and cost distributions of the different technologies and determines what market shares each technology will capture if purely economic criteria are used for technology selection. The most important factor in this analysis is the cost distribution assigned to each technology.

The generation of cost distributions for solar systems is a difficult problem. First, a typical or representative system must be designated, Btu requirements and load factors specified, and accurate cost data accumulated. The system configuration will supposedly have the lowest cost when located in the highest insolation area.

Hand calculations were used to estimate whether storage was cost effective in a solar system that had fossil back-up. The result of these initial calculations was that storage, in the form of heated water, is never cost effective. This is because water heated by a solar steam system would have to be stored under high pressure, which is a very expensive system to build and operate.

The relevant cost components are collectors, land and site prep, installation and back-up. An ideal system supplying 300°F steam is costed out for the most well insolated area of the United States. It is then multiplied by constants that reflect higher temperature requirements and lower levels of insolation. Collector cost is the main driving force behind the cost distribution of solar systems. Installation and land costs are driven by total square footage of collectors. The variability of collector costs in a given system depends on the amount of collector area needed for a certain heat requirement (MMBtu/hr. x load factor) in a certain region of the country with regional insolation differences changing the amount of collector area needed for a given system by more than a factor of 4.

Very little data is available on operating and maintenance costs of solar systems. ITC specified a possible \$3.00 per f^2 of collector area O&M cost, but did not elaborate as to whether this cost is discounted overtime.^{1/} MITRE uses figures that are a percentage of the original capital cost of collectors, and these figures range from 2.9 to 4.0^{2/} percent annually. Vendors quote a cost between 1.0 and 2.0 percent. The figure slightly below 2.0 percent was chosen as being most representative and was included in the ISTUM cost distributions.

The most important aspect of the cost distributions included in ISTUM is that the minimum cost is more than twice

^{1/} Intertechnology Corp., op. cit. pps. 87-255.

^{2/} The Mitre Corp., op. cit. p. 86.

as great as the minimum cost in the original distribution used by MOPPS. One of the reasons for this is that installation costs are the largest single cost component of a solar system. This is something that has either been neglected or seriously understated by most studies analyzing solar industrial potential. The ITC study quoted an installed solar system cost at \$30 a square foot;^{1/} the lowest price quoted by a vendor was \$40.00 a square foot; the highest \$100.000 a square foot. This variability in installation costs is due to several factors, such as heavier piping for high temperature systems, more sophisticated levels of instrumentation, including computer controlled tracking motors and better methods of placement.^{2/}

The cost distributions only partially account for decreases in collector efficiency as temperature requirements escalate. It is conceivable that the cost distributions would have a higher maximum as application temperature requirements escalate and collector area is increased. The data used for these distributions was gathered from vendors, the MITRE/SPURR model documentation, the previously mentioned ITC and BCL studies, an Office of Technology Assessment report on solar energy and various technical publications.^{3/}

1/ Intertechnology Corp., op. cit., p. 211.

2/ Conversation with Ed Rossiter of ACUREX-AEROTHERM.

3/ The most helpful publications were Science, Solar Age, Technology Review, Solar Engineering and New Scientist.

It is the sensitivity of solar cost distribution to regional variability that makes it a difficult technology to model. What is needed is a solar model that would have as its final goal accurate regional cost distributions, which in turn would be modeled against a regional breakdown of where potential industrial markets exist. Modeled as six separate technologies, these distributions and maximum market fractions would be consistent with ISTUM logic. They would not be competing simultaneously against each other, but would be competing against other technologies applicable to a regional market. This regionalization would greatly enhance ISTUM's ability to assess potential industrial use of solar thermal energy.

d. Special Topics

1) Photovoltaics

The basic unit for photovoltaic power systems is an array of cells producing up to a few tens of kilowatts of electricity. Even large central power stations, if they were constructed, would be built up from units of this size for the technology is modular, based on very small scale cells that are built up to provide increasing amounts of power. Because of this modularity, photovoltaics are ideally suited to small scale needs, such as the power requirements of an industrial plant.

The great problem with photovoltaic cells is their extremely high cost. At present, a group of silicon cells now cost about \$15 per watt of generating capacity in full sunlight. Reduction to \$1 a watt - a cost that is expected to make feasible a broad range of specialized applications

is widely anticipated by 1980, particularly for concentrating systems which rely on high conversion efficiencies.^{1/} The other type of system is a flat plate arrangement. Prices must drop 20 to 40 fold before photovoltaic cells come into general use as a source of on-site power. The prospects for less costly photovoltaic power depend more on the application of mass production methods to known techniques than on fundamental breakthroughs or new concepts. Cells manufactured for terrestrial applications require between 10 and 100 manhours of handwork per kilowatt of generating capacity. Another key area is material costs - the extremely pure semi-conductive grade of silicon now used to make cells costs \$65 per ton and is a substantial impact in the cost of the final product.^{2/} Moreover, cells would have to operate about 12 years to recoup the energy expended in their manufacture. But, the bulk of the cost of the cell still stems from a lack of automation and the necessity of assembling a group of cells by hand. Despite these high costs, there already exists a market for terrestrial photovoltaic power systems. Silicon based solar cells with a capacity of about 350 kilowatts were sold in 1976. A recent study by the Department of Defense forecasts a substantial near-term market, eventually as large as 100 MWe per year, at remote military installations and says that photovoltaic systems for such application are competitive even at current prices.

^{1/} Allen L. Hammond, "Photovoltaics: The Semiconductor Revolution Comes to Solar," Science, Vol. 197, July 29, 1977 pps 445-447 and Henry Kelly "Photovoltaic Power Systems: A Tour Through the Alternatives," Science, Vol. 199, February 10, 1978, pps 634-643.

^{2/} Ibid.

RCA, Texas Instruments, Motorola and IBM have all indicated that the cell manufacture and assembly step can be automated with substantial reductions in cost, and are investing significant resources in photovoltaic research and development. Other large corporations notably four major oil companies, are targeting large portions of their solar energy research funds to photovoltaic development.^{1/} A major on-site application now being actively studied by industry is in electrochemical plants for which the low-voltage direct current produced by photovoltaic cells is ideal because the plant could adjust production to changes in the amount of sunlight available, storage of electricity would not be necessary. Observers familiar with the electrochemical industry say that this market could amount to several thousand megawatts.

Some observers believe that the technical skill to construct large photovoltaic manufacturing plants (100 MWe of cells a year) is available, should these markets ever materialize. At present, however, photovoltaics are prohibitively expensive for industrial applications and there is a great deal of ongoing debate concerning cost reductions in both the immediate and the distant future. DOE foresees a \$.50/kw photovoltaic cell by 1985, with further price reductions by the end of the century.^{2/}

^{1/} Ibid and Solar Engineering, "U.S. Grants Stepping into Solar Industry." December, 1976, pps. 4-7.

^{2/} Hammond, op. cit., Kelly, op. cit.

2) Wind Energy

Among possible energy alternatives that have received public attention in the past few years is wind power, a form of solar energy. Wind power has proved to be an economically viable source of energy in the past and will probably be much more economical (in certain applications) in the future. At present, wind energy is not cost competitive with more conventional systems, except in a few isolated areas. However, both small and large machines have the potential for marked cost reduction, and even without the possible advantages of mass production they offer one of the cheapest means of producing solar electricity available today. It has been estimated that by the year 2000, wind could contribute 1 to 2 percent of the country's total energy needs.^{1/} An important fact that is not widely known is that the amount of wind energy available on an annual basis is nearly as large as the average energy flow of sunlight in many regions. The average wind power on the great plains over the course of the year is over 200 watt/m², and in certain places in the Rocky Mountains this reaches up to 500 Watt/m² per year.^{2/}

Two considerations could give wind energy a distinct advantage over other energy technologies for certain applications in certain locations. First, the geography of

1/ Science "Wind Energy: Large and Small Systems Competing" Vol. 197, September 2, 1977, pps. 971-973 and Marshall F. Merriam "Wind Energy for Human Needs", Technology Review, January, 1977, pps 29-39.

2/ Ibid.

the countryside provides a natural concentrator for wind energy that may double its flow, such as the previously mentioned area in the Rocky Mountains (which is near Medicine Bow, Wyoming, and the site of a DOE demonstration project). Second, wind turbines routinely operate at 35 percent efficiency (theoretical maximum is 60 percent); whereas other solar systems produce some form of power with only a 5 percent to 15 percent conversion efficiency. Another possible advantage is the distinctly lower material costs for wind turbines. Problems include storage of electricity, interference with television reception (windmills typically operate at rotation speeds of near 30 cycles per second, which is the synchronization speed of television in the United States), and disruption of scenic landscapes.

At present, there are no applications of wind energy in industry. However, it is a possibility that as industrial electric rates climb, wind power will become an increasingly attractive alternative source of power, especially when combined with other solar technologies. Present capital costs of demonstration plants is about \$800 to \$2200 per kilowatt, and this is expected to fall in the next few years to between \$750 and \$1100 per kilowatt. Despite these high costs, a study of the proposed plant at Medicine Bow concluded that although construction costs would be \$1.00 a kilowatt, electricity could be produced at 2 cents per kilowatt hour.^{1/} One other possibility for cost reductions would be the use of compressed air to turn turbine blades. The now empty oil and gas wells of the Southwest are ideally suited to this type of wind energy system. Initial and

^{1/} Ibid.

admittedly rough cost calculations show the use of compressed air would add 2¢ per kilowatt hour to the cost of the electricity produced.^{1/} Cost reductions in windmill construction could make the use of compressed air a viable alternative in the next few years.

3) OTEC - Ocean Thermal Energy Conversion

Ocean thermal energy conversion is an alternative energy system that utilizes solar energy in the form of heated ocean water. The basic concept behind OTEC is simple - operation of a heat engine, using warm surface water as a heat source and cold water pumped up from the depths as a heat sink. Systems now under study use a closed Rankine cycle, with a working fluid such as propane or ammonia. OTEC plants must circulate large amounts of warm and cold water to produce energy. For example a power plant concept developed for ERDA envisions a huge, supertanker-sized, mostly submerged floating vertical platform, weighing 260,000 long tons and measuring 592 feet in height and 246 feet in outside diameter. A pipe more than 100 feet in diameter would bring cold water from depths of 1500 feet or more. Designed to last 100 years, the platform would contain several power modules, with massive heat exchangers the size of seven-story buildings.^{2/}

OTEC has several highly attractive features; the energy source is vast, renewable, and probably nonpolluting. It is

^{1/} Ibid.

^{2/} Engineering News Reporter, "Ocean Energy Plant Proposals Set", August 4, 1977, p. 17 and the Mitre Corp. Systems Descriptions and Engineering Costs for Solar Related Technologies, Vol. VII - OTEC, April, 1977, for the Energy Research and Development Administration.

available (with some variations) day and night, in any weather, throughout the year - in contrast to the intermittency and fluctuations that trouble direct solar collection. The ocean itself supplies cost-free solar collection and thermal storage.

The technology is not perfected; basic designs exist, but it is still in an immature state of development, both technically and economically. Heat exchangers are the single most critical aspect of OTEC technology demanding considerable research and development efforts. Accurate cost data are not available, but it is safe to say OTEC is prohibitively expensive at present. A real problem that will probably resist technical resolution longer than other problems is the cost of transmitting the energy ashore. One proposed solution to this problem is the place manufacturing facilities close to the OTEC plants, the most likely candidate being an ammonia plant. Johns Hopkins University has developed a detailed conceptual design for a 100 Mwe OTEC plant linked to a unit producing 31 tons of ammonia that is synthesized from hydrogen and nitrogen. Accurate cost and production estimates are not available.

4) Hybrid Systems and Preheat

A topic that continually cropped up in the main body of this report was the possibility of hybrid energy supply systems. A hybrid system uses a combination of energy technologies to supply thermal energy at the least possible cost. Hybrid systems may be more favorable to solar energy than to most other new technologies, although little or no analytical work has been done in this area. An excellent example of a hybrid system would be a conventional, coal

fired boiler that uses both solar preheat and cogeneration. Such a system produces steam. Solar thermal energy could be used to preheat the water, cutting down on fuel costs for heating water going into the boiler. The boiler produces electricity, but also produces a certain amount of steam that is used for manufacturing processes and possible sold to neighboring plants.

Solar preheat is more economical for use with oil fired boilers, because fuel prices are higher and the capital investment lower for oil than they are for coal. There is a direct trade off between the life-cycle costs of a solar preheat system and the life cycle cost of fuel. A modeling effort would have to establish several input sizes in order to develop accurate cost distributions. Three subsystems where solar provides 10, 20, and 40 percent of the energy necessary to heat steam should be modeled, with and without NEP penalties. As the price of oil goes higher solar should become more attractive. However, tax credits to convert to coal could perhaps make a pure coal system more economical than a hybrid system. Four system combinations would merit analysis:

- conventional coal, solar preheat, less than 100°C solar technology
- conventional coal, solar preheat greater than 100°C solar technology
- oil, solar preheat, less than 100°C solar technology
- oil, solar preheat, greater than 100°C solar technology

The Intertechnology Corporation believes a substantial market will exist for solar preheat. They calculate that preheat up to 100°C could supply about 27 percent of industrial process heat, and preheat up to 177°C about 40 percent. This calculation is theoretical, and accompanying data is not available in enough detail to use in establishing a maximum market share for preheat. ITC also believes the market is greater if process requirements and not actual application temperature are analyzed. This is definitely an area that needs further work. However, cost distributions would be calculated for the systems described and technology characterization created in order to assess the maximum market share; a nominal market share and actual market capture would be estimated. This type of effort would be relatively new for this field and could well become the state of art if properly constructed.

6. Geothermal

a. Introduction

Geothermal energy applications in the industrial sector face significantly different economic logic than conventional energy conversion technologies. The rigid constraints on siting and the "supply-side" nature of this group are examples of factors that differentiate capital investment decisions in this group of technologies from other technology groups in the ISTUM model. Additionally there are cross-sectoral factors such as whether geothermal resources are best applied to industrial or utility applications that clearly transcend the scope of the ISTUM modeling effort. As a result of these factors which are discussed in detail in this section, the treatment of geothermal technologies in the ISTUM framework is more approximate than other technologies. It is our intention that the information in this section will provide useful insights into the commercial prospects of geothermal technologies in the industrial sector that the model results can not capture.

The main application of geothermal energy discussed below is industrial process heat, especially in the form of steam. Four types of geothermal energy exist:

- geothermal steam
- geothermal hot water
- geopressured geothermal heat
- geothermal dry heat (hot rock)

Geothermal heat, whether steam, water, or dry heat, is a "material" to be used in various industrial processes. It can either be purchased by a manufacturing facility from

a supplier or it can be produced by the facility itself. Either way, it is not a source of power; rather the use of geothermal heat obviates the need for a source of power that is needed to raise the temperatures of water and/or air. In order to make this analysis consistent with ISTUM logic, it is assumed that no process changes will be needed to facilitate the use of geothermal heat, in any form. Geothermal energy will be discussed both as a primary source of heat/steam and as part of a hybrid system that uses conventional steam/heat, somewhat like preheat as discussed in the section on solar energy.

At present, there are no industrial plants using any form of geothermal energy. An onion dehydration facility that will use geothermal hot water for washing is currently being built in Nevada with a loan guarantee from D.O.E. All commercial development of geothermal energy has been in the area of electric power generation; the great majority of research studies and virtually all research and development money are concerned with utilizing geothermal resources for electric power generation. Most of the studies are caveated with references to potential industrial uses of geothermal energy, but little work has been done in this area. Because of this orientation, the data being generated comes from projects concerned with the generation of electricity and not the supplying of industrial process heat. Even the above mentioned dehydration facility is utilizing geothermal resources originally tested for electric potential but deemed unsuitable for power generation.^{1/} This bias in the data

^{1/} United States Energy Research and Development Administration, Environmental Impact Assessment Geothermal Loan Guaranty Application, Geothermal Food Processors Inc., Churchill County, Nevada, September, 1977, p. 4.

should be kept in mind as individual issues are discussed below.

b. Types of Geothermal Energy

This paper is concerned with two types of geothermal energy although there are actually four types of geothermal energy resources:

- geothermal steam
- geothermal hot water
- geopressurized thermal energy
- geothermal heat (dry rock)

Cost data was generated only for geothermal hot water. Natural steam that is commercially attractive occurs in very isolated instances and is not a readily exploitable resource. High quality steam such as that used by the Geysers power plant in California is only found at the Geysers plant and in Yosemite national park; even if new resources were located, steam of this quality would be used for electric power generation. The latter two systems are experimental systems that have not, at present, been technically demonstrated.

1) Geothermal Steam

At present, geothermal reservoirs have been discovered in the United States with steam whose saturation temperature is as high as 300°C (572°F).^{1/} Steam is recovered through

^{1/} U.S. Congress - Senate Subcommittee on Energy Research and Development, Committee on Energy and Natural Resources Report on Petroleum Industry Involvement in Alternative Sources of Energy, Washington, D.C. GPO Pub. #95-54, p. 28.

boreholes or natural fissures that have been artificially expanded and reinforced. Natural steam may be received either dry saturated, superheated, or wet at the saturation temperature. Pressure may range from slightly above atmospheric to 300 psig. This natural steam is not exactly pure; varying amounts of dissolved minerals and gases are found in these reservoirs, the exact mix being determined by the geological structure and composition of a particular reservoir. The solvents are usually some type of siliceous or saline material and the gases are typically carbon dioxide, hydrogen sulfide gas, methane, ammonia, and hydrogen.

Geothermal steam is ideally suited for low and middle temperature requirements; it requires no backup, for it is a resource that is available seven days a week, twenty four hours a day. Once purified and transported, it requires little technical improvement in order to be used for industrial purposes. The greatest problem with geothermal steam is the site specific quality of the steam; an industrial plant would have to find a reservoir with the necessary temperatures, and would have to tailor its purification and transportation systems to the quality of the steam. This will be discussed in greater detail later on in this section.

2) Geothermal Hot Water

Geothermal hot water is a far more abundant resource than geothermal steam, available almost wherever geothermal steam is available and in many places where steam is not. Geothermal hot water can be used either as hot water or can be raised into steam. This latter alternative is something that has recently been experimented with, and promises some success, for several reasons.

- geothermal hot water is easier to purify than geothermal steam
- geothermal hot water is easier to transport than geothermal steam
- it is easier to regulate the flow of geothermal hot water than it is geothermal steam

At present, geothermal hot water obtained at the Geysers power plant in California is either reinjected into the reservoir or used for a variety of miscellaneous purposes, such as cooling and cleaning of pipe. Only one facility in the United States will be using geothermal hot water by the end of 1978, the onion dehydrating facility previously mentioned. This plant will use the water in liquid form and will not flash it into steam. One reason for the lack of industrial exploitation is the quality of the water; it is usually filled with dissolved minerals and is highly corrosive, especially at higher temperatures (underground, up to 130°C).^{1/} As with steam, one of the primary technical problems facing an industrial facility is the purity of the water; techniques to clean the water must be site specific and may change as the mix of solvents in the water changes over time.^{2/}

1/ Lawrence Livermore Laboratory Present Status and Future Prospects for Nonelectrical Uses of Geothermal Resources, for Energy Research and Development Administration, October, 1975 pps. 23-25.

2/ R. Axtmann and L. Peck "Geothermal Chemical Engineering" AIChE Journal, Vol. 22, September, 1976, pps. 824-825.

3) Geopressurized Thermal Energy

Geopressurized thermal energy is a "new" type of geothermal energy that, unlike geothermal steam, has never been commercially demonstrated. Geopressured thermal energy can be found in geopressured-brine fields which consist of highly porous sands, saturated with brines at temperatures on the order of 200°C and pressures on the order of 900 psi. A study done by Lawrence Livermore Laboratories for ERDA concluded that the heat from these brines can be used for a variety of applications, ranging from the generation of electric power to supplying the thermal energy now used in typical pulp and paper mills and sugar refineries. Under best case or favorable circumstances, these applications are economical when the value of recovered methane is added to the basic heating value.^{1/} Many known geopressured brine fields are uneconomical due to their lack of methane. At present, there are no plans to commercially exploit the geopressurized zones located in the United States.

4) Geothermal Heat (Hot Rock)

Hot dry rock systems consist of impermeable rocks covering a magma chamber, at temperatures on the order of 170°C, and at depths on the order of 2 kilometers.^{2/} Higher temperatures can be found at greater depths. As anticipated at the present

1/ Lawrence Livermore Laboratory, The Geology and Potential Uses of the Geopressure Resources of the Gulf Coast, June, 1976, p. 4.

2/ U.S. Congress - Senate Subcommittee on Energy Research and Development, Committee on Energy and Natural Resources, op. cit., pps. 74-77.

moment, demonstrated techniques for exploitation are not available. One proposed process of exploitation consists of drilling two bores down to the hot rocks, one for the injection of cold water and the other one for the extraction of hot water. Cracks in the rocks between the bores could be provided by thermal action of the cold water or by use of an explosive.

The Department of Energy is currently funding a study to test the technical feasibility of using a geothermal hot rock system to generate steam for an electric power plant.^{1/} Test wells have been drilled and water will be injected to test steam quality. Commercial development of this type of system is not expected until the turn of the century or possibly later. The most attractive feature of hot rock systems is the abundance of hot rock geothermal areas; they exist in all areas of the United States and are not confined to small reservoirs as is geothermal steam and hot water.

c. Geothermal Reservoir Location

The most critical factor in determining an industrial plant's use of geothermal energy is the location of a known reservoir. Different areas of the United States have been classified as having different geothermal potential; the vast majority of this potential has never been drilled and

^{1/} Kenneth Rea, Environmental Investigations Associated with the LASL Hot Dry Rock Geothermal Energy Development Project, for Department of Energy, December, 1977.

is not on the verge of being commercially developed. The ISTUM model can, in its present form, take into account the site specific nature of geothermal reservoirs only through the use of maximum fractions. This is a problem that could, in the future, be rectified in several ways, all difficult, time consuming, and not necessarily reliable. The quickest and most accurate way would be to establish an inventory of geothermal reservoirs that can be commercially developed with existing technology and cross reference this index with one of the available data files on the location of major industries (either MFBI or Census of Manufactures). A maximum transportation distance could then be developed and combined with reservoir and industry location information. This would give a reasonable estimate of the maximum market shares that result from the spatial distribution of energy demand.

The most often used inventory of geothermal resources is that of the the U.S. Geological Survey, which has the responsibility for classifying Federal lands. The USGS has designated about 1.8 million acres in the Western United States as being within "known geothermal resources areas" (KGRA).^{1/} The classifications were made to implement the Geothermal Steam Act of 1970 which contains provisions pertaining to the leasing of Federal lands for geothermal development. The establishment of a KGRA does not require the existence of a producing or potentially exploitable geothermal well. The Geothermal Steam Act identifies a known geothermal resources area as, "an area in which the geology,

^{1/} U.S. Congress Senate Subcommittee on Energy Research and Development of the Committee on Energy and Natural Resources, op. cit. p. 33.

nearby discoveries, competitive interests, or other indicia would, in the opinion of the Secretary (Interior), engender a belief in men who are experienced in the subject matter that the prospects for extraction of geothermal steam or associated geothermal resources are good enough to warrant expenditures of money for that purpose."^{1/}

To have appreciable potential for exploitation, a geothermal reservoir must meet the following requirements: have a relatively high temperature, greater than 65°C to 205°C depending upon the use and production technology; occur at a depth shallow enough to permit economic drilling, currently about 3½ km or less; have sufficient rock permeability to allow the heat transfer agent, water and/or steam, to flow continuously at a high rate; and have a sufficient water recharge to maintain production over many years.^{2/}

One possible problem could result from using the 1975 USGS inventory of KGRA's and keeping it constant through the year 2010. Potential but as yet undrilled areas would have to be added on an incremental basis to compensate for the static nature of the inventory. The selection of that increment would have to be based on somewhat subjective judgement, but this method is preferable to assuming no new commercially exploitable geothermal areas will be discovered in the next thirty two years.

An additional 96 million acres are listed by USGS as having prospective value for geothermal resources (PGRA's).^{3/} Table II-22 contains a listing of the known geothermal resources areas in the Western United States and gives the total acreage of these areas for each state. The maps in Figures

^{1/} Ibid, p. 33.

^{2/} Ibid, p. 33.

^{3/} Ibid, p. 33.

TABLE II-22

KNOWN GEOTHERMAL RESOURCES AREAS

KGRAS	Name	KGRAS	Name
Alaska -- 88,160 acres		3 -- Leach Hot Springs	
1 -- Pilgrim Springs		4 -- Steamboat Springs	
2 -- Geyser Spring Basin. and Okmok Caldera		5 -- Brady Hot Springs	
California -- 1,051,533 acres		6 -- Stillwater-Soda Lake	
1 -- The Geysers		7 -- Darrough Hot Springs	
2 -- Salton Sea		8 -- Geriach	
3 -- Mono-long Valley		9 -- Moana Springs	
4 -- Calistoga		10 -- Double Hot Springs	
5 -- Lake City		11 -- Wabuska	
6 -- Wendel-Amedee		12 -- Monte Neva	
7 -- Coso Hot Springs		13 -- Elko Hot Springs	
8 -- Lassen		New Mexico -- 152,863 acres	
9 -- Glass Mountain		1 -- Baca Location No. 1	
10 -- Sespe Hot Springs.		Oregon -- 84,279 acres	
11 -- Heber		1 -- Breitenbush Hot Springs	
12 -- Brawley		2 -- Crump Geyser	
13 -- Dunes		3 -- Vale Hot Springs	
14 -- Glamis		4 -- Mount Hood	
15 -- East Mesa		5 -- Lakeview	
Idaho -- 21,844 acres		6 -- Carey Hot Springs	
1 -- Yellowstone		7 -- Klamath Falls	
2 -- Frazier		Utah -- 13,521 acres	
Montana -- 12,763		1 -- Crater Springs	
1 -- Yellowstone		2 -- Roosevelt	
Nevada -- 344,027 acres		Washington -- 17,622 acres	
1 -- Beowawe		1 -- Mount St. Helens	
2 -- Fly Ranch			

TOTAL KGRA ACRES -- 1,786,612

Source: U.S. Congress - Senate Subcommittee on Energy Research and Development, Committee on Energy and Natural Resources Report on Petroleum Industry Involvement in Alternative Sources of Energy, Washington, D.C. GPO Pub.# 95-54, p. 34.

II-6, II-7, and II-8 show the locations of the Western KGRA's as well as the locations of the PGRA's with a tabulation of the total acreage per state. Table II-23 outlines the current and projected activity of the major companies holding federal leases for KGRAS.

It is clear that reservoirs, while known, have not necessarily been tested through drilling. In order to develop maximum market share, as well as cost distributions, a constant success/failure ratio would have to be used for all the KGRA's.

Tables II-22 and II-24 demonstrate an interesting fact concerning geothermal resources; they are being explored and developed by development companies rather than end users. It is fair to assume that developers will sell discovered and exploited resources to a user, and this will make certain economies of scale a reality. It would be prohibitively expensive for an industrial user to explore and develop a geothermal reservoir. The oft mentioned onion dehydration facility is using wells discarded by an exploration project that found the wells unsuitable.

It is possible that industrial use of geothermal steam could only be cost effective in the form of geothermal industrial parks, containing several end users receiving geothermal fluids from one reservoir. The cost distributions folded into the model take this possibility into account; the 100 MMBtu/hr cost is linearly scaled down from a 2000 MMBtu/hr system, including the ultimate cost of distribution to a user from a central pipeline. This is a cost distribution of a plant located in a geothermal industrial park; to

FIGURE II-6

KNOWN GEOTHERMAL RESOURCE AREAS

	KGRA	(Acres) PGRA		KGRA	(Acres) PGRA
Arizona -----	88,160	1,473,000	New Mexico -----	152,863	7,482,000
Colorado -----		1,014,000	South Dakota -----		436,000
Idaho -----	21,844	14,845,000	Utah -----	13,521	4,511,000
Montana -----	12,763	3,834,000	Wyoming -----		824,000

Source: U.S. Congress - Senate Subcommittee on Energy Research and Development, Committee on Energy and Natural Resources Report on Petroleum Industry Involvement in Alternative Sources of Energy, Washington, D.C. GPO Pub. #95-54, p. 37.

FIGURE II-7

KNOWN GEOTHERMAL RESOURCE AREAS

Source: U.S. Congress - Senate Subcommittee on Energy Research and Development, Committee on Energy and Natural Resources Report on Petroleum Industry Involvement in Alternative Sources of Energy, Washington, D.C. GPO Pub. #95-54, p. 36.

FIGURE II-8

KNOWN GEOTHERMAL RESOURCE AREAS

Source: U.S. Congress - Senate Subcommittee on Energy Research and Development, Committee on Energy and Natural Resources Report on Petroleum Industry Involvement in Alternative Sources of Energy, Washington, D.C. GPO Pub. #95-54, p.35.

TABLE II-23

MAJOR PROJECTS AND OBJECTIVES OF COMPANIES INVOLVED IN GEOTHERMAL ENERGY

Company and business	Major projects and objectives
Aerojet Nuclear (government contractor).....	Managing a geothermal R. & D. program, under contract to ERDA, at the Idaho National Engineering Lab at Idaho Falls; no commercial goals.
Amax (miner and producer of metals).....	Involved in 2 geothermal drilling and exploration programs, one with Petro-Lewis, and the other with a group of companies; has leased 300,000 acres of potential geothermal land; wants to sell geothermal steam.
J. Hilbert Anderson, Inc. (engineering firm).....	Has done engineering and design work on wet-steam heat exchangers for Magma Energy; wants to continue contract design work and to license technology it develops.
Arizona Public Service (electric gas utility).....	Partially Funding Geothermal Kinetics' drilling and exploration in Arizona; wants to buy geothermal steam to generate electricity.
Austral Oil (oil company).....	Exploring and drilling on its 10,000 acres of potential geothermal land in Colorado; wants to sell geothermal steam.
Bechtel ¹ (engineer and constructor of process plants and powerplants).	Conducting research into wet-steam systems for ERDA.
Geo-Energy Systems (geothermal-technology development venture).	Marketing a patented heat exchanger to exploit wet-steam systems; wants to prove and license its technology.
Geothermal Kinetics (geothermal development venture).	Exploring and drilling in Arizona, Utah, and California; controls 800,000 acres of potential geothermal land, alone and through joint ventures; wants to sell geothermal steam.
Geothermal Resources International (geothermal development venture).	Providing land for 3 Standard Oil of California drilling projects; controls 65,000 acres of geothermal land in 5 States; wants to receive royalties on the sale of geothermal steam, and eventually sell steam itself.
Gulf Oil (oil company).....	Has done some drilling and exploration in California, Oregon, Idaho, and Nevada; controls more than 3,000,000 acres of potential geothermal land; wants eventually to sell geothermal steam; no commercial plans at present.
Ben Holt Co. (engineer and constructor).....	Has designed heat exchangers for wet-steam systems on its own and for the Government and for other firms; wants to license technology it develops, and to design and construct geothermal powerplants for clients.
Magma Power (geothermal development venture)...	Produces and sells geothermal steam to Pacific Gas & Electric, at the Geysers in northern California, in a joint venture with Thermal Power and Union Oil; controls 120,000 acres of potential geothermal property, alone and through joint ventures, in 6 States; wants to continue to sell geothermal steam.
Morton-Norwich Products (food, drug, and chemical producer).	Has assigned the rights of its geothermal leases to the Southern Pacific Land Co.; controls 17,000 acres of potential geothermal land; wants eventually to produce salt and energy; no commercial plans at present.
Pacific Energy—affiliate of Hughes Aircraft (geothermal development venture).	Has contracted to provide geothermal steam to Pacific Gas & Electric for a planned 55-MW powerplant at the Geysers; has leased or subleased over 21,000 acres of potential geothermal property; wants to sell geothermal steam.
Pacific Gas & Electric (electric and gas utility).....	Generates 502 MW of electricity from geothermal steam at the Geysers; wants to increase the electrical capacity of the installation.
Petro-Lewis (oil company).....	Has leased 21,000 acres of potential geothermal property in Colorado; wants to sell geothermal steam.
Public Service Co. of Colorado (electric and gas utility).	Wants to generate electricity from geothermal steam.
Rogers Engineering (engineer and constructor specializing in geothermal projects).	Designed and built 4 powerplants for P.G. & E. at the Geysers; wants to continue to build geothermal powerplants for clients.
San Diego Gas and Electric (electric and gas utility)...	Involved in 2 joint ventures to exploit the wet geothermal resources of California's Imperial Valley; wants to generate electricity from geothermal steam.
Shell Oil (oil company).....	Explored and drilled at the Geysers; has leased 4,000 acres of potential geothermal property; wants to sell geothermal steam.
Southern California Edison (electric utility).....	Involved in 4 joint ventures, with various partners, to exploit wet geothermal resources; hopes eventually to generate electricity from geothermal steam.
Thermal Power (geothermal development venture)...	Produces and sells geothermal steam to P.G. & E. at the Geysers, in a joint venture with Magma Power and Union Oil; has leased 17,000 acres of geothermal property, through joint ventures; wants to continue to sell geothermal steam.
Thermex (geothermal land venture).....	Has bought 75,000 acres of potential geothermal property in 6 States; wants to acquire more geothermal land, and eventually sell geothermal steam.
Union Oil.....	Produces and sells geothermal steam to P.G. & E. at the Geysers, in a joint venture with Magma Power and Thermal Power; controls 120,000 acres of potential geothermal property, alone and through joint ventures; wants to sell more Geysers steam and eventually to develop other deposits.

¹ Did not participate fully in survey.

Source: Kirkland, Ellis, & Rowe, "Horizontal" Oil Company Divestiture and Separation Proposals. Report to the American Petroleum Institute. Oct. 15, 1976, exhibit III-Q.

Source: U.S. Congress - Senate Subcommittee on Energy Research and Development, Committee on Energy and Natural Resources Report on Petroleum Industry Involvement in Alternative Sources of Energy, Washington, D.C. GPO Pub. #95-54, p. 318.

TABLE II-24

HOLDINGS OF FEDERAL GEOTHERMAL LEASES BY COMPANY

KGRA and owner	Bonus	Acreage
Geysers:		
Shell Oil	\$4,500,000	3,874
Signal Oil	2,030,600	876
Occidental Petroleum	447,004	382
Union Oil	220,933	3,448
Thermogenics	22,050	175
Mono-Long Valley:		
Republic Geothermal	515,767	1,773
Getty Oil	98,592	1,895
Chevron Oil	18,459	1,815
East Mesa:		
Republic Geothermal	650,106	6,705
Magma Power	11,398	5,065
Vale: Republic Geothermal	13,831	1,347
Roosevelt Hot Springs:		
Phillips Petroleum	798,856	18,872
Union Oil	51,993	2,560
Getty Oil	24,000	1,920
A.L. McDonald, et al	2,335	40
Brady-Hazen:		
Natomas Oil Co	88,912	5,074
Southern Union Production	15,108	2,402
Geothermal Resources, Intl.	14,000	1,772
Beowawe:		
Chevron Oil	595,652	6,890
Getty Oil	75,602	49,400
Hot Springs Points: Chevron Oil	240,893	4,701
All KGRA's combined:		
Shell Oil	4,500,000	3,874
Signal (Burmah Oil)	2,500,000	876
Republic Geothermal	1,179,704	9,825
Chevron (Standard of CA)	855,004	13,406
Phillips Petroleum	798,856	18,872
Occidental Petroleum	447,004	382
Union Oil Co.	272,926	6,008
Getty Oil	198,194	8,775
Natomas Oil	88,912	5,074
Thermogenics	22,050	175
Southern Union Production	15,108	2,402
Geothermal Resources, Intl.	14,000	1,772
Magma Power	11,398	5,065
A.L. McDonald, et al	2,385	40

Source: U.S. Congress - Senate Subcommittee on Energy Research and Development, Committee on Energy and Natural Resources Report on Petroleum Industry Involvement in Alternative Sources of Energy, Washington, D.C. GPO Pub. # 95-54, p. 389.

remove the plant from the park, all that needs to be done is to excise the distribution costs.

d. Application Issues and Problems

There are four basic application issues or problems that need to be discussed:

- temperature
- transportation
- steam and water purity
- reservoir flows

It should be noted that all of these factors affect not only the technical aspects of geothermal energy but are driving forces behind the cost distributions that will eventually be generated for geothermal energy systems.

1) Temperature

The temperature requirements of industrial processes are the single greatest factor in determining the technical applicability, as well as the costs, of geothermal heat. The original MOPPS model set no temperature limitations on geothermal steam, which is an incorrect assumption. This helped to create a large maximum market share (e.g., 50 percent for direct steam). Rectifying this situation in ISTUM is not an easy task. Temperature requirements are folded into both the cost distributions and maximum fraction specifications in ISTUM's logic, and data concerning industrial temperature requirements are not precise.

The best available data concerning temperature requirements comes from Batelle Columbus Laboratories (BCL) Survey of the Applications of Solar Thermal Energy Systems to

Industrial Process Heat.^{1/} BCL broke out temperature requirements into three ranges; below 100°, 100° to 177°C (350°F), and above 177°C. BCL concluded roughly 35 percent of all industrial demand for process heat falls into temperature ranges below 177°C. The Inter-Technology Corporation (ITC) conducted a similar study which arrived at roughly the same conclusions, with the qualification that its data was more specifically tailored to assess potential applications of solar thermal energy.^{2/} An advantage these three temperature ranges offer is a higher degree of specificity in identifying what industrial applications of geothermal are more likely to find geothermal energy technically feasible.

One thing need also be mentioned. Both BCL and ITC concluded that a considerable (but, as of yet, unquantified) amount of process heat is used at temperatures greater than the actual manufacturing process requires. This leads to the possibility that the maximum market share for geothermal would be greater if estimated by manufacturing process requirements rather than actual application requirements. The data needed is extremely site and process specific. Generating such data would probably require an extensive and focused analysis of several potential industrial geothermal applications. Such data could possibly increase the number of markets where geothermal energy is technically applicable.

1/ Batelle Columbus Laboratories, Survey of the Applications of Solar Thermal Energy Systems to Industrial Process Heat, for the Energy Research and Development Administration, January, 1977.

2/ Intertechnology Corporation, Analysis of the Economic Potential of Solar Thermal Energy to Provide Industrial Process Heat, for the Energy Research and Development Administration, February, 1977.

Actual temperature folded into the ISTUM cost distributions were expressed as Btu/per lb. of steam generated by the water from a well. This was done in order to utilize the cost data available in an accurate way. The three Btu ranges were 300, 600, and 1200 Btu/lb. An issue related to temperature is steam type. Many industrial processes require superheated steam. It is difficult, although not impossible, to superheat geothermal steam.

2) Transportation

Because heat dissipates rapidly, geothermal fluids cannot be transported far from their point of recovery without losing significant heat. The maximum transport distance depends on the initial heat content of the fluids and the use for which the fluids are intended. Transportation of geothermal fluids must be broken down into two groups; transportation of steam and transportation of hot water. For steam used to generate electric power, the maximum lateral distance is about 1 or 2 miles. Of course, the generation of electric power requires high temperature steam (700-900°F), something many industrial processes do not. At present, the maximum distance steam can be effectively transported is unknown. This is a problem that should be resolved by future studies; ISTUM models geothermal hot water that is flashed into steam. The transportation of hot water is constrained by technical limitations, although they are less severe than those governing steam. The longest distance folded into the ISTUM cost distributions is 32 miles. This thirty two mile limit is a function of both cost and technical limitations; in Iceland, geothermal hot water for space heating has been effectively transmitted for distances up to 30 miles. The

temperature requirements for geothermal hot water do not seriously affect the maximum distance it can be transported. This makes the modeling of transportation costs of a geothermal hot water flashed steam system easier and allows for temperature differences from different wells and reservoirs.

3) Steam and Water Purity

A major technical drawback to geothermal power is the problem of dissolved minerals in both geothermal hot water and steam. Geothermal water and steam must be processed before it can be used in industrial processes. Dissolved solids in high concentrations (as high as 35 percent in some wells in the Imperial Valley of California) and gaseous pollutants are normally present.^{1/} Highly saline waters are too corrosive to be used directly and the gaseous pollutants cannot always be vented to the atmosphere. A typical well in the Geysers of California contains 5 percent hydrogen sulfide, along with other gases such as ammonia (6 percent), methane (5 percent) and hydrogen (2 percent).^{2/} Hydrogen sulfide is a particularly difficult to handle gaseous pollutant and sophisticated technological processes have been developed to control emissions, including a scrubbing process that yields commercially marketable elemental sulfur. Technical solutions to the problem of solvents and other gaseous pollutants are available, but require site-specific designs and are, therefore, expensive.^{3/}

^{1/} Chemical and Engineering News, "Geothermal Energy Promising But Risky," October 11, 1976, pps. 27-28.

^{2/} Ibid, pps 27-28.

^{3/} Ibid, pps. 27-28.

An example worth mentioning is the binary fluid cycle which is used to solve the problem of highly corrosive saline water. In this system the hot fluids issuing from the well are used as a heating medium for a second, isolated fluid, which is then either run through turbines or channeled into heating apparatus downstream. Of course, no matter how the fluids are used, there remains the problem of disposing spent saline water from the well.

It should be noted that the use of a binary fluid cycle system will only be economical, in the foreseeable future, for steam electric power generation. It is not cost effective for industrial users, mainly because it is a closed system that constantly re-uses the second fluid. A good deal of industrial process steam is not used in a closed system but is applied to materials, and must be steam, meaning water heated above 212°F, rather than a fluid such as benzene.

Cost information is difficult to find and is extremely site specific. A certain type of purifying system was identified for a geothermal system and data for this system is used to generate the cost distributions included in ISTUM. These costs were calculated as a percentage of overall well costs. Because all reservoirs are geologically different and water quality varies by each application, using a range of percentages is the only practicable way to generate the cost distributions needed for the model.

A related problem is that of environmental contamination due to solvents and gases released as the reservoir is tapped. Hydrogen sulfide again qualifies as the gas posing the most problems. While hydrogen sulfide and other gases may be economically removed from the system channeling steam

into an industrial process, it must not be allowed to escape into the atmosphere. EPA regulations strictly limit the amount of sulfur a point source can put into the atmosphere, and the Geysers plant in California has had trouble in the past meeting increasingly stringent air quality standards. Scrubbers have been used successfully, and will probably be needed to prevent sulfurous gases from escaping into the atmosphere.^{1/}

Excess water will have to be purified as well as the water used by an industrial process. Any excess water allowed to runoff into other bodies of water could pose serious contamination problems if the solvents have not been removed. Many geothermal plants around the world find it most economical to purify geothermal water to the point where it can be sold as mineral water or regular drinking water. Many cost analyses of proposed geothermal hot water projects include the value of this cleansed and commercially marketable water.

4) Reservoir Flows

One possible problem that faces industrial users of geothermal energy is the maintenance of a steady flow of hot water and/or steam from a geothermal reservoir. Many reservoirs, when partially depleted, supply water and steam at a slower rate or lower temperature. Several techniques have been developed to deal with this problem, especially by

^{1/} EIS Corporation, Control of Hydrogen Sulfide Emission from Geothermal Power Plants, Annual Status Report, June 1, 1975-May 31, 1976, prepared for Energy Research and Development Administration, July, 1976.

Pacific Gas and Electric for its Geysers power plant. Reinjection of water and steam to increase the flow of a reservoir is one procedure used, much like the injection techniques used by the oil industry on older, partially depleted wells. At a certain point, maintaining an adequate flow becomes more expensive than drilling a new well into a different section of the reservoir nearby. New wells are therefore drilled, and phased into the overall system as the old wells are phased out. All of this assumes that the reservoir has been adequately tested and measured and a specific productive life has been assigned to the reservoir. Geothermal potential is measured by MWe for periods of thirty years, and reservoirs that are considered to be commercially viable are assumed to have adequate flows for at least thirty years. However, there is much uncertainty with this assessment; no one can precisely gauge the reaction of a reservoir to years of exploitation and depletion.

Other related problems include possible subsidence of land lying atop of geothermal reservoirs (this is an especially critical problem for the geopressured brine fields that line the Gulf Coast).^{1/} Subsidence is the sinking of overburden or land atop a reservoir due to a lack of support from underneath. While subsidence of overcover has not happened at any major geothermal sites around the world, depletion of large, shallow reservoirs could lead to geological changes that could jeopardize the safety of a plant. No data has been collected concerning this possibility, and

^{1/} Lawrence Berkeley Laboratory, Geothermal Subsidence Research Program Plan, for Energy Research and Development Administration, April, 1977.

some basic research is needed before any conclusions can be drawn.

The problems associated with modeling geothermal energy use by industry arise from the site specific (and therefore varied) nature of the resource. Steam quality, heat content, maximum temperature and expected life of a given reservoir differ site by site, and matching reservoirs against different industry demands that are not broken down by temperature or region is an extremely difficult task. It has previously been noted that further study is needed to cross index reservoirs (in the form of KGRAS) against industry demand (broken down, by region or state, as best as is practical). Temperature requirements could be folded in, using the BCL or ITC data cited in the appendix on solar energy. This type of study could provide some rational and defensible basis for assigning new maximum market shares to geothermal technologies.

The technical issues discussed above have been folded into ISTUM through the cost distributions and the maximum market shares. The system modeled is a geothermal hot water system that flashes hot water to make steam. A liberal range of temperature, environmental control systems, and transportation distances have been included in the cost distributions. The cost distributions are methodologically consistent with other technologies' distributions and satisfy the needs of the model.

CHAPTER III

SERVICE AND FUEL DEMANDS

A. Introduction

The ISTUM model depends on a unique energy-use concept -- the service sector. A service sector is the final energy form which goes into the industrial product. For example if a food canner uses steam to cook canned vegetables, then it relies on the steam service sector for energy. Similarly, if a rifle manufacturer uses forges to shape gun barrels, it relies on one of the direct heat service sectors. The ISTUM model is concerned with the energy represented by the service sectors, rather than the initial fuel energy required to produce that particular energy form.

The amount of a energy an industry needs is called its service demand. For example the rubber and plastics industries (SIC 30) needed about 101 trillion Btus of steam in 1974^{1/}, so its steam service demand was 101 trillion Btus. That service demand represents the energy content of the steam after production efficiency and transmission losses. SIC 30 industries actually burned 146 trillion Btus of fuel to produce steam in 1974.

ISTUM forecasts service demands and fuel consumption for each SIC. A four-step process is used to make these projections.

^{1/} ISTUM relies exclusively on 1974 fuel consumption data. The Energy Consumption Data Base, which is used as the basis of most demand estimates, is currently available only through 1974.

First 1974 consumption of each fuel is estimated for all SICs included in the model. Then fuel consumption is converted into service demands: consumption is disaggregated into service sectors and multiplied by the fuel to service sector efficiency.^{1/} Next, service demands are increased according to growth rates in output. The result is service demand projections. Finally the model compares different technologies to determine what technologies industries will use in the future. (This is discussed in the rest of this report.) Fuel consumption can be estimated by dividing the expected service demands fulfilled by each technology by the efficiency of that technology. Figure III-1 shows the four steps ISTUM takes to project fuel demands.

The demand base controls several factors of interest to policy-makers. In each industry it determines which markets have the greatest potential for new energy conserving technologies, it forecasts service demand requirements, and, with the actual market share calculation, it predicts the actual number of Btus consumed by each technology. Chapter VIII of this volume suggests ways policy-makers might use information from ISTUM.

1. Estimating 1974 Fuel Consumption

The Energy Consumption Data Base (ECDB)^{2/} provided the ISTUM model with 1974 energy consumption for each SIC. The

^{1/} These efficiencies represent the number of Btus delivered to a service sector divided by the number of Btus of fuel consumed. In other words production efficiency multiplied by the transmission efficiency.

^{2/} Energy and Environmental Analysis, Inc., Energy Consumption Data Base. Developed for the Federal Energy Administration, June, 1977.

FIGURE III-1

CALCULATION OF ISTUM
FUEL AND SERVICE DEMANDS

ECDB converts physical fuel units into energy units: barrels of oil, cubic feet of gas and tons of coal are converted into Btus. It then lists the number of Btus of each fuel consumed by industrial SIC's in 1974.

ISTUM needs a demand base expressed in Btus of service demand in order to compete technologies. Technologies using different fuels compete for the same energy demand in the model. That demand has to be expressed in homogeneous units divided up between technologies.

2. Calculation of 1974 Service Demands

FIGURE III-2
CALCULATION OF 1974 SERVICE DEMANDS

First, the uses of each fuel in every industry were determined. Each use then was assigned to one of 23 service sectors (see Table III-1). Because the direct heat categories are particularly heterogeneous, they were broken out further into such service sectors as glass melting and ironmaking. Once energy consumption for a particular industry was allocated to service sectors, it was multiplied by process efficiencies to determine the SIC's service demands. The efficiencies represent the number of useable Btus of output divided by the number of Btus of fuel used.

TABLE III-1

SERVICE SECTORS USED IN THE ISTUM MODEL

1. Steam
2. Direct Heat - (Intermediate)
3. Direct Heat - (Dirty)
4. Indirect Heat - (coal capable)
5. Machine Drive
6. Electrolytic
7. Liquid Feedstock
8. Natural Gas Feedstock
9. LPG Feedstock
10. Metallurgical Coal
11. Miscellaneous Energy and Lubes
12. Space Heat
13. Indirect Heat - (not coal capable)
14. Calcining
15. Glass Melting
16. Brick and Clay Firing
17. Ironmaking
18. Steelmaking
19. Steel Reheating
20. Internal Generation
21. Captive Electricity
22. Captive Direct Heat
23. Coke Consumption

For example, the efficiency of converting fuel into steam is the number of Btus of steam used at the point of final application divided by the number of Btus of fuel consumed for steam production. Fuel to service demand efficiencies vary by fuel, service sector, and industry.

3. Projection of Service Demands

The ISTUM model forecasts service demands for each SIC by increasing service demands at the same rate the industry grows. Efficiencies generally increase over time, so the amount of fuel an industry consumes will increase at a slower rate than its service demands. That is, fuel demands will grow more slowly than service demands.

The problem of capital stock retirement complicates the calculations of new and old service demand. For this study, new demand is defined as service demand supplied by equipment purchased after 1974. This analysis assumes that some of the old demand is retired each year following 1974, but that some of the original capital stock will continue to operate past the year 2000 using old technologies at old efficiencies. For example, some existing boilers probably will operate in the year 2000 at present or lower than present efficiencies. New technologies do not compete for old service demand, but rather for incremental demand caused by growth and capital retirement in that industry. Figure III-3 illustrates the method by which new service demands were projected.

4. Projection of Fuel Consumption

ISTUM converts service demand forecasts back into fuel consumption estimates by dividing by efficiencies. New

FIGURE III-3
PROJECTION OF SERVICE DEMANDS

service demands supplied by conservation technologies in the form of fuels not used have infinite efficiencies. In general, new efficiencies exceed old efficiencies since industries tend to develop more efficient processes as time goes on.

B. Determining 1974 Fuel Consumption

1. The Energy Consumption Data Base

The ISTUM model relies heavily on DOE's Energy Consumption Data Base for its calculations of 1974 fuel consumption by SIC. The ECDB was chosen because of its appropriateness to the ISTUM model and quality of data. EEA, Jack Faucett Associates, and Ultrasystems compiled the ECDB for the Federal Energy Administration in May, 1977. The data base lists energy consumption in the industrial, agricultural, mining, transportation, commercial, and household sectors for 1967, 1971, and 1974. The ISTUM model uses the ECDB as the source of 1974 fuel consumption data for the industrial, agricultural, and mining sectors. The ECDB disaggregation of consumption by SIC code, type of fuel, and type of functional use also was used as input to the model.

a. Standard Industrial Classifications

The ECDB generally follows the Census Bureau's standard industrial classification system. Generally, the data base lists SIC fuel consumption at the two-digit SIC level. A few SICs that consume large amounts of energy -- paper, primary metals, and agriculture, for example -- were disaggregated beyond the two-digit SIC level. Generally, the ISTUM model includes energy consumption data for two-digit industrial, agricultural, mining SICs. The model disaggregates the

primary metals industry further -- into steel, aluminum, and other primary metals. The only non-industrial SIC's addressed in the model are crops, livestock, metal mining, and non-metal mining. Table III-2 lists the 26 SICs in the ISTUM model. The model treats each of these SICs as a different entity in all computer runs.

The ECDB investigates the energy consumption in some SICs quite thoroughly, documenting in separate volumes analyses of such high energy users as chemicals, petroleum refining, steel, stone, clay and glass, paper, metal mining, and agriculture. The ECDB also studies the food, textile, and aluminum industries extensively. However, the ECDB does not fully research energy consumption in some of the less energy-intensive SICs, such as apparel manufacture (SIC 23). The Annual Survey of Manufacturers^{1/} was consulted for data on fuel consumption by fuel type for these SICs.

b. Fuels

The ECDB expresses all fuel consumption in terms of Btus of fuel consumed. Secondary fuels have Btu values reflecting their actual Btu values instead of the energy content of their inputs. Thus, the ECDB converts one kilowatt hour of electricity consumption into 3412 Btus of energy consumption, rather than the 10,500 Btus of fossil fuel used to make that electricity. Tables III-3 and III-4 list the conversion factors used to convert standard units of different fuels into Btu consumption.

^{1/} Department of Commerce, Bureau of Census, Annual Survey of Manufacturers, 1974.

TABLE III-2

ISTUM SICs

<u>ISTUM SIC Number</u>	<u>SIC Name</u>
20	Food
21	Tobacco
22	Textiles
23	Apparel
24	Lumber and Wood
25	Furniture
26	Paper and Allied Products
27	Printing and Publishing
28	Chemicals and Allied Products
29	Petroleum Refining and Related Products
30	Rubber and Miscellaneous Plastics
31	Leather Products
32	Stone, Clay, Glass, and Concrete Products
331	Steel
3334	Aluminum
334	Other Primary Metals
34	Fabricated Metals
35	Machinery (except electrical)
36	Electrical Machinery
37	Transportation Equipment
38	Measuring Equipment
39	Miscellaneous Manufacturing Industries
01	Crops
02	Livestock
10	Metal Mining
14	Nonmetal Mining

TABLE III-3

BTU CONVERSION FACTORS
USED IN THE ECDB

<u>Fuel</u>	<u>Units</u>	<u>1967</u>	<u>1971</u>	<u>1974</u>
Distillate Fuel Oil	10^3 Btu/bbl	5825	5825	5825
Residual Fuel Oil	10^3 Btu/bbl	6287	6287	6287
Coal	10^6 Btu/ton	24.88	24.88	24.88
Coke	10^6 Btu/ton	30.12	30.12	30.12
Natural Gas	10^3 /cf	1032	1031	1031
Other Fuels	Btu/\$	614,160	580,040	575,263
Fuels NSK ^{1/}	Btu/\$	(Fuels NSK vary by 2-digit SIC code)		
Purchased Electricity	Btu/kWh	3412	3412	3412
Generated Electricity	Btu/kWh	10,500	10,500	10,500

SOURCE: Bureau of Mines.

^{1/} NSK: Not Specified by Kind.

TABLE III-4

BTU CONVERSION FACTORS FOR FUELS NSK

<u>SIC Code</u>	<u>1967</u>	<u>1971</u>	<u>1974</u>
	Btu/\$	Btu/\$	Btu/\$
20	2,363,444	1,958,945	1,013,319
21	2,371,388	1,652,126	821,667
22	2,325,044	1,743,489	808,913
23	1,386,826	1,424,228	901,031
24	1,413,902	1,263,785	794,211
27	1,441,086	1,557,652	973,095
30	2,560,983	1,949,171	915,452
31	2,142,483	1,706,000	755,357
34	1,702,813	1,585,374	917,302
35	1,833,999	1,687,209	938,013
36	1,904,304	1,659,099	908,147
37	2,028,347	1,653,375	867,635
38	2,028,347	1,660,708	797,224
39	1,732,206	1,638,658	853,080

SOURCE: Bureau of Mines

The Annual Survey of Manufacturers and other sources list fuel breakdowns of energy consumption in different industries. The ECDB used these sources to compile its own version of SIC energy consumption by fuel type. The ECDB allocates energy consumption into 12 different fuels for the industrial SICs and 8 fuels for the agricultural and mining SICs. These fuels include standard listings such as coal and natural gas, unconventional fuels such as asphalt and hydroelectric power, and industry-specific fuels such as liquefied petroleum gas. Table III-5 lists ECDB fuels for industrial, agricultural, and mining SICs. The data base includes consumption of captive fuels (such as the lumber industry's wood waste) as well as purchased fuels. When an industry uses a purchased fuel to create another fuel, the ECDB includes the Btu content of both fuels in its consumption base. A special captive fuel category contains a negative Btu value to offset the double counting. For example, if the food industry uses 26 trillion Btus of oil to generate 8.8 trillion Btus of electricity, the ECDB would list the following fuel consumption figures:

Fuel Consumption in Trillion Btus:

Electricity:	8.8 + purchased electricity
Oil:	26.0 + oil purchased for purposes other than electricity generation
Captive Electricity:	-8.8

Thus total fuel consumption equals the Btu values of fuels actually used.

TABLE III-5

ECDB FUELS

<u>Industrial</u>	<u>Agricultural and Mining</u>
Coal	Coal
Coke-Breeze	Gasoline
Distillate Oil	Distillate Oil
Residual Oil	Lubrication
Asphalt	Liquefied Petroleum Gas
Miscellaneous Petroleum Products	Natural Gas
Liquefied Petroleum Gas	Electricity
Natural Gas	Other Energy
Other Gas	
Hydroelectric Power	
Electricity	
Other Energy	

The ECDB fuel accounting methods offer several advantages to the ISTUM model. Because fuel consumption is expressed in Btus, technologies using different fuels can compete for the same service demands. In the case of electricity, each kilowatt hour competes for the number of Btus it can actually supply rather than the Btu value of its fuel inputs. The ECDB also accounts for unconventional and captive fuels, which represent substantial portions of energy consumption in some of the most energy-intensive industries. As examples, the petroleum refining industry relies on refinery off-gas and the steel industry relies on coke-oven and blast-furnace gas for fuels. The penetration of new technologies could not be predicted without examining the entire potential market instead of just purchased fuels. The ECDB is one of the few energy data bases that includes information on nonpurchased fuels.

c. Functional Use Data

The ECDB disaggregates energy consumption in some industries by functional use. The data base contains functional use data on the large energy intensive industries -- food, textiles, paper, chemicals, petroleum refining, stone, clay, and glass, steel, aluminum, crops, livestock, and metal mining. These functional use breakdowns are particularly useful when determining the service sectors for which an industry used a given fuel. Table III-6 lists the functional uses the ECDB lists for the different SIC groups.

2. Other Data Sources

Three fuel consumption data bases other than the ECDB were examined while developing the ISTUM fuel consumption base: the Annual Survey of Manufacturers, (ASM) the Major Fuel

TABLE III-6

ECDB FUNCTIONAL USES FOR DIFFERENT SIC GROUPS

<u>Manufacturing</u>	<u>Agriculture</u>	<u>Mining</u>
Space Heating	Space Heating/ Grain Drying	Direct Heat 400°F
Space Cooling	Space Cooling	Direct Heat 600°F-1000°F
Lighting	Waterheating	Direct Heat 1000°F-16000°F
Direct Heat < 600°F	Lighting	Direct Heat NSK
Direct Heat 600-1000°F	Refrigeration	Process Steam
Direct 1000-1500°F	Machine Drive/ Irrigation	Electricity Generation
Direct Heat > 1500°F	Farm Vehicles	Machine Drive
Direct Heat/NSK	Miscellaneous Uses	Other Uses/NSK
Raw Material		
Process Steam		
Electricity Generation		
Coke Production		
Machine Drive		
Electrolytic		
Other Uses/NSK		

Burning Installation (MFBI) file, and the National Emissions Data System (NEDS). These data bases could not improve on ECDB fuel consumption data, but all three did provide useful information on other inputs into the ISTUM model.

a. Annual Survey of Manufacturers

The Annual Survey of Manufacturers surveys the fuels purchased by industries in each four-digit SIC code annually. The ECDB relied on the ASM as a primary source, for fuel consumption estimates, and then revised the ASM data for its own estimates. For purposes of the ISTUM model, the ASM was useful only when disaggregating the ECDB fuel or SIC categories. For example, the ECDB aggregates Not Specified by Kind (NSK) and Not Elsewhere Classified (NEC) fuels. Since the ISTUM model specifies all energy by fuel type, ASM NSK fuels were allocated among other fuels, while NEC fuels were left as a separate category.

b. The MFBI survey

The Federal Energy Administration compiled the MFBI survey in 1974. The survey includes fuel consumption data on all installations capable of consuming at least 100 MMBtu/hour of fuel. The data base clearly could not supply the complete fuel consumption information necessary for the ISTUM demand base, but it was examined for other useful information.

The MFBI data base has several anomalies that detract from its reliability as a data source: Most burners show capacity utilizations of greater than 90 or less than 10 percent; the correlation between the size of boilers and their fuel consumption was less than .6; and firms used large

burners and boilers primarily for space heating. These MFBI statistics are probably invalid: most firms use 30 to 80 percent of their burner capacity; boiler size and fuel consumption is highly correlated; and firms use large burners and boilers for direct heat and process steam. So, although some of the MFBI space heating and capacity utilization data were considered when creating the ISTUM demand base, in general the data did not prove useful.

c. The NEDS file

The Environmental Protection Agency (EPA) has compiled the NEDS file over the past 10 years. The data base attempts to compile complete fuel consumption and emissions data on all boilers and burners in the U.S. The original NEDS file contained numerous errors; for example, it left out the state of New York. Because of such errors, most analysts have avoided using NEDS. However, EPA has updated and improved the original NEDS data. These data were consulted for ISTUM but many entries (records) were found to be inaccurate. For example, it included records showing boilers with capacity utilizations less than zero or greater than 100 percent. The remaining records showed believable and useful information on industrial boiler uses (5 percent space heating), capacity utilization (averaging 75 percent), and sizes (primarily between 50 and 200 MMBtus per hour).^{1/} The ISTUM demand base considers these NEDS results, but relies primarily on the ECDB because of the large number of inaccurate NEDS entries.

^{1/} All figures are weighted by Btus consumed.

The MFBI file also might be improved by ignoring bad records, but the NEDS data has much more potential as a tool for analyzing industrial energy consumption.^{1/} The NEDS file includes all fuel burning installations while the MFBI includes information only on installations capable of burning at least 100 MMBtu/hour. In drawing conclusions about an industry's fuel consumption patterns, an analyst should consider small as well as large installations. Potentially the NEDS file can describe total industrial energy consumption more accurately than the MFBI. At the present time, however, neither data base provides accurate information on energy consumption. Both data bases could be improved by careful editing.

3. Improvements in the Original ECDB to MOPPS Transformation

The ISTUM model is an improved version of the industrial section of the MOPPS model, created for the MOPPS task force in the spring of 1977. Since the MOPPS and ISTUM models both rely on the ECDB for energy consumption estimates, their energy consumption estimates rarely differ. The main difference between the two estimates is their treatment of ECDB NSK (Not Specified by Kind) fuels.

The ECDB NSK fuels category includes both NSK and NEC fuels. For purposes of the ISTUM model, the two fuel types were separated using the sources of the ECDB's NSK data -- usually the Annual Survey of Manufacturers. The revised ISTUM includes an NEC fuels category, which the model treats the same as any other fuel. ISTUM maps each industry's NEC fuels into one or two service sectors: for example, wood waste, which the lumber industry uses for fuel, is allocated to the steam and space heating service sectors.

^{1/} Recently, EEA began analyzing the MFBI for the national energy plan. The data base does yield far more reasonable results when some of the bad records are suppressed.

In most industries, it was assumed that small firms used NSK fuels. (These firms often do not report their fuel consumption). Energy consumption patterns in these firms generally coincided with consumption patterns in larger firms though small firms rely on clean fuels such as electricity, natural gas, and distillate oil more often. ISTUM allocates an industry's NSK fuels roughly in proportion to existing fuel consumption in that ECDB industry-functional use category, weighting clean fuels slightly more heavily than dirty fuels.

Tables III-7 and III-8 illustrate the effects of changes in ISTUM demand allocation methodology on the textile industry. Table III-7 shows the original ECDB estimates of textile industry fuel consumption by functional uses. Table III-8 shows how NSK and NEC fuels were disaggregated and how NSK fuel was reallocated roughly in proportion to existing fuel consumption patterns.

C. Allocating Consumption to Service Sectors

Once fuel consumption was determined for each SIC, it was allocated to the service sector for which it was used. For example, boiler fuel consumption was allocated to the ISTUM process steam, space heat, and internal generation service sectors in proportions to the amount of steam used for each application.

1. The MOPPS Allocation Methodology

The MOPPS model relied primarily on ECDB functional use information in allocating fuel consumption to service sectors. Each ECDB functional use-fuel mapping was translated into a single service sector. Table III-9 illustrates the translation

TABLE III-7

ECDB FUEL CONSUMPTION ESTIMATES FOR THE TEXTILE INDUSTRY
(10¹² Btus)

<u>ECDB Functional Uses</u>	<u>Coal</u>	<u>Distillate</u>	<u>Residual</u>	<u>Natural Gas</u>	<u>Electricity</u>	<u>NSK Energy</u>	<u>TOTAL</u>
Space Heat	1.2	1.7	2.3	4.0	1.4		10.6
Space Cooling					30.3		30.3
Lighting					11.1		11.1
Direct Heat/NSK				26.0			26.0
Process Steam	20.0	23.3	32.9	68.1			144.3
Electricity Generation	.5	.5	.8	2.1	-1.3		2.7
Machine Drive					44.2		44.2
Other Uses NSK	.4	.5	.7	1.8	6.1	38.1	47.5
TOTAL	22.1	26.0	36.7	102.0	91.8	38.1	316.7

TABLE III-8

ISTUM FUEL CONSUMPTION ESTIMATES FOR THE TEXTILE INDUSTRY
(10¹² Btus)

<u>ECDB Functional Uses</u>	<u>Coal</u>	<u>Distillate</u>	<u>Residual</u>	<u>Natural Gas</u>	<u>Electricity</u>	<u>NEC Energy</u>	<u>TOTAL</u>
Space Heat	1.2	1.7	2.3	4.0	1.4		10.6
Space Cooling					30.3		30.3
Lighting					11.1		11.1
Direct Heat/NSK				26.0			26.0
Process Steam	20.0	23.3	32.9	68.1			144.3
Electricity Generation	.5	.5	8	2.1	-1.3		2.7
Machine Drive					44.2		44.2
Other Uses NSK	.4	1.9	1.7	7.7	23.9	12.0	47.5
TOTAL	22.1	27.4	37.7	107.9	109.6	12.0	316.7

TABLE III-9
THE ORIGINAL ECDB TO MOPPS TRANSFORMATION FOR THE TEXTILE INDUSTRY
(10¹² Btu/yr)

<u>ECDB Functional Use</u>	<u>Coal</u>	<u>Distillate</u>	<u>Residual</u>	<u>Natural Gas</u>	<u>Electricity</u>	<u>NSK^{a/} Energy</u>	<u>TOTAL</u>
Space Heating	Misc. En. ^{b/} 1.2 ^{c/}	Misc. En. 1.7	Misc. En. 2.4	Misc. En. 4.1	Misc. En. 1.5		10.9
Space Cooling					Misc. En. 32.4		32.4
Lighting					Misc. En. 11.8		11.8
Direct Heat NSK				Clean Dir. Ht. 26.4			26.4
Process Steam	Steam 20.4	Steam 23.8	Steam 33.5	Steam 69.4			147.1
Electricity Gen.	Int. Gen. .5	Int. Gen. .5	Int. Gen. .8	Int. Gen. 2.1	Cap. Elec. ^{d/} -1.3		2.6
Machine Drive					Machine Drive 47.4		47.4
Other Uses NSK ^{e/}						Clean Dir. Ht. 38.1	38.1
TOTAL	22.1	26.0	36.7	102.0	91.8	38.1	316.7

a/ NSK energy - energy not specified by kind. ISTUM service demand category

b/ Misc. En. - miscellaneous energy

c/ Fuel consumed by the SIC-functional use fuel type category

d/ Cap. Elec. - captive electricity

e/ Allocated proportionally among other functional uses by fuel type in the original model

of the ECDB's textile industry fuel consumption and functional uses into the MOPPS textile industry fuel consumption and service sectors.

In the ISTUM model the ECDB functional use categories were refined further. It was not difficult to disaggregate ECDB fuel consumption according to ISTUM service sectors when ECDB functional uses corresponded with ISTUM service sectors. For example, consumption in the ECDB machine drive category simply was translated into the ISTUM machine drive service sector. However, ECDB functional uses and ISTUM service sectors did not always coincide. To take an extreme case, ISTUM maps the ECDB direct heat functional use into three general service sectors (indirect heat, direct heat (intermediate), and direct heat (dirty)) and six process-specific service sectors (calcining, glass melting, brick and clay firing, ironmaking, steelmaking, and steel reheating). To reflect the differences between functional uses and service sectors, individual ECDB functional use fuel categories are allocated into as many as four different service sectors for each SIC.^{1/}

ECDB functional uses were assigned to ISTUM service sectors in four basic steps:

^{1/} The ISTUM model generally allocates ECDB SIC-functional use-fuel categories into only two service sectors. Occasionally, more complexity was needed. For example, ISTUM maps the ECDB steel direct heat functional uses into the ironmaking, steelmaking, steelreheating, direct heat (intermediate), and direct heat (dirty) service sectors. EEA treated the few ECDB categories requiring more than two service sectors as special cases for the ISTUM model and inputted fuel consumption separately.

- translation to service sectors clearly defined by industry and the ECDB functional use-fuel category;
 - disaggregation of the ECDB direct heat functional uses into ISTUM direct heat and process-specific service sectors;
 - allocations of consumption according to data sources other than the ECDB; and
 - allocation of ECDB NSK functional uses to ISTUM service sectors.
2. The First Translation of ECDB Functional Uses Into ISTUM Service Sectors

In order to explain the functional use to service sector translations clearly, each service sector will be defined, and then the applicable functional uses listed.

Steam: Process steam used in the industrial processes. Includes steam for process heat, turbine drives, feedstock (as in ammonia synthesis), and miscellaneous applications such as partial pressure control in steam coil cracking in ethylene manufacture. Does not include steam for space heat or internal generation of electricity, although in the final calculations, steam resulting from cogeneration activities was credited against steam demand in each industry.

The ISTUM steam service sector generally corresponds with the ECDB process steam functional use. However, the ECDB category includes space heating in some industries.

Direct Heat (Intermediate): Applications where combustion products directly impinge on a manufactured product which can

tolerate few or no impurities. Examples are food and textile applications. This definition does not mean that only clean burning fuels such as natural gas or electricity can be used. In some cases, a heat exchanger fired with coal can make hot air which is suitable. Also, fuel oil using proper burners can supply an extremely clean flame which can substitute for natural gas.

This service sector was derived from the ECDB direct heat functional uses. Since those functional uses also apply to several other ISTUM service sectors, each industry-fuel combination was examined separately. The food industry, for example, burns natural gas to generate this clean form of direct heat in curing and cooking processes.

Direct Heat (Dirty): Direct heat applications which generally are not susceptible to contamination or degradation by the combustion product. This definition does not mean that coal can always be used in a direct-fired burner. Sometimes a high sulfur or ash coal can affect quality.

The ECDB direct heat functional uses also include this service sector. For example, paper mills use large amounts of dirty direct heat for drying.

Indirect Heat (Coal Capable): Identical concept to boilers except that hydrocarbons, instead of water, are heated. The current definition is restricted to process heaters in petroleum and chemical industries. A tube wall prevents the combustion products from impinging on the material being heated. Only those processes in which coal can be used without degrading the product are included.

This service sector also was derived from the ECDB direct heat functional use. Since few petroleum and chemical processes let combustion products touch the material being heated, nearly all ECDB direct heat for these industries was mapped into the ISTUM indirect heat service sector.

Machine Drive: Mechanical motion produced by energy other than that supplied by steam turbines. In almost all cases this is identical to electro-mechanical drive supplied by electric motors. An exception is heavy equipment in mining industries.

This service sector includes all of the ECDB machine drive functional use and some of the undefined ECDB functional uses.

Electrolytic: Process where electric current plays a direct role in material processing or transformation. The aluminum, chlor-alkali, and steel (from electric arc furnaces) industries are the main industries using this process.

The service sector corresponds to the ECDB electrolytic functional use.

Liquid Feedstocks: Petrochemical feedstocks for aromatics and olefins production. Olefins production based on liquid feedstocks is the residual demand which would not be supplied by LPG because of supply constraints.

Gas Feedstocks: Methane gas is most common feedstock. Gas feedstocks are used in the manufacture of ammonia.

LPG Feedstock: Olefins (such as ethylene) feedstock which is LPG. This analysis assumed that LPG could not be displaced. By definition, almost all LPG in this application

is ethane, an ideal ethylene feedstock. LPG includes ethane from natural gas.

The energy use for all three feedstock service sectors was estimated from the energy consumption listed in the ECDB chemical industry's raw material functional use. The industry uses miscellaneous petroleum products to create liquid feedstocks, natural gas to create gas feedstocks, and LPG to create LPG feedstocks.

Metallurgical Coal: High quality metallic coal burned by steel firms in coke ovens. The metallurgical coal service sector corresponds exactly with the coal use in the ECDB steel industry's coke production functional use.

Miscellaneous Energy and Lubes: Miscellaneous uses of energy which did not fit well within the service sector definitions used in this analysis. These include space cooling and lighting requirements, lubes and waxes, and asphalt. For the ISTUM analysis, the latter category was not included in the industrial sector. All other miscellaneous uses were treated as a residual and allowed to grow in proportion to the 1975 usage in each industry.

This analysis places the ECDB's space cooling, lighting, irrigation, and miscellaneous functional use energy consumption into the miscellaneous energy service sector. Generally, the purpose of all industrial energy consumption was determined, so the miscellaneous category does not include residual or unspecified energy use.

Space Heating: Energy used to heat buildings. This energy generally is supplied in the form of steam.

This service sector was derived from the ECDB space heat and process steam functional uses, since the ECDB did not analyze the use of steam for space heat thoroughly. The methodology for the development of the ISTUM space heat service sector will be discussed later in this chapter.

Indirect Heat (Not Coal Capable): Energy used for chemical and petroleum indirect heat processes which cannot use coal. Some processes that require indirect heat from fuels other than coal are ammonia production, hydrocracking, hydrotreating, and vacuum distillation. The ECDB lists indirect heat as a type of direct heat in the petroleum and chemical industries.

Calcining: A way of turning stone products into ashy powders by applying direct heat. The heat usually is applied in large rotary kilns -- cylindrical steel chambers tilted to allow material to flow through slowly. The cement industry accounts for most of the calcining service sector, although the lime, concrete, and gypsum industries also calcine their products.

Glass Melting: Heat required to produce glass. Generally, glass makers use regenerative furnaces, which send long, smooth flames over shallow tanks of raw materials to create glass. Most regenerative furnaces burn natural gas, but could be converted for pulverized coal use. The other major furnace used to heat glass is the unit melter. Unit melters are long, narrow chutes; flames from above heat materials as they flow through the chute. As with regenerative furnaces, most unit melters presently use natural gas for fuel.

Brick and Clay Firing: Firing of brick or clay in tunnel kilns. Kiln exhaust gases dry processed and shaped

clay, which then is fired in the kiln. The kiln is a long, refractory chamber with temperatures varying along its length. Presently, most tunnel kilns burn natural gas, but they also could use oil or coal. The main difference between heating brick and heating clay refractories is the latter process requires higher temperatures.

The three service sectors above are process-specific service sectors from the ECDB's SIC 32 direct heat functional use. Direct heat in that SIC was disaggregated into the direct heat service sectors and three processes: calcining, brick and clay firing, and glass melting. Nearly all stone, clay, and glass direct heat processes involve kilns or melters, so very little fuel consumption in the other direct heat service sectors has been included for this SIC.

Ironmaking (Blast Furnaces): Fossil fuels used to preheat blast furnaces. Does not include coke and breeze. A blast furnace is a tall refractory-lined chamber with hot air inputs at the base. Blast furnace stoves inject the hot air. The stoves are fired with fossil fuels, before the charge (iron, scrap, and coke) is dropped in the blast furnaces.

Steelmaking (Open-hearth Furnaces): Furnaces burning fossil fuels to melt a long bath of scrap, which then is covered with molten charge. Oxygen is fed into the bath expediting the creation of steel. This service sector does not include basic oxygen or electric arc furnaces. Basic oxygen furnaces require few fuel inputs, and electric arc furnaces are included in the electrolytic service sector.

Steel Reheating: Several types of furnaces in which steel ingots are formed and finished. Fuels for soaking pits,

slab/bloom reheat furnaces, and billet reheat furnaces are included. Soaking pits heat newly made steel in a thermal bath. Then the steel is reheated and shaped in one of two types of furnaces. Batch furnaces heat stationary steel piles to high temperatures, while continuous furnaces slowly heat steel as it moves along conveyors. Soaking pits and both types of furnaces burn fossil fuels.

The three service sectors above are process-specific service sectors in the steel industry. The industry uses direct heat (dirty) and direct heat (intermediate) as well as the process-specific direct heat service sectors. Energy consumption estimates were derived from the ECDB direct heat fuel consumption in the steel SIC.

Internal Generation: Fuels used for the generation of electricity. These include the full Btu content of fossil fuels burned in boilers that create steam for electricity generation (10,500 Btus per kilowatt hour).

This service sector was derived from the ECDB electricity to warrant self-generation capacity.

Captive Electricity: An artificial service sector created to avoid double-counting fuels burned for electricity generation and then used in other processes as electricity. Each kilowatt hour is valued at the Btu content of electricity -- 3412 Btus per kilowatt hour.

Captive Direct Heat: Coke oven and blast furnace gas. The steel industry uses these gaseous by-products as a fuel. This service sector was created to avoid double counting fuel consumption of metallurgical coal and coke oven gas, or coke and blast furnace gas. These fuels are used exclusively

in the steel industry. This category was derived from the ECDB steel industry's consumption of coke oven gas to produce coke (negative value since the process is reversed).

Coke Consumption: Treated as a separate service sector. Coke is consumed primarily in the steel industry where it is cheaper and more readily available. The chemical, stone, machinery, and equipment industries also consume some coke. This service sector was derived from the ECDB coke and breeze fuel category. The steel industry has a large negative value for its consumption of coke, since it produces more coke than it consumes.

3. Process Analyses

Several different methods were used to refine ECDB functional uses into ISTUM service sectors. Some ECDB direct heat functional uses had to be separated by process, since many different processes require direct heat and at different costs. These processes were put into new process-specific service sectors, so that technologies providing direct heat for different processes would not compete for the same market.

Processes were analyzed in some industries with heterogeneous service sectors. Only the direct and indirect heat service sectors were studied, since other service sectors, such as steam or electrolytic, vary little within an industry. If several processes required the same service sector in an industry, the decision on whether to disaggregate the service sector by process was based on two criteria:

- the cost variability in supplying the service demand for the different processes; and
- the number of Btus used in 1974 to supply the service demand for the different processes.

Generally, a service sector was disaggregated by process if each process consumed at least 100 trillion Btus of fuel, and the costs of supplying that service sector differed for each process. The steel and stone, clay, and glass direct heat sectors met these criteria, as did the chemical and petroleum industry indirect heat sectors. Table III-10 illustrates the results of one ISTUM process disaggregation of the ECDB. The ECDB shows the chemical industry consumed 509 trillion Btus for indirect heat in 1974. For the ISTUM model, it was determined that 282 trillion Btus of that energy were used in non-coal capable processes -- generally ammonia production. The temperature and fuel categories applicable to ammonia production also were determined, and non-coal capable fuel consumption estimates were derived from those ECDB categories.

4. Space Heat

Considerable effort was made to include a space heat service sector in the ISTUM model. Space heating differs greatly from other service sectors, especially in technology costs. Firms operate space heaters less than half the year and often at low load factors, so capital costs affect the technology cost distributions more than fuel or operating costs. Space heating also requires lower temperatures than most direct heat processes. Unconventional technologies such as solar energy can compete more successfully for the space heating service sector than for the high temperature direct heat service sectors.

TABLE III-10

THE ECDB DIRECT HEAT FUNCTIONAL USE AND
THE ISTUM INDIRECT HEAT SERVICE SECTORS
IN THE CHEMICAL INDUSTRY

Functional Use	ECDB Fuels x 10 ¹² Btus				Service Sector	ISTUM Fuels x 10 ¹² Btus			
	<u>Distillate</u>	<u>Residual</u>	<u>Natural Gas</u>	<u>Total</u>		<u>Distillate</u>	<u>Residual</u>	<u>Natural Gas</u>	<u>Total</u>
Direct Heat	31.3	41.9	435.8	509.0	Indirect Heat-Coal Capable	31.3	41.9	153.8	227.0
					Indirect Heat - not coal capable (ammonia)	--	--	282.0	282.0

MOPPS did not include a space heating service sector because of the scarcity of space heat data. The ECDB understates the amount of space heat in industries for which it has functional use data, and it has no functional use data for the industries which use the most space heat^{1/}. ECDB space heat data served as a lower bound for ISTUM space heat estimates, but these estimates were based on other sources -- the Drexel study,^{2/} the MFBI file, and the NEDS file.

The Drexel study sets up a data base of industrial energy use, and then determines the potential for energy conservation in each industry. To set up the data base, Drexel interviewed managers at 33 plants about consumption and uses of energy in their plants. The survey report shows which firms used burners or boilers for space heat and how much space heat each produced. Survey results indicate the importance of space heat for each SIC.

The MFBI survey included one question which asked boiler and burner owners to estimate the percentage of heat production used for space heating. EEA weighted these percentages by the amount of fuel consumed to determine industry-wide averages of the percentage of fuel consumption used for space heating. However, this calculation yielded an industry-wide average of two-thirds of fuel consumption used in space heaters. Because this figure is too high, space heating data were obtained from other sources.

1/ Generally, the machinery and equipment industries.

2/ Drexel University, United Technologies, Inc., and Mathematica, Inc. Industrial Applications Study, Final Report, prepared for ERDA Conservation, 5 vols. CONS/2862-1 through CONS/2862-5, January, 1977.

The NEDS file has an inherent advantage over the MFBI as a source for space heating data -- it includes all burners and boilers instead of only those installations consuming at least 100 MMBtu/hr of fuel. Since space heaters generally are small, NEDS has much more potential as a space heat data source than the MFBI. Only the NEDS boiler data were analyzed, and it was assumed generally that firms generate space heat primarily through steam production. NEDS provided reasonable results on the percentage of steam production used for space heat in most SICs; thus primarily these data were used for space heat fuel consumption estimates in the ISTUM model.

Table III-11 illustrates how the energy consumption of the paper industry's space heat service sector was determined. The ECDB shows the industry burning natural gas for space heat and several different fuels for steam production. The NEDS file shows that residual oil boilers as well as natural gas boilers provide steam for space heating. Consequently, approximately 3 percent of the ECDB's residual oil-process steam category was allocated to space heating in the paper industry.

5. NSK Functional Use Data

The ECDB did not classify all industrial energy consumption by functional use. In energy-intensive industries (i.e., food, textiles, paper, chemicals, petroleum refining, stone, clay, and glass, steel, aluminum, crops, livestock, and metal mining), it usually lists a small amount of undefined energy consumption. In all other industries, the ECDB does not disaggregate energy consumption by functional use at all.

The most difficult problem in transforming the ECDB into an ISTUM demand base was classifying the NSK functional energy consumption. This energy was allocated to service

TABLE III-11

PAPER INDUSTRY PROCESS STEAM AND SPACE HEAT REQUIREMENTS

(1974 - 10¹² Btus)

	ECDB Fuels						ISTUM Fuels					
	<u>Coal</u>	<u>Distillate</u>	<u>Residual</u>	<u>Natural Gas</u>	<u>Spent Liquor</u>	<u>Total</u>	<u>Coal</u>	<u>Distillate</u>	<u>Residual</u>	<u>Natural Gas</u>	<u>Spent Liquor</u>	<u>Total</u>
Space Heat	--	--	--	25.8	--	25.8	--	--	9.9	25.8	--	35.7
Process Steam	166.8	22.8	339.2	209.2	844.9	1583.5	166.8	22.8	329.3	209.2	844.9	1573.6
TOTAL	166.8	22.8	339.2	217.5	844.9	1609.3	166.8	22.8	339.2	217.5	844.9	1609.3

sectors on an industry by industry, fuel by fuel basis. ECDB NSK functional use energy consumption often corresponds to more than one service sector; the ISTUM model's many service sectors made the task of allocating ECDB NSK use fuel consumption easier.

The MOPPS model allocated NSK functional use energy in proportion to other functional uses in the corresponding SIC-fuel type category. In many cases, the proportional allocations did not reflect actual energy consumption patterns accurately. The ECDB derived functional use data from industry reports that sometimes ignored small firms, so NSK functional use energy often is energy used by small firms. These firms do not use fuel for all the purposes large firms do. For example, small firms in the food industry have few boilers, so the revised ISTUM model maps the ECDB SIC 20-natural gas-NSK use category into intermediate direct heat and space heat, but not steam.

Table III-12 shows the results of transforming the ECDB NSK functional use category into the appropriate ISTUM service sectors for the machinery industry. This SIC uses energy for five different ISTUM service sectors, but ECDB has no functional use breakdown. For instance, one ECDB functional use-fuel category, NSK use-natural gas, was disaggregated into three different service sectors. Basically, the functional use breakdown for this SIC was determined specifically for the ISTUM study since the ECDB did not do so.

6. Allocating Sizes and Load Factors

Because of modeling constraints, ISTUM does not use continuous distributions of sizes and load factors of energy

TABLE III-12
ENERGY CONSUMPTION IN THE MACHINERY INDUSTRY
(10¹² Btus)

<u>ECDB Functional Uses</u>	<u>Coal</u>	<u>Coke</u>	<u>Distillate</u>	<u>Residual</u>	<u>Natural Gas</u>	<u>Electricity</u>	<u>NEC Energy</u>	<u>TOTAL</u>
NSK Functional Use	22.3	4.8	18.8	18.3	182.0	100.5	14.4	361.1
<u>ISTUM Service Sectors</u>								
Steam	22.3		16.9	16.5	71.7		13.1	159.6
Coke Consumption		4.8						4.8
Space Heat			1.9	1.8	18.3		1.4	23.4
Direct Heat (Intermediate					91.0			91.0
Machine Drive						100.5		100.5
TOTAL	22.3	4.8	18.8	18.3	182.0	100.5	14.4	361.1

consumption devices (e.g., burners). Instead up to four size-load factor combinations were chosen for each service sector. Service demands were distributed among these combinations in ways that reflected the actual distributions of sizes and load factors. In steam, for example, service demands were distributed among two sizes (50 and 250 MMBtu/hr.) and two load factors (4000 and 7000 hours per year). The four resulting size-load factor combinations were used to reflect the actual sizes and capacity utilizations of industrial boilers.

For a given SIC-service sector combination, service demands were allocated to the different sizes and load factors. These allocations correspond to the actual patterns of energy consumption. For example, 76 percent of the petroleum industry's steam demand is in the large boiler-high load factor category. Only 12 percent of the textile industry's steam demand is in that category, since textile boilers are smaller and operate at lower load factors than petroleum refining boilers.

Generally, estimates of sizes and load factors were derived from four sources: Bureau of Census hours of operating,^{1/} the coal conversion study,^{2/} the MFBI file, and the NEDS file. Table III-13 lists service sector sizes, load factors, and the source of distribution estimates for each. Appendix III-1 includes tables showing the fraction of each SICs service demands allocated to the different size-load factor combinations.

The coal conversion study provided data on burner sizes in the direct and indirect heat service sectors. The study

1/ "Survey of Plant Capacity", 1974, Bureau of the Census.

2/ Energy and Environmental Analysis, "The Potential for Natural Gas Substitution in Selected Industries," prepared for the Department of Commerce, Office of Energy Programs, Draft Report, December 20, 1977.

TABLE III- 13
SIZES AND LOAD FACTORS IN ISTUM

<u>Service Sector</u>	<u>S.D. Sizes in MMBtu/hr</u>	<u>Capacity Factors Hrs/year</u>	<u>Data Source</u>
1. Steam	50, 250	4000, 7000	MFBI, NEDS
2. Direct heat (Intermediate)	10, 50	2000, 6500	coal conversion study
3. Direct heat (Dirty)	10, 50	6500	coal conversion study
4. Indirect heat coal capable	250	7500	coal conversion study
5. Machine drive	20, 100	4000, 7000	estimate
6. Electrolytic	600	6500	estimate
7. Liquid Feedstocks	250	7500	
8. Nat. gas. Feedstocks	250	7500	
9. LPG Feedstocks	maintained for energy accounting only		
10. Met. coal	maintained for energy accounting only		
11. Misc. Energy	maintained for energy accounting only		
12. Space Heat	25, 100	2500, 5500	NEDS data
13. Indirect heat not coal capable	250	7500	coal conversion study
14. Calcining	40	7000	coal conversion study
15. Glass Melting	41.6, 66.7	7000	coal conversion study
16. Brick Firing	13.1	7000	coal conversion study
17. Ironmaking	1.6, 133	5000	coal conversion study
18. Steelmaking	maintained for energy accounting only		
19. Steel Reheating	3, 60	5500	coal conversion study
22. Captive Direct Heat	maintained for energy accounting only		
23. Cok. Con.	maintained for energy accounting only		

Bureau of census hours of operation affected all estimates of capacity factors

examines direct heat processes thoroughly and its burner size estimates are sound. The study analyzes direct heat processes in several industries, leaving only a few of the small industries that consume direct heat (intermediate) uncovered. Distributions of burner sizes in those industries were chosen on the basis of engineering estimates.

The Bureau of Census hours of operation were considered in the capacity factors in all industries. They show how many hours per year the average plant in each industry remained open. While the correlation between hours of operation and capacity factors for energy consuming devices is not perfect, it is very high. In most service sectors variation in hours of operation by industry was used to vary load factors by industry.

The MFBI and NEDS files show substantial data on boilers sizes and capacity utilizations for the steam and space heat service sectors. Both data bases include data on all sizes and load factors in all industrial SICs. Since only NEDS covers boilers smaller than 100 MMBtu/hr., it was the exclusive source of space heat data.

7. Industry-Specific Analysis

Each ECDB industry was analyzed to determine industry-specific problems arising when translating data from ECDB to ISTUM. Seven general sources were consulted for this analysis: The Drexel study, the MFBI file, the NEDS file, the InterTechnology Corporation (ITC) study^{1/}, the Battelle

^{1/} InterTechnology Corporation, "Analysis of the Economic Potential of Solar Thermal Energy to Provide Industrial Process Heat, prepared for ERDA, Solar Energy, February 7, 1977. ■

study^{1/}, the EEA coal conversion study^{2/}, and individuals working in the industries' firms or trade associations. In addition, studies on individual industries were checked. This summary discussed the first three sources earlier; the other sources are described briefly below.

Inter Technology Corporation examined direct heat processes in 79 four-digit industries for their report, "Analysis of the Economic Potential of Solar Thermal Energy to Provide Industrial Process Heat". The ITC report considers steam to be a type of process heat; thus it covers the intermediate direct heat, dirty direct heat, indirect heat, steam, and all process-specific ISTUM service sectors. These service sectors account for 76 percent of the service demand for which new technologies compete.

Battelle also did a study on potential solar applications of industrial process heat. Battelle determined energy consumption patterns for the steam, direct, and indirect heat service sectors in 15 of the most energy-intensive industries. Both the Battelle and ITC studies supplied information with which to check the original ECDB to ISTUM transformation. These studies were especially useful when examining the industries for which the ECDB has no functional use data, making the ECDB to ISTUM transformation difficult.

1/ Battelle Columbus Labs, "Survey of the Applications of Solar Thermal Systems to Industrial Process Heat", prepared for ERDA, Solar Energy, January, 1977.

2/ Energy and Environmental Analysis, "The Potential for Natural Gas Substitution in Selected Industries," prepared for the Department of Commerce, Office of Energy Programs, Draft Report, December 20, 1977.

The coal conversion study examines the ability of industries to switch from natural gas to coal. This study disaggregates energy consumption by process in several industries, since some processes can use coal while others must continue to burn natural gas. This study served as the basis for ISTUM process analyses and also provided some information for the industry-specific analyses.

Industry spokesman had numerous comments about the uses of energy in each industry. Corporate and trade association representatives provided particularly helpful suggestions on the uses of energy in industries for which the ECDB has no functional use data.

Appendix III-2 describes the ways in which energy consumption was allocated in each industry to ISTUM service sectors. It briefly describes where and how ISTUM differs from the ECDB and cites sources justifying and explaining these differences. A complete printout of the ISTUM demand base by industry follows the explanations.

D. Forecasting Service Demand Growth Rates

1. Growth in Output as a Surrogate for Growth in Service Demands

a. The Basic Assumption

Growth rates were projected for each service sector in the ISTUM model. It was assumed that growth in output can be used as a surrogate for growth in service demands. This assumption implies that each unit of output will require the same amount of service demand in each model year. Other potential surrogates cannot model service demand growth rates

nearly as well as output. For instance, value-added growth rates introduce price fluctuations not related to production processes and, therefore, service demands. Sales growth rates also are inaccurate, since they are affected by both input and output growth rates.

The ISTUM model generally projects its demand base in physical rather than dollar terms. The output growth rate equals service demand growth rate assumption is consistent with that modeling procedure. Production processes generate physical output, and they consume service demands. As long as the processes stay the same, the growth rate of output will be the same as the growth rate of service demands.

b. Process Changes: Where the Assumption Fails

ISTUM also can forecast service demands when processes change. These changes fall into two categories: energy-saving process changes, and process changes for reasons extraneous to energy consumption.

(1) Conservation Technologies

The ISTUM methodology handles process changes designed to reduce energy consumption quite simply, by assuming that these technologies can produce service demands while consuming little or no fuel. The glass conglomerates technology (a pelletizing technology for preheating glass container batches) illustrates this concept. Potentially, this technology could cut energy consumption in the glass melting service sector by 5 percent, so ISTUM gives the technology a maximum market share of 5 percent. If the model finds the technology cost-effective, glass conglomerates will capture 5 percent of the service for the glass melting service sector. Other technologies

compete for the other 95 percent of the service demand, causing fuel consumption to drop by 5 percent.

(2) Energy Process Changes for Reasons
Other Than Fuel Savings

ISTUM has a more difficult problem in modeling major processes changes motivated by factors other than conserving energy. Technological innovation occurs for many reasons other than energy conservation: reduced labor time, higher-quality products, cheaper raw materials, and many others. In general, the model avoids this problem of technological innovations implemented for these other reasons.

For example, it does not consider ongoing process changes in the steelmaking service sector. Open-hearth furnaces consumed large amounts of energy (approximately 115 trillion Btus of fossil fuels) to make steel in 1974. Steel companies are in the process of buying basic oxygen furnaces (BOFs) to replace the existing open-hearth furnaces because BOFs cost less to use. BOFs also consume virtually no energy. It is safe to assume that for cost effectiveness reasons basically unrelated to energy consumption, no steel firm will build another open-hearth furnace in this country. Thus the steelmaking service sector will disappear in 10 years even though steel output will increase. However, ISTUM steelmaking service demands increase at the same rate of other service demands of the steel industry.

Some other process changes will cause service demands to shift from one service sector to another. For example, steam from coal boilers may replace gas and oil direct heat technologies, since the steam technology will probably be cheaper to use. Similarly some direct reduction technology may replace the electrolytic reduction process in aluminum.

The ISTUM model does not attempt to predict such process changes, and model results are inaccurate for any service sector in which such changes occur.

2. Output Indexes

Data Resources, Inc. (DRI) provided the ISTUM model with forecasts of production growth rates by SIC. These growth rates were inputted directly into the ISTUM model to calculate service sector growth rates. These are discussed fully in Chapter VI.

a. The DRI Model

DRI maintains a large econometric model of the national economy. The company also maintains submodels to forecast energy consumption, fuel and other prices, and several other important economic factors. These models have made accurate predictions of the course of the economy, enabling DRI to attain its reputation as the world's leading econometric modeling firm.

b. DRI Results

DRI based its forecast of industrial output growth rates on a run of its national economy model. DRI calculated these growth rates by SIC, as shown in Table III-14. There were few problems with converting the DRI SIC list into the ISTUM SIC list. The agriculture and food industries have the same index for output -- food production, so it was assumed that production in food and agricultural industries grew at the same rate.^{1/} The primary metals industry posed

^{1/} If exports of bulk food commodities increase at a different rate than other agricultural production, this assumption does not hold. However, the export sector of the agriculture industry should not change the industry growth rate seriously enough to affect ISTUM results.

TABLE III-14

DRI GROWTH RATES IN OUTPUT

Growth rate projections: compound annual rate (percent)

<u>SIC Number</u>	<u>SIC</u>	<u>1974-75</u>	<u>1975-80</u>	<u>Years 1980-85</u>	<u>1985-90</u>	<u>1990-2000</u>
10-14	Mining	- 2.1	3.54	3.37	2.59	2.09
20	Food	- 0.6	4.81	3.43	2.31	2.04
21	Tobacco	2.1	1.67	1.59	1.07	1.79
22	Textiles	- 7.6	5.68	4.08	3.53	3.08
23	Apparel	- 5.7	5.79	3.05	2.56	1.97
24	Lumber, Wood	- 7.3	8.37	2.51	1.72	1.53
25	Furniture	-14.0	7.17	4.69	4.10	3.28
26	Paper	-13.4	6.11	4.79	3.39	3.14
27	Printing and Publishing	- 4.2	4.48	4.03	3.26	2.95
28	Chemicals	- 7.5	8.75	6.44	5.88	4.76
29	Petroleum Refining	- 0.7	4.38	2.50	2.21	2.03
30	Rubber and Plastics	-14.5	11.79	6.47	7.04	5.15
31	Leather	- 1.7	0.48	-0.09	-1.57	-3.80
32	Stone, Clay, and Glass	-11.4	7.83	2.89	2.99	2.76
331	Basic Steel and Mill Products	-20.6	3.95	3.30	2.50	1.99
332	Iron and Steel Foundries	-18.6	6.41	3.14	2.80	2.28
333	Nonferrous Metals	-23.9	8.27	4.80	3.59	2.67
344-9	Other Primary Metal Products	-21.6	6.01	3.81	3.01	2.32
34	Fabricated Metal Products	-11.5	6.60	3.49	3.25	2.43
35	Nonelectrical Machinery	-10.8	7.26	6.21	4.55	3.93
36	Electrical Machinery	-19.0	8.56	7.57	5.67	4.43
37	Transportation Equipment	-10.2	7.01	3.70	3.45	2.67
38	Instruments	- 8.2	7.80	6.60	5.00	3.81
39	Miscellaneous	- 6.7	6.62	4.43	4.44	3.14

more of a problem, since DRI disaggregated this industry differently from that used in the ISTUM model. This problem was solved by using ASM energy consumption data to weight each of the DRI SIC 33 growth rates by fuel use. The weighted growth rates were then combined to calculate the growth rates in each of the ISTUM primary metals SICs. Table III-15 lists the ISTUM revision of DRI growth rates in industrial output by SIC. Appendix III-1 includes tables showing future service demands based on the ISTUM growth rates.

c. Other DRI Inputs to ISTUM

DRI supplied two other inputs into the ISTUM model: forecasts of fuel price distributions and forecasts of energy capital retirement. Energy capital retirement was discussed earlier in this chapter; the paragraph below discusses fuel prices.

DRI provided estimates of fuel prices and demands in 13 U.S. regions in 1974, 1977, 1980, 1985, and 1990. For the ISTUM model, regional prices were weighted by the demand for fuel in that region to calculate national price distributions for each year. Table III-16 lists DRI fuels and average national prices in each ISTUM year. Table III-17 lists the DRI regions and states which comprise them.

E. Forecasting Fuel Consumption

1. Converting Service Demands into Fuel Consumption

After the ISTUM model projects future service demands by industry, it converts those service demands into fuel consumption projections. This conversion requires two steps:

TABLE III-15
 ISTUM TRANSFORMATIONS OF DRI GROWTH RATES
 Rate Projections; Compound Annual Rate (percent)

ISTUM SIC Number	SIC	1974-75	1975-80	1980-85	1985-90	1990-2000
10	Metal Mining ^{a/}	- 2.1	3.54	3.37	2.59	2.09
14	Nonmetal Mining ^{a/}	- 2.1	3.54	3.37	2.59	2.09
01	Crops ^{b/}	- 0.6	4.81	3.43	2.31	2.01
02	Livestock ^{b/}	- 0.6	4.81	3.43	2.31	2.01
331	Steel ^{c/}	-20.6	3.95	3.30	2.50	1.99
3334	Aluminum ^{d/}	-23.9	8.27	4.80	3.59	2.67
334	Other Primary Metals ^{e/}	-21.3	6.69	3.86	3.09	2.40

All other SIC growth rates identical to DRI's.

- a/ Same as DRI Mining Output Growth Rates.
 b/ Same as DRI Food Output Growth Rates.
 c/ Same as DRI Basic Steel and Mill Products Growth Rates.
 d/ Same as DRI Nonferrous Metals Output Growth Rates.
 e/ Calculated by weighting other DRI primary metals growth rates by their energy consumption in 1974.

Weights: 29 percent Iron and Steel Foundries - SIC 332.
 25 percent Nonferrous Metals other than Aluminum - SIC 333 other than 3334.
 46 percent Other Primary Metals - SIC 334-339.

TABLE III-16

DRI FUELS AND THEIR AVERAGE PRICES FOR FIVE ISTUM YEARS
Delivered prices in \$/MMBtu)

<u>Fuel</u>	<u>Year</u>				
	<u>1974</u>	<u>1977</u>	<u>1980</u>	<u>1985</u>	<u>1990</u>
Electricity	5.53	6.69	7.23	7.99	9.33
Natural Gas	.82	1.73	2.34	2.90	3.24
Coal ^{1/}	.76	.97	1.02	1.16	1.39
Distillate Oil	2.26	2.53	3.06	3.39	3.86
Residual Oil ^{2/}	2.15	1.88	2.32	2.59	3.02

1/ ISTUM multiplies the coal prices above by 1.12 to include sub-unit train delivery premiums

2/ ISTUM adds \$.16 to the above residual oil prices to include delivery costs

TABLE III-17

DRI REGIONS AND STATES WHICH COMPRISE THEM

<u>DRI Region</u>	<u>States</u>
1. New England	Massachusetts, Maine, Vermont, Rhode Island, Connecticut, and New Hampshire
2. Middle Atlantic	Pennsylvania, New Jersey, New York
3. South Atlantic	Delaware, Maryland, District of Columbia, Virginia, West Virginia, Georgia, Florida, South Carolina, North Carolina
4. East North Central	Ohio, Wisconsin, Indiana, Michigan, Illinois
5. West North Central	Kansas, Nebraska, North Dakota, South Dakota, Minnesota, Iowa, Missouri
6. East South Central 1	Kentucky, Tennessee
7. East South Central 2	Alabama, Mississippi
8. West South Central 1	Oklahoma
9. West South Central 2	Texas, Arkansas, Louisiana
10. Mountain 1	New Mexico
11. Mountain 2	Montana, Colorado, Wyoming, Idaho, Utah
12. Mountain 3	Nevada, Arizona
13. Pacific	California, Oregon, Washington, Alaska, Hawaii

- determining the market shares of different technologies industries use to meet service demands (discussed in Chapter IV); and
- dividing service demand by the efficiencies of each of those technologies.

ISTUM separates service demand forecasts into two separate markets: new and old service demand. Conventional technology capital equipment already in place will continue to meet "old" service demand. As that equipment wears out the amount of old service demand will decrease. The service demand in 1974 provides the base for old service demand estimates. The technologies capturing the old service demand market were ascertained by examining the consumption of different fuels in 1974.^{1/} Appendix III-1 includes tables showing the quantities of each fuel used for different service sectors in 1974.

Both new and conventional technologies compete for the new service demand market. ISTUM determines the results

^{1/} Some minor conventional technologies were left out of the ISTUM model. The fuel service sector combinations left out were:

<u>Fuel</u>	<u>Service Sector</u>	<u>Service Demand in 1974 trillion Btus</u>
coke oven gas	steam	17
electricity	steam	3
electricity	direct heat (dirty)	7
electricity	glass melting	13
electricity	brick firing	2
electricity	iron making	6
electricity	steel reheating	5

of this competition by comparing technology costs. In the next iteration of the technology competition , previous winners remain in place since firms do not scrap capital equipment very quickly. New technologies still compete freely for the newest service demand appearing in the last iteration of the model.

After determining the technologies meeting future service demands, fuel consumption is calculated by dividing the amount of service demand each technology captures by the fuel consumption efficiency of that technology. The efficiency of new capital stock probably will exceed the efficiency of old capital stock, so different efficiencies were assigned to new and old technologies. Figure III-4 illustrates the way service demands were converted into fuel consumption for one ISTUM year.

2. Efficiencies

a. Calculations

Energy conversion efficiencies were needed for both new and conventional technologies in order to calculate fuel consumption. In accordance with the service demand methodology, efficiency was defined as follows: the number of Btus actually used in a service sector divided by the number of Btus consumed. For example, boiler efficiencies were calculated using the following equation:

$$\frac{\text{Btus of steam produced} - \text{Btus lost in transmission}}{\text{Btus of fuel consumed}} = \text{Boiler efficiency}$$

FIGURE III-4
CONVERTING FUEL CONSUMPTION INTO SERVICE DEMANDS

Efficiency calculations by boiler makers and most other engineers do not consider transmission losses. Because transmission losses are considered in all of the ISTUM efficiency calculations, ISTUM efficiencies are lower than efficiencies generally used elsewhere.

b. Sources of Efficiency Estimates

Three general sources were consulted for efficiency estimates for old energy equipment: the KVB report on boilers^{1/}, the Institute of Gas Technology study on direct heat^{2/}, and an Iron and Steel Institute study on energy conservation.^{3/} Efficiencies of new equipment were calculated based on sources discussed in Chapter II.

The KVB report discusses in depth both potential and actual boiler efficiencies. Most valuable, though, is the appendix showing results from a survey on efficiencies by fuel type and size and type of boiler. General gas, coal, and residual oil boilers have efficiencies of about

1/ KVB Assessment of the Potential for Energy Conservation Through Improved Boiler Efficiency, prepared for the Federal Energy Administration, January, 1977.

2/ Robert B. Rosenberg, IGT, "Energy Use for Industrial Heat and Power and New Process Developments for Conservation", National Gas Survey, vol. V, "Special Reports, prepared for the Federal Power Commission, 1973, pp. 283-306.

3/ American Iron and Steel Institute, "Energy Conservation in the Steel Industry," paper delivered at 84th General Meeting, May 26, 1976.

80 percent, while distillate oil boilers have efficiencies of about 85 percent.^{1/} Approximately 10 percent was subtracted from each of these efficiencies to account for transmission losses. The resulting numbers were input into the demand base.

The Institute of Gas Technology discusses methods of increasing industrial process efficiencies. The report studies steam efficiencies in the food, paper, chemical, and petroleum industries, and direct heat efficiencies in the stone, clay, and glass and steel industries. It generally assumes efficiencies of about 30 percent for direct heat processes. While the Institute of Gas Technology report does not have an extensive data base, it is one of the few studies that attempts to calculate direct heat process efficiencies.

The American Iron and Steel Institute also estimates direct heat efficiencies in its article on energy conservation. Using a steel reheat furnace as an example, the article points out where efficiency losses occur and calculates a net energy efficiency of 31 percent. Figure III-5 taken from the report, shows how this efficiency is calculated. Considering the Institute of Gas Technology and American Iron and Steel Institute efficiency estimates, the ISTUM model uses energy conversion efficiency of 30 percent for existing fossil fuel direct heat technologies. Table III-18 lists the ISTUM efficiencies for transforming fuel consumption into service demands.

^{1/} It is not clear why distillate boilers would have higher efficiencies than natural gas boilers. One possibility is that distillate boilers may tend to be newer (and hence, more efficient) than gas boilers.

FIGURE III-5
EFFICIENCY OF A STEEL REHEAT FURNACE

$$\frac{22 \text{ percent}}{72 \text{ percent}} = 31 \text{ percent (overall process fuel: service demand efficiency)}$$

SOURCE: IGT.

TABLE III-18

1974 EFFICIENCIES FOR TRANSLATING FUELS INTO SERVICE DEMANDS

<u>Fuels</u> <u>Service Sector</u>	<u>Coal</u>	<u>Coke</u> <u>Breeze</u>	<u>Distillate</u>	<u>Residual</u>	<u>Miscellaneous</u> <u>Petroleum</u>	<u>LPG</u>	<u>Natural</u> <u>Gas</u>	<u>Other</u> <u>Gas</u>	<u>Hydroelectric</u>	<u>Electricity</u>	<u>NEC</u> <u>Energy</u>
Steam	.7	.3	.75	.7			.7	.7			.6
Direct Heat											
Intermediate	.3	.3	.3	.3		.3	.3	.3	.8	.8	.3
Indirect Heat											
Coal Capable	.62		.62	.62		.62					
Machine Drive			.3/.35 ^{a/}	.3			.3		.95	.95	.3
Electrolytic									1.0	1.0	
Liquid Feedstock					1.0						
Natural Gas											
Feedstock								1.0			
LPG Feedstock						1.0					
Metallurgical											
Coal	1.0										
Miscellaneous											
Energy					1.0					.2/.3/.9 ^{a/}	
Space Heat	.65		.75	.7							
Indirect Heat											
Not Coal Capable			.62	.62			.62	.62			
Calcining	.3		.3	.3			.3			.8	.3
Glass Melting		.3	.3				.3			.8	
Brick Firing	.3		.3	.3			.3			.8	
Iron Making				.3			.3	.3		.8	
Steel Making				.3			.3	.3			
Steel Reheating				.3			.3	.3		.8	
Internal Generation	0		0	0			0	0			
Captive Electricity										0	
Captive Direct Heat								.3			1.0
Coke Consumption		1.0									

a/ Some service sector fuel combinations have different efficiencies in different industries.

c. Calculating 1974 Service Demands

1974 service demands in each industry and service sector were calculated by multiplying 1974 fuel consumption by the efficiencies of old energy equipment. Figure III-6 shows how 1974 fuel consumption in the steam service sector was converted into 1974 service demands. Tables III-19 and III-20 list the total fuel consumption and service demands in the ISTUM demand base.

F. Conclusion

The demand base of ISTUM continues to be a strong-point of the model. The soundness of the ECDB as a fuel consumption data source allows the model to calculate 1974 service demands in each industry quite accurately. DRI provided the best available industry growth rates for projecting future service demands.

1. 1974 Fuel Consumption

The ECDB provides fuel consumption estimates for 2 digit SIC codes. Those estimates are generally quite accurate. However, if the ISTUM model is ever disaggregated into 3 or 4 digit SICs, it will need a new fuel consumption data source. The MFBI and NEDS provide surveys on data on burners and boilers by 4 digit SIC, but those data bases should be analyzed and revised before being used.

2. 1974 Service Demands

The weakest, and most difficult, aspect of the demand base is the conversion of 1974 fuel consumption into service demands. The deficiencies fall into three categories:

FIGURE III-6
CONVERTING 1974 FUEL CONSUMPTION INTO SERVICE DEMANDS
(STEAM SERVICE SECTOR)

#S REPRESENT OVERALL AVERAGE

TABLE III-19

TOTAL 1STUM FUEL CONSUMPTION BY SIC (10E12 BTUS) 1974

	STEAM	DIR HT	DIR HT	INDR HT	MACHINE	ELEC	LIQUID	NAF GAS	LPG	MET	MISC RM	SPACE
	1	2	3	4	5	6	7	8	9	10	11	12
FOOD	201	504.6	226.1	15.9		104.5					34.6	30.5
TOBACCO	211	7.0	8.0	3.4								0.5
TEXTILES	221	150.5	43.4			56.1					53.3	10.7
APPAREL	231	16.6	24.7			19.1						4.4
LUMBER, WOOD	241	133.7	55.9			48.9						14.6
FURNITURE	251	14.8	18.7			21.8						3.7
PAPER, ALLIED PROD	261	1573.6		244.5		258.4						25.7
PRINTING, PUBLISH	271	8.0	40.1			38.3						2.7
CHEMICALS	281	1522.0	59.0		309.1	449.6	126.8	771.1	485.7	1074.4		14.2
PETROLEUM REFINING	291	646.5			1124.2	146.8						
RUBBER, MISC, PLAS	301	145.8	32.8			56.2						5.9
LEATHER	311	12.4	9.1									0.4
S.C.G., CONCRETE	321	49.5				152.8						25.3
STEEL	3311	257.6	135.6	140.9		130.9	64.7			2363.1		38.5
ALUMINUM	33341		129.0	19.8		70.5	92.3				1.9	
OTHER FRT. METALS	3341	48.6	292.3	12.0		318.4	15.0					4.1
FABRICATED METALS	341	130.0	116.9			78.4						59.7
MACHINERY (-ELEC.)	351	137.6	91.0			100.5						25.1
ELEC. MACHINERY	361	62.7	52.7			71.6						38.8
TRANSPORT, EQUIP.	371	136.1	60.0			101.0						70.1
MEASURING EQUIP.	381	15.6	8.6			16.8						9.6
MISC MANUFACTURING	391	23.0	11.1			15.7						0.7
TOTAL MANUFACTURING	1	5598.5	1395.0	436.6	1433.4	2256.3	466.5	853.4	485.7	1074.4	2363.1	395.3
CROPS	011		104.7			201.4						27.5
LIVESTOCK	021	10.0	22.2			23.9						48.5
TOTAL AGRICULTURE	1	10.0	126.9			225.3						76.0
METAL MINING	101	3.1	70.3			80.8						0.2
NONMETAL MINING	141	97.3	134.6			73.5						
TOTAL MINING	1	100.4	204.9			154.3						0.2
TOTAL INDUSTRY	1	5708.9	1725.8	436.6	1433.4	2435.9	466.5	853.4	485.7	1074.4	2363.1	408.7

INDR HT|CALCINE|GLASS|DRICK|IRON|STEEL|STEEL|INTERNAL|CAPTIVE|ICAP|DIR|CORE|TOTALS|
 1-COAL|3| 14|HEAT|15|FIR|16|MAX|17|MAX|18|RENT|19|GEN|20|ELEC|21|HEAT|22|CORE|23| 24|

FOOD	201							27.2	79.8			934.6
TOBACCO	211											19.0
TEXTILES	221							3.9	11.3			316.7
APPAREL	231											64.8
LUMBER, WOOD	241											253.3
FURNITURE	251											59.0
PAPER, ALLIED PROD	261							234.0	102.4			2223.8
PRINTING, PUBLISH	271											89.1
CHEMICALS	281	286.7						192.7	63.5		3.2	5211.0
PETROLEUM REFINING	291	1122.7						48.2	15.2			3073.2
RUBBER, MISC, PLAS	301											250.8
LEATHER	311											21.9
S.C.G., CONCRETE	321		724.4	237.8	80.3			6.4	72.0		25.8	1301.3
STEEL	3311					141.0	115.0	578.0	129.7	36.6	489.8	3420.5
ALUMINUM	33341								178.5	67.8		424.2
OTHER FRT. METALS	3341										65.8	756.2
FABRICATED METALS	341										2.2	407.2
MACHINERY (-ELEC.)	351										4.8	361.0
ELEC. MACHINERY	361										0.7	246.7
TRANSPORT, EQUIP.	371										3.1	370.3
MEASURING EQUIP.	381											50.5
MISC MANUFACTURING	391											50.5
TOTAL MANUFACTURING	1	1409.3	724.4	237.8	80.3	141.0	115.0	578.0	319.8	317.6	489.8	20105.6
CROPS	011											333.6
LIVESTOCK	021											118.0
TOTAL AGRICULTURE	1											451.6
METAL MINING	101								28.3	10.7		122.0
NONMETAL MINING	141											305.4
TOTAL MINING	1								28.3	10.7		427.4
TOTAL INDUSTRY	1	1409.3	724.4	237.8	80.3	141.0	115.0	578.0	348.1	328.3	489.8	21034.6

TABLE III-20

TOTAL 1STUM SERVICE DEMANDS BY SIC (10E12 BTUS) 1974

		STEAM	DIR HT	DIR HT	DIR HT	MACHINE	ELEC	LIQUID	HEAT GAS	LPG	NET	MISC	SPACE
		1	2	3	4	5	6	7	8	9	10	11	12
		INTER	DIRTY	COAL	DRIVE	SILIC	FEED	FEED	FEED	FEED	FEED	FEED	FEED
FOOD	201	356.1	67.8	4.8		79.3						7.3	21.4
TOBACCO	211	4.9	4.1	1.0									0.4
TEXTILES	221	106.6	13.0			53.3						40.2	7.8
APPAREL	231	11.7	15.7			17.3							3.2
LUMBER, WOOD	241	92.6	16.8			43.7							9.3
FURNITURE	251	10.3	5.6			15.8							2.4
PAPER, ALLIED PROD	261	1018.1		73.3		245.5							25.0
PRINTING, PUBLISH.	271	5.9	12.0			36.4							1.9
CHEMICALS	281	1057.4	31.2		178.9	352.4	126.8	771.1	485.7	1074.4			9.9
PETROLEUM REFINING	291	452.8			697.0	108.3							
RUBBER, MISC. PLAS	301	101.5	9.9			52.9							4.1
LEATHER	311	9.8	5.5										0.5
S.C.G. CONCRETE	321	35.1				131.7							20.8
STEEL	3311	180.1	40.7	42.7		124.4					2363.1		26.9
ALUMINUM	33341		38.7	10.1		18.8	260.0	82.3				1.9	
OTHER FRT. METALS	3341	34.0	102.8	3.6		163.9	15.0						2.6
FABRICATED METALS	341	90.2	35.1			93.5							41.9
MACHINERY (-ELEC.)	351	27.3	27.3			25.5							17.6
ELEC. MACHINERY	361	43.5	15.8			87.0							27.1
TRANSPORT. EQUIP.	371	94.5	18.0			95.9							47.7
MEASURING EQUIP.	381	10.8	2.6			16.0							6.0
MISC MANUFACTURING	391	16.2	3.3			14.9							0.5
TOTAL MANUFACTURING		3830.6	465.9	135.6	875.9	1877.4	466.5	853.4	485.7	1074.4	2363.1	49.4	276.7
CROPS	011		32.9			103.5							23.4
LIVESTOCK	021	7.5	6.7			22.7							48.5
TOTAL AGRICULTURE			39.5			126.2							6.1
METAL MINING	101	2.0	41.4			57.8						0.2	5.1
NONMETAL MINING	141	68.1	44.7			42.2							
TOTAL MINING		70.1	86.1			99.9						0.2	
TOTAL INDUSTRY		3908.2	591.6	135.6	875.9	2103.5	466.5	853.4	485.7	1074.4	2363.1	121.5	292.8

		INDR HT	CALCINE	GLASS	BRICK	IRON	STEEL	STEEL	INTERNAL	CAPTIVE	CAP	DIR	CORE	TOTALS
		1	2	3	4	5	6	7	8	9	10	11	12	13
		COAL	1	2	3	4	5	6	7	8	9	10	11	12
FOOD	201													536.6
TOBACCO	211													10.4
TEXTILES	221													221.0
APPAREL	231													47.9
LUMBER, WOOD	241													162.3
FURNITURE	251													35.1
PAPER, ALLIED PROD	261													1361.9
PRINTING, PUBLISH.	271													56.2
CHEMICALS	281	177.7												4268.4
PETROLEUM REFINING	291	696.0												1954.2
RUBBER, MISC. PLAS	301													178.3
LEATHER	311													14.6
S.C.G. CONCRETE	321		217.3	79.5	24.9									517.3
STEEL	3311					46.3	34.5	175.9						2791.6
ALUMINUM	33341													411.3
OTHER FRT. METALS	3341													19.7
FABRICATED METALS	341													261.5
MACHINERY (-ELEC.)	351													1.4
ELEC. MACHINERY	361													173.6
TRANSPORT. EQUIP.	371													257.1
MEASURING EQUIP.	381													35.3
MISC MANUFACTURING	391													34.9
TOTAL MANUFACTURING		873.8	217.3	79.5	24.9	46.3	34.5	175.9						13931.0
CROPS	011													159.8
LIVESTOCK	021													91.4
TOTAL AGRICULTURE														251.2
METAL MINING	101													101.4
NONMETAL MINING	141													155.0
TOTAL MINING														256.4
TOTAL INDUSTRY		873.8	217.3	79.5	24.9	46.3	34.5	175.9						14438.6

translation of ECDB functional uses into service sectors, calculations of efficiencies, and allocations of sizes and load factors.

Most ISTUM service sectors were developed from similar ECDB functional uses. In most industries the amount of energy consumed by a service sector will depend upon the amount of energy consumed by the corresponding ECDB functional use. For example, steam service sector consumption usually depends upon the ECDB estimate of consumption for its process steam functional use. However, the ECDB authors have little faith in their functional use data. The ECDB rates all data on an A,B,C,D quality code basis, quality code A being the highest quality data and D being the lowest. Functional use data received a D quality code in all industries. ECDB functional use breakdowns will probably be improved in the near future. If they are improved, the ISTUM demand base should be revised to incorporate the ECDB revisions.

ISTUM uses the efficiencies of existing equipment to convert 1974 fuel consumption into service demands. Except for the KVB boiler study, credible data on existing equipment were scarce. Further study on efficiencies is especially needed for the direct heat service sectors, for which efficiencies were assumed to be the same in all industries and all fossil fuels. It may turn out that the cement industry creates heat more efficiently than the food industry, or that burners convert gas to heat more efficiently than coal. If so, direct heat efficiencies should vary across industries or fuels.

Allocating all consumption in a service sector to at most two sizes and two load factors constrains the model. If a technology is competitive only for extreme size and load factor

cases, these factors presently must be considered in the choice of the technology's maximum fraction and cost distribution. Using more sizes and load factors or size and load factor distributions would allow more accurate modeling. Maximum fractions and cost distributions would be easier to select since they would no longer have to reflect a distributions of sizes and load factors.^{1/}

3. Forecasting Service Demands

ISTUM probably will never improve upon the use of DRI growth rates as a general method of forecasting service demands. The use of those growth rates poses two basic questions: whether DRI can actually predict the growth in output, and whether the growth in output actually reflects increase in service demands. The difficulty in defining output causes the first question to arise. How can a unit of output be defined for an industry which produces many products from a variety of raw materials? The food and chemical industries are two examples. However DRI, using Federal Reserve Board (FRB) production indexes, does attempt to predict output growth rates. Since the FRB and DRI maintain such high credibility for the calculation of such indexes, it seems necessary for ISTUM to accept the DRI output growth rate as the best available.

However those growth rates could be modified for the projection of service demands. Process changes, such as the retirement of open-hearth furnaces, can often be predicted. Since these process changes affect the growth rate of service demands, they should be considered in the conversion of

^{1/} At present each technology has the same maximum fraction for all sizes and load factors. However, it may be zeroed out of particular sizes and load factors.

output growth rates into service demand growth rates. The steelmaking service sector, for example, should have a strongly negative growth rate. Steel firms are replacing open-hearth furnaces with basic oxygen and electric arc furnaces; basic oxygen furnaces consume very little fuel and electric arc furnaces are in another service sector.

4. Forecasting Fuel Consumption

ISTUM forecasts fuel consumption quite accurately. Technologies compete for service demands in each model year; this competition is the crux of the model. Vendors of new equipment provided the fuel consumption efficiencies of these technologies. The service demands supplied by a technology are divided by its efficiency to give an estimate of the fuel it will consume. Summing the consumption of all technologies in a service sector yields a sound estimate of the total amount of fuel consumed for that service sector.

5. Areas for Further Work

In the near future work on the demand base is not nearly as pressing as some other ISTUM problems -- interdependencies and technology cost specifications, for example. However, if the development of the other sections of the model continues, the demand base will begin to constrain model validity. SICs may have to be disaggregated; efficiencies of old equipment may need to be recalculated; or service demands may need to be allocated to more sizes and load factors. While the demand base is not presently the component of ISTUM limiting the validity of results, it may need to be enhanced if the rest of ISTUM is improved.

FIGURE I-2

SCHEMATIC OF INDUSTRIAL SECTOR TECHNOLOGY USE MODEL