A COST ALLOCATION MODEL FOR ASSESSING THE IMPACT OF ENERGY STORAGE TECHNOLOGIES UPON ELECTRIC UTILITIES

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ABSTRACT

In order to assist the Division of Energy Storage Systems in the U.S. Department of Energy in prioritizing, developing, and commercializing storage technologies a computer simulation code has been developed by Argonne National Laboratory to assess the impact of alternative residential heating and cooling technologies upon the electric utility generation, transmission, and distribution systems. Given input information such as plant capacity, forced-outage rates, scheduled maintenance requirements, and economic data for individual generating units, the program uses hourly utility load data together with synoptic weather data to simulate system loads and costs for specified levels of heating/cooling technology penetration.

The program performs five categories of calculations: simulation of residential load, aggregation and propagation of loads through the distribution and transmission subsystems, economic dispatch of generating plant, scheduling of plant maintenance, and calculation of optimal generating plant mix. Originally designed to study the impact of shifting on-peak demand to off-peak periods through the use of customer-owned thermal storage, the code has been extended to handle a variety of electric heating and cooling technologies. The computer running time for a full set of calculations is short, allowing many system alternatives to be examined at low cost.

Results are presented for residential space conditioning systems for two representative utility service areas. In the service area supplied by a winter peaking utility, the lowest cost space heating technologies were found to be storage-augmented either by storage or by an oil furnace. Heat pumps were the most economical heating systems in the service area supplied by the summer-peaking utility while storage air conditioning was cost-effective for cooling in the summer-peaking service area.

INTRODUCTION

The mission of the Division of Energy Storage Systems in the U.S. Department of Energy is to develop, and to cooperate with industry in demonstrating, reliable, cost-effective, and environmentally acceptable energy storage systems. A major thrust of the Division is to stimulate the development and use of commercial energy storage systems throughout the United States. Applications of energy storage technologies exist in transportation, building heating and cooling, industrial processes, and the utilities.

Large differences in the need and requirements for energy storage account for the many application-specific energy storage technologies which are currently under development. Energy storage requirements are associated with:

- Basic differences in applications (e.g. vehicle propulsion, heating and cooling of buildings, industrial processes, electric generation)
- Differences in energy storage systems sizes (e.g. residential, commercial, community systems)
- Regional variations (e.g. climate, fuel availability and fuel costs, construction practices)
- Degree of market penetration of energy storage systems
- Time frame for implementation of energy storage systems

The use of energy storage systems in these areas will provide one or more of the following benefits:

- Increase the substitution of coal, nuclear, and solar energy for petroleum and natural gas
- Enable solar, wind, and other intermittent energy systems to provide continuous service
- Recover waste energy from utilities and industries, and improve process efficiency
- Enable electric utilities to use their facilities more efficiently, thus reducing the need for new generation and transmission facilities

The Federal role in developing energy storage technologies calls for support of Research and Development (R&D) in areas where private firms are unwilling or unable to invest, but from which significant national benefit is anticipated. A preliminary R&D effort is to identify those energy storage options with the greatest potential market impact and conduct theoretical and experimental programs to select those options best suited for further development. Technology assessments are required to analyze potential opportunities and timing of technology development, the risks involved, and potential payoffs for energy conservation and other social benefits, and the appropriate roles for both public and private sectors in each phase of technology development. Technology assessments are conducted through the Technical and Management Analysis Subprogram for the Division of Energy Storage Systems.

The Technical and Management Analysis Subprogram provides the Division of Energy Storage Systems with the information and criteria needed to set and prioritize energy storage R&D activities. Project evaluations are conducted at several stages in energy storage technology research and development. Specific objectives of these evaluations are to:

- Evaluate competing energy storage R&D options to recommend those with the greatest potential for contributing to national energy goals
- Assess the potential environmental impact of new energy storage technologies
- Coordinate commercialization plans for newly developed energy storage technologies
- Recommend and re-evaluate energy storage systems R&D goals
- Provide input to national energy policy planners on new energy storage technologies

To accomplish these objectives, the Technical and Management Analysis Subprogram is organized into three interrelated activity areas:

- R&D Evaluation
- Information Management
- Applications Analysis

Research and Development program evaluation involves addressing a broad range of issues concerning the potential impact of energy storage technologies. Issues to be considered include the effect of energy storage systems on energy savings, the cost of energy, central versus dispersed storage, environmental, health and safety effects, and implied changes in lifestyle.

To provide good information inputs to technology assessments, the Technical and Management Analysis Subprogram is developing a computer network information system that will integrate all information required to perform a wide range of analyses on energy storage technologies and program activities. The Energy Storage Integrated Information System will incorporate into the energy storage program decision-making processes the outcomes of cost/risk/benefit assessments conducted on energy storage technologies.

Applications Analysis provides the basis for identifying priorities among new energy storage technologies. Applications Analysis projects define the suitability of storage technologies for primary end-use as well as provide information about the technical risk and costs of developing a new technology versus the expected benefits.

BACKGROUND

In residential and utility applications, energy storage systems have the potential to reduce electric utility peak load burdens and residential customer energy bills by storing electricity during off-peak periods, when generation costs are low, and making it available during peak load periods. This can result in the following benefits:

- Reduction in the growth rate of utility peak loads with a corresponding reduction in generation, transmission, and distribution capacity
- Improvement of daily load factors, allowing the substitution of utility base-load fuels (coal and uranium) for peak- and intermediate-load fuels (oil and gas)
- Reduction in the cost of electricity supply thereby benefiting the customer and enabling a greater market penetration for electricity (1)

The energy storage systems may be centralized (pumped-hydro, compressed air, etc.), or they may be decentralized (chemical, thermal, batteries) and located at or near the end-use location. Either customer or utility ownership of decentralized systems is possible. In the case of customer ownership, the benefits listed above must exceed the additional capital costs incurred by the customer, and some form of time-of-use rate schedules, peak-period demand charges, load management contract rates, or simple monthly credits is required to allow customers to realize the required payback on their additional capital investment.

Argonne National Laboratory has been contacted by DOE/STOR to assess a broad range of energy storage technologies interfacing electric utility supply networks. The first phase of the project was to assess the costs/benefits of thermal energy storage (TES) systems, where electrical energy is stored in end-use form as heat or cold to provide residential space-conditioning or domestic hot water heating.

The most difficult part of the analysis is estimating the utility savings associated with the introduction of the TES systems. The utility savings are sensitive to the utility's seasonal and daily load profiles, to seasonal weather patterns, and to the level of TES market penetration.

A survey of utility cost-of-service models conducted at the beginning of the project indicated that none of the available models could easily be adapted to the problem of assessing customer TES systems. Consequently, SIMSTOR, a computer simulation model, was developed to calculate the utility costs of meeting conventional and TES loads.

The remainder of this paper is devoted to a discussion of the methodology embodied within SIMSTOR and a discussion of various applications analyses which have been performed using the model. The results of this energy storage analysis effort are used to: (1) evaluate cost-competitiveness and technical performance of specific energy storage technologies, (2) determine the optimum size of storage units for space heating and cooling applications, (3) assess market needs and estimate potential market penetration and commercialization strategies for storage technologies, (4) specify R&D requirements for a national program to develop energy storage technologies.

METHODOLOGY

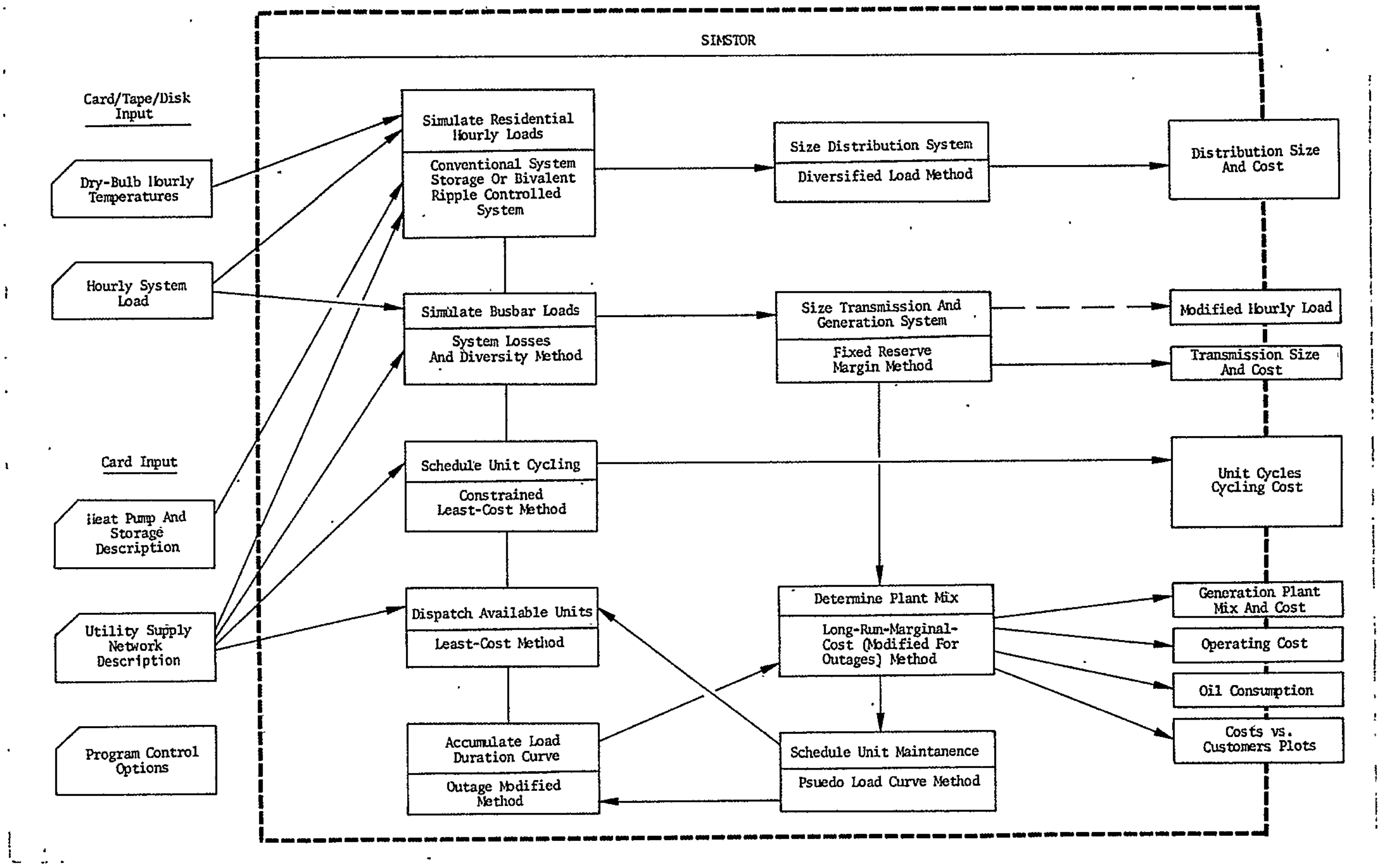
OVERVIEW

SIMSTOR has been designed as a decision-making tool. Running time is short, allowing the examination of many system alternatives. The output is tailored to give the decision-maker detailed information on the storage system impact upon the electric utility supply network including required generation, transmission, and distribution capacity and associated capital costs. The program also calculates unit cycling, fuel, and operation and maintenance (O&M) costs by plant type as well as oil/gas consumption. The overall SIMSTOR methodology is shown in Illustration 1.

Input consists of hourly system load data (8760 hours) with corresponding dry-bulb temperature data; residential device characteristics and appliance saturation data; utility generation, transmission, and distribution operating characteristics; capital expansion costs and operating costs. To reduce input requirements, simplify calculations and reduce program running time, the utility is constructed out of identical units from three generic plant types - base, intermediate, and peak.

SIMSTOR uses the hourly utility load and trihourly weather data together with the TES and conventional system performance characteristics to generate incremental customer load profiles over a full annual (8760 hour) cycle; the program aggregates these profiles and corrects for load diversity and system loss effects to calculate busbar loads and to size the transmission and distribution system; short run marginal costs subject to unit cycling constraints are used to economically dispatch generating units; long-run capital expansion costs together with scheduled maintenance, forced-outage rates, and system reserve margin are used to calculate the optimal mix of generating plant. Because SIMSTOR uses an equilibrium method to solve for optimum plant capacity mix, the estimated utility savings represent long-run marginal cost

ILLUSTRATION 1



savings. Therefore, the savings estimates pertain to planning horizons beyond the construction times or projects to which utilities are already firmly committed. The method's neglect of short-term effects is not considered a serious limitation since the times required to deploy new technologies, such as customer thermal storage systems, in sufficient numbers to produce significant load-altering effects are comparable to the construction periods of base-load generating plants. Short-term effects can be studied by invoking a program option which eliminates the optimization of plant capacity mix. In this case, the user specifies the desired base and intermediate plant mix, and the program only alters the peaker capacity to satisfy the specified system reliability criterion.

RESIDENTIAL DEMAND SIMULATION

Residential demand is simulated at the household level, aggregated, and propagated through the distribution and transmission systems to obtain bus-bar loads. The individual household loads consist of three components:

1. Conventional space conditioning; air conditioning in summer and resistance heating and/or heat pump heating in winter.
2. Conventional domestic hot water heating.
3. Baseload, which consists of all other household loads.

TABLE 1

Space Heating

Resistance Baseboard
Resistance Furnace
Storage Resistance Baseboard
Storage Resistance Furnace
Resistance Furnace with Ripple-Controlled Oil/Gas Furnace Backup
Heat Pump with Resistance Furnace Backup
Heat Pump with Oil/Gas Furnace Backup
Heat Pump with Ripple-Controlled Oil/Gas Furnace Backup
Heat Pump with Storage Resistance Furnace Backup

Space Cooling

Conventional Air-Conditioner
Storage Air-Conditioner

Hot Water Heating

Conventional Hot Water
Storage Hot Water

These loads are calculated on an hourly basis for each day of the year and added to give the nominal diversified residential load. Hourly residential load profiles for the technologies listed in Table 1 are also calculated. Only one space heating and/or one space cooling or domestic water heating technology may be selected for any given run. If a storage technology is chosen, a second routine, is called. This routine takes the selected technology load profile and reallocates the load to off-peak periods subject to the constraints imposed by the storage technology such as maximum charging rate and maximum energy storage capacity. The charging of the storage is done to minimize system generation costs on a daily basis.

Thermal Load Calculation: An algorithm developed from an electric heating survey performed by the Philadelphia Electric Company (2) is used to generate hourly space heating thermal loads. The expression depends upon the current and the antecedent hourly dry-bulb temperatures. This expression accounts for dry-bulb temperature effects on an hour-by-hour, day-by-day basis. All other variables, such as wet-bulb temperature, solar insolation, and wind are only accounted for in an average-day fashion. While more sophisticated thermal load models exist, their use entails the establishment and maintenance of extensive and sometimes difficult-to-obtain data bases. Furthermore, such models will only give undiversified thermal loads for identical houses in identical locations and orientations experiencing identical weather conditions. A utility, on the other hand, faces diversified loads arising from many different types of houses having various orientations and located throughout the utility service area. The SIMSTOR algorithm includes this "diversity-averaging effect" as well as various lifestyle effects such as house occupancy patterns, opening and shutting of doors, and night setback of thermostats.

Diversified electrical cooling loads cannot be accurately simulated as functions of only dry-bulb temperature. Variables such as wet-bulb temperature, wind, solar insolation, and previous days' weather conditions all strongly influence residential cooling demands. To include these effects and yet maintain a manageable data base, a totally different algorithm is used. First, a nonweather-sensitive system load profile is generated by identifying nonholiday days having minimum daily load. To account for differences in load profiles as a function of the day of the week (weekend loads are much lower than weekday loads), a separate nonweather-sensitive load profile for each day of the week is determined. Weather-sensitive-cooling load is determined by subtracting the corresponding day of the week's nonweather-sensitive load profile from the total system load profile. The resulting hourly load profile is taken to be proportional to the residential cooling load profile. The proportionality constant is determined by normalizing the standard house seasonal cooling load to the seasonal weather-sensitive cooling load.

Conventional Resistance Heating: This is a direct electric resistance furnace - the typical system found in electrically heated homes with central heat. The electrical load is set equal to the thermal load for each hour.

Heat Pump Heating: Heat pump electrical demand, as well as heat pump heating capacity, is a function of temperature. The heat pump model (3) uses equations cubic in temperature to characterize the heat pump capacity, HOP, and the heat pump electrical consumption, HPI. These equations are typically valid over the outside temperature range -15 to 70°F. Outside this range the endpoint value, -15 to 70°, is used. A defrost cycle can be programmed to operate over a specified temperature range, nominally 20-40°F, to extend the heat pump performance range by preventing icing up of the outside coil at low temperatures and subsequent compressor damage. In this case, the heat pump is derated over this temperature range. Furthermore, the heat pump is completely shut down below a specified temperature, TEMRES, to prevent possible compressor damage at very low temperatures.

Since heat pump electrical demand, as well as heat pump capacity, is a function of temperature, heat pump performance depends upon the heat pump size relative to the house thermal load. As the outdoor temperature drops, the thermal load on the house increases and the heat pump capacity decreases until the heat pump capacity equals the thermal load. This temperature is referred to as the balance point. The heating load is met entirely by the heat pump above the balance point and supplemented by a resistance backup system below the balance point. For temperatures less than TEMRES the resistance backup system provides the full heating capacity.

Bivalent Heat Pump Heating: This system behaves exactly the same as the conventional heat pump system described above with the exception that backup power is supplied by an oil or gas furnace instead of by an electric furnace. (4)

Ripple-Controlled Bivalent Heat Pump Heating: This system resembles the previous bivalent system except that the utility can switch off the heat pump and switch on the backup system, via a ripple-control unit, during periods when the marginal operating cost for the utility exceeds the marginal cost of the oil furnace in providing one unit of heat to the customer.

Ripple-Controlled Bivalent Resistance Heating: This bivalent system is an electrical resistance furnace with an oil or gas backup unit. Either system is capable of carrying the full load. During periods of utility peak plant operation, utility control substitutes the oil or gas furnace for the electric heater to take advantage of the higher system efficiency of direct oil or gas utilization. The logic for this system is exactly the same as the ripple controlled bivalent heat pump system with an electric furnace replacing the heat pump as the primary source of heat.

Rippel-Controlled Storage Resistance Heating: This is an electric storage furnace (5) with sufficient thermal capacity to supply heat energy to the home for several hours. During this period, the electric resistance heaters do not come on, but heat is withdrawn from the furnace as needed by a thermostatically-controlled fan. During the off-peak period, the furnace storage system is recharged to full capacity. The electrical load is first calculated exactly as in the conventional resistance heating case. Then this load is modified by the storage allocation routine to optimally shift the load to the off-peak (night-time) period by utilizing the available customer storage capacity.

Ripple-Controlled Storage Heat Pump Heating: A storage electric furnace is used as a backup for the heat pump. Thus, the peak loads experienced during extremely cold periods can be met with off-peak electricity. The electrical load is calculated exactly as for the conventional heat pump case. Then the supplemental resistance furnace component of the load is modified by the storage allocation routine to optimally shift this load to the off-peak period by utilizing the available customer storage capacity.

Conventional Air-Conditioning: The standard space cooling system is a vapor compression air conditioner, which can also serve as a heat pump in cooler weather. This unit is sized to provide adequate cooling to the house on the design-day in each utility service area. The residential air-conditioning load is set equal to the calculated weather-sensitive electrical load of the standard house.

Ripple Controlled Storage Air-Conditioning: The storage air conditioner utilizes an icemaker evaporator coil to partially (80%) freeze water in a storage tank. (6) This frozen water is then used to cool the building during on-peak hours without any additional compressor action. The residential air-conditioning load is first calculated, and then this load is modified by the storage allocation routine to optimally shift the load to the off-peak period by utilizing the available storage capacity. The water pump electrical load is small and is currently ignored in modeling the storage air-conditioning system.

Residential Domestic Hot Water Heating: The direct resistance water heater is the standard configuration found in most residential applications today. It consists of a heating element immersed in a storage tank. A thermostat controls the electrical input to the heater so as to maintain the tank's contents at a constant temperature. As water is drawn from the tank, the heater thermostat immediately responds to the cooler incoming makeup water. Although there is some thermal capacity stored in the tank, the controls do not allow its utilization to the benefit of the utility.

Conventional Domestic Hot Water Heating: The residential domestic hot water load is set equal to the daily hot water load profile. (7)

Ripple Controlled Domestic Hot Water Heating:

In the storage resistance heater, a time-of-day utility-actuated control system disconnects the electric heater during the peak-load period regardless of the water temperature variations. During the on-peak period, hot water demand is met entirely by the storage tank's capacity. The residential domestic hot water heating load is first calculated as in the conventional case and then is modified by the storage allocation routine to optimally shift the load to the off-peak period by utilizing the available storage capacity.

Residential Baseload

This load comprises all household appliances other than space conditioning and domestic hot water heating and is about equal to a domestic hot water heating load on an annual basis. However, very little data exists characterizing this load. For this reason, SIMSTOR uses the simple load shape. It consists of one constant load during off-peak hours, and another constant load during on-peak hours. Since the program calculates supply costs associated with the specified technology, incremental load, all terms linear in this load cancel. However, two effects do not cancel.

1. Subsystem sizing (particularly distribution) which is determined by the maximum hourly load on any given subsystem
2. Resistive line loss effects which depend upon the square of the load

ECONOMIC LOAD DISPATCH OF GENERATING UNITS

The utility system is made up of base, intermediate, and peak classes of generating units. All units within a given class are assumed to be identical and are characterized by the parameters listed in Table 2. Each unit is derated (maximum and minimum) to account for its associated average FORCED OUTAGE RATE. The MINIMUM RATING determines the point below which a unit must be shut down for a period not less than the MINIMUM CYCLE TIME. The number of plants within each class is initially specified at the start of a run and is subsequently updated at the end of each pass by the optimum plant mix routine. The actual number of available units in each class is varied throughout the year according to the pattern determined by the maintenance scheduling routine. The generating units are economically dispatched within these MINIMUM RATING and MINIMUM CYCLE TIME constraints - base units first, then intermediate units, and finally peak units.

TABLE 2

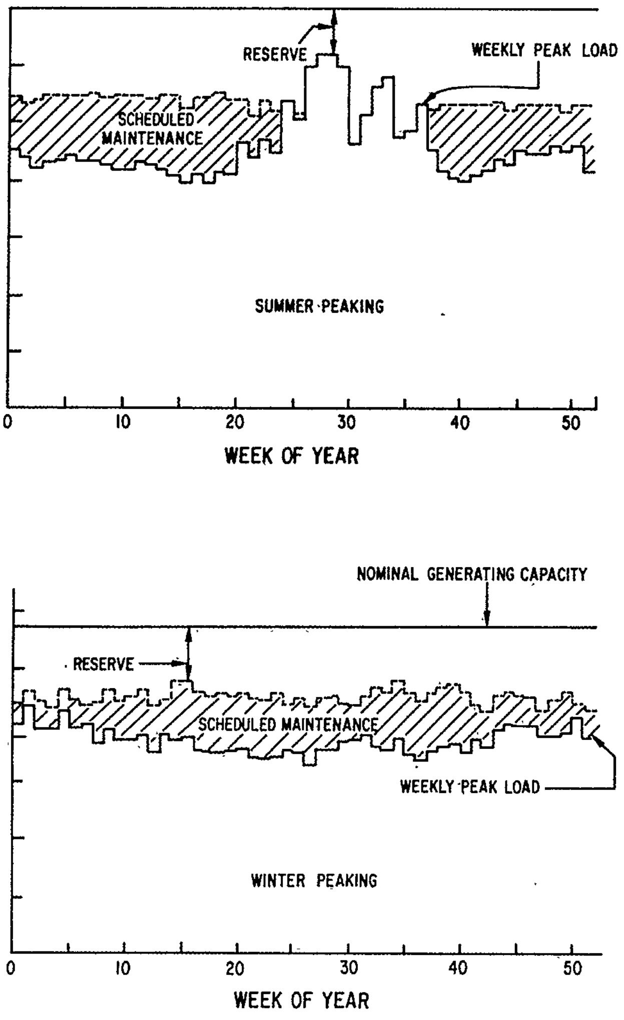
Number of Units
Maximum Rating (MW)
Minimum Rating (MW)
Forced Outage Rate (%)
Scheduled Maintenance (Weeks)
Annual Capital Cost ($/kW/yr)
Fuel Cost (Fixed Heat Rate) ($/MWh)
Operating and Maintenance Cost ($/MWh)
Minimum Cycle Time (Hours)
Minimum Cycle Cost ($/Cycle)

SCHEDULING UNIT MAINTENANCE

Each type of generating unit has associated with it an annual maintenance period, measured in weeks. During this continuous period the unit is not available for meeting system load requirements. (8)

The objective of the maintenance routine is to schedule required unit maintenance downtimes consistent with maximum system reliability. Thus, units are preferentially scheduled down during periods of low system load requirements. This is accomplished by means of a technique that generates a pseudo-load curve consisting of the sum of the weekly peak-load curve and the effective capacity scheduled for maintenance during that week. A unit that needs to be scheduled for downtime is then scheduled for that period which results in the lowest maximum pseudo-load curve upon the unit's addition to the scheduled maintenance capacity. In order to achieve a relatively flat pseudo-load curve, base load units which typically have the largest unit sizes and longest maintenance periods are scheduled first, then intermediate units and finally peak units. Illustration 2 shows the

ILLUSTRATION 2



resulting pseudo-load curve after scheduling all maintenance for a typical summer-peaking utility and a maintenance constrained winter-peaking utility. This second case illustrates the importance of considering scheduled maintenance. For this case, system reserve requirements are determined not by the actual system load peak which occurs in winter but rather by the pseudo-load peak which occurs in spring.

OPTIMAL PLANT MIX CALCULATION

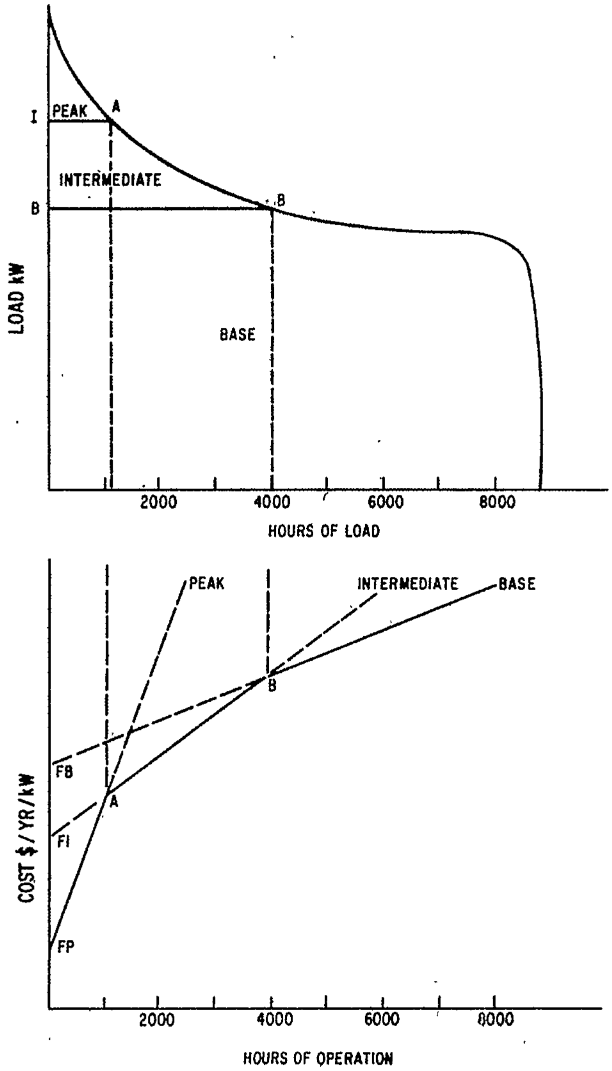
Determination of the optimal plant expansion schedule and mix of plant types is a dynamic process. The objective is to minimize the net present value of providing electrical service over a specified planning period, typically 20-30 years. This requires projections of the following variables over the duration of the planning period:

1. Load
2. Plant Capital and Fixed Maintenance Costs
3. Plant Operating and Variable Maintenance Costs
4. Plant Unit Size and Plant Lifetime
5. Minimum System Reliability
6. Plant Forced Outage and Scheduled Maintenance Outages

To understand the trade-offs involved in determining an optimal plant mix, consider the following simplified example in Illustration 3 where variables 4, 5, and 6 are ignored. The objective is to find the least cost solution for meeting the given load during a single year, or alternatively a static yearly load profile for several years. Illustration 3a shows the year's load duration curve, LDC(X), defined as the number of hours X having load greater or equal to LDC(X) during the year. Thus, LDC(1) represents the yearly peak load while LDC(8760) represent the yearly minimum load. Illustration 3b shows the annual cost associated with running three types of representative plants -- base, intermediate, peak -- as a function of the number of hours of operations. The intercepts -- FB, FI, and FP -- represent the revenue required to cover the fixed costs associated with owning but not operating each plant type -- base, intermediate, and peak, respectively -- and include the following:

1. Return to Equity (Stocks)
2. Return to Debt (Bonds)
3. Depreciation
4. Taxes (Federal, State, Local, and Ad Valorem)
5. Fixed Maintenance (Insurance, Upkeep)

ILLUSTRATION 3



The slopes -- VB, VI, and VP -- represent the variable operating costs associated with producing power from each plant type -- base, intermediate, and peaking, respectively -- and include:

1. Fuel
2. Operating and Maintenance (O&M)

For the costs represented in Illustration 3b, all loads persisting for fewer than A hours are most economically met by peaker plants, loads persisting for more than B hours by base plants. As shown in Illustration 3a the optimal plant mix consists of:

B kW of base plant
I-B kW of intermeidate plant
P-I kW of peaking plant

The program incorporates a more complicated algorithm than presented above to account for the effects of variables 4, 5, and 6. However, the same tradeoff between capital and operating costs drives the optimization, however, leading to somewhat different values for B, I, and P.

Cost of Supply

The objective of the SIMSTOR code is to determine the utility costs associated with meeting a given residential technology. First, a plant mix corresponding to the original utility load curve is run for a full year to determine the baseline utility cost and operation characteristics. Next, a specified number of customers employing the specified technology is added to the system and run for a full year. This results in a new load duration curve and consequently a new optimal plant mix. Since this new plant mix will result in a different maintenance schedule and a different economic dispatch, the program reruns the entire year with this new plant mix. The cost associated with supplying this specified technology is given by calculating the change in utility costs (new - baseline) and dividing by the number of customers. By repeating this procedure, cost of supply as a function of the number of customers installing the specified technology can be obtained.

APPLICATIONS ANALYSIS

The model has been used to evaluate and compare the total costs of supplying space heating and cooling services with various alternative technologies. Under the study method, both the utility's cost of service and those device investment and maintenance costs borne directly by the customer were evaluated. The analyses can be organized into three separate phases of work.

Phase I: Initial studies have identified three dirunal storage technologies for residential space-conditioning and domestic hot water heating which offer customer paybacks as short as three years if utility savings are made available to TES customers through reduced electric rates:

1. Electric storage heaters using refractory brick enclosed in an insulated cabinet to store heat on winter-peaking utilities
2. Storage air conditioning systems using ice storage tanks to store cold on summer-peaking utilities
3. Storage water heaters using larger, better insulated water tanks to provide dirunal storage

Phase II: Subsequent studies have modified and extended SIMSTOR to evaluate more advanced heating systems including heat pumps, storage augmented heat pumps, bivalent heat pumps, and solar heating (space and domestic hot water) using the electric utility as a backup. The solar analysis used a modified version of TRNSYS to calculate collector transient response and calculate utility backup requirements on an hourly basis for input to SIMSTOR. These studies analyzed trade-offs associated with storage size and control strategy and ranked technologies on a life-cycle cost basis including both customer capital costs and utility costs of service. Conventional heat pumps proved most cost-effective within summer-peaking service areas, while storage resistance heaters, storage heat pumps, and bivalent heat pumps had lowest life-cycle cost within winter-peaking service areas.

Phase III: Currently SIMSTOR is being used to compare the benefits of the decentralized storage technologies studied during Phases I and II with centralized utility storage. Additional analyses are in progress to study the impact upon electric utilities of two advanced technology concepts: Electric Vehicles and Integrated Community Energy Systems.

The balance of this paper will be devoted to a summary of the Phase II results. Case studies of a number of utility service areas were performed. The two service areas for which results are presented here were selected to illustrate the important factors affecting the overall cost of service for the different heating and cooling technologies. One service area is located in the Northeast and is supplied by a winter-peaking utility; the other service area, located in the Middle Atlantic Region, is served by a summer-peaking utility.

Study Method: In each service area the individual heating and cooling systems were matched to the load requirements of a 1500 ft^2, well-insulated, detached single family dwelling unit. The heating load amounted to approximately 4 kWh_t/degree-day.

In order to value units of capital consistently on both sides of the electric meter, one set of system cost comparisons was made with heating/cooling device capital costs calculated on the basis of the utility capital recovery rate. This accounting procedure is conceptually equivalent to assuming utility ownership of the heating/cooling device. Another set of comparisons was made with the customer cost of money equal to present mortgage rates less an effective income tax credit.

The annual utility capital costs were calculated with a 17% capital recovery rate for plant of 30 year lifetime. This rate, which is representative of recent utility experience, incorporates a large (≃6%) inflation component in the cost of both bond and equity money. For consistency, fuel costs, which were assumed to have a 0% real rate of escalation, were inflated at the same 6% rate and were discounted by the same (11%) discount rate. The resulting annual fuel levelization factor was equal to 1.77. Because initial-year fuel was valued at full marginal cost, this procedure is not expected to understate fuel costs relative to capital costs.

Utility energy supply costs for space conditioning technologies were calculated for an incremental load corresponding to the addition of 1000 space heating customers and to the addition of 2000 customers for air conditioning. These load increments represent approximately 10 MWe of diversified peak electrical demand if met with conventional heating and cooling technologies. Although utility supply costs change as the number of installations increase -- for example, the marginal cost of supplying storage heating customers increases as the nighttime valleys are filled -- the dependence of supply costs on market penetrations is not discussed here (7).

Because load curves and weather data for a specific year, 1975, were used, the estimated utility supply costs do not constitute a forecast of the costs of meeting device-specific loads. Rather, the calculated costs may be interpreted as representative for utilities expecting to face load curves having shapes similar to the ones used here. Moreover, because of the heterogeneous nature of the electricity market, the estimates of the relative costs of the heating and cooling technologies are not regarded as constituting a universal ranking of the technologies. Before encouraging installation of a particular technology, a utility will want to evaluate the technology under conditions specific to its own service area.

Study Findings: The estimated cost of the different heating and cooling technologies are presented in Tables 3 and 4 for the winter and summer peaking service areas, respectively. As indicated in Table 3, the storage and bivalent systems are the most efficient heating systems in terms of overall cost. Presenting the utility with electric loads only during the off-peak hours, these systems do not contribute to the utility's conincident peak demand.

The ripple-controlled bivalent heat pump is especially attractive. Entailing a small customer capital cost penalty -- approximately $500 over the cost of a heat pump with electric resistance backup -- the heat pump with oil furnace backup achieves substantial savings through the virtual elimination of the on-peak electrical load.

For the service area supplied by a summer-peaking utility, the entire heating season is off-peak so that the benefits of storage and bivalent heating systems are greatly reduced. The conventional heat pump is the most economical heating technology. Storage and bivalent technologies are 10-20% more expensive in terms of overall cost and suffer the disadvantage of being more complicated technologies.

Illustrations 4 and 5 display annualized energy supply costs (utility capital and fuel and bivalent fuel costs) and device (customer) capital costs for each of the heating technologies. The dashed lines represent constant total cost curves. As shown in the figures, storage and bivalent systems are the most efficient technologies in the winter-peaking service area, while the conventional heat pump is the lowest cost technology in the service area supplied by a summer-peaking utility.

DISCUSSION

Subject to the caveats required of any analysis based on a case studies approach, a number of important conclusions can be drawn.

TABLE 3

System	System Characteristics	Contribution to Utility Peak (kW/Customer)	Average Utility Cost (¢/kWh)	Costs ($/Yr/Customer)							
				Energy Supply				Device[c]		Total	
				Utility			Supplemental Fuel[b]	Util. Rate	Mort. Rate	Util. Rate	Mort. Rate
				Generating[a]	T&D	Total					
Space Heating											
Resistance											
Direct	Central Electric Furnace	16.6	9.0	1125	820	1945	--	240	140	2185	2085
Storage	8 hour Central Storage	0.0	1.7	365	0	365	--	535	320	900	685
Bivalent	Ripple Controlled Oil Furnace Backup	0.0	2.9	580	0	580	45	610	380	1235	1005
Heat Pump											
Conventional	2.5 ton (SPF = 2.06)	15.0	11.8	730	740	1470	--	325	200	1795	1670
Storage	8 hour Resistance Storage	0.0	2.9	305	0	305	--	575	350	880	655
Bivalent (Mode 1)	Oil Furnace Backup	3.3	6.4	360	165	525	65	430	280	1020	870
Bivalent (Mode 2)	Ripple Controlled Oil Furnace	0.0	3.0	230	0	230	100	460	300	790	630
Solar											
Resistance	330 ft^2 (50% solar)	10.8	9.6	395	530	925	--	1300	760	2225	1685
Storage Resistance	330 ft^2 (50% solar)	0.0	1.6	155	0	155	--	1360	800	1515	955
Heat Pump	270 ft^2 (SPF = 2.3)	9.1	9.0	365	450	230	--	1110	650	1340	880
Air Conditioning											
Conventional	2.5 ton Heat Pump	0.0	4.3	95	0	95	--	255	175	350	270
Storage	8 hour Ice Storage	0.0	1.6	35	0	35	--	475	310	510	345

[a] Includes generation capital, fuel, cycling, and maintenance costs.

[b] Cost of fossil fuel for bivalent system.

[c] All heat pump device costs are net an air conditioner capital cost credit of $1050.

TABLE 4

System	System Characteristics	Contribution to Utility Peak (kW/Customer)	Average Utility Cost (¢/kWh)	Costs ($/Yr/Customer)							
				Energy Supply				Device[c]		Total	
				Utility			Supplemental Fuel[b]	Util. Rate	Mort. Rate	Util. Rate	Mort. Rate
				Generating[a]	T&D	Total					
Space Heating											
Resistance											
Direct	Central Electric Furnace	0.0	4.2	805	0	805	---	235	140	1040	945
Storage	8 hour Central Storage	0.0	1.9	370	0	370	---	415	245	785	615
Bivalent	Ripple Controlled Oil Furnace Backup	0.0	2.9	450	0	450	20	605	380	1075	850
Heat Pump											
Conventional	2.5 ton (SFP = 2.0)	0.0	2.7	260	0	260	---	325	200	585	460
Storage	8 hour Resistance Storage	0.0	2.3	220	0	220	---	440	270	660	490
Bivalent (Mode 1)	Oil Furnace Backup	0.0	2.5	185	0	185	60	430	280	675	525
Bivalent (Mode 2)	Ripple Controlled Oil Furnace	0.0	2.3	165	0	165	90	460	300	715	555
Solar											
Resistance	300 ft^2 (50% solar)	0.0	2.0	180	0	180	---	1200	710	1380	890
Storage Resistance	300 ft^2 (50% solar)	0.0	1.5	135	0	135	---	1280	750	1415	885
Heat Pump	270 ft^2 (SPF ≃ 2.4)	0.0	2.4	200	0	200	---	940	550	1140	750
Air Conditioning											
Conventional	2.5 ton Heat Pump	5.5	23.3	415	265	680	---	255	175	935	855
Storage	8 hour Ice Storage	0.0	2.1	60	0	60	---	475	310	535	370

[a] Includes generation capital, fuel, cycling, and maintenance costs.

[b] Cost of fossil fuel for bivalent system.

[c] All heat pump device costs are net an air conditioner capital cost credit of $1050.

ILLUSTRATION 4

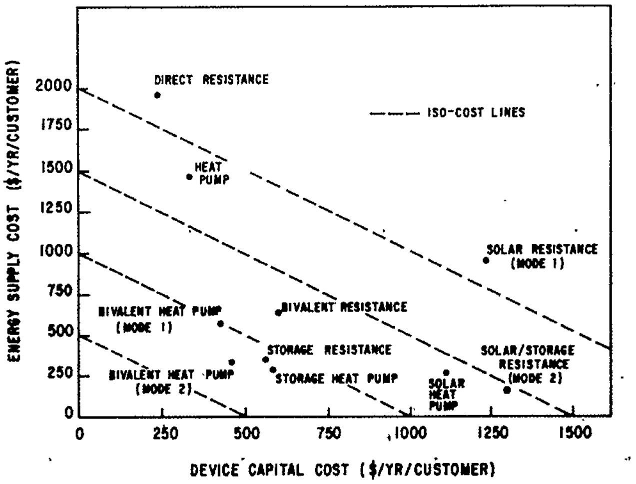
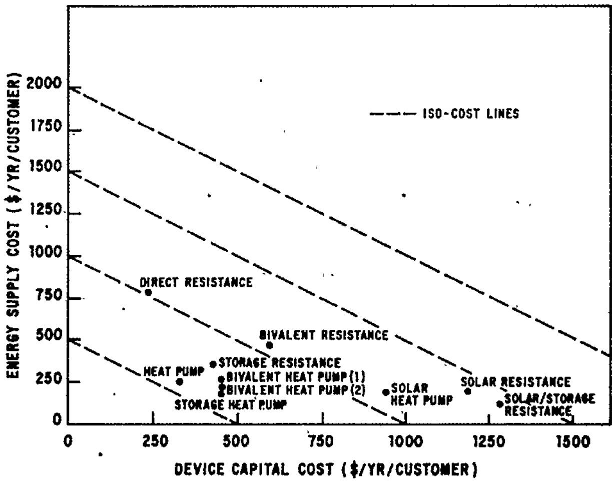


ILLUSTRATION 5



In winter-peaking service areas, several storage and bivalent technologies offer substantial savings relatibe to conventional heat pump and direct resistant heating systems. Largely neglected in the United States, these technologies merit the attention of utilities attempting to reduce the overall cost of electric heating services.

In the summer-peaking service area, the conventional heat pump is the most cost-effective means of supplying heating services. This result, combined with the finding that storage air conditioning is a low cost method of providing summer space conditioning, indicates that a heat pump, using diurnal ice storage during the summer months, is an efficient technology for year round space conditioning.

The economic instrument that encourages the attachment of inefficient technologies to the electric supply grid and discourages the installation of efficient technologies is the present day electric rate schedule. Because the benefits of storage and bivalent technologies stem mainly from improved load factors rather than from direct kilowatt-hour savings, the only efficient and effective method of encouraging their installation is the introduction of some form of peak-load pricing. Following the British example, redesigned price offers may take the form of time-of-use rates or, following the German experience, the form of load management contract rates. If offered on an optional basis, the load management rate must be set sufficiently low relative to the standard rate to provide the customer with the required payback on his additional investment outlay.

CONCLUSION

The results of SIMSTOR analyses, such as presented in this paper, together with results from similar analyses performed for storage applications in transportation, industrial processes, and utilities are being used to reevaluate and prioritize projects within DOE/STOR. The SIMSTOR results have led to modifications of R&D goals and the establishment of a technical validation program to field test attractive TES concepts. Thus, SIMSTOR has proved to be a valuable analysis tool, providing important inputs to the Technical Management Analysis Subprogram for the Division of Energy Storage Systems.

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8. For planning purposes a yearly wrap-around is assumed. Thus for maintenance purposes, Week 1 immediately follows Week 52. Thus a unit scheduled down for an eight-week maintenance period starting during the 48th week would not be available until the 4th week.

9. For a discussion of the dependence of utility supply costs on market penetration, see: J. Asbury, R. Giese, S. Nelson, L. Akridge, P. Graf, K. Heitner, "Assessment of Energy Storage Hot Water Heaters, ANL/ES-54, Argonne National Laboratory, Argonne, Illinois (1976).