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Feasibility Assessment of Customer-Side-of-the-Meter Applications for Battery Energy Storage

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ABSTRACT

Reduction of peak demand on utility systems can be beneficial to both utilities and customers. One means of achieving peak demand reduction is the use of load-leveling batteries. This report describes an investigation of the important techno-economic factors for customer-owned battery energy storage plants. Only current state-of-the-art lead-acid batteries were considered. The study has taken into account realistic battery and balance-of-plant (BOP) costs, current utility rates, and customer load profiles typical of those for which battery storage may be feasible. Battery storage system designs and costs were described and quantified through contacts with vendors and use of previous study results. Utilities with electric rate structures expected to favor customer load-leveling were selected and contacted to obtain the most current rates and customer load profiles.

Using these data for a range of generic applications, an economic analysis was conducted. A baseline application was described and evaluated using internal rate of return (ROR) and payback methods. Certain cost and performance parameters were varied parametrically in order to determine the sensitivity of the analysis results to these parameters. An analysis of five specific customer applications was also made.

The results of this study indicate that battery, power conditioning system and ancillary equipment technologies make construction of customer-side-of-the-meter battery energy storage facilities technically feasible at present. Economic feasibility was found for several applications. The major equipment cost drivers were found to be battery and converter costs. Battery system size (kWh) and BOP costs have a secondary effect on economic viability. Other cost and battery system design factors, including maintenance costs and system efficiency, were found to have little influence on the ROR. Key non-equipment factors found to be important included utility demand charge ($/kW-month) and customer load profile shape.

EPRI PERSPECTIVE

PROJECT DESCRIPTION

The potential advantages of battery energy storage for load leveling and/or peak shaving on a utility system are well documented. Prior reports that are available include EPRI Final Reports EM-264, An Assessment of Energy Storage Systems Suitable for Use by Electric Utilities, Volumes I, II, and III, July 1976; EA-970, Integrated Analysis of Load Shapes and Energy Storage, March 1979; and EM-1192, The Impact on Transmission Requirements of Dispersed Storage and Generation, December 1979. Analysis shows that only when certain very difficult cost and performance targets are met will electric utilities begin to factor batteries into system planning, a necessary precursor to installation. While industrial lead-acid batteries may marginally meet the life, reliability, operation and maintenance, and performance requirements, capital costs of the battery alone (from $600/kW to $1000/kW) make their use unattractive for large utility installations. High costs will prevail for lead-acid batteries until the battery industry makes a substantial investment in process mechanization and facilities. RP1275-12 is an attempt to identify an earlier application that will tolerate the high first cost of today's industrial lead-acid batteries and, in all probability, the high costs for the initial production lots of advanced batteries. Energy storage on the customer's side of the meter is the potential application explored under this project.

PROJECT OBJECTIVE

The objective of this project is to find combinations of utility-rate structure, utility-load profile, and customer load that would result in a satisfactory return on investment by the customer in a peak-shaving battery. Phase I was structured to identify promising existing combinations and to carry out a rate-of-return analysis. Utility-supplied load data were used, and customers were identified only as to the type of industry.

Additional project objectives of Phase I included:

- Up-to-date determination of cost and performance input factors for an industrial lead-acid battery installation
- Determination of sensitivity of the rate of return on investment to battery first cost, efficiency, cycle life, size, discharge rate and maintenance cost, and balance-of-plant cost

This report covers the results of Phase I. The second phase has the objective of identifying several specific customers and refining the analysis for each. It is hoped that one or more customers will be sufficiently convinced of the potential value of a battery storage plant so that a further step, a site-specific engineering design, will be undertaken.

PROJECT RESULTS

Five cases from those analyzed showed a promising rate of return on investment. Industries represented in this small sample are a commuter railroad, a coal mine, an automotive stamping plant, a heavy machinery manufacturer, and a foundry.

Utility demand charge ($/kW-month), customer peak width, and battery first cost were found to have the greatest influence on the return on investment. Other influential factors include converter cost and battery system size (kWh).

Results are considered sufficiently encouraging to proceed with the second phase of the project. This will consist of identifying specific customers with attractive estimates of rate of return followed by customer contact to refine the estimate.

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ACKNOWLEDGMENTS

This report was prepared by the staff of Bechtel Group, Inc. Mr. Walter J. Stolte was the project manager and Mr. Steven W. Eckroad was the project engineer. Responsibility for chapter content was provided by Mssrs. Walter Stolte and Steven Eckroad (Chapters 1, 2, 3, 5, 6, and 7), Mr. Parkash Daryani (Chapters 2 and 4) and Mssrs. Floyd Davis and Gregory Moyer (Chapter 5 and the Appendix). These individuals provided expertise related to technical and cost information for battery energy storage systems, data acquisition, utility rate structures, and economic analysis methodology.

Information on commercial lead-acid batteries was provided by personnel from the following manufacturers: C&D Batteries Division of Allied, Exide Corporation of Inco Electro-Energy, and Gould Inc., Industrial Battery Division. Information on converters was provided by personnel of United Technologies Corporation, The Garrett Corporation and Westinghouse, Inc.

Information on current utility rates and (in some cases) typical customer load profiles were provided by personnel of the following utility companies: American Electric Power Service Corporation, Boston Edison Company, Central Illinois Light Company, Connecticut Light & Power Company, Consolidated Edison Company of New York, Consumers Power Company, Detroit Edison Company, Florida Power Corporation, Illinois Power Company, Indianapolis Power & Light Company, Iowa Electric Light & Power Company, Long Island Lighting Company, Power Authority of the State of New York, and San Diego Gas & Electric Company.

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SUMMARY

Reduction of peak demand on utility systems can be beneficial to both utilities and their customers. One means of reducing peak demand is by use of load-leveling batteries. Large utility owned and deployed batteries have well-documented benefits but, with present day manufacturing processes and battery technology, have capital costs too great to encourage utility use. Smaller customer-owned industrial lead-acid batteries may provide economic benefit to customers faced with high demand charges from their utilities. At the same time, such a market may stimulate the battery industry to make the substantial investments required to bring battery costs down through development of advanced production methods and new technologies. Further, many utility companies could endorse end-user deployment of batteries because of benefits such as increased utilization of existing base load capacity and distribution equipment, and deferal of capital expenditures.

The Research and Engineering Operation of Bechtel Group, Inc. has completed a feasibility study of customer-owned battery storage for the Energy Management and Utilization Division of EPRI. The completed work is the initial phase of an overall program whose objectives are to identify economically viable customer-side-of-the-meter applications for lead-acid battery energy storage; foster implementation by performing detailed designs and analyses for specific sites; and set goals for similar applications using advanced batteries.

The objective of the study was to conduct a preliminary analysis of customer-side battery energy storage applications and identify the key parameters, such as battery data and utility rates, which determine the technical and economic feasibility of such applications.

In order to assess the feasibility of various applications it was necessary to acquire cost and performance data for the major components of a battery storage system, and current utility rates for candidate customers. Cost and performance data for lead-acid batteries and converters were obtained from manufacturers. Balance-of-plant cost data were developed using results of previous studies and

in-house information. Current rate schedules for approximately 20 utilities were obtained. The rates included both traditional flat rates and time-of-day (TOD) rates.

A preliminary economic analysis was conducted for a variety of generic applications using internal rate of return (ROR) and payback methods. The baseline analysis assumed present-day costs and performance data for all equipment except the converter. Certain parameters were varied in order to investigate the sensitivity of the analysis to those parameters. The range of parameter variation chosen was intended to bracket all realistic and reasonably attractive applications for customer-side load-leveling. The cost and performance parameters used are shown in Table S-1.

Table S-1

COST AND PERFORMANCE PARAMETERS

Parameter	Baseline Value	Range Investigated
System Size, MWh ac	10[a]	1 - 50
Discharge Duration, Hours	2	0.5 - 12
Utility Rates		
- On-Peak Demand Charge, $/kW	10	5 - 15
- Off-Peak Demand Charge, $/kW	0	0 - 5
- On-Peak Energy Charge, ¢/kWh	5	1 - 11
- Off-Peak Energy Charge, ¢/kWh	3	1 - 7
Energy Cost Escalation, Percent Over Inflation	2	0 - 4
Inflation Rate	8	8
Battery Cost, $/kWh dc[d]	212[a]	125 - 400[b]
Converter Cost, $/kW ac	119[a]	60 - 465[c]
Balance-of-Plant Cost, $/kWh dc[d] (for 10 MWh System Size)	65[a]	28 - 120[b]
Battery Salvage Value, Percent of Initial Cost	11	3 - 33
Maintenance Cost (annual), $/kWh ac	0.75	0.40 - 4.00
Battery Life, Cycles	1500	1000 - 3000
Number of Discharge Cycles per Year	250	250
Battery Depth-of-Discharge, Percent	80	40 - 80
Efficiency, Percent		
- Battery, Roundtrip	71.8[a]	53.1 - 90.3
- Converter, One-way	97	97
- Overall System, Roundtrip	67.6[a]	50 - 85

(a) For 2-hour discharge rate.
(b) For 10 MWh system size and 1- to 6-hour discharge duration.
(c) 1- to 6-hour discharge duration for both advanced technology and present converter prices.
(d) Costs in $/kWh dc are normalized to $/kWh ac for the economic analysis by dividing by the one-way converter efficiency.

The generic application analysis showed that utilities which incorporate a high demand charge in their monthly billing may have customers for whom installation of a load-leveling battery plant would be mutually beneficial. Typical results for the 10 MWh baseline application are shown in Figure S-1. The before-tax ROR and payback period are shown as a function of discharge duration for three different utility demand charges. The after-tax ROR for the same application is shown in Figure S-2. A wide variety of tax situations may be expected among different applications. Thus, the results shown in Figure S-2 should be taken as an example of the potential effects of taxation on the before-tax ROR.

The parametric analysis indicated that variations in two of the major cost components (battery and converter) of a battery storage system can cause substantial changes in the expected ROR. Figures S-3 and S-4 quantify these results for battery cost and converter cost for a 10 MWh battery system and a $10/kW demand charge. It was found that variations in the BOP cost have a smaller influence on the ROR than battery and converter costs. The results indicate that a ± 40 percent variation in BOP costs produces a variation in the ROR of about 3 percentage points for the baseline application. Also, while there is substantial variability among various manufacturers in salvage credits for used batteries and estimated battery system maintenance costs, neither of these cost components were found to be important economic factors over the range considered. The study further found that the sensitivity of the ROR to battery cycle life, battery system efficiency, energy cost escalation, and off-peak utility rates is of secondary importance over the range investigated for each of these parameters (see Table S-1). The existence of TOD rates has a small but positive effect on the economic viability of customer-owned storage.

Economic analyses were also performed for five specific customer applications. Actual customer load profiles were obtained from utility companies. The analysis results are tabulated in Table S-2. For most of the applications several battery sizes were postulated, corresponding to shaving different power levels from the customer's peak. Some cases show a relatively high before-tax ROR and short payback period, and are judged economically feasible.

The results in Table S-2 are based on a single "typical day" profile for each customer. A more detailed analysis would have to account for the small (or large) variations in profile shape from month to month which would certainly

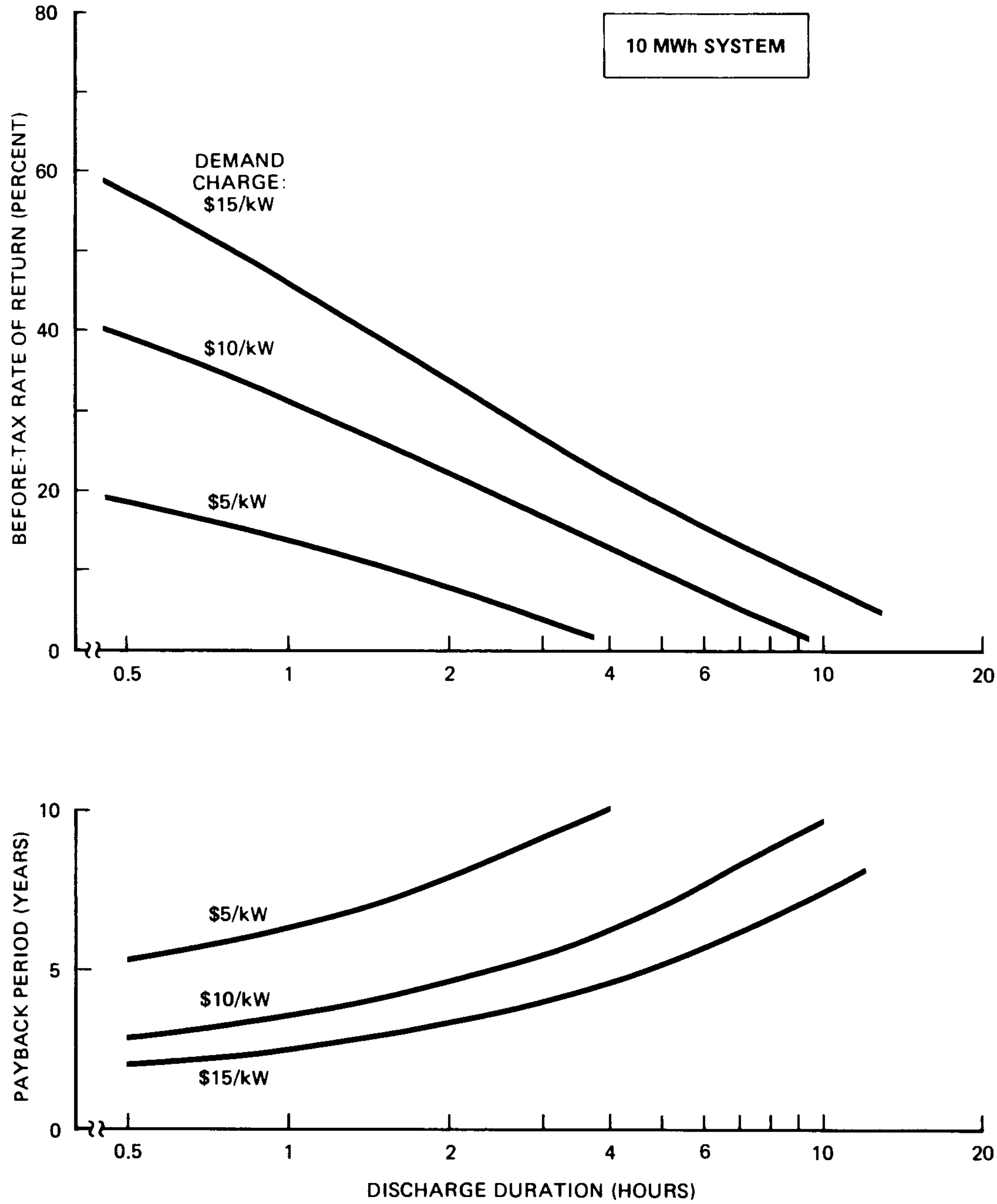

Figure S-1. Before-Tax Rate of Return and Payback Period for 10 MWh System (Baseline System)

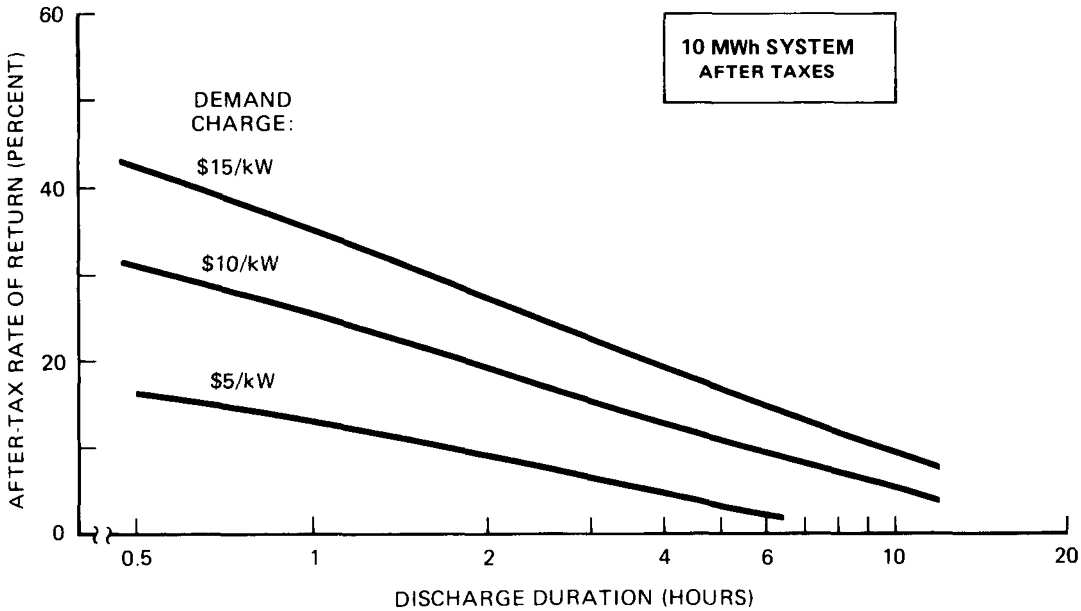

Figure S-2. After-Tax Rate of Return for 10 MWh System

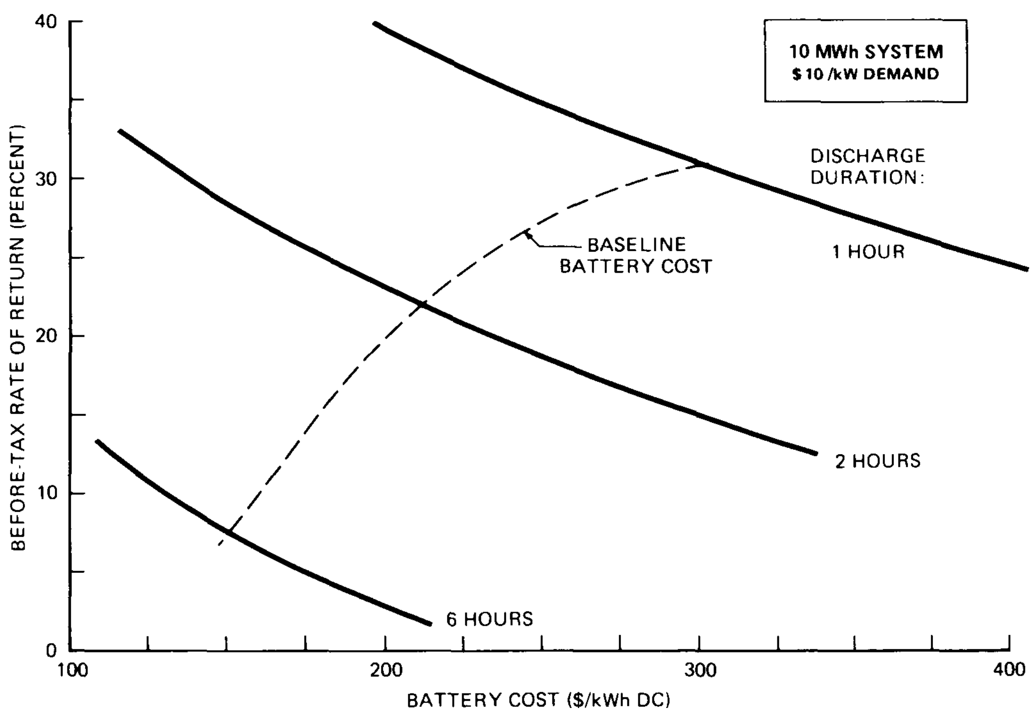

Figure S-3. Before-Tax Rate of Return versus Battery Cost

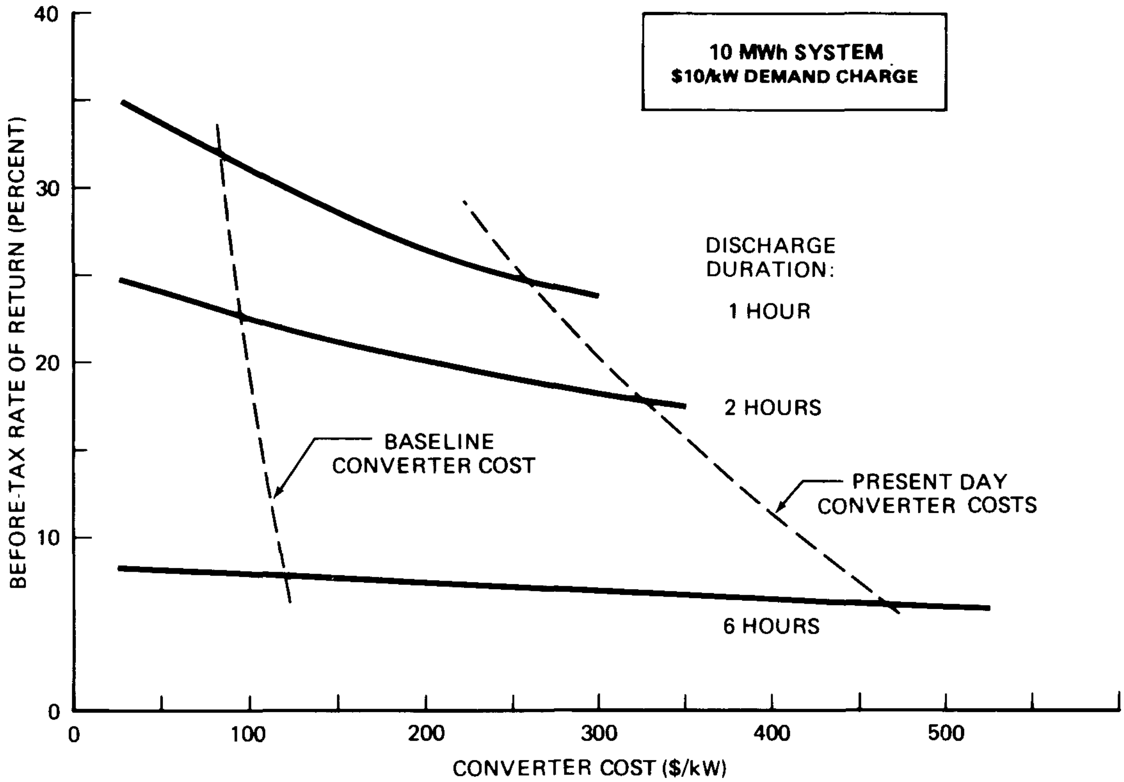

Figure S-4. Before-Tax Rate of Return versus Converter Cost

occur. Thus, the values of ROR shown may be interpreted as average values over the project life assuming that the profiles on which they are based are average representations of the customer's actual pattern of electricity use.

The customer profiles analysed differ significantly in one aspect from the idealized profile assumed for the generic analysis. For the generic analysis it was assumed that the peak to be shaved had a constant power level (i.e., was "square-shaped"). Actual customer peaks are seldom square shaped and hence require the battery to discharge at a varying power level. The study concluded that specific customer applications must be characterized by both an actual and an effective discharge duration in order to understand the behavior of the ROR as a function of battery system size. The actual discharge duration is the period of time over which the battery discharges to the load. The effective discharge duration is that time it would take to deliver the same energy if the peak discharge rate were used. For the generic application, the actual and effective discharge durations are equal to each other. But for most real customer

Table S-2

ANALYSIS RESULTS FOR ACTUAL CUSTOMER LOAD PROFILES AND MID-1982 UTILITY RATES

Application	Demand Charge, $/kW	Battery Capacity, kWh	Discharge Duration, Hours Actual(1)	Effective(2)	Before-Tax ROR, Percent	Payback Period, Years
Coal Mine						
Case A	13.24	1,700	1.5	1.2	31	3.8
Case B	13.24	6,950	6.5	2.7	34	3.5
Railroad						
Case A	16.24	1,900	0.8	0.6	53	2.3
Case B	16.24	5,600	2.0	1.0	58	2.1
Case C	16.24	11,000	2.5	1.3	53	2.2
Case D	16.24	17,900	3.0	1.7	49	2.4
Foundry						
Case A	10.37	240	2.5	0.6	31	4.1
Case B	10.37	510	2.8	1.0	26	4.6
Case C	10.37	700	3.8	1.3	25	4.7
Case D	10.37	1,500	6.5	2.1	22	5.1
Machinery Parts Manufacturer						
Case A	9.93	265	1.8	0.9	21	5.6
Case B	9.93	425	3.3	1.2	22	5.4
Case C	9.93	875	4.5	1.9	18	6.0
Case D	9.93	1,390	5.3	2.5	15	6.4
Stamping Plant						
Case A	10.20	1,605	3.0	2.1	22	4.7

(1) Actual period of time over which battery is discharging.
(2) Defined as the ratio of delivered battery capacity (kWh) to maximum discharge power level (kW).

profiles, the effective discharge duration is less than the actual discharge duration.

The major conclusions of the study may be summarized as follows:

- Battery, converter and ancillary equipment technologies make installation of customer-side-of-the-meter battery energy storage facilities technically feasible at present.
- Economic feasibility is indicated for several applications. Key load-related, techno-economic factors are:
  - On-peak demand charge
  - Discharge duration and load profile shape
  - Battery and converter cost
  - System size (i.e., storage capacity)
- Utility rate structures and the cost of energy are major uncertainties for the future. While on-peak demand charge is a critical factor, off-peak demand and energy charges are of secondary importance to economic viability. The rate of energy cost escalation is also of secondary importance within the limits studied (0 to 4 percent over inflation).
- Costs for the balance-of-plant depend upon both system storage capacity (kWh) and discharge duration. Some variability in costs is expected due to differences in design, but variations in BOP costs would not have a major impact on battery plant economic viability.
- While operating and maintenance costs for customer-owned battery plants (including battery watering and equalization) are uncertain, they do not constitute an important economic factor.
- Battery cycle life may have an important effect on economic viability for lives less than 1500 cycles. However, there is a substantially reduced incentive to improve cycle life beyond 2000 cycles.
- While batteries are net consumers of energy, overall system efficiency is not a critical factor in the viability of battery storage.

- Based on the generic application analysis, certain criteria may be established for selecting promising customer applications. Selection criteria also depend on factors such as the minimum ROR which would be required by a customer and the exact shape of his load profile. Since these cannot be known without interaction with a specific candidate customer, generic criteria must be regarded as approximate and possibly oversimplified. Generic selection criteria for promising applications in the 1 MWh (battery size) range may be listed as follows:

    - Customer's demand charge is in the range of \$11/kW to \$17/kW

    - Customer's peak duration is in the range of 0.5 hour (for \$11/kW demand charge) to 1.5 hours (for \$17/kW demand charge)

    - Energy charge is preferably less than 7¢/kWh

    - Customer peak occurs regularly at least once each billing period and is preferably somewhat coincident with his utility's system peak during some part of the year

Section 1

INTRODUCTION

Reduction of peak demand on utility systems can be beneficial to both utilities and their customers. One means of reducing peak demand is by use of load-leveling batteries which are placed on either the utility's side or the customer's side of the meter.

The Research and Engineering Operation of Bechtel Group, Inc. has completed a feasibility study of customer-owned battery storage for the Energy Management and Utilization Division of EPRI. The completed work is the initial phase of an overall program whose objectives are to identify economically viable customer-side-of-the-meter applications for lead-acid battery energy storage; foster implementation by performing detailed designs and analyses for specific sites; and set goals for similar applications using advanced batteries.

The objective of this study was to conduct a preliminary analysis of customer-side battery energy storage applications and identify the key parameters, such as battery data and utility rates, which make such applications economically viable. The study was accomplished in the following seven tasks:

- Task 1 Literature Review
- Task 2 Battery Data Summary
- Task 3 Balance-of-Plant (BOP) Data Summary
- Task 4 Utility Rate Structure Survey
- Task 5 Identification of Battery Application Types
- Task 6 Preliminary Analyses
- Task 7 Reporting

The literature review (Task 1) identified general characteristics of promising applications and thereby provided guidance in selecting ranges for the data to be gathered in Tasks 2, 3, and 4. In Task 2, technical and cost data on commercially available lead-acid batteries were gathered through contacts with major battery manufacturers. The objective of Task 3 was to postulate initial order-of-magnitude cost and performance of a battery energy storage balance-of-plant. Published studies, manufacturer contacts and in-house information were used. Utilities with rate structures which may justify installing battery energy storage on the customer's side of the meter were identified in Task 4. These utilities were then contacted to obtain their most current rates and customer load profiles typical of those for which battery storage might be beneficial. In Tasks 5 and 6 the data collected in previous tasks were used to assess the potential for economic viability of customer-owned battery energy storage plants and to determine if site-specific design and analysis efforts are warranted for a follow-on phase of the study. The economic analysis consisted of a generic analysis covering the range of attractive applications and an application-specific analysis for several customer load profiles.

In this report, Section 2 describes the results of the literature survey, Section 3 presents battery and balance-of-plant data and Section 4 presents utility rate data. The generic economic analysis is presented in Section 5 and the analysis of specific customer load profiles in Section 6. Section 7 presents the conclusions and recommendations drawn from this study. An appendix describes in detail the methodology used in the economic analysis.

Section 2

LITERATURE REVIEW AND FORMULATION OF SELECTION CRITERIA

Relevant literature on battery energy storage was reviewed in order to identify the characteristics of promising applications. The review was not intended to be exhaustive but was to provide guidance in selecting ranges of study parameters such as battery system size, application characteristics, and favorable utility rates. The review was also the basis for establishing guidelines for the gathering of battery and balance-of-plant data. The bibliography contains a representative listing of the available literature on battery energy storage for load-leveling applications.

LITERATURE REVIEW

While several studies of the use of lead-acid batteries for load-leveling have been done (see bibliography), only two major efforts have assessed battery energy storage on the customer's side of the meter (1, 2). Of these, only the Battelle study (1), has been published at the time of this writing. Numerous studies on the design and cost of battery load-leveling plants have been published but relatively few of these have dealt realistically with the installed and life-cycle costs of conventional lead-acid battery plants. The two major studies in this area were both performed by Bechtel, one for the U.S. Energy Research and Development Administration (ERDA) in 1976 (3) and the other for Sandia National Laboratories (4) which was recently completed but not yet published.

The Battelle study (1) constituted a thorough exploratory investigation of the technical, economic, and non-technical factors of significance to customer-side battery storage. A general battery plant cost equation was developed using the results of previous studies of large battery storage plants. Scaling factors were formulated in order to determine the cost and performance parameters for four battery system sizes (using two battery types: lead-acid [conventional] and zinc chloride). The importance of electric rate structures, regulatory uncertainty, and discharge duration was identified. The study also addressed environmental and institutional factors. A method for analyzing economic viability was developed and carried out for the four battery system sizes chosen. The baseline battery system was found to be viable for customers with high demand charges and short discharge durations. Finally, the market potential for demonstration customers was investigated.

Another study of customer-side load-leveling plants has recently been completed by the Garrett Corporation for the New York State Energy Research and Development Authority (NYSERDA) (2). This evaluates the techno-economic viability of deploying battery storage in New York City subway traction substations. Specific load profile and electric rate data, together with cost and performance data for commercially available lead-acid batteries were used. Battery storage was found to be both technically feasible and economically attractive. Construction of a pilot plant was recommended.

An older study done by Bechtel for ERDA (3) was reviewed. This study investigated ten alternative designs for a lead-acid battery energy storage (LABES) demonstration plant. In the LABES study, a 20 MW plant and all necessary auxiliaries were evaluated for both 3- and 5-hour discharge durations. The data on batteries and converter systems were obtained from manufacturers. Although accurate at the time of the study (1976), the data must be revised and updated for use in the present study. In particular, converter technology has undergone design changes that lower projected costs for advanced designs. Proposed battery cell designs, rather than commercially available models, were used and were generally much larger than those available on the market today. Both battery cell and converter specific costs ($/kWh or $/kW) are known to be dependent on unit size. Hence, cost data from the LABES study must be appropriately scaled for smaller systems. Also, the cost for the BOP contains components (such as shops, cooling systems, and instrumentation) which would not be part of a customer-owned plant using the type of battery cells postulated for this study.

The Bechtel study for Sandia (4) investigated battery system costs for residential and medium-sized commercial/industrial photovoltaic power system applications. Battery systems ranging in size from 16 kWh to 6200 kWh were investigated for commercially available lead-acid and several advanced batteries. Scenarios for battery and balance-of-plant installation, operation, and maintenance were postulated and cost estimates were developed. System size (kWh) was found to be a key factor in BOP costs. However, the study does not specifically address the variation in BOP costs that may be attributed to differences in discharge duration and, further, does not address converter costs.

Environmental and safety aspects of utility-owned battery energy storage facilities were assessed in a recently completed study for EPRI by Bechtel (5). Lead-acid, as well as four types of advanced batteries were evaluated. The study addressed environmental and safety aspects in manufacturing, shipping, installation, operation, maintenance, and ultimate disposition of the cells. The permit hearing procedures for construction of the Battery Energy Storage Test (BEST) facility were also reviewed. Institutional requirements were determined but no major impediments to the installation of large lead-acid battery systems could be identified.

SELECTION CRITERIA

A review of the above studies (as well as others listed in the bibliography) and of in-house information led to the conclusion that current cost and performance data for batteries and converters should be obtained from manufacturers, insofar as possible.

The information presented in Section 3 on batteries and converters was gathered according to the following guidelines:

- Battery cells were generally to be the largest available cell (kWh) in the manufacturer's current line in order to minimize specific costs ($/kWh) for cell, balance-of-plant, and operation and maintenance.
- Battery system voltage was to reflect a compromise between two conflicting requirements: (1) the lower specific converter costs for higher voltages and (2) the higher battery subsystem costs at high voltages.
- Battery specific costs were adjusted to reflect the expected discharge duration of the battery plant. Specific costs were also normalized to the ac output of the plant for the economic analysis, using the one-way efficiency of the converter.
- Volume purchase discounts were applied to costs for batteries. Advanced as well as present-day converter costs were ascertained. (Development costs for converters are also a factor to be considered since converters in the size range required are not currently in production).

A review of the available literature on balance-of-plant design and cost, as well as current Bechtel experience, resulted in the following guidelines which were used for developing BOP cost data for the economic analysis:

- BOP specific costs ($/kWh) were adjusted to reflect both battery system size and discharge duration.

- Battery systems smaller than 500 kWh were judged to be uneconomical and were not considered.

- BOP cost data from previous studies were escalated to mid-1982 price levels using an 8-percent per year inflation factor. Cost data were normalized to the ac output rating of the plant, using the one-way efficiency of the converter.

The results of the Battelle and Garrett studies (1 and 2) and preliminary calculations by Bechtel resulted in a requirements definition for the range of potential customer-side load-leveling applications that are likely to be economically viable. Thus, the gathering of utility rates and application load profile data was guided by the following considerations:

- Both traditional flat rates and time-of-day (TOD) utility rates were considered.

- In the case of traditional flat rates, utilities with a monthly demand charge greater than $5/kW combined with a low energy charge (less than 7¢/kWh) were initially selected as potentially attractive.

- In the case of TOD rates, schedules with a high differential between on- and off-peak rates were identified as the most favorable.

- Load characteristics (such as overall shape, and the duration and time of day of peaks) rather than customer type were identified as the critical application parameters. In particular, only applications with single or multiple peaks, such that the aggregate duration of discharge is less than 4 to 6 hours, are of interest. An aggregate discharge duration of less than 15 minutes, while theoretically very attractive, would probably not be practical nor measurable under current utility metering practice.

- Applications with a load factor of greater than 90 percent were assumed not suitable for load-leveling and hence were not considered.

Section 3

BATTERY STORAGE SYSTEM DESIGN AND COST PARAMETERS

This section discusses the technical and cost aspects of a lead-acid battery load-leveling system. A battery storage system for customer-side-of-the-meter load-leveling applications typically consists of three major subsystems: the battery itself, the power conditioner, and the balance-of-plant (BOP) equipment required for an operable system. The design and cost of these components (and their maintenance and replacement requirements) will affect the technical and economic feasibility of customer-owned load-leveling systems.

BATTERY

The battery subsystem includes the individual battery cells, interconnecting dc wiring up to but not including the dc bus, module containers and/or cell-support racks, and all required accessories to the battery cells such as flash arrestors, filler caps or automatic watering valves, and air-lift pumps.

Technical

The battery cells are conventional lead-acid cells of a type currently used for motive power (e.g. electric truck) or stationary (e.g. emergency power) applications. Characteristics of the cells investigated in this study are shown in Table 3-1.

The cells are designed for cyclic deep-discharge service (e.g. 80 percent depth-of-discharge) while retaining long cycle life. Cells are typically warranted for 1500 to 2000 cycles and may be expected to give up to 3000 cycles for some designs in some applications. Cycle life depends among other things upon the depth to which the cell is regularly discharged. This effect is quantified in Figure 3-1 for typical load-leveling cells. The range shown (shaded area) represents variations among manufacturers.

Currently produced cells are capable of being fully discharged in as little as one-half hour time periods (denoted as the half-hour rate, or C/0.5), provided suitable design of terminal posts and internal lead connectors is employed to prevent overheating.

Table 3-1

LEAD-ACID CELL CHARACTERISTICS

Capacity	New	End-of-Life
At C/10 discharge rate, kWh[a]	5.5 - 7.6	4.4 - 6.1
At C/6 discharge rate, kWh	4.9 - 6.3	3.9 - 5.0
At C/1 discharge rate, kWh	2.4 - 2.7	1.9 - 2.2

Voltage	
Average discharge (@ C/6), volts	1.87 - 1.92
End of discharge cutoff, volts	1.68 - 1.75
End of charge cutoff, volts	2.35 - 2.40
Equalizing charge cutoff, volts	2.60 - 2.65

Life	Warranted	Expected
Cycles	1500 - 2000	2000 - 3000
Years	6 - 8	8 - 12

Charging Requirements	Normal	Equalizing
Frequency, cycles	1	5 - 20
Ampere-hours, percent return (when new)	100 - 110	105 - 120

Energy Efficiency	
At C/6 discharge (C/8 charge), percent	72 - 79

(a) The term C/N is used to denote the discharge rate in terms of the number of hours (N) required to discharge the capacity (C).

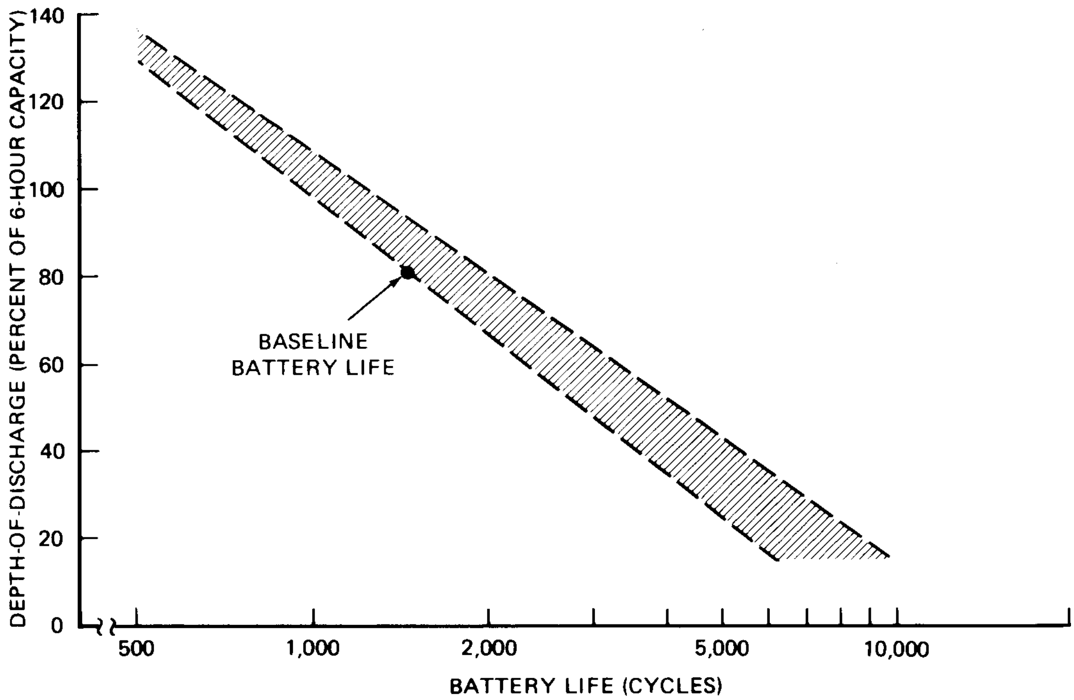

Figure 3-1. Lead-Acid Battery Cycle Life versus Depth-of-Discharge

Lead-acid cells may be rated in terms of their dc kWh storage capacity for a given set of operating conditions. These conditions include discharge rate, age, temperature, and cutoff voltage (6). The "nameplate" cell rating usually refers to the cell when it is new and is discharged at the manufacturer's specified rate. The nameplate capacity of a cell must be derated for discharge rates higher than the manufacturer-specified rate. The loss in capacity is severe for very high rates of discharge. A cell discharged at the 1-hour rate (C/1) may have less than half its capacity at the 6-hour rate (C/6). The actual available capacity decreases with cell age. Therefore, an additional derating factor (typically 0.8) is normally suggested by the manufacturer in order to ensure delivery of rated capacity throughout the cell life (6). This factor gives the end-of-life rating of the cell. Figure 3-2 shows end-of-life capacity versus discharge rate for the cells used in this study. As in Figure 3-1, the range shown (shaded area) represents variations among manufacturers.

The terminal voltage of a lead-acid cell depends upon its state of charge and the rate at which it is being discharged or charged (6). Cell voltage decreases during discharge and increases during charge. To avoid permanent cell damage,

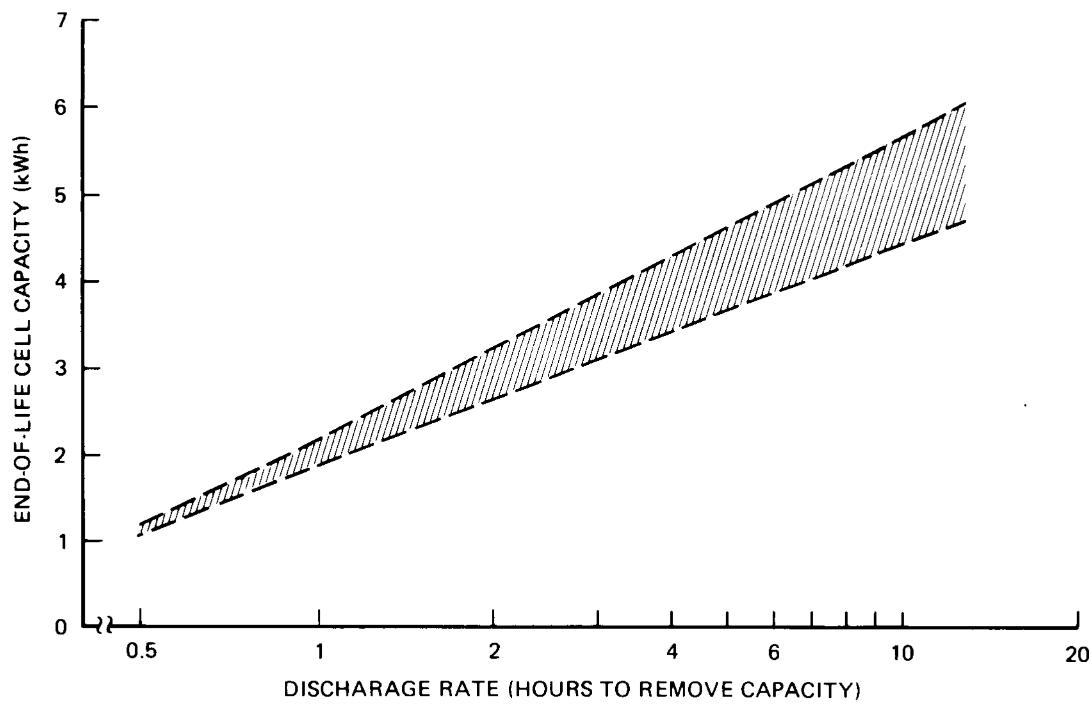

Figure 3-2. Lead-Acid Cell Capacity versus Discharge Rate

cells are not discharged below the cutoff voltage specified by the manufacturer. Charge and equalization cutoff voltages are determined according to the specific cell design and recommended method of chargeback.

Lead-acid cells are connected in series to attain the desired dc system voltage. Design and cost considerations for dc wiring, switchgear, and power conditioning equipment favor high dc system voltage (4). However, battery manufacturers recommend that voltage be no greater than approximately 1000 volts dc for reasons of personnel safety and equipment protection. At this voltage, dc isolation switches and insulated racks are recommended by battery manufacturers. Since the voltage of a lead-acid cell varies over a range of 1.4:1 during normal cycling and 1.55:1 with an equalization cycle, the maximum system voltage at the end of discharge should be about 650 volts dc. Thus, for the cells studied (see Table 3-1), the maximum number of cells in a single series string is about 380 (650 V $\div$ 1.7 V/cell). To achieve system capacities greater than the maximum string capacity (equal to 1500-1900 kWh at the C/6 rate), several parallel-connected strings are used. The use of parallel strings also improves system reliability.

Due to internal electrochemical losses, during each charge cycle a greater amount of charge must be returned than was removed during the previous discharge cycle. Manufacturer-recommended chargeback ranges from about 100 percent to 110 percent of the amp-hours removed during the previous cycle. In conventional cells using lead-antimony alloy grids, the excess charge may double near the end of the cell life. Since these amp-hours are returned at a higher voltage than the voltage at which they were removed, there is an additional reduction in roundtrip energy (kWh) efficiency (6). Roundtrip energy efficiency decreases with increasing discharge rates (and consequent lower discharge voltages), as shown in Figure 3-3. The efficiencies shown represent a range of information gained through vendor contacts and previous studies (2,3,6,7). The solid line is a nominal efficiency used in the economic analysis reported in Section 5.

Most manufacturers recommend a periodic equalization charge every 5 to 20 cycles in which 105 to 120 percent of the amp-hours removed during the previous cycle are replaced. This is to restore all cells to a fully charged condition. Equalization is performed after a normal charge cycle.

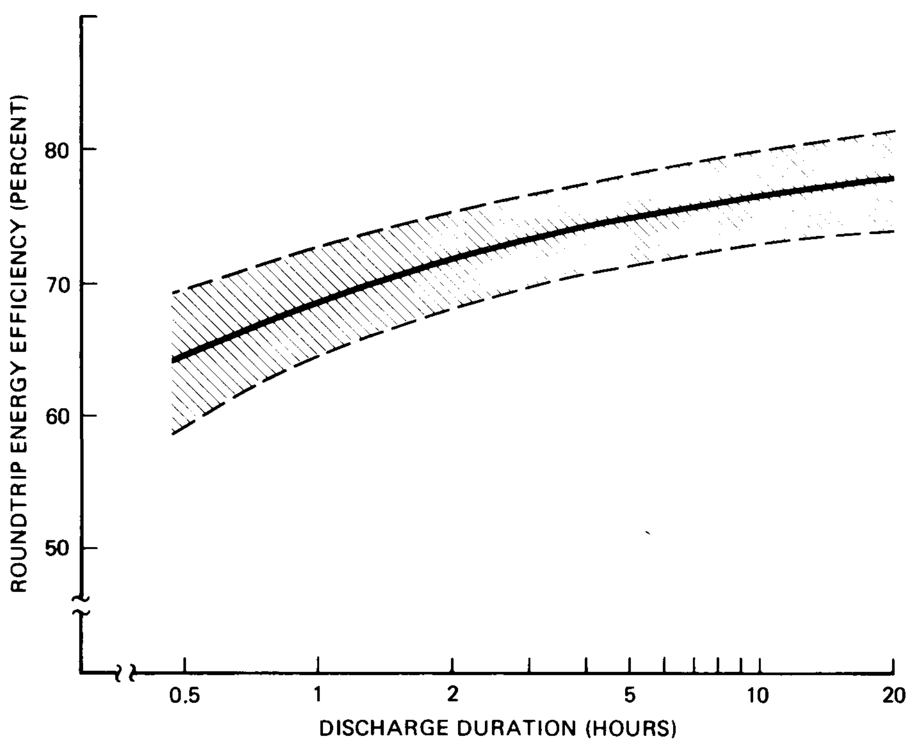

Figure 3-3. Efficiency of a Lead-Acid Cell versus Discharge Duration

The battery efficiencies shown in Figure 3-3 do not include energy losses due to equalization. However, the cost of the energy used for equalization is included in the economic analysis in Section 5.

The battery subsystem includes certain auxiliary equipment and instrumentation required for reliable operation and maintenance of the cells throughout their life. Such equipment may include an air-lift pump system (required in some designs to achieve adequate electrolyte mixing during charge), cell watering systems, and instrumentation for monitoring cell voltage, temperature, and specific gravity. Manufacturers' recommendations vary significantly in regard to the amount of instrumentation required, and the extent to which automated systems for watering and cell monitoring are technically or economically feasible. Also included are flash arrestors for prevention of an externally initiated hydrogen explosion inside the cell.

Ventilation systems, toxic gas monitoring equipment, and sources of compressed air or purified water are not included in the battery subsystem. This equipment is part of the balance-of-plant.

Individual battery cells are either mounted on specially designed racks at the site or shipped to the site in factory prefabricated modules. Typical modules contain eight to 12 cells. In modules, cell interconnectors are welded or "burned" on at the factory to reduce field assembly and maintenance. Field installation includes uncrating or removal of cells from pallets, assembly of racks (if required), and moving, positioning, and interconnecting cells or modules. If required, auxiliary plumbing lines for automatic watering or air-lift systems must be run to each cell. Initial testing and startup of the completed installation is supervised by a manufacturer's technical representative.

Battery Costs

The present study assumes the use of conventional lead-acid cells that are in current production or that may be brought into production within one year. Consequently, cost data are obtainable from several manufacturers. The cost data used in this study are based on informal quotes from three major manufacturers. These data are shown in Figure 3-4 as a composite of the information received from the three manufacturers. The solid line in the figure represents an average, or nominal, cost and was used in this study. The costs shown are for a purchase quantity of 10 MWh and include shipping and

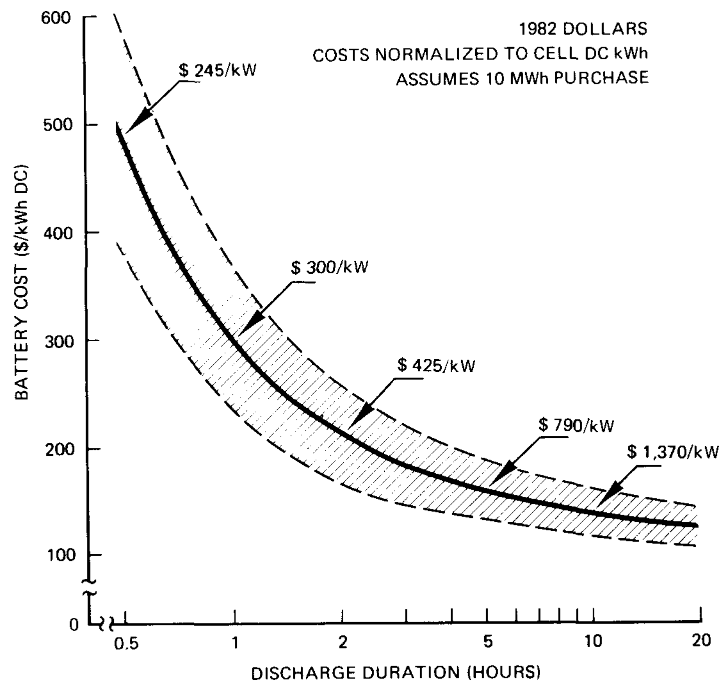

Figure 3-4. Battery Cost (Including Shipping and Installation) versus Discharge Duration

installation costs. The costs are normalized to the end-of-life rating of the battery, assuming 80 percent depth-of-discharge. The cell sizes are those shown in Table 3-1. Specific costs ($/kWh) are seen to rise substantially for short discharge periods due to capacity loss at high rates of discharge, as discussed earlier.

Since lead is a major constituent of a lead-acid battery, manufacturer's quoted prices are tied to the current price of lead. The costs shown in Figure 3-4 are for lead at 32¢/lb. The historical fluctuation of lead prices is shown in Figure 3-5. At lead prices near 32¢/lb, the cost of the battery will increase (or decrease) 0.8 to 1 percent for each one cent increase (or decrease) in lead price.

As mentioned, the costs shown in Figure 3-4 are for a 10 MWh purchase quantity. As this would represent an exceptionally large order, these costs reflect a

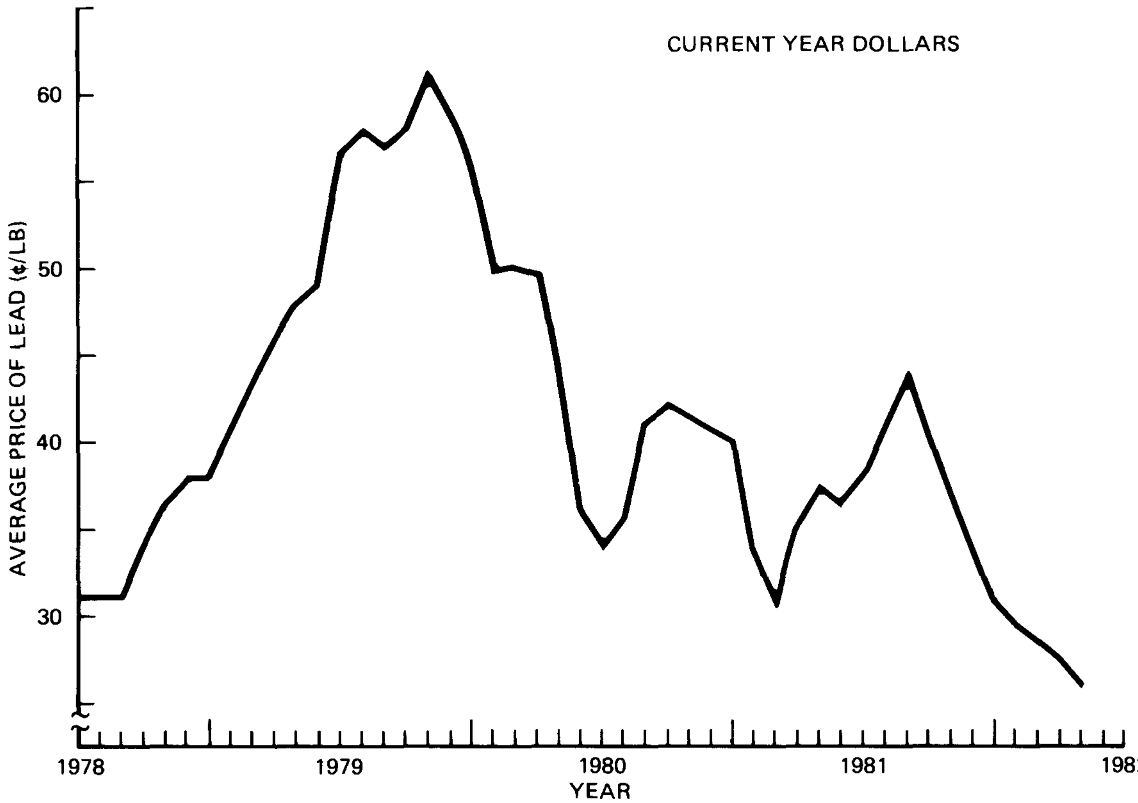

Figure 3-5. Historical Fluctuation of Lead Prices
(Source: Engineering and Mining Journal)

substantial discount (typically 25 to 40 percent) from the list price. Such discounts are common for the type of batteries considered and depend both upon the manufacturer's perception of the likelihood of continued business from the purchaser and on the size of the initial purchase. The approximate variation in battery cost as a function of purchase quantity is shown in Figure 3-6.

The band in Figure 3-6 is a composite of the data obtained from three manufacturers and represents both a variation in quoted cell costs (see Figure 3-4) and in discount schedules used. Quantity cost is expressed as a percent of the 10 MWh purchase quantity cost. The solid line is a nominal, or average cost.

Single purchase quantities at 10 MWh and higher levels may require the opening of additional manufacturing plants in order to accommodate reasonable delivery schedules. Consequently, available discounts may be less than expected for very

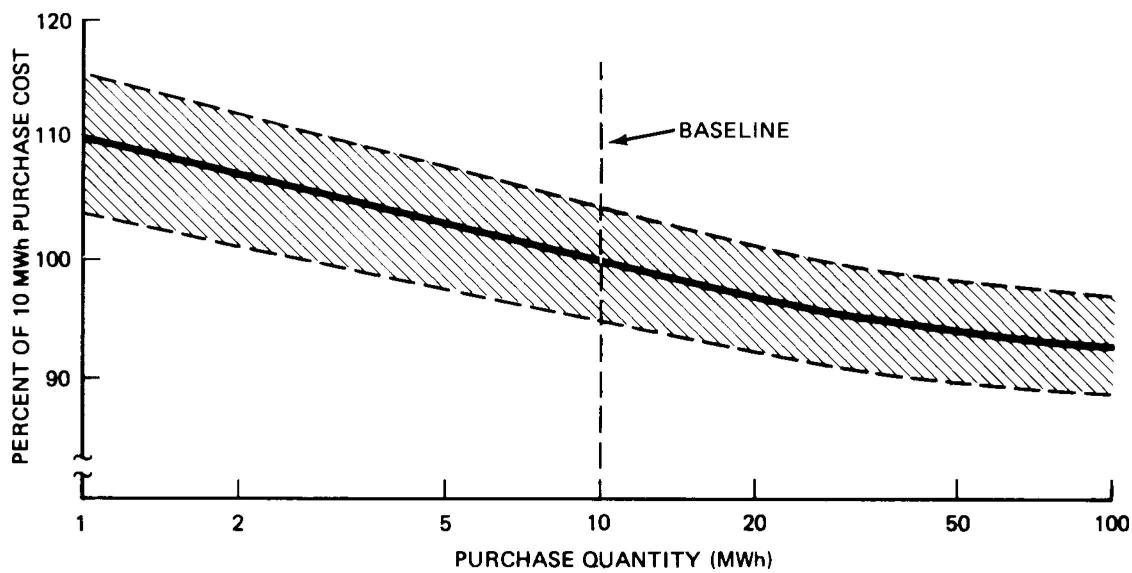

Figure 3-6. Battery Cost versus Purchase Quantity

large orders due to increased one-time tooling costs, unless multiple sales for several systems are expected.

POWER CONDITIONER

A power conditioning subsystem is needed to interface the dc battery with the ac utility system. This section presents technical and cost aspects of this required equipment.

Technical

The power conditioning subsystem is assumed to include all equipment needed to charge and discharge the battery in response to a control signal that sets power level and direction of power flow (i.e., charge or discharge). The dc voltage ranges from the minimum battery discharge cutoff voltage minus resistive voltage drops along the dc bus and cell interconnect wiring. The maximum dc voltage extends to the equalizing charge (if used) or charge cutoff voltage plus bus work voltage drops. The maximum dc current is assumed to be the system rated power divided by the converter efficiency and minimum dc voltage. This assumes that sufficient off-peak time is available to charge the battery at a lower current (i.e., discharge limited). The converter is also capable of being controlled to the low current levels needed at end of charge and for load following. Typical charge and discharge battery voltage and current curves for the rates being considered may be found in Section 3 of Reference 6.

The ac output is at a standard voltage (e.g. 4160v, 13,800v etc.) commensurate with the system's power level. The power factor is as close to unity as possible with a minimum of 0.9 over the entire operating range of the converter. Harmonic distortion is less than 5 percent over the operating range.

The power conditioning subsystem includes all controls and instrumentation needed for safe operation with an externally-supplied control signal to set power level and direction of power flow. The subsystem also includes protective equipment and/or circuits to protect the unit itself and the battery against dc and ac faults. The subsystem design includes features to synchronize with utility voltage, limit ac fault current contributions, and disconnect in the absence of utility line voltage. In general, the converter is assumed to meet the specifications for advanced converters developed by EPRI. Typical specifications are presented in Appendix A1 of Reference 15.

The one-way efficiency of large (i.e., greater than 1 MW) units is expected to be on the order of 95 to 97 percent. It will be shown later that this is not a critical economic parameter.

Converter Costs

The cost of a suitable power conditioning subsystem is difficult to ascertain with accuracy because such units are not commercially available at present. Units have been installed at a limited number of demonstration and/or test facilities. Studies have been and are continuing to be performed for the design of advanced units (15, 16, 17, 18, 19). The converter technology required for batteries is being addressed to some extent in efforts to develop equipment for other dc power technologies such as fuel cells, photovoltaics, and MHD. At present, the closest commercially available equipment is that used for uninterruptible power supplies.

The cost data used in the present study are based on manufacturers' quotes for existing equipment, projected costs from studies, and discussions with manufacturers. These data are shown in Figure 3-7 for both advanced and existing designs. The costs shown are for purchase of a single unit of the power rating indicated and include a range of uncertainty. Costs are normalized to the ac rating of the unit (in kW). The costs do not include nonrecurring development and engineering charges. Such charges will add significantly to the purchase cost of the first units. Estimates by several manufacturers indicate that these charges can range from $0.5 to $2 million. These engineering charges depend on whether the desired unit is a close approximation to other units previously fabricated, designed, or studied by the individual manufacturers.

As mentioned, the advanced-design converters are the results of studies. It is customary to project cost-reducing high-volume production scenarios in such studies. Cost reduction for large purchases is a reality for existing equipment. Volume purchase of components, setting up a production line, multiple unit use of drawings, and reduced marketing can be reasonably expected

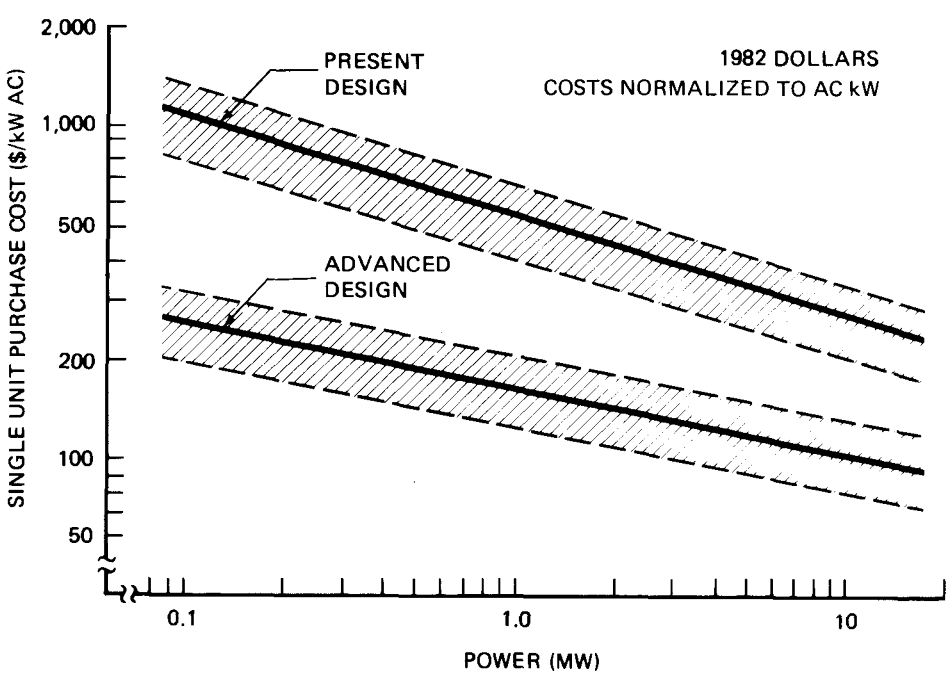

Figure 3-7. Power Conditioner Purchase Cost versus Rated Power

to lower costs. These effects are quantified in Figure 3-8. The data in the figure are based on actual equipment costs and those postulated by manufacturers in studies. As can be seen, there is a range of uncertainty in the volume purchase discount depending on the manufacturer. Also as indicated, there may be no discount until two or three units are purchased.

Most of the cost data projected for advanced designs are for high volume production. The curve in Figure 3-8 was applied to the various high volume cost data in order to determine the single unit cost presented in Figure 3-7. The single unit cost was selected as a basis because of the lack of consistency in postulated manufacturing volumes in the studies used to assemble cost data. Also an inflation rate of 8 percent per year was used, as needed, to bring certain of the converter costs to the selected base of mid-1982 dollars.

For purposes of the preliminary economic analyses, the advanced converter single unit costs were used without nonrecurring engineering charges. A sensitivity analysis was performed to determine the effect on system economics of varying converter cost (see Section 5).

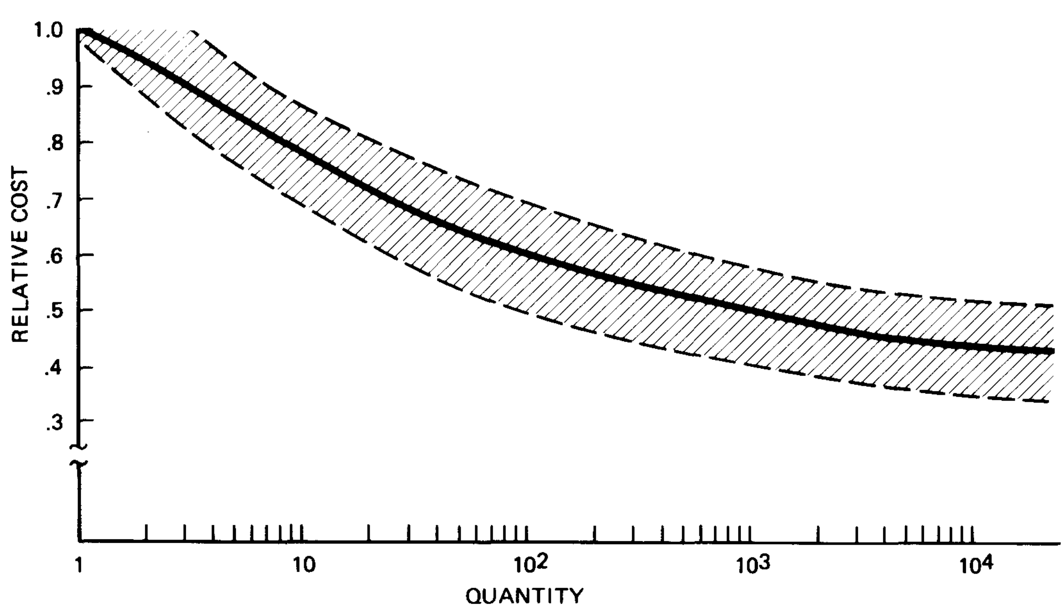

Figure 3-8. Power Conditioner Purchase Quantity Discount

BALANCE-OF-PLANT

The battery and converter are installed in a dedicated facility that provides the structural, mechanical, and electrical support systems required for full operability as a load-leveling plant. This section discusses the technical and cost aspects of the balance-of-plant (BOP) facilities.

Technical

The battery is installed in a separate enclosed room with power conditioning equipment mounted in an adjacent room or area. The specific energy footprint of the conventional lead-acid cells used in this study is about 5 to 9 kWh/ft^2, depending on cell type and arrangement. Consequently, substantial building space is required for the battery room. Cells may be stacked in tiered racks to reduce space requirements. However, this will lead to increased costs associated with installation and reduced accessibility during times of maintenance or replacement. The converter is mounted outside the battery room to minimize the risk of a hydrogen explosion and to protect this equipment from the corrosive acid mist which may be present in the room. Floors (and possibly all interior surfaces) must be protected with acid-resistant paint. A sump to collect potential electrolyte spill is included in the room. Installations also have an eyewash/shower station for personnel safety.

The battery room must be ventilated to remove gases emitted during operation. For conventional lead-acid cells using antimony and arsenic grid alloys, these gases include hydrogen, stibine, and arsine. The latter two, both toxic, are normally generated only during the periodic equalization charges discussed earlier, when cell voltage rises above 2.45 volts. Hydrogen, an explosive gas in low concentrations, is generated both during the finishing portion of the daily chargeback and the periodic equalizing charge. A previous Bechtel study (4) has shown that ventilation requirements can be governed by the emission of stibine. Ventilation rates for stibine may be greater than those for hydrogen by a factor of 1.5 to 5 times (for average emission rates).

Informal discussions with battery vendor personnel indicate that most of the stibine and arsine emitted by the battery decomposes and condenses on nearby surfaces (i.e. within just a few inches of point of exit). For the present study, it was assumed that ventilation fans are sized to maintain hydrogen concentration at a safe level at all times. However, for safety purposes, personnel are to be excluded from the battery room during periods when stibine and arsine may be present in toxic concentrations. These will occur at weekly to monthly intervals, depending on equalization frequency, and may typically be of a few hours duration.

Removal of waste heat generated by battery operation is essential to limit cell temperature and prevent damage. Discussions with manufacturers indicate that the cells used for the present study may be adequately cooled by passive convective heat transfer to the surrounding air. The ventilation fans will provide more than sufficient air exchange.

As mentioned in the sections on the battery and power conditioner, equipment for monitoring the battery's electrical performance and control of its operation is included in the battery and power conditioner subsystems. The remaining required instrumentation relates to safety and includes fire detection, hydrogen monitoring, and stibine and arsine detection. Ventilation fans are to be controlled in conjunction with hydrogen monitoring equipment. Stibine and arsine detectors provide a means of alerting personnel to the presence of toxic levels of those gases. Development of this equipment (not commercially available until recently) for lead-acid battery plants is the subject of ongoing research at Argonne National Laboratory (8).

Electrical equipment may be subdivided into two categories: dc wiring and switchgear, and ac building service and lighting. Due to the presence of hydrogen, all electrical equipement within the battery room must be for Class 1, Division 1, Group B to meet National Electrical Code requirements. The dc bus and switchgear are sized to accommodate the maximum dc voltage and dc current, as discussed in the section on the power conditioner. The ac building service provides distribution for all ac-operated auxiliary equipment (such as fans and gas monitoring equipment) and for lighting.

Other equipment items and systems included for proper operation and maintenance of the battery include a makeup water supply and fire protection. An air compressor will also be required for battery air-lift pumps, if these are used. Cell makeup water is deionized water supplied by passing available city supply water through a deionizer cartridge. Manual or automatic means of distributing makeup water to the individual cells is part of the battery subsystem, as discussed earlier. Fire protection is by overhead CO_2 or water sprinklers, according to battery manufacturer recommendations.

Balance-of-Plant Costs

Battery system BOP costs (excluding converter) are expressed in dollars per kilowatt-hour, reflecting the dependence of BOP costs on battery system size (kWh). Previous studies by Bechtel (3, 4) have shown that BOP specific cost ($/kWh) is inversely proportional to system size. This effect is quantified in Figure 3-9. The data shown are a composite of the results of engineering cost estimates for various system sizes, as reported in the referenced studies.

The costs shown in Figure 3-9 include costs for the following BOP items:

- Enclosed battery room (equipped for lead-acid cells)
- Ventilation system
- Safety monitoring instrumentation
- Wiring and switchgear (dc and ac)
- Auxiliary equipment (e.g., fire protection and make-up water supply)

Some of the BOP items listed above have costs which are a function not only of battery system size (kWh) but also of power rating (kW). Individual cell capacity decreases with increasing discharge rate (Figure 3-2). Thus, it is clear that more cells must be installed to provide a given storage capacity at

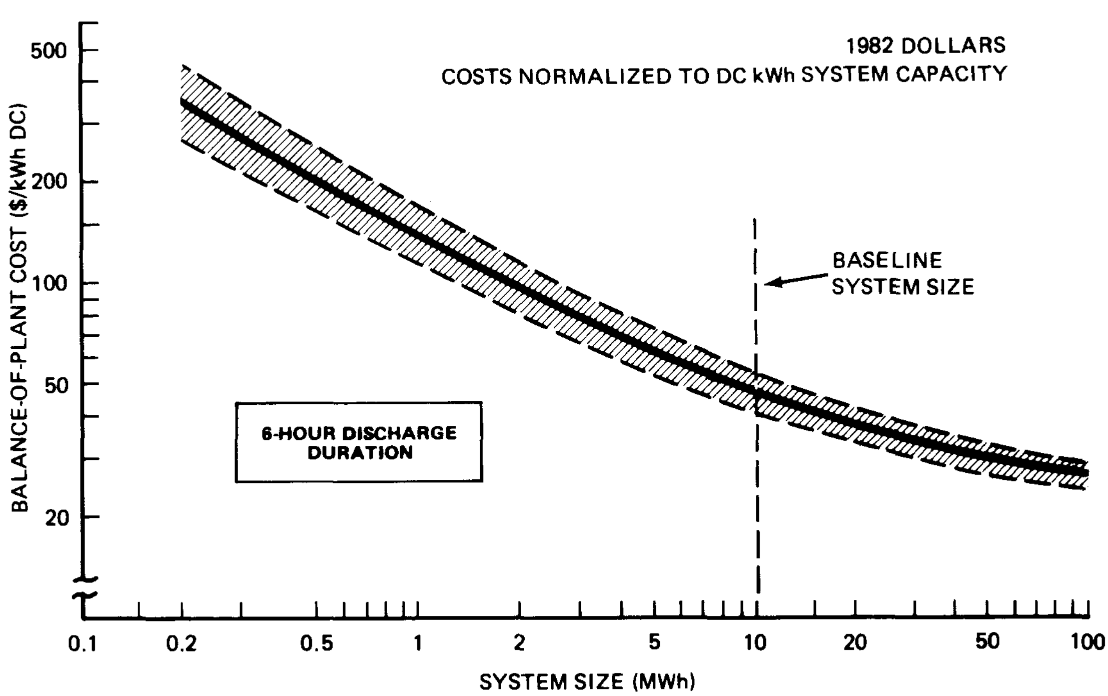

Figure 3-9. Balance-of-Plant Costs

higher power ratings (shorter discharge durations). Also, the performance rating of dc electrical components must be increased for higher power levels. Factors such as these will result in cost increases at higher power levels for building space, dc wiring, and lighting. Other components of the BOP (such as ventilation fans and safety monitoring instrumentation) will remain relatively fixed over a range of power ratings.

Previous studies of BOP design and costs have not explicitly investigated the relationship between battery discharge power and BOP costs. As mentioned, BOP costs have generally been reported in terms of system capacity (i.e., $/kWh). Discharge duration (hence, power rating) of the battery has been identified as a key economic parameter in previous studies (1, 2). Thus, it is important to quantify the relationship between discharge duration and BOP costs. While accurate numbers must await the performance of detailed engineering cost estimates (outside the scope of this study), Figure 3-10 presents a relationship between discharge duration and BOP costs based on the existing published data. The figure shows the percent by which BOP costs at various discharge durations differ from the costs at a 6-hour discharge duration. The data in Figure 3-10 were derived from available BOP cost estimates and cell capacity data supplied

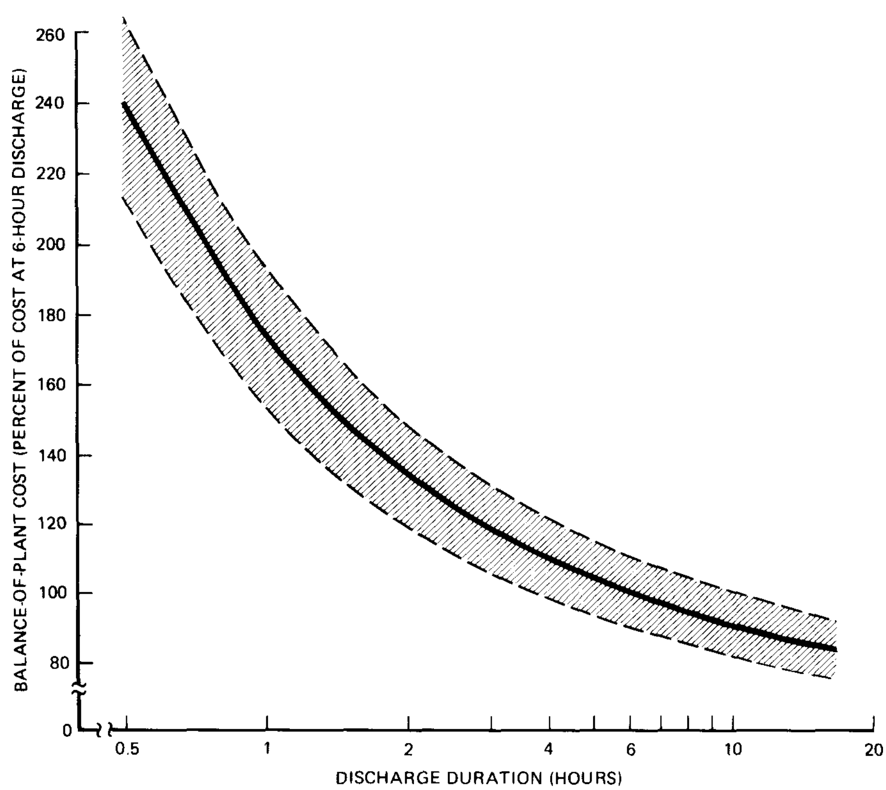

Figure 3-10. BOP Cost Multiplier

by battery manufacturers. The shaded area denotes a ± 11 percent uncertainty due to design and cost variations between the different BOP cost estimates used. BOP costs as a function of both battery system capacity and discharge duration are obtained by applying the data in Figure 3-10 to the data in Figure 3-9.

OPERATING AND MAINTENANCE REQUIREMENTS

The battery, converter, and balance-of-plant equipment require periodic maintenance during the life of the plant. Individual components of these subsystems, particularly the battery cells, will also require replacement one or more times. In addition, there will be operating costs associated with power consumption by auxiliary equipment and battery equalization. This section discusses the operating and maintenance (O&M) requirements and projected costs.

Battery Maintenance and Replacement

The most significant maintenance activity is associated with the battery cells themselves. A lead-acid cell requires the periodic addition of water due to the conversion of cell water to hydrogen and oxygen during normal and equalizing charge periods. Some manufacturers recommend automatic watering systems to reduce manual labor requirements for watering the cells. Periodic cell maintenance may also include checking and tightening of electrical connections at all terminal posts or between modules and removal of accumulated dirt, acid, and corrosion products from cell tops, terminal posts, and flash arrestors. For systems which use automatic watering systems or air-lift pumps, there may be additional maintenance on valves, air and water lines, inline filters, and regulators.

Water requirements of lead-antimony cells (the type investigated here) increase as the cells age. A typical 4 kWh cell requires 0.4 gallons of water every 4 weeks when new, increasing to every 2 weeks in the last quarter of its life. The amount of water and required addition frequency depend somewhat on the amount of space over the plates provided for electrolyte in a particular cell design. Some cells provide more space and hence require water less frequently than other cells of equivalent ampere-hour capacity.

Manufacturers' recommendations for maintenance of cell electrical connections and cleaning of cell tops vary. The frequency of checking cell connections (and tightening if necessary) ranges from checking 10 percent of all bolts quarterly to checking all bolts semi-annually. "Burned-on" connections, used by some manufacturers, do not require any checking or tightening. Cell top cleaning may be recommended quarterly, semi-annually, or not at all, depending on the manufacturer and the cell design. Some automatic watering systems may be installed in such a way as to preclude the accumulation of acid on the tops of the cells. Thus, cell tops in these installations are not expected to accumulate corrosion products and dirt.

The frequency and extent of maintenance that will be required on automatic watering systems in battery installations of the size studied herein is not known. Field experience with these systems is very limited. Engineering tests suggest a 5- to 10-year lifetime with one type of valve in use (the float valve). Another type (the fluidic valve), while containing no moving parts, may require periodic removal of residual deposits from parts of the valve which come in contact with the cell electrolyte.

Inline air filters and pressure regulators for air-lift pump systems may also require occasional maintenance.

Lead-acid cells have cycle and calendar lives such that periodic replacement is required over the life of the rest of the load-leveling equipment. As shown earlier, (Figure 3-1) cycle life depends upon the depth-of-discharge. Depth-of-discharge is typically 80 percent but may be decreased to 60 percent or 40 percent to preserve battery life at the expense of the additional installed capacity required to meet system energy needs. Calendar (shelf or wet) life is limited primarily by corrosion of the positive grid, and is difficult or impossible to predict since it depends on many other factors. These include operating temperature, duty cycle, type of maintenance and other conditions of service which are site- and customer-specific. Battery manufacturers estimate a nominal calendar life of 6 to 8 years for standard motive power cells used for load-leveling applications. Cells of the station power design (with thicker grids) may last 8 to 12 years.

Replacement of all the cells at one time is assumed for simplicity in this study. The customer might maintain a few back-up cells for immediate replacement of cells which fail early. Replacement includes removal and salvage of the old cells, and purchase and installation of new cells. Among the manufacturers contacted, salvage scenarios and available credits vary. One manufacturer proposed rebuilding the cell (requiring shipment of the old cell back to the factory). Other manufacturers would simply scrap the cell locally, reclaiming only the lead (and possibly parts of the cell and container) for reuse. Removal of the old cells is simply the reverse of the installation process except that auxiliary systems such as racks, and air and water lines, if used, may be left in place. However, some repair of these auxiliaries will likely be required during cell replacement.

Converter Maintenance

The converter is expected to require a minimal amount of repair and maintenance. Proposed power conditioning units are estimated to have mean-time-between-failures on the order of 20,000 hours (9) with a mean-time-to-repair of 1.5 hours, exclusive of repair crew dispatch time (10). The power conditioner is not expected to require replacement during the life of the plant considered here (20 years).

Balance-of-Plant Maintenance

Some maintenance and/or repair is required for such balance-of-plant equipment as the ventilation fans, water demineralizer, and air-lift pump compressor, as applicable. Motors require periodic servicing and may need replacement during the facility life. If a cartridge-type demineralizer is used as a source of battery water, the cartridge will require replacement one or more times per year depending on the relative size of the battery. Service on facility utilities (plumbing, lighting, etc.) may be considered as part of the customer's general building maintenance.

Annual Operating and Maintenance Costs

Published information regarding O&M costs for battery plants is limited. One battery manufacturer supplied Bechtel with cost data for their recommended annual service contract for station battery plants. For a 2 MWh system the annual cost of maintenance was $2.40 per installed kilowatt-hour. This charge includes travel, subsistence and weekend overtime for two technicians sent from the factory or service center. Since an automatic watering system was postulated, the annual service consists primarily of cleaning cell tops, servicing connections, and checking cell performance.

A study recently completed by Bechtel for Sandia National Laboratory (4) investigated maintenance and repair/replacement costs for battery storage facilities in the 16 to 6200 kWh capacity range. Manual watering was postulated. It was determined that specific costs ($/kWh) for all items decrease somewhat with increasing system size. The cost for cell maintenance alone (watering and cleaning) accounted for over half of all the maintenance. For a 2 MWh system the cost for annual maintenance was approximately $0.65/kWh, of which cell watering and cleaning accounted for $0.48/kWh. In that study it was assumed that all routine maintenance (including battery watering) would be performed by customer-employed maintenance personnel. This substantially lowers the cost of labor. At the labor rates assumed for the manufacturer's service contract cited above, the costs would have been comparable to the manufacturer's service contract costs.

Using manufacturer-supplied data, the cost of manual watering and cell maintenance was re-evaluated for the present study. A labor cost of $11/hr was used to reflect the cost of owner-employed personnel. Manual watering and cell maintenance for one proposed system would cost $1.70/kWh when the cells are new and increase to $9.40/kWh at the battery's end-of-life. It should be noted that annual payments for maintenance in the later years of a project's life are not as significant as the early years' payments, due to the time value of money. Thus, the effect of the increasing maintenance costs as the battery ages is leveled somewhat in a discounted cash flow economic analysis (discussed in Section 5).

The cost of cell maintenance alone (for systems with automatic watering) was also determined. Costs varied from $0.01/kWh to $0.40/kWh depending primarily on the manufacturers' recommendations as to extent and frequency of service.

Specific costs for battery watering and cleaning were found to be independent of system size provided the same size cell is postulated for all system sizes (as was done in this study).

Based on the results of the Bechtel study for Sandia cited above, it was judged that maintenance costs for the converter and the balance-of-plant equipment (ventilation fans and gas detection equipment in most systems) will be insignificant in comparison to the costs for battery watering and cleaning. An annual maintenance cost of $.75/kWh was chosen to represent the cost of all maintenance and repair (except battery replacement) for the economic analysis. The sensitivity of plant economic viability to maintenance costs was also determined and is reported in Section 5.

Battery Replacement Costs

Costs for removal and disposal of cells at the end of their life were determined. Based upon discussions with battery manufacturers and previous Bechtel studies, labor requirements for removal of spent cells were postulated to be the same as for initial installation. Shipping costs were determined (where applicable) for shipment of the battery back to the factory. A salvage credit was applied to these costs according to the scenario proposed by the battery manufacturer. Salvage value (credits minus costs) were computed for each manufacturer's battery. Values varied accordingly from 3.5 percent to 33 percent of initial battery cost. Bechtel postulated a baseline salvage value of 11 percent of initial battery cost and investigated economic sensitivity to this parameter.

Purchase price, shipping and installation costs of replacement cells were assumed to be equal to that of the original battery. This does not take into account the possible change in lead price between the time the battery is first purchased and the time it is replaced.

Auxiliary Energy Consumption

Energy consumed by auxiliary equipment (e.g., ventilation fans) and by battery equalization constitutes an additional operating cost. The energy consumed by equalization was calculated for each of the three batteries studied and found to vary from 0.75 to 3.0 kWh per cycle per 100 kWh of system size (for systems with a half-hour discharge duration). These values declined by about 10 percent as discharge duration increased to 12 hours. A nominal value of 1.4 kWh per cycle per 100 kWh of system size was used in the economic analysis.

Consumption of energy by auxiliary equipment was estimated to be minimal in comparison to energy consumed by periodic equalization of the battery.

Except for instrumentation, most energy consumption takes place during battery charging which normally would occur during off-peak hours. Where applicable, the economic analysis used off-peak energy rates to calculate the cost of auxiliary energy consumption.

Section 4

ELECTRIC UTILITY RATES

This section presents a brief background discussion of rate schedules prevalent in the utility industry, current rate schedules of utilities having rates expected to favor customer load-leveling, and the procedures used to identify these utilities.

BACKGROUND

Essentially, there are two basic components of electric rate schedules. These are the demand charge and the energy charge. A demand charge is levied for the peak power exhibited by the customer's load. Usually, the load is averaged over a 15- or 30-minute interval to determine "billable" demand. An energy charge is levied on the kilowatt-hours consumed by the customer. Most commercial and industrial users of electricity are billed for both demand and energy consumption.

There are several types of rate schedules currently prevalent in the utility industry, the most common being:

- Traditional flat rates
- Time-of-day rates

Traditional flat rate schedules make no distinction regarding the times of energy use. These rates have fixed demand and energy charges throughout the day and are the most prevalent in the utility industry. As mentioned in Section 2 and as will be shown in detail in Section 5, high demand charges are of particular importance to battery applications.

Flat demand charges have been offered to large users for many years. Currently, a large percentage of utilities have incorporated demand charges in the rate schedules of smaller users. Such charges exist for customers with as little as 5 kW demand. A flat demand charge is an incentive for a customer to reduce peak demand with respect to energy use (i.e., increase load factor). Depending on the coincidence of the customer demand with system load, the improvement of customer load factor will tend to benefit system load factor as well.

Time-of-day (TOD) rates are time dependent. These rates divide the 24-hour day into a peak period (e.g., 10 a.m. to 6 p.m.) and an off-peak period for the rest of the day. Some TOD rates divide the day in three periods; peak, intermediate and off-peak. During the peak period, demand and energy charges are the maximum. In most cases during the off-peak period, there is no demand charge or the demand charge is a certain percentage (e.g., 30 percent) of on-peak demand charge. Usually, the energy charge during the off-peak period is at much lower rates than during the on-peak period. In some cases, demand and energy charges are different during summer and winter months. Some utilities meter off-peak service separately.

The wider usage of time-of-day rates was one of the goals of the Public Utility Regulatory Policies Act of 1978. In most cases, TOD rates apply to a certain group of customers, such as large industrial customers or customers with electric space heating or energy storage. TOD rates for the residential class of customers are in the experimental stages in some areas of the country. Currently, less than one percent of U.S. electric utilities customers are billed on a time-of-day rate. However, a large percentage of utilities have at least an optional time-of-day rate available to selected customers.

SELECTION OF FAVORABLE ELECTRIC RATES

The following procedure was used to select utilities having electric rates favorable for the economic viability of battery energy storage on the customer-side-of-the-meter. The purpose of the selection procedure was to produce a representative rather than exhaustive listing.

States having utilities with a large percentage of oil and natural gas or very large percentage of coal in their generation mix were selected for preliminary screening purposes, since many of these are known to have relatively high demand charges. Table 4-1 (11) shows the percentage of coal, oil, natural gas, nuclear and hydro resources used by various states within the U.S. to generate power. States selected for preliminary screening are marked with a double asterisk on Table 4-1.

In the next step, utilities within the selected states were identified. Emphasis was placed on larger utilities, because these utilities serve large demographic areas with a wide variety of customers. Therefore, there was more

Table 4-1

PERCENTAGE OF ELECTRICITY GENERATED
BY ENERGY SOURCE

State	Coal	Oil	Gas	Nuclear	Hydro
Alabama	55	*	*	29	15
Alaska**	10	14	61	-	15
Arizona	58	8	14	-	21
Arkansas	14	27	16	23	20
California**	-	41	29	6	22
Colorado**	78	2	13	*	7
Connecticut**	*	45	-	53	2
Delaware**	34	59	7	-	-
Florida**	19	48	16	16	*
Georgia**	80	3	*	9	8
Hawaii**	-	100	-	-	*
Idaho	-	-	*	-	100
Illinois**	64	8	2	26	*
Indiana**	98	1	*	-	*
Iowa**	77	2	3	14	4
Kansas**	53	6	41	-	*
Kentucky**	93	*	*	-	7
Louisiana**	-	18	82	-	-
Maine	-	16	-	60	24
Maryland and D.C.	38	26	2	28	6
Massachusetts**	*	80	2	17	1
Michigan**	66	11	3	19	1
Minnesota	57	2	2	37	2
Mississippi	32	38	30	-	-
Missouri**	93	1	3	-	2
Montana	33	*	1	-	66
Nebraska	35	2	6	50	7
Nevada	56	6	26	-	12
New Hampshire**	45	38	*	-	17
New Jersey**	21	45	10	25	-1
New Mexico**	71	2	26	-	*
New York**	13	38	6	18	25
North Carolina**	78	*	*	10	12
North Dakota**	80	*	-	-	20
Ohio**	95	2	*	3	*
Oklahoma	11	*	83	-	6
Oregon	-	2	*	13	85
Pennsylvania**	75	9	*	15	1
Rhode Island**	-	75	24	-	*
South Carolina	40	6	1	44	9
South Dakota	31	*	*	-	69
Tennessee**	79	*	-	-	21
Texas**	25	1	73	-	*
Utah**	87	1	4	-	8
Vermont	*	*	*	78	20
Virginia**	35	40	*	20	4
Washington	8	*	*	4	87
West Virginia**	99	*	*	-	*
Wisconsin**	62	2	4	27	5
Wyoming**	95	*	*	-	5
U.S. Average	48	14	15	11	12

* Less than 1%
**States selected for preliminary investigation purposes.
Source: State Electricity Profiles, Electricity Consumers Research Council (11).

likelihood of finding appropriate applications for battery energy storage. References 12 and 13 were used to identify such utilities.

Preliminary investigations showed that application of battery energy storage for small residential and commercial customers (1 - 50 kW load) will probably not be economical. Therefore, rate schedules of large commercial and industrial customers (50 kW and above) were evaluated. Traditional flat rates and time-of-day (TOD) rates were taken into account. Other types of rate schedules such as interruptable and standby rates were not considered.

The criteria used to identify utilities with favorable traditional flat rates were a high demand charge (more than five dollars per kilowatt) and a low energy charge (less than seven cents per kilowatt-hour). In the case of time-of-day rate schedules, rates having high differentials between on- and off-peak demand and energy charges were considered to be attractive. About twenty utilities were identified which met the above criteria. Table 4-2 shows the list of potential utilities identified. Initial screening of electric rate schedules of selected utilities was conducted by reviewing the National Electric Rate Books, published by the Energy Information Administration of the U.S. Department of Energy (14). Since the rate schedules published in the National Electric Rate Books are at least three to four years old, this source was used only to identify utilities with potentially favorable rates.

In the next phase, utilities with the most favorable rates were selected to obtain the most current rate schedules. These utilities were initially contacted by telephone, followed-up by an EPRI letter to obtain the current rate schedules.

Favorable traditional and time-of-day rate schedules obtained from the selected utilities are shown in Tables 4-3 and 4-4, respectively. (In the tables, the energy charges shown do not include any applicable fuel cost adjustments. These reflect the changing cost of fuel, are changed as frequently as every month, and can be substantial for some utilities. Where the current data was provided the adjustment is shown in a footnote. Rate schedules shown are those in force in mid-1982 and are subject to change. The rates summarized herein do not reflect any applicable terms or conditions and do not necessarily include applicable state and local taxes.) The scope of the study did not permit a complete compilation of all favorable rate schedules. However, it is believed that the rate data presented are representative of favorable current rates.

Table 4-2

INITIAL LIST OF UTILITIES WITH FAVORABLE RATE SCHEDULES

Appalachian Power Company*[a]
Boston Edison Company*
Central Illinois Light Company*
Connecticut Light & Power Company*
Consolidated Edison Company of New York*
Consumers Power Company*
Detroit Edison Company*
Florida Power Corporation*
Illinois Power Company*
Indiana & Michigan Electric Company*[a]
Indianapolis Power & Light Company*
Iowa Electric Light & Power Company*
Kentucky Power Company*[a]
Long Island Lighting Company*
Niagara Mohawk Power Corporation
Ohio Power Company*[a]
Power Authority of the State of New York*
Public Service Electric & Gas Company
San Diego Gas & Electric Company*

* Utilities contacted to obtain current rate schedules
(a) Part of American Electric Power Service Corporation (AEP). Current rate schedules for these utilities were obtained from AEP.

CONCLUSIONS

The selection criteria described above were used to produce a list of 20 utilities having rates that were expected to be favorable for customer-side-of-the-meter battery energy storage. The essential characteristics of these 20 utilities may be summarized as follows:

- Demand charge of 5 to 17 dollars per kilowatt
- Off-peak demand charge low or non-existent
- Energy charge (for most) less than 7 cents per kilowatt hour

As will be shown later, a demand charge substantially less than ten dollars per kilowatt is not attractive to the customer for most applications. The minimum attractive demand charge depends upon other factors such as discharge duration and battery system size. Also, it will be shown that the energy charge and off-peak demand charge are of secondary importance to the economics of customer owned storage.

Table 4-3

MOST FAVORABLE TRADITIONAL RATE SCHEDULES

Utility Name	Schedule	Load Size (kW)	Demand Charge ($/kW)		Energy Charge (¢/kWh)	
Appalachian Power	LGS	Min. 100	8.57	First 100 kW	2.506	
			7.42	Over 100 kW		
	LCP	Min. 1000	15.275	First 1000 kW		
			14.275	Next 3000 kW	2.768	
			13.237	Over 4000 kW		
Boston Edison[a]	G-2	Min. 20	8.55	First 20 kW	3.52	First 290 kWh
	(Jul.-Oct.)		6.74	Next 130 kW	2.42	Next 150 kWh
			5.39	Over 150 kW	1.87	Over 440 kWh
	G-2	Min. 20	8.55	First 20 kW	2.84	First 290 kWh
	(Nov.-Jun.)		5.64	Next 130 kW	1.74	Next 150 kWh
			5.39	Over 150 kW	1.19	Over 440 kWh
	G-3	Min. 150	5.44	First 150 kW	2.56	First 290 kWh
	(Jul.-Oct.)		5.29	Next 650 kW	2.36	Next 150 kWh
			4.91	Over 800 kW	1.81	Over 440 kWh
	G-3	Min. 150	5.44	First 150 kW	1.88	First 290 kWh
	(Nov.-Jun.)		4.19	Next 650 kW	1.68	Next 150 kWh
			3.81	Over 800 kW	1.13	Over 440 kWh
Connecticut Light & Power	35	Min. 50	7.70	First 50 kW	5.791	First 200 kWh/kW
			5.10	Next 150 kW	5.679	Next 100 kWh/kW
			3.30	Over 200 kW	5.579	Next 100 kWh/kW
					5.279	Over 400 kWh/kW
Consolidated Edison Co.	SC-9	Min. 10				
of New York	(May 15-Oct. 15)	(Low Tension)	17.05	First 1300 kW	6.70	First 1.5 million kWh
			16.02	Over 1300 kW	6.51	Over 1.5 million kWh
	(Oct. 16-May 14)	(Low Tension)	14.05	First 1300 kW	6.70	First 1.5 million kWh
			13.02	Over 1300 kW	6.51	Over 1.5 million kWh
	(May 15-Oct. 15)	(High Tension)	15.65	First 1300 kW	6.70	First 1.5 million kWh
			14.72	Over 1300 kW	6.51	Over 1.5 million kWh
	(Oct. 16-May 14)	(High Tension)	12.65	First 1300 kW	6.70	First 1.5 million kWh
			11.72	Over 1300 kW	6.51	Over 1.5 million kWh
Consumers Power Company[b]	C	Min. 5	8.36		3.78	First 200 kWh/kW
					3.38	Over 200 kWh/kW
					plus 0.6768¢/KWh (Surcharges)	

(a) A fuel cost adjustment of 3.63¢/kWh (revised quarterly) must be added to the energy charge.
(b) A TOD demand charge billing is available with this rate and includes a 100 kW minimum and an off-peak billable demand equal to 1/3 of the actual demand.

Table 4-3 (Continued)

Utility Name	Schedule	Load Size (kW)	Demand Charge ($/kW)		Energy Charge (¢/kWh)	
Detroit Edison	LGS	Min. 5	7.80		5.3 4.8	First 200 kWh/kW Over 200 kWh/kW
Florida Power[a]	GSD-1	50 - 500	5.30		3.71	
	GSLD-1	Min. 500	4.50		3.526	
Illinois Power Company	11	Max. 500	-		6.48	For 250 kWh/kW of contract capacity (June 15 - Sept. 14)
			-		6.48	For 175 kWh/kW of contract capacity (Sept. 15 - June 14)
			-		2.89	Over 250 kWh/kW (175 kWh/kw)
Indiana & Michigan Elect. Co.[b]	Q.P.	Min. 850	8.50		0.913	
	I.P.	Min. 8500	7.28		0.913	
Indianapolis Power & Light[c]	S.L.	Min. 50 (Low Voltage)	7.73 7.21 6.68	First 500 kW Next 500 kW Over 1000 kW	0.0 3.04 2.68	First 100 kWh/kW Next 300 kWh/kW Over 300 kWh/kW
	P.L.	500-2000 (High Voltage)	6.71 6.09	500 - 2000 kW Over 2000 kW	0.0 2.80 2.21	First 100 kWh/kW Next 300 kWh/kW Over 300 kWh/kW
	H.L.	Min. 2000 (High Voltage)	14.88 13.80	2000 - 4000 kW Over 4000 kW	0.0 2.19	First 400 kWh/kW Over 400 kWh/kW
Iowa Electric Light & Power Co.	LGS[d] (June-Sept.)	Min. 10	14.04 13.04 12.04 11.04	First 40 kW Next 160 kW Next 800 kW Over 1000 kW	1.20 1.04 0.87 0.72 0.67	First 120 kWh/kW[e] Next 120 kWh/kW Next 110 kWh/kW Next 110 kWh/kW Over 460 kWh/kW
	LGS[d] (Oct.-May)	Min. 10	13.04 12.04 11.04 10.04	First 40 kW Next 160 kW Next 800 kW Over 1000 kW	Same as months of June through September (above)	
Kentucky Power Co.	5	Min. 1000	4.8298		1.578	

(a) A fuel cost adjustment of approximately 1¢/kWh (revised quarterly) must be added to the energy charge.
(b) Utility measures and charges the demand in kVA. For consistency in the table, the numbers have been converted to kW. The multiplying factor used is 0.85.
(c) A fuel cost adjustment of 0.167¢/kWh (revised quarterly) must be added to the energy charge.
(d) Time-of-day (TOD) pricing is also available under this schedule. Off-peak billable demand is one-third actual demand. Off-peak energy is 0.67¢/kWh. On-peak hours are 7 am to 8 pm.
(e) Energy charge is computed using kW of actual demand during month.

Table 4-3 (Continued)

Utility Name	Schedule	Load Size (kW)	Demand Charge ($/kW)		Energy Charge (¢/kWh)	
Long Island Lighting Co.	2-L	7 - 750			7.94	First 6000 kWh
		(Low Voltage)	6.58		7.55	Next 24,000 kWh
		(High Voltage)	5.98		7.09	Over 30,000 kWh
Ohio Power [(a)]	L.P.	Min. 42.5	5.63		0.3	
	I.P.	Min. 6,800				
		Primary Dist.	4.55		0.29	
		Subtrans. Dist.	3.94		0.224	
		Transmission	3.98		0.205	
Power Authority of the State of New York (PASNY)[(b)]	Electric Traction	Not avail.				
	Production[(c)]		9.59		3.14	
	Delivery Service[(c)]					
	(Low Tension)		13.20	First 100 kW	None	
			12.39	Next 100 kW	None	
			7.39	Over 200 kW	None	
	(High Tension)		11.88	First 100 kW	None	
			11.15	Next 100 kW	None	
			6.65	Over 200 kW	None	
	NYCTA - Substation	Not avail.				
	Production [(c)]		9.80		2.99	
	Delivery Service[(c)]					
	(Low Tension)		14.77	First 100 kW	None	
			11.61	Next 100 kW	None	
			5.61	Next 89,800 kW	None	
			1.58	Over 90,000 kW	None	
	(High Tension)		13.29	First 100 kW	None	
			10.45	Next 100 kW	None	
			5.06	Next 89,800 kW	None	
			1.43	Over 90,000 kW	None	
San Diego Gas & Elect.[(d)]	AD	Min. 20	4.50	First 20 kW	2.556	
			4.00	Over 20 kW		

(a) Utility measures and charges the demand in kVA. For consistency in the table, the numbers have been converted to kW. The multiplying factor used is 0.85.
(b) Rates do not reflect any applicable terms, conditions or special provisions nor state and/or municipal taxes.
(c) Customer's bill is the sum of the Production rate and the Delivery Service rate.
(d) A fuel cost adjustment of 6.607¢/kWh (revised every 6 months) must be added to the energy charge.

Table 4-4

MOST FAVORABLE TIME-OF-DAY RATE SCHEDULES

Utility Name	Schedule	Load Size (kW)	Demand Charge ($/kW) Peak	Demand Charge Interm.	Demand Charge Off-Peak	Energy Charge (¢/kWh) Peak	Energy Charge Interm.	Energy Charge Off-Peak	Peak/Off-Peak Hours
Boston Edison[a]	T-1	Min. 10							
	(Jun. 15-Oct. 15)		8.30	70%	30%	7.09	5.29	3.50	11 am - 5 pm On-Peak 10 pm - 9 am Off-Peak
	(Oct. 16-Jun. 14)		7.01	70%	30%	7.09	5.03	3.37	Remaining Intermediate
	T-2	Min. 150							
	(Jun. 15-Oct. 15)	High L.F. (60%)	9.49	60%	30%	4.11	1.85	0.70	
		General L.F. (40%)	7.31	60%	30%	4.61	2.35	1.18	Same as above
		Low L.F. (40%)	6.67	60%	30%	4.84	2.56	1.41	
	(Oct. 16-Jun. 14)	High L.F. (60%)	9.49	60%	30%	4.11	1.72	0.65	
		General L.F. (40%)	7.31	60%	30%	4.61	2.22	1.13	Same as above
		Low L.F. (40%)	6.67	60%	30%	4.84	2.42	1.42	
	T-3	Min. 150 (@ 14 kV)							
	(Jun. 15-Oct. 15)	High L.F. (60%)	6.65	60%	30%	4.07	1.80	0.66	
		General L.F. (40%)	4.46	60%	30%	4.46	2.30	1.13	Same as above
		Low L.F. (40%)	3.83	60%	30%	4.80	2.51	1.36	
	(Oct. 16-Jun. 14)	High L.F. (60%)	6.65	60%	30%	4.07	1.67	0.59	
		General L.F. (40%)	4.46	60%	30%	4.46	2.17	1.09	Same as above
		Low L.F. (40%)	3.83	60%	30%	4.80	2.38	1.32	
Central Illinois Light Company[b]	21	850							
	(Jun. 1-Sept. 30)		12.06	-	50%	3.40	-	1.50	10 am - 10 pm On-Peak Remaining Off-Peak
	(Oct. 1-May 31)		6.78	-	50%	2.30	-	1.50	7 am - 10 pm On-Peak Remaining Off-Peak
	23	Min. 17,000							
	(Jun. 1- Sept. 30)		9.35	-	50%	3.20	-	1.40	Same as above
	(Oct. 1- May 31)		5.61	-	50%	2.10	-	1.40	Same as above

(a) For schedules T-2 and T-3, rates vary according to customer load factor (L.F.), as shown. For all schedules, a fuel cost adjustment of 3.63¢/kWh must be added to the energy charge.

(b) Utility measures and charges the demand in kVA. For consistency in the table, the numbers have been converted to kW. The multiplying factor used is 0.85.

Table 4-4 (Continued)

Utility Name	Schedule	Load Size (kW)	Demand Charge ($/kW) Peak	Interm. Off-Peak	Energy Charge (¢/kWh) Peak	Interm.	Off-Peak	Peak/Off-Peak Hours
Consolidated Edison Co. of New York[a]	SC-9 (High Tension)	Min. 900 kW						
	(May 15-Oct. 15)	Transmission	14.67	(M-F; 8 am-6 pm)	5.61	-	4.63	8 am-10 pm On-Peak
		Primary Dist.	9.75	(M-F; 8 am-10 pm)				10 pm-8 am Off-Peak
		Secondary Dist.	-	(All days; All hours)				
	(Oct. 16-May 14)	Transmission	-	(M-F; 8 am-6 pm)	5.89	-	4.63	
		Primary Dist.	9.75	(M-F; 8 am-10 pm)				Same as above
		Secondary Dist.	4.29	(All days; All hours)				
	SC-9 (Low Tension)							
	(May 15-Oct. 15)	Transmission	14.67	(M-F; 8 am-6 pm)	5.84	-	4.71	
		Primary Dist.	9.75	(M-F; 8 am-10 pm)				Same as above
		Secondary Dist.	4.29	(All days; All hours)				
	(Oct. 16-May 14)	Transmission	-	(M-F; 8 am-6 pm)	6.12	-	4.71	
		Primary Dist.	9.75	(M-F; 8 am-10 pm)				Same as above
		Secondary Dist.	4.29	(All days; All hours)				
Consumers Power	D	Min. 25						(Oct. to Feb.)[b]
			6.55	On-Peak; plus	3.67	3.27	2.97	5 pm-9 pm On-Peak
			1.40	Primary Service, or	plus 0.5648¢/kWh			10 am-5 pm Interim
			0.75	Subtransmission, or	(Surcharges)			7 pm-10 am Off-Peak
			0.40	Transmission				
								(Mar. to Sept.)[b]
								5 pm-9 pm Interim
								9 pm-10 am Off-Peak
	F	Min. 100	8.00	On-Peak; plus	3.40	3.00	2.70	
			1.40	Primary Service, or	plus 0.4998¢/kWh			Same as above
			0.75	Subtransmission, or	(Surcharges)			
			0.40	Transmission				
	J (Metal Melting)	Min. 500	5.14	On-Peak; plus	3.67	3.27	2.97	
			0.75	Primary Service, or	plus 0.5458¢/kWh			Same as above
			0.55	Subtransmission, or	(Surcharges)			
			0.25	Transmission				
Detroit Edison	Primary Supply	Min. 50	7.80	On-Peak; plus	3.65	-	2.95	11 am-7 pm On-Peak
			2.40	Primary Service, or				Remaining Off-Peak
			1.55	Subtransmission, or				
			1.05	Transmission				
	Bulk Supply	Min. 50,000	8.05		3.55	-	2.85	Same as above

(a) Utility sets rates in accordance with customer's supply voltage, as shown.
(b) On-peak hours are effective Monday through Friday. Weekend and holiday use is billed as off-peak.

Table 4-4 (Continued)

Utility Name	Schedule	Load Size (kW)	Demand Charge ($/kW) Peak	Demand Charge ($/kW) Interm.	Demand Charge ($/kW) Off-Peak	Energy Charge (¢/kWh) Peak	Energy Charge (¢/kWh) Interm.	Energy Charge (¢/kWh) Off-Peak	Peak/Off-Peak Hours
Florida Power Corporation	GSDT-1	Min. 35	3.177 Base Charge; plus 2.796 On-Peak Charge			4.922	-	3.206	On-Peak 6 am-10 am 6 pm-10 pm (Nov. - May) 12 pm-9 am (Apr. - Oct.) Remaining Off-Peak
	GSLDT-1	Min. 350	2.695 Base Charge; plus 2.372 On-Peak Charge			4.544	-	3.105	Same as above
Long Island Lighting Company	2-MRP	Min. 750							(June. 1 - Sept. 30)
		Secondary	13.23	3.33	0.0	7.80	7.15	5.98	10 am-10 pm On-Peak
		Primary	11.91	3.03	0.0	7.70	7.10	5.93	12 am-7 am Off-Peak
		Transmission	9.63	2.43	0.0	7.47	6.95	5.87	Remaining Intermediate (Oct. 1 - May 30) 7 am-12 am Intermediate 12 am-7 am Off-Peak
San Diego Gas & Electric[a]	AL-TOU	Min. 500	7.31			4.98	4.38	2.08	(May 16 - Oct. 15) 10 am-5 pm On-Peak 5 pm-9 pm Intermediate 9 pm-10 am Off-Peak (Oct. 16 - May 15) 5 pm-9 am On-Peak 10 am-5 pm Intermediate 9 pm-10 am Off-Peak

(a) A fuel cost addjustment of 6.607¢/kWh must be added to the energy charge. Weekend and holiday use is billed at off-peak rates.

Section 5

PRELIMINARY ECONOMIC ANALYSIS

A preliminary economic analysis was conducted to determine the economic viability of postulated customer-owned battery plants for a variety of potentially attractive situations. This section summarizes the techno-economic factors used to characterize customer-owned load-leveling applications for economic analysis and presents the economic criteria used. A baseline application is described. Results are presented for the baseline application and for various parametric analyses.

TECHNO-ECONOMIC FACTORS

Cost and Performance

The major cost and performance parameters associated with battery energy storage systems are described in Section 3. They are:

- System storage size (MWh)
- Discharge capability (MW)
- Battery cost (initial and replacement)
- Converter cost
- Balance-of-plant cost
- Battery maintenance
- Battery life
- System efficiency

For the generic analysis presented in this section it is assumed that the discharge power experienced by the battery is constant throughout the complete cycle. Thus, the discharge duration may be equated to the ratio of system size (MWh) to discharge capability (MW). However, many actual load profiles have rounded or needle-shaped peaks which do not present a constant power demand on the battery. In Section 6 it will be shown that the economic benefit is improved for peaks which exhibit these traits. Thus, the assumption of a constant power discharge is conservative with respect to assessing economic viability.

Battery cost is related to the discharge duration. The balance-of-plant cost is related to both system size and discharge duration, as discussed in Section 3. Battery charging costs are affected by system efficiency. Annual operating and maintenance costs are related primarily to system size. Sensitivity to variations in all of these parameters was investigated.

Cost and performance data for the battery, converter, and BOP were derived from the information presented in Section 3. All cost data were input as specific cost ($/kW or $/kWh) and were normalized to the ac discharge rating of the battery plant. In the case of the battery and BOP, the cost data presented in Figures 3-4 and 3-9 (shown as $/kWh dc) were divided by the one-way converter efficiency to normalize it to the ac plant rating. All costs are expressed in 1982 dollars.

Utility Rates

Rate schedule data have been described in Section 4. The relevant factors are demand and energy charges. Reduction of peak load demand produces savings to the customer in the demand component of his monthly utility bill. Normally, these savings are partly offset by battery system inefficiency which causes the battery plant to be a net consumer of energy. However, for low energy charges and high demand charges, there will generally be a net savings to the customer. For TOD rates with a large enough differential between on- and off-peak energy charges, the energy component of the bill may also decrease with the introduction of a battery.

Monthly demand charge rates of $5/kW, $10/kW, and $15/kW are investigated with $10/kW as the baseline. On-peak energy charges are assumed to be 5¢/kWh. Off-peak energy charges of between 2¢/kWh and 4¢/kWh are investigated, with 3¢/kWh used for the baseline. Values chosen are not for a specific utility rate schedule. However, the ranges chosen are reasonable representations of the actual rate data presented in Section 4.

ECONOMIC CRITERIA

This section is a general presentation of the economic criteria used in the economic analysis. A detailed description of the methodology and formulas used are presented in the Appendix.

Before-Tax Rate of Return

The primary economic criteria used for evaluation is before-tax rate of return. Rankings produced are the same as those that would be produced by discounted cash flow. Before-tax analysis was used as the basis because of the wide variety of tax situations that could be expected among applications.

Payback

The number of years required to recover the investment at zero percent interest (i.e., payback) is calculated. The payback method is not so rigorous as discounted cash flow or rate-of-return methods. However, for situations where a high degree of uncertainty exists and a firm is interested in its cash position and borrowing, payback has the advantage of indicating the rate at which an investment will liquidate its initial outlay. As a result, it is frequently used to supplement economic measures of desirability such as rate of return. Payback is calculated on a before-tax basis.

After-Tax Rate of Return

After-tax rate of return analysis is conducted for selected cases to illustrate the effect of taxes for what is deemed to be a reasonable situation. This situation includes:

- 48 percent income tax
- 5 year tax depreciation under the Accelerated Capital Recovery System (Economic Recovery Act of 1981)
- 10 percent investment tax credit

The qualification of a battery for additional tax credits as an alternative energy device is uncertain and has not been included in the present economic evaluation.

BASELINE APPLICATION DESCRIPTION

Baseline Application and Parameter Range

The preliminary economic analysis is carried out first by defining a baseline for analysis which is representative of potentially viable customer-side-of-the-meter load-leveling applications. The baseline application is characterized by a specific choice of the techno-economic factors described above. In order to bracket the range of potentially viable applications several sensitivity analyses are conducted. Each major cost and performance parameter is varied over a range of values while the remaining parameters are fixed at their baseline value. Before-tax rate of return is determined parametically for each variation in the set of baseline assumptions. Table 5-1 summarizes the baseline parameter choices and the range of values studied.

Table 5-1

COST AND PERFORMANCE PARAMETERS

Parameter	Baseline Value	Range Investigated
System Size, MWh ac	10[a]	1 - 50
Discharge Duration, Hours	2	0.5 - 12
Utility Rates		
- On-Peak Demand Charge, $/kW	10	5 - 15
- Off-Peak Demand Charge, $/kW	0	0 - 5
- On-Peak Energy Charge, ¢/kWh	5	1 - 11
- Off-Peak Energy Charge, ¢/kWh	3	1 - 7
Energy Cost Escalation, Percent Over Inflation	2	0 - 4
Inflation Rate	8	8
Battery Cost, $/kWh dc[d]	212[a]	125 - 400[b]
Converter Cost, $/kW ac	119[a]	60 - 465[c]
Balance-of-Plant Cost, $/kWh dc[d] (for 10 MWh System Size)	65[a]	28 - 120[b]
Battery Salvage Value, Percent of Initial Cost	11	3 - 33
Maintenance Cost (annual), $/kWh ac	0.75	0.40 - 4.00
Battery Life, Cycles	1500	1000 - 3000
Number of Discharge Cycles per Year	250	250
Battery Depth-of-Discharge, Percent	80	40 - 80
Efficiency, Percent		
- Battery, Roundtrip	71.8[a]	53.1 - 90.3
- Converter, One-way	97	97
- Overall System, Roundtrip	67.6[a]	50 - 85

(a) For 2-hour discharge rate.
(b) For 10 MWh system size and 1- to 6-hour discharge duration.
(c) 1- to 6-hour discharge duration for both advanced technology and present converter prices.
(d) Costs in $/kWh dc are normalized to $/kWh ac for the economic analysis by dividing by the one-way converter efficiency.

As a result of the initial literature survey described in Section 2 and initial calculations by Bechtel, two application parameters (discharge duration and on-peak demand charge) were identified as having a strong influence on economic viability. Thus, the results of the economic analysis are shown explicity for various values of these two parameters.

System size is also expected to have a major influence. Accordingly, the scope of the analysis of the 10 MWh baseline system is duplicated for 1 MWh and 50 MWh system sizes.

The sensitivity of rate of return to variations in the other parameters of Table 5-1 is determined only for the 10 MWh system using a $10/KW on-peak demand charge. In certain cases the sensitivity analysis is further restricted to address only a single discharge duration, 2 hours. These results may be extrapolated to other system sizes, utility demand charges and discharge durations in order to estimate the effect of a given parameter on rate of return.

RESULTS OF PRELIMINARY ANALYSIS

Results of the preliminary economic analysis are presented. The before-tax rate of return (ROR) and payback period are shown, followed by an example calculation of the effects of taxation on the ROR. Sensitivity of the baseline system ROR to component and O&M costs, system design parameters, and utility rate structures are then presented.

Before-Tax Rate of Return

Before-tax ROR and payback period for three system sizes are shown in Figures 5-1 through 5-3. Figure 5-2 gives results for the baseline 10 MWh system. As expected, discharge duration and demand charge are critical parameters for all system sizes. System size is of increasing importance for small systems (less than 10 MWh), but in all cases ranks as a significant factor for economic viability.

A before-tax ROR of 30 percent could be defined as the minimum acceptable return in the commercial/industrial sector for a new technology such as this. Also, payback period should be less than the life (6 years) of the battery (a major cost component). Using these criteria, Figure 5-2 generally shows that economic viability for the 10 MWh system size is limited to applications with the following characteristics:

- Discharge duration less than 3 hours (assuming a $15/kW demand charge)
- Demand charge greater than 7 $/kW (assuming a half-hour discharge duration)

The maximum acceptable discharge duration decreases for lower demand charges. Conversely, the minimum attractive demand charge increases for longer discharge durations.

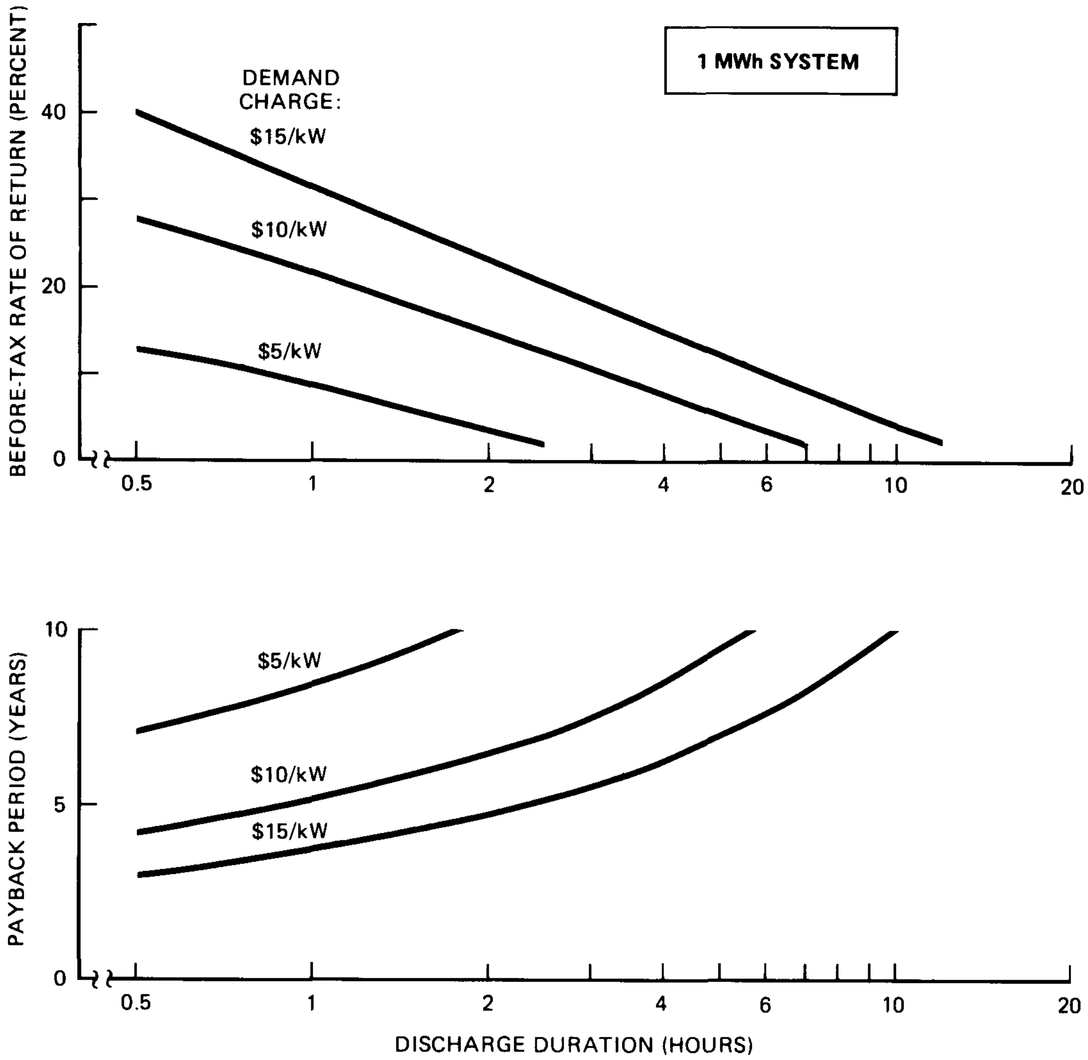

Figure 5-1. Before-Tax Rate of Return and Payback Period for 1 MWh System

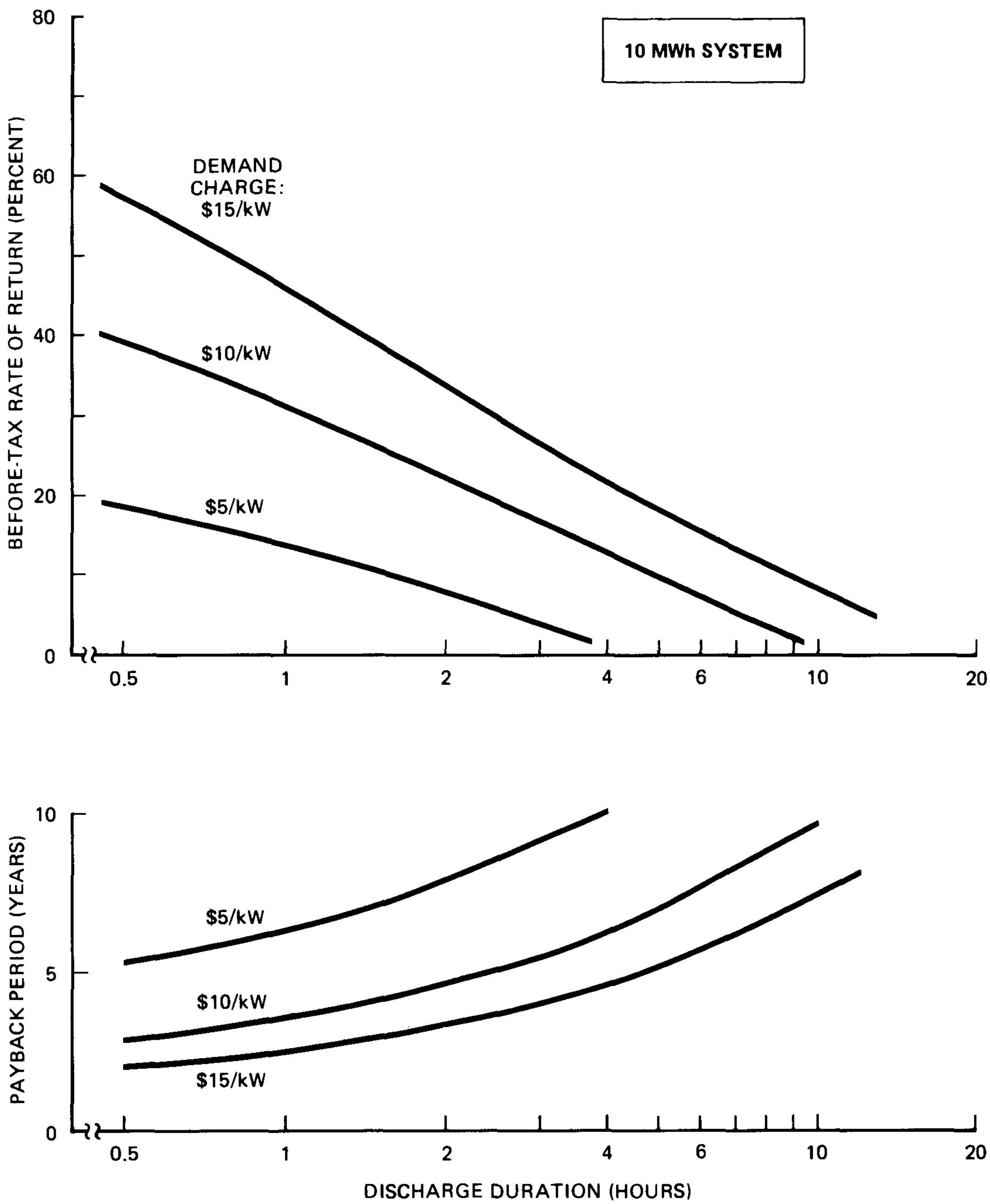

Figure 5-2. Before-Tax Rate of Return and Payback Period for 10 MWh System (Baseline System)

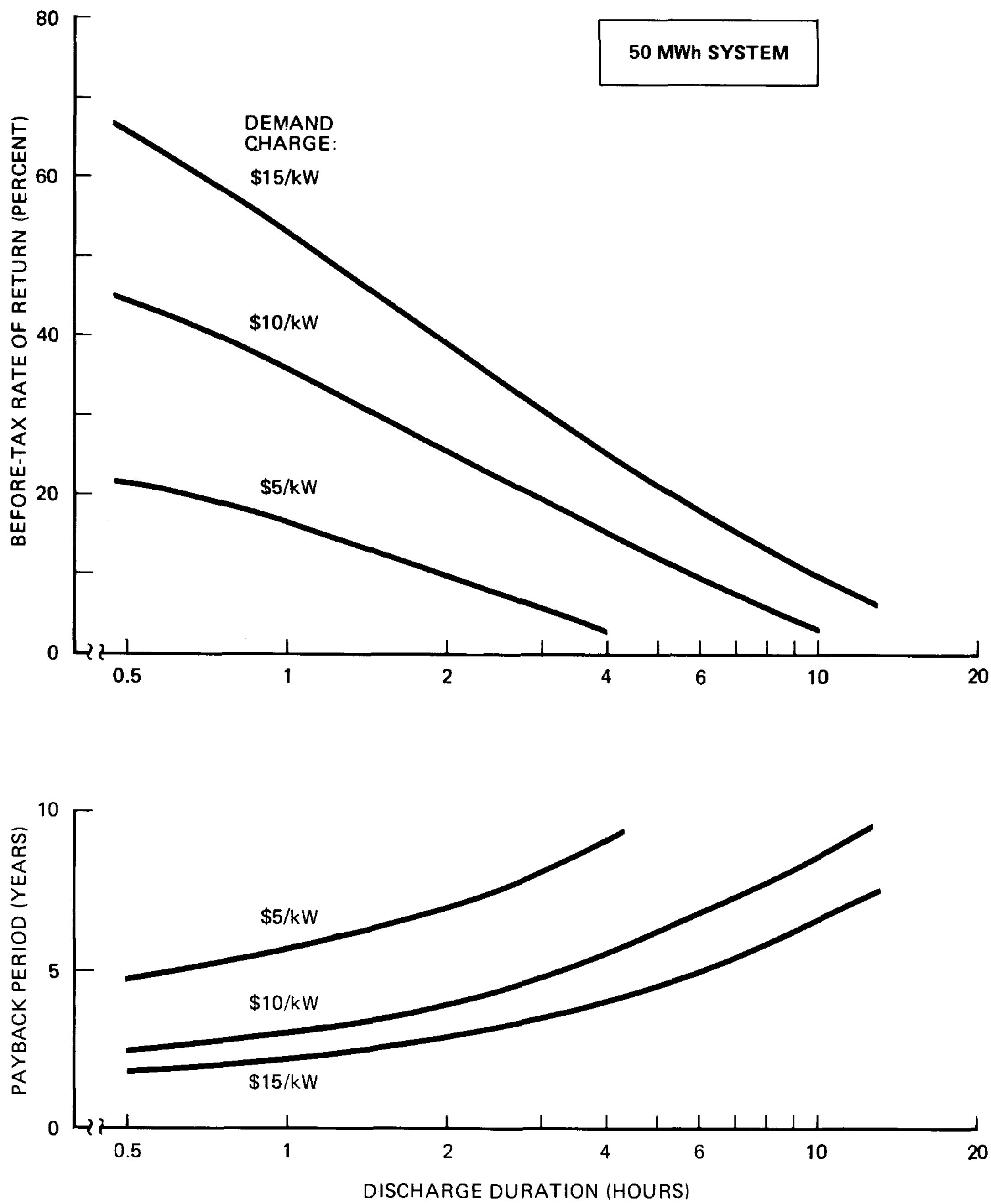

Figure 5-3. Before-Tax Rate of Return and Payback Period for 50 MWh System

The 1 MWh system places greater restrictions on the conditions for viability and the 50 MWh system size increases the allowable latitude in demand charge and discharge duration.

After-Tax Rate-of-Return

An after-tax ROR is computed for the typical situation described earlier. The results for the baseline 10 MWh system are shown in Figure 5-4. Because of the wide variety of possible tax situations, the results shown in Figure 5-4 should be taken as an example of the potential effects of taxation on the before-tax ROR. After-tax payback is not calculated because of potentially misleading results due to the wide variations in return on equity among cases and resulting tax liability. For example, in some cases where return on equity is generally low, the payback period is shortened if the return is lower because of a "tax shelter" effect.

Sensitivity to System Component and O&M Costs

The major system cost components are the battery, converter, and balance-of-plant (BOP). Since cost data for each of these is subject to some variability depending upon actual design, market conditions, and development efforts, the sensitivity of the ROR to these costs was determined for the baseline 10 MWh system. The results are shown in Figures 5-5 through 5-7 for three different discharge durations (note difference in scale). The point of intersection of the dashed line with the solid line in each case represents the cost and ROR of

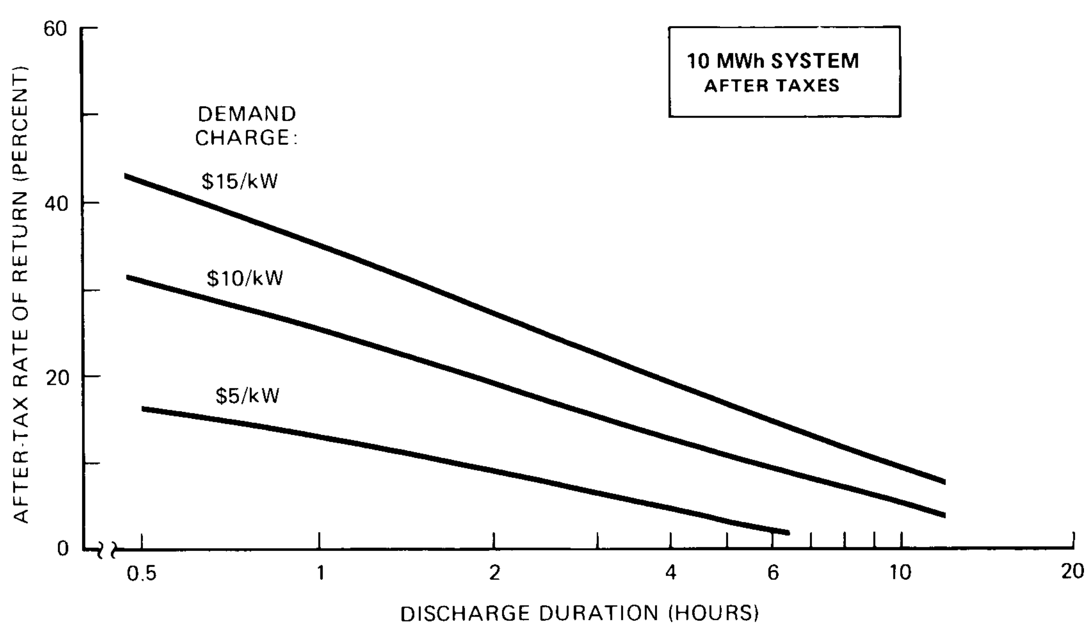

Figure 5-4. After-Tax Rate of Return for 10 MWh System

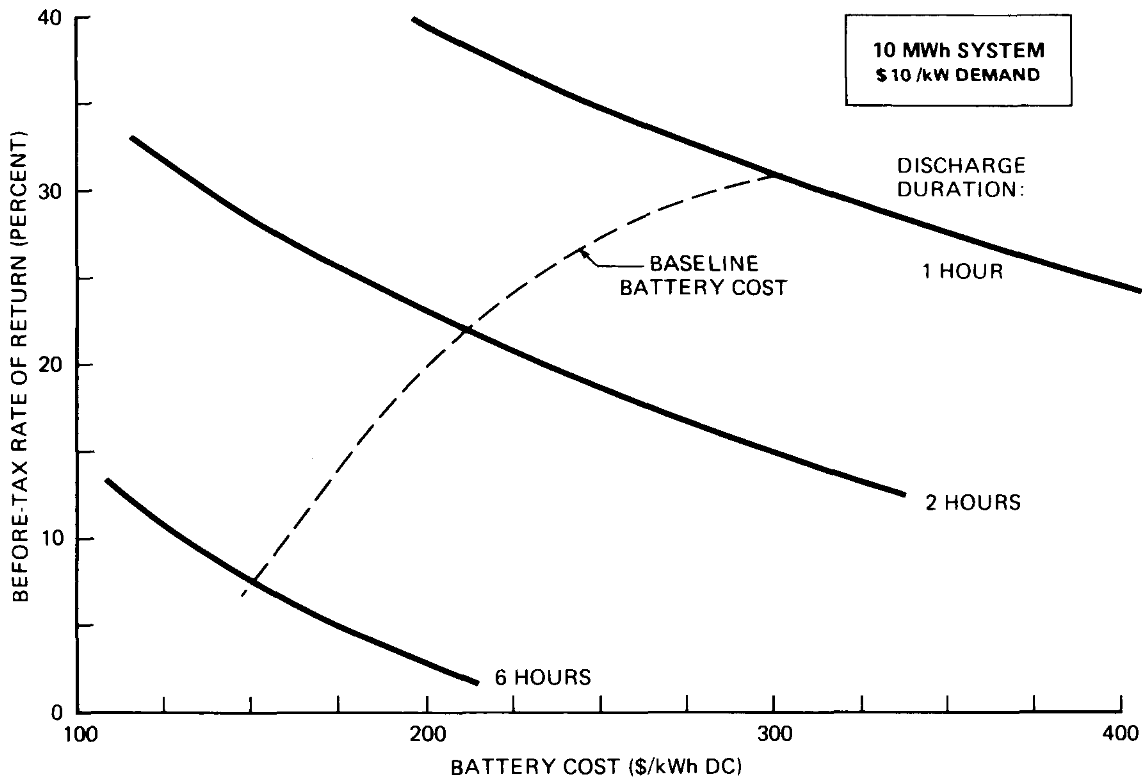

Figure 5-5. Before-Tax Rate of Return versus Battery Cost

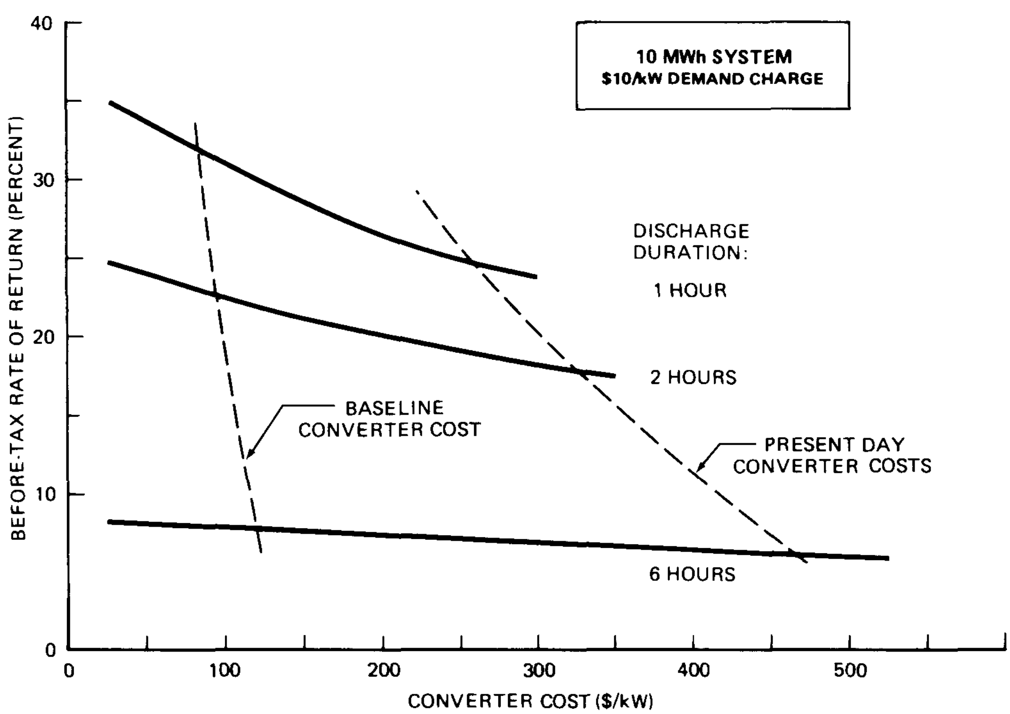

Figure 5-6. Before-Tax Rate of Return versus Converter Cost

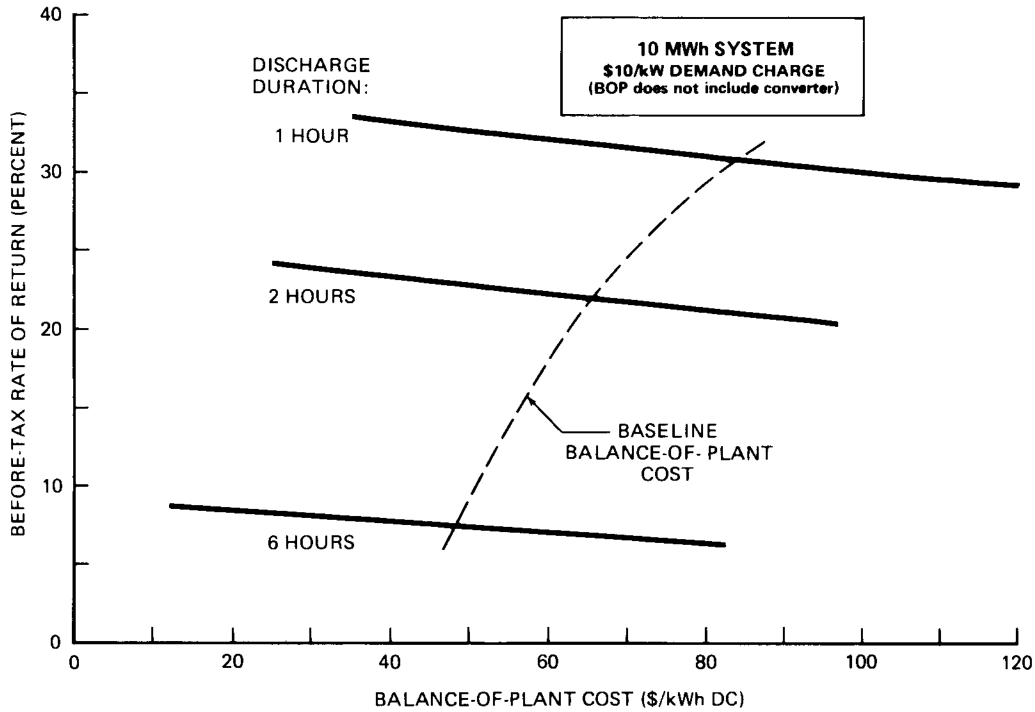

Figure 5-7. Before-Tax Rate of Return versus Balance-of-Plant Cost

the baseline case shown in Figure 5-2. Rates of return are projected for variations in each baseline cost component of ± 25 percent or more. In addition, ROR is shown for present-day converter costs which are substantially greater than the advanced technology converter costs chosen for the baseline application.

As may be seen, battery cost has a significant impact on economic viability with a 20 percent increase in battery cost resulting in a drop of 3 to 4 percentage points in the ROR for the 1-hour case. Converter cost and BOP cost have smaller impacts. Present day converter costs are more than double the baseline cost used. However, for a doubling of converter cost the ROR drops only about 7 percentage points from the base case value of 32 percent for the 1-hour discharge duration. The sensitivity to BOP cost is still less, with a doubling of costs producing about a 3-percentage-point change in the ROR for the 1-hour discharge period. In most cases, however, BOP cost for an actual facility is the least likely of the three subsystems to show significant departures from the baseline cost projections described in Section 3. The results indicate that uncertainty in BOP cost is not a major factor in the economic viability of battery plants.

As mentioned in Section 3, there is considerable variability in the salvage credit expected for load-leveling battery cells. However, a sensitivity analysis has shown the impacts of salvage credit upon ROR to be small. The results are depicted in Figure 5-8, where the range of salvage values investigated (in percent of initial purchase price) is that suggested by manufacturer contacts.

A similar analysis for sensitivity of ROR to maintenance costs was conducted. Results show that for a range of annual maintenance costs from $0.40/kWh to $4.00/kWh there was less than one percentage point change in the ROR for the baseline case. It is concluded that maintenance costs for the systems studied here, though uncertain, are not an important economic factor.

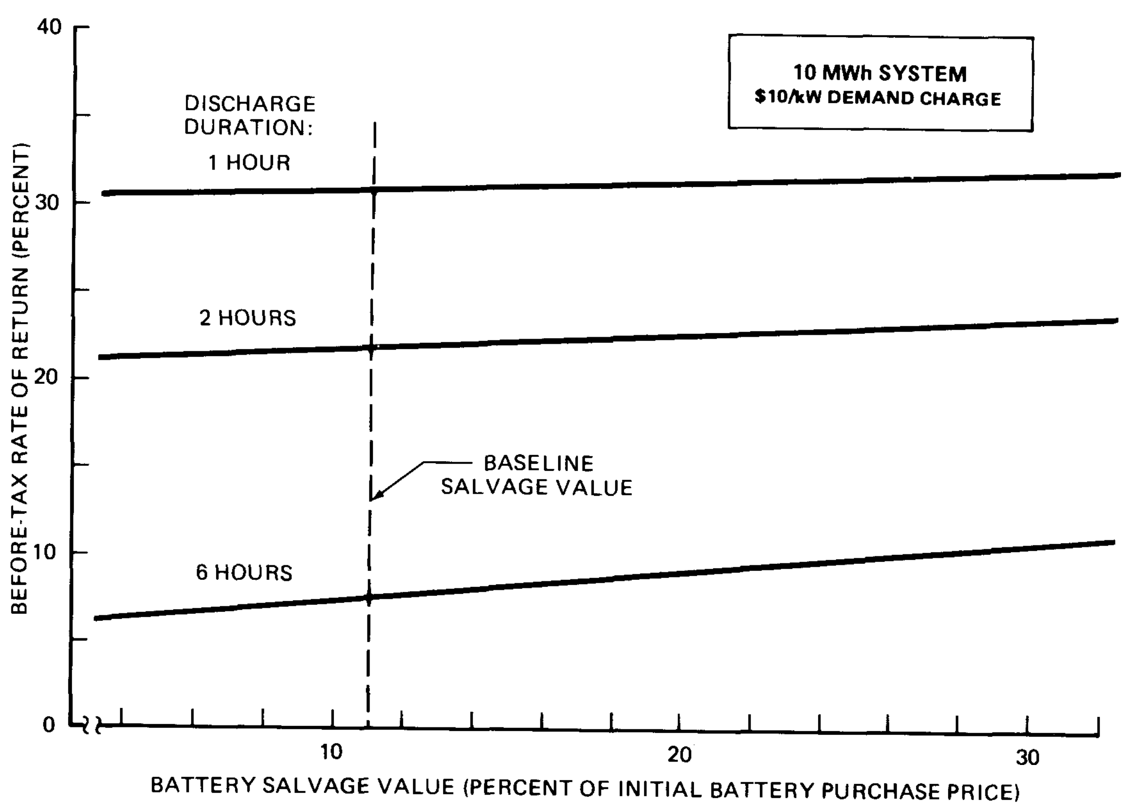

Figure 5-8. Before Tax Rate of Return versus Battery Salvage Value

Sensitivity To System Design Parameters

Battery life and depth-of-discharge, and system efficiency are subject to variability due to cell and/or system design. The effect of these individual parameters on the economic viability of the baseline 10 MWh system was investigated briefly. The results are depicted in Figures 5-9 through 5-11.

The baseline battery life chosen for this study was 1500 cycles at a nominal depth-of-discharge (DOD) of 80 percent. Expected life of these cells may be as much as 3000 cycles. Extended cycle life is the subject of continuing research and development by battery manufacturers. Figure 5-9 suggests that costs associated with extending cycle life beyond about 2000 cycles may not be justifiable for customer-owned load-leveling plants. The reason for this may be traced to the fact that battery life affects system economics through the costs of replacing the battery. These costs, occurring in later years, are discounted by the interest rate (rate of return). At high values of the ROR initial costs predominate over deferred costs making the economic viability less sensitive to small changes in the latter.

Battery life may also be extended by reducing the depth-of-discharge (see Figure 3-1) and installing more cells initially to meet system storage requirements. Figure 5-10 shows the effects of this for three values of DOD (40, 60 and 80 percent). In this case there is a direct trade-off between initial and deferred expenses: a larger investment in the beginning leading to a deferral of expense for battery replacement. Battery replacement is likewise more costly but is deferred in time. Also, because of the greater initial capacity, the effective discharge rate of the battery is smaller. This results in a lower specific cost for the battery and BOP (see Figures 3-4 and 3-10), and a higher efficiency (Figure 3-3). On the other hand, the greater number of cells required causes BOP specific costs (Figure 3-9) and maintenance costs to increase. There is a broad optimum design point which Figure 5-10 shows to be in the neighborhood of 60 percent DOD. The ROR is not strongly affected by this design parameter, for reasons similar to those discussed above for battery life cycle. However, payback period is adversely affected by the larger initial expenditures associated with the shallow depths of discharge. For the 1-hour case payback period increases monotonically from 3.6 years at 80 percent DOD to 4.5 years at 40 percent DOD. For this reason it is concluded that the most economically viable design is the 80 percent DOD system.

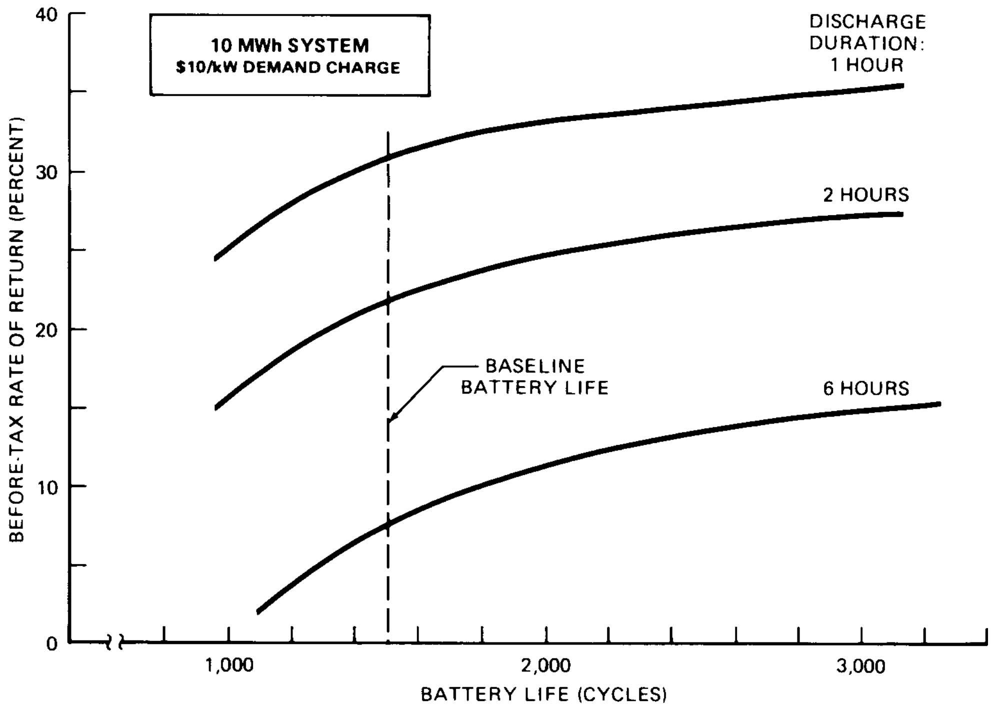

Figure 5-9. Before-Tax Rate of Return versus Battery Cycle Life

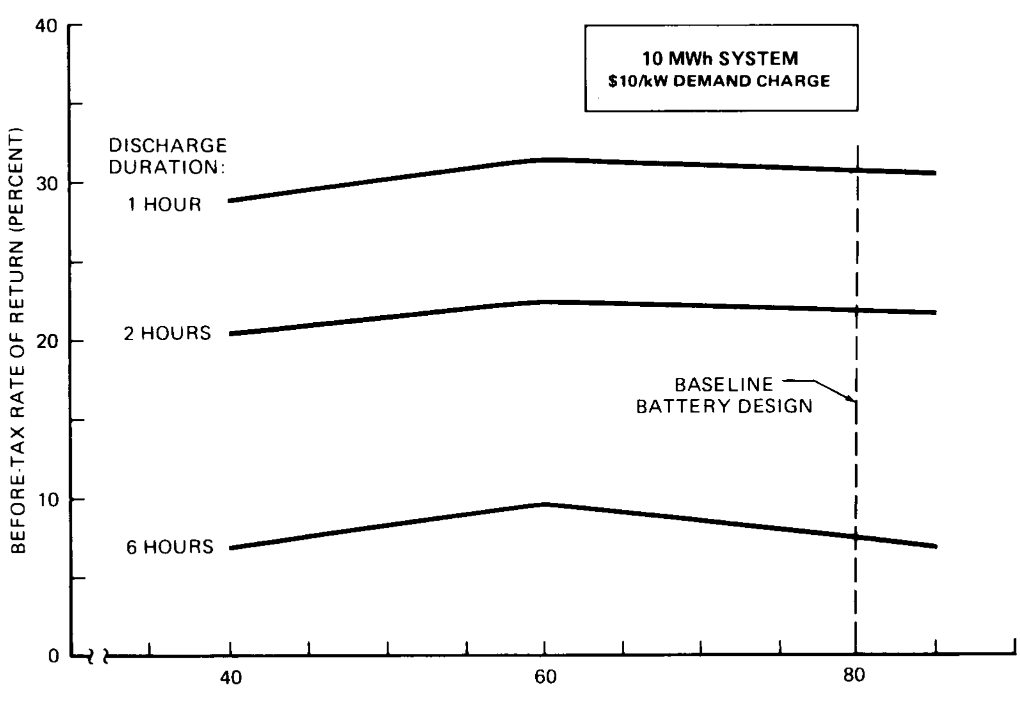

Figure 5-10. Before-Tax Rate of Return versus Battery Depth-of-Discharge

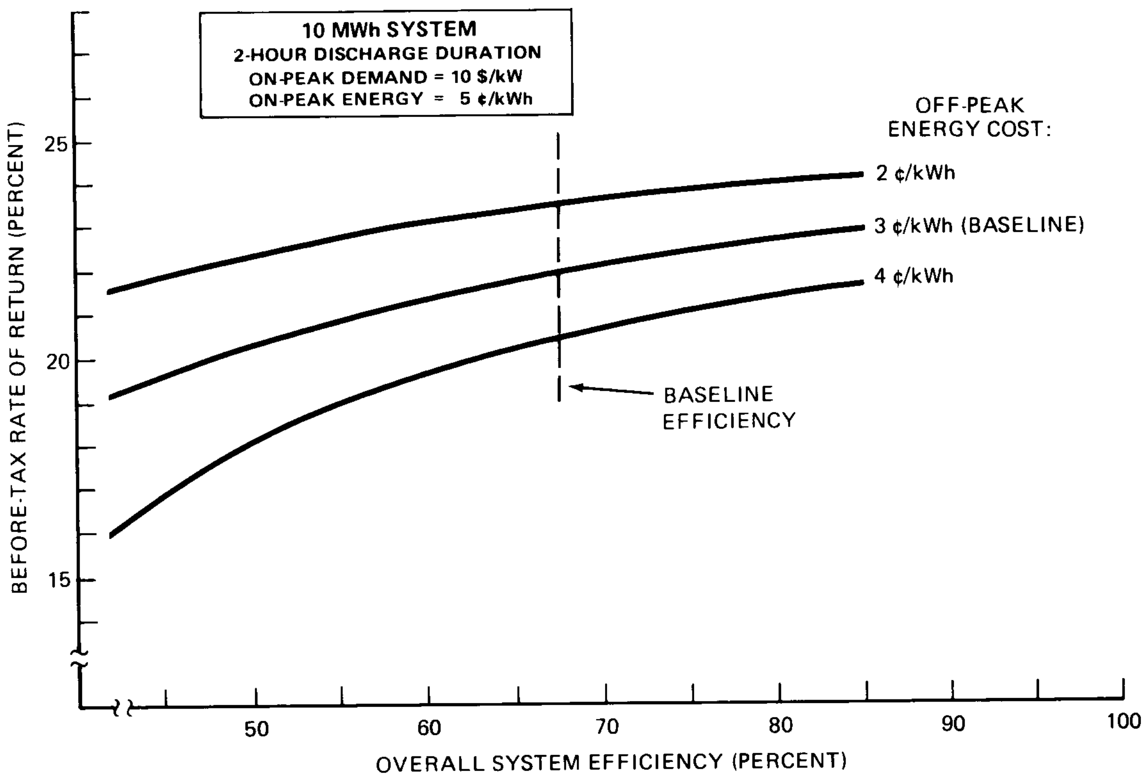

Figure 5-11. Before-Tax Rate of Return versus Overall System Efficiency

As mentioned, overall system efficiency (the product of battery and converter roundtrip efficiencies) is not a critical design factor. This is shown for the baseline 10 MWh system in Figure 5-11, where the vertical scale has been expanded. Since cost savings due to time-of-day energy charges are a function of the ratio of on-peak to off-peak energy cost the ROR is plotted for three values of off-peak energy charge. As seen, a higher ratio of on-peak to off-peak costs improves the economics slightly, but the general shape of the curve remains the same.

Sensitivity to Utility Rates

Rate schedules and the cost of energy in the future are major uncertainties. The baseline analysis assumed that energy costs would escalate at a nominal rate of 2 percent over the rate of inflation (assumed to be 8 percent herein). In order to assess the sensitivity of customer-owned battery system economics to the rate of energy cost escalation, the ROR for the baseline 10 MWh system was computed for additional rates, 0 and 4 percent. The results are shown in Figure 5-12. An increase in ROR of about 2 percentage points for each percentage point increase in energy escalation may be expected for all discharge durations.

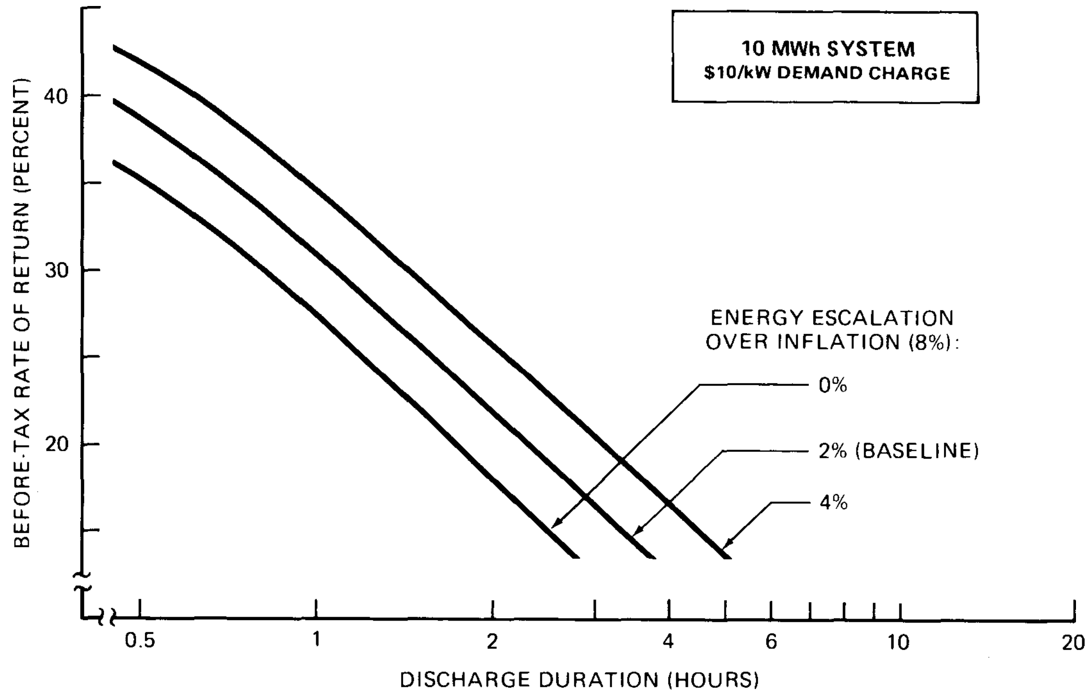

Figure 5-12. Sensivity of Rate of Return to Rate of Energy Cost Escalation

The baseline analysis used time-of-day utility rates with typical values for on-peak and off-peak demand and energy charges. However, as noted in Section 4, there are wide variations among utilities as to actual ratios between on- and off-peak rates. Also, although there is a trend toward time-of-day pricing, many utilities still use traditional rate structures which make no distinction as to the time of day at which the customers peak usage occurs. To investigate the effect of a different choice of on- and off-peak rates, a parametric analysis was performed for the baseline 10 MWh system at the 2-hour discharge duration. Figure 5-13 and 5-14 (note scale change in Figure 5-14) show the results of this analysis for representative on- and off-peak demand and energy charges, respectively. The results show that for both demand and energy components of the utility bill, changes in off-peak costs (for a given on-peak cost) are not a key factor.

Figure 5-15 plots before-tax ROR versus demand charge for the 10 MWh baseline system where the utility uses traditional (non-time-of-day) pricing and the cost of energy is 5¢/kWh. Results for 3 discharge durations are shown and may be compared with results for the basecase analysis in Figure 5-2 where time-of-day pricing was assumed (note scale difference). As can be seen, a customer-owned system with a utility that does not offer time-of-day rates has a slightly poorer ROR. For the 2-hour case at $10/kW demand charge, the ROR is 2 to 3 percentage points less for traditional rate structures.

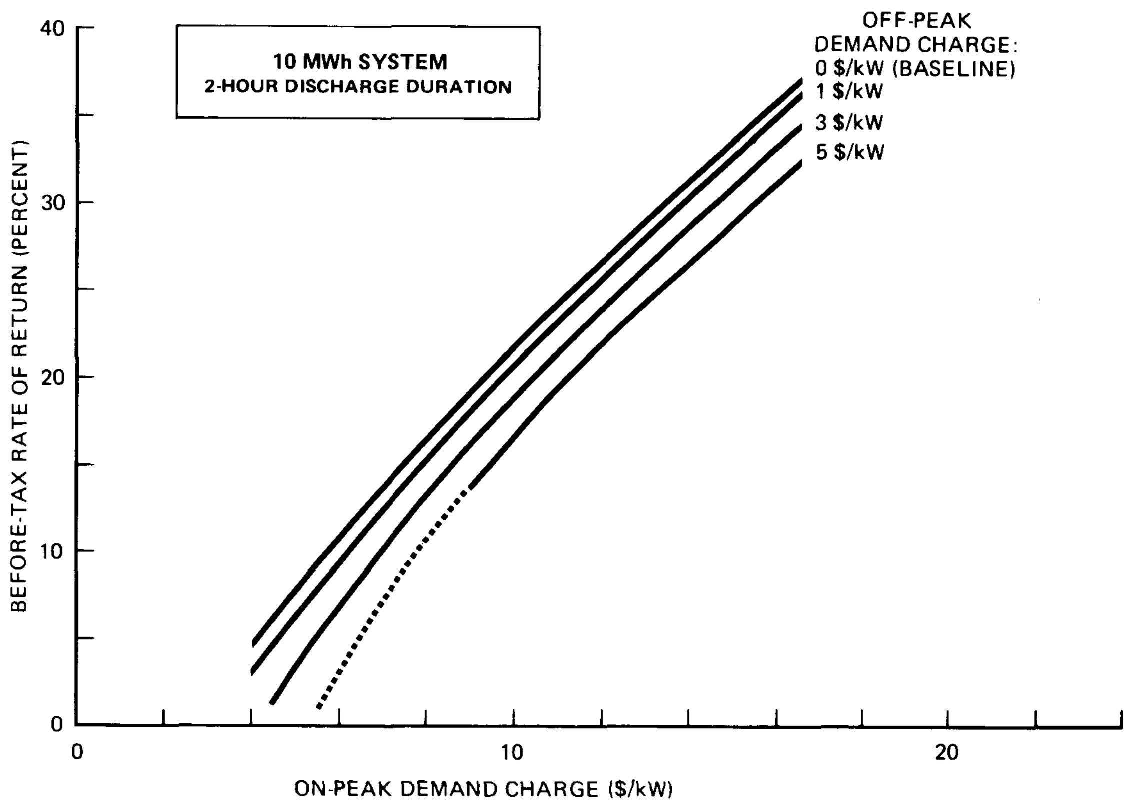

Figure 5-13. Sensitivity of Rate of Return to Off-Peak Demand Charge

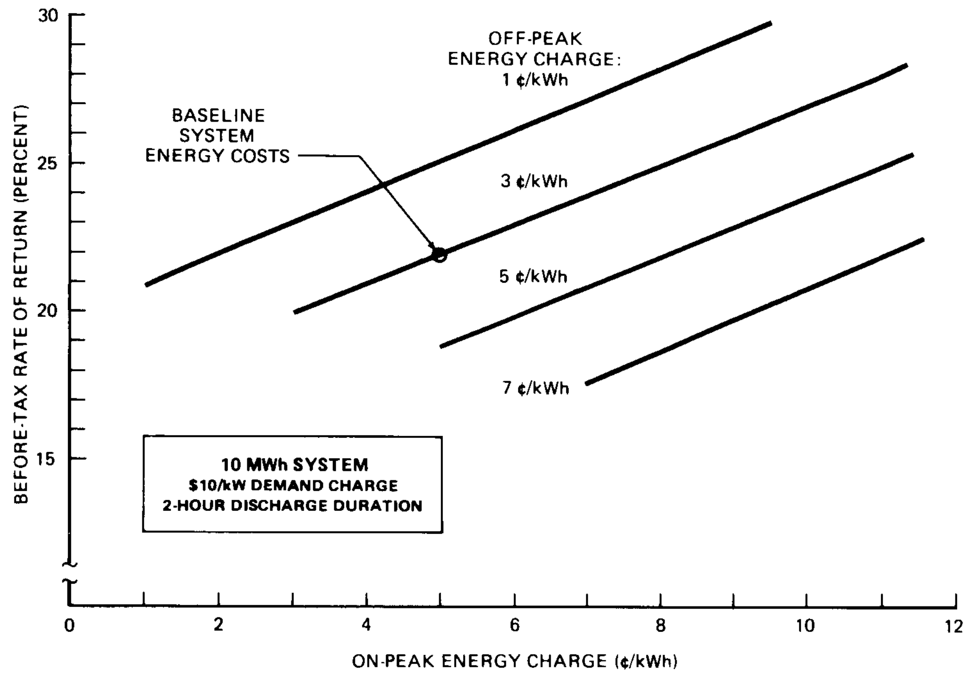

Figure 5-14. Sensitivity of Rate of Return to Off-Peak Energy Cost

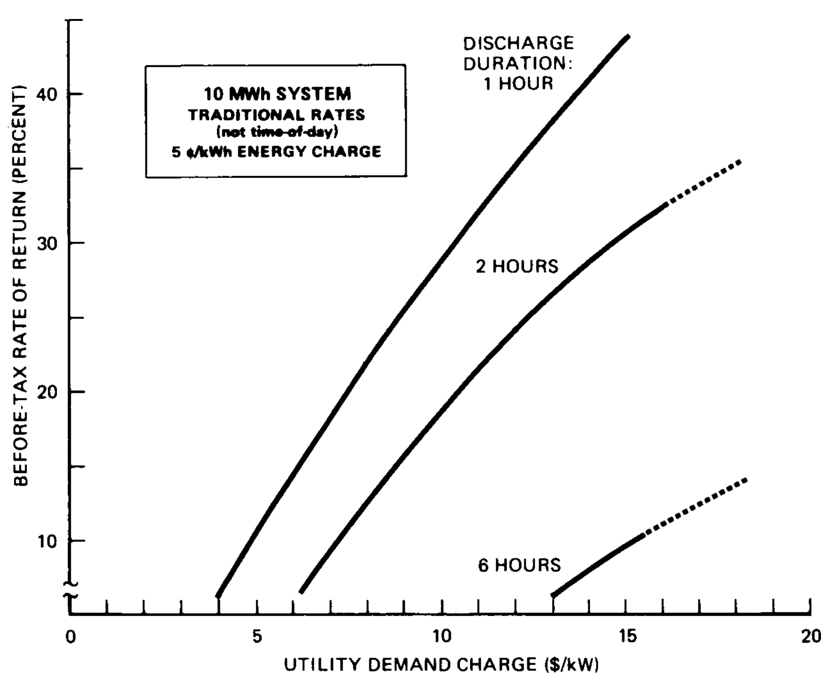

Figure 5-15. Rate of Return for Traditional Rate Structures

Section 6

ANALYSIS OF SPECIFIC APPLICATIONS

An economic analysis of generic application types using idealized load profiles is presented in Section 5. Economic analyses have been performed for five specific applications using actual customer load profiles supplied by utility companies. This section presents the results of these analyses.

SELECTION AND ANALYSIS OF REPRESENTATIVE APPLICATIONS

Using the results of the generic application analysis it is possible establish criteria for initially selecting applications which should prove economically feasible. Promising applications may then be subjected to a detailed economic analysis to quantify their economic potential. Not all initially promising applications will prove to have sufficient benefit after the detailed analysis is performed.

The generic analysis has identified three customer-related criteria which can combine to yield an attractive ROR, listed as follows:

- High demand charge
- Short discharge duration
- Large system size

Since there is an interdependent relationship between these criteria, it is not possible to establish exact bounds for them within which one may find economic viability for all applications. Instead, the parametric curves in Figures 5-1, 5-2, and 5-3 may be used to establish acceptable ranges for any two of the above criteria when the third has been specified.

Actual customer load profiles were obtained from selected utility companies. Because of the time constraints of this study, a relatively small number of customer profiles were analyzed in detail. Using the above procedure, five were chosen as promising. Typical daily profiles for the five are shown in Figures 6-1 through 6-5. Many of the customer profiles reviewed satisfied one of

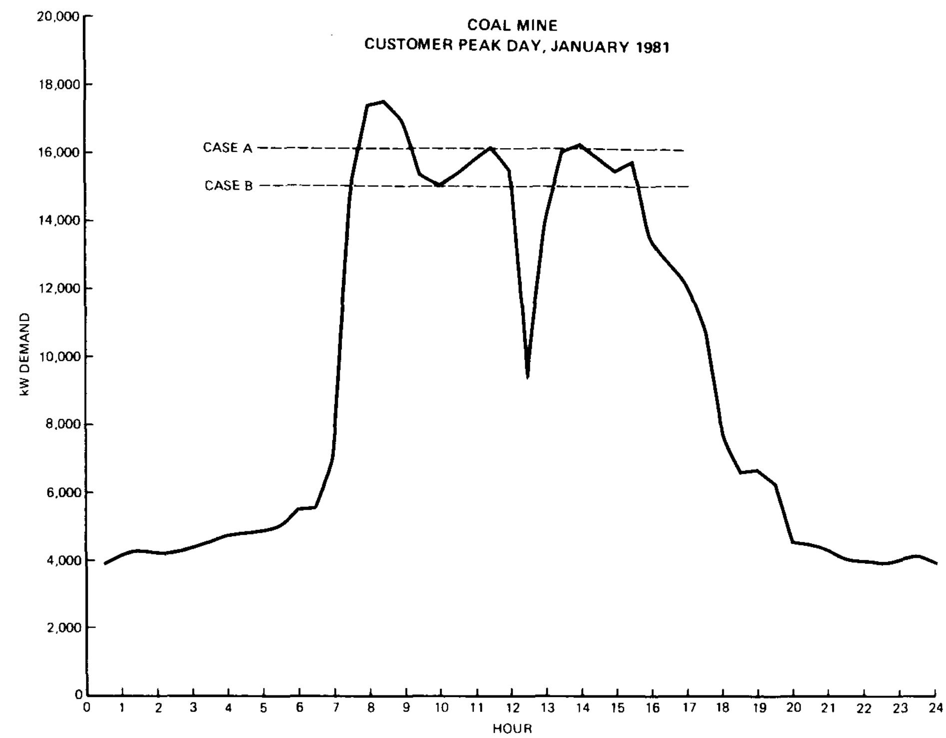

Figure 6-1. Load Profile for Coal Mine

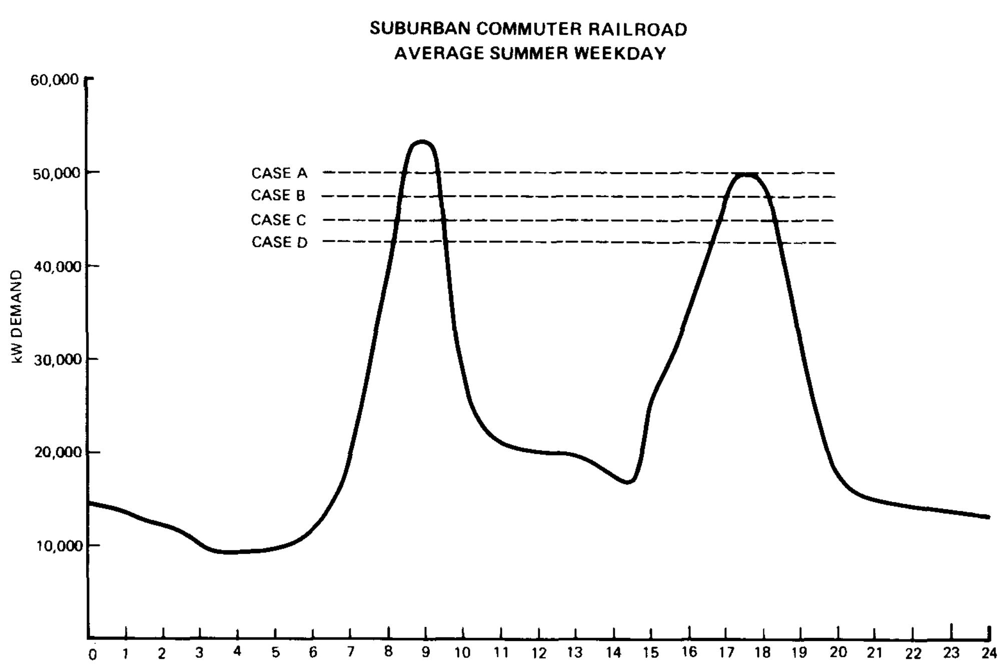

Figure 6-2. Load Profile for Commuter Railroad

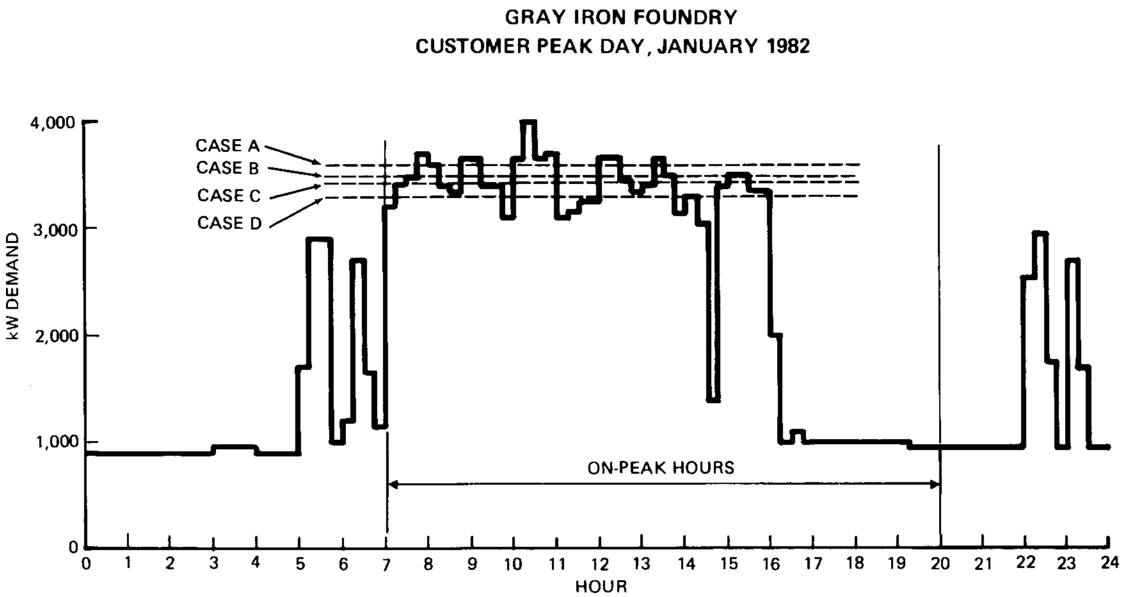

Figure 6-3. Load Profile for Iron Foundry

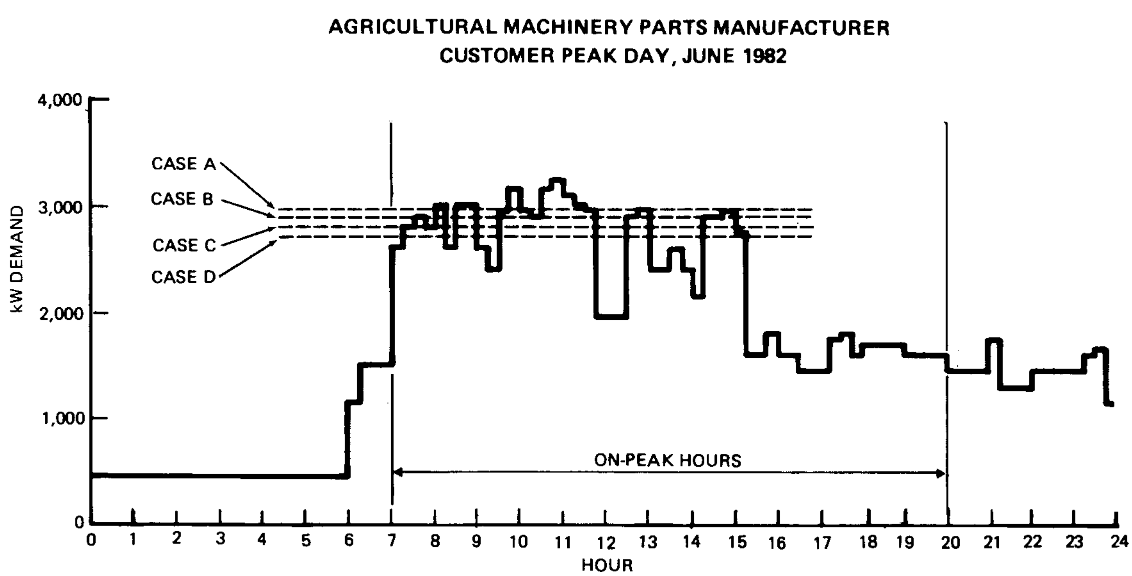

Figure 6-4. Load Profile for Machinery Parts Manufacturer

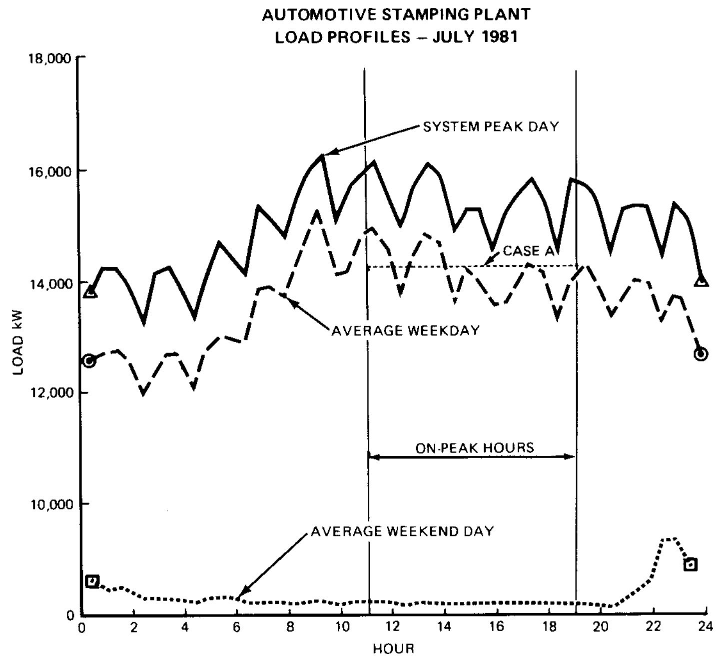

Figure 6-5. Load Profile for Automotive Stamping Plant

the selection criteria but not the others. For example, some with high demand charges were too small (in terms of amount of energy to be displaced) or had peaks too broad to be viable. Others had higher and shorter duration peaks but low or non-existent demand charges. These applications (or similar loads) would be more attractive to the customer if they were located in a utility service area with higher demand charges.

As can be seen in Figures 6-1 through 6-5, the peaks occurring in actual load profiles depart considerably from the ideal constant power peak assumed for the generic economic analysis (see Section 5). As a result, the annual customer savings for these cases cannot be simply calculated (as was done in the Appendix). Instead, the actual bill with and without a battery is computed and the resulting savings divided by the annual delivered energy to obtain annual savings in $/kWh.

Costs for the converter are determined from Figure 3-7 (Advanced Design) using the maximum power level experienced by the battery. Costs for the battery and BOP are determined in the same way as in Section 5. The discharge duration is equal to the delivered energy divided by the average power level. It is assumed that battery performance (kWh delivered versus discharge rate) for widely fluctuating discharge rates may be approximated by assuming the discharge to occur in a series of discrete steps of varying power level and fixed duration (e.g., 15 or 30 minutes). The resulting series of power levels are numerically averaged to obtain the average discharge power level experienced by the battery. Using this method the discharge duration, to be used for determining system efficiency, battery, and BOP cost (see Figures 3-3, 3-4, and 3-10), is equal to the actual time period the battery is discharging (actual discharge duration). It will be seen from the figures just cited that specific system costs (except the converter) decrease with increasing actual discharge duration.

An effective discharge duration, different from the actual discharge duration, may be defined for a given application as the ratio of the delivered energy per cycle (kWh) to the maximum power level (kW) experienced by the battery. The smaller that ratio, the less delivered capacity will be required to shave a given peak from the customer's load.

The effective discharge duration is that period of time required to completely discharge the battery at a constant power level equal to the maximum power level required in the given application. In the Appendix it is shown that demand-related savings ($/kWh) are inversely proportional to the duration of a constant power discharge. With respect of the savings experienced, a battery in an application with a varying discharge power level, may be equated to a battery of the same capacity delivering a constant power discharge over a period of time equal to the effective discharge duration, as defined above. Thus, specific savings decrease according to increases in the effective discharge duration.

Two load-leveling applications with differently shaped peaks of the same height and actual duration of battery discharge may be compared. The one with the shorter effective discharge duration will have the best rate of return. This is because the specific costs will be the same for each application, but the specific savings for the one with the shorter effective discharge duration will be greater.

In all actual load-leveling applications, the effective discharge duration will be less than the actual discharge duration. The amount by which it is less is a measure of the improvement in the expected economic benefit in actual load-leveling applications compared to the predictions of the generic analysis of Section 5. The concept of the effective discharge duration is useful in interpreting the results of the economic analysis of the specific customer load profiles presented in the following section.

ANALYSIS RESULTS

Several cases, using different amounts of storage, were analyzed for each of the customer load profiles presented in Figures 6-1 through 6-5. The horizontal dashed lines in the figures show the power level to which the customer's peak would be reduced by the installation of battery storage. Battery capacity was determined by the area bounded by the profile curve and the horizontal line for each case.

Two battery sizes were postulated for the coal mine (Figure 6-1) corresponding to shaving 1400 kW and 2600 kW, respectively, from the customer's peak. The utility rate schedule for the coal mine has traditional flat rates. The demand charge is $13.24/kW and the energy charge is $0.028/kWh.

Four cases were postulated for the commuter railroad corresponding to shaving 3300 kW, 5800 kW, 8300 kW and 10.8 MW, respectively, from the customer's peak (Figure 6-2). The utility rate schedule for this customer also employs traditional flat rates. The demand charge is $16.24/kW and the energy charge is $0.031/kWh.

Four cases for the iron foundry were postulated in which the customer's peak was reduced by 400 kW, 500 kW, 550 kW and 700 kW, respectively (Figure 6-3). The utility for this customer offers optional time-of-day pricing. The on-peak period is 7 am to 8 pm throughout the year. Although this customer is currently on a special rate schedule that would not result in economic viability for a load-leveling battery, the present analysis assumed that the utility's standard time-of-day rates apply. These are $10.37/kW and $0.027/kWh on-peak and $10.37/kW and $0.023/kWh off-peak. Since demand charges vary seasonally for this utility, a weighted annual average is used. Billable demand during the off-peak period is calculated as one-third of the amount by which the highest off-peak demand exceeds the highest on-peak demand.

Four cases were also analyzed for the agricultural machinery parts manufacturer. The customer's peak was reduced by 300 kW, 350 kW, 450 kW, and 550 kW, respectively (Figure 6-4). Optional time-of-day rates were used since with a battery system there is economic benefit in doing so. The rates are $9.93/kW and $0.028/kWh on-peak, and $9.93/kW and $0.024/kWh off-peak. Demand charges are a weighted annual average of seasonal rates. The on-peak period and rules for calculating demand for this application are the same as for the iron foundry.

One case for the stamping plant (Figure 6-5) was analyzed using a delivered capacity of 1650 kWh to shave 800 kW from the load peak. The utility rate schedule for the stamping plant has time-of-day pricing with an on-peak period from 11 am to 7 pm. The on-peak demand charge is $10.20/kW. The off-peak demand charge is zero. The on- and off-peak energy charges are $0.037/kWh and $0.03/kWh, respectively. In this application, it is economically attractive for the customer to shave only those peaks occurring during the on-peak period.

The analysis results for the customer profiles are shown in Table 6-1. Several cases show a relatively high before-tax rate of return and short payback period and are judged economically feasible.

For three of the applications (coal mine, railroad, and machinery parts manufacturer) the ROR improves slightly as battery system size increases (corresponding to an increasing amount of power shaved and consequent longer discharge time). This appears to be contrary to what has been suggested in the discussion of the generic application analysis (Section 5) where a longer discharge duration results in a decrease in the rate of return (e.g., Figure 5-2). The conflict may be resolved by observing that the effective discharge duration is different (and considerably less) than the actual discharge duration for the chosen customer load profiles. In the generic analysis, the effective discharge duration was assumed equal to the actual discharge duration (corresponding to a constant power discharge). As mentioned, specific savings and costs decrease for an increase in the effective and actual discharge durations, respectively. Clearly, the behavior of the ROR (i.e., increase or decrease) as effective and actual discharge durations increase depends upon which is increasing faster.

Table 6-1

ANALYSIS RESULTS FOR ACTUAL CUSTOMER LOAD PROFILES AND MID-1982 UTILITY RATES

Application	Demand Charge, $/kW	Battery Capacity, kWh	Discharge Duration, Hours Actual[1]	Discharge Duration, Hours Effective[2]	Before-Tax ROR, Percent	Payback Period, Years
Coal Mine						
Case A	13.24	1,700	1.5	1.2	31	3.8
Case B	13.24	6,950	6.5	2.7	34	3.5
Railroad						
Case A	16.24	1,900	0.8	0.6	53	2.3
Case B	16.24	5,600	2.0	1.0	58	2.1
Case C	16.24	11,000	2.5	1.3	53	2.2
Case D	16.24	17,900	3.0	1.7	49	2.4
Foundry						
Case A	10.37	240	2.5	0.6	31	4.1
Case B	10.37	510	2.8	1.0	26	4.6
Case C	10.37	700	3.8	1.3	25	4.7
Case D	10.37	1,500	6.5	2.1	22	5.1
Machinery Parts Manufacturer						
Case A	9.93	265	1.8	0.9	21	5.6
Case B	9.93	425	3.3	1.2	22	5.4
Case C	9.93	875	4.5	1.9	18	6.0
Case D	9.93	1,390	5.3	2.5	15	6.4
Stamping Plant						
Case A	10.20	1,605	3.0	2.1	22	4.7

(1) Actual period of time over which battery is discharging.
(2) Defined as the ratio of delivered battery capacity (kWh) to maximum discharge power level (kW).

Since the specific savings decrease linearly with effective discharge duration but specific costs decrease exponentially with increasing actual discharge duration (e.g., Figure 3-4), an optimum battery system size may be expected for some customer profiles. For the optimum system size the ROR is a maxiumum. This is shown to be true for the railroad and machinery parts manufacturer in Table 6-1. In each of these applications the system denoted as Case B yields the highest ROR. Larger and smaller systems result in lower values of the ROR. The same effect may be true of the other applications in Table 6-1. However, analysis of the additional cases required to determine the maximum ROR, was beyond the scope of the present study.

The reader is cautioned about attaching undue significance to the apparent relationship between system size and the maximum ROR achievable in a specific application. It is possible that an optimum system size does not exist in all applications. Moreover, the determination of the optimum system size depends on the specific shape of the load profile. In the foregoing analysis, the profile shapes (Figures 6-1 to 6-5) were assumed to be the same for each month of the year and for each year of the project life. For the applications chosen this was a generally accurate assumption. A more detailed analysis would have to account for the small (or large) variations in profile shape from month to month which would certainly occur in actual customer applications. These would result in varying savings from month to month in an existing facility and hence would impact the actual ROR. Thus, the values of the ROR shown in Table 6-1 must be interpreted as average values over the project life assuming that the profiles on which they are based are average representations of the customer's actual pattern of electricity use.

In all of the cases analyzed, the ROR achieved is better than if the peaks had been square shaped for the reasons already mentioned. This may be verified by using the figures in Section 5.

CONCLUSIONS

Based on the foregoing analyses of actual customer load profiles, the following conclusions may be drawn:

- Certain customer applications exist within some utility service areas for which customer-owned load-leveling plants are economically attractive.

- The economic benefit to be obtained from a battery plant depends upon the shape of the peak shaved as well as the actual duration of discharge.

- Peaks with non-constant demand (rounded or needle-shaped) during the discharge period have a higher rate of return than those with a (nearly) constant demand. Thus, for a given required ROR, the maximum attractive (actual) discharge duration will be greater than indicated by the results of Section 5.

Section 7

CONCLUSIONS AND RECOMMENDATIONS

An investigation of customer-side-of-the-meter battery energy storage has been conducted. This section presents conclusions and recommendations derived from that effort.

CONCLUSIONS

The following conclusions are based on an analysis of the results of the study:

- Battery, converter and ancillary equipment technologies make construction of customer-side-of-the-meter battery energy storage facilities technically feasible at present.

- Economic feasibility is indicated for several applications. Key load-related techno-economic factors are:

  - On-peak demand charge

  - Discharge duration and load profile shape

  - Battery and converter cost

  - System size (i.e., storage capacity)

- For utilities which use demand metering, a relatively high on-peak demand charge is a necessary but not sufficient condition for achieving economic viability for customer-side-of-the-meter load-leveling. A demand charge of $5/kW may be described as the lower limit of attractive rates. However, demand charges of substantially less than $10/kW will not prove favorable in most cases. Several utility companies currently employ demand charges in the range of $10/kW to $17/kW.

- Utility rate structures and the cost of energy in the future are major uncertainties. While on-peak demand charge is a critical factor, off-peak demand and energy charges are of secondary importance to economic viability. The rate of energy cost escalation is also of secondary importance within the limits studied (0 to 4 percent over inflation).

- Time-of-day (TOD) pricing by electric utilities improves the rate of return that a customer may expect from installing a battery plant. However, TOD pricing is not required for customer-side storage viability.

- For a 10 MWh system size, economic viability may be achieved for applications having a constant discharge of less than 3 hours duration depending on the demand charge and the desired ROR. For larger systems with sufficiently high demand charges, the maximum attractive discharge duration may be greater than 3 hours.

- Many actual customer profiles have peaks with a varying demand during the discharge period. The economic benefit to be obtained from leveling varying demand peaks is better than the economic benefit from leveling peaks with a constant power level.

- A wide variation in battery costs may be expected due to quantity discounts, design differences and the price of lead. Battery cost has a significant impact on the economic viability of customer-owned battery load-leveling plants.

- Converter costs may vary due to factors such as availability of already designed equipment, advanced technology and quantity purchases. However, the impact of converter cost on economic viability is not so great as battery cost. (The lower costs of advanced converters were used as the baseline for the economic analyses presented.)

- Costs for the balance-of-plant depend upon both system storage capacity (kWh) and discharge duration. Some variability in costs is expected due to differences in lead-acid cell design, system voltage, and local code requirements. The results indicate that ±40 percent variation in BOP costs would not have a major impact on battery plant economic viability.

- While operating and maintenance costs for customer-owned battery plants (including battery watering and equalization) are uncertain, they do not constitute an important economic factor.

- Battery cycle life may have an important effect on economic viability for lives less than 1500 cycles. However, there is a substantially reduced incentive to improve cycle life beyond 2000 cycles. Currently available batteries are warranted for 1500 to 2000 cycles in the traditional applications for which they were designed.

- System economic viability is only slightly affected by depth-of-discharge (DOD) over the 40 to 80 percent DOD range considered. A broad maximum occurs at 60 percent. The ROR decreases less than one percentage point in going to 80 percent DOD for discharging times of two hours or less.

- While batteries are net consumers of energy, overall system efficiency is not a critical factor in system economics. The impact of system efficiency (typically 65 to 72 percent in this study) is coupled to the off-peak energy charge.

RECOMMENDATIONS

The present study has identified key parameters, and defined a range of generic characteristics needed for economically feasible customer-side-of-the-meter battery energy storage systems. It is recommended that a follow-on effort be conducted to foster the construction of systems that are mutually beneficial for both the customer and utility company. Among the goals of that effort would be the dissemination of information to utilities on a potential option for reducing system peaks and improving their load factor. The extent to which this option impacts the utility industry will depend on its perception and acceptance by utilities and their customers, as well as on demonstrably favorable economics.

Specific items recommended for a follow-on effort under the direction of EPRI include:

- Further contact with interested utility companies to:
  - present the results of the study
  - elicit their comments and guidance
  - identify specific, potential customers
  - aid in establishing contact with identified customers
  - insofar as possible, estimate whether economically favorable rate schedules are likely to remain in effect during the construction and payback period for identified applications.

- Contact with one or more potential customers to:
  - present the results of the study
  - ascertain their interest in constructing, owning, and operating a battery energy storage facility
  - obtain application-specific data from interested customers
- Performance of application-specific conceptual designs that include:
  - application/customer-specific requirements
  - investigation of the impact of, and schedules for, specially designed cells, sealed cells, and improved-state-of-the-art (ISOA) cells
  - selection and specification of a battery cell
  - investigation of the development and/or procurement of a power conditioning subsystem
  - development of a conceptual balance of plant design
  - investigation of energy-related tax credits and, if warranted, third party financing
  - customer-specific cost estimates and economic analysis
  - integration of the battery and test data into the BEST facility program.
- Dissemination of the results of the above-described efforts via a report, meetings, or other means and, if warranted, proceeding toward the recommendation for the detail engineering, procurement and construction of customer-side-of-the-meter battery energy storage systems.
- Extension of the study to advanced batteries with characteristics different from lead-acid batteries.

Section 8

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Appendix A

ECONOMIC ANALYSIS
RATE OF RETURN

The internal rate of return is a widely accepted index of profitability. It is defined as the interest rate that reduces the net present value (NPV) amount of a series of costs and savings to zero. Thus,

$$NPV_{total\ savings} = NPV_{total\ costs}$$

In this section, savings and costs before and after taxes are discussed, as well as the computerized method used to calculate rate of return. A table of symbols used in the following discussion appears at the end of this section

SAVINGS

The potential savings that might be brought about by the customer use of a battery energy storage system are reduction in demand charges plus the effect of reduced (or increased) energy charges. Annual demand-related savings per kWh of delivered battery capacity (S_1) depend on peak (DONPK, \$/kW) and off-peak (DOFPK, \$/kW) utility monthly demand charges, the ratio of charge to discharge power (RATIO), and the hours of operation of the battery. The hours of operation is dependent on the annual frequency of discharge (JCYCLE, cycles or days) and length of discharge (DISPRD, hours per cycle or day). That is,

$$S_1 = (\text{DONPK-RATIO} \times \text{DOFPK}) / [\text{DISPRD} \times (\text{JCYCLE}/12)]$$

In this formulation, the battery is assumed to be discharged at a constant power (i.e., the customer's peak is square-shaped). It should be noted that peak and off-peak charges (demand and energy) refer to the application rather than the utility system. For example, the peak charge for a night-peaking application might correspond to the off-peak system charge.

Annual energy-related savings per kWh of delivered battery capacity (S_2) depend on peak (EONPK, \$/kWh) and off-peak (EOFPK, \$/kWh) energy charges for the specific battery application and the roundtrip system efficiency (ENEFF)

$$S_2 = \text{EONPK} - \text{EOFPK/ENEFF}$$

The system efficiency ENEFF is the product of the round trip battery and converter efficiencies. The factor S_2 may be positive (savings) or negative (cost) depending on the peak and off-peak energy charges for the application and the system efficiency.

The annual energy delivered by the battery is a function of battery capacity (DELCAP, kWh/cycle) and frequency of discharge. The annual energy savings (ESAVE, $) is a function of savings per kWh and the annual energy delivered

$$ESAVE = (S_1 + S_2) \times DELCAP \times JCYCLE$$

and

$$NPV_{savings} = ESAVE \left[\frac{1 + g_e}{1 + d}\right]^{20}$$

where g_e = escalation rate for electricity costs
d = discount rate.

COSTS BEFORE TAX

Costs can be expressed in terms of three cost components: fixed ($), power-related ($/kW), and energy-related ($/kWh) costs. A total life-cycle cost for each application is also developed by combining these three cost components as follows:

$$NPV_{\substack{\text{total costs}\\ \text{before tax}}} = NPV_{fixed} + NPV_{\substack{\text{power-}\\ \text{related}}} \times (\text{Power Rating})$$

$$+ NPV_{\substack{\text{energy-}\\ \text{related}}} \times (\text{Energy Rating})$$

In this analysis, life-cycle costs include the following:

- Initial capital costs
- Periodic replacement costs
- Salvage value
- Value of unused battery life at the end of the project
- Maintenance costs
- Cost of energy losses due to battery operation

The before-tax net present value of the three components of each of these costs is developed using simple discounted cash flow formulas. The basecase analysis is based on the following assumptions:

- Capital and maintenance cost escalation rates are equal to general escalation, assumed to be 8 percent.
- Energy costs escalate at a real rate of 2 percent, i.e., 2 percent above general escalation.
- The additional cost of the electric energy due to battery inefficiency and auxiliary power consumption is the off-peak energy charge (30 mills/kWh).

The formulas described below were used to convert cash flows over the project life to net present values expressed in mid-1982 dollars. For all cases, the analysis assumed a 20-year project life with operation beginning in the middle of 1982.

The NPV of initial capital costs is the same as the capital costs (NPV_{CC} = CC) since it is assumed that construction is completed within one year, and is completed by mid-1982. The middle of 1982 is also the cost and net present value base year. Thus, escalation factors or discount factors do not apply to initial capital costs.

Battery types having service lives less than 20 years require replacement during the project life. The net replacement cost is equal to the replacement cost (REP) less the salvage value (SAL) of the old battery. The net present value of these costs, assuming k replacements and a battery life of m years is:

$$NPV_{rep} = \left[\frac{1+g_c}{1+d}\right]^{m} (REP-SAL) + \left[\frac{1+g_c}{1+d}\right]^{2m} (REP-SAL) + \cdots + \left[\frac{1+g_c}{1+d}\right]^{km} (REP-SAL)$$

where g_c = general escalation rate for capital
d = discount rate.

This summation can be expressed in closed form as:

$$NPV_{rep} = \left[\frac{1+g_c}{1+d}\right]^{m} \left[\frac{\left[\frac{1+g_c}{1+d}\right]^{km} - 1}{\left[\frac{1+g_c}{1+d}\right]^{m} - 1}\right] (REP-SAL) \qquad \text{if } g_c \neq d$$

$$NPV_{rep} = k\ (REP-SAL) \qquad \text{if } g_c = d$$

The number of replacements, k, needed over a 20-year period can be expressed as:

$$k = \text{integer value of } \frac{(20-e)}{m}$$

where e = arbitrary small value that ensures the calculation will not include a battery replacement coincident with the end of the project.

The last battery installed may have remaining useful life at the end of the project. A credit for this unused battery life is included in the calculations by assuming straight-line economic depreciation. This implies that the value of a battery declines linearly over its life to a value equal to the salvage value. The value attributable to unused life is:

$$UL = \left[(FF \times REP)-SAL\right]\left[\frac{\text{Battery Remaining Life}}{m}\right]$$

where m = battery life
FF = the fraction of replacement cost that is depreciable.

The battery remaining life can be expressed as the difference between the combined lives of all batteries installed (1 original plus k replacements) and the project life of 20 years:

$$\text{Battery Remaining Life} = (k + 1)m - 20$$

The total value of the battery at the project end includes the value of unused life and the battery salvage value. The net present value of the battery at the end of year 20 is then:

$$NPV_{ul} = (UL+SAL)\left[\frac{1+g_c}{1+d}\right]^{20}$$

All maintenance that is performed throughout the year and repeated each year is called frequent maintenance. Cost data for frequent maintenance is presented as an annual cost, FM, expressed in mid-1982 dollars. The net present value of frequent maintenance costs can be represented by

$$NPV_{fm} = \left[\frac{1+g_m}{1+d}\right] FM + \left[\frac{1+g_m}{1+d}\right]^2 FM + \cdots + \left[\frac{1+g_m}{1+d}\right]^{20} FM$$

where g_m = escalation rate for maintenance.

An equivalent, closed-form representation is:

$$NPV_{fm} = \left[\frac{1+g_m}{g_m-d}\right] \left[\left[\frac{1+g_m}{1+d}\right]^{20} -1\right] FM \qquad \text{if } g_m \neq d$$

$$NPV_{fm} = 20\ (FM) \qquad \text{if } g_m = d$$

Infrequent maintenance refers to any maintenance costs incurred at intervals exceeding one year. The net present value of infrequent maintenance is calculated by explicitly calculating and summing net present values of each infrequent maintenance cost. For example, the NPV of a cost (IM_j), incurred in year j is

$$NPV_{IM_j} = \left[\frac{1+g_m}{1+d}\right]^j IM_j$$

Energy losses due to battery operation are primarily due to auxiliary equipment such as ventilation fans and to periodic battery equalization. The annual cost of auxiliary energy consumption depends on the energy consumption per cycle and the cycling frequency:

(Annual Energy Cost) = (AUXLOS) (JCYCLE) (EOFPK)

where AUXLOS = kWh/cycle consumed by auxiliary equipment and battery equalization.

The calculation of the net present value of annual energy cost is similar to the frequent maintenance calculation:

$$NPV_{losses} = \left[\frac{1+g_e}{g_e-d}\right]\left[\left[\frac{1+g_e}{1+d}\right]^{20} -1\right]\left[\text{Annual Energy Cost}\right] \quad \text{if } g_e \neq d$$

$$NPV_{losses} = 20\ (\text{Annual Energy Cost}) \qquad \text{if } g_e = d$$

COSTS AFTER TAX

The savings resulting from the use of a battery energy storage system will result in income, some of which may be taxable depending on tax status of the organization owning the system and any tax regulations that may apply to the specific application of the system.

The factors which affect the amount of tax are:

- Taxable revenue
- Assumed effective tax rate (48 percent)
- Tax depreciation method (5-year ACRS)
- Investment tax credits (10 percent)
- Plant life (20 years)
- Debt-equity ratio (0.4)
- Assumed debt rate (10 percent)

In any given year:

$$\text{Income tax} = \frac{\text{TAX}}{1 - \text{TAX}}\ [\text{Equity Return + Book Depreciation - Tax Depreciation}] - \frac{1}{1 - \text{TAX}}\ [\text{Investment Tax Credit}]$$

where TAX = tax rate.

Equity return is the product of the return on equity rate (ROE) and the undepreciated capital investment. Calculated ROR, debt-equity ratio and assumed debt rate determine ROE.

Thus, for year i:

$$R_i = CAP\ (1 - \frac{(i-1)}{20})\ (ROE)\ (1-DERAT)$$

where

R_i = equity return before taxes in year i

CAP = the equivalent capital investment (discounted sum of initial investment, replacements and salvage)

DERAT = amount of debt in firm divided by debt plus equity (accounts for debt interest deductions from income tax)

Book depreciation is straight line. Tax depreciation can be the sum of the years' digits (SOYD) or 5-year accelerated cost recovery system (ACRS). DEP_i is the tax depreciation in year i of the equivalent capital investment (CAP) and XITC is the investment tax credit rate. Then,

$$NPV_{taxes} = \left[\frac{TAX}{1-TAX} \sum_{i=1}^{20} (R_i + \frac{CAP}{20} - DEP_i)\right] - \frac{1}{1-TAX}\ (CAP \times XITC)$$

and

$$NPV_{total\ cost} = NPV_{\substack{total\ costs \\ before\ taxes}} - NPV_{taxes}$$

Book depreciation (CAP/20 in the above equation) is assumed to be taken over 20 years. However, it is recognized that the economic life of some components is less than 20 years (e.g., battery cells). Therefore, a more detailed accounting of book depreciation would increase taxes. This would result in a somewhat lower after-tax ROR than computed by this method.

RATE OF RETURN CALCULATION

A two-step procedure is used to calculate before-tax rate of return.

Step 1

A function (VAL) is calculated for discount rates over a range deemed practical for many applications (0 to 80 percent), where

$$VAL = NPV_{\text{total savings}} - NPV_{\text{total costs}} \qquad \text{(before or after taxes)}$$

Step 2

A binary search is conducted to determine the discount rate at which VAL=0. The function is also checked for two possible occurrences: 1) the rate of return lies outside the range of search, and 2) multiple rates of return are within the area of search. In the case of the first occurrence, the upper boundary of the search range is increased. The second case is made theoretically possible by the cash flow pattern associated with the battery energy storage system in which substantial capital outlays are made for replacements during its life. Should multiple rates of return occur, the function VAL is the output so that the multiple rates can be calculated by linear interpolation.

PAYBACK ANALYSIS

Payback is commonly defined as the time required to recover the first cost of an investment from the net cash flow produced by that investment for an interest rate equal to zero. Expressions such as: "The investment will pay for itself in less than three years" refer to payback. The payback approach tends to favor shorter lived investments because of the time value of money.

Nevertheless, the payback period does give some measure of the rate at which an investment will liquidate its initial outlay. For those situations where there is a high degree of uncertainty concerning the future and a firm is interested in its cash position and borrowing commitments, the payback period can supply useful information about investments that are under consideration. As a result, this measure of investment desirability is frequently used to supplement other bases for comparison such as rate of return analysis.

The before-tax cash flows as developed to calculate before-tax rate of return are used to calculate payback. After-tax cash flows could also be used, theoretically. However, the wide range of returns on equity (ROE) among cases and the corresponding variation in tax liability make after-tax payback a questionable measure for this application. For each year i, the cumulative capital investment (CUMCAP) and the cumulative positive cash flow (CUMCSH) are developed.

When

$$CUMCSH_i \geq CUMCAP_i$$

the payback period is calculated based on linear interpolation of $CUMCAP_i$ between $CUMCSH_{i-i}$ and $CUMCSH_i$.

LIST OF SYMBOLS USED

A list of the symbols used in the foregoing section is presented in alphabetical order in Table A-1.

Table A-1

LIST OF SYMBOLS USED

Name	Description
AUXLOS	Energy (kWh/cycle) consumed by auxiliary equipment and battery equalization
CAP	Equivalent capital investment (discounted sum of initial investment, replacements, and salvage)
CC	Initial capital cost
CUMCAP	Cumulative capital investment
CUMCSH	Cumulative positive cash flow
d	Discount rate (fraction)
DELCAP	Battery capacity delivered per cycle (kWh/cycle)
DEP_i	Tax depreciation in year i of the equivalent capital investment (CAP)
DERAT	Amount of debt in firm divided by debt plus equity
DISPRD	Length of battery discharge per cycle (hours)
DOFPK	Utility off-peak monthly demand charge ($/kW)
DONPK	Utility on-peak monthly demand charge ($/kW)
ENEFF	Overall system roundtrip energy efficiency (fraction)
EOFPK	Utility off-peak energy charge ($/kWh)
EONPK	Utility on-peak energy charge ($/kWh)
ESAVE	Annual energy savings ($)
FF	Fraction of battery replacement cost (REP) that is depreciable
FM	Annual cost of frequent (scheduled) maintenance
g_c	General escalation rate for capital (fraction)
g_e	Nominal escalation rate for electricity cost (fraction)
g_m	Nominal escalation rate for maintenance costs (fraction)
IM_j	Infrequent (unscheduled) maintenance cost incurred in year j
JCYCLE	Frequency (cycles or days per year) of battery discharge
k	Number of battery replacements during project life
m	Battery life (years)
NPV	Net present value
R_i	Equity return before taxes in year i
RATIO	Ratio of battery charge to discharge power
REP	Replacement cost of battery (not including salvage credit)
ROE	Rate of return on equity
ROR	Rate of return on investment
S_1	Annual demand-related savings per kWh of delivered battery capacity ($/kWh)
S_2	Annual energy-related savings per kWh of delivered battery capacity ($/kWh)
SAL	Salvage value of battery at end of life
TAX	Income tax rate (fraction)
UL	Dollar value attributable to unused battery life at the end of the project life
VAL	The difference between the NPV of total savings and the NPV of total costs for a given discount rate
XITC	Investment tax credit rate (fraction)