**ECONOMIC ASSESSMENT OF THE UTILIZATION
OF LEAD-ACID BATTERIES IN ELECTRIC UTILITY SYSTEMS**

(N)

Final Report

April, 1977

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CONTENTS

<u>Section</u>		<u>Page</u>
ES	Executive Summary	x
1	Introduction	
	1.1 Objectives of Study	1-1
	1.2 Sources of Data	1-1
	1.3 Battery Costs and Savings Considered	1-2
	1.4 Consideration of Inflation	1-2
2	The Generation Reference System and Lead/Acid Battery Data	
	2.1 Generation Reference System Data	2-1
	2.2 Lead/Acid Battery Data	2-11
3	Transmission and Distribution Savings from Dispersed Siting	
	3.1 Identification of Transmission System Applications	3-1
	3.2 Transmission Savings	3-2
	3.3 Comparison of Savings - Three Transmission Applications	3-18
	3.4 Identification of Distribution Savings	3-20
4	Production Cost Savings	
	4.1 Methodology	4-1
	4.2 Results and Analysis	4-3
5	Other Battery Costs and Savings	
	5.1 Battery Capital Cost Analysis	5-1
	5.2 Capital Cost Savings of Replacing Other Units	5-6
	5.3 Effects of Short Construction Lead Time	5-11
	5.4 Effects of Use as Spinning Reserve	5-11
	5.5 Effects on Reserve Requirements	5-14
	5.6 Transmission and Distribution System Losses	5-20
	5.7 Use of Batteries for Reactive Power Supply	5-20
	5.8 Effects on Fuel Consumption	5-22

CONTENTS

<u>Section</u>		<u>Page</u>
6	Sensitivity Analyses	
6.1	Generation Fuel Cost Differentials	6-1
6.2	Battery Efficiency	6-3
6.3	Battery Duty Cycle	6-3
6.4	Battery Capital Cost	6-9
6.5	Battery Life	6-9
6.6	Transmission and Distribution Savings	6-9
6.7	Inclusion of Inflation in Analysis	6-12
7	Overall Economics and Conclusions	
7.1	Breakeven Capital Costs	7-1
7.2	Summary and Conclusions	7-6
Appendix A	The Reference System Development	A-1
Appendix B	Production Cost Program	B-1
Appendix C	Transmission Requirements - Methodology	C-1
Appendix D	Distribution Requirements - Methodology	D-1
Appendix E	Distribution - Primary and Secondary Systems	E-1
Appendix F	Development of Carrying Charges	F-1

LIST OF TABLES

<u>Table</u>		<u>Page</u>
ES-1	Transmission Deferrals from Battery Additions	xv
ES-2	Transmission Savings Analysis - Application 3	xvi
ES-3	Distribution Savings Analysis	xvii
ES-4	1980 Reference System Characteristics	xix
ES-5	Reference System Expansion Units	xx
ES-6	Reference System Fuel Costs	xxi
ES-7	Capital Costs and Operating Characteristics of Lead-Acid Storage Batteries	xxiii
ES-8	Capital Cost Analysis	xxv
ES-9	Production Cost Analysis	xxvi
ES-10	Summary of Lead-Acid Battery Costs and Savings	xxix
2-1	Reference System Load Model	2-2
2-2	Reference System Generation Mix-1980	2-9
2-3	Operating Characteristics of Reference System Generating Units	2-10
2-4	Capital Costs of Conventional Future Generating Units (1975 \$)	2-12
2-5	Operating Characteristics of Conventional Future Generating Units	2-13
2-6	Retirement Schedule for the Reference System Generating Units	2-14
2-7	Reference System Fuel Costs	2-15
2-8	Reference System Optimum Expansion	2-16
2-9	Capital Costs and Operating Characteristics of Lead-Acid Storage Batteries	2-18
3-1	Transmission Deferrals from Battery Additions	3-3
3-2	PSE&G Northern Zone Base Import Conditions 1977-1987	3-5
3-3	PSE&G Northern Zone Load and Capacity Conditions 1977-1987	3-8
3-4	PSE&G Northern Zone 1977-1987 CETL/CETO Conditions - Battery Application 1	3-9
3-5	Fair Lawn Load Area 1981-1987 Load and Capacity Conditions	3-11
3-6	PSE&G Northern Zone 1977-87 CETL/CETO Conditions - Battery Application 2	3-17
3-7	PSE&G Northern Zone 1977-87 CETL/CETO Conditions - Battery Application 3	3-19
3-8	Transmission Savings Analysis - Application 1	3-21
3-9	Transmission Savings Analysis - Application 2	3-22
3-10	Transmission Savings Analysis - Application 3	3-23
3-11	Northern Zone 13-kV Substation Load and Capacity 1986-1995	3-27
3-12	Calculation of 1985 Northern Zone Effective Excess Substation Capacity	3-28
3-13	Summer Peak Load and Capacity Conditions - Kuller Road Substation	3-30
3-14	Example of Load Buildup on New 13-kV Substation - Post 1985 Period	3-33
3-15	Distribution Savings Analysis	3-35
3-16	Assignment of Batteries for Substation Relief	3-36

<u>Table</u>	<u>Page</u>
4-1 Schedule of Generating Capacity Additions - Application 3	4-2
4-2 Production Cost Saving (Penalty) - Installation of 440 MW of Lead-Acid Batteries with 5 Hour Discharge Period	4-4
4-3 Battery Operation (Cycles) - 440 MW of Lead-Acid Batteries Replace Peaking Capacity	4-5
5-1 Lead-Acid Battery Capital Cost Analysis (5 Hour Batteries) - Application 1	5-2
5-2 Lead-Acid Battery Capital Cost Analysis (5 Hour Batteries) - Application 2	5-3
5-3 Lead-Acid Battery Capital Cost Analysis (5 Hour Batteries) - Application 3	5-4
5-4 Capital Cost Savings Analysis - Elimination of 500 MW of Peaking Capacity	5-7
5-5 Capital Cost Savings Analysis - Elimination of 400 MW of Intermediate Capacity	5-8
5-6 Capital Cost Savings Analysis - Deferral of Gas Turbine Installations	5-9
5-7 Overall Economic Evaluation of Peaking Capacity Replacement vs. Intermediate Capacity Replacement	5-10
5-8 Spinning Reserve Benefits - 440 MW of Lead-Acid Batteries Replace Peaking Capacity	5-13
5-9 Effects on Installed Capacity Reserve Requirements - 440 MW of Lead-Acid Batteries Replace 500 MW of Gas Turbine Peaking Capacity	5-15
5-10 PSE&G T&D Losses - Application 3 - 1983	5-21
5-11 Average Annual Increased (Decreased) Fuel Consumption - Batteries Considered for Spinning Reserve - 440 MW of Lead-Acid Batteries Replace Peaking Capacity	5-24
6-1 Sensitivity to Fuel Cost Differentials - 440 MW of Lead-Acid Batteries Replace Peaking Capacity	6-2
6-2 Sensitivity to Battery Efficiency - 440 MW of Lead-Acid Batteries Replace Peaking Capacity - 65% Battery Efficiency	6-4
6-3 Sensitivity to Battery Efficiency - 440 MW of Lead-Acid Batteries Replace Peaking Capacity - 75% Battery Efficiency	6-5
6-4 Sensitivity to Battery Duty Cycle - 440 MW of Lead-Acid Batteries Replace Peaking Capacity - 3 Hour Discharge Period, 5 Hour Charge Period	6-6
6-5 Sensitivity to Battery Duty Cycle - 440 MW of Lead-Acid Batteries Replace Peaking Capacity - 10 Hour Discharge Period, 10 Hour Charge Period	6-7
6-6 Sensitivity to Battery Duty Cycle - Effect on Capital Cost	6-8
6-7 Sensitivity to Battery Life - Effect on Capital Cost - 440 MW of 5-Hour Batteries	6-11
6-8 Sensitivity to Inflation - Lead-Acid Battery Capital Cost Analysis - Application 3	6-13
6-9 Sensitivity to Inflation - Transmission Savings Analysis - Application 3	6-14

<u>Table</u>		<u>Page</u>
6-10	Sensitivity to Inflation - Distribution Savings Analysis - Application 3	6-15
6-11	Sensitivity to Inflation - Production Cost Savings - Lead-Acid Batteries Replace Peaking Capacity	6-16
6-12	Sensitivity to Inflation - Capital Cost Savings Analysis - Elimination of 500 MW of Peaking Capacity	6-17
6-13	Sensitivity to Inflation - Spinning Reserve Benefits - Lead-Acid Batteries Replace Peaking Capacity	6-18
6-14	Sensitivity to Inflation - Summary of Effects	6-19
7-1	Summary of Lead-Acid Battery Costs and Savings	7-2
7-2	Theoretical Maximum Production Cost Savings from Off-Peak Nuclear Energy	7-8
A-1	An Analysis of 1971 Peak Loads	A-2
A-2	1971 Annual Load Factor Analysis - Privately & Publicly Owned Electric Systems	A-4
A-3	Generation Mix Analysis	A-5
A-4	Reference System Generation Mix - 1980	A-6
A-5	Load Growth Analysis and Projected Peak Loads	A-8
C-1	PSE&G Northern Zone Transmission Forecast	C-7
E-1	Primary and Secondary Distribution Savings Analysis (Theoretical Maximum) - Application 3	E-8
E-2	Primary Distribution Savings Analysis (Theoretical Maximum) - Application 3	E-9
E-3	Secondary Distribution Savings Analysis (Theoretical Maximum) - Application 3	E-10
F-1	Year by Year Battery Revenue Requirements	F-2,3,4,5
F-2	Construction Compound Interest Factor (CCIF) Unit Present Worth of Mean Annual Survivors (UPWMAS)	F-6
F-3	Carrying Charges	F-7
F-4	Inflation Adjusted Present Worth Factor and Carrying Charges	F-9

LIST OF FIGURES

<u>Figure</u>		<u>Pa</u>
ES-1	Public Service Territory	xii
ES-2	1976 PSE&G Northern Zone - 230 and 345 kV Transmission	xiv
ES-3	Optimum Nuclear Expansion Generation Mix	xxii
ES-4	Sensitivity to Battery Life - Effect on Battery Carrying Charges	xxiv
ES-5	System Reliability - Installed Reserve Requirements - Effect of Limited Energy	xxviii
2-1	Reference System Weekly Peak Load Trend	2-3
2-2	Reference System Daily Peak Load Trend	2-4
2-3	Reference System Daily Loadshapes - Spring Season	2-5
2-4	Reference System Daily Loadshapes - Summer Season	2-6
2-5	Reference System Daily Loadshapes - Fall Season	2-7
2-6	Reference System Daily Loadshapes - Winter Season	2-8
3-1	Northern Zone and PSE&G System Peak Day Load Cycle Curves	3-6
3-2	Northern Zone Cumulative % -Hours Energy vs. Percent of Peak Load	3-7
3-3	Fair Lawn Area and PSE&G System Peak Day Load Cycle Curves	3-12
3-4	Fair Lawn Load Area Cumulative % -Hours Energy vs. Percent of Peak Load	3-13
3-5	Configuration of Typical High Capacity Distribution Substation	3-25
3-6	Substation Configuration (with Batteries)	3-26
3-7	PSE&G Northern Zone Substation Load and Capacity	3-32
4-1	Load and Incremental Cost vs. Time - 1980	4-6
4-2	Load and Incremental Cost vs. Time - 1995	4-7
5-1	System Reliability - Installed Reserve Requirements - Effect of Limited Energy	-5-17
5-2	System Reliability - Effect of Limited Energy	5-18
6-1	Sensitivity to Battery Life - Effect on Battery Carrying Charges	
7-1	Battery Breakeven Capital Cost vs. Transmission and Distribution Savings	7-3
7-2	Battery Breakeven Capital Cost vs. Battery Life	7-5
C-1	Public Service Territory	C-2
C-2	1976 PSE&G Northern Zone - 230 and 345 kV Transmission	C-4
C-3	Fair Lawn Load Area One-Line Diagram	C-9
D-1	Typical PSE&G Northern Zone Substation Peak-Day Load Curve	D-2
D-2	Typical PSE&G Northern Zone Substation Peak-Day Load Curve (with 5% peak load reduction using batteries)	D-3
D-3	Rectangularized Version of Figure D-1 Load Curve	D-6
D-4	Charging Energy Available for Substation Loaded to Emergency (Firm) Capacity	D-8
D-5	Charging Energy When Substation is Loaded to 110% of Emergency Rating - 55MW x 500 MWH of Batteries Installed	D-9
D-6	Charging Energy Available For Substation Loaded to Normal Capacity	D-1

<u>Figure</u>		<u>Page</u>
D-7	Discharge Energy Required for Emergency Contingency (One Substation Transformer Out) for Substation Loaded to Normal Capacity	D-13
D-8	Relationship of Discharge Requirement to Available Charge Energy	D-15
D-9	Charge in Batteries as a Function of Time-Of-Day	D-17
E-1A	Distribution Primary Feeder Configuration	E-2
E-1B	Distribution Primary Feeder Configuration (with Battery Installed)	E-2
E-2	Distribution Secondary System	E-5

EXECUTIVE SUMMARY

INTRODUCTION

The purpose of this study is to search for and identify specific applications in which lead-acid batteries might be economically competitive on an electric utility system. Particular attention is given to searching the PSE&G system for installations of batteries which could defer or cancel costly transmission and/or distribution projects. Although the transmission and distribution data are based on specific applications on the PSE&G system, the generation data are based on a national reference system. This system was developed in RP-729-1 "Economic Assessment of the Utilization of Fuel Cells in Electric Utility Systems" which was prepared by PSE&G for EPRI. Data on lead-acid battery costs and characteristics were provided by ERDA. The Report analyses and summarizes all costs and savings attributable to lead-acid batteries.

GENERAL APPROACH

The general approach used in the battery assessment is to first identify specific applications for the PSE&G transmission and distribution system. The amounts and required characteristics of lead-acid batteries to satisfy the needs of the transmission applications are determined.

Having determined the amount of batteries required, this battery capacity is substituted for alternate peaking and intermediate type generating capacity. All costs and savings associated with the batteries are then analysed including the following:

- Battery capital cost
- Transmission and distribution saving
- Production cost saving
- Spinning reserve saving
- Alternate capacity saving
- Quick lead time saving
- Generating reserve requirement saving
- Losses
- Reactive Capacity

The underlying methodology in which all costs and savings are equated in comparable terms is the "minimum revenue requirement" discipline. This methodology, which is very commonly used in the electric utility industry, is explained in several standard textbooks on Engineering Economics. In this report, the methodology has been used to calculate all costs and savings in

terms of "present worth of all future revenue requirements" (pwafrr), using a cost of money (interest rate) of 10%. Costs and savings are finally summarized in terms of equivalent \$/kW cost of batteries.

BASIC CONCLUSIONS

- 1) With the base data, total savings could not be identified which could justify installation of lead-acid batteries in spite of very substantial transmission savings.
- 2) Several parameters were found which, if for a particular utility are substantially different from those used in this report, could result in justification of lead-acid batteries. In general a utility should have a combination of the following characteristics:
 - (a) A relatively large percentage of nuclear capacity.
 - (b) A large differential between fuel prices for base load units and for peaking units.
 - (c) An application resulting in large transmission savings.
- 3) Continuing inflation and the recognition by utilities that there will be a continuing inflation will make the economics of lead-acid batteries more attractive. In particular, a reasonable differential between fuel prices for base load units and for peaking units will make batteries economically competitive.

TRANSMISSION SAVINGS (See Appendix C for Methodology)

The PSE&G transmission system development is typically planned to provide the transmission capability to satisfy various functional requirements. One of these requirements is the delivery of emergency power to the system or a sub-area of the system and is called the Capacity Emergency Transfer Objective (CETO). The ability of the transmission system to deliver this emergency power is termed the Capacity Emergency Transfer Limit (CETL).

Batteries sited in the PSE&G system or a sub-area of the system would have the effect of reducing the system's or sub-area's CETL. By locating sufficient batteries in an area, it would be possible to defer transmission projects planned primarily for CETL/CETO reasons.

A survey of the planned transmission developments in the 1977-87 periods reveals that three specific underground transmission projects, which would provide increased CETL capacity to the generation deficit Northern Zone of the PSE&G system (Figure ES-1), could potentially

FIGURE ES-1

be deferred by the installation of battery capacity. Also, by locating a portion of these batteries in the Fair Lawn load area within the Northern Zone, an additional underground transmission project could be deferred. The existing Northern Zone transmission system and those facilities identified as deferment candidates are shown in Figure ES-2.

Starting with the base system CETL/CETO conditions for the PSE&G Northern Zone (no battery installations) and knowing the CETL increase associated with each transmission deferral candidate as well as the potential CETO reduction accruing from a given amount of battery capacity installation, a simple relationship can be developed stating the specific transmission project deferrals possible as a function of the amount of batteries installed. From this generalized relationship, three specific quantity/location applications were formulated based on CETL/CETO requirements. These applications were then adapted to obtain the secondary benefit resulting from the location of some of the required Northern Zone battery installation specifically in the Fair Lawn load area to permit delay of that area's planned reinforcement. The three applications and their associated deferrals are summarized in Table ES-1. The transmission savings derived from the most promising application are shown in Table ES-2.

It was assumed that batteries installed to provide emergency transmission and distribution protection would normally operate on a system economic dispatch basis. Therefore, the load cycle characteristics of the Northern Zone and Fair Lawn load area were compared to the PSE&G system load cycle to assure that the batteries, operating on a system basis, would be sufficiently charged to provide the necessary protection.

DISTRIBUTION SAVINGS

Having identified the most promising application of batteries in the PSE&G system and having quantified the number of MW required, we investigated the additional savings achievable from locating these batteries at distribution substations. These additional savings are derived from the postponement of planned substations in the 1979-1985 period and from the postponement of unidentified substations required in the post-1985 period.

These savings are summarized on Table ES-3. Further savings from applying batteries at the ends of primary and secondary distribution circuits are achievable but installation of the batteries on these circuits is judged to be not feasible.

FIGURE ES-2

NOTE

Transmission project
deferrals shown dark
(Planned Service Date)

**1976 PSE&G NORTHERN ZONE
230 AND 345-KV TRANSMISSION**

TABLE ES-1

TRANSMISSION DEFERRALS FROM BATTERY ADDITIONS

Application	Battery Additions		Facilities Deferred	Planned Service Date	Deferred Service Date	Estimated Capital Cost (current)
	(MW)	(YEAR)		(YEAR)	(YEAR)	(\$x1000)
1 (1)	85	1979	a. Hawthorne-Hinchmans 230-kV cable and Waldwick 230-kV 600 MVA PAR ⁽²⁾	1979	1980	5,900
			b. South Mahwah-Waldwick 345-kV cable oil circulation equipment	1983	(3)	700
			c. Hawthorne-Fair Lawn 230-kV cable and Fair Lawn 230/138-kV autotransformer	1984	1987	5,300
2 (4)	85	1979	a. Hawthorne-Hinchmans 230-kV cable and Waldwick 230-kV 600 MVA PAR	1979	1980	5,900
	85	1981	b. South Mahwah-Waldwick 345-kV cable oil circulation equipment	1983	(3)	700
			c. Hawthorne-Fair Lawn 230-kV cable and Fair Lawn 230/138-kV autotransformer	1984	1988	5,300
			d. Aldene-Essex 230-kV cable and Essex 230-kV 600 MVA PAR	1981	1982	26,200
3 (5)	85	1979	a. Hawthorne-Hinchmans 230-kV cable and Waldwick 230-kV 600 MVA PAR	1979	1982	5,900
	110	1980	b. South Mahwah-Waldwick 345-kV cable oil circulation equipment	1983	(3)	700
	190	1981	c. Hawthorne-Fair Lawn 230-kV cable and Fair Lawn 230/138-kV autotransformer	1984	1988	5,300
	55	1983	d. Aldene-Essex 230-kV cable and Essex 230-kV 600 MVA PAR	1981	(3) (6)	26,200

Notes

- (1) Approximately 75 MW of the total 85 MW must be located in the Fair Lawn load area
 (2) PAR - Phase Angle Regulator
 (3) Deferred indefinitely beyond 1987
 (4) Approximately 150MW of the total 170 MW must be located in the Fair Lawn load area
 (5) Approximately 150MW of the total 440 MW must be located in the Fair Lawn load area
 (6) It would cost approximately \$200,000,000 to install enough batteries to indefinitely defer the Aldene-Essex project (\$26,200,000).

TABLE ES-2

TRANSMISSION SAVINGS ANALYSIS
APPLICATION 3

<u>Service Date</u>	<u>1979</u>	<u>1981</u>	<u>1983</u>	<u>1984</u>
Capital Cost Cancelled or Deferred (million dollars)	5.9	26.2	0.7	5.3
Cancel or No. of Years Deferred	3	cancel	cancel	4
CCIF	1.05	1.05	1.05	1.05
% Carrying Charges	15	15	15	15
Levelized Annual Revenue Requirements (million dollars/year)	.93	4.13	.11	.83
Pwafrs Saving (1979 million dollars)	<u>2.54</u>	<u>34.1</u>	<u>.75</u>	<u>1.79</u>
Pwafrs Saving Total	\$39.2 million			

TABLE ES-3
DISTRIBUTION SAVINGS ANALYSIS

<u>Service Date</u>	<u>Application 3</u>		
	<u>1981</u>	<u>1990</u>	<u>1991</u>
Capital Cost Cancelled or Deferred (million dollars)	1.74	3.48	6.96
No. of Years Deferred	3	3	3
CCIF (1)	1.05	1.05	1.05
% Carrying Charges (2)	15	15	15
Levelized Annual Revenue Requirements (million dollars/year)	.27	.55	1.10
Pwafrr Savings	<u>.61</u>	<u>.53</u>	<u>.96</u>
TOTAL Pwafrr Saving	\$2.1 million		

GENERATION COSTS AND SAVINGS

The 1980 load and capacity data for the Reference System are shown in Table ES-4. The generating units selected for the expansion of the Reference System are shown in Table ES-5. The fuel prices used for the study are shown in Table ES-6.

The capital costs, fuel prices, and most of the generating unit operating characteristics were supplied by EPRI. The Reference System expansion is shown in Figure ES-3 as an optimum generation mix. Optimum generation mix is that combination of generating units which minimizes the present worth of all future revenue requirements for capital related charged and production cost (fuel, operation, and maintenance). The optimum mix for the Reference System does not contain enough nuclear capacity to provide nuclear charging energy for lead-acid batteries.

The lead-acid battery data are shown in Table ES-7. These data were supplied by ERDA. The capital cost is primarily a function of energy storage capability, rather than MW size as is typical of most other types of generating capacity. The carrying charges for the battery portion of the plant have been calculated as a function of life, and are shown in Figure ES-4.

Conventional generating units are available only in relatively large, discrete sizes. The size and schedule of the battery installations determined in Section 3 does not allow an exact MW for MW replacement of capacity in the Reference System. The generation analysis considers two possible replacement scenarios:

1. Replace 500 MW of gas turbine peaking capacity with 440 MW of lead-acid batteries.
2. Replace a 400 MW oil steam intermediate unit with 440 MW of lead-acid batteries and postpone 350 MW of gas turbine peaking capacity for periods of one to three years.

Table ES-8 summarizes the generation capital costs and savings for the replacement of gas turbine or oil steam capacity with lead-acid storage batteries. Table ES-9 summarizes the production cost savings and penalties for the replacement of gas turbine or oil steam capacity with lead-acid storage batteries. The combined capital and production cost savings and penalties show that the replacement of gas turbine capacity is the least costly alternative by a pwafr of \$38 million.

The outage rates of lead-acid batteries are projected to be significantly lower than gas turbine units. Therefore, the replacement of gas turbines with batteries would result in

TABLE ES-4

1980 REFERENCE SYSTEM CHARACTERISTICS

PEAK LOAD:	6,000 MW, Summer
LOAD FACTOR:	60%
GROWTH RATE:	6% Per Year, Load and Energy
INSTALLED CAPACITY:	7200 MW
INSTALLED RESERVES:	20%

	<u>Nuclear</u>	<u>Coal Steam</u>	<u>Oil Steam</u>	<u>Gas Turbine</u>	<u>Conven- tional Hydro</u>	<u>Pumped Storage Hydro</u>
Total Capacity	800 MW	3200 MW	1800 MW	600 MW	600 MW	200 MW
Capacity Mix	11.1%	44.4%	25.0%	8.3%	8.3%	2.8%
		69.4%				
Projected (1) 1980 Mix for U.S.	13.2%	65.3%		9.4%	9.8%	2.3%

(1) EEI National Power Survey, April 1975.

TABLE ES-5
REFERENCE SYSTEM EXPANSION UNITS
DATA PROVIDED BY EPRI (1)

<u>TYPE</u>	<u>CAPACITY</u> (MW)	<u>1975</u> <u>CAPITAL COST</u> (\$/KW)
Nuclear	800	540
Oil Intermediate	400	240
Combined Cycle	250	210
Gas Turbine	150	120

Note:

- (1) RP-729-1, "Economic Assessment of the Utilization of Fuel Cells in Electric Utility Systems".

TABLE ES-6
REFERENCE SYSTEM FUEL COSTS
DATA PROVIDED BY EPRI (1)

<u>FUEL</u>	<u>1980 FUEL PRICE</u> <u>(1975 \$/MBtu)</u>
Nuclear	0.60
Coal	1.20
Oil #6	2.05
Oil #2	2.45

Note:

- (1) RP-729-1, "Economic Assessment of the Utilization of Fuel Cells in Electric Utility Systems".

FIGURE ES-3
OPTIMUM NUCLEAR EXPANSION
GENERATION MIX

TABLE ES-7

CAPITAL COSTS AND OPERATING CHARACTERISTICS
OF LEAD-ACID STORAGE BATTERIESCAPITAL COSTS

<u>Initial Investment</u>	<u>10-Hour Battery</u>	<u>5-Hour Battery</u>	<u>3-Hour Battery</u>
Installed Cost (\$/kW)			
Battery Costs	368	184	111
Other Energy Related Costs	284	142	85
Converter Costs	74	74	74
Total	726	400	270
Lead Time (years)	2	2	2
CCIF	1.05	1.05	1.05
Estimated Life (years) (exclusive of Batteries)	30	30	30
Carrying Charges (exclusive of Batteries)	15	15	15
<u>Battery Replacement</u>			
(\$/kW)	276	138	83
Estimated Life	2000 cycles up to 14 years		
Carrying Charges	Determined as a function of life in Section 5.		

OPERATING CHARACTERISTICS

Efficiency (%)	75	70	65
Charging Time (hours)	10/13	5/7/10	3/5/10
Charging Capacity (% of rated load)	133/100	143/100/- 71	154/100/- 46
Fixed O&M	None		
Variable O&M (mills/kWh)	0.5	0.5	0.5
Forced Outage Rate (%)	4	4	4
Annual Maintenance (week/year)	1	1	1

FIGURE ES-4

SENSITIVITY TO BATTERY LIFE
EFFECT ON BATTERY CARRYING CHARGES

TABLE ES-8
CAPITAL COST ANALYSIS
PWAFFR, 1979 million dollars

Replace Peaking Capacity

Lead-Acid Battery Cost	(264)
Gas Turbine Savings	<u>79</u>
Net Capital Penalty	(185)

Replace Intermediate Capacity

Lead-Acid Battery Cost	(264)
Oil Steam Savings	<u>130</u>
Net Capital Penalty	(134)

TABLE ES-9

PRODUCTION COST ANALYSIS
PWAFFR SUMMARY
1979 Million Dollars

	<u>Replace Peaking Capacity</u>	<u>Replace Intermediate Capacity</u>
Operating Savings (Penalty)	16	(73)
Spinning Reserve Savings	<u>58</u>	<u>58</u>
Total Production Cost Savings (Penalty)	74	(15)

reduced installed capacity reserve requirements and an associated capital cost saving.

However, the limited energy constraint of lead acid batteries may reduce their load carrying capability, thereby increasing reserve requirements. Figure ES-5 shows an estimate of battery load carrying capability as a function of the amount of battery capacity installed. The net effect of battery availability and limited energy is to reduce the Reference System reserve requirement by approximately 60 MW. Capital cost savings for this amount of capacity are already included in the analysis (440 MW of batteries replaced, 500 MW of gas turbines).

The construction lead time required for lead-acid batteries is projected to be two years, compared to longer lead times required for all other types of capacity except gas turbines.

The pwafrr savings due to batteries short lead time is zero with respect to gas turbines and \$16 million with respect to oil steam units. These savings are included in the capital cost analysis.

SUMMARY OF COSTS AND SAVINGS

Table ES-10 summarizes all of the costs and savings identified for lead-acid batteries. This table shows each component not only in terms of pwafrr but also in equivalence of \$/kW of installed cost. As can be seen, savings of \$294/kW have been identified as compared with the estimated \$400/kW cost.

SENSITIVITY ANALYSES

Several of the key parameters in the analysis have been varied to determine the most important elements affecting the overall economic results. Results of these sensitivity analyses indicate that a combination of parameter changes would be sufficient to justify lead-acid battery installations. The most important parameters, other than the cost of the batteries themselves, have been found to be:

1. The relative costs of fuel for base load generating units (coal and nuclear) as compared to fuel for peaking units (oil).
2. The relative mix of nuclear, coal, and oil units on the particular utility system, and
3. The magnitude of transmission projects which could be cancelled.
4. The inclusion of inflation in the economic analyses.

FIGURE ES-5

TABLE ES-10

SUMMARY OF LEAD-ACID BATTERY COSTS AND SAVINGS

<u>Cost or Saving Component</u>	<u>Pwafrr Cost (Saving) millions of 1979 Dollars</u>	<u>Equivalent Battery Installed Cost (\$/kW)</u>	<u>Section Reference</u>
<u>COST</u>			
Battery Capital Cost	264	400	5.1
<u>SAVINGS</u>			
Transmission	(39)	(59)	3.3
Distribution	(2)	(3)	3.7
Production Cost and Spinning Reserve	(74)	(112)	4.2 and 5.4
Replacement Capacity	(79)*	(120*)	5.2
Total	(194)	(294)	
<u>NET PENALTY</u>	70	106	

* Includes credits for capacity reserve requirement savings. There are no credits for short installation lead time when compared to gas turbines.

In addition, it was determined that a recognition that inflation may be here to stay increases the incentives to install batteries. The assumption of a 6% inflation rate combined with a coal-oil fuel price differential on the order of \$1.25/MBtu is sufficient to make lead-acid batteries a break-even proposition for the reference system.

It should be noted that the 10% cost of money used throughout this report inherently includes an inflation adjustment. Thus, 10% is a proper value to use for the sensitivity to the inclusion of inflation analysis. To be completely consistent, a cost of money on the order of 4-5% should have been used for all other analyses. This would have decreased the net penalty for lead-acid batteries which was shown in Table ES-10.

Section 1

Introduction

1.1 OBJECTIVES OF STUDY

It is generally acknowledged that lead-acid batteries are not presently competitive for wholesale electric utility applications*. The purpose of this report is to search for and identify specific applications where lead-acid batteries might be competitive. Particular attention is given to searching the PSE&G system for installations of batteries which could defer or cancel costly transmission projects. Promising transmission applications are assessed and an analysis of all potential battery savings including those on the generating, transmission, and distribution systems is made. The potential savings are compared with the costs of installing the batteries.

1.2 SOURCES OF DATA

1.2.1 Battery Data

All cost and other battery data were supplied by ERDA except for carrying charges.

1.2.2 Generation System Data

A reference system whose load and generation capacity characteristics are representative of large U.S. electric utilities is used in this analysis. This reference system is that which was developed in RP-729-1, "Economic Assessment of the Utilization of Fuel Cells in Electric Utility Systems" which was prepared by PSE&G for EPRI. The reference system data includes load data, characteristics of existing generating units, fuel costs, and characteristics and timing of future generating unit additions.

1.2.3 Transmission and Distribution Data

All transmission and distribution data are based on the PSE&G system and on PSE&G costs.

*"An Assessment of Energy Storage Systems Suitable for Use by Electric Utilities" EPRI EM-264 Project 225, ERDA E(11-1)-2501 Final Report July 1976.

1.3 BATTERY COSTS AND SAVINGS CONSIDERED

The analysis considers the following potential costs and savings for installation of lead-acid batteries:

- Battery capital cost
- Transmission plant savings
- Distribution plant savings
- Generation production cost savings
- Capital cost savings from replacement of alternate generating capacity
- Effects of short construction lead time
- Effects on installed capacity reserve requirements
- Effects of use as spinning reserve
- Effects on transmission and distribution losses
- Effects of use as reactive power supply

The methodologies used in determining the above are included throughout the report.

Sensitivity analyses are also made on some of the key variables. These analyses provide insights into the sets of circumstances which are necessary to economically justify lead-acid batteries.

1.4 CONSIDERATION OF INFLATION

The basic analyses in this report were done using constant costs, i.e., without considering inflation. This was done because the reference system, which is the basis of the analyses, was taken from EPRI RP-729-1. That work also did not consider inflation. It should be noted that the 10% cost of money used throughout this report inherently includes an inflation adjustment. A cost of money on the order of 4 to 5% should have been used to be completely consistent with the constant cost approach.

The task of developing escalation rates for the many cost components involved is beyond the scope of this report. However, it is important to recognize the potential effects of continuing inflation and the resultant escalation of costs. Therefore, we have included some sensitivity analyses using a 6% annual escalation rate applied to all costs.

Section 2

The Generation Reference System and Lead-Acid Battery Data

2.1 GENERATION REFERENCE SYSTEM DATA

A prerequisite of this analysis is the development of a reference system whose load and generation capacity characteristics are representative of U.S. electric utilities. The reference system data developed by PSEG for RP-729-1, "Economic Assessment of the Utilization of Fuel Cells in Electric Utility Systems", has been reviewed and is utilized in this analysis.

A detailed rationale supporting the reference system selection and its specific characteristics is provided in Appendix A. The most significant features are described below.

The 1980 peak load was selected to be 6000 MW with a load factor of 60%, based on an analysis of U.S. companies having a 1971 peak load greater than 1500 MW. The reference system is a summer peaking system. Five representative companies were identified as having peak loads and load factors close to the values selected for the reference system. Table 2-1 summarizes the reference system load model developed from data for one of the five representative companies. Figures 2-1 through 2-6 show the weekly peak loads, daily peak loads and hourly integrated loads. When combined, the weekly, daily, and hourly loads generate an hour by hour chronological load curve for an entire year. The annual growth rate for the reference system was selected to be 6% for both peak load and energy, thus maintaining a constant load factor.

The reference system has a generating capacity of 7200 MW in 1980, assuming a 20% reserve margin over the 6000 MW peak load. The generation mixes of the five representative companies were analyzed and compared with 1980 projections from the April, 1975 EEI National Power Survey. The resulting generation mix contains 11% nuclear, 70% fossil steam (45% coal, 25% oil), 8% combustion turbines, 8% conventional hydro, and 3% pump storage hydro. Table 2-2 shows the reference system generation mix for 1980. Table 2-3 shows the operating characteristics of the reference system units. The 500, 600, and 800 MW fossil units are considered to be "must run" units; that is, they must remain on line during brief low load periods (such as overnight and weekends), when economic dispatch considerations alone might not require them to be in service. Reasons for this "must run" requirement include design characteristics, such as long shutdown and start times, and the need for local generation to provide area protection.

TABLE 2-1
REFERENCE SYSTEM LOAD MODEL

a) ANNUAL PEAK LOADS AND ENERGIES

<u>Year</u>	<u>Peak Load (MW)</u>	<u>Energy (GWH)</u>	<u>Year</u>	<u>Peak Load (MW)</u>	<u>Energy (GWH)</u>
1980	6000	31536	1990	10740	56449
1981	6360	33428	1991	11390	59866
1982	6740	35425	1992	12070	63440
1983	7150	37580	1993	12800	67277
1984	7570	39788	1994	13570	71324
1985	8030	42206	1995	14380	75581
1986	8510	44729	1996	15240	80101
1987	9020	47409	1997	16160	84942
1988	9560	50247	1998	17130	90035
1989	10140	53296	1999	18150	95396
			2000	19240	101125

Annual growth rate for the reference system is 6% for both peak load and energy. Annual load factor for the reference system is assumed to be constant at 60%.

b) Seasonal Peak Loads, Energies, and Load Factors

<u>Season</u>	<u>Winter</u>	<u>Spring</u>	<u>Summer</u>	<u>Fall</u>
Peak Load - % of annual	84.7	74.1	100.0	79.0
Energy - % of annual	37.9	10.2	41.1	10.8
Load Factor - %	69.9	71.7	64.2	71.6

The winter and summer seasons are each 20 weeks long. The spring and fall seasons are each 6 weeks long. The seasonal load factors are based on the seasonal peak loads.

FIGURE 2-1
REFERENCE SYSTEM
WEEKLY PEAK LOAD TREND

FIGURE 2-2

REFERENCE SYSTEM
DAILY PEAK LOAD TREND

FIGURE 2-3

REFERENCE SYSTEM
DAILY LOADSHAPES - SPRING SEASON

FIGURE 2-4
REFERENCE SYSTEM
DAILY LOADSHAPES - SUMMER SEASON

FIGURE 2-5
REFERENCE SYSTEM
DAILY LOADSHAPES - FALL SEASON

FIGURE 2-6
REFERENCE SYSTEM
DAILY LOADSHAPES - WINTER SEASON

TABLE 2-2

REFERENCE SYSTEM GENERATION MIX - 1980

Peak Load = 6000 MW

Installed Capacity = 6000+1200 MW

Reserve Required = 20% = 1200 MW

= 7200 MW

	Number of Units - Capacity in MW					
	Nuclear steam	Coal steam	Oil steam	Combustion turbines	Conventional Hydro	Pump Stor- age Hydro
		4-100	2-100	8-25	6-100	2-100
		2-200	1-200	4-50		
		1-300	1-300	2-100		
		2-400				
		1-500	1-500			
			1-600			
	<u>1-800</u>	<u>1-800</u>				
Total Capacity	800 MW	3200 MW	1800 MW	600 MW	600 MW	200 MW
% Mix	11.1%	44.4%	25.0%	8.3%	8.3%	2.8%
Projected(1) 1980 Mix for U.S.	13.2%	65.3%		9.4%	9.8%	2.3%

Note: (1) EEI National Power Survey, April, 1975

OPERATING CHARACTERISTICS OF REFERENCE SYSTEM GENERATING UNITS

2-10

(1) Seasonal variations in Hydre capacity and energy

<u>Quarter</u>	<u>Capacity Available & Rating</u>	<u>Energy Distribution</u>
1	100%	35%
2	100%	35%
3	90%	10%
4	90%	20%
	100% = 600 MW	100% = 2500 GWH

Various sizes and types of conventional generating units were considered for the expansion of the reference system through the year 2000. Tables 2-4 and 2-5 show the operating characteristics and the capital costs of the expansion units. Table 2-6 shows the retirement schedule assumed for the existing generating units of the reference system. Table 2-7 shows the costs assumed for the various types of fuel. These data were developed by PSE&G and EPRI for RP-729-1.

Given the reference system and expansion unit data shown in Tables 2-1 through 2-7, RP-729-1 developed several Optimum Expansion plans for the reference system through the year 2000. The Optimum Expansion with nuclear units as base load capacity and without fuel cells was used for this study. Table 2-8 shows this Optimum Expansion plan.

Installed capacity requirements were based on a nominal reserve requirement of 20% of annual peak load, with a tolerance of $\pm 2\%$. The Optimum Expansion has reserves close to the minimum limit of 18% because economies of scale were not recognized in the capital costs and no credit was given for excess capacity.

The objective of the Optimum Expansion evaluation is to minimize the pwafr capital costs for unit additions plus the pwafr production costs over the study period. Since the capital related charges to infinity are included in the objective function, the system production cost for the final year of the study (the year 2000 in this case) is also assumed to hold to infinity.

The present worth of this amount is included in the evaluation.

Since the reference system does not have sufficient peaking capacity in 1980, gas turbine additions are significant in the early 1980's. This situation enhances the operation of lead-acid batteries. Total capacity additions in the 1981-2000 study period are 36% nuclear, 41% intermediate, and 23% gas turbines. In the long term, this level of nuclear base load capacity is not sufficient to maintain a high capacity factor for the batteries. However, the relatively small amount of total battery capacity to be installed and the high capital cost of battery and nuclear capacity does not justify the installation of additional nuclear capacity for the purpose of increasing battery operation.

2.2 LEAD-ACID BATTERY DATA

All data on lead-acid batteries used in these analyses were provided by the U.S. ERDA. ERDA has provided data for battery installations having three full load discharge times; 10 hours,

TABLE 2-4

CAPITAL COSTS OF CONVENTIONAL FUTURE GENERATING UNITS (1975 \$)

<u>Unit Type</u>	<u>Size (MW)</u>	<u>Lead Time (Years)</u>	<u>CCIF</u>	<u>Estimated Life (Years)</u>	<u>Carrying Charges (%)</u> (2)	<u>Installed Cost \$/kW</u>
Nuclear	800-2000	10	1.52	30	18	540
Coal (B)	600-1500	6	1.30	30	18	430
Oil (B)	600-1500	5	1.10	30	18	300
Oil (I)	400- 600	5	1.10	30	18	240
Comb. Cycle	150- 250	3	1.08	30	18	210
Gas Turbine	50- 200	2	1.05	30	18	120

TABLE 2-5

OPERATING CHARACTERISTICS OF CONVENTIONAL FUTURE GENERATING UNITS

Unit Type	Size (MW)	EPRI				Fixed O&M (\$/kW-yr.)	Variable O&M (Mills/kWhr)	Forced Outage Rate (%)	Annual Maintenance (Weeks)	(1)
		Heat Rate at % Load (Btu/kWhr)								
		25%	50%	80%	100%					
Nuclear	800-2000	12,550	10,825	10,170	10,000	5.0	0.3	17	10/7-7-7-7-10	
Coal (B)	600-1500	13,100	10,575	9,710	9,500	4.0	1.0	17 (2)	9/5-7-5-7	
Oil (B)	600-1500	10,760	9,540	9,110	9,000	3.6	.35	17 (2)	9/5-7-5-7	
Oil (I)	400-600	13,830	11,830	11,150	11,000	3.2	.2	15.5 (2)	8/4-6-4-6	
Comb. Cycle	150-250	-	10,000	8,700	8,500	.90	3.7	22	4/4-4-4-4	
Gas Turbine	50-200	-	15,000	12,500	12,000	.26	5.0	15	4/4-4-4-4	

(1) Annual maintenance (wks./yr.) - 2nd year/repeatable cycle.

(2) Balanced draft type units assumed.

TABLE 2-6

RETIREMENT SCHEDULE FOR THE
REFERENCE SYSTEM GENERATING UNITS

Date of Retirement (by January 1)	Units Retired
1983	2 x 100 MW (coal)
1986	2 x 100 MW (oil)
1989	2 x 100 MW (coal)
1991	1 x 200 MW (coal)
1993	1 x 200 MW (oil)
1995	1 x 200 MW (coal)
1998	2 x 300 MW (coal and oil)

TABLE 2-7
REFERENCE SYSTEM FUEL COSTS

<u>Fuel</u>	1980 Fuel Price (1975 \$/MBtu)		
	<u>Base</u>	<u>High</u>	<u>Low</u>
Nuclear	0.60	0.80	0.30
Coal	1.20	2.00	0.75
Oil #6	2.05	3.50	2.00
Oil #2	2.45	3.90	2.40

TABLE 2-8

REFERENCE SYSTEM OPTIMUM EXPANSION

Year	Nuclear (MW)	Oil Intermediate. (MW)	Combined Cycle (MW)	Gas Turbine (MW)	Total Additions (MW)
1981	0	0	0	450	450
1982	0	400	0	0	400
1983	0	0	0	450	450
1984	0	400	0	300	700
1985	0	400	0	150	550
1986	0	400	250	0	650
1987	800	0	0	0	800
1988	0	400	0	150	550
1989	800	0	0	0	800
1990	800	0	0	0	800
1991	0	400	0	600	1000
1992	800	0	0	150	950
1993	800	0	0	0	800
1994	0	0	1000	150	1150
1995	800	0	0	150	950
1996	800	400	0	0	1200
1997	0	800	0	300	1100
1998	0	400	0	750	1150
1999	800	400	500	150	1850
2000	<u>0</u>	<u>0</u>	<u>1000</u>	<u>300</u>	<u>1300</u>
Total	6400	4400	2750	4050	17600
% of Total	36%	25%	16%	23%	

5 hours, and 3 hours. Capital costs and operating characteristics for the batteries are shown in Table 2-9. For each discharge time, 3 charge times are considered: a 10 hour charge time, a charge time such that the maximum charge load and the maximum discharge capacity are equal, and a charge time such that the maximum charge time and the minimum discharge time are equal.

Many of the items shown in Table 2-9 are inter-related and must be evaluated carefully. For example, the charge time will affect the size of the charging equipment and therefore the cost of that equipment. The charge time may also affect the economic operation of the battery plant, and therefore the life and carrying charges of the batteries. This will be considered in Section 4.

In Section 3 on transmission and distribution system applications, the selection of several promising specific battery locations will specify the MW size, the minimum discharge time, and the minimum charge time most suitable for the selected battery installations.

TABLE 2-9

CAPITAL COSTS AND OPERATING CHARACTERISTICS
OF LEAD-ACID STORAGE BATTERIESCAPITAL COSTS

<u>Initial Investment</u>	<u>10-Hour Battery</u>	<u>5-Hour Battery</u>	<u>3-Hour Battery</u>
Installed Cost (\$/kW)			
Battery Costs	368	184	111
Other Energy Related Costs	284	142	85
Converter Costs	74	74	74
Total	726	400	270
Lead Time (years)	2	2	2
CCIF	1.05	1.05	1.05
Estimated Life (years) (exclusive of Batteries)	30	30	30
Carrying Charges (exclusive of Batteries)	15	15	15

Battery Replacement

(\$/kW)	276	138	83
Estimated Life	2000 cycles up to 14 years		
Carrying Charges	Determined as a function of life in Section 5.		

OPERATING CHARACTERISTICS

Efficiency (%)	75	70	65
Charging Time (hours)	10/13	5/7/10	3/5/10
Charging Capacity (% of rated load)	133/100	143/100/- 71	154/100/- 46
Fixed O&M		None	
Variable O&M (mills/kWh)	0.5	0.5	0.5
Forced Outage Rate (%)	4	4	4
Annual Maintenance (week/year)	1	1	1

Section 3

Transmission and Distribution Savings from Dispersed Siting

3.1 IDENTIFICATION OF TRANSMISSION SYSTEM APPLICATIONS

The following have been selected as the three most promising applications of lead-acid battery installations on the PSE&G system that could result in deferment of presently planned transmission and/or distribution system reinforcements:

1. Addition of 85 MW of battery capacity in the PSE&G Northern Zone in 1979. This installation will:
 - a. Defer a planned Hawthorne-Hinchmans Avenue 230-kV pipe-type cable of about 6 miles, a Walldwick 230-kV 600 MVA phase angle regulator (PAR) and related station work from May, 1979 to May, 1980.
 - b. Defer indefinitely a planned (May, 1983) oil circulation system for the existing South Mahwah-Walldwick 345-kV pipe-type cable of about 5 miles.
 - c. Defer a planned Hawthorne-Fair Lawn 230-kV pipe-type cable of about 2 miles, a Fair Lawn 230/138-kV autotransformer and related station work from May, 1984 to May, 1987. In order to effect this delay, about 85% of the 85-MW battery addition must be installed in the Fair Lawn load area.
2. Addition of 170 MW of battery capacity in the PSE&G Northern Zone (85 MW in 1979 and 85 MW in 1981). This installation will:
 - a. Defer a planned Hawthorne-Hinchmans Avenue 230-kV pipe-type cable of about 6 miles, a Walldwick 230-kV 600 MVA PAR and related station work from May, 1979 to May, 1980.
 - b. Defer indefinitely a planned (May, 1983) oil circulation system for the existing South Mahwah-Walldwick 345-kV pipe-type cable of about 5 miles.
 - c. Defer a planned Hawthorne-Fair Lawn 230-kV pipe-type cable of about 2 miles, a Fair Lawn 230/138-kV autotransformer and related station work from May, 1984 to May, 1988. In order to effect this delay, about 85% of the 170-MW battery addition must be installed in the Fair Lawn load area.

- d. Defer a planned Aldene-Essex 230-kV pipe-type cable of about 18 miles, an Essex 230-kV 600 MVA PAR and related station work from May, 1981 to May, 1982.
3. Addition of 440 MW of battery capacity in the PSE&G Northern Zone (85 MW in 1979, 110 MW in 1980, 190 MW in 1981 and 55 MW in 1983). This installation will:
- a. Defer a planned Hawthorne-Hinchmans Avenue 230-kV pipe-type cable of about 6 miles, a Waldwick 230-kV 600 MVA PAR and related station work from May, 1979 to May, 1982.
 - b. Defer indefinitely a planned (May, 1983) oil circulation system for the existing South Mahwah-Waldwick 345-kV pipe-type cable of about 5 miles.
 - c. Defer a planned Hawthorne-Fair Lawn 230-kV pipe-type cable of about 2 miles, a Fair Lawn 230/138-kV autotransformer and related station work from May, 1984 to May, 1988. In order to effect this delay, about 35% of the 440-MW battery addition must be installed in the Fair Lawn load area.
 - d. Defer indefinitely a planned (May, 1981) Aldene-Essex 230-kV pipe-type cable of about 18 miles, an Essex 230-kV 600 MVA PAR and related station work.

3.2 IDENTIFICATION OF TRANSMISSION SAVINGS

The transmission project deferrals identified above resulting from the siting of battery capacity in the PSE&G system are summarized in Table 3-1 and discussed below:

Application 1

The addition of 85 MW of battery capacity in the PSE&G Northern Zone in 1979 will result in the deferral of two transmission developments planned for relief of forecast Northern Zone CETL/CETO¹ deficits and one development planned for relief of forecast Fair Lawn load area load/capacity deficits.

Installation of the Hawthorne-Hinchmans Avenue 230-kV pipe-type cable (6 mi) and a new 600 MVA PAR at Waldwick Switching Station (Table 3-1, Item 1-a) will complete a 230-kV phase angle

¹For discussion of Capacity Emergency Transfer Limit/Objective (CETO/CETL) and related transmission methodology, see Appendix C.

TABLE 3-1
TRANSMISSION DEFERRALS FROM BATTERY ADDITIONS

<u>Application</u>	<u>Battery Additions</u>		<u>Facilities Deferred</u>	<u>Planned Service Date</u>	<u>Deferred Service Date</u>	<u>Estimated Capital Cost (current)</u>
	(MW)	(YEAR)		(YEAR)	(YEAR)	(\$x1000)
1 (1)	85	1979	a. Hawthorne-Hinchmans 230-kV cable and Walldwick 230-kV 600 MVA PAR (2)	1979	1980	5,900
			b. South Mahwah-Walldwick 345-kV cable oil circulation equipment	1983	(3)	700
			c. Hawthorne-Fair Lawn 230-kV cable and Fair Lawn 230/138-kV autotransformer	1984	1987	5,300
2 (4)	85	1979	a. Hawthorne-Hinchmans 230-kV cable and Walldwick 230-kV 600 MVA PAR	1979	1980	5,900
	85	1981	b. South Mahwah-Walldwick 345-kV cable oil circulation equipment	1983	(3)	700
			c. Hawthorne-Fair Lawn 230-kV cable and Fair Lawn 230/138-kV autotransformer	1984	1988	5,300
			d. Aldene-Essex 230-kV cable and Essex 230-kV 600 MVA PAR	1981	1982	26,200
3 (5)	85	1979	a. Hawthorne-Hinchmans 230-kV cable and Walldwick 230-kV 600 MVA PAR	1979	1982	5,900
	110	1980	b. South Mahwah-Walldwick 345-kV cable oil circulation equipment	1983	(3)	700
	190	1981	c. Hawthorne-Fair Lawn 230-kV cable and Fair Lawn 230/138-kV autotransformer	1984	1988	5,300
	55	1983	d. Aldene-Essex 230-kV cable and Essex 230-kV 600 MVA PAR	1981	(3) (6)	26,200

Notes

- (1) Approximately 75 MW of the total 85 MW must be located in the Fair Lawn load area
- (2) PAR - Phase Angle Regulator
- (3) Deferred indefinitely beyond 1987
- (4) Approximately 150MW of the total 170 MW must be located in the Fair Lawn load area
- (5) Approximately 150MW of the total 440 MW must be located in the Fair Lawn load area
- (6) It would cost approximately \$200,000,000 to install enough batteries to indefinitely defer the Aldene-Essex project (\$26,200,000).

regulated transmission path between Waldwick and Cedar Grove Switching Stations and result in a 200-MW increase in the PSE&G Northern Zone CETL. This project is currently scheduled for service in May, 1979 at an estimated capital cost of \$5,900,000 (current dollars). As shown on Table 3-2, the 1979 CETO is 1879 MW, the CETL, assuming scheduled completion of the project, is 2000 MW and CETL/CETO surplus is 121 MW. The deferral of this planned transmission development from May, 1979 to May, 1980 would change the 1979 CETL to 1800 MW and result in a CETL/CETO deficit of 79 MW. The amount of battery capacity required to be added to the Northern Zone to achieve a CETO reduction of 79 MW (and a corresponding increase in the CETL/CETO surplus to zero) is determined to be 85 MW (based on the use of 5-hour batteries with a nominal 95% availability rate). This determination was made by analyzing the PSE&G Northern Zone peak day load cycle curve (Figure 3-1). This curve is represented in percent of Northern Zone peak load and is based on selected substation and switching station data from the 1975 peak day. By integrating the area under this curve with respect to percent peak (from 100% to 0%), a new curve (Figure 3-2, Curve A) can be developed. This new curve represents the cumulative percent hours of energy under the load cycle curve versus percent peak load equal to or greater than a given value. The complement of this curve (Figure 3-2, Curve B) is the cumulative percent hours of energy not under the load cycle curve (valley area) versus percent peak load equal to or less than a given value. Using these two curves on Figure 3-2, the Northern Zone peak load data (Table 3-3) and the Northern Zone CETL/CETO conditions for 1977-1987 (Table 3-4) the required energy storage capacity (in MWh) of batteries installed to achieve a given Northern Zone CETO decrease can easily be determined. Also, a check can be made to confirm the Northern Zone's ability to charge the batteries during off-peak periods. Specifically, in the Northern Zone, it is desired to reduce the 1979 CETO by reducing the peak load by 79 MW. The 1979 Northern Zone forecast peak load is 3449 MW. Reducing this value by 79 MW yields 3370 MW or 97.7% of the forecast peak. From Figure 3-2, Curve A, the percent hours of battery energy that would be required to decrease the Northern Zone peak load (and thereby decrease the CETO) by 79 MW is 2% h on a 1979 peak load of 3449 MW, this represents 69 MWh of energy. The 85 MW of 5-hour batteries in this application contains over 400 MWh of energy ($85 \text{ MW} \times 5 \text{ h} \times 0.95$) which is well above the minimum requirement. By inspection, no limitations exist to charging 85 MW of batteries in the off-peak periods. The use of 3-hour batteries would provide 242 MWh of energy discharge capability, also sufficient to support the Northern Zone CETO reduction. However, as will be discussed below, 3-hour batteries are not suitable to support the required capacity increase in the Fair Lawn load area.

Addition of a forced oil circulation system to the existing South Mahwah-Waldwick 345-kV pipe-type cable (Table 3-1, Item 1-

TABLE 3-2

PSE&G NORTHERN ZONE
BASE IMPORT CONDITIONS(1)
1977-1987

<u>YEAR</u>	<u>CETO</u> ⁽²⁾ (MW)	<u>CETL</u> ⁽³⁾ (MW)	<u>CETL/CETO</u> <u>SURPLUS</u> (MW)	<u>ETG</u> ⁽⁴⁾ (MW)	<u>NTL</u> ⁽⁵⁾ (MW)	<u>NTL/ETG</u> <u>SURPLUS</u> (MW)
1977	1673	1800	127	1045	1600	555
1978	1765	1800	35	1038	1600	562
1979	1879	2000	121	1244	1800	556
1980	1986	2000	14	1242	1800	558
1981	2163	2400	237	1360	2000	640
1982	2270	2400	130	1520	2000	480
1983	2419	2500	81	1766	2000	234
1984	2585	3000	415	2076	2500	424
1985	2749	3500	751	2475	2700	225
1986	2922	3500	578	2471	2700	229
1987	3120	3500	380	2876	3000	124

NOTES:

- (1) Based on PSE&G plans as of April, 1976
- (2) CETO - Capacity Emergency Transfer Objective
- (3) CETL - Capacity Emergency Transfer Limit
- (4) ETG - Extra-Territorial Generation
- (5) NTL - Normal Transfer Limit

NORTHERN ZONE AND PSE&G SYSTEM
 PEAK DAY LOAD CYCLE CURVES
 (BASED ON AUGUST 1, 1975)

FIGURE 3-1

FIGURE 3-2

TABLE 3-3
PSE&G NORTHERN ZONE
LOAD AND CAPACITY CONDITIONS⁽¹⁾
1977-1987

<u>YEAR</u>	<u>LOAD</u> (MW)	<u>INSTALLED</u> <u>GENERATING</u> <u>CAPACITY</u> (MW)	<u>INSTALLED⁽²⁾</u> <u>GENERATION</u> <u>RESERVE (DEFICIT)</u>	
			(MW)	(%)
1977	3245	3162	(83)	(2.6)
1978	3338	3162	(176)	(5.3)
1979	3449	3162	(287)	(8.3)
1980	3579	3189	(390)	(10.9)
1981	3752	3189	(563)	(15.0)
1982	3859	3189	(670)	(17.4)
1983	4008	3189	(819)	(20.4)
1984	4177	3189	(988)	(23.7)
1985	4341	3189	(1152)	(26.5)
1986	4510	3189	(1321)	(29.3)
1987	4708	3189	(1519)	(34.3)

⁽¹⁾ Based on PSE&G plans as of April, 1976

⁽²⁾ Represented in percent of load

TABLE 3-4

PSE&G NORTHERN ZONE 1977-87 CETL/CETO CONDITIONS(1)(2)
BATTERY APPLICATION 1

	A	B	C	D	E	F	G	H	I
	TRANSMISSION PROJECT DEFERRALS							BATTERY ADDITIONS	
	Base Conditions (3)			Hawthorne-Hinchmans 1979 to 1980 (4)		S. Mahwah-Waldwick 1983 to Beyond 1987(5)		85 MW(1979)	(6)
YEAR	CETO (MW)	CETL (MW)	SURPLUS(7) (MW)	CETL (MW)	SURPLUS(7) (MW)	CETL (MW)	SURPLUS(7) (MW)	CETO (MW)	SURPLUS(7) (MW)
1977	1673	1800	127	1800	127	1800	127	1673	127
1978	1765	1800	35	1800	35	1800	35	1765	35
1979	1879	2000	121	1800	(79)	1800	(79)	1800	0
1980	1986	2000	14	2000	14	2000	14	1907	93
1981	2163	2400	237	2400	237	2400	237	2084	316
1982	2270	2400	130	2400	130	2400	130	2191	209
1983	2419	2500	81	2500	81	2400	(19)	2340	60
1984	2585	3000	415	3000	415	2900	315	2506	394
1985	2749	3500	751	3500	751	3400	651	2670	730
1986	2922	3500	578	3500	578	3400	478	2843	557
1987	3120	3500	380	3500	380	3400	280	3041	359

Notes

- (1) Based on PSE&G plans as of April, 1976
 (2) CETL/CETO - Capacity Emergency Transfer Limit/Objective
 (3) From Table 3-2
 (4) Table 3-1, Item 1-a.
 (5) Table 3-1, Item 1-b.
 (6) 85 MW of 5-hour batteries with a nominal 5% forced outage rate result in a 79 MW CETO reduction
 (7) Surplus (deficit) = CETL minus CETO

Key

- C = B - A
 D = B - 200 MW(1979 only)
 E = D - A
 F = D - 100 MW(1983-1987)
 G = F - A
 H = A - 79 MW(1979-1987)
 I = F - H

b) will result in a 100-MW increase in the Northern Zone CETL. This project is currently scheduled for service in May, 1983 at an estimated capital cost of \$700,000 (current dollars). Following the 1979 installation of 85 MW of battery capacity and the Hawthorne-Hinchmans cable/Waldwick PAR project deferral from 1979 to 1980, the 100-MW CETL increase provided by the South Mahwah-Waldwick reinforcement is no longer required. Therefore, the project can be deferred indefinitely beyond 1987 with no resultant CETL/CETO deficits. The CETL/CETO conditions reflecting this deferral, in addition to the previous deferral and the battery installation, are shown in Table 3-4.

The installation of a new 230-kV pipe-type cable from Hawthorne 230-kV Substation to Fair Lawn Switching Station and a new 230/138-kV autotransformer at Fair Lawn (Table 3-1, Item 1-c) will result in an approximately 300 MVA increase in the capacity of the Fair Lawn load area. This project is currently scheduled for service in May, 1984 at an estimated capital cost of \$5,300,000 (current dollars). Inspection of the Fair Lawn load area load/capacity conditions (Table 3-5) reveals deficits of 35 MVA (1984), 63 MVA (1985), 65 MVA (1986) and 98 MVA (1987) exclusive of the transmission capacity provided by the planned 1984 reinforcement and any battery capacity. If some portion of the 85-MW battery installation proposed in Application 1 is located specifically in the Fair Lawn load area, the planned Hawthorne-Fair Lawn project could be deferred. area capacity can be determined by analyzing the peak day load cycle curve (Figure 3-3). This curve is represented in percent of area peak load and is based on data from the 1975 peak day. By integrating the area under this curve with respect to percent peak (from 100% to 0%), a new curve (Figure 3-4, Curve A) can be developed. This new curve represents the cumulative percent hours of energy under the load cycle curve versus percent peak load equal to or greater than a given value. The complement of this curve (Figure 3-4, Curve B) is the cumulative percent hours of energy not under the load cycle curve (valley area) versus percent peak load equal to or less than a given value. Using these two curves on Figure 3-4, the Fair Lawn area peak load data for 1984-1987, the existing capacity of the Fair Lawn area and the methodology described in Appendix C, the battery energy storage requirements (in MWh) to achieve a given area capacity increase can easily be determined. Also, a check can be made to confirm the area's ability to charge the batteries during off-peak periods. From the determined energy storage requirements, assuming the use of 5 hour batteries with a nominal 5% forced outage rate, the required magnitude of the battery installation (in MW) can be calculated. Specifically for the Fair Lawn area, it is desired to increase the area capacity by 65 MW in 1986. Since the battery additions required for this increase will be part of the 85 MW added in 1979 for Northern Zone CETL/CETO reasons, the smaller 1984 and 1985 Fair Lawn load/capacity deficits will automatically be relieved. The

TABLE 3-5
FAIR LAWN LOAD AREA
1981-1987 LOAD AND CAPACITY CONDITIONS⁽¹⁾
(MVA)

	<u>1981</u>	<u>1982</u>	<u>1983</u>	<u>1984</u>	<u>1985</u>	<u>1986</u>	<u>1987</u>
<u>LOAD</u>							
Fair Lawn	386	392	402	379	379	364	379
E. Fair Lawn				30	36	41	47
Kuller Road	15	20	24	35	44	49	55
N. Hasbrouck Hts.	<u> </u>	<u> </u>	<u> </u>	<u>19</u>	<u>34</u>	<u>39</u>	<u>45</u>
TOTAL LOAD	401	412	426	463	491	493	526
<u>CAPACITY⁽²⁾</u>							
138-kV Cables ⁽³⁾	388	388	388	388	388	388	388
Transferrable Load	<u>40</u>	<u>40</u>	<u>40</u>	<u>40</u>	<u>40</u>	<u>40</u>	<u>40</u>
TOTAL CAPACITY	428	428	428	428	428	428	428
CAPACITY SURPLUS(DEFICIT)	<u>27</u>	<u>16</u>	<u>2</u>	<u>(35)</u>	<u>(63)</u>	<u>(65)</u>	<u>(98)</u>

NOTES

- (1) Based on PSE&G plans as of April, 1976
- (2) Excluding 300 MVA increase from planned Hawthorne-Fair Lawn 230-kV cable project (1984)
- (3) Based on 2 cables in service, each with a 204 MVA 300-hour emergency rating and an assumed 5% flow imbalance.

FIGURE 3-3

FIGURE 3-4

capacity of Fair Lawn prior to the scheduled 1984 reinforcement is 428 MVA as indicated and explained in Table 3-5. This is 87% of the 1986 forecast peak load of 493 MVA. From Figure 3-4, Curve A, the percent hours of battery energy that would be required to increase the Fair Lawn area capacity (or reduce the effective area load) by 65 MW is 70% h. On a 1986 peak load of 493 MVA, this represents 345 MWh of energy. To meet this energy requirement, 73 MW of 5-hour batteries (with a nominal forced outage rate of 5%) need to be installed in the Fair Lawn area ($345 \text{ MWh} / (5 \text{ h} \times 0.95)$). Checking the area's ability to charge these batteries during the off-peak period shows that for 345 MWh of energy discharged at peak load, and assuming a 70% conversion efficiency, the off-peak charging requirement is 493 MWh ($345 \text{ MWh} / 0.70$). Converting this charging requirement to percent hours yields 100% h ($493 \text{ MWh} / 493 \text{ MVA peak}$). From Figure 3-4, Curve B, depicting off-peak charging capability in percent of peak load, the area capacity (exclusive of batteries) required to charge, 73 MW of batteries is found to be 61.5% or 303 MW. Since this is less than the 428 MVA capacity of the area excluding batteries, there is sufficient off-peak charging capability available to support the proposed installation. It should be recognized that since the capacity of the Fair Lawn local load area is based on one of the three 138-kV cable supplies being out of service for up to 300 hours, the battery installation would only be called on to operate for this purpose under cable outage conditions.

The foregoing analysis of battery installations in the Fair Lawn load area was based on using a 5 hour lead-acid storage battery. Repeating this analysis using a 3-hour battery, the required battery installation to provide 345 MWh of battery discharge capability would be 121 MW ($345 \text{ MWh} / (3 \text{ h} \times 0.95)$). Since the total Northern Zone battery addition in this application is 85 MW, the 3-hour battery is not a suitable choice.

The batteries installed in the PSE&G Northern Zone and the included Fair Lawn load area will normally be operated on a PSE&G system economic dispatch basis. However, to provide the necessary emergency capacity benefits to the Northern Zone and the Fair Lawn load area, the batteries must be sufficiently charged to provide the energy required to achieve CETO and/or local load area peak load reductions in the event of a critical transmission outage. If, for instance, the zone or local load area load cycle lagged the system load cycle, the batteries could possibly be fully discharged (based on system economic dispatch) before the peak load of the critical zone or local load area actually occurred. Therefore, no reduction in CETO and/or local load area peak load would be possible in the event of a critical transmission outage. On the other hand, if the zone or local load area load cycle curve slightly leads the system curve, the batteries will be charged and ready to operate for a possible

zone or local load area emergency before the discharge of these batteries is required for system economic dispatch.

Inspection of the PSE&G Northern Zone and Fair Lawn load area load cycle curves indicates a sufficiently close coincidence to, or leading of, the PSE&G system load cycle curve to establish acceptable operation.

Application 2

The addition of 170 MW of battery capacity in the PSE&G Northern Zone (85 MW in 1979 and 85 MW in 1981) will result in the deferral of three transmission developments planned for relief of Northern Zone CETL/CETO deficits and one development planned for the relief of forecast Fair Lawn load area load/capacity deficits.

Installation of the Hawthorne's-Hinchmans Avenue 230-kV pipe-type cable (5.9 mi) and a new 600-MVA PAR at Waldwick Switching Station (Table 3-1, Item 2-a) and the addition of a forced oil circulation system to the existing South Mahwah-Waldwick 345-kV pipe-type cable (Table 3-1, Item 2-b) will result in Northern Zone CETL increases of 200 MW and 100 MW, respectively as discussed under "Application 1" above.

Installation of the Aldene-Essex 230-kV pipe-type cable (18 mi), a 600 MVA PAR at Essex and related station work at Essex and Aldene (Table 3-1, Item 2-d) will complete an additional phase angle regulated link between the PSE&G Northern and Central Zones and result in a 400-MW increase in the Northern Zone CETL. This project is currently scheduled for service in May, 1981 at an estimated cost of \$26,200,000 (current dollars). In order to effect the deferral of the Aldene-Essex project from 1981 to 1982, the 1981 Northern Zone CETO (Table 3-6) must be reduced by 163 MW to 2000 MW. This 163-MW reduction in CETO as a result of a battery installation is equivalent to a peak load reduction of 163 MW. The 1981 Northern Zone peak load is 3752 MW (Table 3-3). Reducing this value by 163 MW yields 3589 MW or 95.7% of the forecast peak. From Figure 3-2, Curve A, the percent hours of battery energy required to decrease the Northern Zone peak load (and thereby decrease the CETO) by 163 MW is 9% h. On a 1981 peak load of 3752 MW, this represents 338 MWh of energy. The 170 MW of 5-hour batteries in this application contain over 800 MWh of energy ($170 \text{ MW} \times 5 \text{ h} \times 0.95$) which is well above the minimum requirement. No limitations exist to charging 170 MW of batteries in the off-peak periods. The use of 3-hour batteries would provide 485 MWh of energy discharge capability and would also be sufficient to support the Northern Zone CETO reduction. However, as in "Application 1", the use of 3-hour batteries is

precluded by the Fair Lawn load area requirements as discussed below.

The addition of 170 MW of battery capacity to the PSE&G Northern Zone permits the deferral of the Hawthorne-Hinchmans project from 1979 to 1980, the South Mahwah-Waldwick oil circulation project from 1983 to beyond the 1987 period and the Aldene-Essex project from 1981 to 1982 without incurring any CETL/CETO deficits. The resultant CETL/CETO conditions are shown in Table 3-6.

Installation of the Hawthorne-Fair Lawn project can be deferred from 1984 to 1988 based on the installation of a portion of the total 170 MW Northern Zone battery installation in the Fair Lawn load area to relieve the 98-MW capacity deficit existing in 1987. Since the battery additions required for this increase will be part of the 170-MW added in 1979 and 1981 for Northern Zone CETL/CETO reasons, the smaller 1984, 1985 and 1986 Fair Lawn capacity deficits will automatically be relieved. The 428 MVA capacity of the Fair Lawn load area prior to the Hawthorne-Fair Lawn reinforcement is 81% of the 1987 forecast peak load of 526 MVA. From Figure 3-4, Curve B, the percent hours of battery energy required to increase the Fair Lawn area capacity (or reduce the effective area load) by 98 MW is 135% h. On a 1987 peak load of 526 MVA, this represents 710 MWh of energy. To provide this required amount of energy, 149 MW of 5-hour batteries (with a nominal forced outage rate of 5%) need to be installed in the Fair Lawn load area ($710 \text{ MWh} / (5 \text{ h} \times 0.95)$). Checking the area's ability to charge these batteries during the off-peak period shows that for 710 MWh of energy discharged at peak load, 1014 MWh of charging capability must exist off-peak, assuming a 70% conversion efficiency ($710 \text{ MWh} / 0.70$). Converting this charging requirement to percent hours yields 193% h ($1014 \text{ MWh} / 526 \text{ MVA peak}$). From Figure 3-4, Curve B depicting off-peak charging capability in percent of peak load, the area capacity (exclusive of batteries) required to charge 149 MW of batteries is found to be 71.5% or 376 MW. Since this is less than the 428 MW actual capacity of the area, there is sufficient off-peak charging capability available to support the proposed installation. To relieve the Fair Lawn area deficit by installing 3-hour instead of 5-hour batteries would require 249 MW of 3-hour batteries. Since this is more than the total battery installation under "Application 2", the 3-hour battery is unacceptable in this application.

Application 3

The addition of 440 MW of battery capacity in the PSE&G Northern Zone (85 MW in 1979, 110 MW in 1980, 190 MW in 1981 and

BATTERY APPLICATION 2

	A	B	C	D	E	F	G	H	I	J	K
	TRANSMISSION			PROJECT		DEFERRALS		BATTERY ADDITIONS			
	BASE CONDITIONS (3)			Hawthorne-Hinchmans 1979 to 1980 (4)		S. Mahwah - Waldwick 1983 to beyond 1987 (5)		Aldene-Essex 1981 to 1982 (6)		85 MW (1981) (7)	
YEAR	CETO (MW)	CETL (MW)	SURPLUS (7) (MW)	CETL (MW)	SURPLUS (7) (MW)	CETL (MW)	SURPLUS (MW)	CETL (MW)	SURPLUS (MW)	CETO (MW)	SURPLUS (MW)
1977	1673	1800	127	1800	127	1800	127	1800	127	1673	127
1978	1765	1800	35	1800	35	1800	35	1800	35	1765	35
1979	1879	2000	121	1800	(79)	1800	(79)	1800	(79)	1800	0
1980	1986	2000	14	2000	14	2000	14	2000	14	1907	93
1981	2163	2400	237	2400	237	2400	237	2000	(163)	2005	(5)
1982	2270	2400	130	2400	130	2400	130	2400	130	2112	288
1983	2419	2500	81	2500	81	2400	(19)	2400	(19)	2261	139
1984	2585	3000	415	3000	415	2900	315	2900	315	2427	473
1985	2749	3500	751	3500	751	3400	651	3400	651	2591	809
1986	2922	3500	578	3500	578	3400	478	3400	478	2764	636
1987	3120	3500	380	3500	380	3400	280	3400	280	2962	438

Notes:

- (1) Based on PSE&G plans as of April, 1976
 (2) CETL/CETO - Capacity Emergency Transfer Limit/Objective
 (3) From Table 3-2
 (4) Table 3-1, Item 2a.
 (5) Table 3-1, Item 2b.
 (6) Table 3-1, Item 2d.
 (7) 85 MW of 5-hour batteries with a nominal 5% forced outage rate result in a 79 MW CETO reduction.
 (8) Surplus (Deficit) = CETL minus CETO

Key

- C = B-A
 D = B-200 MW(1979 only)
 E = D-A
 F = D - 100 MW(1983-1987)
 G = F-A
 H = F - 400 MW(1981 only)
 I = H - A
 J = A - 79 MW(1979-1987) - 79MW(1981-1987)
 K = H - J

55 MW in 1983) will result in the further deferral of the transmission projects discussed in "Application 2" above.

The Hawthorne-Hinchmans project can be deferred from 1979 to 1982, the South Mahwah-Waldwick oil circulation project from 1983 to beyond 1987 and the Aldene-Essex project from 1981 to beyond 1987. The largest CETL/CETO deficit created by these deferrals is 419 MW in 1983 (Table 3-7). Taking the 1983 Northern Zone peak load of 4008 MW (Table 3-3) and reducing this value by 419 MW yields 3589 MW or 89.5% of the forecast peak. From Figure 3-2, Curve A, the percent hours of battery energy required to decrease the Northern Zone peak load (and thereby decrease the CETO) by 419 MW is 45% h. On a 1983 peak load of 4008 MW, this represents 1804 MWh of energy. The 440-MW of 5-hour batteries in this application contain 2090 MWh of energy ($440 \text{ MW} \times 5 \text{ h} \times 0.95$), an excess over the minimum requirement. Checking the Northern Zone's ability to charge these batteries during the off-peak period shows that for 1804 MWh of energy discharged at peak load, 2577 MWh of charging capability must exist off-peak, assuming a 70% conversion efficiency ($1804 \text{ MWh}/0.70$). Converting this charging requirement to percent hours yields 64% h ($2577 \text{ MWh}/4008 \text{ MW peak}$). From Figure 3-2, Curve B depicting off-peak charging capability in percent of peak load, the Northern Zone capacity (exclusive of batteries) required to charge 440 MW of batteries is found to be 65% or 2605 MW. Since the Northern Zone transmission is capable of supplying 3589 MW of load, there is sufficient off-peak charging capability available to support the installation. 440 MW of 3-hour batteries would provide only 1254 MWh of energy ($440 \times 3 \text{ h} \times 0.95$) which is insufficient to support the required CETO decrease. The PSE&G Northern Zone CETL/CETO conditions existing following the proposed (Application 3) battery installations and the specified deferrals are shown in Table 3-7. The Hawthorne-Fair Lawn project can be deferred from 1984 to 1988, as it was in "Application 2" above, by locating 149 MW of the total 440 MW in the Fair Lawn load area.

The battery installation in this application is assumed to be sufficient in quantity and location to alleviate the need in the 1983-1987 period for a Fifteenth Street substation planned for 1983. The costs for this work are included in the Aldene-Essex project.

3.3 COMPARISON OF SAVINGS - THREE TRANSMISSION APPLICATIONS

As can be seen from Table 3-1, the three transmission applications identified require differing amounts of batteries at different service dates and result in a combination of transmission line deferrals and cancellations. It will be necessary to state the transmission savings as well as all other battery costs and savings in a common unit so that rational

TABLE 3-7

PSE&G NORTHERN ZONE 1977-87 CETL/CETO CONDITIONS^{(1) (2)}
BATTERY APPLICATION 3

	<u>A</u>	<u>B</u>	<u>C</u>	<u>D</u>	<u>E</u>	<u>F</u>	<u>G</u>	<u>H</u>	<u>I</u>	<u>J</u>	<u>K</u>
	<u>TRANSMISSION PROJECT DEFERRALS</u>									<u>BATTERY ADDITIONS</u>	
				Hawthorne-Binchmans 1979 to 1982(4)	S. Mahwah-Waldwick 1983 to beyond 1987(5)		Aldene-Essex 1981 to beyond 1987(6)		85 MW(1979)(7) 110 MW(1980)(8) 190 MW(1981)(9) 55 MW(1983)(10)		
	<u>BASE CONDITIONS(3)</u>										
<u>YEAR</u>	<u>CETO</u> <u>(MW)</u>	<u>CETL</u> <u>(MW)</u>	<u>SURPLUS(11)</u> <u>(MW)</u>	<u>CETL</u> <u>(MW)</u>	<u>SURPLUS(11)</u> <u>(MW)</u>	<u>CETL</u> <u>(MW)</u>	<u>SURPLUS(11)</u> <u>(MW)</u>	<u>CETL</u> <u>(MW)</u>	<u>SURPLUS(11)</u> <u>(MW)</u>	<u>CETO</u> <u>(MW)</u>	<u>SURPLUS(11)</u> <u>(MW)</u>
1977	1673	1800	127	1800	127	1800	127	1800	127	1673	127
1978	1765	1800	35	1800	35	1800	35	1800	35	1765	35
1979	1879	2000	121	1800	(79)	1800	(79)	1800	(79)	1800	0
1980	1986	2000	14	1800	(186)	1800	(186)	1800	(186)	1801	(1)
1981	2163	2400	237	2200	37	2200	37	1800	(363)	1797	1
1982	2270	2400	130	2400	130	2400	130	2000	(270)	1904	96
1983	2419	2500	81	2500	81	2400	(19)	2000	(419)	2001	(1)
1984	2585	3000	415	3000	415	2900	315	2500	(485)	2167	333
1985	2749	3500	751	3500	751	3400	651	3000	251	2331	669
1986	2922	3500	578	3500	578	3400	478	3000	78	2504	496
1987	3120	3500	380	3500	380	3400	280	3000	(120)	2702	298

Notes

- (1) Based on PSE&G plans as of April, 1976
 (2) CETL/CETO - Capacity Emergency Transfer Limit/Objective
 (3) From Table 3-2
 (4) Table 3-1, Item 3a.
 (5) Table 3-1, Item 3b.
 (6) Table 3-1, Item 3d.
 (7) 85 MW of 5-hour batteries with a nominal 5% forced outage rate result in a 79 MW CETO reduction
 (8) 110 MW of 5-hour batteries with a nominal 5% forced outage rate result in a 106 MW CETO reduction
 (9) 190 MW of 5-hour batteries with a nominal 5% forced outage rate result in a 181 MW CETO reduction
 (10) 55 MW of 5-hour batteries with a nominal 5% forced outage rate result in a 52 MW CETO reduction
 (11) Surplus (Deficit) = CETL minus CETO

Key

- C = B-A
 D = B-200 MW (1979-1981)
 E = D-A
 F = D - 100 MW (1983-1987)
 G = F-A
 H = F-400 MW (1981-1987)
 I = H-A
 J = A - 79 MW (1979-1987) - 106 MW (1980-1987) - 181 MW (1981-1987) - 52 MW (1983-1987)
 K = H-J

comparison can be made. The unit which will be used will be the "present worth of all future revenue requirements" (pwafr). The pwafr values will be expressed in terms of 1979 dollars throughout this report. Pwafr is a universally recognized criterion of economic choice for the U.S. utility industry. It is the summation of the present worth of each year's minimum revenue requirements from the beginning of a study period (in our case 1979) to eternity. These minimum revenue requirements are obtained from customers to cover all expenses associated with installation and operation of the equipment. The criterion for economic choice is to minimize pwafr. For a fuller explanation of the concept of pwafr, the reader is encouraged to consult "Profitability and Economic Choice" - P. H. Jeynes, Iowa State University Press, 1968.

Tables 3-8 through 3-10 summarize the pwafr transmission savings for these applications. The CCIF and percent carrying charge values are consistent with the values used in the EPRI sponsored fuel cell analysis. The text associated with the battery cost analysis in Section 5 provides a fuller explanation of the meanings of these terms.

The values on the three tables indicate total transmission pwafr savings for the three applications of \$3.1 million, \$6.9 million, and \$39.2 million respectively. Dividing these savings by the amounts of batteries required for these applications yields transmission pwafr savings per kW of batteries installed as follows:

	<u>Transmission Pwafr Savings</u>	<u>kW of Batteries</u>	<u>Transmission Pwafr Saving per kW of Batteries</u>
Application 1	\$ 3.1 million	85,000	\$ 36.3/kW
Application 2	\$ 6.9 million	170,000	\$ 40.5/kW
Application 3	\$39.2 million	440,000	\$ 89.1/kW

As can be seen, Application 3 results in the highest per unit transmission savings. Subsequent sections of this assessment will therefore concentrate on Application 3.

3.4 IDENTIFICATION OF DISTRIBUTION SAVINGS

The specific battery installations required for the transmission plans in the 1979-1985 period can also generate two types of distribution system savings:

- A. Specific savings from the postponement of planned substations in the 1979-1985 period.

TABLE 3-8

TRANSMISSION SAVINGS ANALYSIS
APPLICATION 1

<u>Service Date</u>	<u>1979</u>	<u>1983</u>	<u>1984</u>
Capital Cost Cancelled or Deferred (million dollars)	5.9	0.7	5.3
Cancel or No. of Years Deferred	1	cancel	3
CCIF(1)	1.05	1.05	1.05
% Carrying Charges(2)	15	15	15
Levelized Annual Revenue Requirements (million dollars/year)	.93	.11	.83
Pwafrr Saving (1979 million dollars)	<u>.93</u>	<u>.75</u>	<u>1.41</u>
Total Pwafrr Saving	\$3.1 million		

- (1) Construction compound interest factor, a factor in which the capital cost is adjusted to include the cost of money for capital expenditures made prior to the service date, 10% cost of money used.
- (2) Carrying charges of return (10%) depreciation and associated taxes.

TABLE 3-9

TRANSMISSION SAVINGS ANALYSIS
APPLICATION 2

<u>Service Date</u>	<u>1979</u>	<u>1981</u>	<u>1983</u>	<u>1984</u>
Capital Cost Cancelled (million dollars) or Deferred	5.9	26.2	0.7	5.3
Cancel or No. of Years Deferred	1	1	cancel	4
CCIF	1.05	1.05	1.05	1.05
% Carrying Charges	15	15	15	15
Levelized Annual Revenue Requirements (million dollars/year)	.93	4.13	.11	.83
Pwafr Savings (1979 million dollars)	.93	3.41	0.75	1.79
Pwafr Savings Total		\$6.9 million		

See notes on Table 3-8.

TABLE 3-10

TRANSMISSION SAVINGS ANALYSIS
APPLICATION 3

<u>Service Date</u>	<u>1979</u>	<u>1981</u>	<u>1983</u>	<u>1984</u>
Capital Cost Cancelled or Deferred (million dollars)	5.9	26.2	0.7	5.3
Cancel or No. of Years Deferred	3	cancel	cancel	4
CCIF	1.05	1.05	1.05	1.05
% Carrying Charges	15	15	15	15
Levelized Annual Revenue Requirements (million dollars/year)	.93	4.13	.11	.83
Pwafrr Saving (1979 million dollars)	<u>2.54</u>	<u>34.1</u>	<u>.75</u>	<u>1.79</u>
Pwafrr Saving Total		\$39.2 million		

See notes on Table 3-8.

B. General savings from the postponement of unidentified substations required in the post-1985 period.

These savings are both realized by installing the batteries on the low voltage busses of high capacity 13-kV substation as shown on Figures 3-5 and 3-6. The battery capacity is available to operate normally as part of the economic dispatch of the system and is also available after a substation transformer failure to reduce the emergency loading on the remaining transformer to within its rating, thereby postponing the need for substation reinforcement.

Further savings from applying batteries at the ends of primary or secondary distribution circuits are not feasible. This is further discussed in Appendix E.

In the analysis which follows, it has been predetermined that there is sufficient off-peak energy available at the specific substations to charge the battery installations. The methodology used to make these determinations is discussed in Appendix D.

The savings generated from the postponement of planned substations in the 1979-1985 period are determined very specifically, since PSE&G's Substation Plan presently extends to 1985. The savings from the post-1985 substation postponements are determined by projecting the 1976-1985 Northern Zone 13-kV substation load forecast to the year 1995 at a uniform representative rate and comparing this load to the effective area substation capacity. This comparison, which is shown on Table 3-11, shows that additional substation capacity will be needed beginning in 1990 to raise to effective Northern Zone substation capacity.

The effective Northern Zone substation capacity was determined as follows (See calculations on Table 3-12):

First, the 1985 excess capacity margin for each of the thirty-one Northern Zone substations was calculated.

Second, the capacity margins were expressed in percent of 1985 substation load.

Third, the expected value of the thirty-one substation capacity margin statistics was calculated.

Fourth, the effective Northern Zone capacity margin was calculated as the product of 1985 Northern Zone load and expected value of the capacity margin.

FIGURE 3-5

CONFIGURATION OF TYPICAL HIGH CAPACITY DISTRIBUTION SUBSTATION

(STEPS DOWN TRANSMISSION VOLTAGE TO DISTRIBUTION VOLTAGE
FOR SUPPLY TO INDIVIDUAL CUSTOMERS SERVED AT PRIMARY
AND SECONDARY VOLTAGES)

FIGURE 3-6
SUBSTATION CONFIGURATION
(WITH BATTERIES)

TABLE 3-11

NORTHERN ZONE 13-kV SUBSTATION LOAD AND CAPACITY
1986-1995

<u>Year</u>	<u>Substation Load (1)</u>	<u>Effective Substation (2) Capacity</u>	<u>Capacity Deficit</u>
1986	2170	3000	-
1987	2365	3000	-
1988	2575	3000	-
1989	2810	3000	-
1990	3060	3000	60
1991	3335	3000	335
1992	3635	3000	635
1993	3963	3000	963
1994	4320	3000	1370
1995	4710	3000	1710

(1) non-coincident sum of substation peak loads.

(2) based on 1985 expected value of excess substation capacity.

TABLE 3-12
CALCULATION OF 1985 NORTHERN ZONE
EFFECTIVE EXCESS SUBSTATION CAPACITY

Substation Group #1	1985 Forecasted Load (MW)	1985 Excess Capacity (MW) (1)	1985 Excess Capacity (%)	Group Average Excess Capacity (%)	1985 Northern Zone Excess Substation Capacity (% of peak load)
I					
1	76	0	0		
2	87	0	0		
3	74	0	0		
4	75	0	0		
5	65	0	0		
6	76	0	0		
7	128	0	0		
8	76	0	0		
9	76	0	0		
10	134	0	0		
11	75	1	1		
12	72	1	1	0	44.8
II					
1	53	7	13		
2	64	9	14		
3	59	6	10		
4	53	12	23		
5	58	7	12	14	
III					
1	103	33	32		
2	100	34	34		
3	43	17	40		
4	82	38	45	38	
IV					
1	38	22	59		
2	87	52	60		
3	38	23	61	54	
V					
1	30	31	104		
2	36	32	89		
3	36	32	89		
4	34	26	76	90	
VI					
1	22	38	173		
2	17	48	282		
3	22	38	173	209	

(1) Excess capacity is the amount by which the substation capacity exceeds the load

(2) NZ Excess Capacity (%) = $\frac{\sum nx}{N}$

Where n= number of substations in group

N= total number of substation in Northern Zone

X=Average excess capacity in group

Fifth, the effective Northern Zone substation capacity was calculated as the sum of the 1985 Northern Zone substation load and capacity margin in MW.

Although this approach is general and does not identify individual future substations, it does provide a reasonable approximation of the time frame and gross capacity of future additions which can be used in subsequent economic comparisons of alternate plans.

The savings are assessed for each of the three battery application scenarios discussed in Section 3.1. The savings are the present worth in 1979 of all future reserve requirement savings due to the location of the batteries on the low voltage busses of 13 kV substations. The assessment and subsequent savings do not include the installation specifically required at Fair Lawn Switching Station which was discussed in Section 3.1.

The capital cost used for substations is \$29/kW or \$1,740,000 for a nominal 60 MVA substation, which is a current PSE&G estimate used for study purposes.

3.5 DISCUSSION OF 1979-1985 SUBSTATION POSTPONEMENTS

There is one 13 kV substation planned for the Northern Zone in the 1979-1985 period. This substation, known as Kuller Road, will be installed in 1981 and will relieve an existing 13 kV substation known as Clifton Substation. Clifton Substation serves a load area of residential, commercial and light industrial customers. It serves new customers and also relieves small local area 4 kV substations whose loads are being held constant to avoid reinforcement.

The load of Clifton is expected to exceed the firm substation capacity in 1981. The plan is to install Kuller Road Substation in 1981 and relieve Clifton to Kuller Road.

The estimated load expected on Kuller Road Substation through 1985 is shown on Table 3-13.

The installation of Kuller Road could be postponed by installing batteries at Clifton to increase its firm capacity. As was determined by the methodology discussed in Appendix D, up to 24 MVA of battery capacity can be installed at Clifton and used as firm substation capacity, increasing the station capacity from 76 MVA to 100 MVA (at unity power factor).

Since the load on Kuller Road Substation was transferred from Clifton, then the addition of a full 24 MW of batteries at Clifton would postpone Kuller Road to 1984, which can be seen

TABLE 3-13

SUMMER PEAK LOAD (1) AND CAPACITY CONDITIONS
KULLER ROAD SUBSTATION

<u>Year</u>	<u>Load (2)</u>	<u>Capacity (3)</u>	<u>Deficit</u>
1981	15	60	-
1982	20	60	-
1983	24	60	-
1984	35	60	-
1985	44	60	-

- (1) PSE&G electric system experiences a summer peak, as do most of the individual substations.
- (2) After required relief of Clifton Substation.
- (3) Summer emergency rating of remaining transformer with one transformer forced out.

from Table 3-13. At this time the capacity deficit at Clifton would be $(35-24) = 11$ MVA.

3.6 DISCUSSION OF POST-1985 SUBSTATION POSTPONEMENTS

Figure 3-7 shows the Northern Zone load and effective capacity in graphical form for the years 1985-1995. It shows an initial capacity deficit of 60 MW in 1990 and deficits of 250 MW each year hence. This is approximately equal to one substation in 1990 and 3.3 substations every year thereafter.

To assess the ability to postpone some of these substations under each of the three battery installation scenarios, the first step is to determine how long a battery installation would postpone a substation reinforcement in the middle-1990's. First, assume that a new substation would be used to relieve two existing substations in a load area by that time. Assuming a capacity of 75 MVA (at 1.0 pf) for each substation and a load growth of 8%, the load of the new substation for the first six years is shown on Table 3-14. Under these assumptions, a new substation would be fully loaded in five years. The average load growth rate is $(75 \text{ MVA}/5 \text{ years}) = 15$ MVA per year.

Now batteries can be installed at both Substation A and B to avoid installing a new Substation. If the maximum allowable block is installed at each station, the capacity of each would be raised from 75 MVA to 100 MVA and relief would not be required until 1994 as shown on Table 3-14. This would require placing 25 MW at both Substation A and B.

Therefore, for substations scheduled for service in the 1986-2000 period, the conclusions are as follows:

- A. A new substation will grow to its full capacity in 5 years.
- B. The average load growth rate for a new substation is 15 MVA per year.
- C. A battery placement of 50 MW will postpone a new substation for 3 years.

Knowing the number of substations required in each year in the Northern Zone and the battery capacity available for placement in each of the three transmission plan scenarios, the savings for these postponements can be calculated.

FIGURE 3-7
PSE&G
NORTHERN ZONE
SUBSTATION LOAD AND CAPACITY

TABLE 3-14

EXAMPLE OF LOAD BUILDUP ON NEW 13-kV SUBSTATION
POST 1985 PERIOD

	<u>1990</u>	<u>1991</u>	<u>1992</u>	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
<u>Substation A</u>							
Load (MW)	75	81	87	94	102	110	119
Capacity (MW)	75	75	75	75	75	75	75
Deficit (MW)	0	6	12	19	27	35	44
(transferred to New Substation)							
<u>Substation B</u>							
Load (MW)	75	81	87	94	102	110	119
Capacity (MW)	75	75	75	75	75	75	75
Deficit (MW)	0	6	12	19	27	35	44
(transferred to New Substation)							
<u>New Substation</u>							
<u>Load</u>							
from Sub A (MW) -		6	12	19	27	35	44
from Sub B (MW) -		6	12	19	27	35	44
Total (MW)	-	12	24	38	54	70	88
Capacity (MW)	-	75	75	75	75	75	75
Deficit (MW)	-	0	0	0	0	0	13

3.7 DISTRIBUTION SAVINGS

The savings resulting from postponement of substations is summarized on Tables 3-15 and 3-16 for the three battery application scenarios proposed in Section 3.1. They show a savings which ranges from \$500,000 to \$2,000,000. This translates into a savings of around \$5 per kilowatt of battery capacity installed.

TABLE 3-15
DISTRIBUTION SAVINGS ANALYSIS

	<u>Application 1</u>	<u>Application 2</u>	<u>Application 3</u>
<u>Service Date</u>	<u>1981</u>	<u>1981</u> <u>1990</u>	<u>1981</u> <u>1990</u> <u>1991</u>
Capital Cost Cancelled or Deferred (million dollars)	1.74	1.74 1.74	1.74 3.48 6.96
No. of Years Deferred	2	3 3	3 3 3
CCIF ⁽¹⁾	1.05	1.05 1.05	1.05 1.05 1.05
% Carrying Charges ⁽²⁾	15	15 15	15 15 15
Levelized Annual Revenue Requirements (million dollars/year)	.27	.27 .27	.27 .55 1.10
Pwafr Savings	<u>.43</u>	<u>.61</u> <u>.25</u>	<u>.61</u> <u>.53</u> <u>.96</u>
TOTAL Pwafr Savings \$.43 million \$.86 million \$ 2.1 million			

(1) Construction compound interest factor, a factor in which the capital cost is adjusted to include the cost of money for capital expenditures made to the service date, 10% cost of money used.

(2) Carrying charges of return (10%), depreciation and associated taxes.

TABLE 3-16

ASSIGNMENT OF BATTERIES FOR SUBSTATION RELIEF

Application 1 - Install 85 MW in 1979

Requirement for Fair Lawn Switching Station	65 MW
Postpone Kuller Road from 1981 to 1983	<u>20 MW</u>
	85 MW

Application 2 - Install 85 MW in 1979
Install 85 MW in 1981

Requirement for Fair Lawn Switching Station	95 MW
Postpone Kuller Road from 1981 to 1984	25 MW
Postpone One Future Substation 1990-1993	50 MW

Application 3 - Install 85 MW in 1979
Install 110 MW in 1980
Install 190 MW in 1981
Install 55 MW in 1983

Requirement for Fair Lawn Switching Station	95 MW
Postpone Kuller Road From 1981 to 1984	25 MW
Postpone Six Future Substations	
#1 and #2 - from 1990 to 1993	100 MW
#3 thru #6 - from 1991 to 1994	220 MW

Section 4

Production Cost Savings

4.1 METHODOLOGY

Production costs in this analysis are defined as those costs for a generating system associated with operating the system for a period of time. The production costs specifically include fuel cost and operating and maintenance costs. Capital related costs such as depreciation and interest are not included as production costs.

Three separate battery applications were identified in Section 3. These applications require installations of 85, 170, and 440 MW of lead-acid batteries respectively. These applications all require a battery with a minimum five hour discharge time. An evaluation of 3- and 10-hour batteries is discussed in Section 6.

Section 3 showed that the full installation of 440 MW of batteries results in the largest transmission cost savings per kW of batteries installed. On this basis, we have used the 440 MW application for further analysis.

Referring to Table 2-8, one can see that generating units are installed in relatively large discrete unit sizes. This is generally true in the utility industry. The addition of 440 MW of batteries to the optimum expansion results in the modified expansion programs shown in Table 4-1. Table 4-1 is based on replacing 500 MW of future gas turbines (peaking capacity) or a 400 MW oil steam unit (intermediate capacity) with batteries. A discussion of the mismatch of capacities is contained in Section 5.

The production cost savings (or penalties) for installing 440 MW of lead-acid batteries in place of either peaking or intermediate capacity are estimated by simulating the economic dispatch of all of the generating units on the system through the year 2000. Total production costs for the generating system without batteries are compared with those in which batteries have been added. These simulations were made by using a production cost computer program. This program is described in Appendix B. These simulations do not consider any use of batteries for spinning reserve. Additional production cost savings from batteries used as spinning reserve are determined in Section 5.

TABLE 4-1

SCHEDULE OF GENERATING CAPACITY ADDITIONS
APPLICATION 3

<u>Year</u>	<u>Reference System</u>	<u>Batteries Replace Peaking Capacity</u>	<u>Batteries Replace Intermediate Capacity</u>
1979	1-100 MW GT*	85 MW batteries	85 MW batteries
1980	1-100 MW GT*	110 MW batteries	110 MW batteries
1981	3-150 MW GTs	190 MW batteries 2-150 MW GTs	190 MW batteries 2-150 MW GTs
1982	1-400 MW Oil	1-400 MW Oil	1-150 MW GT 2-100 MW GTs
1983	3-150 MW GTs	55 MW batteries 2-150 MW GTs	55 MW batteries 3-150 MW GTs

* Data of Section 2 shows additional units being installed after 1980. For purposes of this analysis, it is assumed that two of the 100 MW gas turbines shown in the existing 1980 system were installed in 1979 and 1980.

4.2 RESULTS AND ANALYSIS

Table 4-2 shows the annual production cost savings (or penalties) associated with replacing peaking and intermediate capacity with batteries. As can be seen, there is a pwafr saving of about \$15.7 million for replacing gas turbines with 5 hour discharge/7 hour charge batteries and a \$72.9 million penalty for replacing intermediate capacity. The Table also shows that there are essentially no additional savings for oversizing the converter equipment to allow the batteries to be charged in 5 hours. A 10 hour charge period is shown to have somewhat reduced savings. Therefore, subsequent analyses of 5 hour discharge batteries will be also based on a 7 hour charge period.

Table 4-3 shows the operation of the batteries in cycles as determined in the production cost studies. One cycle is completed when a battery has generated an amount of energy equal to its energy storage capability.

Table 4-3 shows that the operation of the batteries drops off significantly after 1983, then declines slowly and erratically for the remainder of the study period. Table 2-8, which shows the optimum expansion of the reference system, offers some explanations for this behavior. Between 1980 and 1986, only peaking and intermediate capacity is added to the system. This indicates that the 1980 reference system has an excess of base load capacity, which promotes the operation of the batteries. The 1980 reference system contains 64% base load capacity (conventional hydro, nuclear, and coal, Table 2-2). The optimum expansion includes only 36% base load capacity. Thus the percentage of base load capacity in the system is declining during the study period, and the operation of the batteries declines in parallel. In years when a nuclear unit is added, the operation of the batteries increases.

Figures 4-1 and 4-2 show a typical summer day load shape and the incremental cost of serving the load for the years 1980 and 1995, respectively. At any given load level, the incremental cost is the cost to provide the next MW of generation. Therefore, the shape of the incremental cost curve determines the system dispatch.

It can be seen from Figure 4-1 that in 1980 there is a broad off-peak valley in the incremental cost curve. Thus substantial quantities of low cost charging energy can be provided for the batteries. The incremental cost at minimum load is 37% of the incremental cost at peak load.

Figure 4-2 shows that by 1995 the off-peak valley has narrowed significantly, and the incremental cost at minimum load

TABLE 4-2

PRODUCTION COST SAVING (PENALTY)
(\$ 1000)
INSTALLATION OF 440 MW OF LEAD-ACID BATTERIES
WITH 5 HOUR DISCHARGE PERIOD

Year	Replace Peaking Capacity			Replace Intermediate Capacity		
	5 Hour Charge	7 Hour Charge	10 Hour Charge	5 Hour Charge	7 Hour Charge	10 Hour Charge
1979	577	538	464	577	538	464
1980	814	801	479	814	801	479
1981	2527	2520	2122	2527	2520	2122
1982	1166	1132	859	(6150)	(6164)	(6626)
1983	2489	2432	1996	(6268)	(6347)	(7039)
1984	1289	1229	956	(11887)	(11964)	(12226)
1985	1467	1510	1353	(12156)	(12194)	(12408)
1986	816	788	624	(12065)	(12083)	(12212)
1987	1027	1037	1023	(7796)	(7787)	(7926)
1988	496	523	446	(11132)	(11121)	(11196)
1989	1545	1532	1440	(6475)	(6437)	(6696)
1990	1722	1712	1378	(7060)	(7116)	(7708)
1991	2011	2006	1900	(8533)	(8544)	(8739)
1992	2524	2518	2262	(9775)	(9791)	(10141)
1993	3773	3644	2958	(6572)	(6800)	(7739)
1994	1716	1705	1545	(10107)	(10151)	(10455)
1995	3055	2984	2525	(7115)	(7254)	(8143)
1996	2102	2002	1598	(6705)	(6860)	(7365)
1997	1739	1700	1357	(9844)	(9890)	(10034)
1998	1690	1737	1668	(12671)	(12653)	(12778)
1999	1180	1200	1158	(10646)	(10630)	(10753)
2000	1426	1466	1459	(12703)	(12683)	(12706)
Pwafrr Saving (Millions of Dollars - 1979)						
	15.9	15.7	13.5	(72.6)	(72.9)	(75.9)

TABLE 4-3

BATTERY OPERATION (CYCLES) (1)
440 MW OF LEAD-ACID BATTERIES
REPLACE PEAKING CAPACITY

5 Hour Discharge Period, 7 Hour Charge Period

Year	Annual Cycles	Cumulative Cycles			
		1979 Installation	1980 Installation	1981 Installation	1983 Installation
1979	280	280	-	-	-
1980	296	576	296	-	-
1981	260	836	556	260	-
1982	194	1030	750	454	-
1983	197	1227	947	651	197
1984	105	1332	1052	756	302
1985	85	1417	1137	841	387
1986	67	1484	1204	908	454
1987	91	1575	1295	999	545
1988	52	1627	1347	1051	597
1989	113	1740	1460	1164	710
1990	151	1891	1611	1315	861
1991	81	2123(2)	1692	1396	942
1992	96	96	1788	1492	1038
1993	172	268	1960(3)	1664	1210
1994	88	356	88	1752	1298
1995	142	498	230	142(3)	1440
1996	139	637	369	281	1579
1997	61	698	430	342	61(3)
1998	39	737	469	381	100
1999	41	778	510	422	141
2000	23	801	533	445	164

Notes

- (1) A cycle is defined as energy produced divided by energy storage capability, i.e. the equivalent number of times the battery is fully discharged.
- (2) Battery replaced after 13 years of operation (2000 cycles).
- (3) Battery replaced after 14 years of operation (maximum life).

FIGURE 4-1
LOAD AND INCREMENTAL COST
VS.
TIME

FIGURE 4-2

LOAD AND INCREMENTAL COST
VS.
TIME

has increased to 42% of the incremental cost at peak load. The width of the peak period has also narrowed somewhat. Thus, there is less charging energy available to the batteries off peak, and less demand for the batteries on peak. Base load units provide only 51% of the total system capacity in 1995 as compared to 64% in 1980. It is clear from Figures 4-1 and 4-2 how reduction in base load capacity significantly reduces economic operation of the batteries.

Section 5

Other Battery Costs and Savings

Section 3 has identified potential transmission and distribution savings and Section 4 has identified the production cost savings from operation of lead-acid batteries. This section will identify the costs associated with batteries as well as additional savings attributable to their use. This section will discuss the 5 hour discharge battery only. Discussions of other size batteries are contained in Section 6 as part of the sensitivity analysis.

In specific, this section will evaluate the monetary effects of the following items:

- 1) Battery capital costs
- 2) Capital cost savings from replacement of alternate generating capacity
- 3) Effects of short construction lead time
- 4) Effects of use as spinning reserve
- 5) Effects in installed capacity reserve requirements
- 6) Losses
- 7) Reactive Capacity

This section will not summarize all of the costs and savings. The summary is contained in Section 7 where the overall economic analysis is provided.

5.1 BATTERY CAPITAL COST ANALYSIS

Tables 5-1, 5-2, and 5-3 summarize the analyses of the total present worth of the capital costs for the three potential battery applications. The service dates and the amounts of batteries for each application are those which were developed in Section 3. The battery capital cost data are taken from Table 2-9.

The "CCIF" shown on the tables is the construction compound interest factor. The cash expenditures required to build a facility are not all made at the same time. For some types of facilities, expenditures may be made over a period of as much as ten years or more prior to the service date. The sum of the expenditures must be adjusted, or future worthed to the service

TABLE 5-1

LEAD-ACID BATTERY CAPITAL COST ANALYSIS (5 HOUR BATTERIES)
APPLICATION 1

<u>Service Date</u>	<u>1979</u>
Amount of Batteries (MW)	85
Unit Capital Cost (\$/kW)	
Battery Only	184
Other Plant	216
Total Capital Cost (million dollars)	
Battery Only	15.64
Other Plant	18.36
CCIF	1.05
% Carrying Charges	
Battery Only	19.0 (1)
Other Plant	15.0
Levelized Annual Revenue Requirements - (million dollars/year)	
Battery Only	3.12
Other Plant	<u>2.89</u>
Total	6.01
Pwafrr (1979 million dollars)	60

(1) 13 year life, as determined in Section 4. See Table 4-3.

TABLE 5-2

LEAD-ACID BATTERY CAPITAL COST ANALYSIS (5 HOUR BATTERIES)
APPLICATION 2

<u>Service Date</u>	<u>1979</u>	<u>1981</u>
Amount of Batteries (MW)	85	85
Unit Capital Cost (\$/kW)		
Battery Only	184	184
Other Plant	216	216
Total Capital Cost (million dollars)		
Battery Only	15.64	15.64
Other Plant	18.36	18.36
CCIF	1.05	1.05
% Carrying Charges		
Battery Only	19.0 (1)	18.3 (2)
Other Plant	15.0	15.0
Levelized Annual Revenue Requirements (million dollars/year)		
Battery Only	3.12	3.01
Other Plant	<u>2.89</u>	<u>2.89</u>
Total	6.01	5.90
Pwafr (1979 million dollars)	<u>60</u>	<u>49</u>
Total Pwafr	\$109 million	

(1) 13 year life, as determined in Section 4. See Table 4-3.

(2) 14 year life, as determined in Section 4. See Table 4-3.

TABLE 5-3

**LEAD-ACID BATTERY CAPITAL COST ANALYSIS (5 HOUR BATTERIES)
APPLICATION 3**

<u>Service Date</u>	<u>1979</u>	<u>1980</u>	<u>1981</u>	<u>1983</u>
Amount of Batteries (MW)	85	110	190	55
Unit Capital Cost (\$/kW)				
Batteries Only	184	184	184	184
Other Plant	216	216	216	216
Total Capital Cost (million dollars)				
Battery Only	15.64	20.24	34.96	10.12
Other Plant	18.36	23.76	41.04	11.88
CCIF	1.05	1.05	1.05	1.05
% Carrying Charges				
Battery Only	19.0 (1)	18.3 (2)	18.3 (2)	18.3 (2)
Other Plant	15.0	15.0	15.0	15.0
Levelized Annual Revenue Requirements (million dollars/year)				
Battery Only	3.12	3.89	6.72	1.94
Other Plant	2.89	3.74	6.46	1.87
Total	<u>6.01</u>	<u>7.63</u>	<u>13.18</u>	<u>3.81</u>
Pwafrr (1979 million dollars)	<u>60</u>	<u>69</u>	<u>109</u>	<u>26</u>
Total Pwafrr	\$264 million			

(1) 13 year life, as determined in Section 4. See Table 4-2.

(2) 14 year life, as determined in Section 4. See Table 4-2.

date by a factor which we call the CCIF to account for the effects of expenditures made at different times during the construction period.

Since batteries have a short construction lead time and expenditures are made over a short period of time, this factor is relatively small. For comparison purposes, it can be seen from Table 2-4 that the CCIF for most other types of generating units is larger than 1.05.

The carrying charges shown on Tables 5-1 to 5-3 are based on an individual analysis of the battery equipment.

Data in Section 2 on generating equipment used a 15% carrying charge rate for all types of units other than batteries. This 15% is a standard number which is typical for the electric industry. Carrying charges consist of three major components:

- 1) cost of money;
- 2) depreciation; and
- 3) taxes.

The cost of money, assumed as 10%, is common to all types of equipment, batteries as well as other generating units. Depreciation, however, is a function of the average life of the equipment and the salvage value of the equipment. Batteries have a shorter average life than gas turbines and this component will result in higher depreciation carrying charges. Offsetting this for the battery equipment is the much higher net salvage. Table 2-9 shows that the replacement cost of the battery equipment is only $3/4$ of the original cost. This, in effect, means that $1/4$ of the installation cost is recoverable as net salvage.

To quantify the combined effects of the above, the data for the gas turbines and for lead-acid batteries were used to determine carrying charges to be used by PSE&G. The differential between the standard 15% carrying charge for gas turbines and PSE&G's carrying charge for gas turbines was then applied to PSE&G's battery carrying charge to provide a comparable carrying charge for batteries for use within this study. A more detailed explanation of carrying charge development is contained in Appendix F.

The levelized annual revenue requirements shown on the tables are determined by multiplying the capital costs by the CCIF by the percent carrying charges. These levelized annual revenue requirements are an equivalent annual cost for the period from the year of service data to eternity.

In order to present these data in consistent terms with savings associated with the batteries, the values have been converted into "pwafrr" values in terms of 1979 dollars. The use of pwafrr is discussed in Section 3.3. Values for the battery installations scheduled subsequent to 1979 are equated to 1979 values by discounting at a 10% cost of money.

5.2 CAPITAL COST SAVINGS OF REPLACING OTHER UNITS

Table 4-1 showed the schedule of generating unit additions during the 1979-1983 period for the reference system and for the cases in which 440 MW of batteries replace either peaking or intermediate capacity. As can be seen, it is not possible to substitute the exact amount of battery capacity needed for transmission reasons for the exact amount of alternate types of capacity. This is because most other types of generating capacity are typically installed in relatively large discrete unit sizes. Table 4-1 showed that the 440 MW of batteries will replace either 500 MW of gas turbines or 400 MW of oil intermediate capacity. In addition, for the intermediate capacity replacement case, the deferral of several gas turbine installations is also accomplished.

Similar expansions are not analyzed in detail for transmission Applications 1 and 2. The overall economic analysis of Section 7 will generalize on the capital cost savings associated with Application 3.

Tables 5-4 and 5-5 outline the capital cost savings associated with replacing peaking and intermediate capacity for Application 3. The methodologies used to calculate the values of these tables are identical to those used for calculating the battery capital costs earlier in this Section. Table 5-6 shows the additional value of being able to defer gas turbines in the intermediate capacity case.

At this point, it may be determined that the installation of lead-acid batteries is most economic when they replace peaking capacity rather than intermediate capacity. In Section 4.2 it was found that there is an \$89 million pwafrr production cost saving for replacing peaking capacity rather than intermediate capacity. However, there is an offsetting \$51 million pwafrr capital penalty. Table 5-7 shows that the net pwafrr savings for the peaking capacity replacement is \$38 million. The more economic peaking capacity replacement application will be used for all further analyses.

TABLE 5-4

CAPITAL COST SAVINGS ANALYSIS
ELIMINATION OF 500 MW OF PEAKING CAPACITY

<u>Service Date of Unit Cancelled</u>	<u>1979</u>	<u>1980</u>	<u>1981</u>	<u>1983</u>
Capacity Cancelled (MW)	100	100	150	150
Unit Capital Cost (\$/kW)	120	120	120	120
Total Capital Cost (million dollars)	12	12	18	18
CCIF	1.05	1.05	1.05	1.05
% Carrying Charges	15	15	15	15
Levelized Annual Revenue Requirements (million dollars/year)	1.89	1.89	2.83	2.83
Pwafrr Savings (1979 million dollars)	<u>18.9</u>	<u>17.2</u>	<u>23.4</u>	<u>19.3</u>
Total Pwafrr Savings	\$79 million			

TABLE 5-5
CAPITAL COST SAVINGS ANALYSIS
ELIMINATION OF 400 MW OF INTERMEDIATE CAPACITY

<u>Service Date</u>	<u>1982</u>
Capacity Cancelled (MW)	400
Unit Capital Cost (\$/kW)	240
Total Capital Cost (million dollars)	96
CCIF	1.10
% Carrying Charges	15
Levelized Annual Revenue Requirements (million dollars/year)	15.8
Pwafrr Savings (1979 million dollars)	119
Plus Pwafrr Savings of GT Deferrals (See Table 5-6)	<u>11</u>
Total Pwafrr Savings (1979 million dollars)	130

TABLE 5-6

CAPITAL COST SAVINGS ANALYSIS
DEFERRAL OF GAS TURBINE INSTALLATIONS

<u>Original Service Date</u>	<u>1979</u>	<u>1980</u>	<u>1981</u>
Capacity Deferred (MW)	100	100	150
No. of Years Deferred	3	2	1
Unit Capital Cost (\$/kW)	120	120	120
Total Capital Cost (million dollars)	12	12	18
CCIF	1.05	1.05	1.05
% Carrying Charges	15	15	15
Levelized Annual Revenue Requirements (million dollars/year)	1.89	1.89	2.83
Pwafr Saving (1979 million dollars)	5.2	3.3	2.3
Total Pwafr Saving	\$11 million		

TABLE 5-7

OVERALL ECONOMIC EVALUATION OF
PEAKING CAPACITY REPLACEMENT

vs.

INTERMEDIATE CAPACITY REPLACEMENT

PWAPRR SAVING (PENALTY) - 1979 \$ MILLIONS

	<u>Batteries Replace</u>		<u>Savings</u>	<u>Reference</u>
	<u>Peaking</u>	<u>Intermediate</u>	<u>(Penalty)</u>	
	<u>Capacity</u>	<u>Capacity</u>	<u>for Peaking</u>	
Production Cost	16	(73)	89	Table 4-2
Capital Cost				
Battery Installed	(264)	(264)		Table 5-3
Peaking Eliminated	79			Table 5-4
Intermediate Eliminated		130		Table 5-5
	<hr/>	<hr/>		
Net Capital	(185)	(134)	(51)	
Total Cost	(169)	(207)	38	

5.3 EFFECTS OF SHORT CONSTRUCTION LEAD TIME

The relative savings for battery installations attributable to a short construction lead time as compared with other units are already included in the capital cost analyses of Tables 5-1 through 5-6. Nevertheless, it is useful to specifically indicate how these savings are derived and what they are.

The lead time for lead-acid batteries is expected to be shorter than that for other types of capacity, with the possible exception of gas turbines. In this analysis we have assumed that the construction period is such that the majority of the capital expenditures are made about six months prior to the service date of the unit. Therefore the capital investment accrues only about 6 months of interest before the unit is installed. Using a cost of money of 10%, about 5% of the capital cost is added in interest charges. This 5% is included in Tables 5-1 through 5-3 by means of the CCIF of 1.05.

If the batteries could be installed with no construction lead time at all, that is if all capital expenditures are made at the in-service date, the CCIF would be 1.0. Using the data of Table 5-3, the pwafrr for the capital cost of the 440 MW of lead-acid batteries would be reduced by \$13 million. $\$264 \text{ million} \times (1 - 1.0/1.05)$.

Gas turbines also have a short lead time and their CCIF is also 1.05. There are therefore no savings for the batteries' short construction lead time vs. peaking gas turbine capacity.

Similarly, it can be seen from Table 5-3 that the pwafrr for the capital cost of the batteries would be increased by about \$13 million if the construction lead time were identical to that of the 400 MW oil unit. $\$264 \text{ million} \times (1.1/1.05 - 1)$. This \$13 million is the saving associated with the short battery lead time as compared to the steam unit.

5.4 EFFECTS OF USE AS SPINNING RESERVE

Spinning reserve is a term which indicates a requirement for a sufficient amount of generating capacity in excess of the load to be synchronized and capable of being loaded in a very short period of time to provide adequate tie line regulation in the event of load variations or equipment failure. Typically, spinning reserve requirements are approximately equal to the capacity of the largest generating unit on a system. The system may be a single isolated company, or it may be interconnected with the spinning reserve being shared by individual members of a power pool. The reference system has a spinning reserve requirement equal to 3-1/2% of the peak load. This assumes a

sharing of spinning reserve requirements with other companies in the reference system's power pool. This is also true of PSE&G and many other large utilities.

The practical effect on total system production costs of a spinning reserve requirement is the need to uneconomically load a number of relatively low cost generating units below their rated capacities so that these units can pick up additional load as needed or to bring on line and operate a number of high cost units at minimum load.

For purposes of this analysis, it is assumed that lead-acid batteries will physically be capable of providing the equivalent of spinning reserve. This means not only that sufficiently sophisticated controls are installed, but also that the battery be kept in a state that it can pick up load at any time. During periods when the batteries are charging, the charge rate must be controllable. During periods when the battery is discharging at less than its capacity, the battery must be able to discharge at a faster rate. During periods between charging and discharging, the battery must be on the line ready to discharge as needed.

The production cost program used for this study is not designed to consider the spinning reserve value of batteries for any of the conditions described above. Therefore, the production cost savings shown previously do not include any spinning reserve benefits.

To estimate the maximum spinning reserve benefit, the spinning reserve requirement for the reference system was lowered by the capacity of the batteries installed. A further restraint was added in which the batteries were not allowed to operate. The results of such operation were compared with the reference system base case. Table 5-8 summarizes these results and shows a potential saving of \$67 million. The spinning reserve savings of Table 5-8 and the production cost savings of Table 4-2 are not completely additive in that during periods of battery discharge, full spinning reserve benefits are not available.

In order to estimate the portion of the spinning reserve savings that are available when the batteries are allowed to operate freely for economic dispatch, the battery operation and system incremental cost were analyzed.

The production cost studies show that, on the average, the batteries are discharging for 1650 hours per year at 50% of rated capacity. This is equivalent to 825 hours per year at full capacity. Therefore, we assume that 9.4% of the time ($825/8760 = 9.4\%$) the batteries are not providing any spinning reserve as a result of their operation. However, it is not sufficient to discount the spinning reserve savings of Table 5-8 by 9.4%, since

TABLE 5-8

SPINNING RESERVE BENEFITS

440 MW OF LEAD-ACID BATTERIES REPLACE PEAKING CAPACITY

<u>Year</u>	<u>Reduction in* Spinning Reserve Requirement (MW)</u>	<u>Production Cost Saving (\$1000)</u>
1979	85	578
1980	195	2222
1981	223	5945
1982	235	6510
1983	250	6590
1984	265	6307
1985	281	6431
1986	298	6237
1987	316	6415
1988	335	7587
1989	355	7364
1990	376	7564
1991	399	7886
1992	422	8237
1993	440	8559
1994	440	8314
1995	440	8280
1996	440	9138
1997	440	9306
1998	440	9310
1999	440	10243
2000	440	8685
Pwafrr (1979 dollars)		\$67 million

*MW reduction of spinning reserve requirement equal to the lesser of:

- 1) the amount of batteries installed, and
- 2) 3-1/2% of the system peak load.

spinning reserve savings vary with the load, being the greatest at peak times when the batteries are operating and therefore not providing spinning reserve.

To estimate the relative value of spinning reserve of peak and off-peak times, we assume that the cost of spinning reserve is proportional to the incremental production cost. The production cost studies indicate that the batteries typically discharge over a 6 hour period, and that the incremental production cost during this period is about 1.4 times greater than the average incremental cost. Since the batteries are operating 9.4% of the time, when the potential spinning reserve saving is 1.4 times greater than average, we conclude that the total potential spinning reserve saving lost due to battery operation is $9.4\% \times 1.4 = 13\%$ or \$9 million. The combined production cost and spinning reserve savings are therefore \$16 million (Table 4-2) plus \$58 million (Table 5-8 less 13%) or \$74 million.

5.5 EFFECTS ON RESERVE REQUIREMENTS

In previous sections, 440-MW of lead-acid batteries have been somewhat arbitrarily equated to 500-MW of gas turbine peaking capacity. This section will determine the precise gas turbine equivalent. The basic criterion for this determination is that each capacity addition provides the same reliability to the system. There are three main characteristics of lead-acid batteries which are sufficiently different from those of gas turbines to affect the relative value of capacity additions on system reliability. These are:

- (1) the lower forced and scheduled outage rates of lead-acid batteries;
- (2) the smaller unit sizes of lead-acid batteries; and
- (3) the limited energy nature of lead-acid batteries.

The methodology used to assess the first two of these effects is the Loss of Load Probability (LOLP) method, which is the most commonly used method in the electric utility industry. A computer model was used to determine reserve requirements for the system with 440 MW batteries added to and 500 MW of gas turbines deleted from the reference system. The savings in reserve requirement for the battery additions were then used to determine the total in equivalent gas turbine capacity equal in reliability to 440-MW of batteries.

Table 5-9 summarizes the effects on the reserve requirement of lead-acid batteries. The values are shown both for situation

TABLE 5-9

EFFECTS ON INSTALLED CAPACITY RESERVE REQUIREMENTS
 440 MW OF LEAD-ACID BATTERIES REPLACE
 500 MW OF GAS TURBINE PEAKING CAPACITY

<u>System Conditions</u>	<u>Outage Rate Credit</u>	<u>Unit Size Credit</u>	<u>Limited Energy Penalty</u>	<u>Total Reserve Credit</u>	<u>Installed Capacity Penalty</u>	<u>Net Reserve Credit</u>
Isolated Reference System	90 MW	4 MW	(0 to -54 MW)	(40 to 94 MW)	-60 MW	(-20 to 34 MW)
Interconnected Reference System or Low Load Factor System	57 MW	0 MW	(0 to -26 MW)	(31 to 57 MW)	-60 MW	(-29 to -3 MW)

in which the reference system is an isolated system and for a larger interconnected pool. The first column shows the amount of reduced reserve requirement for the 440 MW of batteries, taking into account only the lower forced and scheduled outage requirements of lead-acid batteries. The 90-MW reduction for the isolated reference system is quite significant since the reference system has a very flat curve of weekly peaks (See Figure 2-1). In this case, the lower scheduled outage requirement is important. In a larger pool, or in a more sharply summer (or winter) peaking company, there would be more low load weeks during which scheduled maintenance could be performed. The value shown on the table for the interconnected system are based on the difference in forced outage rates alone. These two values in effect show a very high and a very low reserve savings for the batteries due to a low outage rate.

The second column shows the effects on reserve requirement of small unit size. For purposes of this analysis, a unit size of 10-MW for lead-acid batteries is assumed. The effect is small because the gas turbines themselves are not large units.

Figure 5-1 illustrates the effect of the limited energy nature of lead-acid batteries. The Figure shows the relationship between percent load carrying capability and the amount of batteries installed as a percentage of "adjusted peak load". The "adjusted peak load" is the annual system peak load reduced by the amount of energy storage or other limited energy capacity on the system. The figure shows that 5-hour batteries may be installed up to about 5% of the adjusted peak load without penalty for limited energy. Similarly, 3-hour batteries may be installed up to about 1.5% of the adjusted peak load. It is not correct to assume that after the allowable 1.5% of 3-hour batteries have been installed, an additional 3.5% ($5.0 - 1.5$) of 5 hour batteries may be added without penalty. This is because battery capacity totaling 5% of adjusted peak requires 5 hours of storage. A combined installation of 1.5% of 3-hour batteries and 3.5% of 5 hour batteries has an average storage of only 4.4 hours.

The effect of limited energy illustrated in Figure 5-1 was developed by examining a typical summer day load shape for various study years. This typical summer day has a peak equal to 85% of the annual peak load. Figure 5-2 shows the analysis for the year 1985. First the load shape is plotted. Then, assuming some system problem which would require maximum utilization of the energy storage capacity, the existing 200-MW storage pumped

FIGURE 5-2
SYSTEM RELIABILITY
EFFECT OF LIMITED ENERGY

hydro unit is scheduled. The Figure shows that the 10 hour storage unit is generating over a period of 11 hours. By operating at reduced loads before and after the peak, this unit has sufficient storage capability to provide full rated output during the peak period.

The operation of the existing pumped hydro unit has reduced and broadened the peak period. When the operation of the 440 MW of batteries is scheduled, we find that they must operate over a 9-hour period if the peak is to be leveled out. The 5-hour storage capability of the batteries is insufficient to cover this and still provide the rated capacity of 440 MW at the time of peak (4 P.M.). The battery can only be operated at 414 MW, otherwise it will be discharged before the end of the peak period, and a new peak will be created (6 P.M.). In this case, 24 MW of capacity is thus unavailable at the time.

If the scheduling was reversed, and the battery was scheduled first, it would be possible to discharge the battery at the full rated capacity at the time of peak. However, the total stored energy (battery plus pumped hydro) is the same, and it would now be the pumped hydro unit which would have to operate at the 24 MW reduced load. In a real situation, it is likely that both types of capacity would be operated below rated capacity, and that the total reduction would be more than the minimum 24 MW due to uncertainties in the magnitude and duration of the peak period. Note that there is sufficient time during the overnight period to fully recharge both the pumped hydro unit and the batteries for the reference system. For a system with a higher daily load factor (flatter load shape) the availability of off-peak charging energy may become an additional constraint.

Figure 5-1 is valid only for a company with the same hourly load shape as the reference system. The sharper the daily peak the more effective a battery will be. Conversely a company with very flat daily load shape will have a larger limited energy penalty.

The results shown on Figures 5-1 and 5-2 are for illustrative purposes, and are hand calculated based on a typical summer hourly load shape for the reference system. Each company would have to make more rigorous evaluations using its own system load data, and investigate all seasons of the year.

The data on Figure 5-1 is used to provide the range of reserve requirement penalties shown in the third column of Table 5-9. This is shown as a range since the value is different for each year. The value will also change if additional energy storage is added in subsequent years. The fourth column shows the net total of all three reserve requirement adjustments. The table further shows that our arbitrary selection of 500-MW of gas

turbines was reasonable. The rightmost column shows that, depending on circumstances, a further adjustment could be positive or negative. Therefore, the effects on reliability are that 440-MW of batteries are essentially equal to 500-MW of gas turbines for a savings of 60-MW in gas turbine capacity. This is equal to 12% of the gas turbine capacity replaced. The dollar savings are 12% of the value of Table 5-4 or a power saving of \$9 million.

5.6 TRANSMISSION AND DISTRIBUTION SYSTEM LOSSES

The PSE&G bulk system MW losses (I^2R) average approximately 2% of the system peak load during the 1977-87 period. This has been found to be true during off-peak periods as well as peak periods. As discussed here, the bulk system includes the PSE&G generating station step-up transformers, the 500, 230 and 138-kV transmission system (including autotransformers) and the switching station and high voltage substation transformers.

The addition of batteries to the PSE&G system at the low side of the switching station and high voltage substation transformers as described in Applications 1, 2 and 3, will result in a small net increase in the bulk system losses. This net increase is the composite effect of a peak load reduction during periods of battery discharge and a valley load increase during periods of battery charging. Since the batteries have an efficiency of 70%, the valley load increase is 1.43 times the peak load decrease. To evaluate the magnitude of the loss increase resulting from the 440-MW battery addition in Application 3, we will assume a typical annual battery operation of 1650 hours per year at half load as described in Section 5.4. This mode of battery operation would yield a net increase in average annual energy generated of 156 GWh/yr. ($1650 \text{ h/yr} \times 440 \text{ MW} \times 1/2 \times (1/.70 - 1)$). Based on the April, 1976 forecast, the 1983 system peak load is 9050 MW. Assuming an average annual load factor of 60%, the net increase in losses will be 0.4 MW or approximately 3500 MWh per year. (See Table 5-10.) Using an average system incremental cost of 21 mills/kWh, the monetary penalty associated with these increased losses is \$75,000/yr. This is insignificant compared to other costs and savings identified.

5.7 USE OF BATTERIES FOR REACTIVE POWER SUPPLY

Batteries can theoretically be used to supply reactive power by controlling the power factor at which the batteries supply current.

TABLE 5-10
PSE&G T&D LOSSES
APPLICATION 3
1983

	<u>Base System</u>	<u>Application 3 (+ 400 MW Batteries)</u>
Peak Load (MW)	9050 (1)	8610(2)
Annual Energy (GWh)	47,567(3)	47,723(4)
Annual Load Factor (%)	60	63.3
Levelized Annual Load (MW)(6)	5430	5450
Levelized Annual Bulk System Losses (MW)(7)	108.6	109.0
Increase in Losses Over Base System		0.4 3500 MWh/yr(8)
Cost Penalty for Increased Losses		\$75,000/yr(9)

Notes

- (1) Based on PSE&G plans as of April, 1976.
- (2) Base system peak load minus 440 MW of batteries.
- (3) 9050 MW times 8760 h/yr times 60% load factor.
- (4) Base system energy plus 156 GWh.
- (5) Annual Energy divided by (Peak Load times 8760 h).
- (6) Load Factor times Peak Load.
- (7) Levelized Annual Load times 2%.
- (8) 0.4 MW times 8760 h/yr.
- (9) 3500 MWh/yr times 21 mills/kWh (average incremental cost).

Reactive capacity is used by utilities for several purposes including:

- 1) Controlling voltages at various locations in the system;
- 2) Reducing line currents below the thermal ratings of the lines (by improving power factor);
- 3) Reducing line losses; and
- 4) Supplying reactive power requirements of customers.

In PSE&G, the large majority of reactive capacity is supplied by pole-top capacitors on distribution circuits. These devices cost about \$6/kVAR. Reactive capacity is needed most during peak periods. For batteries to provide reactive capacity, they would have to operate in that manner during the peak. This would reduce their ability to provide real power during the peaks. Since reactive power is so relatively inexpensive as compared to other battery savings during peak periods, the value as reactive capacity is negligible.

5.8 EFFECTS ON FUEL CONSUMPTION

The addition of lead-acid batteries (or any other type of energy storage generation) to a system will cause a shift in fuel consumption. Base load units, using nuclear, coal, and No. 6 fuel oil, will consume additional fuel to supply charging energy to the batteries. High cost intermediate and peaking units, using No. 6 and No. 2 fuel oil, will consume less fuel as they are displaced by battery generation. The net effect on total fuel consumption will depend on the difference in efficiency between the peaking units being displaced and the base load units providing the charging, relative to the efficiency of the batteries. As an example, the least efficient gas turbines have an incremental heat rate of 12,500 Btu/kWh in the 80-100% loading range. The most efficient fossil steam unit has an incremental heat rate of 9,300 Btu/kWh in the 80-100% loading range. If batteries are used to replace 100 kWhs of peaking generation, 1,250,000 Btu of No. 2 oil will be saved (100 kWh x 12,500 Btu/kWh). The batteries will consume 143 kWhs of charging energy (100 kWh/70% efficiency), or 1,328,600 Btu of coal (143 kWh x 9,300 Btu/kWh). Net fuel consumption increases by 78,600 Btu, because the difference in efficiency between the base load unit and the peaking unit is less than the efficiency loss of the battery.

When batteries are considered to provide spinning reserve, base load fuel consumption will increase and peaking fuel

consumption will decrease, since no uneconomic loading of the units will be required to provide the spinning reserve (see Section 5.4). In this mode of operation, batteries will provide a net saving in total fuel consumption since the battery does not operate to provide spinning reserve and the cycle efficiency is no longer a factor. Referring to the previous example, assume that considering batteries to provide spinning reserve will allow increased loading of the base load unit, increasing generation by 100 kWhs. Increased coal consumption is 930,000 Btu ($100 \text{ kWh} \times 9300 \text{ Btu/kWh}$). Generation from the peaking unit is reduced by 100 kWhs, saving 1,250,000 Btu of No. 2 oil, as before. Net fuel consumption decreases by 320,000 Btu.

Table 5-11 shows the total effect on fuel consumption for the replacement of 500 MW of gas turbine peaking capacity with 440 MW of batteries for spinning reserve.

As can be seen, the batteries save over 1/2 million barrels of oil per year for the study period.

TABLE 5-11

AVERAGE ANNUAL INCREASED (DECREASED) FUEL CONSUMPTION
BATTERIES CONSIDERED FOR SPINNING RESERVE

440 MW OF LEAD-ACID BATTERIES
REPLACE PEAKING CAPACITY

5 Hour Discharge Period, 7 Hour Charge Period

Unit Type	Base Load		Intermediate		Peaking	
Fuel Type	<u>Nuclear</u>	<u>Coal</u>	<u>No. 6 Oil</u>	<u>No. 6 Oil</u>	<u>No. 2 Oil</u>	<u>Total</u>
MBtu x 1000	0	2380	1790	(290)	(4920)	(1040)
Tons x 1000	-	110	-	-	-	110
Barrels x 1000	-	-	300	(50)	(850)	(600)

Section 6

Sensitivity Analyses

Previous sections of this assessment have identified costs and savings associated with lead-acid batteries using single point estimates of the various parameters. This section will analyze the effects of varying some of the key parameters so that insights can be developed as to what sets of circumstances are necessary to justify a lead-acid battery installation. These sensitivity analyses will be utilized to determine breakeven costs in Section 7.

In specific, sensitivity analyses are made in this section on the following:

- 1) Generation fuel cost differentials
- 2) Battery efficiency
- 3) Battery duty cycle
- 4) Battery capital cost
- 5) Battery life
- 6) Transmission and distribution savings
- 7) Inclusion of inflation

6.1 SENSITIVITY TO GENERATION FUEL COST DIFFERENTIALS

The analysis in Section 4 on production cost savings utilized only the "base" or average expected fuel costs of Table 2-7. The production cost savings were modest and small compared to the capital cost of the battery. Since lead-acid batteries utilize available base load capacity during off-peak load periods to displace peaking capacity, the overall economics should be sensitive to the differential operating costs between base load capacity and peaking capacity. To investigate this differential, production costs for the case of 440 MW of 5-hour batteries displacing peaking capacity were repeated using the low estimated nuclear and coal fuel cost and the high estimated oil costs of Table 2-7. Results of these production cost savings are shown on Table 6-1. The pwafrr savings for production cost are increased to \$126.4 million as compared with the \$15.7 million of Table 4-2.

Table 6-1

SENSITIVITY TO FUEL COST DIFFERENTIALS
440 MW OF LEAD-ACID BATTERIES
REPLACE PEAKING CAPACITY

Low Nuclear and Coal Fuel Costs, High Oil Fuel Costs

Year	Production Cost Saving (Penalty) (\$ 1000)	Annual Cycles	Cumulative Cycles			
			1979 Installation	1980 Installation	1981 Installation	1983 Installation
1979	3,339	294	294	-	-	-
1980	6,977	321	615	321	-	-
1981	14,835	288	903	609	288	-
1982	11,566	229	1132	838	517	-
1983	14,255	217	1349	1055	734	217
1984	8,187	83	1432	1138	817	300
1985	11,047	63	1495	1201	880	363
1986	10,296	42	1537	1243	922	405
1987	12,934	95	1632	1338	1017	500
1988	11,289	31	1663	1369	1048	531
1989	14,914	127	1790	1496	1175	658
1990	13,756	151	1941	1647	1326	809
1991	14,635	70	2011	1717	1396	879
1992	15,056	91	91(1)	1808	1487	970
1993	17,753	172	263	2071	1659	1142
1994	13,475	120	383	120(2)	1779	1262
1995	16,474	181	564	301	181(2)	1443
1996	16,862	171	735	472	352	1614
1997	15,159	84	819	556	436	84(2)
1998	15,802	35	854	591	471	119
1999	14,865	52	906	643	523	171
2000	15,344	25	931	668	548	196

Pwafrr Saving (1979 Dollars)

\$126 million

Notes

- (1) Batteries replaced after 13 years of operation after 2000 cycles.
(2) Batteries replaced after 14 years of operation (maximum life).

Spinning reserve savings for lead-acid batteries are also affected by changing fuel costs. Following the procedure in Section 5.4, the maximum possible spinning reserve savings were first determined. By restricting battery operation to achieve maximum utilization for providing spinning reserve, the maximum spinning reserve savings are calculated to be \$169 million. Then, we estimate that \$22 million of the spinning reserve savings are lost by allowing normal economic operation. The combined production cost savings for generation and spinning reserve amount to \$273 million.

6.2 SENSITIVITY TO BATTERY EFFICIENCY

The production cost savings of Section 4 were based on an overall battery efficiency of 70%. Tables 6-2 and 6-3 show the results of the case of 440 MW of 5-hour batteries replacing peaking capacity with the efficiencies changed to 65% and 75% respectively. Higher efficiencies results in greater production cost savings. However, the figures show that the savings are not greatly affected for the modest changes in efficiency evaluated.

6.3 SENSITIVITY TO BATTERY DUTY CYCLE

It was determined in Section 3 that a 5-hour battery was required for the transmission applications selected. It is the intent here to investigate the effects of 3-hour and 10-hour batteries.

Tables 6-4 and 6-5 show the production cost savings and operation of 3 and 10 hour batteries, respectively. Comparison with Table 4-2 shows that production cost savings increase with the increased battery discharge period. The improvement in battery efficiency with increased discharge period (Table 2-9) is the major contributor to the increased production cost savings. From a production cost viewpoint, a 10-hour battery is the most desirable.

Capital costs for lead-acid batteries vary significantly with battery duty cycle (Table 2-9). Table 6-6 compares the capital costs for 440 MW of lead-acid batteries with 3, 5, and 10 hour discharge periods. (The data for the 5-hour battery are condensed from Table 5-3). The capital cost penalties for the higher discharge batteries far outweigh the production cost savings. The most economic battery installation is therefore the one with the shortest discharge period which will meet the transmission application requirements and not result in an undue decrease in load carrying capability (Section 5.5).

Table 6-2

SENSITIVITY TO BATTERY EFFICIENCY
440 MW OF LEAD-ACID BATTERIES
REPLACE PEAKING CAPACITY

65% Battery Efficiency

Year	Production Cost Saving (Penalty) (\$ 1000)	Annual Cycles	Cumulative Cycles			
			1979 Installation	1980 Installation	1981 Installation	1983 Installation
1979	156	246	246	-	-	-
1980	79	247	493	247	-	-
1981	1224	198	691	445	198	-
1982	(55)	156	847	601	354	-
1983	917	154	1001	755	508	154
1984	(43)	78	1079	833	586	232
1985	394	61	1140	894	647	293
1986	(239)	44	1184	938	691	337
1987	329	74	1258	1012	765	411
1988	(245)	35	1293	1047	800	446
1989	643	93	1386	1140	893	539
1990	530	132	1518	1272	1025	671
1991	1248	65	1583	1337	1090	736
1992	1644	81	1664	1418	1171	817
1993	2210	150	150(1)	1568	1321	967
1994	1024	72	222	72(1)	1393	1039
1995	2032	123	345	195	123(1)	1162
1996	902	120	465	315	243	1282
1997	866	48	513	363	291	48(1)
1998	933	26	539	389	317	74
1999	451	28	567	417	345	102
2000	898	13	608	430	358	115

Pwafrr Saving (1979 Dollars)
\$6 million

Notes

(1) Batteries replaced after 14 years of operation (maximum life).

Table 6-3

SENSITIVITY TO BATTERY EFFICIENCY
440 MW OF LEAD-ACID BATTERIES
REPLACE PEAKING CAPACITY

75% Battery Efficiency

Year	Production Cost Saving (Penalty) (\$ 1000)	Annual Cycles	Cumulative Cycles			
			1979 Installation	1980 Installation	1981 Installation	1983 Installation
1979	778	291	291	-	-	-
1980	1438	311	602	311	-	-
1981	3758	284	886	595	284	-
1982	2404	226	1112	821	510	-
1983	3935	233	1345	1054	743	233
1984	2311	129	1474	1183	872	362
1985	2309	107	1581	1290	979	469
1986	1399	83	1664	1373	1062	552
1987	1938	110	1774	1483	1172	662
1988	1144	68	1842	1551	1240	730
1989	2418	136	2046	1687	1376	866
1990	2744	170	170(1)	1794	1546	1036
1991	2671	98	268	1999	1644	1134
1992	3240	118	386	118(2)	1762	1252
1993	4760	197	583	315	1965	1449
1994	2153	108	691	423	108(3)	1557
1995	3694	164	855	587	272	1721
1996	2789	160	1015	747	432	1881(4)
1997	1832	82	1097	829	514	82
1998	1967	58	1155	887	572	140
1999	1443	57	1212	944	629	197
2000	1590	39	1251	983	668	236

Pwafrr Saving (1979 Dollars)
\$23 million

Notes

- (1) Batteries replaced after 11 years of operation after 2000 cycles.
 (2) Batteries replaced after 12 years of operation after 2000 cycles.
 (3) Batteries replaced after 13 years of operation after 2000 cycles.
 (4) Batteries replaced after 14 years of operation (maximum life).

TABLE 6-4

SENSITIVITY TO BATTERY DUTY CYCLE
440 MW OF LEAD-ACID BATTERIES
REPLACE PEAKING CAPACITY

3 Hour Discharge Period, 5 Hour Charge Period

Year	Production Cost Saving (Penalty) (\$ 1000)	Annual Cycles	Cumulative Cycles			
			1979 Installation	1980 Installation	1981 Installation	1983 Installation
1979	8	273	273	-	-	-
1980	(374)	287	560	287	-	-
1981	727	261	821	548	261	-
1982	(474)	205	1026	753	466	-
1983	461	215	1241	968	681	215
1984	(348)	107	1348	1075	788	322
1985	203	86	1434	1161	874	408
1986	(379)	62	1496	1223	936	470
1987	128	95	1591	1318	1031	565
1988	(399)	47	1638	1365	1078	612
1989	488	125	1763	1490	1203	737
1990	164	172	1935	1662	1375	909
1991	1140	89	2024	1751	1464	998
1992	1471	111	111	1862	1575	1109
1993	1719	188	299	2050	1763	1297
1994	878	97	396	97(2)	1860	1394
1995	1722	160	556	257	160(2)	1554
1996	658	155	711	412	315	1709
1997	840	69	780	481	384	69(4)
1998	859	36	816	517	420	105
1999	334	41	857	558	461	146
2000	877	18	875	576	479	164

Pwafrr Saving (1979 Dollars)
\$4 million

Notes

- (1) Battery replaced after 13 years of operation after 2000 cycles.
(2) Battery replaced after 14 years of operation (maximum life).

TABLE 6-5

SENSITIVITY TO BATTERY DUTY CYCLE
440 MW OF LEAD-ACID BATTERIES
REPLACE PEAKING CAPACITY

10 Hour Discharge Period, 10 Hour Charge Period

Year	Saving (Penalty) (\$ 1000)	Annual Cycles	Cumulative Cycles			
			1979 Installation	1980 Installation	1981 Installation	1983 Installation
1979	1068	229	229	-	-	-
1980	2204	235	464	235	-	-
1981	4528	189	653	424	189	-
1982	3228	143	796	567	332	-
1983	4692	141	937	708	473	141
1984	2831	80	1017	788	553	221
1985	2706	64	1081	852	617	285
1986	1830	51	1132	903	668	336
1987	2378	68	1200	971	736	404
1988	1503	42	1242	1013	778	446
1989	2820	81	1323	1094	859	527
1990	3568	104	1427	1198	963	631
1991	2917	57	1484	1255	1020	688
1992	3595	69	1553	1324	1089	757
1993	5872	125	125(1)	1449	1214	882
1994	2559	65	190	65(1)	1279	947
1995	4467	102	292	167	102(1)	1049
1996	3435	102	394	269	204	1151
1997	2034	48	442	317	252	48(1)
1998	2217	34	476	351	286	82
1999	1650	33	509	384	319	115
2000	1711	23	565	407	348	138

Pwafrr (1979 Dollars)
\$29 million

Notes

(1) Battery replaced after 14 years of operation (maximum life).

TABLE 6-6
SENSITIVITY TO BATTERY DUTY CYCLE
EFFECT ON CAPITAL COST

Battery Duty Cycle (Hours)	3	5 ¹	10
Unit Capital Cost (\$/kw)			
Batteries Only	111	184	368
Other Plant	159	216	358
Total Capital Cost (million dollars)			
Battery Only	48.84	80.96	161.92
Other Plant	69.96	95.04	157.72
CCIF	1.05	1.05	1.05
% Carrying Charges			
Battery Only	18.4	18.4	18.4
Other Plant	15	15	-15
Levelized Annual Revenue Requirements (million dollars/year)			
Battery Only	9.44	15.67	31.28
Other Plant	11.02	14.96	24.84
TOTAL	20.46	30.63	56.12
Pwafrr (1979 million dollars)	176	264	484

¹ Condensed from Table 5-3

6.4 SENSITIVITY TO BATTERY CAPITAL COST

The capital related cost for a battery is directly proportional to the \$/kW installed cost. For example, if the capital cost of a battery is reduced by 25%, the pwafr of the cost will also be reduced by 25%. This relationship will be used in the breakeven analyses of Section 7.

6.5 SENSITIVITY TO BATTERY LIFE

The data for lead-acid batteries indicate that the battery life is expected to be 14 years or 2000 cycles, whichever comes first. Production cost analyses have indicated that, for the base fuel cost cases, the batteries would have lives of 13 and 14 years. Figure 6-1 shows the relationship between battery carrying charges and battery life. Using this relationship, Table 6-7 shows revised capital cost analyses for the 440 MW of lead-acid batteries if all of the batteries had lives of 7 years, 14 years, and 20 years. The results show that the costs associated with a battery are quite sensitive to life for relatively short life periods, but becomes less sensitive as the life increases. Note that the expected life of the "other equipment" is kept at a constant 30 years for this analysis.

6.6 SENSITIVITY TO TRANSMISSION AND DISTRIBUTION SAVINGS

Table 3-8 has shown a summary of the transmission savings identified for the 440 MW of batteries. The vast majority of those savings were associated with the cancellation of the \$26.2 million Aldene-Essex cable scheduled for a 1981 service date. For purposes of this sensitivity analysis, this single transmission cancellation will be analyzed and generalized. The relative values of the transmission savings to the battery cost can now be calculated as:

$$\begin{aligned} &\text{Transmission Savings} && \text{Transmission \$ Cancelled} \\ &(\$/\text{kW of battery}) && \text{kW of battery installed} \\ &= && \\ &\text{X } \frac{\text{CCIF transmission}}{\text{CCIF battery}} && \text{X } \frac{\% \text{ carrying charge transmission}}{\% \text{ carrying charge battery}} \end{aligned}$$

Using:	CCIF transmission	=	1.05
	CCIF battery	=	1.05
	% carrying charge transmission	=	15
	% carrying charge battery	=	18.3
			(weighted average)

FIGURE 6-1

SENSITIVITY TO BATTERY LIFE
EFFECT ON BATTERY CARRYING CHARGES

TABLE 6-7

SENSITIVITY TO BATTERY LIFE
EFFECT ON CAPITAL COST
440 MW OF 5-HOUR BATTERIES

Battery Life (Years)	7	14(1)	20
Unit Capital Cost (\$/kW)			
Batteries Only	184	184	202
Other Plant	216	216	243
Total Capital Cost (million dollars)			
Batteries Only	80.96	80.96	80.96
Other Plant	95.04	95.04	95.04
CCIF	1.05	1.05	1.05
% Carrying Charges			
Batteries Only	26.3	18.3	16.2
Other Plant	15	15	15
Levelized Annual Revenue Requirements (million dollars/year)			
Batteries Only	22.35	15.67	13.77
Other Plant	14.96	14.96	14.96
Total	37.31	30.63	28.73
Pwafrr (1979 million dollars)	321	264	248

(1) Condensed from Table 5-3. 14 years is essentially the average life, weighted by capacity, of the 4 battery installations.

The transmission savings will be equal to 82% of the dollars of transmission facilities cancelled per kW of battery installed. This relationship will be used in Section 7 to determine breakeven capital costs.

6.7. INCLUSION OF INFLATION IN ANALYSES

All of the foregoing analyses have assumed that there will be no escalation of any costs. In real life, however, costs have been and are continuing to go up. This sensitivity analyses explores the effects of possible future inflation. For purposes of this analysis, it will be assumed that all costs will escalate at a rate of 6% per year compounded. Using the base data as 1975 costs, the cost in a future year is determined by multiplying the 1975 base cost by 1.06^n where n is the number of years after 1975.

Tables 6-8 through 6-14 show the effects of including 6% escalation on the major cost and savings components of the case of 440 MW of lead-acid batteries replacing peaking capacity.

These tables show the effects of inflation on all components of the analysis. These include not only the use of escalation on future costs and savings but also the effects of inflation on the capital related carrying charges. An explanation on the modification to the carrying charges used is contained in Appendix F.

1)	Battery Capital Cost	-	Table 6-8
2)	Transmission Savings	-	Table 6-9
3)	Distribution Savings	-	Table 6-10
4)	Production Cost Savings	-	Table 6-11
5)	Replacement Capacity Savings	-	Table 6-12
6)	Spinning Reserve Savings	-	Table 6-13

Table 6-14 illustrates the relative effects of escalation on each of the components. In this table, the battery capital cost is taken to be 100%. As can be seen from the table, inclusion of inflation in the analysis improves the relative economics of lead-acid batteries. The primary reason for this is that the continuing escalation of the annual production cost and spinning reserve savings give more weight to these factors in the analysis.

Table 6-8

Sensitivity to Inflation(1)

Lead-Acid Battery Capital Cost Analysis
Application 3

Costs Escalated at 6% Per Year

<u>Service Date</u>	<u>1979</u>	<u>1980</u>	<u>1981</u>	<u>1983</u>
Amount of Batteries (MW)	85	110	190	55
Unit Capital Cost (\$/kW)				
Battery Only	232	246	261	293
Other Plant	273	289	306	340
Total Capital Cost (million dollars)				
Battery Only	19.72	27.06	49.59	16.12
Other Plant	23.21	31.70	58.14	18.92
CCIF	1.05	1.05	1.05	1.05
% Inflation Adjusted Carrying Charges				
Battery Only	32.4 (2)	30.7 (3)	30.7 (3)	30.7 (3)
Other Plant	21.1	21.1	21.1	21.1
Levelized Annual Revenue Requirements (million dollars/year)				
Battery Only	6.71	8.72	15.99	5.20
Other Plant	5.14	7.04	12.88	4.19
Total	11.85	15.76	28.87	9.39
Pwafpr (1979 million dollars)	118.5	143.3	237.8	64.2
Total	\$564 million			

(1) See Table 5-3 for analysis excluding inflation.

(2) 13 year life.

(3) 14 year life.

Table 6-9

Sensitivity to Inflation(1)

Transmission Savings Analysis
Application 3

Costs Escalated At 6% Per Year

<u>Original Service Date</u>	<u>1979</u>	<u>1981</u>	<u>1983</u>	<u>1986</u>
Capital Cost at Original Service Date (million dollars)	7.0	37.2	1.1	9.0
Cancel or No. of Years Deferred	3	cancel	cancel	4
Capital Cost at Deferred Date (million dollars)	8.8	-	-	11.3
CCIF	1.05	1.05	1.05	1.05
% Inflation Adjusted Carrying Charges	21.1	21.1	21.1	21.1
Levelized Annual Revenue Requirements (million dollars/year)				
For Original Service Date	1.64	8.24	.24	1.99
For Deferred Service Date	1.95	-	-	2.50
Pwafrr (1979 million dollars)				
For Original Service Date	16.4	68.1	1.6	12.4
For Deferred Service Date	14.7	-	-	0.6
Net Saving	<u>1.7</u>	<u>68.1</u>	<u>1.6</u>	<u>1.8</u>
Total Pwafrr	\$73 million			

(1) See Table 3-10 for analysis excluding inflation.

Table 6-10
Sensitivity to Inflation (1)
Distribution Savings Analysis
Application 3
Costs Escalated at 6% Per Year

<u>Original Service Date</u>	<u>1981</u>	<u>1990</u>	<u>1994</u>
Number of Years Deferred	3	3	3
Capital Cost At Original Service Date (million dollars)	2.47	8.34	17.68
Capital Cost At Deferred Service Date (million dollars)	2.91	9.93	21.06
CCIF	1.05	1.05	1.05
% Inflation Adjusted Carrying Charge	21.1	21.1	21.1
Levelized Annual Revenue Requirements (million dollars/year):			
For Original Service Date	.55	1.85	3.92
For Deferred Service Date	.65	2.20	4.67
PWAFAR (1979 million dollars)			
For Original Service Date	4.55	6.48	12.49
For Deferred Service Date	<u>4.04</u>	<u>5.79</u>	<u>11.18</u>
Net Saving	0.51	0.69	1.31
Total Pwafrr Saving	\$2 million		

(1) See Table 3-15 for analysis excluding inflation.

Table 6-11

Sensitivity to Inflation (1)
Production Cost Savings

Lead-Acid Batteries Replace Peaking Capacity

Costs Escalated 6% Per Year

<u>Year</u>	<u>Production Cost Saving (\$1000)</u>
1979	679
1980	1072
1981	3574
1982	1702
1983	3876
1984	2076
1985	2704
1986	1496
1987	2087
1988	1116
1989	3464
1990	4103
1991	5096
1992	6780
1993	10401
1994	5159
1995	9570
1996	6806
1997	6126
1998	6635
1999	4859
2000	6292
Present Saving (1979 dollars)	\$ 51.1 million

(1) See Table 4-2 for analysis excluding inflation.

Table 6-12

Sensitivity to Inflation(1)

Capital Cost Savings Analysis
Elimination of 500 MW of Peaking Capacity

Costs Escalated at 6% Per Year

<u>Service Date of Unit Cancelled</u>	<u>1979</u>	<u>1980</u>	<u>1981</u>	<u>1983</u>
Capacity Cancelled (MW)	100	100	150	150
Unit Capital Cost (\$/kW)	151	161	170	191
Total Capital Cost (million dollars)	15.1	16.1	25.5	28.7
CCIF	1.05	1.05	1.05	1.05
% Inflation Adjusted Carrying Charges	21.1	21.1	21.1	21.1
Levelized Annual Revenue Requirements (million dollars/year)	3.34	3.57	5.65	6.36
Pwafrr Saving (1979 million dollars)	<u>3.34</u>	<u>32.5</u>	<u>46.7</u>	<u>43.4</u>
Total Pwafrr	\$156 million			

(1) See Table 5-4 for analysis excluding inflation.

Table 6-13

Sensitivity to Inflation (1)

Spinning Reserve Benefits
Lead-Acid Batteries Replace Peaking Capacity

Costs Escalated at 6% Per Year
YEAR (\$1,000)

1979	730
1980	2,974
1981	8,433
1982	9,789
1983	10,503
1984	10,656
1985	11,517
1986	11,866
1987	12,908
1988	16,183
1989	16,649
1990	18,128
1991	20,035
1992	22,180
1993	24,430
1994	25,155
1995	26,555
1996	31,065
1997	33,535
1998	35,562
1999	41,473
2000	37,275

Pwafrr Saving (1979 dollars) \$252 million

(1) See Table 5-8 for analysis excluding inflation.

Table 6-14
Sensitivity to Inflation
Summary of Effects
Costs Escalated at 6% Per Year

<u>Costs Percent</u>	<u>% of Battery Installed Cost</u>	
	<u>Without Inflation</u>	<u>With Inflation</u>
mission	14.8	12.9
tribution	0.8	0.3
rection Cost and Spinning Reserve	28.0	47.9
placement Capacity	29.9	27.7
	<hr/>	<hr/>
TOTAL	73%	89%

Section 7

Overall Economics and Conclusions

Various benefits were identified and quantified in the previous sections of this report. Table 7-1 summarizes the battery savings and costs developed in previous sections of this Report. The table shows the pwafrr savings which have previously been identified and also translates the pwafrr values into an equivalent \$/kW for the battery installation. Savings have been identified which total \$294/kW as compared with the \$400/kW installed cost. Thus we have not identified savings sufficient to justify installation of the batteries. It remains now to determine what will be necessary to make lead-acid batteries justifiable.

7.1 BREAKEVEN CAPITAL COSTS

Table 7-1 shows the credits for installing lead-acid batteries in terms of the \$/kW capital cost of the batteries. The table further shows a net penalty of \$106/kW. This section will use the results of the sensitivity analyses performed in Section 6 to determine breakeven capital cost for the lead-acid batteries.

7.1.1 Transmission and Distribution Savings

Figure 7-1 shows the breakeven capital cost as a function of transmission and distribution savings. The equivalencies of transmission savings to \$/kW battery cost developed in Section 6.6 were used for this figure. The breakeven battery cost in \$/kW was derived by taking the non-transmission and distribution credits of Table 7-1 (\$232/kW for spinning reserve, production cost, and replacement capacity) and adding 82% of the transmission and distribution savings (see Section 6.6). It should be noted that the T&D savings are associated with cancellations. Any deferrals of transmission must be translated to an equivalent cancellation for this figure to be used.

The figure shows that a transmission cancellation with a value of about \$200/kW of batteries installed will be necessary to justify the estimated \$400/kW battery cost.

TABLE 7-1

SUMMARY OF LEAD-ACID BATTERY COSTS AND SAVINGS

<u>Cost or Saving Component</u>	<u>Pwafrr Cost (Saving) millions of 1979 Dollars</u>	<u>Equivalent Battery Installed Cost (\$/kW)</u>	<u>Section Reference</u>
<u>COST</u>			
Battery Capital Cost	264	400	5.1
<u>SAVINGS</u>			
Transmission	(39)	(59)	3.3
Distribution	(2)	(3)	3.7
Production Cost and Spinning Reserve	(74)	(112)	4.2 and 5.4
Replacement Capacity	(79)*	(120*)	5.2
Total	(194)	(294)	
<u>NET PENALTY</u>	70	106	

*Includes credits for short installation load time and reserve requirement saving.

FIGURE 7-1

BATTERY BREAKEVEN CAPITAL COST
VS.
TRANSMISSION AND DISTRIBUTION SAVINGS

7.1.2 Battery Efficiency

No reasonable improvement of the assumed 70% efficiency would be sufficient by itself to significantly reduce the breakeven battery capital cost. Table 6-3 has indicated that an increase of the battery efficiency has increased production savings by only \$7 million in pwafr. This is equivalent to a battery capital breakeven cost reduction of only \$11/kW.

7.1.3 Battery Life

Figure 7-2 shows the breakeven capital cost as a function of battery life. In this case, the life of the battery equipment only is varied, the other equipment has a constant 30 year life.

The data for the Table are derived from Table 7-1 and the data of Tables 6-7 and Figure 6-1. The pwafr savings for the batteries of Table 7-1 (totalling \$194 million) are equated to a breakeven \$/kW by applying the ratio of the \$400/kW battery cost data for our study to the pwafr costs of the batteries for various lives shown on Table 6-7.

The curve shows that the breakeven capital cost does not approach the estimated \$400/kW cost for any reasonable life.

7.1.4 Fuel Cost Differential

The sensitivity analysis of Section 6.1 has shown that the combined production cost and spinning reserve savings increase from \$74 million to \$273 million if the high oil costs and low nuclear and coal costs of Table 2-7 are used.

This increase of \$199 million is equivalent to \$301/kW. This would increase the breakeven capital cost of the lead-acid batteries to \$595/kW, a figure greater than the estimated cost of \$400/kW.

This analysis was based on the low nuclear and coal costs of Table 2-7 and the high oil costs of that table. The differential costs between coal and oil in this case represent an extreme estimate.

The key fuel costs are those for coal and oil since in our system there is essentially no excess nuclear energy for battery charging. Using coal and the average of the two oil prices, the savings in \$/kW of battery from production cost and spinning reserve are:

FIGURE 7-2
BATTERY BREAK-EVEN CAPITAL COST
VS.
BATTERY LIFE

<u>Case</u>	<u>Price Differential</u> <u>Oil-Coal (\$/MBtu)</u>	<u>Savings</u> <u>(\$/kW)</u>
Base	1.05	112
High Differential	2.95	413

An inspection of Table 7-1 indicates that these savings must be in the order of \$218/kW to justify lead-acid batteries. By interpolation of the above table, the fuel price differential must be in the order of \$1.75/MBtu to achieve lead-acid battery breakeven.

7.1.5 Mix of Units on Reference System

The entire analysis in this Report has been based on one reference system of generating units. This reference system does not have a sufficient amount of nuclear capacity so that nuclear units would be backed off during light load periods. Batteries or other forms of energy storage devices would be more economic if such a situation existed. A company having significant amounts of off-peak nuclear energy available to charge batteries would have to make its own analysis of the potential production cost savings. Using data in this report, a theoretical maximum value could be calculated as shown on Table 7-2. In this case, it is assumed that the reference system has sufficient off-peak nuclear energy to completely charge the batteries each week day and that the battery discharge would displace gas turbine capacity for each week day. Weekends are not included since loads are usually low enough to obviate generation with expensive units such as gas turbines.

The figure shows a \$118 million savings as compared to \$16 million in the base case. This increase of \$102 million is equivalent to \$154/kW of battery installed cost. This is enough to overcome the indicated \$106/kW penalty of Table 7-1.

7.1.6 Identification of a Credible Breakeven Scenario

Section 6.7 has shown that including inflation in the economic analyses will significantly improve the economic viability of batteries. Table 6-14 shows that the major impact of inflation is on the production cost and spinning reserve savings component. Therefore, in order to identify a credible scenario in which lead-acid batteries may prove to be economic, we have re-evaluated the break-even analysis for fuel cost differential including the effects of inflation.

As discussed in Section 7.1.4, the key fuel costs are those for coal and oil. When 6% annual inflation is considered, the savings in \$/kW of battery capital cost due to production cost and spinning reserve are:

TABLE 7-2

THEORETICAL MAXIMUM PRODUCTION COST SAVINGS
FROM OFF-PEAK NUCLEAR ENERGY

Capacity of Batteries	440 MW
Hours/Year discharge	250 days ⁽¹⁾ x 5 hours = 1250 hrs.
MWhr generated	550,000 MWhr/yr
<u>Gas Turbine Costs Displaced</u>	
Fuel	\$29.4/MWhr ⁽²⁾
Variable O&M	\$ 5 /MWhr
TOTAL	\$34.4/MWhr
Saved	\$18.92 million/yr
<u>Cost to Charge with Nuclear</u>	
Fuel (\$/kW hr)	\$8.57/MWhr ⁽³⁾
Variable O&M	\$.43
	\$9 /MWhr
\$Cost	\$4.95 million/yr
<u>Battery O&M Cost</u>	\$.28 million/yr ⁽⁴⁾
Net Production Cost Saving	\$13.69 million/yr
Pwafrr Saving (1979 dollars)	\$118 million ⁽⁵⁾

(1) 52 weeks x 5 days less 10 holidays

(2) #2 oil cost of \$2.45/MBtu; heat rate of 12,000 Btu/kWhr

(3) \$0.60/MBtu fuel; heat rate of 10,000 Btu/kWhr -0.7 efficiency

(4) 550,000 MWhr/yr at 0.5 mills/kWhr

(5) Assumes installations in 1979, 1980, 1981 and 1983 as in Table 5-3

<u>Case</u>	<u>Price Differential Oil-Coal (\$/MBtu)</u>	<u>Savings (\$/kW)</u>
Base	1.05	191
High Differential	2.95	682

Table 6-14 has shown that the total for all savings components amounts to 355 \$/kW (89% of the \$400/kW battery capital cost). An additional savings due to production cost and spinning reserve of \$45/kW is sufficient to make batteries break-even. By interpolation of the above table, the coal-oil fuel price differential must be in the order of \$1.25/MBtu.

7.2 SUMMARY AND CONCLUSIONS

The PSE&G transmission and distribution systems have been searched for potential applications where substantial savings could result from installations of lead-acid batteries. Such an installation has been found in which batteries can delay and postpone large transmission capital expenditures. In spite of this, total savings could not be identified such that they could justify the installation of lead-acid batteries.

Sensitivity analysis were performed on several of the key variables in an attempt to identify those circumstances which are necessary to justify the batteries.

Several parameters were found which, if substantially different from those used in this report, could result in the justification of lead-acid batteries. The most important of these parameters were found to be:

- 1) The differential between the fuel prices for base load and peaking generating units. The higher this differential, the larger the production cost credits will be for the batteries.
- 2) The mix of types of existing and future generating units of the particular electric utility. In particular, a system with a relatively large percentage of nuclear capacity in its system will produce relatively large production cost credits for lead-acid batteries.
- 3) The transmission savings which can accrue from battery installations.

In addition, continuing inflation and a recognition by the utility that there will be continuing inflation will make battery installations, as well as other capital intensive types of capacity, attractive.

Although not specifically analyzed in this report, the daily load shape of the individual utility will influence the economics of lead-acid batteries. In general a utility with a poor (low) daily load factor will have a greater incentive to install the batteries. Correspondingly, improvements of daily load factors by such means as load management will decrease the incentives to install batteries.

Appendix A*

The Reference System Development

*Reproduced from EPRI EM-336, Project 729-1 "Economic Assessment of the Utilization of Fuel Cells in Electric Utility Systems."

Peak Load

Under RP-225, "An Assessment of Energy Storage Systems Suitable for Use by Electric Utilities", 1971 peak load data were collected for 199 electric utilities (totaling 90% of the installed capacity of the nation). These data were analyzed and the results are shown in Table A-1. The average peak load of all the companies in this sample is 1488 MW. However, 58% of the companies had peak loads less than 1000 MW and contributed only 14% of the total of the sample peak loads. The smallest company that has indicated interest in large fuel cells had a peak load greater than 1500 MW in 1971. The average 1971 peak load of the above sample eliminating the smaller companies as well as and the 1971 average peak load of the companies currently supporting the large fuel cell development are shown in Table A-1.

The average peak load growth of all utilities from 1971 to 1974 was 6.1% per year. The 1974 average peak load was calculated using this growth rate and is shown in Table A-1. There are two different growth rates reported for 1976-80 period: (1) 5.5%/year in Electrical World (Sept. 15, 1975) and, (2) 7% in 57th Semi Annual Electric Power Survey (April 1975) prepared by the Edison Electric Institute. The expected average peak loads in 1980 were calculated based on both these growth rates and are shown in Table A-1.

The average 1980 peak load for all companies with 1971 peak load greater than 1500 MW (minimum size of companies supporting fuel cell development), assuming the lower growth rate of 5.5% per year, is 6186 MW. It is unrealistic to base the average on either all companies including very small companies (some of them having no generation) or only the companies supporting the fuel cell development. Therefore, the Reference system peak load is selected to be 6000 MW in 1980 based on the growth of 5.5% per year applied to the 1971 average of systems greater than 1500 MW.

Load Shape and Load Factor

Load factor is the ratio of the average load supplied during a given period to the peak load (or maximum load) occurring in that period. Annual load factor (in percent) of a system can be calculated as:

TABLE A-1

AN ANALYSIS OF 1971 PEAK LOADS

(a) 1971 Peak Loads

<u>1971 Peak Load (MW)</u>	<u>Number of Companies</u>
1 - 1000	115
1001 - 1500	24
1501 - 2000	15
2001 - 3000	17
3001 - 4000	10
4001 - 5000	5
5001 - 10000	11
10001 - 15000	1
15001 - 20000	1
	<u>199</u>

(b) Average Peak Load

<u>Companies Included</u>	<u>MW Size as % of Total Sample</u>	<u>Average Peak Load</u>			
		<u>1971</u>	<u>1974</u>	<u>1980</u>	
			(1)	(2)	(3)
All 199 Companies	100	1488	1779	2455	2670
Companies with higher than 1000 MW peak load	86	3020	3610	4981	5418
Companies with higher than 1500 MW peak load	76	3750	4483	6186	6728
Companies supporting FCG-1 Fuel Cell Program	15	4890	5846	8067	8773

Notes:

- (1) 1971-74 growth = 6.1%/year - "Electrical World, Sept. 15, Page 46"
- (2) 1974-80 forecast growth = - "Electrical World, Sept. 15, 5.5%/year Page 46"
- (3) 1974-80 forecast growth = - "EEI National Power Survey - April 1975" 7.0%/year

$$\frac{\text{Energy, MWh, supplied per year} \times 100}{(\text{Peak Load, MW}) \times 8760 \text{ hours/year}}$$

Load factor and the load shape (daily, weekly, and seasonal load variation) are important characteristics of a system which dictate the most economical mix of different types of generating units.

The results of the annual load factor analysis under Project RP-225 are shown in Table A-2. The average load factor, weighted by peak loads, is a more meaningful value than the other averages and the values are 60.4% for all companies, 58.6% for summer peaking companies, and 64.8% for winter peaking companies. Since the economics of fuel cells would not significantly depend upon the season in which the peak occurs, the all company average value (rounded to 60%) is selected as the reference system annual load factor.

Five companies having an annual load factor close to 60% and a peak load close to 6000 MW were analyzed to select the reference system load shape. One company was selected from the five based on the criteria that it should not be too far south or too far north (no extremes) in the nation. The annual load factor of this company in 1971 was slightly different from 60% and a minor adjustment was made in the seasonal peaks to obtain exactly 60% load factor before using this load shape for the reference system.

Generation Mix of the Reference System

The five companies analyzed to select the reference system load shape were further analyzed to identify the number, size, and type of units these companies installed in the past. From information obtained from the 1975 Electrical World Utility Directory, the average number of different size and type of units installed by the five companies by January 1, 1975 were determined and are shown in Table A-3. Also shown in the table are the approximate years different sizes of fossil steam units were added and the expected retirement period (based on a 40 year life). Assuming that units less than 100 MW size will be retired before 1980, these units were not included in the reference system.

The reference system should have a capacity of 7200 MW assuming 20% reserve over the 6000 MW peak load. The national average of reserve is about 20% of peak load as reported in the EEI Electric Power survey. The number and sizes of generating units selected for the reference system are shown in Table A-4, based on the analysis shown in Table A-3. The generation mix for 1980 of the reference system approximates the projected 1980

TABLE A-2

1971 ANNUAL LOAD FACTOR ANALYSIS -
PRIVATELY & PUBLICLY OWNED ELECTRIC SYSTEMS

<u>Description</u>	<u>All Companies</u>	<u>Summer Peaking Companies</u>	<u>Winter Peaking Companies</u>
Number Companies	199	129	70
Annual Load Factors (%):			
Range	44.9	40.1	30.9
Minimum Value	37.3	37.3	51.3
Maximum Value	82.2	77.4	82.2
Average:			
1) Unweighted	58.6	56.8	61.9
2) Weighted (Peak Load)	60.3	58.6	64.8
3) Weighted (Annual Energy)	61.0	59.3	65.4
Median	58.7	57.1	61.9
Standard Deviation:			
1) Unweighted	7.25	7.01	6.54
2) Weighted (Peak Load)	6.75	6.21	6.07
3) Weighted (Annual Energy)	6.83	6.24	6.28

Source: RP-225 Project Tasks B.

TABLE A-3

GENERATION MIX ANALYSIS

(a) Number of Units Vs. Size and Type

Basis: 5 companies having annual load factor close to 60% and peak load close to 6000 MW.

Unit Size, MW		Average Number of Units				
Range	Average	Fossil Steam	Nuclear Steam	Conventional Hydro	Pumped Storage	Combustion Turbines
1- 50	25	10		6		14
51- 150	100	14			1	4
151- 250	200	5				0-1
251- 350	300	2				
351- 450	400	2				
451- 550	500	2				
551- 650	600	0-1				
651- 750	700	1	0-1			
751- 850	800	0-1	0-1			
851- 950	900	0-1				
951-1050	1000	0				
Average Mix		81.1%	6.9%	1.6%	2.1%	8.3%

(b) Unit Size (Fossil) Vs. Period of Installation

Unit Size	Period of Installation (Years)	Expected Retirement Period (Years)
Below 100 MW	1940-1945	1980-1985
100 MW	1945-1950	1985-1990
200 MW	1950-1955	1990-1995
300 MW	1955-1960	1995-2000
400 MW	1960-1965	2000-2005
600-800 MW	1965-1975	2005-2015

TABLE A-4

REFERENCE SYSTEM GENERATION MIX - 1980

Peak Load = 6000 MW
 Reserve Required = 20% or 1200 MW
 Installed Capacity = 6000 + 1200
 = 7200 MW

	<u>Fossil Steam</u>	<u>Nuclear Steam</u>	<u>Conventional Hydro</u>	<u>Pumped Storage Hydro</u>	<u>Combustion Turbines</u>
	6 x 100		6 x 100	2 x 100	8 x 25
	3 x 200				4 x 50
	2 x 300				2 x 100
	2 x 400				
	2 x 500				
	1 x 600				
	<u>1 x 800</u>	<u>1 x 800 MW</u>			
	5000 MW	800 MW	600 MW	200 MW	600 MW
<u>% Mix</u>					
Reference System:	69.5%	11.1%	8.3%	2.8%	8.3%
Projected 1980					
Average for U.S. (1)	65.3%	13.2%	9.8%	2.3%	9.4%
1971 Average for the companies supporting fuel cell development (2)	72.3%	4.4%	8.5% (total hydro)		14.8%

Notes:

- (1) EEI National Power Survey, April, 1975.
 (2) Based on the data from RP-225.

average mix for the U.S. This mix is not significantly different from that of companies currently supporting large fuel cell development.

Peak Load Data for Reference System Expansion

A number of recent forecasts of United States electricity usage have been analyzed by the IEEE Energy Forecast Working Group and reported in April 1975.* The forecast growth varied from 2.2% to 6.8% per year between 1973-2000 period. The Working Group's recommendations are shown in Table A-5. Also shown in the table are forecasts made by Electrical World** in September 1975. The energy growth rate is slightly higher than the peak load growth, due to the possible future load management measures. For simplicity, it is assumed in this project that the annual load factor will be constant. A 6% annual growth rate for both peak load and energy is selected for the Reference System based on the data shown in Table A-5. The annual peak load and energy are shown in Table A-5 based on 6% growth rate.

* "Electric Energy Technology Forecast - Energy Needs", C. A. Falcone, Paper presented at the IEEE Intercom '75, April 1975, New York.

** 26th Annual Electrical Industry Forecast, Electrical World, September 15, 1975, pp. 35-50.

TABLE A-5

LOAD GROWTH ANALYSIS AND PROJECTED PEAK LOADS

(a) Annual Growth Rate

	IEEE Energy Forecast Working Group (1)		Electrical World (2) (9/15/75)	
	<u>Capacity</u>	<u>Energy</u>	<u>Non-Coincident Peak Load</u>	<u>Total Output</u>
1973-1985	5.6%	6.2%	5.2%	5.3%
1985-2000	5.2%	5.9%	-	-
1980-1995			5.3%	5.4%

Annual growth rate selected for the reference system = 6.0%
for peak load and energy.

(Annual load factor is assumed to be constant at 60%.)

(b) Annual Peak Loads and Energy

<u>Year</u>	<u>Annual Peak Load MW</u>	<u>Energy MWH</u>	<u>Year</u>	<u>Annual Peak Load MW</u>	<u>Energy MWH</u>
1980	6000	31536	1990	10740	56449
1981	6360	33428	1991	11390	59866
1982	6740	35425	1992	12070	63440
1983	7150	37580	1993	12800	67277
1984	7570	39788	1994	13570	71324
1985	8030	42206	1995	14380	75581
1986	8510	44729	1996	15240	80101
1987	9020	47409	1997	16160	84942
1988	9560	50247	1998	17130	90035
1989	10140	53296	1999	18150	95396
			2000	19240	101125

(1) "Electric Energy Technology Forecast - Energy Needs",
C. A. Falcone, Paper presented at the IEEE Intercon 75,
April 1975, New York.

(2) "26th Annual Electrical Industry Forecast", Electrical
World, September 15, 1975, Pages 35-50.

Appendix B

Production Cost Program

This program simulates operation of the generating units in a system to meet the load considering incremental economic dispatch and calculates production costs (fuel, start-up, operation and maintenance) for each unit and for the system. This program was developed by PSE&G in 1970 and since then it has been extensively used for studies related to many planning and operating decisions. The program is also being used by some of the other member companies in the Pennsylvania-New Jersey-Maryland (PJM) pool. The following are the main features of the program.

1. Can simulate a single system or two interconnected systems considering the tie limits.
2. Can handle nuclear and fossil units, gas turbines, fuel cells, energy storage devices, and all types of hydro units.
3. Generating unit forced outages can be represented by derating units or as random outages by input. Higher immature forced outage rates in the case of new units are recognized.
4. Generating unit maintenance is scheduled in weekly intervals levelizing capacity reserves at different weekly peak loads.
5. Loads are represented by a chronological load characteristic in bi hourly intervals.
6. Generating units are dispatched in each bi hourly interval using their incremental cost (fuel and variable O&M) curves adjusted for penalty factors. The minimum dispatch capacity is specified and incremental cost vs. output curve is represented by five points.
7. Separate dispatch scheduling. Routines also exist for run-of-river hydro, pondage hydro and energy storage type generating capacity.
8. Fuel escalation can be specified.
9. Spinning reserve requirement is checked in unit dispatch.

10. Weekly and annual production costs for each unit and for the system can be obtained. Fuel, startup, and fixed and variable operation and maintenance costs are identified separately.
11. The program can be used for long range studies of 20-30 year periods. Individual year and present worth of total costs can be obtained.

Appendix C

Transmission Requirements - Methodology

C-1 GENERAL REQUIREMENTS

The PSE&G transmission system development is typically planned to provide the transmission capability required for one or more of the following generic purposes:

- I. Outlet and transmission of power from remotely located PSE&G extra-territorial generating capacity (ETG) to the PSE&G system load centers.
- II. Delivery of normal (economy and/or ETG) and emergency power from neighboring power systems into the PSE&G system.
- III. Delivery of normal and emergency power to and between subareas of the PSE&G system.
- IV. Supply of power to local load areas within the system.
- V. Transmission supply to high voltage substations.

For each of these functional requirements, the transmission system is developed so that it can be operated at all load levels to meet various unscheduled contingencies while maintaining a prescribed level of reliability of service.

A survey of the PSE&G planned transmission developments in the 1976-1987 period reveals that dispersed siting of battery capacity in the PSE&G system could potentially result in the deferral of three transmission projects planned for the delivery of emergency power to one of the sub-areas of the system. (Requirement Type III above). Also, these same battery capacity installations could potentially result in the deferral of one transmission project planned to supply power to a specific local load area within this same sub-area of the PSE&G system (Requirement Type IV above).

C-2 DELIVERY OF POWER TO SYSTEM/SUB-AREA

The critical PSE&G sub-area referred to above, namely the "Northern Zone," is comprised of the four northern-most operating divisions of the company; i.e. Bergen, Passaic, Essex and Hudson Divisions as depicted on Figure C-1. The Northern Zone accounts for nearly 50% of the total PSE&G system load while its installed generating capacity remains relatively unchanged through the

FIGURE C-1

period under study. The Northern Zone load and installed generating capacity conditions forecast for the 1977-87 period are shown in Table 3-2, found in Report Section 3.

Electrically speaking, the Northern Zone is presently interconnected with the remainder of the PSE&G system and neighboring utilities via two (2) 345-kV circuits, three (3) 230-kV circuits and six (6) 138-kV circuits. The 230 and 345-kV Northern Zone transmission is shown on the attached diagram (Figure C-2). In the 1977-87 period, these interconnections will be reinforced with the addition of one new 230-kV circuit, the upgrading of one existing 230-kV circuit to 500 kV and the reinforcement of one of the existing 345-kV circuits to achieve an increased rating. Also, various internal Northern Zone reinforcements are scheduled to further enhance the system transmission capability for delivering increasing amounts of normal and emergency power to the generation deficient Northern Zone. These reinforcements are tabulated in Table C-1.

The power flows on all but one of the major transmission paths across the Northern Zone interface can be controlled or regulated, either directly or indirectly, by use of phase angle regulating transformers (PARS). Three such units exist now with two more planned for installation during the study period. The effective use of these PARS permits optimization of the power flows across the Northern Zone interface, thereby maximizing the power delivery capability to this critical PSE&G sub-area.

There are two basic modes of power delivery to and between sub-areas of the PSE&G system that are considered in planning evaluations; normal and emergency. The need for delivery of normal power results from system/pool economy dispatch and/or the delivery of proportionate shares of PSE&G-owned ETG to each of the sub-areas or zones of the system. The total system ETG is allocated to each zone in proportion to the zone load. In the case of the PSE&G Northern Zone, this zone ETG allocation approximates the same level of power delivery as does the economy dispatch.

The capability of the transmission system to support the delivery of zone ETG over extended periods of time is called the Normal Transfer Limit (NTL). The NTL is that amount of power that can be delivered to one electrical area (a system or sub-area of the system) such that:

- a) no transmission facility is loaded beyond its summer normal rating with all transmission in service and contracted power wheeling in effect.
- b) following the loss of any single transmission facility or pair of facilities on the same structure, no

FIGURE C-2

NOTE

Transmission project
deferrals shown dark
(Planned Service Date)

**1976 PSE&G NORTHERN ZONE
230 AND 345-KV TRANSMISSION**

remaining facility is loaded beyond its summer 4 hour rating. In special situations, short-time emergency ratings may be applied where phase angle regulation is available to effectively reduce transmission loadings to within acceptable levels.

The second mode of power delivery considered in planning evaluations is emergency power. The amount of emergency power required to be delivered to the PSE&G system or a sub-area of the system, such as the Northern Zone, is called the Capacity Emergency Transfer Objective (CETO). The CETO is that amount of power that must be able to be delivered to one electrical area via the transmission system in order to maintain a prescribed level of reliability of service. This reliability level is defined, in probabilistic terms, as a Loss of Load Probability (LOLP) of one day in ten years. The CETO for a specific area can be calculated based on this criteria of reliability, the availability characteristics of the area's installed generators and a probabilistic model of the area's load.

The maximum amount of emergency power that can be delivered to the PSE&G system or a sub-area of the system, such as the Northern Zone, is called the Capacity Emergency Transfer Limit (CETL). The CETL is that amount of power that can be delivered to one electrical area (a system or sub-area of the system) such that:

- a) no transmission facility is loaded beyond its summer one-day emergency rating (summer normal rating for underground cables) with all transmission facilities in service and,
- b) following the loss of any single transmission facility (overhead line, underground cable, transformer, PAR, bus section, etc.) no remaining facility is loaded beyond its summer 4 hour emergency rating. In special situations, short-time emergency ratings may be applied where phase angle regulation is available to effectively reduce transmission loadings to within acceptable levels.

Planning the Northern Zone transmission development requires simultaneous consideration of both the normal and emergency power delivery criteria. Comparison of zone NTL versus ETG and CETL versus CETO and evaluation of the resultant surplus (deficit) conditions establish the need and timing for the future reinforcements required to satisfy these criteria. It should be recognized that transmission reinforcements implemented to effect a required increase in NTL may also provide an increase in CETL and vice versa.

The NTL/ETG and CETL/CETO conditions for the PSE&G Northern Zone corresponding to the forecast load and installed generation (Table 3-3, Section 3) and the planned transmission developments relating to the Northern Zone (Table C-1) were shown in Table 3-2, Section 3.

The addition of battery capacity to the PSE&G system in general, or to the Northern Zone in particular, would have the effect of reducing that area's CETO by an amount approximately equal to the installed capacity of the batteries less the average amount of battery capacity unavailable due to forced outage but have no effect on the normal power delivery limit or requirements since the batteries would operate primarily in a peaking mode. For purposes of this analysis, a nominal 5% forced outage rate was assumed. Therefore, a 100 megawatt (MW) battery capacity installation would result in a direct reduction in area CETO of 95 MW. This direct reduction in CETO assumes that the limited energy characteristics of the batteries will not adversely impact on the magnitude of the CETO reduction. However, depending on the energy storage capacity of the batteries (i.e. 3 hour, 5 hour or 10 hour) and the characteristics of the area load, the effective CETO reduction could be less. For example, 100 MW of batteries with only 1 hour storage capability (100 MWh total energy) and a nominal 5% forced outage rate could not support a full 95 MW CETO reduction when the magnitude and duration of the area load and resultant CETO dictate an energy requirement of greater than 100 MWh.

Starting with the base system CETL/CETO conditions for the PSE&G Northern Zone (no battery installations) and knowing the CETL increase associated with each transmission reinforcement as well as the potential CETO decrease accruing from a given amount of battery capacity installation, a simple relationship can be developed relating specific transmission project deferrals to the amount of battery capacity installed.

From this generalized relationship, three specific quantity/location applications were formulated based on CETL/CETO requirements. Finally, the NTL/ETG conditions resulting from these deferrals were evaluated to ensure continued compliance with the normal import criteria.

C-3 SUPPLY TO LOCAL LOAD AREA

The Fair Lawn load area, located primarily in the PSE&G Passaic Division, is the specific "local load area" referred to in the "General Requirements" section above. This area is comprised of the existing Fair Lawn Switching Station and three future transmission-supplied substations: Kuller Road (1981), East Fair Lawn (1984) and North Hasbrouck Heights (1984). North

TABLE C-1

PSE&G NORTHERN ZONE
TRANSMISSION FORECAST (1)

<u>YEAR</u>	<u>SCHEDULED REINFORCEMENT</u>
1979	Hawthorne-Hinchmans Ave. 230-kV cable and Waldwick 230-kV 600 MVA PAR ⁽²⁾
1980	-
1981	Aldene-Essex 230-kV cable and Essex 230-kV 600 MVA PAR
1982	-
1983	Addition of forced oil circulation to the existing South Mahwah-Waldwick 345-kV cable
1984	Rebuild the existing Montville-Roseland 230-kV circuit to 500-kV construction. Hawthorne-Fair Lawn 230-kV cable and Fair Lawn 230/138-kV auto-transformer. Rebuild the existing Roseland-Kearny (Meadows) 138-kV towerline to 230-kV bundled-conductor construction
1985	Rebuild the Jefferson-Montville portion of the existing Kittatinny-Montville 230-kV circuit to 500 kV. Roseland 500/230-kV stepdown station Jefferson 500-kV Switching Station
1986	-
1987	Rebuild Roseland-Cedar Grove 230-kV towerline to bundled-conductor 230 kV

(1) Based on PSE&G plans as of April, 1976.

(2) PAR - Phase Angle Regulator

Hasbrouck Heights Substation will be located in the PSE&G Bergen Division immediately adjacent to Passaic Division, while the other two future substations will be in Passaic Division itself. The Fair Lawn load area is supplied by three 138-kV underground cables, two from the Athenia Switching Station and one from the Bergen Switching Station. The Kuller Road and East Fair Lawn Substations will be supplied from the Athenia - Fair Lawn 138-kV cables (one substation on each cable) while the North Hasbrouck Heights Substation will be supplied from the Bergen-Fair Lawn 138-kV cable. Figure C-3 shows a one-line diagram of this transmission supplied load area.

The maximum amount of power that can be supplied to the Fair Lawn 138-kV load area via the transmission cables is based on the criteria that following the loss of any one of the cables supplying the load area, no remaining cable is loaded beyond its summer 300 hour emergency rating. (The use of the 300 hour rating is based on the estimated repair time for a failed underground cable.) By obtaining reasonably balanced loads on the two remaining cables, following the loss of one cable, the maximum transmission supply capacity to the load area is equal to the sum of the 300 hour emergency ratings of the remaining cables as adjusted for power flow imbalance. Additional load supply "capacity" also exists in the form of transferable load. The 1977-87 Fair Lawn load area load and capacity conditions are summarized in Table 3-5, Section 3.

The installation of a new 230-kV cable from Hawthorne 230-kV Substation to Fair Lawn Switching Substation and a new 230/138-kV autotransformer at Fair Lawn is planned for service in 1984 to relieve the forecast load/capacity deficits beginning in 1984. The installation of this circuit will increase the capacity of this load area by approximately 300 MVA.

The addition of battery capacity to any local load area in general, or the Fair Lawn load area in particular, would have the effect of increasing the capacity of the load area (or decreasing the effective load) by an amount approaching the installed capacity of the batteries less a nominal 5% forced outage rate. The amount of capacity increase resulting from battery installations is a function of the energy storage capacity of the batteries (in MWh) and the load duration characteristics of the load area. For example, suppose it was desired to increase the future capacity of any area via battery installations to relieve a forecast load/capacity deficit. Let us assume that the forecast peak load of the area is 500 MW, the peak day load cycle characteristics are known and the forecast load/capacity deficit to be relieved is 50 MW. By integrating the peak day load cycle curve for load levels greater than the capacity (450 MW in this case) the required battery energy storage can be determined. Suppose this determination was made and the resultant energy

FAIR LAWN LOAD AREA
ONE-LINE DIAGRAM

requirement was 300 MWh. Now, let us further assume that the type batteries we propose to install have 5 hour storage capability at rated MW output and a 5% forced outage rate. Therefore, 50 MW of this type battery contains 237.5 MWh ($50 \text{ MW} \times 5 \text{ h} \times 0.95$) of energy. To provide the required 300 MWh of energy, 63 MW of 5-hour batteries need to be installed ($300 \text{ MWh} / (5 \text{ h} \times 0.95)$).

After determining the magnitude of the battery installation required to effect the desired capacity increase, an evaluation of the system's ability to charge these same batteries must be made. Basically, the same methodology is used for this determination as was used to determine the quantity of batteries required for a capacity increase. The maximum battery capacity charging that can be supported for a given load area is a function of the charging requirements of the battery installation (in MWh), the load duration characteristics of the load area and the load area capacity exclusive of batteries. Continuing with the assumptions from the previously discussed example, we are planning to install 63 MW of 5-hour batteries with an assumed conversion efficiency of 70%. The charging requirements for this installation are approximately 430 MWh ($(63 \text{ MW} \times 5 \text{ h} \times 0.95) / 0.70$). By calculating the valley area between the off-peak portion of the peak day load curve and the load area capacity exclusive of batteries (again, 450 MW in our example), the maximum capacity available for battery charging can be determined. Once this determination is made, the maximum capacity for battery charging is compared to the charging requirements. If the capacity exceeds the requirement, the proposed installation is valid.

The three specific quantity/location applications formulated from the CETL/CETO methodology were adapted to obtain the secondary benefit resulting from the location of some of the required Northern Zone battery installations specifically in the Fair Lawn load area.

Appendix D

Distribution Requirements - Methodology

D-1 GENERAL

The batteries which are to be located at distribution substations will be used two ways:

- A. to provide economy energy when called by economic dispatch during normal conditions
- B. to carry a share of the substation load following the outage of a substation transformer.

The analysis which follows will provide guidelines for matching battery installations to individual substations. Specifically, the analysis will:

- A. Quantify the relationship between MW requirements for batteries and the ability to charge that many batteries at specific substations;
- B. Identify the kinds of load area (in terms of business sector) where battery installations at substations would be useful;
- C. Provide generalized curves which could be applied to the problem of sizing battery installations for a variety of load factors and substation capacities.

D-2 RELATIONSHIP BETWEEN BATTERY DISCHARGE CAPACITY AND AVAILABLE CHARGING ENERGY

To determine whether a specific MW capacity will "fit" at a substation, consider the typical substation peak-day load curve of Figure D-1. Following a substation transformer failure, the batteries will discharge during peak-load period to reduce the substation peak load by, say 5%. To do this, the battery must discharge some energy from around 12 noon to 5 P.M. with the peak MW output occurring around 2 P.M. The energy needed, as shown on Figure D-2, must be replaced during off-peak so that the batteries are fully charged before the next peak-load period. Due to the electro-chemical conversion process efficiency of 70%, the total energy to be replaced is equal to 143% of the energy used. Since the energy is a product of kW capacity and time, the efficiency can be accounted for by varying either or both of the two variables such that the total charge energy is equal to 1.43 times the discharge energy.

FIGURE D-1
TYPICAL PSE&G NORTHERN ZONE
SUBSTATION
PEAK-DAY LOAD CURVE

FIGURE D-2

TYPICAL PSE&G NORTHERN ZONE
SUBSTATION
PEAK-DAY LOAD CURVE
(with 5% peak load reduction
using batteries)

Physically, the battery installation will have a thermal capacity dictated by the MW capacity of the inversion equipment. The inverter itself is a bilateral device and is therefore assumed to have one rating for charging and discharging. It has sufficient control systems to regulate the rate of charging and discharging up to the thermal rating of the equipment in either mode. For example, a 5 MW installation could be installed to charge or discharge from 0 to 5 MWh/hr without exceeding the 5 MW thermal capacity of the inverter.

It is assumed that the battery installation will be sized for the discharge requirement. This assumption means that maximum allowable charge load will not exceed the maximum discharge capacity. This assumption is reasonable since there seems to be sufficient time to replace discharged energy during off-peak periods. If the off-peak period was substantially briefer, then a larger inverter could be installed which would allow higher charging load and shorter charging time.

The charge energy is shown on Figure D-2. The substation load curve is altered such that the new peak load is 95% of its former value and the total energy supplied increases by the difference between the charging energy and the discharging energy, which is equal to .43 times the discharge energy.

The modified load curves show the basic dynamics caused by batteries; as batteries are added, the daytime peaks are shaved and the nighttime valleys are filled. It also shows that as more batteries are installed, the charging load eventually cause the net nighttime load to exceed the net daytime load which is the daytime load reduced by the battery discharge capacity. These batteries can be added up to the extreme that the nighttime load plus charging load equals the thermal capacity of the substation.

The next task is then to determine the number of batteries which can be charged in this off-peak valley by finding the energy between the load curve and the thermal capacity line during the "legal" charging period which will be hypothesized.

Two cases will be considered accounting for substations limited by:

- A. Normal thermal ratings with all facilities in service (Normal Capacity)
- B. Emergency thermal rating with one of the two substation transformers forced out (Emergency or Firm Capacity)

For PSE&G high capacity 13 kV substation, the following ratings apply:

- A. Normal Capacity - equal to the normal thermal rating of the two substation transformers

$$50 \text{ MVA (normal rating)} \times 2 = 100 \text{ MVA}$$

- B. Emergency Capacity - equal to the emergency thermal rating of one substation transformer (other transformers assumed to be forced out) plus normal load which can be automatically transferred to an adjacent 136kV substation through automated distribution feeder ties in an emergency.

$$60 \text{ MVA (emergency rating)} + 15 \text{ MVA (typical transferrable load)} = 75 \text{ MVA}$$

Assume that:

- A. No charging can take place between the hours of 11 A.M. and 8 P.M.
B. Battery charging time is seven hours at full load.
C. Battery discharge time is five hours at full load.

Assumption A divides the day into a charge interval and a discharge interval. Assumptions B and C will be used later to size the individual battery modules which will make up the total battery installation at a substation.

In order to simplify the integrations of the areas for each of the two substation capacity scenarios, the load curve of Figure D-1 is rectangularized by averaging the load over selected intervals. The intervals are selected on the basis of their reasonably constant slope. Referring to Figure D-1, the intervals selected for averaging are:

12 Mid.	-	7 A.M.
7 A.M.	-	11 A.M.
11 A.M.	-	1 P.M.
1 P.M.	-	4 P.M.
4 P.M.	-	8 P.M.
8 P.M.	-	11 P.M.
11 P.M.	-	12 Mid.

The rectangularized load curve is shown on Figure D-3.

The load curves will be per-unitized so that 100 MVA equals 1 per-unit or 100% load. This will allow generalization of results which can be extended to substations of different capacities serving loads having similar characteristics.

FIGURE D-3
RECTANGULARIZED VERSION
OF FIGURE D-1 LOAD CURVE

Note that the energy available for charging depends strongly on the substation peak-day load factor. The cases which will be illustrated are for the rectangularized load curve of Figure D-1, which depicts a peak-day load factor of .78. Note that a higher load factor would shift the entire load curve up while holding the peak constant, since an increased load factor implies more MWh under the load curve. The sensitivity of the results to peak-day load factor is critical since individual substation peak-day load factors do vary substantially. Results calculated for the two examples which follow will be repeated for a variety of load factors and presented in graphical form in the last part of this section.

Scenario 1 - Battery Installation at Substation Limited by Emergency Capacity

Figure D-4 shows the peak-day load curve for a substation limited by its emergency capacity. The loads are per-unitized at a rate of 1% per 1 MVA. The capacity is 75 MVA (@ unity power factor) or 75% and the peak load is 75% (load equals capacity).

The total energy available for charging is 721% hours (721 MWh for the specific PSE&G substation) with a peak charging load of 58% (58 MW for the PSE&G substation). If a battery installation of this size were installed, the discharge capability would be 505 MWh at a peak output of 58 MW. The thermal capacity required for the inverter system is 58 MVA (at unity power factor).

The first conclusion for the scenario therefore is that a battery installation can be installed at this station with a energy discharge capability of up to 500 MWh (conservative round-off) and a peak capacity output of up to 55 MW (conservative round-off). This conclusion is valid as long as the substation load is held to within the substation emergency capacity.

Notice what happens if the substation load is permitted to grow beyond the substation emergency capacity as in Figure D-5. In this figure, each step of the substation load of Figure D-4 is allowed to grow a uniform 10%, which simulates load growth at a constant power factor. The result is that the substation experiences a normal overload (load exceeds normal capacity of the station) of 10% during charging. This type of an overload is especially serious since it is long in duration and does not depend on a contingency (transformer outage, etc.) to occur.

FIGURE D-4
CHANGING ENERGY AVAILABLE
FOR SUBSTATION LOADED TO
EMERGENCY (FIRM) CAPACITY

FIGURE D-5
CHARGING ENERGY WHEN
SUBSTATION IS LOADED TO 110%
OF EMERGENCY RATING

55 MW x 500 MWH OF BATTERIES INSTALLED

To avoid this overload, there are several possible actions which can be taken:

1. Reinforce substation with additional transformers.
2. Limit the load so that it does not exceed the emergency capacity. This can be accomplished by transferring load growth to adjacent substations, which will advance the reinforcement date of these substations.
3. Restrict the charging of the batteries installation so that the charging load does not cause a normal overload.
4. Install fewer batteries to allow for substation load growth.

Looking at these actions, we find that the first two are quite similar since each requires the advancement of substation reinforcement. But the purpose of installing the batteries at substations was to postpone substation reinforcements. Therefore, since the first two proposed actions cause a reinforcement rather than postpone one, they are not constructive alternatives and can be discarded.

The third alternate is workable but restrictive. The primary reason for installing the batteries was to replace higher cost energy from peaking and intermediate generating units and this energy will be needed most during the peak periods of the day. Restricting the use of the batteries during the summer peak load season would therefore seriously penalize the effectiveness of the batteries as production capacity. Therefore, this alternative is likewise discarded.

The only alternative then is to size the battery installation at the substation so that the charging load will never cause the normal load to exceed the normal capacity.

The condition will be satisfied if the batteries are sized based on a substation peak load which is equal to the normal substation capacity (the load-carrying capability under normal (all-in) operating conditions).

The sizing calculation for the normally-limited substation will be covered in Scenario 2.

It should be mentioned at this point that there may be cases where a maximum number of batteries must be installed at a substation irrespective of the substation benefits. Such may be the case when there are a large number of batteries to be installed in a relatively small area.

Larger installations may be desirable at individual substations to avoid installing large step-up transformers to connect the batteries to the transmission. These batteries could be installed up to the full 55 MW/500 MWh already determined. The batteries would have no affect on the substation capacity and the substation load (without batteries) would still have to be limited to the emergency substation capacity (no net charge).

Scenario 2 - Battery Installation at Substation Limited by Normal Capacity

Figure D-6 shows the peak day load curve for a substation limited by its normal capacity. The load are again pre-unitized at a rate of 1% per 1 MVA. The normal capacity is 100% or 100 MVA (at unity power factor) and the peak load is also 100%.

The total energy available for charging in this case is 465% hours (465 MWh for the specific PSE&G substation) with a peak charging load of 44% (44 MW). The discharge capability of this battery system would be 326% - hours (326 MWh) at a peak output of 44% (44 MW). The thermal capacity required for this inverter system is 44 MVA (at unity power factor).

The initial conclusion is that a battery installation can be installed at this substation with a energy discharge capability of up to 320 MWh (conservative round-off) at a peak output of 40 MW (conservative round-off). This conclusion is valid for all substations loaded to the substation normal capacity.

Although the substation under study carries a normal peak load equal to the normal capacity, the station load must be reduced to the emergency capacity in the event of a transformer outage. This load reduction is accomplished by discharging the battery installation as shown on Figure D-7. The figure shows that the discharge requirement is 238% hours (238 MWh) at a peak output of 25 MW. Through Figure D-6 it was determined that this substation could support a battery installation which discharged 326 MWh at 44 MW peak. Therefore, the second conclusion to be drawn is that there is enough off-peak energy available to support a battery installation which would keep the substation load within the emergency capacity in the event of a transformer outage.

It should be reiterated here that these two conclusions are only valid for the peak day load factor of the load curve shown. Notice from Figure D-7 that as the load factor increases the load curve tends to shift upward, resulting in less charge energy available and more discharge energy required to keep the substation load within the emergency ratings. Eventually, there will be a point where there is not sufficient charge energy to

FIGURE D-6
CHARGING ENERGY AVAILABLE
FOR SUBSTATION LOADED TO
NORMAL CAPACITY

FIGURE D-7
DISCHARGE ENERGY REQUIRED
FOR EMERGENCY CONTINGENCY
(ONE SUBSTATION TRANSFORMER OUT)
FOR SUBSTATION LOADED TO
NORMAL CAPACITY

cover the discharge requirement. This conclusion can be seen in the generalized curves in the last section.

Summary of Conclusions for Substation Scenarios

Summarizing all conclusions from the foregoing treatments of PSE&G substations have a peak day load factor .78, they are:

- A. The absolute maximum battery installation which could be installed at a PSE&G substation would be 500 MWh x 55 MW (discharge). With this maximal installation, no substation capacity would be gained, but the need for step-up transformers to transmission voltages for the battery installation would be eliminated.
- B. If 238 MWh x 25 MW (discharge) of batteries are installed, the substation can carry a normal load of up to the normal substation capacity. During emergency conditions (transformer outage), there is enough energy available to reduce the substation load to within the substation emergency ratings.
- C. When the substation is loaded to its normal ratings, there is sufficient off-peak energy to charge 320 MWh x 40 MW (discharge), which is more than sufficient to cover the requirement of B, above.

D-3 GENERALIZED SIZING CURVES

Figure D-8 shows graphically the results of the battery sizing calculations performed for a range of substation peak-day load factors and substation capacity ratios (ratio of emergency capacity to normal capacity). The scales are per-unitized (1 MW = 1%) so that the curves can be projected to substations having a variety of capacities.

The figure shows the relationship between battery discharge requirements and the ability to charge. It specifically shows that the charge and discharge lines "cross-over" at a load factor of .8 for the PSE&G substation (capacity ratio = .75).

D-4 LOAD AREAS FAVORING BATTERY INSTALLATIONS

Figure D-9 which represents a PSE&G high capacity substation equipped with batteries, shows the amount of charge in the batteries at each hour of a normal summer daytime. The solid line shows that the battery charges from 8 P.M. until 11 A.M.

(the legal charge interval) and completely discharges from 11 A.M. to 8 P.M.

If a transformer failure occurs, the total energy available to reduce peak load to within emergency ratings is equal to the energy in the battery at the time of failure plus the amount of energy which can be replaced before the next peak period. This sum is shown as the dotted line on the figure. Referring to Figure D-7, the replacable energy is the area between the hours of 12 A.M. and 7 A.M.

This model is representative of substations with daytime peak periods whose durations essentially correspond to the system peak duration. Daytime substation peaks in the PSE&G system are characteristic of most load areas except predominantly residential load areas. Therefore most urban center areas, industrialized suburban areas and highly industrial areas would exhibit daytime peaks.

Figure D-9 shows that for these types of load areas batteries could be added at substations and at most daytime hours there would be sufficient charge in batteries to cover an emergency period initiated by the failure of a substation transformer. The dashed horizontal line shows the amount of energy required to cover a full substation peak period. The figure assumes that the transformer can be replaced in 24 hours and therefore only one full substation peak period must be covered by the battery discharge energy.

The predominantly residential load area would not be a practical location for a battery installation. This results from the fact that the residential substation would peak in the late evening, usually around 8 P.M., while the system would peak at mid-afternoon. The late evening peak would cause the "illegal charging interval" shown on Figure D-4 to be extended to around 12 midnight. This would cause a decrease of around 20% in the amount of battery capacity which would be charged, although the amount required on discharge to limit the substation load would remain the same. The effect of this reduction in terms of Figure D-4 is to shift the available charge energy curve downward while holding the discharge requirement line constant. The result is that there would be only four hours per day when sufficient charge is in the battery to cover a substation emergency period following a transformer failure. This compares to eleven hours for the day peak substation.

The conclusion for these residential-type application is that the availability of a full-battery charge is very low due to its short duration. Therefore, using the batteries for firm substation capacity carries with it a high risk of not meeting the substation load during transformer outages. Therefore, the

FIGURE D-9
CHARGE IN BATTERIES
AS A FUNCTION OF
TIME-OF-DAY
(peak-day, normal discharge
for system requirements)

residential substations are not favorable locations for battery installations as compared to other substations.

Appendix E

Application of Batteries to Distribution Primary and Secondary Systems

E-1 GENERAL

Although the attachment of batteries to distribution primary feeders and secondary feeders could provide some small savings, these applications were judged infeasible based on the following facts:

- A. Batteries would have to be widely dispersed and installed at non-utility property, on existing wood poles, in underground vaults and on pads. It is doubted that the batteries with the required inversion hardware could be manufactured economically in small enough sizes to allow this type of installation.
- B. The amount of new primary and secondary facilities which can be deferred is small since most new primary and secondary facilities are required to connect new loads into the existing system grid. Some saving can be derived from postponing new substation feeder positions and express primary feeders runs from the substation to the load area. Also, distribution line transformers reinforcements could be deferred. But the primary and secondary backbone grid within the load area must be expanded to reach and connect new customers and much new construction would still be necessary even if batteries were installed.

The following two exercises show the analysis for determining the benefits for installing batteries on primary and secondary distribution circuits neglecting the physical limitations mentioned.

E-2 INSTALLATION OF BATTERIES ON PRIMARY DISTRIBUTION

Figure E-1A shows a pair of 13-kV primary feeders emanating from a distribution substation. The feeders carry a normal load (without batteries) of 10 MVA and each can carry an emergency load of 20 MVA for a short time (24 hours). The feeders are tied together at their tails through a normally-open sectionalizing device called a tie recloser. Each feeder is capable of carrying the load of both feeders in an emergency (feeders connected together through the recloser and fed from one feeder position). So although the normal capacity is 12 MVA per feeder, the load

FIGURE E-1A
DISTRIBUTION PRIMARY FEEDER CONFIGURATION

FIGURE E-1B
DISTRIBUTION PRIMARY FEEDER CONFIGURATION
(WITH BATTERY INSTALLED)

must be limited to 10 MVA so that the emergency load will not exceed 20 MVA for any single-contingency failure.

The analysis is simplified by the following assumptions:

1. There are sufficient off-peak hours to charge the batteries
2. feeder off-peak load is equal to 40% of the peak load
3. the peak discharge in MW is equal to the peak charging load (MW)

Let:

$PMAX_N$ = maximum allowable feeder load under normal conditions determined by thermal ratings)

$PMAX_E$ = maximum allowable feeder load under emergency conditions (determined by thermal ratings)

PBD = battery peak discharge

PBC = peak demand of batteries while charging

~~During a peak day period the maximum area load~~ PL_N which can be supplied by the feeder under normal conditions is:

$$PL_N = PMAX_N + PBD$$

During the charging period the feeder load is 40% of the peak load and the batteries are charging. So:

$$.4 PL_N = PMAX_N - PBC$$

Since the charge and discharge peaks are assumed to be equal, the equations are:

$$PL_N = PMAX_N + PBD$$

$$.4 PL_N = PMAX_N - PBD$$

Knowing that the summer normal rating is 12 MVA, solve for the peak allowable area load.

$$1.4 PL_N = 2 PMAX_N = 2(12) = 24$$

$$PL_N = 17.1 \text{ MVA}$$

Solving the first equation for peak battery discharge:

$$PBD = PL_N - PMAX_N = 17.1 - 12 = 5.1 \text{ MVA}$$

Under the emergency condition both feeder loads are carried from one feeder position at the substation. Assuming that 5.1 MW of batteries is installed on each feeder, the load which can be carried from the local area is:

$$\begin{aligned} PL_E &= P_{MAX_E} + PBD \\ &= 20 \text{ MVA} + 10.2 \text{ MVA} \\ PL_E &= 30.2 \text{ MVA} \end{aligned}$$

Since this is equal to the load of both feeders the maximum load allowable per feeder is $(30.2/2)$ 15.1 MVA, which is smaller than the load calculated for the normal case and will be therefore the new loading limitation.

Figure E-1B shows the two 5 MW batteries installed on the feeder loop. They must be located close to the recloser to minimize the chance of isolating the battery from the heavily-loaded feeder in the event of a feeder fault (wire down, etc.).

In summary, the installation of up to 10 MW of batteries on a distribution feeder is theoretically possible. A 10 MW installation would increase the feeder loop's normal load-carrying capability from 20 to 30 MVA which is an increase of 5.0 MVA or 50% per feeder.

E-3 INSTALLATION OF BATTERIES ON SECONDARY DISTRIBUTION

Figure E-2 shows the typical arrangement of secondary distribution feeders. Secondary distribution is supplied from primary distribution through small distribution line transformers. The most common pole-mounted distribution transformer used by PSE&G has a capacity of 100 kVA.

The procedure for evaluating the benefits of batteries installed on secondary distribution similar to that used in the previous section on primary distribution. Two exercises will be performed.

The first exercise will determine how much customer load can be carried on a 100 kVA distribution line transformer if a maximum complement of batteries were installed on the secondary. The discharge capability of this maximum complement is also determined.

First, assume:

1. off-peak load level is 40% at peak

DISTRIBUTION SECONDARY SYSTEM

E-5

2. there are sufficient off-peak hours to charge batteries
3. peak discharge in MW is equal to peak charging load

Let:

PL = customer load to be carried by secondary

PD = peak discharge of battery (MW)

PT = load on distribution line transformer

The daytime peak load on the transformer is:

$$PT = PL + PD$$

Since maximum allowable load on the distribution line transformers is 100 kVA, this becomes:

$$100 \text{ kVA} = PL + PD$$

The nighttime transformer load also cannot exceed the transformer rating. Therefore,

$$100 \text{ kVA} = .4 PL + PD \text{ (charge peak=discharge peak)}$$

Adding the two equations:

$$200 = 1.4 PL; PL = 143 \text{ kVA}$$

Solving for the battery peak:

$$PD = 143 - 100 = 43 \text{ kVA}$$

Therefore, up to 43 kW of batteries can be installed on a secondary system to carry a peak load of 143 kVA of load through a 100 kVA distribution line transformer.

The second exercise will determine what size transformer is required to carry 100 kVA of customer load on a secondary system where a full complement of batteries is installed. Using the same two equations:

$$PT = PL + PD$$

$$PT = .4 PL + PD$$

$$2.0 PT = 1.4 PL$$

$$PT = 70 \text{ kVA}$$

$$PD = 30 \text{ kVA}$$

So, if a 30 kW of batteries were installed on a secondary system, a 70 kVA distribution line transformer would be required to carry 100 kVA of customer load.

E-4 SAVINGS

Tables E-1 through E-3 summarize the pwafr savings which can be derived from locating batteries on distribution primary and secondary feeders for the most promising battery application (Application 3) described in Section 3. These savings are theoretical maximums based on the following external assumptions:

1. All batteries required for Application 3 can be installed on primary or secondary feeders.
2. Every 5 MW of batteries installed will replace 5 MW of primary feeder capacity in the year of installation.
3. Every 30 kW of batteries installed will allow the installation of one 75 kVA distribution transformer in place of a 100 kVA transformer in the year of installation.

It was also assumed that the feeder loads grow 8% per year, which is the same rate used for the future substation analysis of Section 3. At this rate, a 5 MW increase in primary feeder capacity will postpone reinforcements for four years.

The capital savings for primary feeder postponements was evaluated at \$40/kW, which is the current PSE&G estimated cost for primary distribution circuit reinforcements.

The capital savings for replacing 100 kVA transformers with 75 kVA transformers was evaluated at an incremental cost of \$1.50/kW.

The results show that the maximum theoretical pwafr savings is in the order of \$6.3 million. Ninety percent of the total results from the postponement of primary feeders while the remaining ten percent is attributable to installing smaller distribution line transformers.

TABLE E-1

PRIMARY AND SECONDARY DISTRIBUTION SAVINGS ANALYSIS
(THEORETICAL MAXIMUM)

APPLICATION 3

<u>Service Date</u>	<u>1979</u>	<u>1980</u>	<u>1981</u>	<u>1983</u>
Capital Cost Cancelled (Million Dollars)	.10	.13	.23	.065
Capital Cost Deferred (Million Dollars)	2.7	3.4	6.0	1.7
Number of Years Deferred	4	4	4	4
CCIF	1.0	1.0	1.0	1.0
% Carrying Charges	15	15	15	15
Levelized Annual Revenue Requirement (Million Dollars/Year)	.4	.5	.9	.3
PWAFRR Savings (1979 Million Dollars)	<u>1.4</u>	<u>1.7</u>	<u>2.6</u>	<u>.6</u>
PWAFRR Savings Total	\$6.3 million			

TABLE E-2
PRIMARY DISTRIBUTION SAVINGS ANALYSIS
(THEORETICAL MAXIMUM)

APPLICATION 3

<u>Service Date</u>	<u>1979</u>	<u>1980</u>	<u>1981</u>	<u>1983</u>
Capital Cost Deferred (Million Dollars)	2.7	3.4	6.0	1.7
Number of Years Deferred	4	4	4	4
CCIF	1.0	1.0	1.0	1.0
% Carrying Charge	15	15	15	15
Levelized Annual Minimum Revenue Requirement (Million Dollars/Year)	.4	.5	.9	.3
PWAFRR Savings (1979 Million Dollars)	<u>1.3</u>	<u>1.5</u>	<u>2.3</u>	<u>.6</u>
PWAFRR Savings Total	\$5.7 million			

TABLE E-3
SECONDARY DISTRIBUTION SAVINGS ANALYSIS
(THEORETICAL MAXIMUM)

APPLICATION 3

<u>Service Date</u>	<u>1979</u>	<u>1980</u>	<u>1981</u>	<u>1983</u>
Capital Cost Cancelled (Million Dollars)	.10	.13	.23	.065
CCIF	1.0	1.0	1.0	1.0
% Carrying Charge	15	15	15	15
Levelized Annual Minimum Revenue Requirement (Million Dollars/Year)	.02	.02	.03	.01
PWAFRR Savings (1979 Million Dollars)	<u>.15</u>	<u>.18</u>	<u>.28</u>	<u>.07</u>
PWAFRR Savings Total	\$.68 million			

Appendix F

Development of Carrying Charges

The carrying charges used in this report were developed using the Minimum Revenue Requirements Discipline. The carrying charges are expressed as a percentage of the capital investment and include revenue requirements for return on investment, depreciation and taxes.

The carrying charges can be determined by first calculating the expected year-by-year costs, or revenue requirements, associated with a particular project, then present worthing the revenue requirements at the cost of money and then dividing by a factor called the "Sum of the Present Worth of the Mean Annual Survivors".

Table F-1 shows the year by year revenue requirements for a battery with a 14 year life and 25 percent salvage at the end of its life. Also shown in Table F-1 is the sum of the present worth of capital recovery revenue requirements which is both return on and of the capital (return and depreciation), and the sum of the present worth of federal income taxes. These are used in Table F-3 to calculate the carrying charges for return, depreciation and federal income taxes.

The "Unit Present Worth of the Mean Annual Survivors" (UPWMAS) is based on a probability of retirement curve for the particular type plant in question. The example shown in Table F-1 assumes the retirement date is known with certainty, which allows the UPWMAS to be calculated by the simplified formula shown in Table F-2. Also shown in Table F-2 is the calculation of Construction Compound Interest Factor (CCIF) which adjusts the capital cost for the cost of money during the construction period.

Table F-3 shows the development of the carrying charges. The values for present worth of capital recovery (PW CAP REC) and present worth of federal income taxes (PW FIT) are from Table F-1, and the values for CCIF and UPWMAS are from Table F-2.

INFLATION

Results in the body of the report are based on two assumptions as to future inflation. The base case in the report assumes no escalation of costs. The sensitivity analysis to inflation in Section 6.7 is based on a continuing 6 percent per year compound escalation.

TABLE 1-1

1944 BY YEAR DEDUCTION REQUIREMENTS

	1	2	3	4	5	6	7	8	9	10	11	12	13
YEAR	RA CONS EXPEND	AFDC ACCRUAL	GROSS PLANT	RETIRE- MENTS	WORK DEPRIC	SALVAGE	DEPRIC RESERVE	TAX DEPRIC	HOUSE DEPRIC	NORMAL ACCRUAL	NORMAL RESERVE	REMOVAL ACCRUAL	REMOVAL AMORT
-1	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
0	50.00	.00	50.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
1	100.00	.00	100.00	.00	5.36	.00	.00	8.00	7.14	.41	.00	.00	.00
2	100.00	.00	100.00	.00	5.36	.00	5.36	7.67	7.14	.25	.41	.00	.00
3	100.00	.00	100.00	.00	5.36	.00	10.71	7.33	7.14	.09	.66	.00	.00
4	100.00	.00	100.00	.00	5.36	.00	16.07	7.00	7.14	-.07	.75	.00	.00
5	100.00	.00	100.00	.00	5.36	.00	21.43	6.67	7.14	-.23	.69	.00	.00
6	100.00	.00	100.00	.00	5.36	.00	26.79	6.33	7.14	-.39	.46	.00	.00
7	100.00	.00	100.00	.00	5.36	.00	32.14	6.00	7.14	-.55	.07	.00	.00
8	100.00	.00	100.00	.00	5.36	.00	37.50	5.67	7.14	-.71	-.48	.00	.00
9	100.00	.00	100.00	.00	5.36	.00	42.86	5.33	7.14	-.87	-1.19	.00	.00
10	100.00	.00	100.00	.00	5.36	.00	48.21	5.00	7.14	-1.03	-2.06	.00	.00
11	100.00	.00	100.00	.00	5.36	.00	53.57	4.67	7.14	-1.19	-3.09	.00	.00
12	100.00	.00	100.00	.00	5.36	.00	58.93	4.33	7.14	-1.35	-4.27	.00	.00
13	100.00	.00	100.00	.00	5.36	.00	64.29	4.00	7.14	-1.51	-5.62	.00	.00
14	100.00	.00	100.00	100.00	5.36	25.00	69.64	3.67	7.14	-1.67	-7.13	-12.00	-2.40
15	100.00	.00	.00	.00	.00	.00	-.00	3.33	.00	1.60	-8.60	.00	-2.40
16	100.00	.00	.00	.00	.00	.00	-.00	3.00	.00	1.44	-7.20	.00	-2.40
17	100.00	.00	.00	.00	.00	.00	-.00	2.67	.00	1.28	-5.76	.00	-2.40
18	100.00	.00	.00	.00	.00	.00	-.00	2.33	.00	1.12	-4.48	.00	-2.40
19	100.00	.00	.00	.00	.00	.00	-.00	2.00	.00	.96	-3.36	.00	.00
20	100.00	.00	.00	.00	.00	.00	-.00	1.67	.00	.80	-2.40	.00	.00
21	100.00	.00	.00	.00	.00	.00	-.00	1.33	.00	.64	-1.60	.00	.00
22	100.00	.00	.00	.00	.00	.00	-.00	1.00	.00	.48	-.96	.00	.00
23	100.00	.00	.00	.00	.00	.00	-.00	.67	.00	.32	-.48	.00	.00
24	100.00	.00	.00	.00	.00	.00	-.00	.33	.00	.16	-.16	.00	.00
25	100.00	.00	.00	.00	.00	.00	-.00	.00	.00	.00	-.00	.00	.00
26	100.00	.00	.00	.00	.00	.00	-.00	.00	.00	.00	-.00	.00	.00
27	100.00	.00	.00	.00	.00	.00	-.00	.00	.00	.00	-.00	.00	.00
28	100.00	.00	.00	.00	.00	.00	-.00	.00	.00	.00	-.00	.00	.00
29	100.00	.00	.00	.00	.00	.00	-.00	.00	.00	.00	-.00	.00	.00
30	100.00	.00	.00	.00	.00	.00	-.00	.00	.00	.00	-.00	.00	.00
31	100.00	.00	.00	.00	.00	.00	-.00	.00	.00	.00	-.00	.00	.00
32	100.00	.00	.00	.00	.00	.00	-.00	.00	.00	.00	-.00	.00	.00
33	100.00	.00	.00	.00	.00	.00	-.00	.00	.00	.00	-.00	.00	.00

F-2

TABLE F-1 (Con't)

YEAR	14 REMOVAL RESERVE	15 ITC ACCRUAL	16 ITC AMORT	17 ITC RESERVE	18 NET PLANT	19 RETURN	20 INTERES	21 FII PAID	22 REVENUE REQUIRE	23 PW FACTOR	24 PW CAP REC	25 PW FIT
-1	.00	.00	.00	.00	.00	.00	.00	.00	.00	1.10	.00	.00
0	.00	3.50	.11	.00	50.00	5.00	2.02	-.85	7.55	1.00	8.39	-.85
1	.00	3.50	.21	3.39	76.61	9.66	3.90	-.44	18.27	.91	17.02	-.40
2	.00	.00	.21	6.68	87.55	8.75	3.54	2.72	16.87	.83	11.70	2.25
3	.00	.00	.21	6.47	82.15	8.22	3.32	2.58	16.03	.75	10.11	1.94
4	.00	.00	.21	6.24	76.92	7.69	3.11	2.45	15.22	.68	8.72	1.68
5	.00	.00	.21	6.05	71.84	7.18	2.90	2.34	14.44	.62	7.51	1.45
6	.00	.00	.21	5.83	66.92	6.69	2.71	2.23	13.67	.56	6.46	1.26
7	.00	.00	.21	5.62	62.17	6.22	2.51	2.12	12.94	.51	5.55	1.09
8	.00	.00	.21	5.41	57.57	5.76	2.33	2.03	12.22	.47	4.76	.95
9	.00	.00	.21	5.20	53.13	5.31	2.15	1.95	11.54	.42	4.07	.83
10	.00	.00	.21	4.98	48.86	4.89	1.97	1.87	10.87	.39	3.47	.72
11	.00	.00	.21	4.77	44.74	4.47	1.81	1.81	10.24	.35	2.95	.63
12	.00	.00	.21	4.56	40.79	4.08	1.65	1.75	9.62	.32	2.51	.56
13	.00	.00	.21	4.35	36.99	3.70	1.50	1.70	9.03	.29	2.12	.49
14	.00	.00	.21	4.14	33.35	3.34	1.35	15.87	13.09	.26	-.73	4.18
15	-9.60	.00	.21	3.92	14.48	1.45	.59	1.22	6.45	.24	1.25	.29
16	-7.20	.00	.21	3.71	10.69	1.07	.43	1.17	5.86	.22	1.02	.25
17	-4.80	.00	.21	3.50	7.06	.71	.29	1.13	5.30	.20	.83	.22
18	-2.40	.00	.21	3.29	3.59	.36	.15	1.10	4.76	.18	.66	.20
19	.00	.00	.21	3.08	.28	.03	.01	-1.14	-.34	.16	.13	-.19
20	.00	.00	.21	2.86	-.46	-.05	-.02	-1.02	-.48	.15	.08	-.15
21	.00	.00	.21	2.65	-1.05	-.11	-.04	-.89	-.57	.14	.04	-.12
22	.00	.00	.21	2.44	-1.48	-.15	-.06	-.76	-.64	.12	.01	-.09
23	.00	.00	.21	2.23	-1.75	-.17	-.07	-.61	-.68	.11	-.01	-.07
24	.00	.00	.21	2.02	-1.86	-.19	-.07	-.46	-.70	.10	-.02	-.05
25	.00	.00	.21	1.80	-1.80	-.18	-.07	-.29	-.69	.09	-.04	-.03
26	.00	.00	.21	1.59	-1.59	-.16	-.06	-.28	-.65	.08	-.03	-.02
27	.00	.00	.21	1.38	-1.38	-.14	-.06	-.27	-.62	.08	-.03	-.02
28	.00	.00	.21	1.17	-1.17	-.12	-.05	-.26	-.59	.07	-.02	-.02
29	.00	.00	.21	.95	-.95	-.10	-.04	-.25	-.56	.06	-.02	-.02
30	.00	.00	.21	.74	-.74	-.07	-.03	-.24	-.52	.06	-.02	-.01
31	.00	.00	.21	.53	-.53	-.05	-.02	-.22	-.49	.05	-.01	-.01
32	.00	.00	.21	.32	-.32	-.03	-.01	-.21	-.46	.05	-.01	-.01
33	.00	.00	.11	.11	-.11	-.01	-.00	-.10	-.22	.04	-.01	-.00
											<u>96.81</u>	<u>16.93</u>

Footnotes to Table F-1

1. MA (CONS EXPEND) - Average annual balance of construction expenditures.
2. AFDC ACCRUAL - The cost of money during the construction period is not capitalized during the construction period. However, the revenue requirements during the construction period are reflected in the in-service life carrying charges.
3. GROSS PLANT - Sum of the accumulated construction expenditures less retirements. (4_n)
4. RETIREMENTS - Original cost of plant retired from service.
5. MOOD DEPREC - Calculated at 1/average life times the gross plant balance adjusted for salvage. $(5_n) = (1/14) \times (.75) \times (4_n)$
6. SALVAGE - Salvage value of plant less the cost of removal.
7. DEPREC RESERVE - Sum of depreciation accruals less retirements, $(7_n) = (7_{n-1}) + (5_{n-1}) - (4_{n-1}) + (6_{n-1})$
8. TAX DEPREC - Tax deductible sum - of-years-digits depreciation. $(8_n) = (TL-n+1)/(TL(TL+1)/2) \times (\text{original cost})$
9. BASE DEPREC - Straight-line depreciation of original cost excluding salvage, to which the tax savings of accelerated depreciation are "normalized" or spread out over the life of the project per regulatory commission approved accounting. $9_n = (1/14 \times 100)$
10. NORMAL ACCRUAL - Revenue requirements reflecting the "normalization" of the tax savings from accelerated depreciation. $(10_n) = t \times ((8_n) - (9_n))$
11. NORMAL RESERVE - Accumulation of the normalization accruals which serve as a source of investment capital, in fact provided by the customers, and requiring no revenue requirement for return on investment. The reserve accounts are eventually zeroed at some point in time. $(11_n) = (11_{n-1}) + (10_{n-1})$
12. REMOVAL ACCRUAL - Tax effect of salvage. $(12_n) = -t \times (6_n)$
13. REMOVAL AMORT - Removal accrual amortized over a 5 year period.
14. REMOVAL RESERVE - Unamortized balance of cost of removal tax effects.
15. ITC ACCRUAL - Investment tax credit @ 7% of the construction expenditures. $15_n = ((1_n) - (1_{n-1})) \times 0.07$

ITC AMORT - Amortization of the tax credit over a period of 33 years.

ITC RESERVE - Unamortized balance of investment credits.
 $(17_n) = (17_{n-1}) + (15_{n-1}) - (16_{n-1})$

NET PLANT - Gross plant less reserves. Reflects the remaining investment in the project provided by the utility's stock and bond holders. $(18_n) = (3_n) - (7_n) - (11_n) - (14_n) - (17_n)$

RETURN - Cost of money times net plant. Reflects return required on the utility's outstanding securities.
 $(19_n) = (18_n) \times (i)$

INTERES - Deductible interest component of the total requirement for return. $(20_n) = (18_n) \times (0.04042)$

IT PAID τ Federal Income Taxes paid.
 $(21_n) = \frac{\tau}{1-\tau} [(19_n) - (20_n) + (6_n) + (5_n) - (8_n) + (10_n) + (12_n) - (13_n) + (15_n) - (16_n)] - \frac{(15_n)}{1-\tau}$

REVENUE REQUIRE - Revenue Requirements.
 $(22_n) = (19_n) + (21_n) + (5_n) + (10_n) + (15_n) - (16_n) + (12_n) - (13_n)$

PW FACTOR - Present Worth Factor. $(23_n) = 1/(1+i)^n$

PW CAP REC - Present Worth of Capital Recovery.
 $(24_n) = [(22_n) - (21_n)] \times (23_n)$

PW FIT - Present Worth of Federal Income Taxes. $(25_n) = (21_n) \times (23_n)$

TL = Tax Life = 24
 n = year
 t = 0.48
 i = 0.10

TABLE F-2

Construction Compound Interest Factor (CCIF)

<u>Time</u>	<u>Construction Expenditure</u>	<u>Present Worth Factor</u>	<u>Future Worth</u>
-1	50	1.10	55
0	50	1.00	50
			<u>105</u>

where Present Worth Factor = $1/(1+0.1)^N$
 $N = \text{Time}$

$$CCIF = \frac{105}{100} = 1.05$$

Unit Present Worth of Mean Annual Survivors (UPWMAS)

$$UPWMAS = (1 - (1/(1 + i)^N))/i = 7.37$$

$$\text{where } i = 0.10 \\ N = 14$$

$$PWMAS = CCIF * CE * UPWMAS$$

$$PWMAS = 1.05 * 100 * 7.37 = 773.85$$

where CE = Sum of Construction Expenditures
 PWMAS = Sum of the Present Worth of the Mean Annual Survivors

TABLE F-3

Carrying Charges

A. Carrying Charge (CC) for Return and Depreciation:

$$CC = \xi PW \text{ CAP REC (from Table F-1)} / \xi PW MAS$$

$$CC = 98.41 / 773.85 = 0.1272$$

$$\text{RETURN} = 0.10 = 10.00\%$$

$$\text{DEPRECIATION} = 0.1272 - 0.10 = 2.72\%$$

where $\xi PW \text{ CAP REC}$ = Sum of Present Worth
of Capital Recovery

B. Carrying Charge for Federal Income Taxes:

$$CC = \xi PW \text{ FIT (from Table F-1)} / \xi PW MAS$$

$$CC = 16.93 / 773.85 = 0.0219 = 2.19\%$$

C. Carrying Charge for State and Local Taxes = 3.40%

$$\text{Total Carrying Charge} = \underline{\underline{18.3\%}}$$

Table F-4 shows the adjustment made to the carrying charges to recognize a 6 percent continuing inflation. This adjustment is called Inflation Adjusted Present Worth Factor (IAPWF) and is used to convert a standard carrying charge to a present worth of all future revenue requirements including escalation. The fundamental reason for these higher carrying charges is the requirement to recover through depreciation an inflated replacement value for equipment being retired. A more complete technical description is contained in Treatment of Inflation in Engineering Economic Analysis by Frank Cassidy and G. W. Schirra of PSE&G, presented at the IEEE-ASME Joint Power Generation Conference, at Buffalo, N.Y. in September, 1976.

Table F-4

Inflation Adjusted Present Worth Factor and Carrying Charges

A. Inflation Adjusted Present Worth Factor (IAPWF)

$$IAPWF = \frac{1 + \frac{\beta_d}{K}}{\beta_d + 1}$$

$$\text{where } i = 0.10$$

$$r = 0.06$$

$$K = \frac{1 + i}{1 + r} - 1$$

$$K = \frac{1.10}{1.06} - 1 = 0.377$$

$$\beta_d + 1 = \frac{1}{UPWMAS \text{ (from Table F-2)}} = \frac{1}{7.37} = .1357$$

$$UPWMAS = \frac{1}{K + \frac{\beta_d}{K}}$$

$$\text{Also } UPWMAS = (1 - (1/(1 + K)^{14}))/K = 10.72$$

$$\therefore \frac{\beta_d}{K} = \frac{1}{UPWMAS} - K = 1/10.72 - 0.377 = 0.0555$$

$$IAPWF = \frac{1 + \frac{0.0555}{0.377}}{0.1357} = 18.21$$

B. Carrying Charge adjusted for Inflation

RETURN	10.00%
DEPRECIATION	1.65
FEDERAL INCOME TAXES	1.76
STATE AND LOCAL TAXES	3.40
	<u>16.81</u>

Present Worth of All Minimum Revenue Requirements Factor
(PWAFMARRF)

$$PWAMRRF = CC * CCIF * IAPWF$$

$$PWAMRRF = .1681 * 1.05 * 18.21 = 3.2$$

$$\text{Inflation adjusted carrying charge} = \frac{3.2}{CCIF} * i = 30.6\%$$