Conservation
—
Division of Buildings
and
Community Systems

Market Assessment of Fuel Cell Total Energy Systems Summary Report

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Total Energy Systems
Summary Report

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Resource Planning Associates, Inc.

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Table of Contents

	<u>Page</u>
LIST OF FIGURES	v
LIST OF TABLES.	vi
FOREWORD	vii
ABSTRACT.	ix
1. INTRODUCTION AND CONCLUSIONS	1
1.1 Approach and Methodology	4
1.2 Major Conclusions	7
REFERENCES	10
2. METHODOLOGY	11
2.1 Economic and Market Penetration Analyses	11
2.1.1 Economic Comparisons.	11
2.1.2 Market Diffusion	16
2.2 Market Segmentation	19
2.2.1 Time	19
2.2.2 Regions	20
2.2.3 Installation Type	20
2.2.4 Building Types	20
2.2.5 Building Size	21
2.3 Comparative Systems Analysis	23
2.3.1 Reference Building Selection	23
2.3.2 FCTES and Alternative Systems	24
2.3.3 Comparative Energy Systems Analysis Program (CESAP)	28
2.4 Extrapolation of Cost and Performance Data From Reference Building to All Other Size Ranges	35
2.4.1 Reference Segment System Cost Estimation	35
2.4.2 Extrapolation from Reference Building to Other Sizes	37
2.5 Effect of FCTES Use on Energy Resource Demands	39
2.6 Institutional, Legal, and Regulatory Analysis Methodology	43
2.6.1 Preliminary Issue Analysis and Telephone Survey	43

	<u>Page</u>
2.6.2 Field Interviews	43
2.6.3 Labor Practices and Operation Regulations . . .	45
REFERENCES	46
3. RESULTS OF ANALYSES	47
3.1 The Market for FCTES	47
3.1.1 Base Case Projections	47
3.1.2 Sensitivity Analyses.	52
3.2 Resource and Energy Use	62
3.2.1 Effects on National Energy Use	64
3.2.2 National Energy Use Effects — Range	65
3.2.3 National Cost Savings	67
3.3 Institutional, Regulatory, and Legal Analysis	68
3.3.1 Results	68
3.3.2 Conclusions	70
APPENDICES	
A. Base Case Description	71
B. Sensitivity Analyses Results	77
C. Supplementary Technical Data.	94
C.1 Criteria for Choice of Building Construction Quality .	94
C.2 Procedure for Extrapolating System Cost From Reference Buildings to Other Sizes	97
D. Sample Pre-Interview Letters.	99
E. Interview Procedure	101

LIST OF FIGURES

	<u>Page</u>
1.1 Market Model Logic	5
2.1 Energy System Discounted Cash Flow Equation, Private Ownership	14
2.2 Energy System Discounted Cash Flow Equation, Utility Ownership	15
2.3 Illustrative Market Penetration Curves	18
2.4 Department of Energy Regions	21
2.5 First Generation Fuel Cell Powerplant Heat Balance	26
2.6 System 1 Block Diagram	30
2.7 System 3 Block Diagram	31
2.8 System 4 Block Diagram	31
2.9 Comparative Energy Use Model	41
3.1 Summary of Assumptions: Base Case Market Analyses	48
3.2 Base Case Sales Projections.	49
3.3 Summary of FCTES Market Model Scenarios	54
3.4 Sensitivity Analyses Sales Projections	55
3.5 Sample Energy Balance: Conventional System	63
3.6 Sample Energy Balance: Fuel Cell System	64
3.7 Savings of Primary Energy and Net Increase in Use of Natural Gas Due to FCTES	65
A.1 Region 2 (NY, NJ) Fuel [Gas] Prices	72
C.1 Building T/E Distribution for Multi-family Residence in DOE Region 5 as Estimated by United Technologies Corporation.	95
C.2 Changes in T/E with Energy Conservation Practices	96

LIST OF TABLES

	<u>Page</u>
2.1 Reference Building Characteristics	5
2.2 Fuel Cell Cost	27
2.3 Supply and Demand Priorities for Systems 1 and 2	32
2.4 Illustrative Seasonal Performance Factors.	33
2.5 Major System Cost Items	36
2.6 Example Cost Estimation	38
2.7 Comparison of Fuel Cell and Conventional Prime Mover Efficiencies	40
3.1 Percentage of FCTES Sold for Retrofit for Each Module Size	50
3.2 Components of Changes in National Fuel Use, and Charges Over Time	66
C.1 Exponents for Cost Scaling Equations	98

FOREWORD

The Department of Energy (DOE) is promoting the development of the phosphoric acid fuel cell. Present-day fuel cells use natural gas or naphtha as fuels. They have excellent electrical load-following characteristics and high generating efficiency in small-size units; consequently, electric utilities have expressed interest in them for peaking applications.

The fuel cell also generates thermal energy with a sufficiently high temperature (140-200°F) to be useful for space conditioning and water heating applications, and is a relatively environmentally benign energy source. These properties, together with the electricity generation characteristics, make the fuel cell a potential candidate for total energy systems. The objective of this assessment was to estimate the market penetration potential of fuel cell total energy systems (FCTES) in non-industrial, single building applications. This study is based on the phosphoric-acid fuel cell modules being developed by United Technologies Corporation. They have developed a 40 kW(e) unit with waste heat recovery and have proposed a government-supported demonstration program in preparation for commercialization of this unit.

This assessment was initiated under joint sponsorship of the Division of Buildings and Community Systems (BCS) and the Division of Conservation Research and Technology (CONRT), Office of Conservation, Energy Research and Development Administration (now Department of Energy).

The Oak Ridge National Laboratory (ORNL) was given overall responsibility for performing the assessment and subcontracted with Resource Planning Associates, Inc. (RPA) to develop the market model and to study the non-technical barriers and incentives likely to be associated with FCTES implementation. The study was divided into five tasks as follows:

- Task 1 — Market Definition and Segmentation
- Task 2 — Institutional Analysis

Task 3 — Competitive Systems Analysis

Task 4 — Market Penetration Assessment

Task 5 — Analysis of Barriers and Incentives

Task 1, 2, 4 , and 5 were completed by RPA, while project management, Task 3, and final preparation of this summary report were the responsibility of ORNL.

In addition to the listed authors, important contributions and valuable suggestions were received from G. S. Leighton, G. E. Voelker, I. Sewell, and J. J. Cuttica of DOE; P. Bolan and J. Brown of UTC; and H. Bailly, D. Herring, S. Berger, R. Berman, H. Lowitt, S. Bowden, D. Hessian, A. Luttwak, D. Derrington, J. Kelly, and M. Strauss of RPA.

ABSTRACT

This report summarizes an investigation of the potential market penetration of fuel cell total energy systems (FCTES) into the non-industrial, single building market. Nine building types, two types of construction, and the ten Department of Energy (DOE) regions were used to model the market for the time period 1985-2000. Input data developed for the penetration model included size distributions of each building type and performance and cost characteristics of FCTES and competing conventional systems. Two fuel cell systems, fuel cell - heat pump and fuel cell - central boiler and chiller, were assumed to compete with two conventional systems, electric heat pump and central chiller-boiler models. Two fuel cell supply situations were considered: (a) one in which only 40 kW(e) modules were available, and (b) one in which a catalog of 25, 40, 100, and 250 kW(e) modules were available.

Data characterizing the economic climate, the intended market, and system cost and performance were used to determine the present value of life-cycle costs for each system in each market segment. Two market models were used to estimate FCTES sales. In the first, the perfect market model, FCTES sales were assumed to occur in all segments in which that system had the lowest present-valued costs. In the second, a market diffusion model was used to obtain a more probable (and lower) sales estimate than that of the perfect market model.

Results are presented as FCTES sales for each market segment by FCTES module size and the effect on primary energy use by fuel type. Probable sales predicted by the diffusion model during the 15-year period range from 0.56 million kW if only 40-kW(e) units are available to 3.45 million kW if the four-unit catalog is available. If the four-unit catalog is available and an extra 10% investment tax credit is allowed fuel cell owners, probable sales jump to ten million kW. Utility ownership was assumed for these cases; when private ownership was assumed, sales were reduced. The effect on national energy consumption is projected to be quite small. The high sales case is projected to save

2.0 quadrillion Btu's in fuel for electrical generation, but to increase natural gas consumption by 1.4 quadrillion Btu's during the 15-year period as compared to the conventional boiler-chiller system. For comparison, the projected natural gas consumption in the residential and commercial sectors in the same 15-year period is about 130 quadrillion Btu's. Deregulation of natural gas prices was projected to have a small effect, reducing sales and energy savings by only about 10%.

1. INTRODUCTION AND CONCLUSIONS

The U. S. Department of Energy (DOE) is promoting the development of 40 kW(e) fuel cell modules with waste heat recovery. Groups of these modules would be installed in individual buildings to provide electricity and part of the space and water heating requirements. It is recognized that use of total energy systems would save energy as compared to supplying thermal and electrical energy independently. At full load, fuel cells would convert about 40% of the fuel energy into electricity, and an additional 46% would be available to meet thermal loads.

The objective of this study was to provide DOE with sufficient market information for development of a national RD&D program for commercialization of fuel cell total energy systems (FCTES). Specifically, we aimed to determine the expected market penetration, impacts, and benefits of FCTES in comparison with alternative conventional systems. The influence of module size, geographic region, user sector, and institutional constraints were considered in determining the success of FCTES as a competitor.

The scope of the study was determined by ground rules established with DOE at the beginning and by assumptions made during the course of study. The most important of these are:

1. Information on cost and performance of FCTES would be used as supplied by United Technologies Corporation (UTC).
2. Only the residential and commercial sectors would be considered.
3. At least two and no more than six fuel cell modules would be used in a single installation.
4. Two supply situations would be considered:
 - (a) one in which only 40 kW(e) modules were available and
 - (b) one in which a catalog of 25, 40, 100, and 250 kW(e) modules was available.

5. Two or more fuel cell modules per installation would provide reliability equal to that of the electrical grid, and the FCTES would be isolated from the electrical grid.
6. The analysis would be completed for each of the ten DOE regions, and one city from each region would be used to represent climatic influences.
7. Only single building applications would be considered.
8. The period considered would be 1985 to 2000.
9. Problems of natural gas supplies would not be considered.
10. Utility ownership and private ownership would be considered.

The fifth ground rule is quite important because significant additional costs would be incurred if either an electrical grid connection or excess fuel cell capacity were required. Limited information is available concerning probable unscheduled maintenance because of the lack of operating experience. It was felt likely by UTC that unscheduled outages would occur no more frequently than does loss of electricity from the electrical grid. In addition, the requirement for a minimum of two modules per installation reduces the probability that more than a 50% loss of power would occur. If many fuel cell modules are installed in the same area, it is anticipated that a utility or a service organization will probably have a spare unit available to install in place of defective units in an emergency situation, minimizing the required down time. Disruptions of service for routine maintenance can be prevented by scheduling work during periods when normal building loads can be supplied without one of the modules. Another possibility is temporary use of a mobile unit for the period of scheduled maintenance. In light of these considerations, this ground rule was considered appropriate for the purposes of this assessment.

The seventh ground rule eliminated the possibility of considering FCTES for groups of neighboring buildings. Such a group might be composed of buildings whose individual load profiles made use of FCTES economical, but whose combined profile could well be met by a FCTES.

Estimating the market for FCTES for such applications would have been difficult because there is little information available about groups of buildings that might be potential users.

Although natural gas supply problems were not considered, it should be recognized that most current thinking is that natural gas supplies will be depleted within a few decades. Synthetic fuels may become available to meet demands for natural gas, but some additional development work is required to demonstrate the ability of the fuel cell to use such fuels. Also, additional economic analyses using projected synthetic fuel costs and fuel cell costs might be required to formulate future fuel cell development policy.

1.1 Approach and Methodology

The procedure used to project sales for FCTES, while requiring extensive data manipulation, was conceptually straightforward. The market model logic is shown in Fig. 1.1. First, data bases were developed to characterize the potential customers for FCTES and to establish cost and performance characteristics for each of the four competing systems. These data bases were then used to perform economic analyses to determine the present value of the costs anticipated for each system in each market segment. Finally, decision analyses were done to project FCTES sales on the basis of a comparison of the present-valued costs.

The potential customers were characterized by projecting the size distribution of building stock for each of nine building types in each of the ten DOE regions in each of three time periods between 1985 and 2000. Separate estimates were developed for stocks of existing (retrofit) buildings and new construction during each period. In order to adequately represent the building size distributions, we used the numbers of buildings in each of thirty size ranges between zero and 260,000 square feet. Representative load profiles (electrical and thermal), building construction properties, and other user-determined operation characteristics (e.g., ventilation) were determined for each type of building.

Because it would be an unmanageable task to design and simulate each of four energy systems in each market segment (10 regions x 9 building types x 2 types of construction x 30 size ranges = 5,400 market segments), the competing energy systems analyses were performed in detail for 480 market segments, and algorithms were developed to extrapolate the results to all other segments. The analyses were done by using the building operation and construction characteristics together with weather tapes for each DOE region in an hourly computer code. The output of the computer code includes information needed to verify system designs and to determine annual consumption of natural gas and electricity. From these data, cost and fuel consumption summaries for each system in each market segment were developed for use in the economic analyses.

Fig. 1.1. Market Model Logic.

The above data bases were used along with assumed economic parameters in a computerized economic analysis. This analysis considered the effect of taxes, discount rates, fuel costs, and many other parameters to determine the present value of all costs incurred by each system in each market segment. Economic data bases were developed to represent privately-owned systems, deviations from assumed fuel cell module costs, the allowance of additional tax credits for fuel cell system owners by government, and alternative fuel price scenarios. These data bases were used to perform sensitivity analyses to show the influence of various market and policy environments.

The decision analyses were performed by using the present-valued cost results from the economic analyses. Two market models were used. An upper limit to sales was estimated by assuming that FCTES sales occurred whenever a fuel cell system had the lowest present-valued cost (perfect market model). Unfortunately, knowledge of the comparative

cost of competing systems and the number of potential customers is not sufficient to estimate the sale of FCTES. Buyer behavior can seldom be summarized by cost alone. Many factors that affect buyers decisions cannot be quantified. However, economists and market researchers have tried to find simple mathematical formulations that are reasonable representations of actual buyer behavior. One of these models, the Bass durable product diffusion model, was used in this study. The Bass model builds from simple assumptions about innovative and imitative purchase decisions to produce a time-dependent penetration path for market sales.

1.2 Major Conclusions

In this study we developed sales estimates for FCTES based on a variety of assumptions. Our base case assumed that a four-unit catalogue of fuel cell modules (25, 40, 100, and 250 kW) will become available in 1985, that natural gas will be available for fuel cells, that fuel prices will be as forecasted by the Project Independence Evaluation System (PIES) Base Case, and that there will be no institutional, legal, or regulatory barriers to FCTES implementation. It was also assumed that there will be no government incentive for FCTES other than the 10% business investment tax credit, that the FCTES are utility-owned, and that market penetration is predicted by the Bass model. Fuel cell module costs were provided by UTC.

Additional sales projections were obtained by varying the base case assumptions. For example, it could be assumed that only 40 kW modules will be available, that sales will occur whenever FCTES have lower life-cycle costs than conventional systems, that fuel prices will be higher than forecasted by the PIES model, that the FCTES will be privately-owned, that the government will allow a 20% investment tax credit for FCTES, or that fuel cell module costs will differ from those projected by UTC.

We project that 3.4 million kW of FCTES capacity will be installed between 1985 and 2000 under base case assumptions. A total of 890 trillion Btu's of natural gas, but no electricity, will be consumed by the FCTES during this period as compared to 430 trillion Btu's of gas and 660 trillion Btu's of fuel for electrical generation for the conventional chiller-boiler systems in the same buildings. This implies a savings of 660 trillion Btu's of fuels for electrical generation (primarily coal and uranium), but an increase of 460 trillion Btu's of natural gas consumption during the period as a result of FCTES implementation. This represents an insignificant change in energy consumption in the residential and commercial sectors when measured by any yardstick. For example, projected consumption of natural gas by these sectors during the same 15-year period is about 130 quadrillion Btu's. A national cost savings of \$700 million (1976 dollars) is projected during the period

as compared to using the conventional chiller-boiler systems. This savings represents the present-value the life-cycle cost savings resulting from FCTES use over the system economic lifetime. This savings represents a 10.5% reduction in life-cycle costs as compared to the conventional system.

The most reasonable range of estimates of market penetration is from 0.9 to 9.9 gigawatts for the 15-year period. The low case is based on the assumption that the capital cost of FCTES will be 40% higher than UTC estimates. The high case is based on the assumption of an additional ten percent investment tax credit. If the federal government decides to encourage total energy applications, and FCTES specifically, the latter sales projection may be more meaningful than our base case estimate.

For these market penetration estimates, it was assumed that a catalog of 25, 40, 100, and 250 kW modules would be available beginning in 1985. Under this assumption, the 40 kW module appears to sell best with respect to the number of modules, but the 250 kW module sells best with respect to total installed capacity. The choice of a 40 kW module for a demonstration program is, therefore, not inconsistent with our results. UTC has proposed a federally sponsored demonstration program which would lead to commercial availability of the 40 kW module by the mid-1980's (see Reference 1 for a timetable of the proposed program). However, additional units would be added to the catalog at a later date, probably at least two to three years later. If it is assumed that 40 kW modules are introduced in 1985, but the remaining catalog units are not introduced until 1990, projected sales under base case assumptions drop to about two gigawatts.

The largest regional market for FCTES is in DOE Region 2 (New York and New Jersey). More FCTES will be installed in multi-family residences than in any other building type. There are three reasons for these two types of market dominance. First, Region 2 has the largest population of any of the 10 DOE regions. Second, electricity prices in that region are high, which favors an efficient system like FCTES. Third, because of the climate in Region 2, the thermal and electrical loads of

Ownership of FCTES by utilities or other third parties will significantly enhance sales. This is particularly true of retrofit installations, where third-party financing is a major incentive.

Based on our institutional analysis we feel that local and national policies on the use of natural gas will probably not be a barrier to the use of FCTES. Utility franchise issues and utility grid backup will also probably not be long-term barriers, but could impede initial introduction of the technology.

Deregulation of natural gas prices has a small effect on the quoted results. When base case assumptions are used, but with fuel prices based on deregulated natural gas prices substituted for the original fuel price projections, sales and energy savings estimates are reduced by about ten percent from base case results.

References

1. "Venture Analysis Case Study for On-Site Fuel Cell Energy Systems," prepared for D.O.E. by United Technologies Corporation, Power Systems Division, UTC report FCR-0783, July 1978.

2. METHODOLOGY

2.1 Economic and Market Penetration Analyses

A computerized market model was developed to project the potential market penetration of FCTES. This model integrates the building-equipment buyer's decision process with data that describe the total available market and the economics of FCTES and competing systems. This section describes the way the model simulates the buyer-decision process, and the way it projects FCTES sales. The first part describes the way the model determines whether or not FCTES are economically attractive to each market segment (the market segments are described in Sect. 2.2, below), and the second shows the way it simulates the effects of lags in market penetration caused by diffusion effects. Following sections provide a more detailed description of market segments, the analysis of buildings and systems, and the calculation of fuel savings.

2.1.1. Economic Comparisons

In each run of the model, fuel-cell total-energy systems (the fuel cell with heat pump, and fuel cell with electric chiller and gas-fired boiler) are compared economically to conventional systems (grid electricity and either the heat pump or chiller-boiler combination). The model projects the capital and operating costs of each system over 20 years for each segment, to produce a cost cash-flow. The projection is based on differences in capital and operating costs, and operating efficiencies between competing systems.

System Capital Costs. To allow consideration of the possible effects on FCTES sales from changes of the module sizes available, the model can consider two different assumptions about the availability of FCTES:

- * The only fuel-cell module size available is 40 kW.
- * Four different module sizes are available: 25 kW, 40 kW, 100 kW, and 250 kW.

The model calculates the peak electrical requirement of the segment from developed correlations of peak demand versus building size; if the demand is greater than 240 kW, in the case where only 40 kW modules are available, or greater than 1,500 kW,* if the catalog of modules is available, then the segment is skipped as a potential customer for FCTES. If FCTES can meet the peak demand, a module configuration (that is the number and sizes of the modules that minimize capital cost) is chosen, and module costs are computed. Installed costs of other parts of the system were similarly calculated from correlations of cost versus building size that were developed for this assessment.

Both of the FCTES configurations have nonannual expenses that are incurred at fixed multi-year intervals. Examples of these nonannual costs include replacement of the fuel cell stack every five years, and replacement of the fuel processor every ten years. The discounted cash flow accounts for the time-phasing of nonannual costs.

The conventional systems that compete with FCTES are combinations of conventional (grid-supplied) electrical service with either an electric heat-pump or a central gas-fired boiler and electric chiller. The market model computes the electrical and thermal demands of each building from reference building data and equations relating loads to building size and assumes that the building is supplied with electricity from the grid. It computes the cost of a properly-sized HVAC system in a similar way. The capital cost for the systems that compete with FCTES are only equal to the cost of the HVAC system necessary to meet building thermal demands. The model can consider other systems as well.

Annual Costs. The annual costs of system operation and maintenance are a function of system size, fuel prices, and building energy demand. These costs are constant over time, except as fuel prices vary. Although depreciation is not an out-of-pocket expense, it is included in the equation. The components of annual costs include:

*These limits derive from the technical limit of six modules in any single system. If only the 40kW module is available, the largest FCTES will be 240kW; if the catalog is available, the largest will be 1,500 kW.

- Insurance. The model includes an annual insurance charge that is a percentage of capital cost.
- Depreciation. The model uses the different depreciation methods used by different building sectors.*
- Fuel costs. The model calculates fuel costs (which includes grid supplied electricity) for each segment using regional retail commercial fuel price projections and the amounts of fuel required. Annual consumption of each type of fuel is based on the mean building size in the segment under consideration and developed correlations for fuel use versus building size for each system. Annual fuel requirements are assumed constant for each year of the life of every system.
- Amortization. When systems are financed by loans, their owners must pay both principal and interest. The amount of debt is determined by multiplying the fraction of capital investment that is typically financed by loans, by the capital cost. The model uses a special subroutine to calculate a principal and interest payment schedule for the debt, using the appropriate cost of capital for the segment and ownership arrangement.
- Operations and maintenance. Operations and maintenance costs are a function of system size and installed cost.

Net Present Cost Calculation. To summarize the cost cash flow associated with energy-system use, the model computes a net present cost (NPC). The manner in which NPC is calculated varies with system ownership.

If the system is user-owned, the user absorbs all costs of acquisition and operation directly. Tax effects are included in two ways: by subtracting the deductible portion of depreciation from the cash-flow, and by multiplying the remainder of the cash flow by (1 minus the tax rate) to calculate after-tax costs. The cash flow is then discounted at the appropriate rate for the market segment. The discounted cash flow is added to the effective net capital cost, equal to the equity portion of the capital cost minus any investment tax credit to produce the NPC. The capital cost is not discounted, since it occurs before all other costs (time zero). The equations the model uses are shown in Figs. 2.1 and 2.2.

ORNL-DWG 78-20200

$$\text{NET PRESENT COST}_p = E_p + \sum_{t=1}^H \frac{[A(t) - \tau_p \cdot d_p(t) + (1 - \tau_p) \cdot (M(t) + O(t) + NS(t) + I(t) + FL(t))]}{(1 + r_p)^t}$$

p = DENOTES THAT ITEM IS CHANGED FOR PRIVATE SECTOR OWNERSHIP

$A(t)$ = PAYMENT NEEDED TO AMORTIZE REMAINING DEBT IN PERIOD t

$$r_p = \frac{E_p}{D_p + E_p} r_{Ep} + \frac{D_p}{D_p + E_p} r_{Dp}$$

τ_p = TAX RATE, PRIVATE SECTOR

r_p = COST OF CAPITAL, PRIVATE SECTOR*

$d_p(t)$ = DEPRECIATION IN PERIOD t , PRIVATE SECTOR (VARIES BY DEPRECIATION SCHEDULE)

E_p = EQUITY PAYMENT, PRIVATE SECTOR*

$M(t)$ = MAINTENANCE COST IN PERIOD t

D_p = DEBT PAYMENT, PRIVATE SECTOR*

$O(t)$ = OPERATION COST IN PERIOD t

r_{Ep} = COST OF EQUITY, PRIVATE SECTOR*

$NS(t)$ = INSURANCE COST IN PERIOD t

r_{Dp} = COST OF DEBT, PRIVATE SECTOR*

$I(t)$ = INTEREST PAYMENT IN PERIOD t

H = TIME HORIZON

$FL(t)$ = RETAIL FUEL COST IN PERIOD t

*VARIES BY SECTOR

Fig. 2.1. Energy System Discounted Cash Flow Equation,
Private Ownership.

$$\text{NET PRESENT COST}_u = E_u + \sum_{t=1}^H \frac{[A(t) - \tau_u \cdot d_u(t) + (1 - \tau_u) \cdot (M(t) + O(t) + NS(t) + I(t))]}{(1 + r_u)^t}$$

u = DENOTES THAT ITEM IS CHANGED FOR UTILITY OWNERSHIP

$$r_u = \frac{E_u}{D_u + E_u} r_{Eu} + \frac{D_u}{D_u + E_u} r_{Du}$$

$$\begin{aligned} \text{NET PRESENT REVENUES NEEDED TO} &= \frac{\text{NET PRESENT COST}_u}{1 - \tau_u} = \text{NPR}_u \\ \text{YIELD UTILITY NET PRESENT COST} & \end{aligned}$$

$$\begin{aligned} \text{NET PRESENT COST TO PRIVATE OWNER} &= \sum_{t=1}^H \frac{(1 - \tau_p)((\text{NPR}_u \cdot \text{CRF}) + \text{FL}(t))}{(1 + r_p)^t} \\ \text{OF UTILITY OWNERSHIP} & \end{aligned}$$

CRF = CAPITAL RECOVERY FACTOR

Fig. 2.2 Energy System Discounted Cash Flow Equation, Utility Ownership.

When the system is utility-owned, the user incurs some costs directly and some indirectly. Indirect costs are those initially absorbed by the utility and passed on to the user. Direct costs are incurred and absorbed by the user alone. The indirect costs include all costs except fuel and possible grid backup. The indirect costs, including the amortized capital cost are discounted, using a utility discount rate, into an NPC. This utility NPC is multiplied by a capital recovery factor which incorporates the utility's rate of return. The adjusted utility NPC is the revenue the utility must receive from the investment. This is also the amount of money which must be paid by the user to the utility.

The model does not simulate a particular financial arrangement for utility ownership, but uses a general model that charges the full

financial costs of the utility owner to the user. The utility payment is added to the fuel and backup costs to create the user's cash flow. The cash flow is multiplied by (1 minus the tax rate) as before, and the cash flow discounted to the NPC using the rate appropriate for each market segment.

2.1.2 Market Definition

We assume that all energy-system buyers and operators base their decisions on cost effectiveness, as measured by net present costs. Since we are only concerned with sales of FCTES, the model first determines whether they are cost-effective for a particular segment. If FCTES have the lowest NPC in any particular segment, we assume that they can be sold in that segment and proceed to examine market penetration. If FCTES is not the cheapest system for that segment, we proceed to the next segment.

The "perfect market" model assumes that all buyers immediately choose the product with the lowest NPC. Economists usually use the theory of perfect markets in analyzing the market potential for a new product. This theory has four major assumptions:

- The services the competing products provide are identical.
- Consumers have perfect information about all products, and about the future.
- Consumers have no problem borrowing money.
- Consumers are rational.

Under these assumptions, the cheapest good will always capture the entire market.

In practice, these assumptions are never true. Even when the new product becomes available and is cheapest, it may be many years until it achieves a substantial market share — it might find no market at all. The process by which products come into use over time is called diffusion.

Diffusion has been formally modeled and empirically examined in a wide variety of contexts. Diffusion of an innovation may take time for a number of reasons, including:

- The slow spread of information
- Uncertainty about possible applications
- The desire of consumers to wait for further price reductions resulting from mass production

Studies of the diffusion of actual innovations have generally shown that successful ones grow in use following an S-shaped curve, (such as a Gompertz or logistic function) with a time scale on the horizontal axis, and percentage of market penetration on the vertical axis. Due to the problems listed above, we would expect that the proportion of adopters of the new product starts small, then grows rapidly up to a point. Subsequently, the rate of growth falls off, and with time the number of actual users of the product approaches the number of potential users.

This pattern has been observed for a wide range of new goods and technical and social innovations, including industrial processes, governmental innovations, and consumer durable goods.

The Bass Model. To simulate the actual diffusion process, the model uses a version of a diffusion model developed by Frank Bass.¹ This model is based on the assumption that, for many buyers, the probability that they will purchase a new product is based on the number of persons already using that product. Bass assumed that a small number of buyers, the innovators, are not influenced by others in their initial purchase. The majority of buyers, on the other hand, are imitators. Their probability of purchasing the new good depends on the number of persons who have already made purchases. The diffusion model requires a coefficient of innovation (p) and a coefficient of imitation (q). These values are used in an exponential function that calculates the cumulative percentage of the market that has been penetrated at any given time. The model uses the average of the cumulative penetration percentages of each of the five years in a period to represent the penetration rate for that period. Bass assumed that the coefficient of innovation (p) and the coefficient of imitation (q) are constant. The higher p is, the more important innovators are relative to imitators.

Estimates of the Coefficients for Bass Models A multiple regression technique was used to estimate the Bass coefficients, based on data concerning sales of air-conditioning units of all types, heat pumps, and total-energy systems.

These estimates of p and q were then used as base cases for the estimates of p and q for our market model. Those values were modified to reflect our views on innovation in each building sector.

Diffusion Effects on Sales Market penetration rates were then calculated by using the p and q estimates. The model calculates the number of buildings that will use FCTES by multiplying the total number of eligible buildings in each segment by the penetration fraction (a number between 0 and 1) to calculate the number of buildings for which FCTES will be bought. Illustrative penetration fraction versus time from initial commercialization curves are shown in Figure 2.3. The number of buildings times the number of modules per building gives the number of FCTES modules sold in a segment.

Fig. 2.3. Illustrative Market Penetration Curves.

2.2 Market Segmentation

The data base of eligible buildings was constructed in terms of square feet of space. Square feet of building space is an appropriate measure because building energy demands are usually estimated on that basis. The projected stock of eligible buildings incorporates the influences of demographic and economic changes, estimates of building life and removal rates, and historical and planning factors.

The market model considers the national market for FCTES in individual, non-industrial buildings through the year 2000. We disaggregated the market into 16,200 segments, for the years 1985 to 1999. The segments are characterized by differences in:

- time
- building types
- region
- installation types
- building sizes

While this large number of segments allows us to capture a great deal of detail in the market, and hence the differences between segments, it is not a very accurate representation of the differences between buildings. However, given the limitations of the data available, we believe that our segmentation is fine enough to capture the economic differences between potential FCTES users, and thus allows us to make reasonable comparisons between competing energy systems.

2.2.1 Time

Our projections of FCTES use are for the three 5-year periods between 1985 and 2000. We limit ourselves to these 15 years because it is unlikely that FCTES could be sold in substantial numbers before 1985, and because projecting sales after 2000 is too uncertain. Five-year periods were used because, it was felt that the data obtained adequately represented the time dependence of market penetration. Our data base includes information for years 1975 to 1984, but no FCTES will be commercially available in that period.

The breakdown we use does enable us to capture:

- * changes in energy prices that might change the relative costs of different systems
- * changes in the number of buildings that could use FCTES
- * the effects of market diffusion
- * changes in the mix of fuels used by central-station electricity-generating plants, and therefore the primary fuels displaced by FCTES.

2.2.2 Regions

The potential market was segmented by the 10 Department of Energy (DOE) regions, which comprise all of the United States. A map of the DOE regions is shown in Fig. 2.4.

While these regions are, from an economic, energy use, or climatological point of view, only arbitrary collections of states, few data are available on more pertinent regional divisions at a similar level of disaggregation. Further, the regions are convenient because DOE's Project Independence Evaluation System (PIES) model uses them to forecast energy prices and use. Where finer data were available, they were aggregated to the regional level.

2.2.3 Installation Type

Since FCTES could be used in either new buildings, or to replace outdated HVAC systems, new and retrofit installations were distinguished in our buildings data base. The economics and market acceptability of FCTES, as well as load profiles, differ between new and retrofit applications and this distinction was important to identification of appropriate demonstration applications.

2.2.4 Building Types

Both the energy demands and financial characteristics of building operations vary considerably according to the purpose for which the

Fig. 2.4. Department of Energy Regions.

building is used. To capture the differences between building uses, the building market was segmented into nine types: offices, hotels and motels, schools, colleges, hospitals, public administration buildings, other institutional buildings, multi-family residences, and shopping centers.

2.2.5 Building Size

Knowing the size distribution of the buildings that comprise the potential market for FCTES is important for two reasons. First, costs vary according to building sizes, and the resulting economic rankings of FCTES and other energy systems may also change. Second, one purpose of this study was to assess the attractiveness of a 40 kW FCTES module. The number and sizes of FCTES module sales depend largely on specific estimates of building utility demands which vary with building size for each type.

We originally restricted our building size breakdown to twenty ranges, from 0 square feet to 260,000 square feet and over. However, a finer disaggregation in the smaller size ranges was later deemed desirable. Our final data base, and thus our results, is based on a breakdown to thirty ranges.

2.3 Comparative Systems Analysis

Cost and performance data for fuel cell and conventional systems in each market segment are needed to predict the market penetration of FCTES. The total market is broken up into 16,200 market segments for this study — 9 building types x 2 levels of construction x 10 regions x 30 building size ranges x 3 time periods. For each segment, it was necessary to develop system cost and performance data for each of 4 alternative systems described below, for a total of 64,800 sets of cost and performance numbers. The real costs of the systems were assumed to be independent of the time period, but still 21,600 segments remain. A complete analysis for each segment is prohibitively expensive, both in time and money, so methods were devised to reduce the number of cases to be analyzed.

The greatest simplification resulted from development of techniques to extrapolate cost and performance results for a single building size and shape to all other buildings of the same type (two installation types—new and retrofit—were still considered). The extrapolated data were compared to data obtained by analyzing a second building size in selected cases, and good agreement was obtained.

In addition, six reference building types were judged to be adequate to model the nine building types mentioned above, as ownership rather than building construction differentiated some of the building types.

These simplifications reduced the required number of detailed analyses from 64,800 to 480.

2.3.1 Reference Building Selection

As mentioned above, the nine building types listed in the market segment definition section were modeled by only six structures. Colleges and schools were modeled with the same structure; so were offices, public administration, and other institutional buildings. Architectural characteristics for the six reference buildings were selected from published literature and from other ongoing ORNL work. This approach allowed us to compare our buildings loads to those predicted by other investigators.

When supplementary information about building shell characteristics or building operating data was required, the American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE) recommendations were followed. Only in a few cases (e.g., hospital hot water demand) was it necessary to develop information from sources other than ASHRAE. Some of the most important non-site-specific building characteristics are shown in Table 2.1.

2.3.2 FCTES and Alternative Systems

To successfully penetrate the market, the FCTES must be economically competitive with alternative methods of supplying space conditioning, water heating, and electricity. For the purposes of this analysis, two fuel cell systems and two conventional systems were considered. All buildings were assumed to have central equipment rooms and hydronic loops to distribute hot and chilled water throughout the building. All systems were assumed identical outside the equipment room. No costs for building space were considered for any of the systems.

The four systems considered were:

- System 1. Fuel cells with waste heat recovery and an electric heat pump; no thermal storage; gas-fired boiler for heat pump backup.
- System 2. Fuel cells with waste heat recovery; no thermal storage; gas-fired boiler supplies heat demand when heat recovery is insufficient; electrically-driven compressive chiller for cooling.
- System 3. Electric chiller for space cooling; gas-fired boiler for space and water heating; no thermal storage; gas and electricity supplied by conventional utilities.
- System 4. Electric heat pumps for cooling and heating; electric water heater; electric boiler for heat pump backup; no thermal storage; electricity supplied by conventional utility.

Table 2.1 Reference building characteristics.

	<u>Retail Store</u>	<u>Office</u>	<u>Hospital</u>	<u>School</u>	<u>Garden Apts</u>	<u>Motel</u>
Floor area (ft ²)	12,060	40,500	100,000	40,000	43,200	40,000
Stories	1	3	4	1	2	2
Ceiling Height (ft)	18.5	12.0	13.0	14.0	8.0	9.0
Glass Area (% of wall area)	10	30	25	20	18	30
Design indoor temperature (°F)	73.5	73.5	73.5	73.5	73.5	73.5
Design relative humidity (summer control only)	50%	50%	50%	50%	50%	50%
Infiltration and Ventilation (air changes/hr)	0.6	1.75	2.9	2.0	1.0	1.7
Peak Domestic Electric Load (w/ft ²)	4.3	11.1	4.8	4.0	1.2	1.5
Peak Occupancy	60	253	560	500	163	160

The fuel cell modules considered in this study are the phosphoric acid type being developed by United Technologies Corporation (UTC). Present modules require natural gas or naphtha for fuels, but the fuel processing stage can be designed to use other low-sulfur-content light distillates. Fuel cell modules are composed of many individual fuel cells, each normally operating at an electrical potential of slightly less than one volt. The individual cells can be connected in a series-parallel arrangement to provide almost any combination of output voltage and current. In addition to electricity, the fuel cell delivers thermal energy in three forms — steam at 250°F, hot water at 160°F, and hot water at 140°F. The performance characteristics are independent of module size, but vary with load as shown in Fig. 2.5. The costs vary relatively slowly with module size as shown in Table 2.2.

Fig. 2.5. First Generation Fuel Cell Powerplant Heat Balance.
(Source: United Technologies Corporation)

Table 2.2 Fuel cell cost (\$/kW)^a

(Source: United Technologies Corporation)

Size (kW)	25	40	100	250
Installed cost ^b	471	426	390	378
Annual Maintenance ^c	11	7	3	1
Stack Replacement ^d	98	96	96	96
Fuel Processing Replacemnt ^e	77	77	77	77

^a All estimates are based on a 10,000 unit/year (40kW equivalent) production rate, independent of size. Costs are in January 1976 dollars.

^b Installation labor cost is based on Connecticut rates.

^c Maintenance costs assume one planned outage to change filters and one unplanned outage.

^d Stack replacement occurs every five years. The cost omits labor cost; parts salvaged are assumed to cover labor cost. A \$30/kW credit for salvaged catalyst is included.

^e Fuel processing equipment replacement occurs every ten years.

2.3.3 Comparative Energy Systems Analysis Program (CESAP)

Cost and performance data for the fuel cell and conventional systems were developed by predicting the loads required by a building, selecting the components for each system, and simulating performance of each system to predict energy inputs needed. This work was performed using an hourly computer code, the comparative energy systems analysis program CESAP, which is an expanded version of the ORNL 1973 comparative energy analysis program developed for use with the Modular Integrated Utility System (MIUS) project.² The code is designed primarily as a tool to perform comparative systems analyses, rather than to predict accurately the actual loads for a specific building, but comparisons of its predictions with those of NECAP³ and Meriwether⁴ show good agreement.

Building Load Calculation Thermal transport between the exterior and interior of buildings is modeled by using transfer functions introduced in the 1972 *ASHRAE Handbook of Fundamentals*. Specifically, the loads calculation is an implementation of Chapter 22, "Air-Conditioning Cooling Load" and the transfer function coefficients are obtained from tables in the same reference. The calculations are done for one-hour intervals, so in addition to the building architectural properties (wall, roof, floor, and glass areas; lag times associated with building thermal inertia, and a parameter characterizing building construction), hourly weather data and non-environment-related user loads (water heating, process heat, and electrical requirements) must be specified. Profiles describing the building operation (occupancy, indoor temperature, humidity, shading coefficients, and ventilation) are also specified for each hour. The program is designed to handle two different types of daily operation, working days and holidays or weekends, for example. Hourly weather data was input from tapes available for one city in each DOE region.

To calculate the net building load for each hour the contributions from each source are summed. The heat losses and gains considered are those because of transmission, ventilation and infiltration, electrical

power use, regulation of humidity, solar radiation through glass, and latent and sensible heat of occupants. From the heat balance, the actual thermal and electrical demands on the energy system can be determined. Values for longer time periods are computed by summing over consecutive hours.

For the purposes of this comparative assessment, it was considered appropriate to assume that one wall faces due north and that all walls had the same area and the same amount of glass. Microclimate effects are ignored and the indoor temperature, humidity, etc., are assumed to be constant throughout the building interior.

System Performance Simulation The alternative heating, ventilating, and air-conditioning (HVAC) systems have been described briefly in Sect. 2.3.2. The simulations for systems 1, 2, and 4 were carried out in a series of CESAP subroutines. Design and performance data for system 3 were obtained by extrapolation of system 2 results.

Block diagrams showing the major system components are shown in Figs. 2.6 through 2.8. Beneath each figure is a brief description of how major components were sized. System 2 was identical to system 1 (shown in Fig. 2.6), except that a chiller was used in place of the heat pump, and the gas-fired boiler was larger.

In conventional systems, space conditioning and water heating systems operate independently, and electricity and gas are supplied by conventional utilities. Gas boilers and water heaters operate at full capacity for the portion of each hour necessary to supply that hour's loads. Either one or two heat pumps or chillers can be operated at a given time, depending on whether one unit can supply the demand.

The fuel cell system logic is more complicated. Chillers or heat pumps are operated to meet thermal demands and the fuel cell is operated to follow the total electrical demand. The waste heat available is determined from part-load efficiency curves supplied by UTC (Fig. 2.5). The complication arises from the need to allocate three waste heat streams and coordinate their use with system operation. The waste heat streams were allocated according to the priorities shown in Table 2.3. Thermal storage is included in the logic, but it was judged economically unattractive and was eliminated from our final system designs.

ORNL-DWG 78-20196

Fig. 2.6. System 1 Block Diagram.

System component sizing:

Installed fuel cell capacity was selected to meet the absolute maximum one-hour average peak electrical load occurring in a five year period. The heat pump was sized to meet all but the thirty highest cooling load hours per year (75 for ASHRAE 90/75) averaged over a five year period. Auxiliary gas boilers supplement the heat pump and fuel cell waste heat available to meet the average peak space heating load during five year period.

Fig. 2.7. System 3 Block Diagram.

System Component Sizing:

Electric chillers and gas boilers were sized the same way as for System 1.

Fig. 2.8. System 4 Block Diagram.

System Component Sizing:

The heat pumps were sized the same way as for System 1. Electric boilers were sized to meet the average peak one-hour space heating load during a five-year period.

Table 2.3 Supply and Demand Priorities for Systems 1 and 2.

DEMAND SIDE PRIORITIES

*Priorities for heat source for water heating

1. 140°F fuel cell water
2. 160°F fuel cell water
3. 250°F fuel cell water
4. Thermal storage
5. Gas water heater or boiler

*Priorities for heat source for space heating

1. 160°F fuel cell water
2. 250°F fuel cell steam
3. Thermal storage
4. Heat pump (for System 1 only)
5. Gas Boiler

SUPPLY SIDE PRIORITIES

*Priorities for use of heat from 140°F water

1. Water heating
2. Cooling tower

*Priorities for use of heat from 160°F water

1. Water heating
2. Space heating
3. Thermal storage
4. Cooling tower

*Priorities for use of 250°F steam

1. Water heating
2. Space heating
3. Thermal storage
4. Cooling tower

The heat pump and chiller properties used for this study are based on 1976 technology⁵⁻⁶ and two identical units were assumed to be installed in each system to improve reliability. For nominal capacities up to 80 tons, reciprocating units are used; for greater capacities, centrifugal units are used. The influence of outdoor air temperature on heat pump and chiller capacity and coefficient of performance was considered in the simulations. The seasonal performance factors (SPF) depend on climate, but illustrative values are shown in Table 2.4.

Part-load boiler efficiencies were taken into account in the simulations for systems 1 and 2, but only average values were used for systems 3 and 4 (60% and 75%, respectively). The average efficiency is expected to be relatively low for systems 1 and 2 because the boiler operates only when other heat sources prove insufficient. As an example, the calculated efficiency for the multi-family residence reference building in Region 2 is 44% for both systems 1 and 2.

Table 2.4 Illustrative Seasonal Performance Factors (SPF). Region 2, Multifamily Residence Reference Building. Pre-ASHRAE 90/75 Building

<u>System</u>	<u>Heat Pump or Chiller SPF*</u>	
	<u>Heating</u>	<u>Cooling</u>
1	2.1	3.1
2	—	3.3
3	—	3.3
4	2.0	3.1

*Does not include fan coils or building thermal distribution systems.

Costs for system components other than heat pumps and chillers were taken from accepted cost manuals. Heat pump and chiller costs were taken from previous ORNL work⁵⁻⁶. All costs used in the study were expressed in 1976 dollars.

2.4 Extrapolation of Cost and Performance Data From Reference Building to All Other Size Ranges

The approach used to estimate the cost and performance information for each market segment was to perform two detailed analyses for one building size for each building type in each of ten cities. One analysis was done using ASHRAE 90/75 building standards (for new buildings), and another for pre-ASHRAE 90/75 buildings. Each analysis consisted of a computer run to determine required component sizes and annual energy use. Once component sizes were selected, system costs could be determined.

System cost, energy use, and peak load data were developed for each of the 480 reference segments. These data, along with scaling laws developed to extrapolate the data from the reference building size range to all other size ranges, were used as input to the market penetration model.

The procedure for system cost estimation and illustrative data for one reference segment follow in Sect. 2.4.1. The method used to extrapolate these data to all other building size ranges is explained in Sect. 2.4.2.

2.4.1 Reference Segment System Cost Estimation

Annual energy use data (kWhr of electricity and cubic feet of gas), and peak demands on each system component are available directly from the computer printout. All quantities except the peak electrical load are averages over five years. The peak electrical load used was the absolute peak (including air conditioning) observed during the five year period.

For each reference segment, cost data were determined for each of the major components shown in Table 2.5, except that fuel cell costs were included separately during the market penetration analysis. For each component, a material cost, an installation labor cost, and an annual operation and maintenance (O&M) cost were estimated. The

Table 2.5 Major system cost items.

System 1	System 2
- heat exchanger (4)	- heat exchanger (4)
- pumps (12)	- pumps (12)
- heat pumps (2)	- chillers (2)
- cooling tower	- cooling tower
- gas boiler	- gas boiler
- fuel cells	- fuel cells
- contingency*	- contingency*
System 3	System 4
- water heater	- water heater
- pumps (12)	- pumps (12)
- chillers (2)	- heat pumps (2)
- cooling tower	- cooling tower
- gas boiler	- electric boiler
- contingency*	- contingency*

*25% of material and labor costs.

material costs and labor costs are summed, and increased by 25% to cover the costs of miscellaneous items (connecting piping, wiring, controls, etc.). Table 2.6 shows cost data for one illustrative market segment.

2.4.2 Extrapolation from Reference Building to Other Sizes

Because of the impracticality of performing the detailed cost and performance analyses for each size range, a procedure was developed to extrapolate the results from the reference buildings to other sizes.

The peak loads and annual energy requirements were assumed to scale linearly with building size. This assumption was tested by comparing extrapolated results to computer run results for the reference size and one smaller size for the hospital, and for the reference size and one larger size for the retail store. The building shapes were also changed. Excellent agreement was obtained between extrapolated and calculated energy use results. This result is not too surprising as many of the input loads are assumed independent of building size. This result implies that overall energy demand is relatively insensitive to characteristics of the building shell.

To extrapolate reference building cost data to other building sizes, an overall system cost scaling law was synthesized from the cost scaling laws of major system components. The non-fuel-cell costs were assumed to be a function only of the air conditioning design load. Since it was also assumed that the design air conditioning load varied linearly with floor area for a given building type and region, it follows that the equipment cost is a function only of the floor area. The form of the scaling equation used is:

$$\begin{aligned} \text{Cost for building size } X &= \\ &(\text{Cost for reference building of Size } Z) \left(\frac{X}{Z}\right)^s \end{aligned}$$

where s is the scaling factor for the system of interest.

The system cost scaling functions are discussed in Appendix C.

Table 2.6. Example Cost Estimate.

System 1 (Fuel cell-heat pump)
 System 5 (Chicago)
 Building Type 9 (Multi-family dwelling)
 Retrofit

<u>Cost Item</u>	<u>Material</u>	<u>Labor</u>	<u>Annual O&M</u>
4 heat exchangers	6,290	2,070	160
12 pumps	7,030	4,200	220
two 390,000 Btu/hr heat pumps	42,080	340	1,690
cooling tower	5,070	1,840	140
gas boiler, 813,000 Btu/hr	3,160	1,880	100
Subtotal	63,630	10,330	2,310
Contingency	15,910	2,580	0
TOTAL	79,540	12,910	2,310
(Total per square foot)	(1.84)	(0.30)	(0.053)

2.5 Effect of FCTES Use on Energy Resource Demands

The primary benefit to the nation that will result from FCTES use will be reduced energy consumption. Primary energy savings will occur because FCTES will produce electricity efficiently and on-site (thus avoiding the transmission and distribution losses inevitable with central generating plants) and because waste heat from FCTES will be usable for space conditioning and water heating.

To estimate the potential energy savings from FCTES use, we compared FCTES with a conventional reference system. The conventional reference system chosen was the electric chiller/gas-fired boiler combination, with grid-supplied electricity (system 3), as this was the most frequently used conventional system.

This choice for a reference system means that larger increases in gas use will be predicted than if the reference system used gas-fired heat pumps or gas-fired absorption coolers instead of electric chillers. If, on the other hand, we used an all-electric reference system, or one that used an oil burner, we would predict still larger increases in gas use (though still greater savings in energy).

For each segment, the primary energy required by FCTES and the conventional systems to meet building HVAC and electrical needs was estimated. The computation accounts for both the efficiency of generation and the efficiency of transmission and distribution.

For every kilowatt-hour (kWhr) of electricity used by the conventional system, the central station power plant must produce approximately 1.1 kWhr of electricity to compensate for transmission and distribution (T&D) losses. By using this factor, with estimates of heat rates (measures of the conversion efficiency of generating equipment, expressed in terms of Btu/kWhr), the amount of primary fuel that would be displaced by FCTES electricity generation was determined.

Estimates of generation equipment heat rates were grouped into the types listed in Table 2.7. There is a substantial difference between the heat rates of fuel cell⁷ and conventional generators,⁸ after adjustment

(multiplication by 1.1) to account for T&D losses. Fuel cells require only 8,750 Btu to generate 1 kWhr of electricity, while all other systems require over 11,000 Btu.

Table 2.7 Comparison of fuel cell and conventional prime mover efficiencies.

<u>Prime Mover</u>	<u>Heat Rate (Btu/kWhr)</u>
Fuel Cell	8,750
Nuclear	11,902
Oil and natural gas	11,880
Coal	11,880
Hydro, solar, geothermal synthetic	11,421

Data on electricity generation by type of generating equipment were projected by DOE's Project Independence Evaluation System (PIES) model to estimate fuel savings. These projections were best for our purposes because their assumptions are also consistent with those of fuel price projections used in the market model.

Electricity generation projections are for each of the 10 DOE regions, and for the years 1980, 1985, and 1990. Since cumulative sales of FCTES were projected at 5 year intervals between 1985 and 2000, we averaged the total electricity produced in the forecast years that begin and end each 5 year period (e.g., we take the average of the 1985 and 1990 projections to serve as the basis for our forecast of cumulative savings to the year 1990). For the FCTES forecast years 1994 and 1999, the PIES projections for 1990 alone were used.

In computing changes in energy use due to FCTES, the model (Fig. 2.9) accounts for the distribution of FCTES sales over time. We use the simplifying assumption that the total FCTES capacity installed in each 5 year period is installed in equal increments over the 5 years. Thus, the fuel-use change that would occur in any period due to capacity installed in that period is equal to one-half of that which would result from the total capacity installed by the end of that period. In subsequent time periods, the energy savings from this capacity was doubled.

Fuel Savings Calculations

* Derived by comparing FCTES with reference system.

** Kilowatt hours saved compared with reference system only; does not include savings due to the use of FCTES waste heat to meet building thermal demands.

*** BTU of gas used compared with reference system only; does not include energy savings due to FCTES electricity generation to meet building electrical demands.

Fig. 2.9. Comparative Energy Use Model.

To be completely accurate, the times at which FCTES operate should have been matched with the fuel mix used by power plants operating at those times. For example, at night, utilities use mainly base-load equipment. Furthermore, the PIES data are aggregates of all the utilities in each region and lose any fuel mix variations with regions. Finally, the PIES data uses the simplifying assumption that all areas face the same load-duration curve and corresponding generating mix (65% base-load, 33% intermediate load, and 2% peak-load). Given these limitations, the approximation of adding electricity produced by all types of generators is probably fair because, as the number of FCTES increases, the aggregate load profile of FCTES users will probably approach that of utility system customers.

Also, our market model extends to the year 2000. The mix of prime movers is assumed constant after 1990, although this will probably not be strictly true. However, since virtually all conversions of oil- and natural gas-fired plants to coal will be completed by 1990, the only changes thereafter will be that more coal, solar, geothermal, and nuclear power plants may be built to meet the new demand.

The model uses the PIES information to weight the measure of electricity saved to reflect both the primary fuel saved and regional variations in primary fuels saved. Because of the greater efficiency of fuel cells and the fact that they have no transmission and distribution losses, these energy savings are substantial. When the use of fuel cell waste heat is also included, the savings are even greater.

2.6 Institutional, Legal, and Regulatory Analysis Methodology

The institutional, legal, and regulatory environment that FCTES might face was analyzed primarily to identify issues that might be raised when FCTES enter the marketplace. While the results of our analysis (discussed in greater detail elsewhere, and summarized in Sect. 3.3) are not used directly in our projections, they are useful qualifications of those results.

It was clear at the outset that it would be nearly impossible to quantify any of the potential effects of non-financial variables on a market that would not be significant until the late 1980's. Thus, we restricted our investigation to an assessment of the potential issues associated with FCTES use. DOE may wish to consider these issues in its planning of FCTES program development.

2.6.1 Preliminary Issue Analysis and Telephone Survey

To start, we developed hypotheses about potential barriers to FCTES, based on studies of the commercial potential of similar energy systems. These hypotheses formed the core of a preliminary analysis of the potential regulatory, legal, and institutional issues that might arise from the use of FCTES.

We then prepared a telephone survey form and used it to guide interviews with persons knowledgeable about utility regulation and the institutional environment of on-site electricity generation. The telephone survey served to complete our definition of the important issues and confirm our initial hypotheses. Both the initial issue analysis and the telephone survey prepared us to conduct field interviews.

2.6.2 Field Interviews

The first step in conducting field interviews was to identify a group of states for in-depth analysis. The states were chosen to reflect variations in:

1. consumption of gas
2. availability of gas
3. forecast of curtailments
4. regulatory atmospheres
5. use of gas for electricity generation
6. membership of gas companies in TARGET (a utility group working with UTC on fuel cell R&D)

Interviews were conducted in California, Illinois, New York, Ohio, Pennsylvania, and Texas.

Major gas, electric, and dual-utility companies as well as the public utility commissions in these states were contacted to identify the individuals who could provide useful information and insights. A special effort was made to interview executives in charge of planning, research and operation; legal counsels; research consultants; tariff and rate staff; and engineering staff. We usually began by asking to speak with executives in legal or marketing positions. When contacted utilities were members of TARGET, we asked to speak with the representatives to TARGET.

The individuals identified were contacted by telephone to explain the purpose of our study and to arrange meetings with them and members of their staffs. Telephone conversations were followed up with letters explaining in greater detail the main topics (see Appendix E). Background information was compiled on the companies we were planning to visit, mainly to ascertain that they were not atypical in any respect (e.g., mix of customers served, operating procedures).

To minimize bias in the results, we developed an interview procedure (see Appendix F) to guide us in obtaining adequate information while maintaining a neutral posture. The interviews, conducted by teams of RPA consultants, began with short, introductory remarks outlining the purpose and scope of the FCTES market penetration study, providing some information on the 40 kW fuel-cell module, and indentifying the principal elements of our analysis. The people interviewed were asked to comment on a broad range of issues, potential problems, and possible solutions. At the end of each interview, we raised topics that had not been covered in the course of our discussions.

2.6.3 Labor Practices and Operation Regulations

The current status of labor practices and local regulations that govern the installation and operation of HVAC equipment were also analyzed. Pertinent literature was reviewed and telephone and personal interviews were conducted with people who know about the issues involved with using HVAC equipment.

Conventional HVAC equipment as well as FCTES were discussed. The advantage of this tactic is that people were sufficiently familiar with the conventional HVAC equipment and could thus make comparisons more easily. However, FCTES may not necessarily face the same environment as conventional HVAC systems. Therefore, results of our research, which are summarized in Sect. 3.3, can serve as a general guide for understanding the potential regulatory and union environment that FCTES might face.

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3. RESULTS OF ANALYSES

3.1 The Market for FCTES

3.1.1 Base Case Projections

The base case represents what are considered to be the most reasonable assumptions about the future market environment for FCTES and their competitors. The scenarios reflect a reasonably favorable market environment and a market that has not been influenced by federal government actions. The assumptions are summarized in Fig. 3.1 and a detailed description appears in Appendix A. The appendix also explains the sensitivity analyses of the effects of changes in the assumptions on the projected market for FCTES. Appendix B summarizes the results of each scenario run.

Total Sales. The base case projection (see Fig. 3.2) is that the FCTES sales rate will increase constantly and that 3.4 million kilowatts of FCTES capacity will be installed by the end of this century. Projected sales increase from 426,000 kW in the period 1985-1989 (average annual sales of 85,000 kW per year) to 1,466,000 kW in the period 1990-1994 (average annual sales of about 293,000 kW per year), and increase again to 1,563,000 kW in the period 1995-1999 (average annual sales of 313,000 kW per year).

This time pattern of sales is an important aspect of our projections of future FCTES sales, for three reasons. First, FCTES are projected to sell best in the latter periods, when we are least certain of our projections. Thus, energy prices and HVAC systems are likely to differ from our projected values. Second, FCTES capital cost estimates are based on the unit manufacturing costs of a plant that would produce the equivalent of 10,000 40 kW modules per year. This is the equivalent of 400,000 kW per year and 6 million kW of FCTES capacity between 1985 and 2000. However, FCTES will probably not sell fast enough to the non-industrial sectors to keep such a hypothetical plant operating at full capacity until the end of the 1980's or at the beginning of the 1990's. Accordingly, the FCTES costs used by the model for the first 5 year

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Fig. 3.1. Summary of Assumptions: Base Case Market Analysis.

- * FCTES sold between 1985 and 2000.
- * PIES base case energy prices (1975 model year).
- * No limitations on natural gas availability (unlimited hookups).
- * No institutional, legal, or regulatory impediments to FCTES use.
- * No government incentives.
- * All building types are eligible.
- * FCTES users will not have backup from electricity grid.
- * Utility ownership of units.
- * FCTES diffuse through the market.
- * Most favorable depreciation schedule for tax purposes double declining balance.
- * Catalog of FCTES module sizes available.
- * Ten percent investment tax credit applied to FCTES.
- * RPA estimates of cost of capital (interest and discount rates).
- * No changes in United Technologies Corporation estimates of FCTES capital cost.
- * Full production of FCTES by manufacturer.

Fig. 3.2. Base Case Sales Projections.

period are probably too low and thus, the projection of FCTES sales is too high unless there is an appreciable industrial market. This implies a possible feedback effect, as fewer and later sales would retard FCTES market diffusion, raise costs, etc. However, if other applications of fuel-cell technology (such as industrial applications) provided a significant market the problem might not arise. The model does show that the longer FCTES is in the market, the greater sales will be. The market model projects that non-industrial FCTES sales will require 80% of the capacity of the hypothetical facility by the late 1990's.

Sales by Installation Type. Base case sales projections indicate that most sales, in terms of kW of capacity, occur for retrofit applications of FCTES. Retrofit accounts for about 77% of the FCTES capacity

sold in the 1985-1989 period. The retrofit share declines to 76% in the next five year period, and declines further to 68% of the market in the 1995-1999 period.

Retrofitting will account for a smaller market share in terms of buildings than in terms of kilowatts. Sixty-three percent of the buildings using FCTES in the 1985-1989 period are not new; the percentage declines to 62% in the next period, and drops to 53% in the 1995-1999 period.

The size of the modules used varies considerably between installation types. As Table 3.1 shows, the relative importance of the retrofit market declines somewhat with time within each size class. The retrofit market will also rely heavily on 250 kW modules.

Table 3.1 Percentage of FCTES units sold for retrofit for each module size.

Module Size (kW)	Units sold for retrofit (%)			Total(%)
	1985-1989	1990-1994	1995-1999	
25	45	52	44	47
40	65	62	53	58
100	68	64	54	60
250	84	84	78	81

Sales by Region. FCTES sales, measured on the basis of kilowatts installed, will vary significantly among regions. Nine of the ten DOE regions will be penetrated. Region 10 (Washington, Oregon, and Idaho) was excluded from the potential market because the PIES Base Case projection of natural gas supply for that region showed that virtually no gas would be available in that area by 1990. In scenario 5, which assumes that wellhead natural gas prices will be deregulated, we presumed that natural gas would be available in Region 10 and that FCTES will sell there. Region 2 (New York and New Jersey) is by far the dominant

region. Region 2 sales represented 43, 45, and 49 % of installed FCTES capacity in the periods 1985-1989, 1990-1994, and 1995-1999. Region 2 sales were 46% of sales for the whole 15-year period.

Over the 15 year period, Region 6 (Arkansas, Louisiana, Oklahoma, Texas, and New Mexico) was the second most important region, accounting for about 18% of the FCTES sales. Regions 5, 3, 1, 9, and 4 ranked next, in order of importance, and in total accounted for about 33% of all sales (see Sect. 2.2 for a map of the DOE regions). Regions 7 and 8 accounted for 3% of sales.

Sales by Building Type. Our base case projections show that only 3 of our 9 building types will ever use FCTES. This result does not vary between periods, and neither does the relative importance of the three types.

The multi-family residences dominate the FCTES market, accounting for 73% of all installed capacity over the 1985-1999 period. The multi-family residential sector's share decreases from 78% to 77%, and finally to 68%, over the three periods.

Hotels and motels are the second most important market for FCTES, accounting for 20% of sales over the whole period. Hospitals account for 7% of installed FCTES capacity.

Sales by Building Size. Except for the largest size range (260,000 square feet and greater), the distribution of FCTES sales with building size is fairly uniform. Over the 15-year period, the biggest buildings accounted for 18% of all FCTES capacity installed. The next 9 size ranges accounted for 56% of all sales, and the next 16 ranges account for the rest, or about 26% of FCTES sales. The last two ranges, 0-2,500 square feet and 2,500-5,000 square feet were not penetrated at all, and sales in the next two ranges were negligible.

This result is not surprising, as larger buildings automatically need more capacity to meet their demands. Also, the larger FCTES units are cheaper, per kilowatt, than smaller ones.

Sales by the Unit Size. The sales breakout by number of units for each size showed clearly that the 40 kW module will sell best. The 250 kW module is quite important, and the 25 kW and 100 kW modules are least

important. In the 15-year period, about 35,000 fuel cell modules are sold; 17,000 are the 40 kW size, 8,600 are 250 kW modules, 4,700 are 25 kW modules and 5,000 are 100 kW modules.

However, the 250 kW module will be the most important, on the basis of installed kilowatts of capacity, accounting for 2.2 million of the 3.4 million kilowatts of FCTES capacity sold during the 15 year period, or 65% of all sales. The 40 kW module will account for 0.7 million kW, and the 100 kW and 25 kW modules will account for sales of about 0.5 million and 0.1 million kW.

3.1.2 Sensitivity Analyses

The base case (described in Sect. 3.1.1) represents what we feel to be the most reasonable assumptions about the future market environment for FCTES and their competitors. Under these assumptions, FCTES would penetrate 9 of the 10 DOE regions. A total of 3.4 million kW of FCTES capacity would be installed in 12,000 buildings in 3 building types between 1985 and 2000. Seventy-three percent of that capacity would be installed in retrofit applications.

The base case assumptions are, however, open to question. There is no guarantee that only utilities will own FCTES or that real energy prices will not rise substantially.

To illustrate the effects on market penetration of changes in important assumptions, we postulated 15 different scenarios as alternative to our base case. These scenarios include assumptions that differ from those of the base case on:

- Ownership of FCTES
- Market diffusion model
- Investment tax credits
- Fuel prices
- FCTES capital cost
- Existence of a catalog of module sizes.

A diagram of the differences among the 16 scenarios is presented in Fig. 3.3. The projections resulting from the assumptions of each scenario are summarized in Appendix B; sales are displayed in Fig. 3.4. The sections that follow contain discussions of the results of varying the major assumptions.

Ownership of FCTES. More FCTES would be sold if they were owned by utilities than if they were owned privately because utilities spread the payments for FCTES service over a longer period. For retrofitters (who have particularly high costs of capital), this difference is crucial. Without utility ownership, there is virtually no retrofit market.

Under scenario 3, which assumes no utility ownership, only 6% of all FCTES sold would be for retrofit applications. Sales of FCTES for retrofitting would be only 3% as great as they would be under base case assumptions. While sales for new construction would be slightly higher than they would be under the base case, losing the retrofit market would reduce the total market for FCTES to about 1 million kW.

If utilities do not own FCTES, only Regions 2 and 6 would be penetrated; however, the same building types would be penetrated as under base case assumptions.

Under scenario 10, which assumes no utility ownership and also immediate penetration of the market, there would still be hardly any sales for retrofitting. The same regions and building types that would be penetrated in scenario 3 would also be penetrated in scenario 10.

Market Diffusion Seven of our scenarios assume that FCTES will be bought immediately whenever they are cheaper to own and use than competing systems. Assuming that market diffusion would follow an S-shaped curve eliminates nearly all sales before 1989. However, the period between 1985 and 1989 has the greatest potential market. Under the immediate penetration scenarios, the greatest sales would take place between 1985 and 1989.

If market diffusion is assumed, as in the base case, not only would there be virtually no sales in the earliest period, but sales in the two later periods would never be as great as if there were immediate penetration. Nevertheless, even assuming the effects of diffusion, sales

	VARIABLE SETTINGS														
	MODULE SIZE AVAILABLE		MARKET DIFFUSION		ENERGY PRICES		FUEL CELL OWNERSHIP		EXTRA ITC*		FCTES CAPITAL COST ADJUSTMENT				
	40 KW ONLY	25,40,100,250 KW	PERFECT MARKET	BASS-1	FEA BASE	RPA-1	RPA-2	UTILITY	PRIVATE	NONE	10%	NONE	UP 10%	UP 20%	UP 40%
SCENARIO 1 (BASE CASE)		●		●	●			●		●		●			
SCENARIO 2		●	●		●			●		●		●			
SCENARIO 3		●		●	●				●	●		●			
SCENARIO 4		●		●	●			●			●	●			
SCENARIO 5		●		●		●		●		●		●			
SCENARIO 6		●		●			●	●		●		●			
SCENARIO 7		●		●	●			●		●			●		
SCENARIO 8		●		●	●			●		●				●	
SCENARIO 9		●		●	●			●		●					●
SCENARIO 10		●	●		●				●	●		●			
SCENARIO 11		●	●		●			●			●	●			
SCENARIO 12		●	●			●		●		●		●			
SCENARIO 13		●	●				●	●		●		●			
SCENARIO 14		●	●		●			●		●			●		
SCENARIO 15	●			●	●			●		●		●			
SCENARIO 16	●		●		●			●		●		●			

*INVESTMENT TAX CREDIT

*INVESTMENT TAX CREDIT

Fig. 3.3. Summary of FCTES Market Model Scenarios.

Fig. 3.4. Sensitivity Analyses Sales Projections.

of FCTES projected under various scenarios range between 56 and 65% of what they would be if the market were penetrated immediately.

Investment Tax Credits. The base case assumes that there would be a 10% investment tax credit (ITC), as is now the case for such investments. An additional 10% ITC would greatly increase sales of FCTES. Under scenario 4, which differs from the base case only in assuming an extra 10% ITC, total sales in the 15-year period would be 9.9 million kW, nearly three times what they would be under the base case. Five building types (instead of three under base case assumptions) would be penetrated, the new types being office buildings (quite significantly) and shopping centers. However, multi-family residences would continue to dominate the market, accounting for 62% of all sales in the 15 year period. Shopping centers would account for 20% and hotels and motels for 14%. Hospitals and office buildings would account for the remaining 4%.

An additional 10% ITC would also change the regional pattern of FCTES sales. Region 2 would still be the most important (although sales would barely increase in terms of capacity), but over 1 million kW of capacity would be sold in each of Regions 4, 5, 6, and 9. Region 3 would have sales of about 500,000 kW, Region 1 about 300,000 kW and sales in Regions 7 and 8 would be negligible.

The largest buildings would continue to dominate the market, although buildings in several of the smaller size ranges would buy significant numbers of FCTES. However, the 9 largest size ranges would account for 77% of sales.

The new market, would be much more important under scenario 4 than under the base case. Seventy-two percent of sales over the 15-year period would be for new buildings as compared to twenty-six percent in the base case.

The extra ITC would cost \$0.5 billion in lost tax revenue between 1995 and 1999, when half of the FCTES capacity would be sold. Over the 15-year period, the extra ITC would come to \$2 billion.

Scenario 11 assumes the extra ITC, as well as immediate penetration of the market. The main difference between the results under these assumptions and the results under the base case is that the 1985-1989 period would be much more important and total sales much greater if there were immediate penetration. The total extra ITC under scenario 11 would be nearly \$2 billion.

Fuel Prices. Three different fuel price scenarios are used in this study. The first (FEA Base) uses the FEA base case PIES run. The second (RPA-1) and third (RPA-2) are modifications of these prices based on alternative plausible national energy policies.

The FEA base case PIES run presumes that a set of special assumptions and circumstances will apply to the energy economy in the future, as a best guess about its nature, given that the Congress has not yet (early 1978) finished its deliberations on the National Energy Plan. The FEA base case is fairly optimistic and anticipates that the present regulatory structure will continue.

Specifically, the base case assumes that current domestic natural gas and oil wellhead pricing policies will remain in effect, and that

the price of crude, delivered to New York, is constant at \$13 per barrel in 1976 dollars. The wellhead price regulation assumption, on natural gas, is that the ceiling price of new natural gas dedicated to the interstate market is held constant. The assumption on oil prices is that domestic controls on old oil remain and that the entitlements program continues. The PIES forecast is also based on the Data Resources, Inc., August 1976, "Control Long" macroeconomic forecast, as modified by the President's Council of Economic Advisers. This forecast, known by the acronym CEASPIRIT-77, shows real GNP increasing by about 3% per year between 1980 and 1990 and total industrial production increasing by about 4% per year.

The PIES base case also assumes that:

- o No natural gas is transported from Alaska's North Slope until 1990
- o Four Outer Continental Shelf areas (each assumed to be 300,000 acres) are leased each year
- o North Slope oil production is 1.2 million barrels per day in 1980, rises to 1.6 in 1985, and declines to 1.2 by 1990
- o Conversions from oil to coal required by the Energy Supply and Environmental Coordination Act are carried through completely, and scrubbers (flue gas desulfurizers) are used as prescribed by law
- o 400 billion cubic feet of liquified natural gas are imported in 1980, 1,200 billion cubic feet in 1985, and 2000 billion cubic feet in 1990
- o Energy-supplying technologies not currently in use do not provide any energy in 1980, provide less than 1% by 1985, and provide less than 2% by 1990
- o Only nuclear capacity that is now at least 2% complete will be completed. This capacity is assumed to be the lower bound by 1985*

* The PIES model predicts that by 1990, no natural gas would be available for commercial customers in Region 10 (Northwest). We simulated the effect of this prediction in our market model by setting the 1990 price at \$99.99/million Btu, and the computer interpolated the exorbitantly high prices which are shown between 1985 and 1990. In the RPA deregulation scenarios, we assumed that gas would be available in that region at the price of distillate fuel oil.

FEA base case prices have been modified on the assumption that energy prices in general are influenced by the level of world oil prices and by the extent and severity of federal wellhead price control. We made two scenarios based on combinations of the following postulates: (1) that the wellhead price for new gas will eventually be deregulated and (2) that the real price of oil will rise substantially by 1990. Our less pessimistic scenario (RPA1) presumes that the price of new natural gas is deregulated and no other prices change. We also assume for the purpose of keeping the adjustment simple, that the impact of deregulation on natural gas prices is not felt until after 1980, because old contracts for natural gas still dominate deliveries to interstate users. We set the price of natural gas at that of distillate fuel oil wherever the PIES price for natural gas was below that level; this adjustment was needed in most of the regions and was based on the idea that the two fuels compete.

Our second scenario (RPA-2) assumed the same change in natural gas pricing policy, but included a change in the price of oil. We assumed that the world price of oil would start to rise in 1980 and reach \$20 per barrel by 1990. We included this change by making the simplifying assumption that the increase in oil prices would be passed through directly to the delivered price of distillate. The \$7 per barrel increase is equal to an additional cost of \$1.21 per million Btu. This translates to a simple increase in prices of \$0.11 per million Btu per year (which implies that the annual percentage increase in prices declines over time).

We also adjusted the delivered prices of commercial electricity for the increase in oil prices. We did this by first multiplying the increased cost of oil by the inverse of an assumed overall generating efficiency. We picked 40% as our assumed conversion efficiency, which is perhaps a bit high for a national aggregate, but is probably fair for the future. We then multiplied this extra fuel cost by the projected percentage of electricity generated in each region by distillate turbines or residual-oil steam plants, and added the product to the base case price projection. We limited this procedure to regions that obtained at least 10% of

their electricity from oil product-fired plants. In 1980, the PIES model forecasts that 6 of the 10 regions get at least 10% of their electricity from the use of distillate or residual oil; the highest relative use was 50% in Region 1 (New England). By 1990, only 3 regions are expected to use petroleum in significant amounts to generate electricity -- Region 1 is expected to get only 20% of its electricity from petroleum--so that although the corrected increase in electricity prices due to an oil price rise was \$3.03 per million Btu, the increase in Region 1's delivered electricity price is expected by only \$0.61.

Scenarios 5 and 6 are identical to the base case except that they assume the RPA-1 and RPA-2 price forecasts, respectively. Scenarios 12 and 13 also use RPA-1 and RPA-2, respectively, and also assume immediate penetration of the market. Under scenario 5, FCTES sales (measured in almost any terms) would be no more than 10% below what they would be under base case assumptions. FCTES would penetrate Region 10. The comparative economics of FCTES would not be substantially altered by deregulation of the wellhead price of natural gas.

However, the effects of much higher oil prices (and therefore of higher natural gas prices) would be quite significant. Under scenario 6, only 60% as many FCTES would be sold as under the base case. This is because the market for FCTES for new buildings would be much less important when fuel prices are higher, while the market for retrofitting would not be much affected. Under scenario 6, 78% as many FCTES would be sold for retrofitting as under the base case, but only 7% as many for new construction. FCTES would sell to only two types of buildings, multi-family residences, and hotels and motels. Hotels and motels would account for only 3% of sales. Sales by building size would also be concentrated. The 9 largest size ranges (from 100,000 square feet up) would account for 85% of sales. Only 14 building size ranges would have capacity of more than 25,000 kW installed in the 15-year period.

FCTES Capital Costs. Since fuel cells have not yet been mass produced, their capital costs are uncertain. Our base case assumes the costs estimated by UTC, but under scenarios 7, 8, and 9, capital costs

are assumed to be 10%, 20%, and 40% higher than those estimates. Under scenario 4, an extra 10% ITC is given FCTES, and this would have the same effect as a capital cost 10% lower than the UTC estimates.

The market for FCTES would be quite sensitive to changes in fuel cell capital costs. A 10% higher capital cost would reduce the total market (measured in kW installed) by 7% over the 15 year period. A 20% higher cost would reduce the market by 25%; a 40% higher cost, by 73%. Similar reductions would occur in the number of buildings in which FCTES were installed.

The size distribution of the buildings in which FCTES were installed would not change much for 10% and 20% higher costs. For 40% higher costs, however, there are almost no sales in buildings smaller than 100,000 square feet. Also for costs 40% higher than under base case assumptions, (scenario 9) only two building types would use FCTES in all three periods, and multi-family residences would account for over 99% of the market.

Under base case assumptions, 73% of all FCTES capacity was used for retrofitting during the 15-year period. Higher costs would increase the relative importance of the retrofit market. If costs were 10% higher than under base case assumption, 73% of FCTES would be used in retrofitting. If costs were 20% higher, the retrofit share of the market would be 80%. If costs were 40% higher, the retrofit share would be 99%. Total sales for retrofit would not decline as sharply as sales for new construction if costs were higher. If costs were 10% higher than under base case assumptions, 93% as much retrofit capacity would be sold. If costs were 20% higher, 83% as much would be sold. If they were 40% higher, only 37% as much would be sold.

Existence of a Catalog of Module Sizes. The base case assumes that a full catalog of module sizes (25, 40, 100, and 250 kW) would be available when FCTES are sold commercially. If, however, the 40 kW size was the only one available, FCTES sales would be considerably less.

Scenario 15 is identical to the base case except that only the 40 kW module is assumed to be available. Scenario 16 assumes that only the 40 kW module would be available and that the entire market would be penetrated immediately.

Under scenario 15, only 0.6 million kW of capacity would be sold during the 15-year period and only about 4,000 buildings would use FCTES. Under this scenario, the total number of sales would be approximately equal to the number of 40 kW modules alone that would be sold under base case assumptions.

Only Regions 1, 2, 5, 6, and 9 would be penetrated under scenario 15, and Region 2 would account for 63% of all sales. Multi-family residences would account for 54% of sales, hotels and motels for 43%, and hospitals for 3%. FCTES would penetrate no other building types under this scenario.

The retrofit market would be relatively smaller if only the 40 kW size were available, accounting for 49% of the total market. In fact, however, more 40 kW modules would be sold for retrofitting under base case assumptions than under scenario 15 assumptions.

There are three reasons why sales would be substantially greater if the full catalog were available. First, larger units would cost less per kilowatt. Second, if various sizes were available, installations could meet peak demand with less idle capacity. Third, FCTES could serve buildings too large or too small to be served by 40 kW modules alone.* Thus, under scenario 15, FCTES would penetrate only 18 size ranges (from the 7,500-10,000 square foot range to the 90,000-100,000 square foot range). Only four of these ranges would have sales of over 50,000 kW.

Under scenario 16, total sales would be 874,000 kW. With immediate penetration, FCTES would sell more than 50,000 kW in each of seven size ranges. These seven ranges would account for 71% of FCTES sales.

*For technical reasons, at least two and no more than six modules must be connected in each FCTES. Thus, if the catalog is available, the smallest FCTES will be 50kW and the largest 1500kW. If only the 40kW module is available FCTES will range only between 80kW and 240kW.

3.2 Resource and Energy Use

As stated earlier, the fuel cell system versus conventional system resource and gas use comparisons were carried out by using the central chiller - boiler system as the conventional system. As it turns out, the central chiller - boiler system is indeed the competing conventional system in almost all cases (97-99% of market segments).

The average effect on total energy use and on gas use of FCTES implementation is discussed below, but two example energy balances are shown in Figs. 3.5 and 3.6 to illustrate detailed effects. Balances are displayed for the fuel cell-heat pump system and the conventional central chiller - boiler systems in the reference multi-family residence in Region 2. This is the best selling building in the best selling region, so the example is highly relevant.

The fuel input mixture shown at the electrical generating plant for the conventional system is based on the average generating mix for DOE Region 2 during the period 1980-2000 as predicted by the PIES model. The amount of natural gas used for generating electricity is negligible, but what little there is, is included in the oil category. In this example, the gas use for the fuel cell system is 36% higher than that of the conventional system. If thermal storage were used, it is probable that some of the "unused available waste heat" would displace some of the auxiliary boiler gas consumption and perhaps some of the heat pump heating load. In the most optimistic case, however, the fuel cell system gas consumption would still be 27% greater than that of the conventional system. To obtain this result, it was necessary to assume that the unused waste heat available replaced all the auxiliary heat load and part of the heat pump load. This is quite improbable in practice. Only by increasing the building T/E ratio* can the gas

*The T/E ratio is defined in this study as the energy equivalent of metered gas divided by the energy equivalent of the metered electricity referenced to the central chiller-boiler system. Defined in this way, differences in T/E reflect differences in building properties.

Fig. 3.5. Sample Energy Balance: Conventional System.

consumption in the fuel cell system be reduced to less than that of the conventional system.. UTC has found that, for buildings with T/E greater than about four, fuel cells will conserve gas when compared to a conventional chiller-boiler system.

An examination of total primary energy consumption, independent of its form, shows that the fuel cell system uses 33% less energy than the conventional system. Thus, the fuel cell system, while using increased quantities of natural gas, conserves significant quantities of total energy resources.

Fig.3.6 SAMPLE ENERGY BALANCE: FUEL CELL SYSTEM

NOTE: ALL VALUES = 10^6 EQUIVALENT Btu
*SPF = SEASONAL PERFORMANCE FACTOR OVER (1) COOLING SEASON
(2) HEATING SEASON. Btu OUTPUT/Btu INPUT

This result coupled with the increased use of natural gas leads naturally to speculation about synthetic fuel use by a fuel cell. This question is left for future research.

3.2.1 Effects on National Energy Use

Under the assumptions of our base case, the FCTES sold between 1985 and 1999 will result in a net national energy savings of 0.23 quadrillion Btu during that period. Total national energy consumption during the same period is projected to be about quadrillion Btu's. Thus the fuel cell sales have a negligible effect on U.S. energy consumption. This calculation is based on the assumption that FCTES will compete with conventional systems that use grid electricity, and gas-fired boilers.

During the period 1985-1999, the FCTES that will be sold will use 0.85 quadrillion Btu of natural gas, but no other fuel. The conventional systems that FCTES will replace would have used 0.42 quadrillion Btu of natural gas as boiler fuel and a further 0.66 quadrillion Btu of primary fuels (nuclear fuel, coal, oil, and natural gas, and other) for generating electricity.

The net savings of 0.23 quadrillion Btu is equal to an average annual energy savings of 15.3 trillion Btu. This means that the FCTES sold would save approximately the equivalent of 0.5 million tons of bituminous coal or 3 million barrels of oil per year.

Table 3.2 highlights the components of changes in national fuel use, and their change over time, in the base case. All of the entries reflect the cumulative effects caused by the operation of FCTES installed in any previous period, except for the last two lines, which only compare the gas used by FCTES and competing systems installed in a given period. (A discussion of the model's cumulation algorithm can be found in Sect.2.4).

3.2.2 National Energy Use Effects-Range

The range of effects on national energy use due to the use of FCTES between 1985 and 1999 is great, as can be seen clearly in Fig. 3.7. In the most optimistic case, scenario 11 (which assumes a perfect market and an extra 10% investment tax credit) 1.4 quadrillion Btu of energy would be saved over the 15 year period. In the least optimistic case, scenario 15 (which assumes that only 40 kW systems are available) the net saving of primary energy is only 0.05 quadrillion Btu over the 15-year period.

Fig. 3.7. Savings of Primary Energy & Net Increase in Use of Natural Gas Due to FCTES.

Table 3.2 Components of Changes in National Fuel Use, and
Changes Over Time
(10¹⁵ Btu)

	Period			TOTAL
	1985-1989	1990-1994	1995-1999	
Primary energy savings due to FCTES use (from cumulative sales)	0.03	0.18	0.44	0.65
FCTES natural gas use (from cumulative sales)	0.04	0.24	0.57	0.85
Conventional system gas use (from cumulative sales)	0.02	0.12	0.28	0.42
Net increase in gas use (from cumulative sales)	0.02	0.12	0.29	0.43
Conventional system, gas use (from sales in each period only)	0.02	0.08	0.08	
FCTES gas use (from sales each period only)	0.04	0.16	0.17	

The 0.66 quadrillion Btu of generating fuels saved would include approximately 0.22 quadrillion Btu of nuclear power; 0.27 quadrillion Btu of coal; 0.11 quadrillion Btu of oil and natural gas; and 0.06 quadrillion Btu derived from hydropower, geothermal, solar and synthetic fuels.

Region 2 would account for 44% of the savings in generating fuel (0.29 quadrillion Btu) and 44% of the net increase in the use of natural gas (0.19 quadrillion Btu). Thus, the net savings in that region would be 0.10 quadrillion Btu over the 15-year period.

3.2.3 National Cost Savings

The national cost savings resulting from FCTES implementation were estimated by comparing the present value of the life cycle costs incurred by using the cheaper of the two FCTES to the present value of the life cycle costs of the cheaper of the two conventional systems. The difference between these two values summed over all segments in which the FCTES sold yields the desired national cost savings.

For the base case, the present value of the life cycle costs of using FCTES in the segments for which sales were predicted between 1985 and 2000 is \$5.95 billion. If conventional systems were instead used in these same segments, the present value of the associated costs would be \$6.65 billion. The total present value of the saving associated with using FCTES is \$0.70 billion or a 10.5% reduction from conventional system costs.

3.3 Institutional, Regulatory, and Legal Analysis

Until FCTES are commercialized, it will be virtually impossible to determine the institutional, regulatory, and legal climates in which they will operate. However, there was a consensus among the state, utility, and regulatory representatives interviewed. If FCTES are perceived as being in the public interest — however that may be defined in a given state or regulatory area — there will be no serious barriers to their use.

Because our experience in analyzing the market development of other new technologies shows the importance of these sorts of non-economic factors, we have analyzed the potential institutional, regulatory, and legal issues that may arise, even though this analysis had to be qualitative at this time. The methodology was discussed in Sect. 2.5.

3.3.1 Results

Although the market model can accomodate lags in penetration in particular regions due to regulatory or legal barriers, or restrictions on natural gas hookups, we felt that we could not predict conditions that FCTES might face in the mid-1980's. However, several potentially important issue areas were defined: availability of natural gas, utility regulation, and backup service.

Availability of natural gas. State and federal restrictions on natural-gas hookups and allocation priorities, formulated in response to recent shortages, could slow the rate of FCTES commercialization. Even assuming a favorable regulatory climate, the eventual extent of FCTES market penetration may depend largely on the availability of natural gas.

Although national policies will influence the states, many will require formal proceedings to establish policies on use of natural gas by FCTES. Furthermore, curtailments and hookup restrictions, which vary

by state and by utility, may preclude the marketing of FCTES by utilities or private companies in some areas.

The severity of the potential effect of such restrictions will depend on the real natural-gas supply situation, and the perceptions of natural gas supply/demand imbalances held by decision makers in both the private and public sectors. The ease of gaining regulatory approval for FCTES will depend on the regulatory climate that results from the future effects of federal policies on the use of natural gas, the gas situation of each state at the time FCTES are commercialized, and the perceptions at that time of the future gas situation.

Utility regulation. State regulatory commissions might not grant gas companies or building owners (who might be classified as public utilities if they provided electricity to their tenants) permission to own and operate FCTES. To protect electric utilities, and to avoid duplication of power services offered to the public, most state regulatory commissions have the authority to grant or deny certification to build and operate electrical generation and distribution equipment to any utility, or other organization that is defined as serving the public. The criteria that determine whether or not individual FCTES owners would be considered utilities vary by state. Until FCTES use is relatively widespread, state regulatory commissions will probably have to hold hearings to resolve ownership questions on a case-by-case basis. Over the long term, if FCTES penetration is substantial, modifications to state regulations and statutes might accommodate fuel-cell or other total-energy systems.

Federal initiatives on behalf of FCTES could decrease the likelihood that FCTES will be impeded because of state regulations. Such initiatives could be demonstration and public information programs, participation in state regulatory hearings, or new legislation aimed at reducing barriers to total energy or cogeneration technologies.

Backup service. For this study, it was assumed that there was no grid connection. However, if grid connection is desired because of lower than anticipated reliability, the issue of backup rates may be very important. The extra costs of ensuring customers a reliable power

supply, either through tie-in with an electric-utility grid for backup service or through redundant FCTES capacity, could significantly influence the economics of FCTES. If grid backup were used as a form of reliability insurance, the rate structures that utilities would offer FCTES users would have to reflect the true cost of providing that service (some utilities might not even provide such service). The cost would be determined as some function of the utilities' cost of service, the degree of FCTES market penetration, and the reliability of FCTES. Reliability would have to be proven.

The rate structures in most utility service areas are not automatically applicable to FCTES backup service. Hearings might have to be held to establish appropriate rates and, if necessary, force the utilities to provide backup.

3.3.2 Conclusions

As a consequence of some of the potential issues, barriers might arise that could impede the rapid commercialization of FCTES in the short term. These barriers would depend upon each state's or service area's particular energy situation, policies, and regulatory process. Until FCTES are commercialized, it is virtually impossible to predict state and local attitudes.

Many of the potential barriers to commercialization could arise simply because existing regulatory procedures do not anticipate technologies such as FCTES. Consequently, new rules and laws may be needed rather than the reinterpretation of existing regulations. Almost all of the people interviewed indicated that they expect the institutional and regulatory issues arising from FCTES to be resolved within three to five years. A five-year delay would have significant economic consequences. Delaying the start of sales in the base case to 1990 would reduce sales from 3.4 million kilowatts to 1.6 million kilowatts by the year 2000.

If FCTES are introduced in a way that recognizes and works effectively within the structure of the utility industry and its regulatory environment (e.g., by including regulatory bodies in DOE demonstration programs), institutional and regulatory constraints are not likely to pose significant barriers to FCTES ownership and operation.

APPENDIX A. BASE CASE DESCRIPTION

Fuel Price

In analyzing the potential market for FCTES, 16 possible scenarios (all in accordance with the study ground rules) are considered for the future up to the year 2000. For the base case, wherever there were no specific study ground rules the assumptions made were generally favorable to the development and sales of FCTES. However, the model can deal with scenarios that differ in one or more of 14 ways.

For our base case, fuel prices forecast by the Project Independence Evaluation System (PIES) Base Case were used. They are based on constant world oil prices in real terms (\$13 per barrel, delivered to New York, in 1975 dollars) and slow deregulation of the wellhead price of natural gas in interstate markets. The PIES Base Case has a lower delivered price of natural gas than either of our other two price forecasts, RPA-1 and RPA-2. RPA-1 keeps the assumption about world oil prices, but assumes immediate deregulation of new natural gas prices. RPA-2 also assumes immediate deregulation of new natural gas prices, as well as an oil price rise of \$7 per barrel in real terms by 1990. Since the price of electricity is not tied directly to the price of oil, FCTES would be favored by a relatively low natural gas price. To analyze the sensitivity of FCTES market penetration to energy costs, the RPA-1 and RPA-2 prices are used in scenarios 5 and 6. Figure A.1 illustrates the differences between the fuel price projections by showing the natural gas prices from 1980 to 2000 for all three cases. The relationships are similar for other regions.

Availability of Gas

In the base case, there is no limit on the number of gas hookups available for potential FCTES users.

Fig. A.1. Region 2 (NY, NJ) Fuel [Gas] Prices.

Institutional, Legal, and Regulatory Barriers

The base case assumes that there will be no legal or regulatory impediments and that FCTES may be used in all regions in all periods. Research on possible institutional and legal barriers to the use of FCTES indicates that, at worst, the use of FCTES might be delayed by legal problems in only a few states. Furthermore, it is felt that the way will be cleared for FCTES implementation if such action is perceived to be in the public interest.

Availability of Government Incentives

Since government decision makers need to know how the FCTES would fare in the market without federal intervention, the base case does not include any government incentives for FCTES, other than the standard 10% investment tax credit (ITC) (explained in more detail below). Thus, the base case includes no demonstration program or special subsidies to make FCTES more attractive to potential users. However, scenario 4 illustrates the possible effects of an extra 10% ITC for FCTES owners.

Building Eligibility

The base case assumes that any building type, (which implies a class of owners and set of attitudes) will consider FCTES in a manner similar to our economic-decision submodel. That is, all building owners and operators will regard FCTES rationally, and FCTES will not encounter any special constraints. While this assumption is certainly generous — the real world is hardly ever this amenable to change — it gives an upper bound to the maximum potential market for FCTES. Differences in the cost of capital are accounted for in the NPC calculations, and differences in market penetration rates resulting from differences in buyer behavior are accounted for by the diffusion model.

Need for Backup Electricity

One ground rule of our study was the assumption that FCTES would be sufficiently reliable to need no backup from the electricity grid. Therefore, our base case does not include any charges for backup services.

Ownership

The model distinguishes between utility and private ownership of FCTES in calculating net present costs of system use. Since gas-utility ownership or leasing has been most thoroughly explored (by UTC and the TARGET companies), utility ownership is assumed in the base case.

Utility ownership determines which discounted cash flow equation the model uses and the values of certain parameters. FCTES sales are projected for private, non-utility ownership in scenarios 3 and 10 to allow comparison of the effects of the economics of individual ownership.

Market Diffusion

For the base case, the diffusion model simulates the lags in market penetration usually experienced by a new product.

In simulating "perfect market" penetration (scenarios 2, 10, 11, 12, 13, 14, and 16) the potential penetration rate is unavoidably

overestimated, to some extent. Thus, sales of FCTES capacity and attendant fuel savings, with and without diffusion effects, were compared to show the importance of diffusion.

The Bass diffusion model has limited predictive validity, but the "perfect market" serves as an upper bound to our estimate of potential FCTES penetration. In addition, this analysis could be important to government decision makers because it indicates the impact a demonstration program might have.

Depreciation Schedule

Since the tax advantages of rapid depreciation of investment in FCTES capacity might be important to potential users, the most optimistic depreciation schedule, double-declining balance, was used in the base case. The advantage of double-declining balance is that the present value of tax relief is greatest when the investment is depreciated as quickly as possible. Whoever owns the system would want to take advantage of the favorable tax treatment afforded by ownership. In some instances, though, the ability of FCTES owners (either utilities or private individuals) to choose the most attractive schedule may be limited by tax code or regulatory restrictions.

FCTES Module Size

For the base case, a catalogue of different size fuel cell modules is assumed available to give designers greater flexibility. UTC has suggested that a full catalog would include 25, 40, 100, and 250 kW modules.

The fuel-cell unit that is the development size for the fuel-cell total-energy system that we are studying has a design capacity of 40 kW(e). Since the 40 kW unit has had the most complete design and development work done on it, it was used for our sensitivity analyses of the effects on the potential FCTES market of only offering one unit size. Since this unit would probably be used in FCTES demonstration, and might also be the first to be used in commercial application, at least in the

early years of fuel-cell use in buildings, it is appropriate and useful to look at its potential market. Scenarios 15 and 16 assumed that only the 40 kW module would be available.

Availability of Investment Tax Credits

Since the base case assumes that utilities will own the FCTES, the 10% investment tax credit (ITC) is applied in the cash flow equation. If FCTES are defined by the Internal Revenue Service as heating, ventilating, and air conditioning (HVAC) equipment, the ITC would not be available to private owners. Investment in HVAC equipment is specifically exempted from eligibility for the ITC in the tax code, but utility investment in capital equipment does qualify. Accordingly, in evaluating private ownership, the 10% ITC is not used.

It is also of interest to investigate the possible effects on the market for FCTES that would result from ITC code changes. This illustrates the effects of government incentives aimed at increasing FCTES market penetration. Scenario 4 shows the effect of an extra 10% ITC for FCTES.

It is interesting to note that either ITC would only apply to FCTES if it were utility-owned. This factor enhances the competitive position of FCTES compared with conventional, non-utility-owned energy systems.

Cost of Capital

To ensure that the market model accurately represents the financial decision-making process that potential FCTES owners and operators might use, we analyzed the costs of capital (discount and interest rates) to utilities and to building owners and operators in different sectors. These estimates were used in the net present cost equations.

FCTES Capital Cost

For the base case, fuel cells will cost \$426 per kW in the 40 kW module. Scenarios 7, 8, and 9 show the effects of higher capital

costs. In scenario 4, the extra 10% ITC can be seen as representing a 10% lower capital cost.

Production Level

In all cases analyzed, it was assumed that anyone who wants to buy an FCTES may do so; there is no supply constraint at any time.

APPENDIX B. SENSITIVITY ANALYSES RESULTS

Introduction

The following tables summarize the results of the FCTES market model projections, for the base case and fifteen additional scenarios.

The first two lines show the total FCTES capacity installed and the number of buildings fitted with new FCTES in each five-year period. The next four lines show the number of FCTES units sold in each period, by unit size.

The next section shows a breakdown of the types of primary energy that would be saved through FCTES on-site electricity generation. Those projections assume that the savings due to the total capacity installed in one period have cumulative effects in the following periods, but that the energy savings resulting from FCTES installed in one period are only a result of the average installed capacity through the period. We assume that FCTES are sold at a constant rate during each period.* Thus, the primary energy savings in the first period are computed for half the installed capacity projected, and in the next period savings are computed for twice those of the first period, plus the savings due to capacity installed in the second period.

The four lines in the natural gas consumption section represent four different sets of computations. Only the last line is comparable with the entries in the primary energy savings section. The first line shows the amount of natural gas that would be consumed by FCTES installed in each period.

The second line shows the amount the conventional system would use if FCTES were not available, and the third shows the net increase in gas consumption that would result from FCTES use. The fourth is a cumulation of the net increase. It is also computed on the assumption that the use of gas increases with successive increases in the use of FCTES, including those increases due to installations made in any previous periods.

* Thus the average installed capacity is equal to one-half the capacity installed by the end of the period. We calculate the savings on the basis of this figure.

Summary of Model Runs

Scenario 1

	1985-89	1990-94	1995-99	Total*
Total installed FCTES capacity (10^6 kW)	0.4	1.5	1.6	3.4
Number of buildings using FCTES	1,378	4,861	5,540	11,779
Number of FCTES units sold (10^3)				
25 kW	0.6	1.9	2.3	4.7
40 kW	2.0	7.0	8.0	17.0
100 kW	0.6	2.1	2.3	5.0
250 kW	1.1	3.7	3.8	8.6
Decrease in primary energy use due to FCTES (10^{12} Btu)**				
Nuclear	9.0	59.6	147.3	215.8
Coal	13.2	77.3	183.8	274.3
Oil	6.4	32.2	74.5	113.1
Othert	<u>2.8</u>	<u>16.7</u>	<u>39.9</u>	<u>59.5</u>
Total	31.4	185.8	445.5	662.7
Natural gas consumption (10^{12} Btu)				
FCTES	43.6	165.8	173.8	
Conventional reference system	21.8	81.2	81.5	
Net increase in gas use	21.8	84.6	92.3	
Cumulative increase in gas use††	21.8	128.2	305.1	455.2

* Totals may not add due to rounding.

** When compared with a conventional reference system.

† Hydropower, synthetic fuels, geothermal power.

†† Including increases in gas use due to FCTES continuing to operate from previous periods.

Summary of Model Runs

Scenario 2

	1985-89	1990-94	1995-99	Total*
Total installed FCTES capacity (10^6 kW)	2.3	1.9	1.6	5.8
Number of buildings using FCTES	7,405	6,286	5,654	19,345
Number of FCTES units sold (10^3)				
25 kW	3.1	2.4	2.3	7.8
40 kW	10.5	9.1	8.1	27.7
100 kW	3.2	2.7	2.4	8.3
250 kW	5.8	4.9	4.0	14.7
Decrease in primary energy use due to FCTES (10^{12} Btu)**				
Nuclear	53.9	163.0	265.3	482.2
Coal	79.9	227.6	352.2	659.7
Oil	38.4	102.8	152.2	293.4
Other†	17.0	48.8	75.9	141.8
Total	189.2	542.2	845.6	1,577.1
Natural gas consumption (10^{12} Btu)				
FCTES	264.7	219.8	177.3	
Conventional reference system	133.1	107.3	83.1	
Net increase in gas use	131.6	112.5	94.2	
Cumulative increase in gas use††	131.6	375.7	582.5	1,089.7

* Totals may not add due to rounding.

** When compared with a conventional reference system.

† Hydropower, synthetic fuels, geothermal power.

†† Including increases in gas use due to FCTES continuing to operate from previous periods.

Summary of Model Runs

Scenario 3

	1985-89	1990-94	1995-99	Total*
Total installed FCTES capacity (10^6 kW)	0.1	0.4	0.6	1.1
Number of buildings using FCTES	520	1,995	2,828	5,343
Number of FCTES units sold (10^3)				
25 kW	0.2	0.9	1.3	2.4
40 kW	0.8	3.1	4.3	8.2
100 kW	0.2	0.8	1.1	2.1
250 kW	0.2	0.7	1.0	2.0
Decrease in primary energy use due to FCTES (10^{12} Btu)**				
Nuclear	2.3	17.0	47.9	67.2
Coal	3.7	24.6	67.1	95.4
Oil	2.4	13.0	33.4	48.8
Other†	<u>0.7</u>	<u>4.7</u>	<u>12.9</u>	<u>18.4</u>
Total	9.1	59.3	161.3	229.8
Natural gas consumption (10^{12} Btu)				
FCTES	8.2	35.3	51.9	
Conventional reference system	2.7	10.0	14.7	
Net increase in gas use	5.5	25.3	37.2	
Cumulative increase in gas use††	5.5	36.4	99.1	141.1

* Totals may not add due to rounding.

** When compared with a conventional reference system.

† Hydropower, synthetic fuels, geothermal power.

†† Including increases in gas use due to FCTES continuing to operate from previous periods.

Summary of Model Runs

Scenario 4

	1985-89	1990-94	1995-99	Total*
Total installed FCTES capacity (10^6 kW)	1.0	3.8	5.0	9.9
Number of buildings using FCTES	3,117	11,516	14,743	29,376
Number of FCTES units sold (10^3)				
25 kW	1.0	4.2	5.5	10.7
40 kW	4.4	15.7	19.5	39.6
100 kW	1.5	5.5	7.3	14.3
250 kW	2.7	10.2	13.5	26.4
Decrease in primary energy use due to FCTES (10^{12} Btu)**				
Nuclear	25.0	168.7	449.7	643.2
Coal	36.2	224.4	585.2	845.7
Oil	16.3	79.8	189.3	285.4
Other†	8.8	51.3	129.2	189.3
Total	86.3	524.2	1,353.4	1,963.6
Natural gas consumption (10^{12} Btu)				
FCTES	104.7	412.4	533.7	
Conventional reference system	45.7	166.7	197.1	
Net increase in gas use	59.0	245.7	336.6	
Cumulative increase in gas use††	59.0	363.7	946.0	1,368.8

* Totals may not add due to rounding.

** When compared with a conventional reference system.

† Hydropower, synthetic fuels, geothermal power.

†† Including increases in gas use due to FCTES continuing to operate from previous periods.

Summary of Model Runs

Scenario 5

	1985-89	1990-94	1995-99	Total*
Total installed FCTES capacity (10^6 kW)	0.4	1.4	1.4	3.1
Number of buildings using FCTES	1,107	4,172	4,660	9,939
Number of FCTES units sold (10^3)				
25 kW	0.4	1.5	1.8	3.6
40 kW	1.6	6.2	7.0	14.9
100 kW	0.5	1.7	1.9	4.1
250 kW	1.0	3.6	3.6	8.2
Decrease in primary energy use due to FCTES (10^{12} Btu)**				
Nuclear	8.3	56.2	138.8	203.3
Coal	11.7	68.2	160.6	240.6
Oil	5.5	28.2	64.7	98.4
Other†	<u>2.8</u>	<u>16.6</u>	<u>39.2</u>	<u>58.7</u>
Total	28.3	169.2	403.3	601.0
Natural gas consumption (10^{12} Btu)				
FCTES	40.6	156.0	160.5	
Conventional reference system	20.7	78.3	77.8	
Net increase in gas use	19.9	77.7	82.7	
Cumulative increase in gas use††	19.9	117.5	277.9	41,513

* Totals may not add due to rounding.

** When compared with a conventional reference system.

† Hydropower, synthetic fuels, geothermal power.

†† Including increases in gas use due to FCTES continuing to operate from previous periods.

Summary of Model Runs

Scenario 6

	1985-89	1990-94	1995-99	Total*
Total installed FCTES capacity (10^6 kW)	0.3	0.9	0.9	2.0
Number of buildings using FCTES	693	2,435	2,437	5,565
Number of FCTES units sold (10^3)				
25 kW	0.2	0.9	0.9	2.1
40 kW	1.0	3.6	3.5	8.2
100 kW	0.2	0.8	0.8	1.9
250 kW	0.8	2.6	2.5	5.9
Decrease in primary energy use due to FCTES (10^{12} Btu)**				
Nuclear	6.1	38.2	89.8	134.0
Coal	7.9	42.3	94.0	144.1
Oil	3.7	18.0	39.2	60.9
Other†	<u>1.9</u>	<u>10.4</u>	<u>23.7</u>	<u>36.0</u>
Total	19.6	108.9	246.7	375.0
Natural gas consumption (10^{12} Btu)				
FCTES	29.9	106.1	102.9	
Conventional reference system	16.8	60.6	58.7	
Net increase in gas use	13.1	45.5	44.2	
Cumulative increase in gas use††	13.1	71.7	161.4	246.3

* Totals may not add due to rounding.

** When compared with a conventional reference system.

† Hydropower, synthetic fuels, geothermal power.

†† Including increases in gas use due to FCTES continuing to operate from previous periods.

Summary of Model Runs

Scenario 7

	1985-89	1990-94	1995-99	Total*
Total installed FCTES capacity (10^6 kW)	0.4	1.4	1.4	3.2
Number of buildings using FCTES	1,128	4,357	5,009	10,494
Number of FCTES units sold (10^3)				
25 kW	0.4	1.5	1.9	3.8
40 kW	1.7	6.4	7.4	15.4
100 kW	0.5	1.8	2.0	4.2
250 kW	1.0	3.6	3.7	8.3
Decrease in primary energy use due to FCTES (10^{12} Btu)**				
Nuclear	8.2	56.0	139.3	203.6
Coal	11.9	71.0	170.0	253.0
Oil	5.7	29.8	69.4	104.8
Othert†	<u>2.7</u>	<u>16.0</u>	<u>38.1</u>	<u>56.7</u>
Total	28.5	172.8	416.8	618.1
Natural gas consumption (10^{12} Btu)				
FCTES	40.3	157.2	164.5	
Conventional reference system	20.0	75.9	76.4	
Net increase in gas use	20.3	81.3	88.1	
Cumulative increase in gas use††	20.3	121.9	291.2	433.4

* Totals may not add due to rounding.

** When compared with a conventional reference system.

† Hydropower, synthetic fuels, geothermal power.

†† Including increases in gas use due to FCTES continuing to operate from previous periods.

Summary of Model Runs

Scenario 8

	1985-89	1990-94	1995-99	Total*
Total installed FCTES capacity (10^6 kW)	0.3	1.1	1.2	2.6
Number of buildings using FCTES	843	3,069	3,397	7,309
Number of FCTES units sold (10^3)				
25 kW	0.2	0.8	0.9	1.9
40 kW	1.3	4.7	5.2	11.2
100 kW	0.4	1.4	1.6	3.5
250 kW	0.9	3.1	3.0	7.0
Decrease in primary energy use due to FCTES (10^{12} Btu)**				
Nuclear	7.1	46.5	113.4	167.0
Coal	10.1	58.1	136.2	204.4
Oil	4.8	24.3	55.3	84.4
Other†	<u>2.3</u>	<u>13.4</u>	<u>31.3</u>	<u>47.0</u>
Total	24.3	142.3	336.2	502.8
Natural gas consumption (10^{12} Btu)				
FCTES	35.6	132.4	135.5	
Conventional reference system	18.0	65.9	65.5	
Net increase in gas use	17.6	66.5	70.0	
Cumulative increase in gas use††	17.6	101.6	238.0	357.2

* Totals may not add due to rounding.

** When compared with a conventional reference system.

† Hydropower, synthetic fuels, geothermal power.

†† Including increases in gas use due to FCTES continuing to operate from previous periods.

Summary of Model Runs

Scenario 9

	1985-89	1990-94	1995-99	Total*
Total installed FCTES capacity (10^6 kW)	0.1	0.4	0.4	0.9
Number of buildings using FCTES	195	690	714	1599
Number of FCTES units sold (10^3)				
25 kW	0.0	0.1	0.1	0.1
40 kW	0.2	0.8	0.9	2.0
100 kW	0.1	0.3	0.3	0.8
250 kW	0.4	1.4	1.4	3.1
Decrease in primary energy use due to FCTES (10^{12} Btu)**				
Nuclear	2.5	16.7	40.2	59.4
Coal	3.1	17.5	40.3	61.0
Oil	1.9	9.5	20.8	32.2
Other†	0.8	4.8	11.2	16.9
Total	8.3	48.5	112.5	169.5
Natural gas consumption (10^{12} Btu)				
FCTES	13.5	51.5	52.5	
Conventional reference system	7.2	27.6	28.1	
Net increase in gas use	6.3	23.9	24.4	
Cumulative increase in gas use††	6.3	36.5	84.8	127.6

* Totals may not add due to rounding.

** When compared with a conventional reference system.

† Hydropower, synthetic fuels, geothermal power.

†† Including increases in gas use due to FCTES continuing to operate from previous periods.

Summary of Model Runs

Scenario 10

	1985-89	1990-94	1995-99	Total*
Total installed FCTES capacity (10^6 kW)	0.6	0.5	0.6	1.7
Number of buildings using FCTES	2573	2575	2888	8036
Number of FCTES units sold (10^3)				
25 kW	0.9	1.1	1.3	3.3
40 kW	3.9	3.9	4.4	12.3
100 kW	1.0	1.1	1.2	3.3
250 kW	1.1	1.0	1.1	3.2
Decrease in primary energy use due to FCTES (10^{12} Btu)**				
Nuclear	13.6	44.3	80.2	138.1
Coal	22.4	68.6	118.2	209.2
Oil	14.4	40.2	64.0	118.5
Other†	<u>4.3</u>	<u>13.1</u>	<u>22.6</u>	<u>39.9</u>
Total	54.7	166.2	202.1	505.7
Natural gas consumption (10^{12} Btu)				
FCTES	50.9	48.9	53.5	
Conventional reference system	17.4	14.1	15.2	
Net increase in gas use	33.5	34.7	38.3	
Cumulative increase in gas use††	33.5	101.7	174.9	310.1

* Totals may not add due to rounding.

** When compared with a conventional reference system.

† Hydropower, synthetic fuels, geothermal power.

†† Including increases in gas use due to FCTES continuing to operate from previous periods.

Summary of Model Runs

Scenario 11

	1985-89	1990-94	1995-99	Total*
Total installed FCTES capacity (10^6 kW)	6.2	5.2	5.1	16.5
Number of buildings using FCTES	18306	15552	15124	48982
Number of FCTES units sold (10^3)				
25 kW	5.9	5.7	5.7	17.3
40 kW	25.4	21.1	20.0	66.5
100 kW	9.1	7.3	7.4	23.9
250 kW	16.6	13.9	13.8	44.3
Decrease in primary energy use due to FCTES (10^{12} Btu)**				
Nuclear	162.0	486.8	815.0	1463.8
Coal	238.2	685.0	1107.3	2030.5
Oil	105.0	274.0	401.9	780.8
Other†	56.6	159.2	250.6	466.4
Total	561.8	1605.0	2574.8	4741.5
Natural gas consumption (10^{12} Btu)				
FCTES	681.4	561.1	545.9	
Conventional reference system	292.7	223.9	201.2	
Net increase in gas use	388.7	337.2	344.7	
Cumulative increase in gas use††	388.7	1114.5	1796.3	3299.5

* Totals may not add due to rounding.

** When compared with a conventional reference system.

† Hydropower, synthetic fuels, geothermal power.

†† Including increases in gas use due to FCTES continuing to operate from previous periods.

Summary of Model Runs

Scenario 12

	1985-89	1990-94	1995-99	Total*
Total installed FCTES capacity (10^6 kW)	2.0	1.8	1.4	5.2
Number of buildings using FCTES	5962	5385	4736	16083
Number of FCTES units sold (10^3)				
25 kW	2.1	1.9	1.8	5.8
40 kW	8.8	8.0	7.1	23.9
100 kW	2.5	2.2	1.9	6.6
250 kW	5.6	4.7	3.7	14.0
Decrease in primary energy use due to FCTES (10^{12} Btu)**				
Nuclear	50.0	152.0	248.0	450.0
Coal	69.7	198.2	305.3	573.1
Oil	32.5	87.4	129.6	249.4
Other†	<u>16.9</u>	<u>48.2</u>	<u>74.5</u>	<u>139.6</u>
Total	169.1	485.8	757.4	1412.1
Natural gas consumption (10^{12} Btu)				
FCTES	245.3	205.3	163.4	
Conventional reference system	126.2	103.3	79.3	
Net increase in gas use	119.1	102.0	84.1	
Cumulative increase in gas use††	119.1	340.1	526.2	985.4

* Totals may not add due to rounding.

** When compared with a conventional reference system.

† Hydropower, synthetic fuels, geothermal power.

†† Including increases in gas use due to FCTES continuing to operate from previous periods.

Summary of Model Runs

Scenario 13

	1985-89	1990-94	1995-99	Total*
Total installed FCTES capacity (10^6 kW)	1.5	1.2	0.9	3.6
Number of buildings using FCTES	4012	3169	2476	9657
Number of FCTES units sold (10^3)				
25 kW	1.4	1.2	0.9	3.6
40 kW	6.1	4.7	3.6	14.4
100 kW	1.4	1.1	0.8	3.3
250 kW	4.4	3.4	2.5	10.3
Decrease in primary energy use due to FCTES (10^{12} Btu)**				
Nuclear	37.1	108.1	168.1	313.3
Coal	47.7	130.2	190.6	368.5
Oil	22.6	58.9	83.5	165.0
Other†	<u>11.3</u>	<u>31.5</u>	<u>46.9</u>	<u>89.7</u>
Total	118.7	328.7	489.1	936.5
Natural gas consumption (10^{12} Btu)				
FCTES	181.9	139.2	104.6	
Conventional reference system	102.4	79.6	59.6	
Net increase in gas use	79.5	59.6	45.0	
Cumulative increase in gas use††	79.5	218.5	323.0	621.0

* Totals may not add due to rounding.

** When compared with a conventional reference system.

† Hydropower, synthetic fuels, geothermal power.

†† Including increases in gas use due to FCTES continuing to operate from previous periods.

Summary of Model Runs

Scenario 14

	1985-89	1990-94	1995-99	Total*
Total installed FCTES capacity (10^6 kW)	2.0	1.8	1.5	5.3
Number of buildings using FCTES	6045	5623	5108	16776
Number of FCTES units sold (10^3)				
25 kW	1.9	1.9	1.9	5.7
40 kW	9.0	8.3	7.5	24.7
100 kW	2.5	2.3	2.0	6.8
250 kW	5.5	4.7	3.8	14.1
Decrease in primary energy use due to FCTES (10^{12} Btu)**				
Nuclear	49.4	150.9	247.7	448.0
Coal	71.2	205.2	320.8	597.3
Oil	34.2	92.7	138.8	265.6
Othert†	<u>16.0</u>	<u>45.9</u>	<u>71.7</u>	<u>133.6</u>
Total	170.8	494.7	779.0	1444.5
Natural gas consumption (10^{12} Btu)				
FCTES	243.5	207.7	167.8	
Conventional reference system	121.5	100.3	77.8	
Net increase in gas use	122.0	107.4	90.0	
Cumulative increase in gas use††	122.0	351.5	549.0	1022.5

* Totals may not add due to rounding.

** When compared with a conventional reference system.

† Hydropower, synthetic fuels, geothermal power.

†† Including increases in gas use due to FCTES continuing to operate from previous periods.

Summary of Model Runs

Scenario 15

	1985-89	1990-94	1995-99	Total*
Total installed FCTES capacity (10^6 kW)	0.06	0.23	0.27	0.56
Number of buildings using FCTES	429	1,717	2,083	4,229
Number of FCTES units sold (10^3)				
25 kW				
40 kW	1.4	5.6	6.8	13.9
100 kW				
250 kW				
Decrease in primary energy use due to FCTES (10^{12} Btu)**				
Nuclear	1.3	9.3	24.5	35.2
Coal	1.7	10.8	27.4	39.9
Oil	1.1	6.0	14.4	21.6
Other†	<u>0.4</u>	<u>2.7</u>	<u>6.8</u>	<u>9.9</u>
Total	4.5	28.8	73.1	106.6
Natural gas consumption (10^{12} Btu)				
FCTES	4.8	20.0	24.0	
Conventional reference system	2.4	9.6	10.7	
Net increase in gas use	2.4	10.4	13.3	
Cumulative increase in gas use††	2.3	15.0	38.7	56.0

* Totals may not add due to rounding.

** When compared with a conventional reference system.

† Hydropower, synthetic fuels, geothermal power.

†† Including increases in gas use due to FCTES continuing to operate from previous periods.

Summary of Model Runs

Scenario 16

	1985-89	1990-94	1995-99	Total*
Total installed FCTES capacity (10^6 kW)	0.30	0.29	0.28	0.87
Number of buildings using FCTES	2,307	2,204	2,112	6,623
Number of FCTES units sold (10^3)				
25 kW				
40 kW	7.6	7.3	6.9	21.8
100 kW				
250 kW				
Decrease in primary energy use due to FCTES (10^{12} Btu)**				
Nuclear	7.4	23.6	40.7	71.7
Coal	9.6	28.7	47.7	85.9
Oil	6.3	17.5	27.1	50.9
Other†	<u>2.4</u>	<u>7.3</u>	<u>11.9</u>	<u>21.6</u>
Total	25.7	77.1	127.4	230.1
Natural gas consumption (10^{12} Btu)				
FCTES	27.5	25.9	24.3	
Conventional reference system	14.5	12.6	10.8	
Net increase in gas use	13.0	13.3	13.5	
Cumulative increase in gas use††	13.0	39.4	66.2	118.6

* Totals may not add due to rounding.

** When compared with a conventional reference system.

† Hydropower, synthetic fuels, geothermal power.

†† Including increases in gas use due to FCTES continuing to operate from previous periods.

APPENDIX C. SUPPLEMENTARY TECHNICAL DATA

C.1 Criteria for Choice of Building Construction Quality

Building energy usage data compiled by United Technologies suggests that our reference building selection has resulted in lower T/E* ratios than the median T/E for the existing building stock. The United Technologies data is based on actual metered electric and gas usages of a number of buildings scattered across the country taken in the 1972-1977 time period.

Figure C.1 shows a building distribution curve of UTC projected T/E ratios from 1 to 12 for existing apartments in DOE Region 5 (Chicago). The data point labeled "ORNL" represents the T/E ratio for the reference multi-family residence (retrofit) in this region.

Based on measured T/E ratios from buildings that have had energy audits conducted and cost effective energy conservation measures enacted, we believe that UTC building data includes some buildings which are operated in a less than optimal cost effective manner. Most energy conservation modifications which are easily applied to existing buildings reduce the T/E ratio.

For example, in 1974 the Committee on Energy Conservation of the National Petroleum Council¹ examined the question of potential energy conservation in the United States from 1974-1978 for the residential/commercial building sector. They identified conservation measures requiring no capital investment, small investments (e.g. weatherstripping), substantial investments (building modifications) and totally new construction. Figure C.2 shows a bar chart depicting the effect on T/E of implementing those energy conservation measures which require little or no capital investment. The base case is assumed to represent the median T/E ratio of $\sqrt{6}$ found by the UTC building energy usage data file. As a conservation measures are deployed as shown in Fig. C.2, the assumed T/E ratio drops from 6 to 3.3.

* The T/E ratio as used here is the ratio of the energy content of metered natural gas use to the energy content of the metered electricity, assuming that the conventional central chiller-central boiler system (System 3) is installed in the building.

Fig. C.1. Building T/E Distribution for Multi-family residences in DOE Region 5 as Estimated by United Technologies Corporation.

We feel that fuel cells must be able to sell in buildings that are operated in an energy conserving manner. Therefore, selection of buildings with lower than the existing median T/E ratio is desirable, since not all cost effective energy conserving measures have been undertaken in high T/E buildings. Retrofitting existing buildings with fuel cells should be done only after other more cost effective energy conservation measures have been implemented.

Fig. C.2. Changes in T/E with Energy Conservation Practices.

C.2 Procedure for Extrapolating System Cost From Reference Buildings to Other Sizes

As mentioned in Sect. 2.4, a detailed cost analysis was done only for the reference buildings; costs for other size ranges were estimated by using equations of the form:

Cost for building of size X =

$$\text{Cost for building of size Z} \times \left(\frac{X}{Z}\right)^s$$

- X = floor area of building of interest.
- Z = floor area of reference building.
- s = weighted exponent for specific cost component (material, installation labor, O&M) and type of heat pump or chiller (reciprocating or centrifugal) used in this system.

One of two types of heat pumps or chillers is used in a particular system, depending on the magnitude of the design cooling load. For design loads less than or equal to 160 tons, reciprocating units are used, while centrifugal units are used for larger loads. One hundred sixty tons was chosen as the break-point for economic reasons; two units were used in each installation, and reciprocating units are more economical for sizes under 80 tons, while centrifugal units are more economical for larger sizes. The exponents used in the system cost scaling laws were calculated by taking the weighted sum of exponents for system components. The weighting factors chosen were the fraction of total system cost contributed by each component for the reference multifamily residence.

Six scaling equations were derived in all. Equations to scale material, installation labor, and annual O&M costs were developed for both systems with reciprocating equipment and systems with centrifugal equipment. The exponents are shown in Table C.1.

Table C.1. Exponents for cost scaling equations.

	<u>Reciprocating</u>	<u>Centrifugal</u>
Material	0.66	0.74
Installation labor	0.81	0.81
O&M	0.77	0.77

To use these equations, the design cooling load was first calculated. The size of the load was compared to 160 tons, and the appropriate set of exponents was chosen. Then that set of exponents, along with the required floor areas and reference building costs, was used to calculate costs for the building of interest.

REFERENCE

1. "Potential for Energy Conservation in the United States: 1974-1978 Residential/Commercial," National Petroleum Council, September 10, 1974.

APPENDIX D. SAMPLE PRE-INTERVIEW LETTERS

October 6, 1977

Mr/s.
Assistant Vice President
Gas Utility

Dear Mr/s.

Resource Planning Associates, Inc., (RPA) in conjunction with the Oak Ridge National Laboratory, has been retained by ERDA's Office of the Assistant Administrator for Conservation (now in the U.S. Department of Energy) to review the development program for 40 kilowatt fuel cell total energy systems. A major component of our analysis will be an evaluation of the institutional constraints that such an energy system might face.

In order to assess the range of potential problems, RPA is conducting a series of interviews with utilities and public utility commissions throughout the country. As agreed in our discussion with you on Thursday, my associate, _____, and I will be meeting you and _____ on Wednesday, November 19, 1977 at 9:30 a.m.

Some of the specific issues we would like to discuss include:

- o Franchise or certification laws which might prevent a gas company from serving customers with electricity.
- o The ability of fuel cell users to connect with the electricity grid for back-up.
- o Current policies in your state or service area governing new hook-ups for gas users, and the future availability of natural gas.
- o The extent of the market for fuel cells.
- o The effect of state and national energy policy on the future of the fuel cell.

We look forward to meeting with you and members of your staff.

Sincerely,

Name
Position

October 6, 1977

Mr/s.
Vice President
Electric Utility

Dear Mr/s.

Resource Planning Associates, Inc. (RPA) in conjunction with the Oak Ridge National Laboratory, has been retained by ERDA's Office of the Assistant Administrator for Conservation (now in the U.S. Department of Energy) to review the development program for 40 kilowatt fuel cell total energy systems. A major component of our analysis will be an evaluation of the institutional constraints that such an energy system might face.

In order to assess the range of potential problems, RPA is conducting a series of interviews with utilities and public utility commissions throughout the country. As agreed in our discussion with Mr. _____ on Thursday, my associate, _____, and I will be meeting you and _____ on November 1, 1977 at 2:00 p.m. We would also be interested in meeting with members of your legal, tariff and R&D staffs.

Some of the specific issues we would like to discuss include:

- o The criteria that you will consider in formulating a response to gas companies' efforts to operate fuel cells that provide heating and electricity to buildings.
- o The effect of fuel cell use on demand for electric service, the quality of service, and the revenue requirements of your company.
- o The criteria for the backup rate structure you would propose for fuel cell users.
- o The effects of state and national energy policy on the future of fuel cells.

We look forward to meeting with you and members of your staff.

Sincerely,

Name
Position

APPENDIX E. INTERVIEW PROCEDURE.

INTERVIEW GUIDE FOR
DISCUSSION WITH REPRESENTATIVES
OF UTILITY COMPANIES AND
REGULATORY COMMISSIONS

INTRODUCTORY REMARKS

- o Description of RPA role as consultant to DOE on study of market potential of FCTES and how discussion will aid in analysis of potential institutional or regulatory barriers
- o Description of FCTES applications, performance, operation, and financial characteristics
- o Brief overview of topics to be discussed in more depth
 - State natural-gas situation and policy
 - Franchise and territory issues
 - Standby (backup) and electric-load issues

STATE NATURAL-GAS SITUATION AND POLICY

- o Are pipelines that serve the state currently able to fulfill their contracts?
 - If there are problems, do they vary between service areas?
 - How is the supply situation expected to change in the near future?
- o Does the state currently have policies that restrict:
 - New attachments by gas users completely, or by end-use or quantity criteria?
 - Advertising or promoting load growth?
 - Any generation of electricity using natural gas?
- o Would fuel cells be considered a use of gas for electric generation, or a space and water heating use?
- o Does the state have an implicit or explicit policy aimed at sharply reducing gas use?
- o Would the special efficiency characteristics of the FCTES be convincing to a state regulatory commission?

FRANCHISE AND TERRITORY ISSUES

- o Description of possible FCTES ownership arrangements
 - Gas-utility ownership of system, user billed for system capital and O & M costs, and gas used
 - Electric-utility ownership of system, user billed for electricity
 - Private (user) ownership of system, possible submetering arrangement for other users (applicable to apartment buildings, shopping centers)
 - Joint venture between gas and electric utility, or ownership by dual electric/gas utility
- o For each arrangement, considering experience with similar situations and applicable laws:
 - Would an FCTES installation conflict with territorial grants already made to electric utilities?
 - Would an FCTES installation conflict with the franchises previously granted by municipalities to local electric utilities?
 - Would an FCTES installation be considered a public utility, and therefore be subject to regulation by the state regulatory commission? If so, what costs would be incurred by the owner or operator?
 - How would the state regulatory commission view the fuel cell in light of past state policy on self-generation?
 - How would an organization presenting the FCTES to a regulatory body best make its case to gain approval?
 - Would an FCTES installation need a new certificate of public convenience and necessity, or would an amendment to a presently existing certificate be sufficient?
- o If a commission did not grant approval, or an opposing utility was not willing to accept new competition without a fight, how long would the litigation take to settle the dispute?
- o Has there been experience in the state with other total energy systems?

STANDBY (BACKUP) AND ELECTRIC-LOAD ISSUES

- o Will the state commission require that self-generator meet certain service quality standards?
- o Can the state regulatory commission require electric utilities to provide standby service? Is there any precedent in the state from experience with other total-energy systems?
- o Have other self-generators used (or been refused) standby service?
- o If potential FCTES users felt that standby rates were too high, could they seek relief from the regulatory commission?
- o Is RPA's methodology for estimating standby rates (full marginal cost of extra generating capacity and transmission and distribution equipment) applicable?
- o How valid is the concept of diversity?
- o How is the fuel cell likely to affect the electric utility's load mix?

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- 157. P. Wilson, Resource Planning Associates, Inc., 44 Brattle Street, Cambridge, MA 02138.
- 158. J. Winder, McKinsey and Company, Inc., 1700 Pennsylvania Avenue, Washington, D.C. 20006.
- 159. K. Vora, Resource Planning Associates, Inc., 44 Brattle Street, Cambridge, MA 02138.
- 160. Assistant Manager for Office of Energy Research and Development, DOE-ORO
- 161-187. Technical Information Center, Department of Energy, P.O. Box 62, Oak Ridge, TN 37830.
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