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R-943271

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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Regarding

PENNSYLVANIA POWER & LIGHT COMPANY
Docket Number R-00943271

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Volume II of II
Documents Produced by PP&L in USDC, EDPa, CA #91-5176 and CA #92-2359

On Behalf of
Central Eastern Pennsylvania Fuel Oil Dealers

Economic & Policy Analysis, Inc.
13300 Council Bluff Drive
Austin, Texas 78727

April 12, 1995

Exhibit Index
Voume II of II
Documents Produced by PP&L in USDC, EDPa, CA #91-5176 and CA #92-2359

CEPFOD Exhibit No. 2

RESIDENTIAL MARKETING PERFORMANCE UPDATE

APRIL 4, 1986

Marketing & Economic Development

TABLE OF CONTENTS

I. EXECUTIVE SUMMARY

PP&L's marketing efforts in the residential sector have resulted in a commanding share (85% in the first quarter, 1986) of all new dwelling units utilizing electric space and water heating. Marketing goals for electric heat saturation are being exceeded but there is cautious optimism. Current market share of new units now being connected is single - 87%, town - 95%, apartment - 77% and mobile home - 33%. The present fossil fuel pricing situation poses great challenges to maintaining saturation levels. We are seeing an increase in the number of homes planning to use fossil fuels as their heating fuel source on new service requests.

The impact of lower fossil fuel prices on saturation will depend largely on the length of time, current low pricing levels remain in effect. PP&L's standard residential rate cannot compete on a price only basis with either gas or oil in the heating fuel market.

Fossil fuel prices will also have a negative effect on the marketing of Nite-Saver thermal storage space heating systems. The operational costs of a Nite-Saver system on the Residential Thermal Storage (RTS) rate has been very competitive with gas and oil systems but as prices continue to fall that competitive position disappears and the builders, contractors and especially homeowners begin to focus upon the higher installation costs of a Nite-Saver system versus a gas or oil heating system.

In order to maintain our large share of the market, we must continue to be innovative and receptive to the needs of the residential marketplace. Once a homeowner decides to install a fossil-fuel heating system, we have lost that customer for the life of the heating system or twenty (20) years. The following positive factors will be used to combat the loss of market share:

<u>Four Star Home Program</u>

This new home demand management program will continue to gain better acceptance among builders, contractors and customers through the effective use of a well balanced corporate media campaign and the increased use of co-op advertising by builders. Additions to the Four Star lineup this year include the Model Home Program which will provide thirty Four Star homes available for general public viewing across our service territory. Through the first quarter of 1986, 4.7% of all new electrically heated single and town homes have installed storage heating. This is up from 3.77% at year end 1985 and 2.82% in March 1985.

<u>Central Eastern Pennsylvania Heat Pump Association (CEPHPA)</u>

This growing organization is our greatest ally against the negative saturation impact of lower priced fossil fuels. All contractor members of CEPHPA receive technical training on the Heat Pump Plus System.

DM 064165

RTS Rate 2 kw Demand Forgiveness

The 2 kw rate enhancement of January 1, 1986 has received positive reviews from builders, contractors and homeowners. The 2 kw demand forgiveness increases annual savings by approximately $150. The current fossil fuel pricing situation made the RTS rate revision which increases homeowner savings very timely.

Mobile Home Program

The Mobile Home Program introduced in 1985 was responsible for increasing electric heat saturation (33% of units connected in the first quarter, 1986) in the manufactured housing market. Participating mobile home dealers used our marketing brochure to sell insulation packages which then made the installation of electric heat a viable option for the customer. Our recent participation in the Pennsylvania Manufactured Housing Association Show in Harrisburg has generated greater awareness of our Mobile Home Program for dealers.

The present residential marketplace is constantly changing due to the unstable economies in the pricing of fossil fuels. If PP&L is to maintain its #1 position among energy suppliers, we must continue to offer our customers more value for their energy dollar. Our regulated pricing structure does not allow for quick fixes to respond to sudden market fluctuations so we must deliver a message of stability and quality service to our customers. This message delivered by our marketing programs, brochures and allies should focus on PP&L's relatively stable rates that aren't subject to drastic change such as fossil fuels. We must point out that our electric service cost is less likely to change and more likely to remain stable over the lifetime of home ownership.

DM 064166

4

II. NEW CONSTRUCTION -- ELECTRIC HEAT SATURATION

A. Introduction

Since the start of our marketing program, PP&L has taken a dominant position in the new home construction market. We have succeeded in raising electric heat saturation from 61% (pre-marketing) to its present (3/86) level of 85% in all new dwelling units now being connected.

In order to maintain the high level of saturation for 1986 that we have attained since reentering the marketing arena poses new challenges. Changing economic factors will give our competitors new advantages which may erode our present market share.

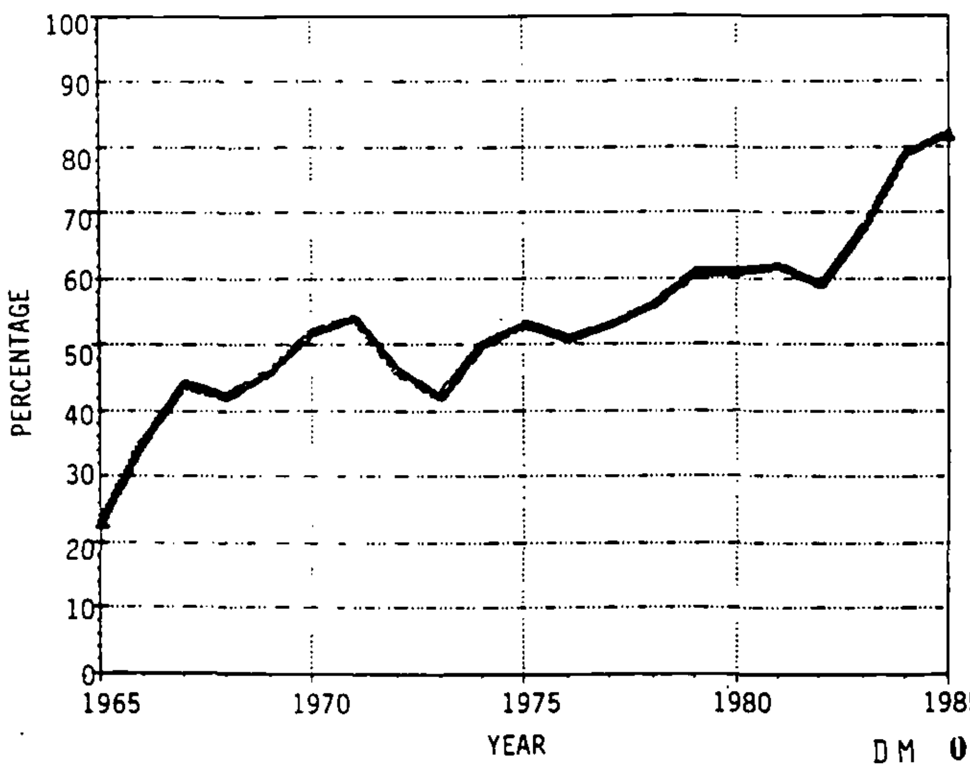
Substantial decreases in the price consumers pay for fossil fuels since the beginning of 1986 will have an impact on the new home market. Although during the first three months of 1986 we have been able to maintain saturation at 85%, our competition will begin to chip away at us unless we are prepared to meet the challenge through our marketing efforts.

B. Performance Review

Chart I illustrates the strong achievements registered by our residential personnel since the recent change in our corporate direction to emphasize marketing.

CHART I

**PP&L'S SHARE OF THE MARKET
NEW RESIDENTIAL DWELLING UNITS
1965 THROUGH DECEMBER 1985**



A comparison of 1984-1985 percent share of market data shows new home electric heat increasing from 79% to 82% at year end 1985, as shown in Table I. The largest area of increase is in the mobile home market where electric heat saturation improved by 10%, due to PP&L's Mobile Home Program introduced during 1985.

TABLE I
RESIDENTIAL NEW CONSTRUCTION
PERCENT SHARE OF MARKET
1984 -- 1985

	1984					1985				
	Single Family Homes	Town Houses/ Twins	Apartments	Mobile Homes	Total	Single Family Homes	Town Houses/ Twins	Apartments	Mobile Homes	Total
Elec.	86%	88%	77%	15%	79%	86%	87%	80%	25%	82%
Oil	7%	2%	6%	62%	11%	7%	1%	5%	51%	9%
Gas	3%	10%	14%	16%	7%	4%	11%	14%	19%	7%
Other	4%	0%	3%	7%	3%	3%	1%	1%	5%	2%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Table II shows the 1984-1985 share of market captured by the major energy suppliers by actual number of dwelling units. Total new construction increased in 1985 by 10.2% when compared with 1984. The most significant increase was a 14.7% rise in the construction of single family homes. Improvements in the economy and lower mortgage interest rates are contributing factors in this increase.

TABLE II
RESIDENTIAL NEW CONSTRUCTION
SHARE OF MARKET BY DWELLING UNITS
1984 -- 1985

	1984					1985				
	Single Family Homes	Town Houses/ Twins	Apartments	Mobile Homes	Total	Single Family Homes	Town Houses/ Twins	Apartments	Mobile Homes	Total
Elec.	6,961	1,596	1,831	175	10,563	8,112	1,667	2,127	210	12,11
Oil	576	32	150	743	1,501	654	23	142	434	1,25
Gas	233	180	335	192	940	336	227	371	167	1,10
Other	293	5	50	91	439	280	1	25	42	34
Total	8,063	1,813	2,366	1,201	13,443	9,382	1,918	2,655	853	14

DM 064168

6

Historically, electric baseboard space heating has been the most dominant system being installed. A comparison of electric space heating systems installed in 1984-1985, Table III, demonstrates the changes that are beginning to surface in the market. Baseboard has dropped by 4% while heat pumps have increased by 4% and now account for 33% of the electric space heating systems being installed. National figures indicate that heat pumps represent 30% of the electric heat market.

TABLE III
ELECTRIC SPACE HEATING SYSTEMS
1984 -- 1985 INSTALLATIONS BY TYPE

Space Heating System	1984 Installations	% of Total	1985 Installations	% of Total	Change
Ceiling Cable	135	1%	128	1%	--
Baseboard	6,981	66%	7,475	62%	-4%
Ceramic Room	42	0%	163	1%	+1%
Ceramic Central	0	0%	0	0%	--
Warm Air Furnace	52	1%	90	1%	--
Hydronic	13	0%	10	0%	--
Hydronic Off-Peak	2	0%	0	0%	--
Heat Pump	3,084	29%	4,020	33%	+4%
Heat Pump Plus	155	2%	209	2%	--
Ground Water Heat Pump	15	0%	15	0%	--
Dual Fuel Heat Pump	84	1%	6	0%	--
Total	10,563	100%	12,116	100%	

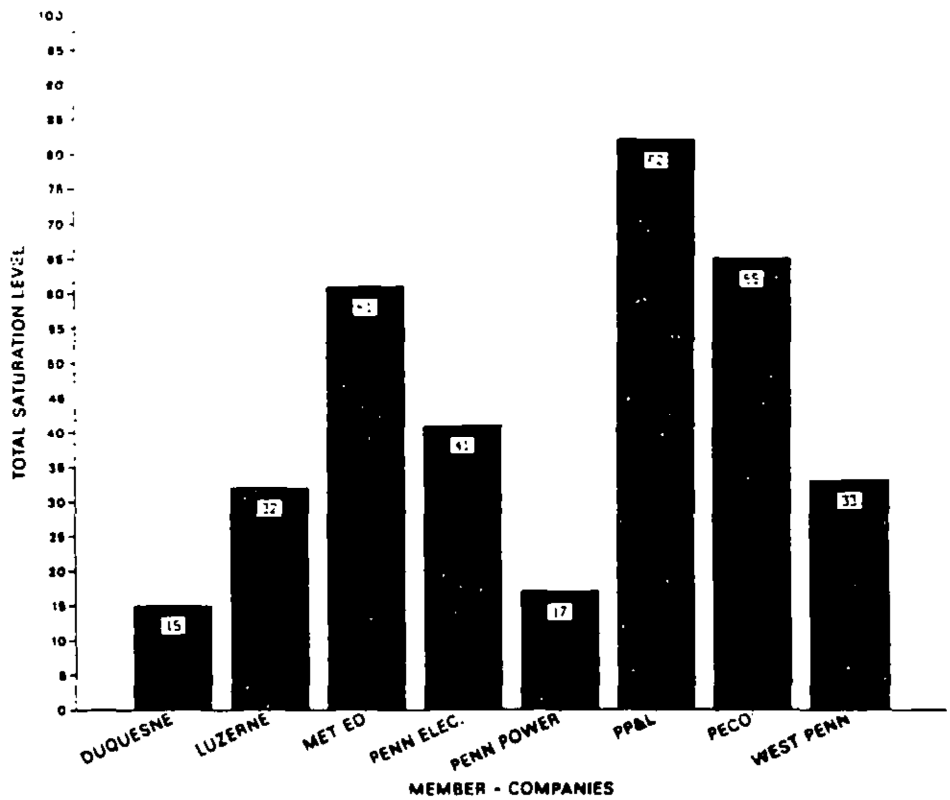
Chart II shows the electric heat saturation experienced by P.E.A. member companies for 1985.

Philadelphia Electric Company attained 65% electric heat saturation in total new dwelling units, with 86.4% of their 7,785 new electric connects being heat pumps or 6,729 units. West Penn Power, with the lowest residential rate in Pennsylvania, have maintained electric heat saturation at 41% since they shifted over 12 years ago from a marketing to an energy conservation/load management phase. MetEd has seen their saturation drop from 68% in 1984 to 61% in 1985. They cite increased competition from fossil fuel suppliers as the reason for the decline. Luzerne Electric Division-UGI experienced a sharp decrease in saturation during 1985. They saw their saturation drop from 70% in 1984 to its current level of 32% and they also attribute this to increased competitor activities.

DM 064169

CHART II

1985
ELECTRIC HEAT SATURATION - NEW CONSTRUCTION
PEA MEMBER COMPANIES



C. 1986 Objectives

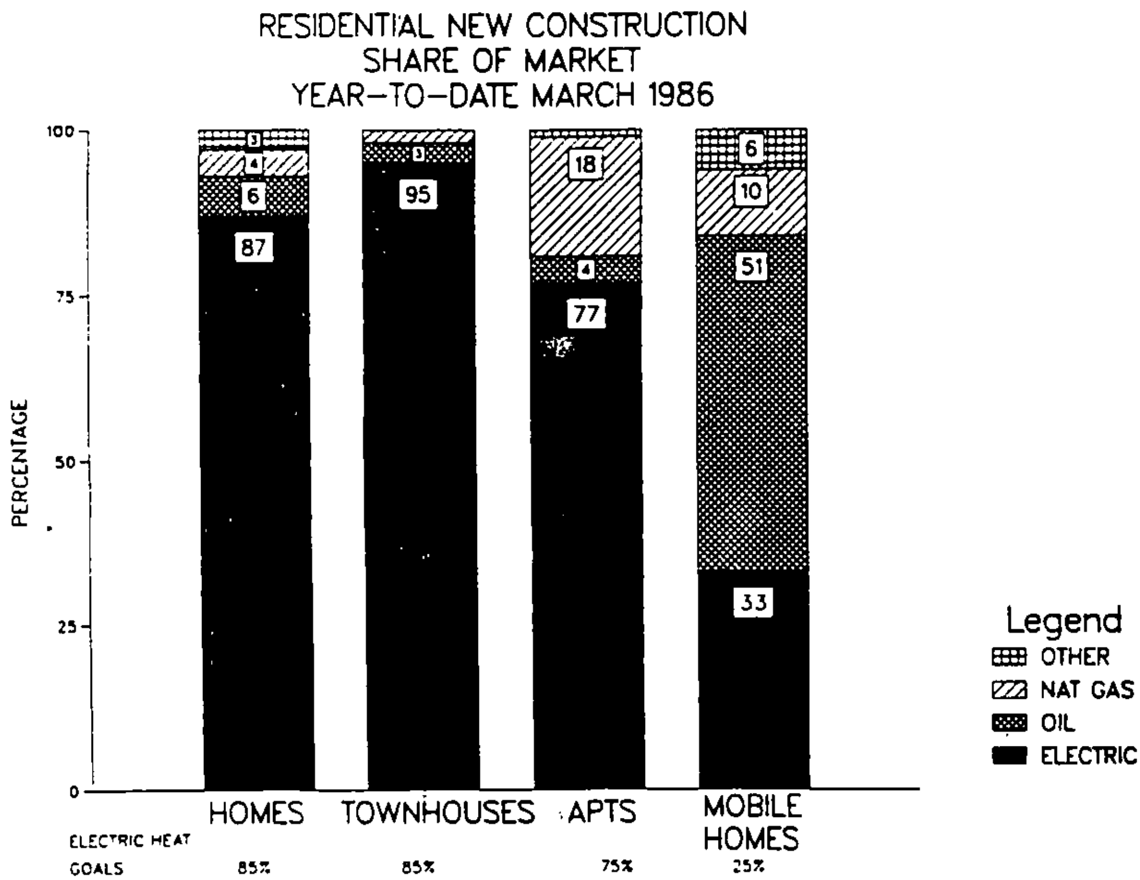
Electric heat saturation goals for 1986 have targeted increased market penetration in town houses, apartments and mobile homes. The goals by housing type are shown in Table IV.

TABLE IV
1986 RESIDENTIAL MARKETING GOALS
PERCENT SATURATION

	1986 GOAL
Single Homes	85%
Town Houses/Twins	85%
Apartments	75%
Mobile Homes	25%

First quarter attainment, as shown on Chart III, points out that we are exceeding the established 1986 saturation goals in each category. However, we are concerned that decreases in fossil fuel prices will have an effect on saturation. The majority of the houses connected to our lines in the first quarter of 1986 were built late in the third quarter or during the fourth quarter of 1985 when oil prices were approximately $1.05/gallon.

CHART III



D. Factors Influencing Performance

1. **Positive Factors**

a. Central Eastern Pennsylvania Heat Pump Association (CEPHPA)

The heat pump association will continue to be our strongest ally in the residential marketing area. The continuing development of contractors' marketing and technical skills is critical to the further growth of the organization. Unless membership in the association provides tangible returns to contractor members, CEPHPA will not move forward and assume a leadership role in our service territory.

DM 064171

9

CEPHPA, during its first year, provided a forum for the constant exchange of ideas and information between PP&L and contractors. The 1986 cooperative advertising program for contractors will help spread the word about efficient electric heat pump systems and the many benefits they offer homeowners.

b. Four Star Home Program

Even though the Four Star Home concept is designed as a load management program, it creates positive feelings about the cost of electric heat in the minds of building contractors and customers.

Builders have used the positive connotations of our Four Star Home Program to assist them in marketing electric heat. The Four Star Home Program is used by builders as a tool to market electric heat (first step) and to increase customer satisfaction with their home through lower operating costs of a Nite-Saver System (second step).

Four Star Home Program Cooperative Advertising

In providing cooperative advertising to builders, we have gained even greater overall cooperation from a key ally. Many builders now have optional plans for each house design which include installation costs for various electric heating systems (Heat Pump, Heat Pump Plus, Ceramic), not just baseboard. The Four Star Home Program has something to offer to the builder and it has provided immediate returns into him and PP&L.

c. Promotional Brochures/Handouts

Three marketing brochures have been revised and five new marketing pieces developed for use by our residential personnel and builder/contractor allies in our efforts to deliver specific marketing information to our customers. At a recent Builders Show in Harrisburg, one of our strongest builder allies, Donco Homes, estimated his firm gave out over 750 PP&L brochures concerning the Four Star Home Program, Heat Pump Plus and Ceramic Storage Heating Systems.

Continued development and improvement of marketing brochures will only enhance our position with our customers, allies and competitors.

d. Mobile Home Program

The introduction of the Heat Pump Mobile Home Program in 1985 has contributed substantially in raising the saturation of electric heat in manufactured housing units. The dealers are appreciative of our marketing efforts and view our return to the promotion of efficient electric equipment in manufactured housing as a very positive step in increasing electric heat applications. Our promotional brochure has received very positive reviews and is used by the dealers to assist them in marketing insulation packages to their customers. Once the customer commits on the insulation package, electric heat becomes a viable purchase consideration.

This market should continue to improve during 1986 based on the positive responses we have received from dealers throughout our service territory. We are marketing our Mobile Home Program to the manufacturers in an effort to qualify more homes for our program. Our recent participation in the Pennsylvania Manufactured Housing Association show in Harrisburg has led to increased interest from manufacturers and dealers who participated in the week-long show.

Active Participation in Homebuilders Associations

Even though this may not appear to be a major factor in influencing the saturation performance of electric heat, our division personnel are highly regarded within their respective local builder associations. This has enabled PP&L to receive favorable response and treatment from the members of the various association. Many of our division residential personnel are officers in the association enabling them to establish close working relationships with key major builders.

2. Negative Factors

a. Fossil Fuel Prices

Continuing decline in fossil fuel prices will have negative impact on our electric heat saturation. At the present, our standard residential rate cannot compete on a price only basis with gas or oil in the heating market. We have already seen an increase in the number of new connects planning to use gas or oil as the heating fuel.

A recent review of new service requests received over the past two months by Susquehanna residential personnel revealed the following information about fuel choice:

Electric	-- 60%
Oil	-- 24%
Gas	-- 3%
Coal	-- 6%
Wood	-- 7%

If prices remain stable at their current level, the impact to saturation could be substantial (10%-15%).

DM 064173

b. <u>Competition Specials</u>

Most gas companies will provide $100/lot to help cover the cost of trenching and will underwrite any reengineering costs from electric utilities to convert development to gas. Discussions are currently underway between gas companies and developers concerning bulk rate discounts for developments that choose gas for heating and cooking. Most gas companies will not extend their distribution network unless they are assured of 80% saturation in the development.

Most gas and oil companies are sponsoring free use of equipment in model homes and gas companies are also providing lucrative co-op advertising allowances. One oil dealer in the Lehigh Valley will install an oil furnace with central air for $1,000 if you contract to buy oil from his firm for a minimum of three years.

We will closely monitor these situations due to the potential negative impact it could have to our marketing efforts.

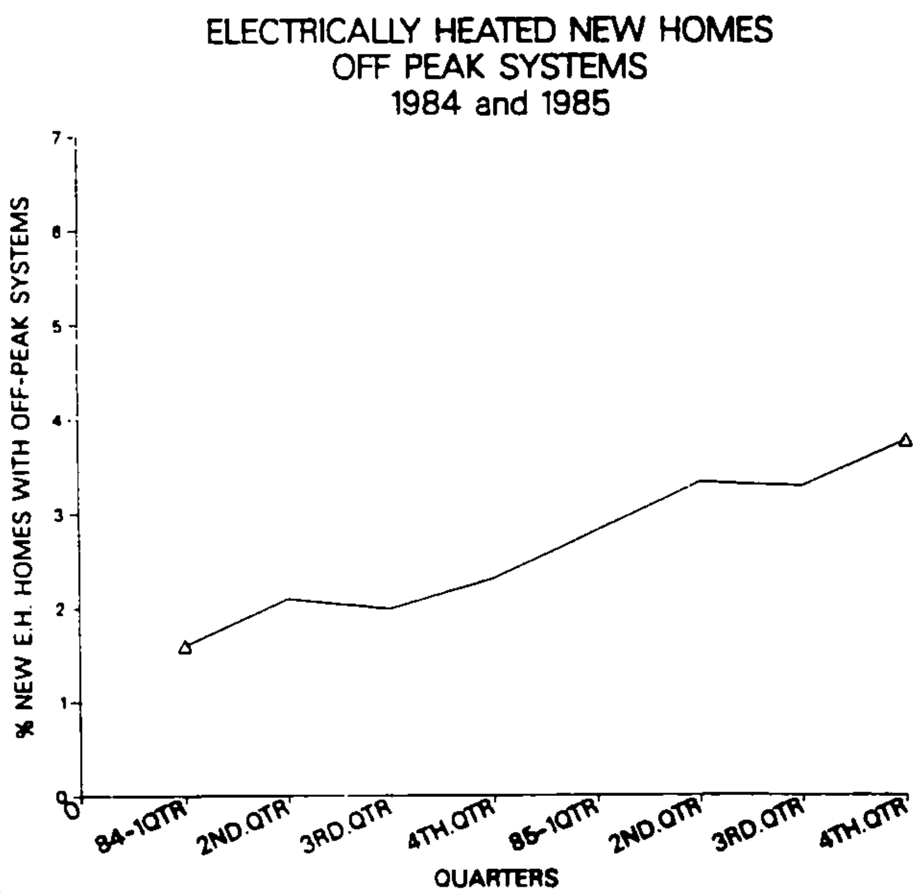
DM 064174

III. **NEW CONSTRUCTION -- OFF-PEAK SYSTEMS**

A. Since the inception of marketing Nite-Saver systems in 1981 through March, 1986, 943 customers have installed storage space and water heating systems and are currently billed on the RTS rate. Based on data obtained during the winter peak day of January 21, 1985, the kw shifted by these systems to nighttime off-peak hours equals 6.5 kw (5.5 space heating + 1 kw water heating) per customer. For the 943 customers this equates to a total of 6,130 kw shifted.

The marketing of Nite-Saver systems has begun to make an impact in the marketplace. In January 1984, 1.6% of the electric heat customers installed off-peak systems while as of the end of December 1985, 3.77% were off-peak. Performance through the first quarter of 1986 is 4.7%.

CHART IV



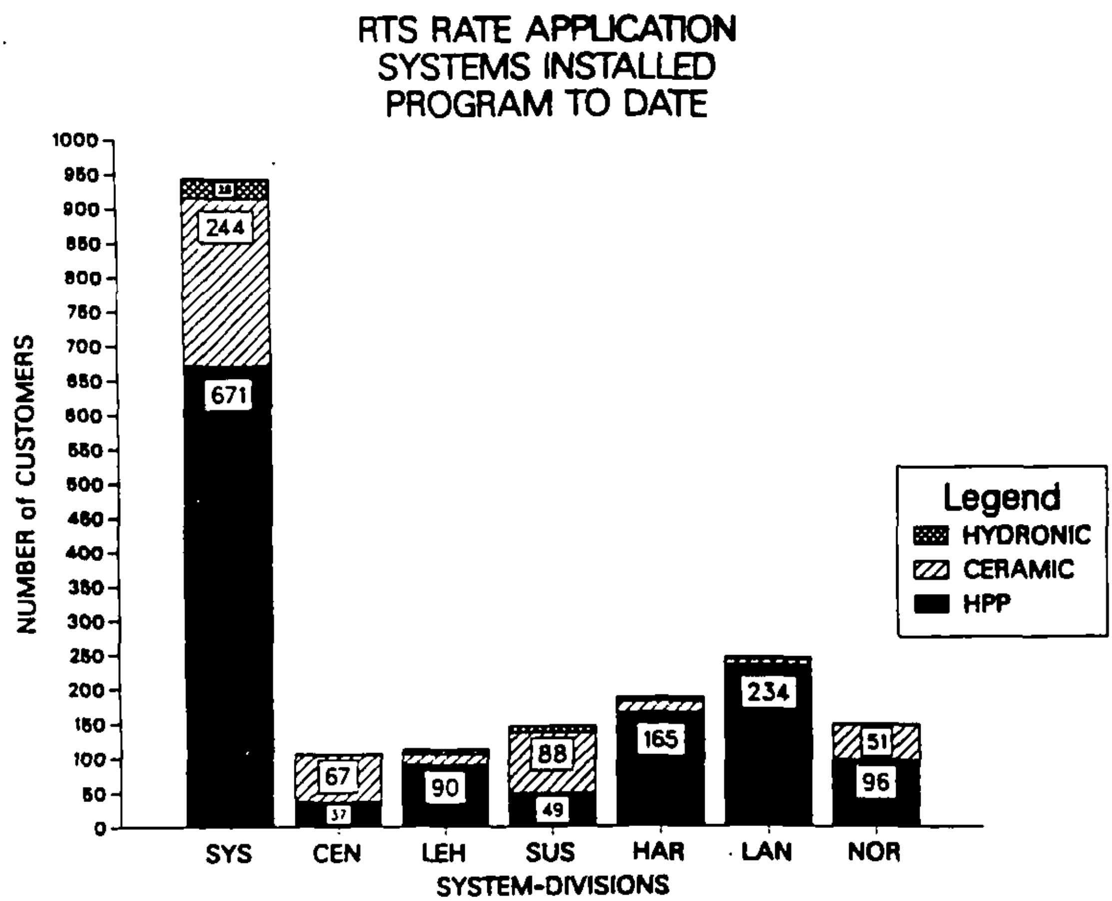
B. Performance Review

Chart V details Nite-Saver heating installations by system type. Although Heat Pump Plus systems account for 71% of the installations, ceramic storage systems, with 26% of the installations, have begun to impact the market primarily in the Northern tier or our service territory (Susquehanna, Central and Northern Divisions). One hundred ninety-six (196) of the 235 or 83% of the ceramic installations are located in these divisions. Susquehanna Division now has 63% of their 126 storage heating installations utilizing ceramic room units. The need for central air conditioning is not as important to customers in those divisions, thus the ceramic storage room units lend themselves quite well in satisfying this market segments heating requirements.

Harrisburg, Lancaster and Lehigh Divisions account for 414 or 74% of the Heat Pump Plus installations systemwide since a majority of customers in these divisions feel air conditioning is a necessity.

During the first quarter of 1986, Lehigh Division has already achieved 72% (18 units) of their total Nite-Saver systems (25 units) that they reported for the entire year in 1985. This significant improvement in their marketing performance can be attributed to the receipt of Underwriters Laboratory (U. L.) listing by both Hydrokinetix and Vaughn water storage systems. Lehigh Valley electrical inspectors had refused to allow storage systems to be installed without U. L. listing.

CHART V



DM 064176

14

TABLE V

SYSTEMS ON RTS RATE THROUGH MARCH 31, 1986

Division	Heat Pump Plus	Ceramic	Hydronic	Total
Central	37	67	2	106
Lehigh	90	15	7	112
Susquehanna	49	88	9	146
Harrisburg	165	16	6	187
Lancaster	234	7	3	244
Northern	96	51	1	198
Total	671	244	28	943

C. Factors Influencing Performance

1. **Positive Factors**

a. Vaughn and Hydrokinetix Heat Pump Plus Dealer Network

Both Vaughn Manufacturing and Hydrokinetix Company have engaged in building a major sales network which will further strengthen Heat Pump Plus sales. Vaughn is offering a special sales promotion to contractors who sell a certain number of Sepco Plus water storage units. Jim Vaughn is announcing his sales promotion program at dinner meetings in each division during the month of April. Both Hydrokinetix and Vaughn are planning to conduct training seminars for PP&L residential personnel and separate seminars for HVAC contractors.

b. Four Star Home Program

The Four Star Home Program has begun to impact the marketing results of Nite-Saver systems. The following enhancements to the program for 1986 include:

1. Four Star Model Home Program

We have developed a program which enables a builder/developer to install a Nite-Saver heating system in a Model Home at no additional cost to the builder/developer. An attractive co-op advertising plan is offered as part of the Model Home package and response to this program addition has been outstanding. Thirty (30) Four Star Model Homes will be available to the general public for viewing during the coming year. One builder in the Harrisburg area has already sold five additional Four Star Homes out of his recently opened Four Star Model Home.

DM 064177

2. Four Star Advertising

The current corporate Four Star Home advertising campaign features a well-balanced media mix. The 1986 campaign will continue to build recognition for the Four Star Home Program.

3. Four Star Cooperative Advertising

During the past three months, builder cooperative advertising usage has been outstanding. Builders who previously did not participate have decided to join our team due to strong consumer interest in the program, competitive Four Star builder success, and their desire to tie their individual advertising efforts to our successful corporate campaign.

4. Four Star Host Program

During our assessment of the Four Star Home Program in July of 1985, the need for a Four Star Host Program was identified by the General Office residential staff. The Four Star Host Program is designed to allow our residential personnel the opportunity to utilize satisfied owners of Four Star Homes as hosts to potential Four Star homeowners to familiarize them with the economies and convenience of Four Star living.

c. <u>RTS Rate 2 kw Demand Forgiveness</u>

Builders, contractors and customers familiar with our Four Star Home Program were very excited about the rate enhancement of January 1, 1986, which provided a 2 kw demand forgiveness. This RTS rate change results in additional savings of approximately $150 per year. Builders and contractors are so positive they use the 2 kw demand forgiveness in their marketing of Four Star Homes. They point out that this is a sign that PP&L is truly committed to the success of the Four Star Home Program. This change came at a very appropriate time when fossil fuel prices began to fall.

2. **Negative Factors**

Increasing competitor activity is being conducted by gas and oil companies. The key factors, similar to those listed in the electric heat saturation discussion include:

a. Special fossil fuel heating equipment deals and financing.
b. Free trenching in developments that choose all gas fuel supply.
c. Recent media coverage of lower fossil fuel prices due to OPEC situation.
d. Advertised rate reductions by gas companies.
e. Aggressive advertising campaign by gas companies and a select group of oil distributors.

IV. CONVERSIONS

A. Introduction

Prior to the establishment of a marketing program, PP&L was experiencing approximately 600 conversions from fossil fuel to electric heat per year. Our goal was to double this number, thereby resulting in a total of 1,200 conversions each year.

We would prefer to see conversions to off-peak storage systems, however, only 4% of the customers converting to electric space heating invested in an off-peak storage system during 1985. A conversion task force has been assembled to specifically address the marketing of off-peak systems.

B. Performance Review

Comparing 1984 with 1985 (Table VI), although there was a drop in the total number of conversions, there was almost a 100% increase in the number of off-peak installations. Through the first quarter of 1986 we have attained our 5% off-peak goal for conversions.

TABLE VI
1984 -- 1986 CONVERSIONS

	Goal	# Conversions Conventional	# Conversions Off-Peak	Total # Conversions	% Off-Peak
1984	1,200	1,281	26	1,307	2%
1985	1,200	1,093	45	1,138	4%
3/86	1,200	255	14	269	5%

Table VII indicates that electric baseboard is still the backbone of our conversion efforts commanding a 78% share of the total conversions reported for 1985.

TABLE VII
1985 ELECTRIC SPACE HEATING CONVERSIONS
SYSTEM INSTALLATION

Heating System	System Totals	Percent System Saturation
Ceiling Cable	3	.26%
Baseboard	888	78.03%
Ceramic Room Storage Heaters	33	2.89%
Ceramic Central	2	.17%
Warm Air Furnace	86	7.55%
Hydronic (water)	5	.43%
Hydronic Off-Peak (water storage)	2	.17%
Heat Pump	103	9.05%
Heat Pump Plus	8	.70%
Ground Water Heat Pump	3	.26%
Dual Fuel Heat Pump	5	.43%
Total	1,138	100%

DM 064179

C. Factors Influencing Performance

1. **Positive Factors**

a. Installation Costs

The first cost of installation is paramount to the conversion customer in most cases. As previously mentioned, electric resistance baseboard is the most frequent choice of our customers due to its low economy of installation. Not only is baseboard reasonable in cost to install, but it can be done quickly and be installed in phases, one room at a time or whatever you choose.

b. Ceramic Storage Room Units

Ceramic storage room units which are basically oversized baseboard units with heat storage and load management capabilities are viewed as strong contenders for the conversion market. Ceramic storage systems would be applicable for customers who are considering converting from a fossil fuel hydronic heating system.

c. Heat Pumps

Heat pump conversions from fossil fuel heating systems is generally feasible when a customer is interested in adding central air conditioning to an existing warm air furnace. The success of conversion efforts to heat pumps is strongly determined by the existing duct work in the home which must be adequately sized to handle larger volumes of low velocity air to insure proper comfort conditions.

d. Heat Pump Plus Systems

Customers planning to convert to a standard heat pump are good candidates for marketing Heat Pump Plus systems. The advantage to installing storage backup capabilities is the low operating cost of the system which then becomes competitive with oil or gas when the customer receives service on the RTS Rate.

e. RTS Rate Availability

The RTS rate is available to customers converting from their present fossil fuel system to either a Heat Pump Plus or a Ceramic Storage Heating System. The operating costs for both of these systems on the RTS Rate makes them cost competitive.

f. Grant Availability

To help offset the higher installation cost of a conversion to either a Heat Pump Plus or a Ceramic Storage Heating System, a cash grant is available. These grants are available only when the conversion is being made from an existing fossil-fuel space heating system.

DM 064180

2. ***Negative Factors***

a. Fossil Fuel Prices

The decline in fossil fuel prices will have a negative impact on the conversion market. Our standard residential rate is not competitive on an operating cost basis with gas or oil in the heating market.

b. Competition Specials

One oil dealer will convert an existing warm air system for $1,000, however, the customer must commit to buy oil from the dealer for three years.

Gas company will run free laterals to homes in developments if the customer converts to gas.

c. Increased Advertising Activities

Oil companies (dealers) are advertising the lower prices now in effect.

Testimonial advertising utilized by the gas industry utilizes their most efficient heating systems.

In the advertising where comparisons of operating costs are shown, the gas and oil companies compare their most efficient systems against electrically heated systems on the standard residential rate.

M&ED/2066
RDM/RJR:ddf

DM 064181

CEPFOD Exhibit No.3

Frank Mayberry A9-4

6/13/91

(1)

Here's the information we discussed for use in your response to Joe Clifford's questions on the RTS report. Give me a call w/ any questions.

Dave Selkregg

Question 1

The Task Force decided that the effect of the RTS Program on PP&L earnings is ~~[illegible]~~ one important economic consideration. The earnings analysis is used to show how the RTS program affects PP&L economics prior to a base rate case. After a base rate case the new customer sales and revenue requirements are reflected in the rates.

To consider the post-rate case effect of RTS the report compares the RTS rate of return to the RS rate. From this analysis it can be concluded that to maintain the RTS/RS rate differential in the long-term either shareowners ~~[illegible]~~ would accept a lower than allowed rate-of-return or other customers would subsidize RTS.

Although not included in the report, the Task Force did study the 20 year effect of RTS on PP&L revenues and revenue requirements (see attachment 1). This analysis showed that ~~[illegible]~~ if the customer alternative were

- Electric Heat - revenue requirements are reduced by about $2000 (minus marketing costs) over 20 years (present value) from lower energy costs and reduced demand. However, PP&L revenues are reduced by about $7000 over 20 years ~~and~~ from the lower customer rate.
- Fossil Heat - PP&L revenue requirements are increased by about $6000 (Plus marketing costs) over 20 years. Revenues are also increased by about $6000.

Accordingly, when new customers are influenced to install RTS instead of ~~elec~~ alternative electric heat PP&L needs to recover about $5000 plus marketing costs (present value) per RTS customer in addl. rate revenue from other customers.

DS 0067699

Question 4

- The following gives a more detailed description of figure 1:

RTS Customer

- The figure is based on annual average KWH sales to RTS customers of about 24,200 KWH (assumes 70% HPt; 30% ceramic).

- Annual revenue to PP&L from the 24,200 KWH sales at the RTS rate equals about $1166.

- The portion of the annual revenue that goes to PP&L earnings from RTS customers equals about $395.

- The 5-year cumulative present value of the annual earnings from the RTS customer equals about $1520.

  - 10-year cumulative PV equals 2490

- The 5-year cumulative PV of earnings from the RTS customer minus marketing cost of $2300 equals negative 780.

  - 10 year equals 190.

General Residential Customer

- The 5-year cumulative PV of earnings for a general residential customer with 9000 KWH usage (average for GR customer w/ single family home) equals about [illegible].

  - 2200 for 10 year cumulative PV.

Electric Heat

- Figure 1 assumes 30% baseboard and 70% HP for a weighted average kwh usage of 24300 kwh per electric heat customer.

SPECIALLY CONFIDENTIAL

DS 0067709

- The portion of annual revenue that goes to [illegible] earnings from the average electric heat customer equals about $835.

- The 5 year cumulative PV of earnings from the average electric heat customer equals about $3210

  - $5260 for 10 year PV

- Because the lower branch of the decision tree represents the customer alternative absent RTS, program costs are not included for electric heat (i.e. it is assumed that total marketing costs for electric heat, other than RTS, are not affected by the elimination of the RTS program.

Attachment 2 presents an alternative way of presenting RTS program earnings effects.

Question 5

- The 1991 RTS projections were used as the best estimate of future effects of RTS. However, actual results are similar, and would not change the economic evaluation appreciably.

Here are historical RTS program costs from ACRs:

	Year	RTS Total Cost	# Customers	cost/cust.
	87	3,799,740	1697	2239
	88	3,889,446	2014	1931
	89	5,173,032	2246	2303
	90	3,937,450	1543	2551
(DSM Filing)	91	3,717,000	1600	2323

Question 7

The capacity value of RTS was not directly included in the earnings analysis for the following reasons:

- Potential earnings from capacity value are small compared to the difference in incremental earnings between RTS + other electric heat customers. RTS has a capacity cost for installations which would have been fossil heat (due to increased demand during peak periods).

- The reduced PP&L ARM obligation resulting from influencing cust. to chose RTS instead of electric heat will enhance PL earnings only if the resulting capacity credits are sold, and revenues flow to earnings. Because this benefit is uncertain, it was not directly comparable to the relatively certainty of customer rate revenue.

Attachment 3 shows revised figures w/ capacity value included.

DS 0067702

CEPFOD Exhibit No. 4

WAC -
Note Change to Fact #3.
RCT

Competition heats up in residential energy arena

by Henry A. Courtright

Manager-Residential Marketing

"Electric heat is for the birds," says our competition in aggressive advertising. But, PP&Lers can counter this claim with facts about the benefits and economy of modern electric heat.

Seen any penguins waddling around lately? Maybe you have, on natural gas industry billboards. These black-and-white polar birds are a symbol of our competitors' latest attempt to give electric heat pumps a chilly reputation.

Gas-industry newspaper ads say that now and over the long run natural gas heat will cost less than electric heat. In addition, their bill inserts state that electric heat and heat pumps are inconvenient, less efficient and costlier to maintain than gas systems. All their claims, of course, are based on their versions of facts and figures.

But there are several important facts that our competition's advertising ignores. These facts show a clearer picture of the economy and convenience of electric heat in PP&L's service area:

FACT #1: Heat pumps are the most efficient way to heat and cool homes. They actually put out more heat energy than they consume, making them more than 100 percent efficient! Even the most efficient gas furnaces cannot outperform heat pumps.

FACT #2: PP&L's money-saving RTS (Residential Thermal Storage) rate is about 40 percent lower than the regular residential rate. Customers with Nite-Saver electric storage heat, including the Heat Pump Plus, pay the low rate for all the electricity they use in the home, not just the heating.

FACT #3: A home's total energy use determines its utility bills. On the RTS rate, customers can enjoy lower overall energy costs than with natural gas heat, because they pay the low RTS rate for all the electricity they use.

FACT #4: The Gas Research Institute predicts a 6 percent annual price increase for gas through the year 2,000 -- adding up to a whopping 72 percent total increase! During the same time period, PP&L expects the price of electricity to increase only 1.1 percent annually -- less than our current annual inflation rate.

FACT #5: Prices quoted for electric heat in our competitors' ads do not represent residential electricity prices in PP&L's service territory. **PP&L customers with Nite-Saver electric heat pay an average of $117 a month for their total energy bill.**

FACT #6: Flameless electric heat produces no smoke, soot, ashes, fumes or noxious odors, nor does it deplete the oxygen in the home the way fossil-fuel heating systems do. There's no need for a chimney or venting.

How do we answer the natural gas industry's increasingly aggressive advertising? How can you help successfully market electric heat? Use facts.

For starters, we turned their penguins into our allies on a bill insert to our customers. The insert explores "The Chilling Truth About Heat Pumps" and emphasizes that heat pumps cool and heat. Another bill insert explains the double value of heat pumps using the testimonial of a Lancaster area couple, happy with the comfort and economy of their Heat Pump Plus. Also, articles in News 'n Views bill inserts regularly discuss electric heat options for new and older homes.

Some PP&L divisions have taken their own approaches, using such methods as letters to retirees, employees and trade allies on how modern electric heat stacks up against the competition; bulletin board postings on electric heat; and Nite-Saver electric storage heat ads in cooperation with heating and cooling contractors. Our residential consultants take every opportunity to refute competitors' claims in conversations with builders, trade allies, homeowners and new customers. Articles in magazines and special supplements in area newspapers have also presented the benefits of electric heat.

You, as an individual, can contribute to the success of our marketing effort by knowing the facts about electric heat. Then, when the conversation turns to home heating, you'll know how our product outperforms the competition and you can counter their claims.

Because the fact is, our customers get more with modern electric heat: comfort, safety, cleanliness, convenience and economy.

CEPFOD Exhibit No. 5

W. F. Hecht's Senate Testimony
Possible Questions and Answers

Q1. Who pays for the economic development program -- ratepayers or stockholders?

A. Economic development programs were included as operating expenses in PP&L's last rate case. Since that time the benefits from sales to new or expanded businesses have exceeded added expenses over those included in our base rates.

Q2. Doesn't the RTS rate actually lose money; and, therefore, don't residential customers, who can't take advantage of such a rate, subsidize this class of customers?

A. The RTS rate was included in our last rate case and was modified slightly, with commission approval, as part of the Economic Development Incentives II rate filing effective January 1, 1988.

Q3. Is the marketing of special rates prevalent in other states as an incentive for economic development?

A. Yes, numerous utilities across the country are advertising on a regular basis in national publications their incentive rates for industry.

Q4. Isn't PP&L now in a marketing position because of poorly planned excess capacity?

A. PP&L has been able to manage its available capacity to make the best use of retail and bulk power sales. The revenue return provided by the commission from our last rate case support the capacity in that case. Available capacity has been sold on term sales to Atlantic City Electric, Baltimore Gas & Electric and Jersey Central Power & Light. These sales agreements will allow the return to PP&L of available capacity to meet our customers' needs in the future.

Q5. The EDI III "rate"...since its cost is low enough to attract new industry, isn't it actually a revenue loser, and subsidized by all other PP&L customers?

A. The level of the credit for added economic development sales was approved by the commission. The pricing covers incremental cost to supply the energy sales which may not have occurred without the EDI credit.

Q6. The special residential RTS rate...what assurance do customers have that it won't go the way of the cancelled electric heat rate?

A. The RTS rate has a guarantee provision that commits the rate availability to a customer for a minimum of 10 years or reimburses the customer $50 per month until the 10 years expire.

Q7. Aren't the grants actually kickbacks to large residential developers and subsidized by all residential customers?

A. The storage heating grants are designed to provide an approximate five-year payback on the added investment by the customer. The grant is available to the person deciding to install the storage heating system, sometimes this is the home owner or sometimes the builder.

Q8. The argument that off-peak rates defer the need for future generation facilities doesn't make sense. PP&L presently admits to having excess capacity, how can PP&L justify this position?

A. The development of an off-peak program cannot occur overnight. PP&L has been actively pursuing storage heating installations since 1982 and since that time storage heating market share has grown to 13 percent of new electrically heated homes. This is the highest new home saturation of any utility in the nation but only one-half the way to PP&L's objective of 25 percent included in our Least Cost Plan.

Q9. Why did PP&L try to influence legislators' opinions by a letter writing campaign?

A. Our efforts were to inform heating contractors, builders and others of the effect the bill would have on them. Their response by writing letters indicates their concern about this bill.

M&ED/r7262
HAC/WAC:jpo

July 11, 1988

CEPFOD Exhibit No. 6

PP&L

Copy to:

E. F. Reis	TW-15	W. F. Hecht	TW-5
G.. D. Caliendo	TW-3	L. C. Bartholomew	TW-17
J. M. Pavelko	TW-15	M. J. Berish	TW-14
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April 16, 1987

Mr. Robert K. Campbell	TW-16
Mr. M. F. Hertzog	TW-16
Mr. J. T. Kauffman	TW-16
Mr. C. E. Russoli	TW-16
Mr. B. D. Kenyon	TW-16
Mr. L. L. Nonemaker	TW-16

RESPONSE TO CMC ACTION ASSIGNMENT #1579
ISSUES ASSOCIATED WITH NIGHTTIME PEAK

The attached report responds to CMC Action Assignment #1579:

"Evaluate and recommend appropriate strategies to deal with the nighttime peak demand issue raised by the long term sales forecast".

The report was developed by a PCG Task Team and reflects the review input and consensus of all Task Team members. In addition, the report was reviewed by PCG and comments from PCG members have been incorporated.

The report addresses:

- The effect of the current marketing goals on future sales and peak load growth and future load shapes.

- PP&L's future load/capacity/reserve situation and the effect on Installed Capacity Obligation if these marketing goals are achieved.

- The economic impacts in terms of revenue requirements resulting from the marketing goals and the nighttime peak.

Additional information related to the nighttime peak issue will be provided in other material being developed for EPC-87. This material includes:

- The Least Cost Planning Process being developed by PCG Task Team #10.

- The Company's financial projections for EPC-87.

RHB

Robert H. Ballard
Chairman, Task Team #10

Attachment

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29

RESPONSE TO CMC ACTION ASSIGNMENT #1579
ISSUES ASSOCIATED WITH NIGHTTIME PEAK
PCG TASK TEAM #10

APRIL 16, 1987

30

RESPONSE TO CMC ACTION ASSIGNMENT #1579
ISSUES ASSOCIATED WITH NIGHTTIME PEAK
PCG TASK TEAM #10

APRIL 16, 1987

RESPONSE TO CMC ACTION ASSIGNMENT #1579
ISSUES ASSOCIATED WITH NIGHTTIME PEAK
PCG TASK TEAM #10

BY:
PCG TASK TEAM #10

SYSTEM PLANNING

R. H. BALLARD, CHAIRMAN
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K. J. PRICE

TABLE OF CONTENTS

INTRODUCTION

- o This report is in response to CMC Action Assignment #1579:
  "Evaluate and recommend appropriate strategies to deal with the nighttime peak demand issue raised by the long term sales forecast".
  The forecast used in this assignment was presented to CMC on September 29, 1986, and was referenced as the 9/86 "Integrated" Forecast.

- o This report identifies the issues associated with a nighttime peak demand by comparing peak demand and sales both with and without long term marketing.
  - The 9/86 "Base" Forecast reflects the impact of marketing and economic development programs for the short term horizon only (1986-1987).
  - The 9/86 "Integrated" Forecast assumes a significant impact of the marketing and economic development for the full forecast period (1986-2006). The results of this forecast portray a higher annual peak demand growth and a shift to a nighttime winter peak beyond 1995.

- o The 9/86 "Integrated" Forecast has been termed the 9/86 Forecast when submitted on previous occasions.

- o The analysis in this report:
  - Delineates the current marketing program and its goals
  - Discusses PP&L's future load, capacity and reserve situation
  - Provides a revenue requirements analysis to determine economic impacts of the nighttime peak.

- o This report deals only with the issues and strategies associated with the nighttime peak demand issue raised by the 9/86 "Integrated" Forecast. Related reports will be provided by:
  - Task Team #10 as a part of the Least Cost Planning process
  - The Company's financial projections for EPC 87.

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34

SUMMARY AND CONCLUSIONS

- PP&L's present marketing and economic development programs provide near-term benefits through 1995 by increasing sales and reducing the revenue requirements per KWH.
    - Any increase in sales increases Cost of System Output (CSO).
    - This increase is offset by a reduction in fixed revenue requirements per KWH.
    - The net result is a decrease in revenue requirements per KWH.

- Continuing today's marketing programs and achieving the goals for the Residential Thermal Storage (RTS) system, described on page 7, through the long-term beyond 1995 will:
    - Result in a rate of peak demand growth that advances the need for additional resources,
    - Increase revenue requirements per KWH,
    - Increase the need for additional distribution facilities.

- The achievement of the currently established RTS marketing goals is responsible for the significantly increased peak demand and the shift to nighttime peak demand beyond 1995.
    - The magnitude of the peak demand and not the timing (daytime or nighttime) is of primary importance.

- Seasonal differences of peak demand occurrence are recognized in the PJM formula for determining Installed Capacity Obligation (ICO) but time of day is not.
    - Recognizing time of day in the ICO formula is not expected to significantly change the ICO for PP&L because PP&L already receives credit for having its peak at a time different than the PJM annual peak.

- o The addition of significant amounts of RTS systems may effect future cost-of-service allocation to the rate classes.
    - Beyond 1995, RTS customers may contribute proportionately more toward the system peak than other rate classes.
        - o Rates may have to be changed to reflect new use of facilities by customer groups.

- o To accomplish the current RTS goals, an infrastructure outside of PP&L is being developed to manufacture, distribute, sell, install and maintain RTS systems.
    - As this infrastructure develops, it may be difficult for PP&L to reduce RTS installations because considerable non-PP&L resources have been committed to this effort.
    - Of specific concern is the effect on local dealers and installers.

- o There are two basic strategies which could allow PP&L to deal with the concerns of the high peak demand growth caused by the achievement of the long term RTS goals.
    - At some time, decrease the emphasis on RTS systems.
    - Manage peak demand growth through more sophisticated forms of load control strategy applied to the RTS systems.

- o The opportunities to apply alternate load control strategies to the RTS systems are limited primarily due to the high peak day load factor, the longer RTS system recharge duration on colder days and the load control strategy already included in the 9/86 "<u>Integrated</u>" Forecast.
    - The 9/86 "<u>Integrated</u>" Forecast already includes load control strategies to delay the start of the RTS off-peak recharge period to 7 PM-8 PM and a non-standard 2.5 KW water heater element in over one-half of the off-peak water heating systems.
        - o Current practice allows these systems to begin recharging in the 5 PM-7 PM period and includes a standard 4.5 KW water heater element.
        - o These strategies included in the 9/86 "<u>Integrated</u>" Forecast mitigate the magnitude of the nighttime peak and delay its daytime to nighttime shift to 1995.

36

SUMMARY AND CONCLUSIONS

- For these reasons, the application of additional load control to mitigate high peak demand growth associated with the 9/86 "Integrated" Forecast does not appear to be a viable strategy.

- A decrease in the emphasis on RTS systems could defer the need for additional resources, including NUG as installed capacity or new supply-side resources.
  - The RTS programs were developed to provide customers with the benefits of lower cost operation during off-peak periods and also to manage peak demand growth while increasing sales.
  - As these programs succeed in the marketplace, there will be less benefits available because the off-peak cost advantages will be reduced.
  - A strategy that can be applied to limit the growth of the RTS systems as the cost advantages diminish involves first removing the existing grant program and then, only if necessary, restricting the rate incentive to existing customers.
  - To achieve increased sales, other marketing programs could be emphasized.

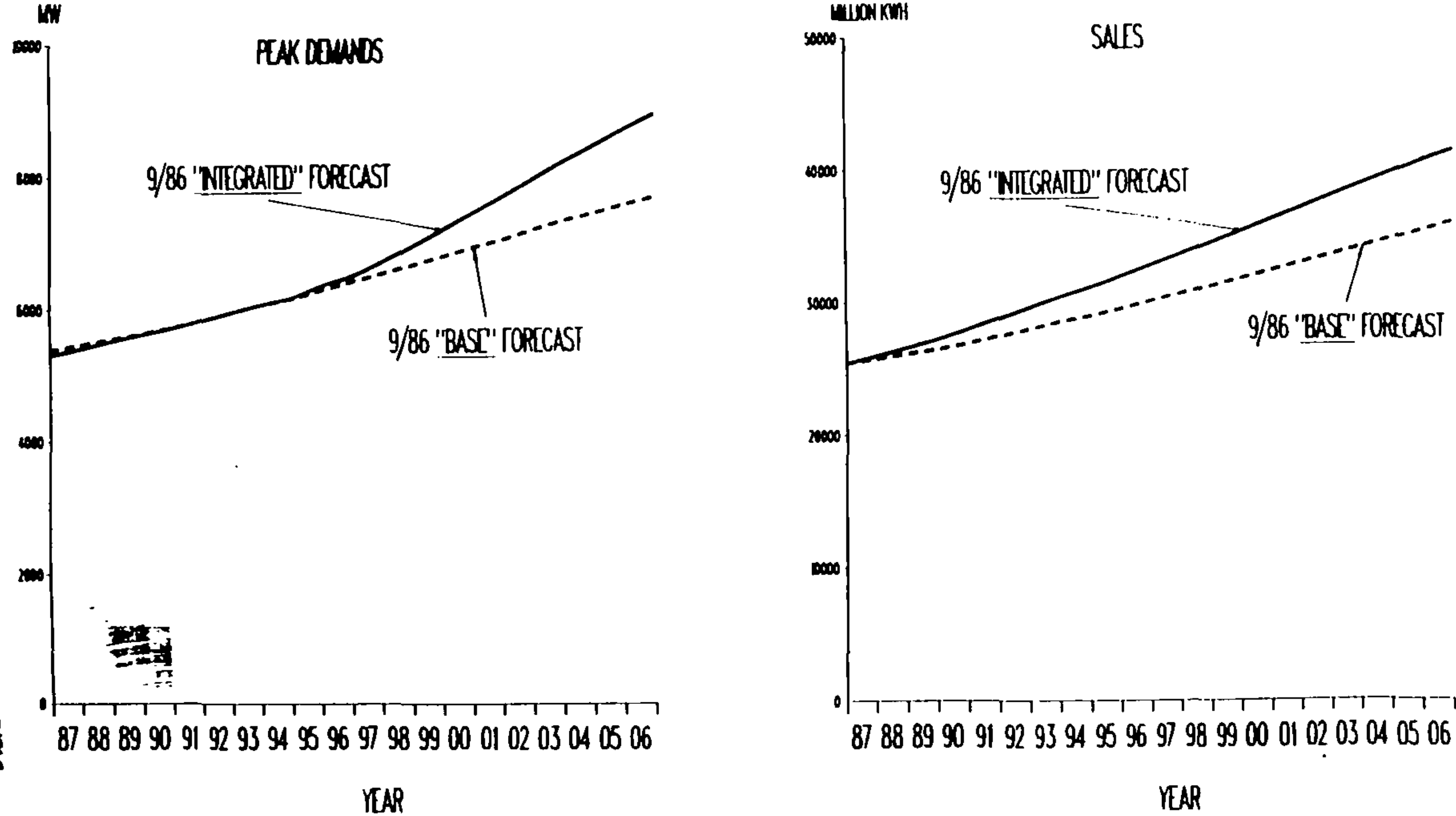
RECOMMENDATIONS

- o Continue the current marketing and economic development programs in the near-term to achieve the benefits of additional sales.

- o Diversify the residential marketing programs to avoid the high rate of peak demand growth projected in the later years in the 9/86 "Integrated" Forecast. Specifically:
  - Reduce the emphasis of the RTS programs in the long term.
  - Reexamine the marketing program to identify other sales opportunities.

FIGURE 1

PEAK DEMANDS AND SALES COMPARISION



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FORECAST COMPARISON

Description of Forecasts

o The 9/86 "Base" Forecast reflects:

- Sales and peak demands that result from expected economic growth.
- The effect of short term (1986-87) marketing and economic development including:
    - o Continued increase of electric heating market share of new homes.
    - o Additional commercial and industrial sales.
    - o No major changes to PP&L's load shape.
- A comparable development to previous forecasts such as the 9/85 Forecast which was used to develop the Reference Case for EPC 86.

o The 9/86 "Integrated" Forecast reflects:

- Sales and peak demands that result from the significant attainment of marketing and economic development goals.
- The effect of long term (1986-2006) marketing and economic development including:
    - o Increased residential sales achieved by the installation of RTS systems in new homes.
    - o Conversion of existing fossil fueled heating systems to RTS systems.
    - o Increased commercial and industrial sales through continued marketing and economic development programs.

o As shown in Figure 1 on the facing page, there are significant differences between these two forecasts. The data for this figure are shown in Appendix 1.

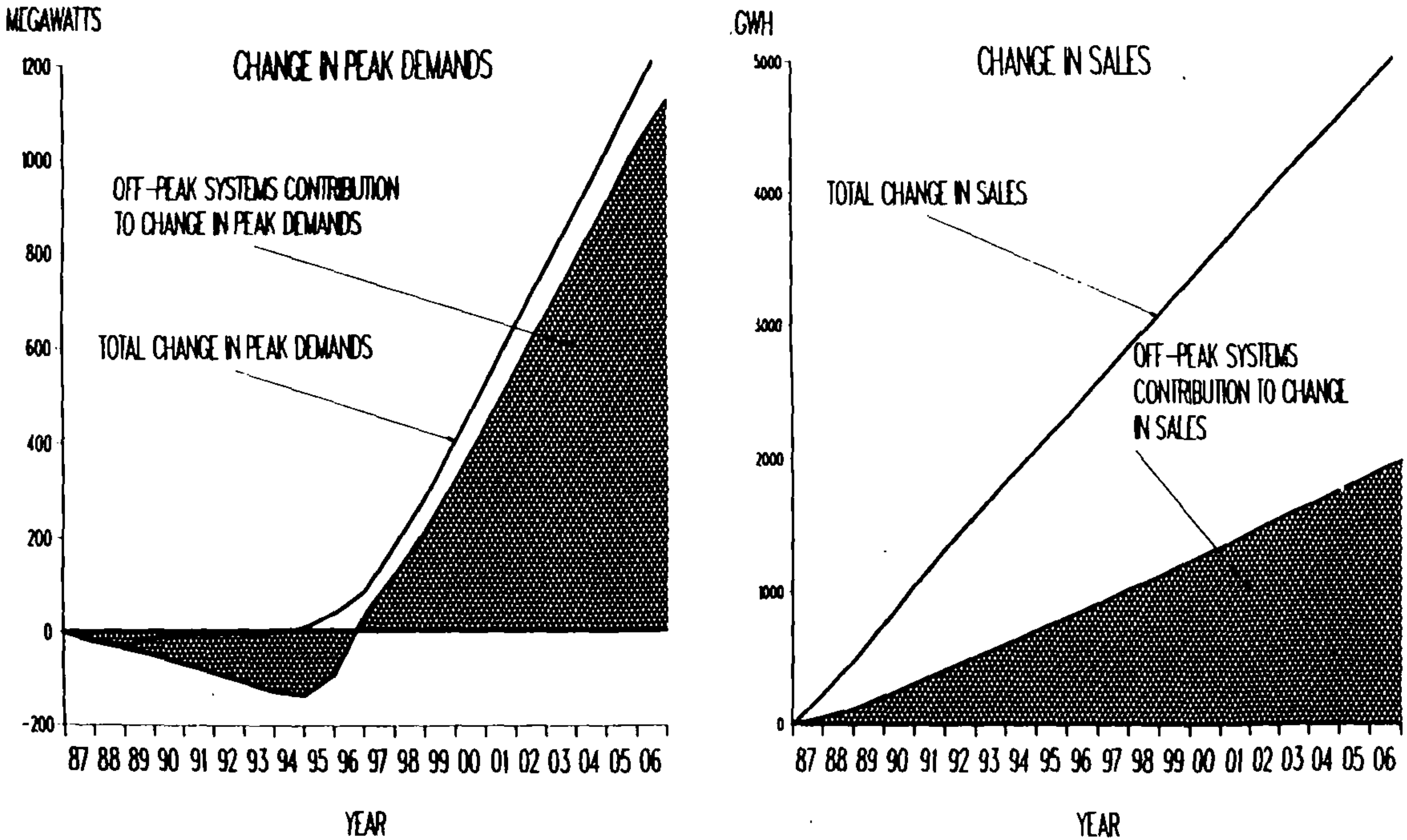
- The peak demands (after 1995) and sales (1988 through 2006) in the 9/86 "Integrated" Forecast are higher than the 9/86 "Base" Forecast.
- The 9/86 "Integrated" Forecast also projects a shift in PP&L's winter peak from 9 AM to 9 PM in 1995.

40

FIGURE 2

COMPARISON OF PEAK DEMANDS AND SALES FOR

9/86 "INTEGRATED" FORECAST COMPARED TO 9/86 "BASE" FORECAST



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41

Comparison of Peak Demands and Sales

- As shown in Figure 2 on the facing page, the differences between the 9/86 "Base" and 9/86 "Integrated" Forecasts result from the increased sales and resulting peak demands associated with the attainment of the marketing and economic development goals as reflected in the 9/86 "Integrated" Forecast for the full 1986-2006 period.

- The predominant cause of the difference in system peak demands of the two forecasts is the RTS systems. In the 9/86 "Integrated" Forecast:
  - Prior to 1995, peak demand is lower due to the reduced daytime demand caused by the substitution of conventional heating systems with RTS systems in the new home market.
  - After 1995, peak demand is higher due to the increased nighttime demand contribution of these units in the new home and existing home conversion markets.

- The predominant portion of the difference in energy sales is due to industrial/commercial marketing and economic development.

- Prior to 1995 in the 9/86 "Integrated" Forecast, the RTS programs reduce the peak demand while contributing 1/3 of the energy sales increase.
  - However, by 2005, the RTS systems contribute up to 90% of the additional peak demand while contributing about 1/3 of the increase in sales.

- At the end of the forecast period,
  - The winter peak demand is growing at about 250 MW per year in the 9/86 "Integrated" Forecast as compared to about 120 MW per year for the 9/86 "Base" Forecast. Annual growth in winter peak demand during the 1974 to 1985 period averaged about 115 MW per year.
  - Sales are growing at about 850 GWH per year in the 9/86 "Integrated" Forecast as compared to 575 GWH for the 9/86 "Base" Forecast. Sales gains from 1974 to 1985 averaged about 525 GWH per year.

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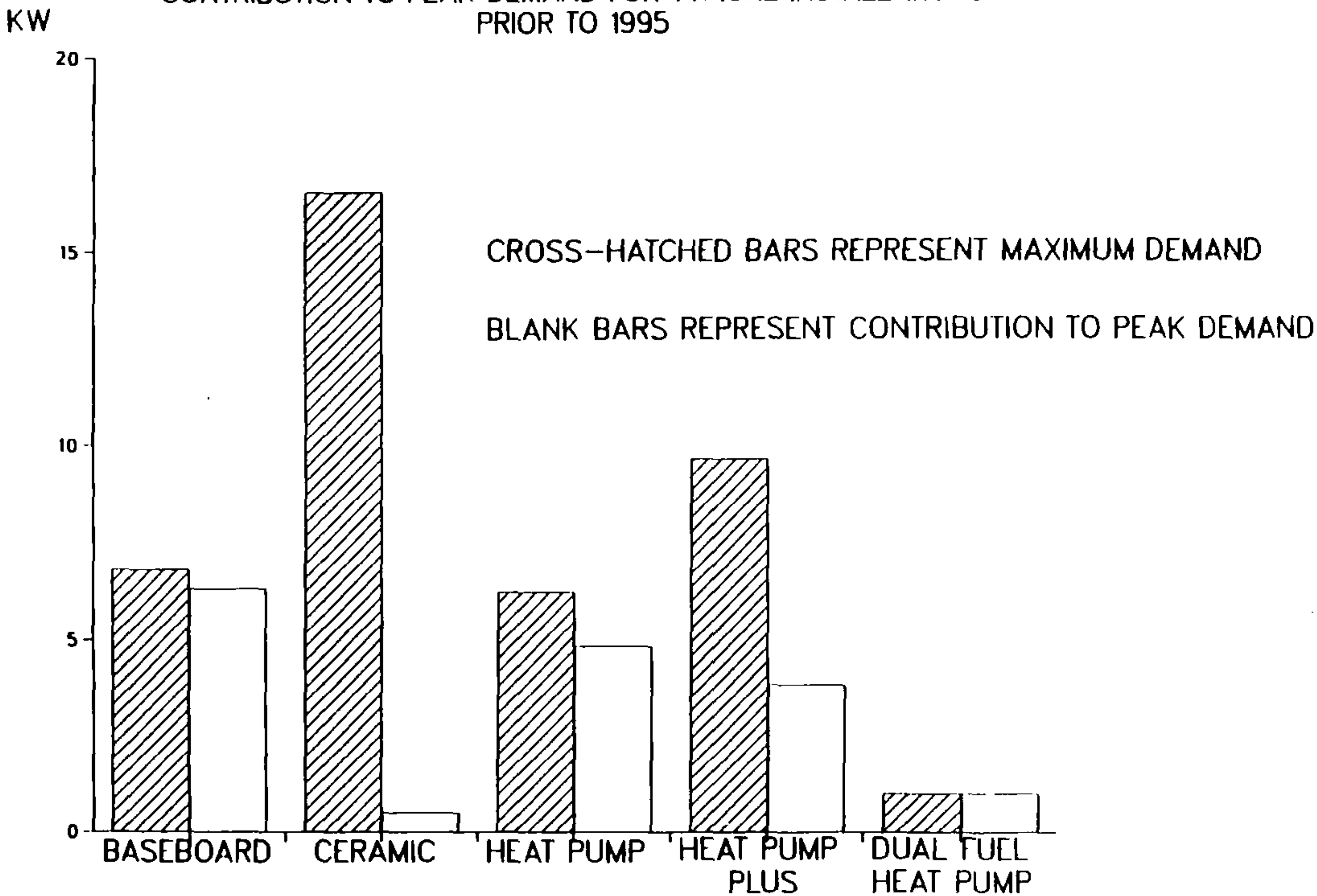
42

FIGURE 3
SPACE HEATING SYSTEM MAXIMUM DEMAND AND
CONTRIBUTION TO PEAK DEMAND FOR TYPICAL INSTALLATIONS
PRIOR TO 1995



Characteristics of Residential Heating System

- The RTS systems which cause the largest change in peak demands include:
  - Heat Pump Plus used primarily in new dwellings
    - Heat Pump Plus includes hot water as a storage medium; water is heated at night and provides the supplemental heat for the heat pump during the day. (Resistance elements normally provide the supplemental heat in air-to-air heat pumps).
  - Ceramic storage used for both new dwellings and conversions of existing dwellings
    - Ceramic storage provides heat throughout the day from energy stored in ceramic bricks heated at night.
    - Most ceramic units are designed to be located in and provide heat for individual rooms.
  - Hydronic Storage (which is modeled as ceramic storage) used primarily for conversions of existing dwellings.
    - The storage may be either in a central water tank or in a solid medium with heat transfer to the water loop.

- Figure 3, on the facing page compares the maximum demand contribution with an outdoor ambient of 7°F for typical heating systems and the projected contribution at the historical hour of system peak demand (9 AM).
  - For more severe outdoor temperatures, there is a larger difference between the peak demand for the conventional heating systems compared to RTS systems.

- Baseboard resistance heating with a 6.3 kW demand per typical installation , and conventional heat pump (air-to-air) with a 4.8 kW demand, have been the heating systems with the largest contribution to the historical hourly peak demand.
  - Both types of heating systems have their maximum peak demand contribution at about 7 AM.

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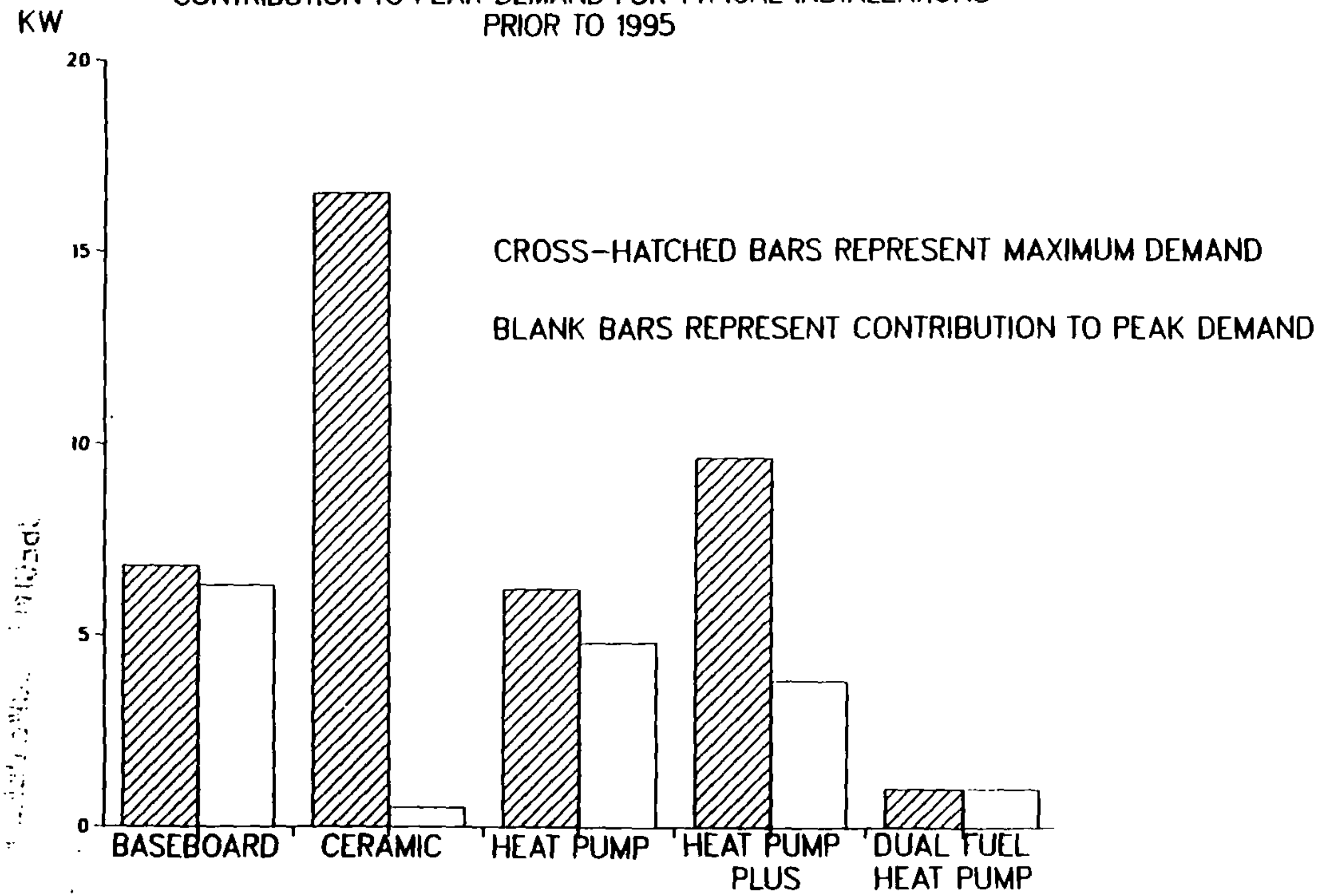
FIGURE 3
SPACE HEATING SYSTEM MAXIMUM DEMAND AND
CONTRIBUTION TO PEAK DEMAND FOR TYPICAL INSTALLATIONS
PRIOR TO 1995



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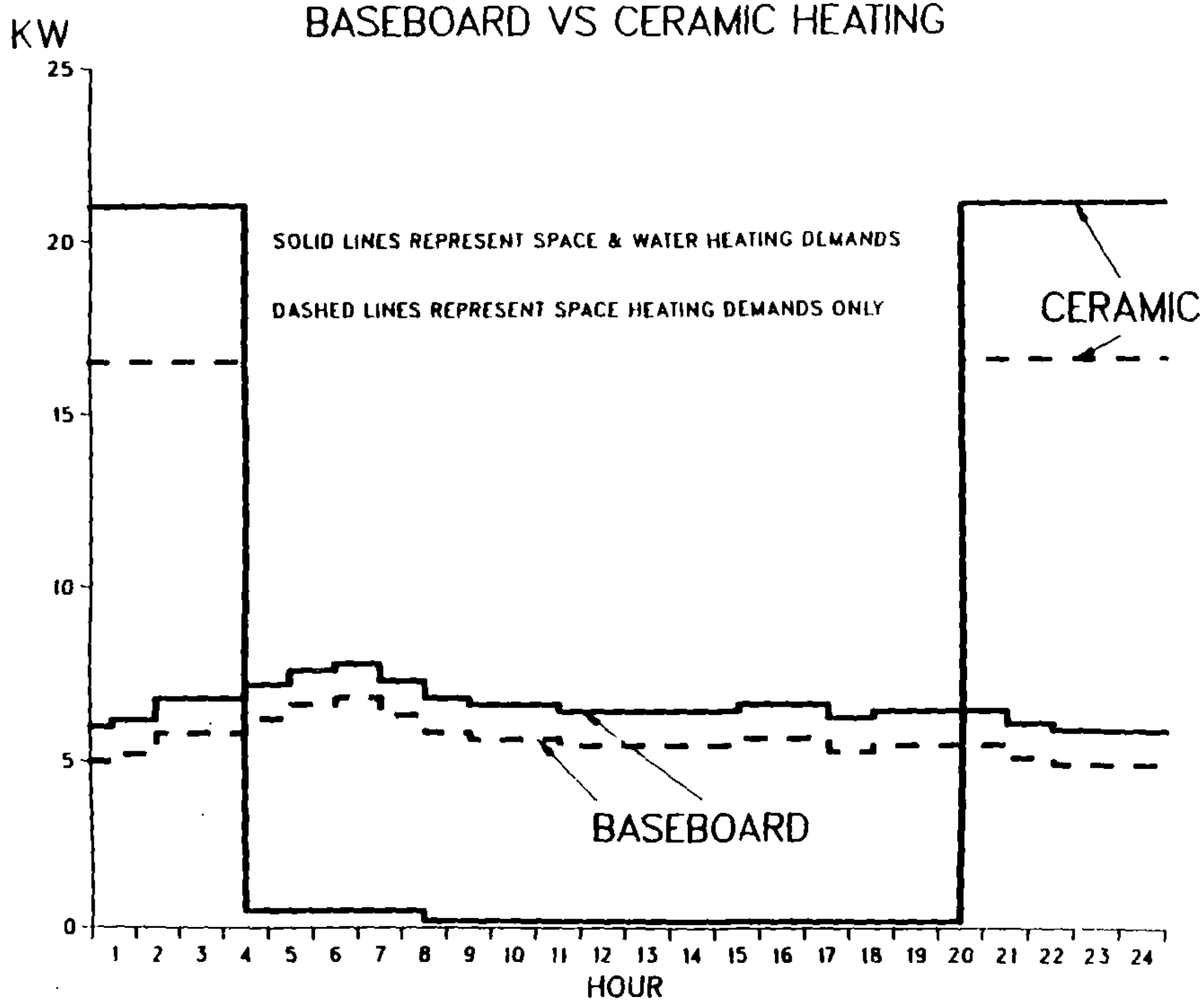
- o Ceramic storage and Heat Pump Plus systems have the highest hourly peak demand of 16.5 kW and 9.6 kW per typical installation, respectively, occurring anytime after 5 PM to 7 PM.

- o The continued installation of ceramic storage and storage assisted heat pumps (hot water) in lieu of baseboard resistance, air-to-air heat pump and fossil fueled systems will ultimately change the maximum contribution to the system peak demand when the peak shifts from daytime to nighttime.

- o In nearly all cases, these RTS systems will also have an off-peak water heating system, which will further increase the maximum peak demand of the system.
  - An off-peak water heater contributes an undiversified 4.5 kW (element nameplate rating) to an hourly demand in the first 2-3 hours of the weekday off peak period.
  - The diversified contribution of a standard electric hot water heater is approximately 1 kW during the daytime peak hour.
  - The 9/86 "<u>Integrated</u>" Forecast assumes that about half of the applicable water heaters will use a non-standard 2.5 KW water heating element.

46

FIGURE 4
TYPICAL HOURLY HEATING DEMAND ON WINTER PEAK DAY
BASEBOARD VS CERAMIC HEATING



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Typical Hourly Heating Load

- Figure 4, on the facing page, shows the 24-hour demand profile to demonstrate the typical impact of the electric baseboard resistance and ceramic storage heating systems on a winter day with a 7°F outdoor ambient temperature.

- Demand for a typical electric baseboard heating installation remains relatively flat over the entire 24 hour period on a winter day.

- A six to eight hour recharge duration is required for ceramic storage units on a day with 7°F outdoor ambient temperatures.
  - The demand associated with charging for the ceramic units is, by design, primarily limited to the off-peak nighttime period and produces greater demands in this period than the baseboard installations.
    - The required recharge period for the off-peak water heater is about 2 to 3 hours.

- The magnitude of the ceramic system demand at the time of the nighttime system peak is about 2.5 times larger than the baseboard resistance demand.
  - However, during the daytime, the ceramic system demand is lower than the baseboard resistance demand.

- As RTS systems are added to the PP&L system, in the 1986-1995 period, there will be:
  - No increase in the system peak demand resulting from the RTS systems.
  - An increase in energy use during the off-peak periods.

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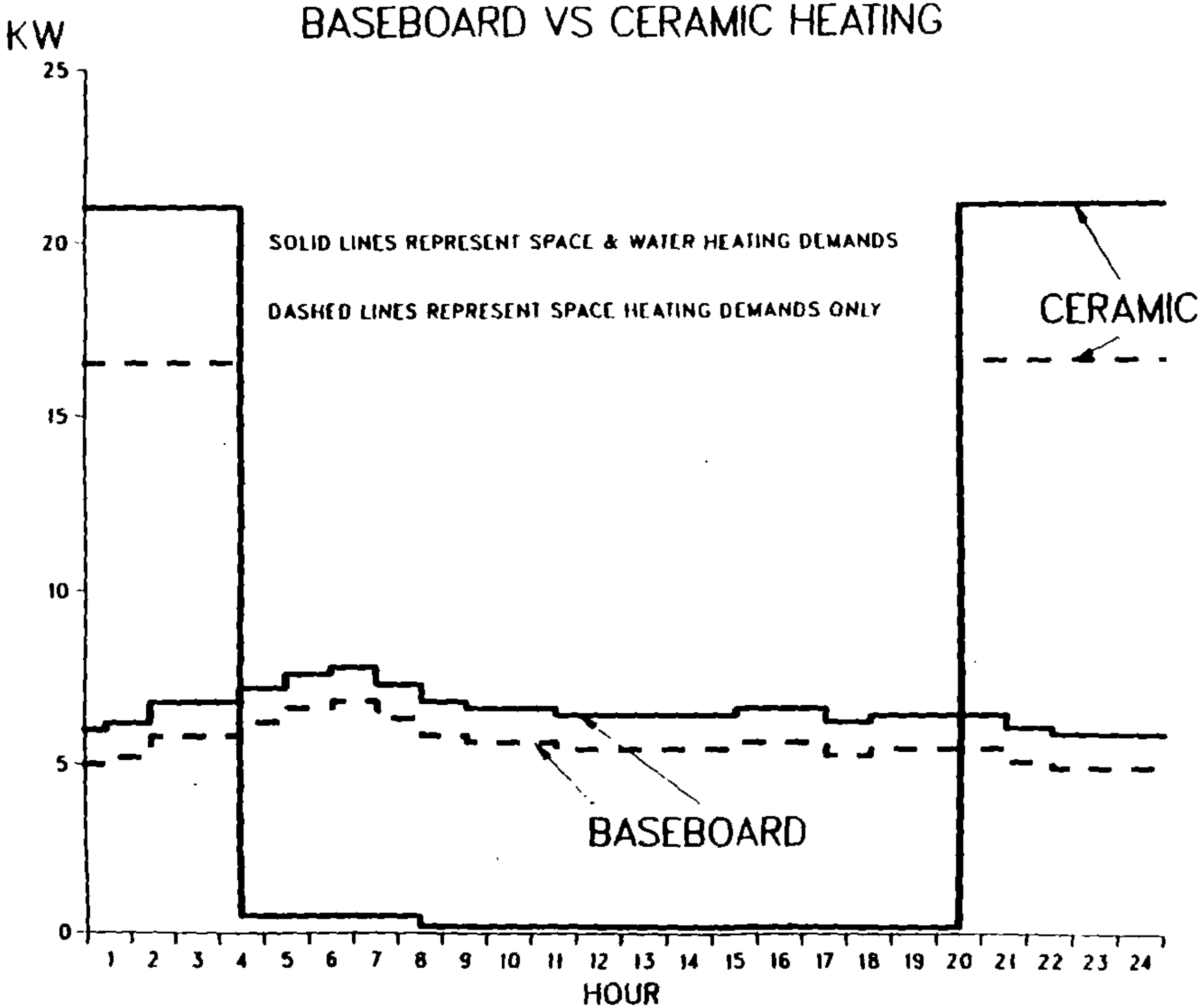
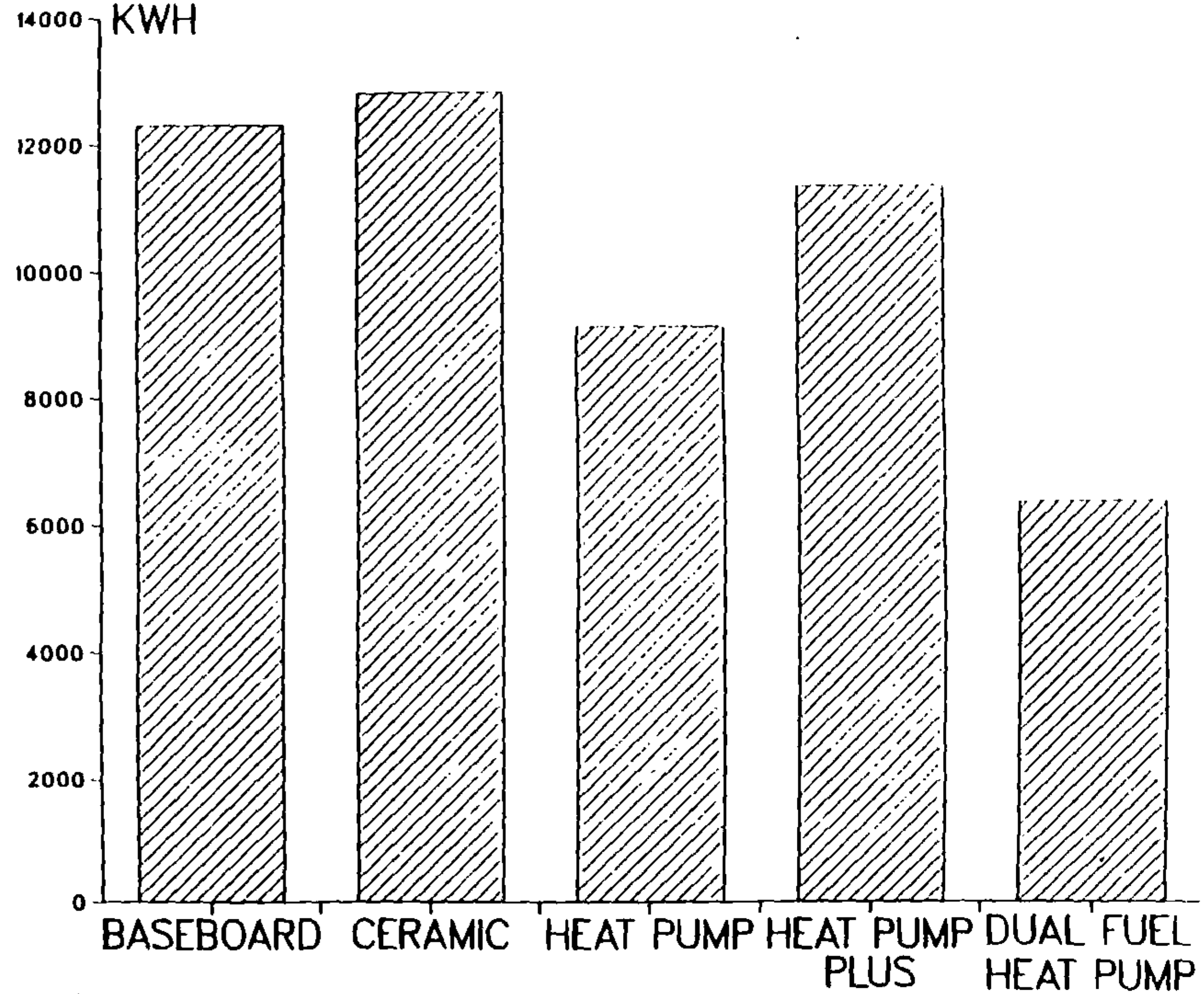
FIGURE 4
TYPICAL HOURLY HEATING DEMAND ON WINTER PEAK DAY
BASEBOARD VS CERAMIC HEATING



- As more RTS systems are added after 1995, PP&L's system peak demand for the 9/86 "Integrated" Forecast shifts to the nighttime and exceeds the daytime peaks in the 9/86 "Base" Forecast.
  - The RTS rate schedule includes a 14 hour off-peak period.
  - The RTS systems are designed to recharge for 12 hours on severe winter days with an average outdoor ambient temperature range of -6°F (Northern/Central Divisions) to 0°F (Lancaster/Harrisburg Divisions).
  - An 11 to 12 hour recharge strategy is assumed in the 9/86 "Integrated" Forecast.
    - With a shorter recharge period, the nameplate KW of future RTS systems may have to be increased to adequately recharge these systems on severe winter days.
    - Otherwise, it may be necessary to recharge these RTS systems during daytime hours.

FIGURE 5
SPACE HEATING SYSTEM ENERGY USE DURING HEATING SEASON
FOR TYPICAL INSTALLATIONS



Space Heating System Energy Use

- Figure 5, on the facing page, shows the space heating system energy use during the heating season for typical installations.
  - The energy use is based on average weather data for the 1982 to 1986 period and a typical 1800 sq. ft. home with alternative fuel customers deleted from the data sample.

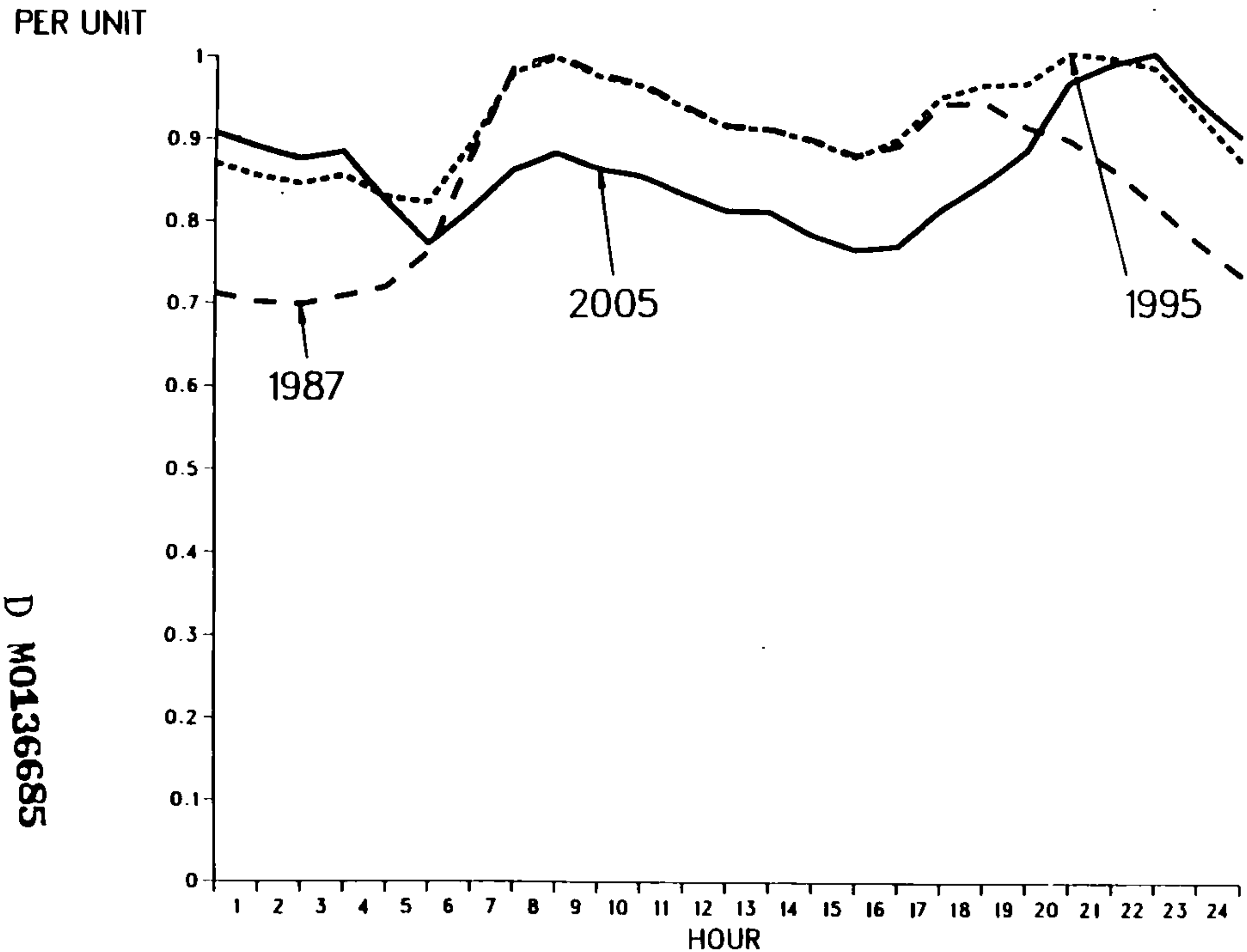
- The ceramic storage heating systems use about 5% more energy than the baseboard units primarily because of losses.

- There are three heat pump systems shown. The energy use varies based on how heat is provided to supplement the heat pump when outside temperatures are low.
  - The standard heat pump uses electric heating elements.
  - The Heat Pump Plus uses heat stored in water tanks to supplement the heat pump. This water storage is reheated using electric heating elements during the nighttime.
  - With a Dual Fuel Heat Pump, the heat pump is shut down and a fossil fuel furnace provides the heat.

- The Heat Pump Plus has a higher energy use then the standard heat pump due to:
  - Losses which are about 10% of the total.
  - Customers maintaining higher living space temperatures since heating costs are less.

FIGURE 6

9/86 "INTEGRATED" FORECAST WINTER PEAK DAY HOURLY DEMAND IN PER UNIT OF THE DAILY MAXIMUM



PP&L Peak Day Load Shape

- o Figure 6 shows the effect of the marketing programs in shifting load to the nighttime and the relative level of loads throughout the day. This figure shows the load shape in per unit of the maximum hourly demand.

- o The load shape for the 9/86 "Base" Forecast remains essentially unchanged through 2006 and has a daily peak demand which occurs about 9 AM.
  - The system peak day load factor is about 87%.

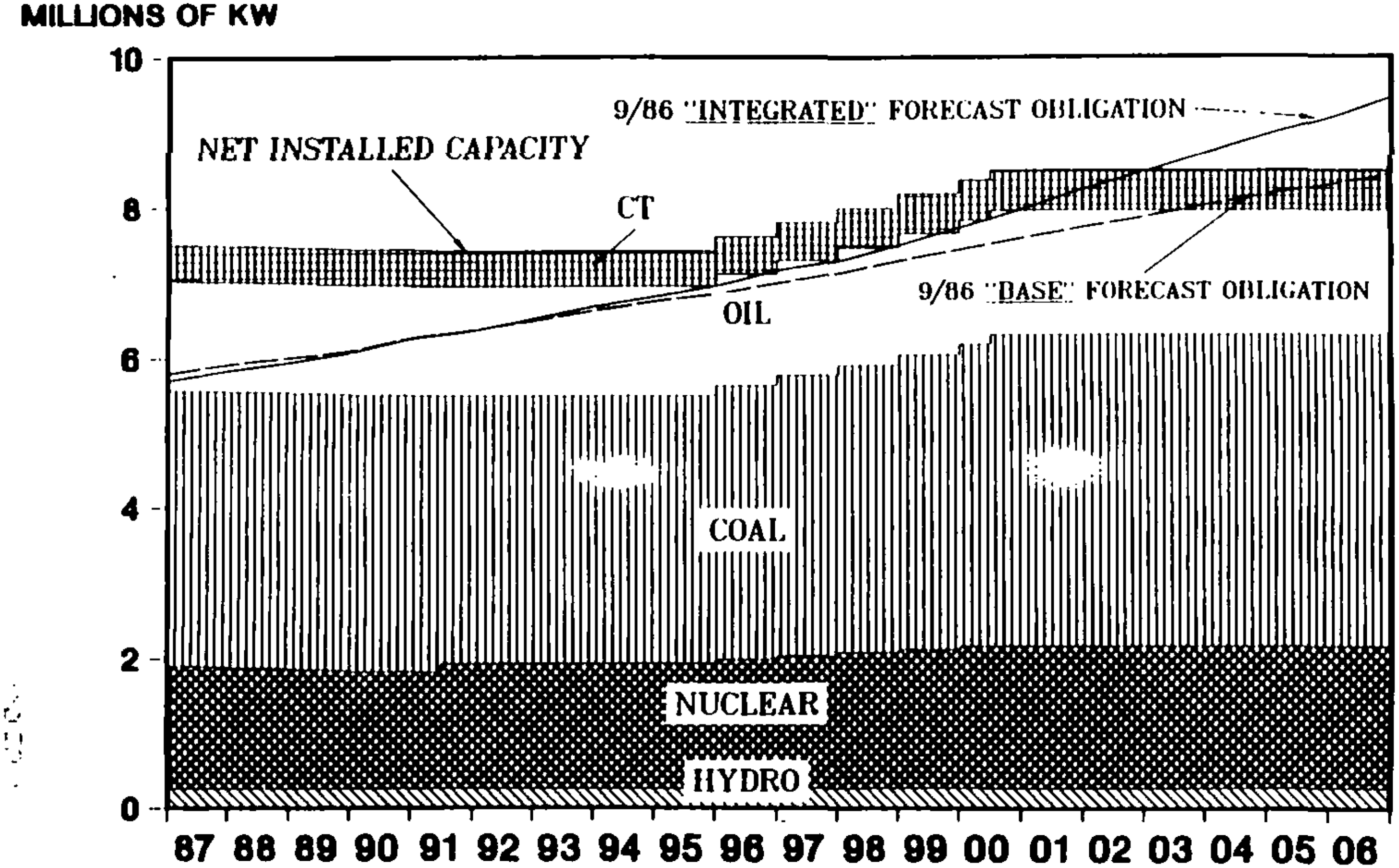
- o The 9/86 "Integrated" Forecast has the same load shape and load factor as the 9/86 "Base" Forecast in 1987.
  - By 1995, the load shape for the 9/86 "Integrated" Forecast is relatively flat with the peak demand occurring at night; the daily load factor increases to about 92%.
  - By 2005, the load shape for the 9/86 "Integrated" Forecast is becoming less flat with a predominant nighttime peak; the daily load factor decreases to about 86%.

- o The shift to a nighttime peak would have occurred prior to 1995 had the 9/86 "Integrated" Forecast not already included the effects of
  - Load control strategy to delay the recharge starting time of RTS systems to a 7 PM-8 PM period from the current starting period of 5 PM-7 PM.
  - Reduction in water heater element size from a standard 4.5 KW to a non-standard 2.5 KW in some off-peak water heating systems.

- o This alternate load control strategy was applied in the 9/86 "Integrated" Forecast to mitigate the off-peak demand contributions at the time of the secondary peak (6 PM to 8 PM) on the winter system peak day.

54

FIGURE 7
9/86 "BASE" FORECAST AND 9/86 "INTEGRATED" FORECAST OBLIGATION/CAPACITY COMPARISON



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Impact on Installed Capacity Obligation (ICO)

- Figure 7, on the facing page, shows the 9/86 "Base" Forecast and 9/86 "Integrated" Forecast obligation/capacity comparison. Load/Capacity/Reserve (L/C/R) tables are provided in Appendix 2.

- PP&L's ICO will increase for the 9/86 "Integrated" Forecast compared to the 9/86 "Base" Forecast after 1995 due to PP&L's higher winter peak.

- PP&L's winter peak occurring at night will not affect PP&L's ICO since time of day of peak occurrence is currently not a factor in the PJM formula for determine ICO.
  - PP&L will continue to receive credit for seasonal peak diversity as long as PJM remains a summer peaking pool.
  - PJM is expected to remain summer peaking at least through 2005.

- Recognizing the hour of the daily peak (daily peak diversity) in the calculation of ICO would not likely benefit PP&L while PJM is summer peaking and may not benefit PP&L after PJM becomes winter peaking.
  - PP&L will continue to benefit from seasonal diversity credit regardless of the time of day of winter peak occurrence.

- PJM total installed capacity requirement will not change as a result of recognizing daily diversity.
  - Recognizing daily diversity would only result in a reallocation of ICO among PJM member companies.
  - If daily diversity were recognized during both summer and winter peaks, summer peaking companies may gain more than PP&L.
  - Other PJM companies are also promoting time of day rates to shift load from on-peak to off-peak periods.

56

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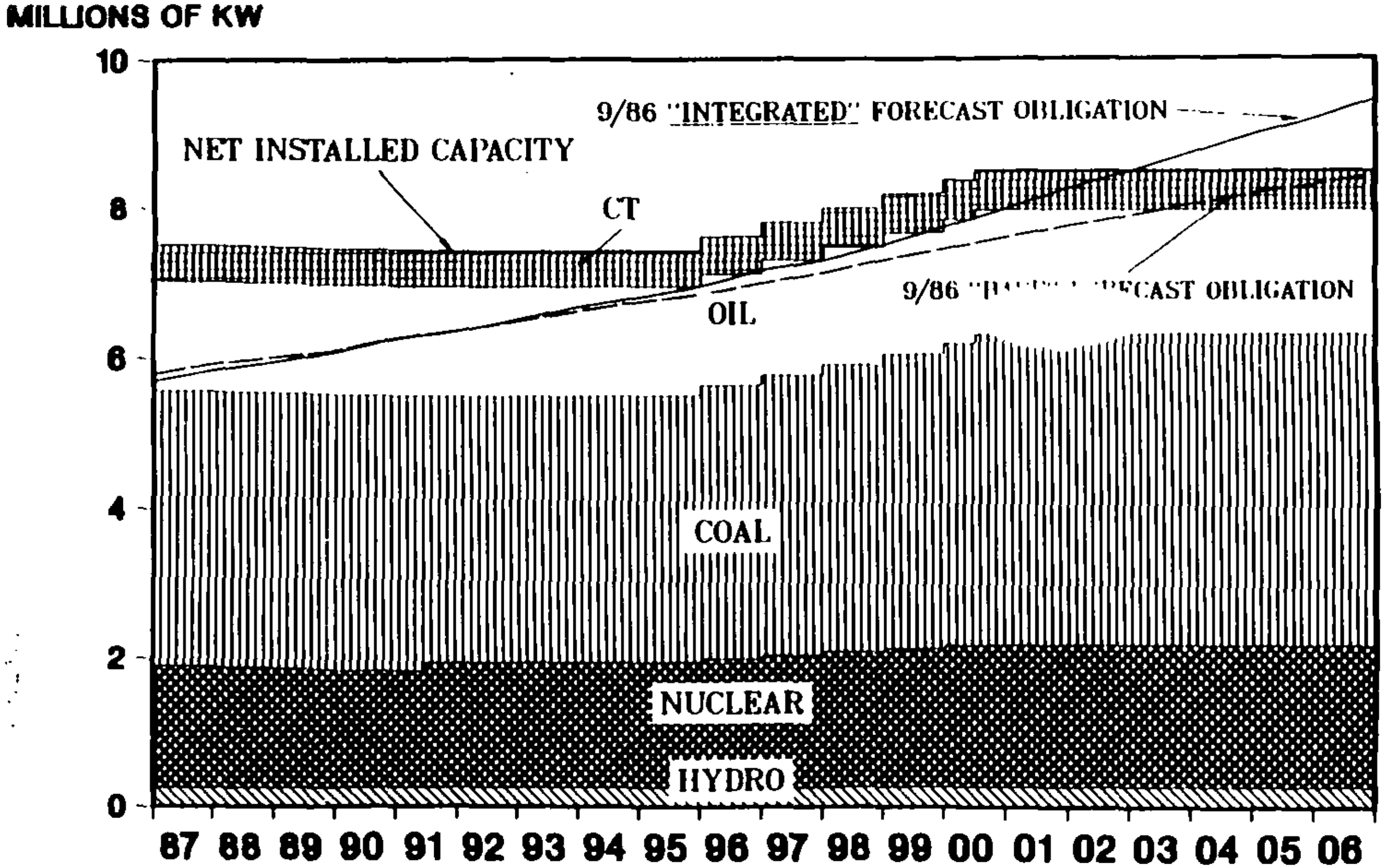
FIGURE 7
9/86 "BASE" FORECAST AND 9/86 "INTEGRATED" FORECAST OBLIGATION/CAPACITY COMPARISON



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- o All PJM companies, including PP&L, share in summer diversity credit which recognizes that the individual summer peaks occur at different times throughout the summer period.
  - Recognizing daily summer diversity would only provide a refinement to the present summer diversity credit.

- o Other PJM companies would likely attempt to modify other areas of the ICO formula such as the penalty factor for large unit sizes which is currently inactive.
  - PP&L's ICO could increase if the unit size factor were reactivated because PP&L has seven large units.

- o The need for additional resources is advanced four years to 2003 for the 9/86 "Integrated" Forecast.

- o Greater amounts of resources are required in the 9/86 "Integrated" Forecast.
  - The peak demand level (250 MW per year) is growing at twice the peak demand level (120 MW per year) of the 9/86 "Base" Forecast
  - The additional capacity needed to meet PP&L's ICO over the last four years studied is equivalent to a 1000 MW plant.
  - May require reliance on NUG as capacity.

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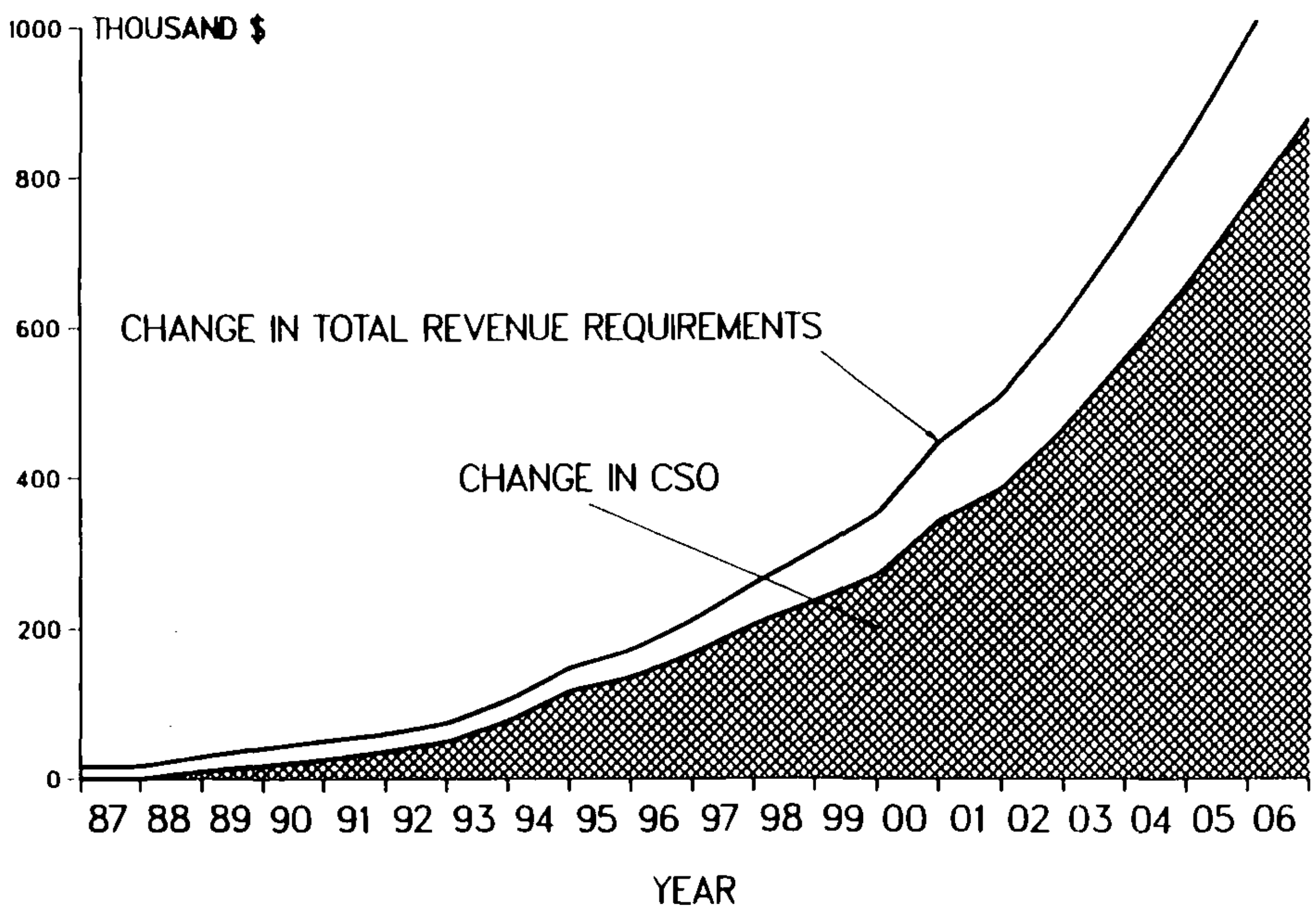
58

FIGURE 8
CHANGE IN TOTAL REVENUE REQUIREMENTS
9/86 "INTEGRATED" FORECAST COMPARED TO 9/86 "BASE" FORECAST



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59

Revenue Requirement Projections

- Figure 8 shown above shows the increase in total revenue requirements for the 9/86 "Integrated" Forecast as compared to the 9/86 "Base" Forecast.

- Revenue requirements are all the costs incurred in the production, transmission and distribution of electricity and include:
  - Carrying charges
    - Return on investment
    - Depreciation - return of investment
    - Taxes
  - Expenses
    - Operation and maintenance
    - Cost of System Output (CSO)
      - CSO is defined as fuel cost for customer sales plus purchased power costs less savings from interchange and two party transactions.
- The revenue requirements are based on a 13% common equity rate of return.

- CSO is a function of sales levels and time-of-day that sales occur.
  - The CSO change in the 9/86 "Integrated" Forecast reflects the shift in sales to the nighttime and higher sales.

- The 9/86 "Integrated" Forecast has higher total revenue requirements than the 9/86 "Base" Forecast.
  - About 3/4 of the increase in total revenue requirement results from an increase in CSO.
    - Fuel cost for PP&L's customer load is higher due to increased customer sales.
    - Interchange sales are lower.
  - The remainder of the revenue requirements increase results from additional distribution costs and marketing expenses.
  - Distribution system costs are discussed on page 18.

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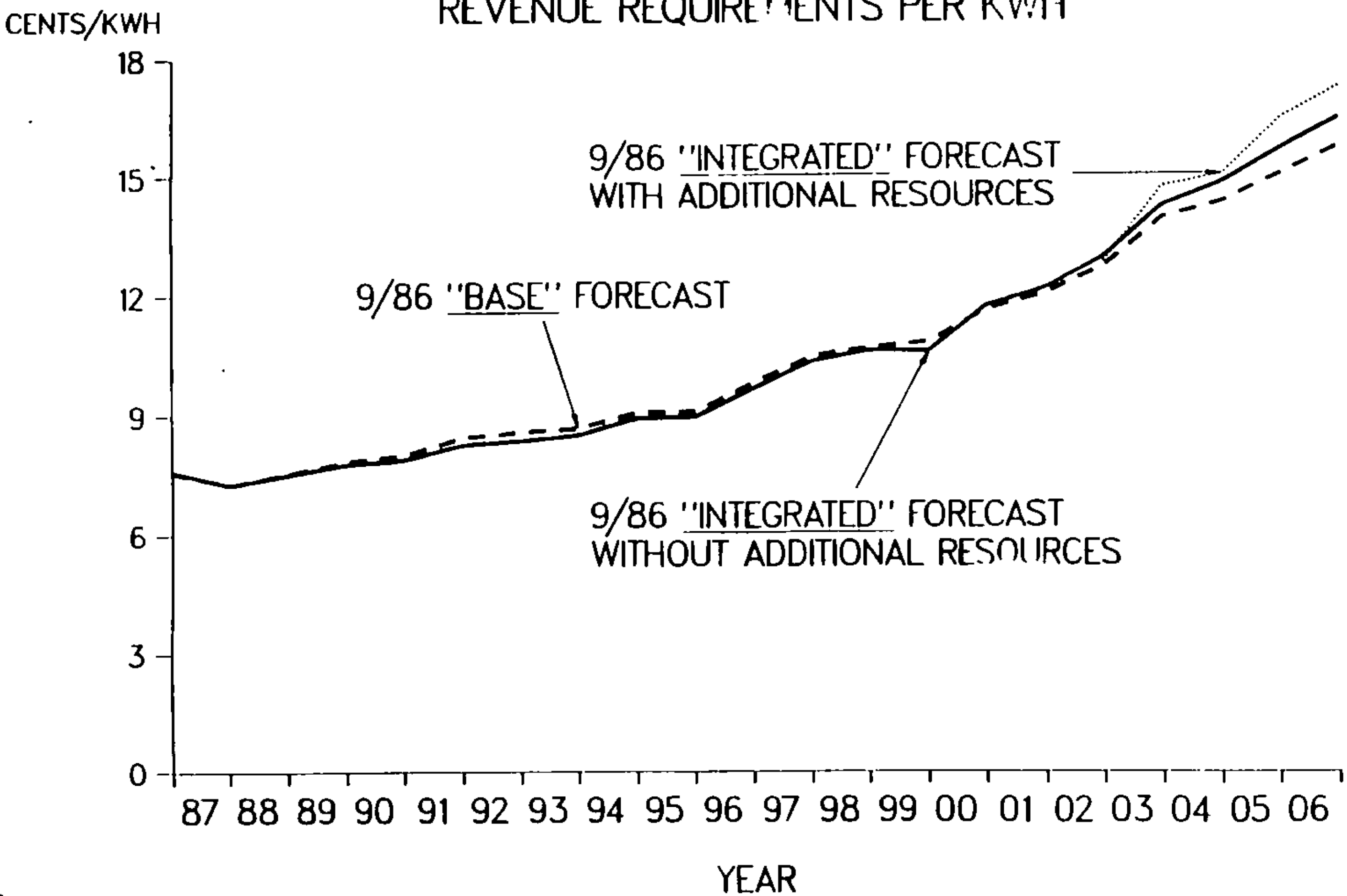
60

FIGURE 9
REVENUE REQUIREMENTS PER KWH



Revenue Requirements Per KWH

- o Figure 9 compares the revenue requirements per KWH for the 9/86 "Base" Forecast and 9/86 "Integrated" Forecast.
  - Although total revenue requirements are higher for the 9/86 "Integrated" Forecast, sales are also higher.

- o Prior to 2000, the revenue requirements per KWH for the 9/86 "Integrated" Forecast are approximately the same (1 to 2% lower) as the 9/86 "Base" Forecast.

- o After 2000, the revenue requirements per KWH for the 9/86 "Integrated" Forecast increase faster than the 9/86 "Base" Forecast reaching an amount 4% higher at the end of the forecast period.
  - This comparison does not include the capital and O&M costs associated with additional resources.

- o Adding resources (assumed to be generating capacity for this analysis) would cause the 9/86 "Integrated" Forecast total revenue requirements to be about 10% higher than the 9/86 "Base" Forecast at the end of the forecast period.
  - This is the net impact of increasing fixed costs partially offset by decreasing CSO.

- o The levelized revenue requirement per KWH over the 20 year period for the 9/86 "Base" Forecast and 9/86 "Integrated" Forecast are nearly the same, about 9 cents per KWH.

Distribution System Costs

- o At the individual customer level, increases in demand, regardless of when that increased demand occurs, may increase the fixed cost of serving that customer.
  - Larger and more costly distribution transformers will be installed.
  - Heavier and more costly secondary runs will be required.

- o Installing an RTS system in lieu of a conventional heating system will impact the distribution system and to a lesser extent, the regional transmission system.
  - As long as the existing distribution system has unused capacity during the hours when new load is added, no additional distribution system costs will be incurred.
  - Not all distribution circuits have their heaviest loading during the hour of the system peak.
    - o Distribution circuits with a high concentration of residential electric heating customers already experience a peak demand at about 7 PM to 8 PM.
  - To a lesser extent, RTS systems may delay the need for distribution system additions when the circuits have higher daytime demands and lower nighttime demands.

- o Distribution system impacts from RTS systems are very location sensitive.
  - If many RTS installations are concentrated, the peak demands on distribution feeders and substations will increase and potentially exceed the facility ratings.
    - o Thus, additional feeders, substations and transmission will need to be built.

- o Overall, for purposes of this study, it is estimated that the incremental transmission and distribution system capital expenditures could be about a five hundred dollars per KW of RTS systems.

Infrastructure

- o Infrastructure refers to the manufacturers, dealers and installers needed to provide the equipment to support PP&L's marketing programs.

- o The growth of the RTS market will require a major expansion in supply of ceramic heating equipment and other thermal storage systems. This expansion may include the development of manufacturing facilities in the U.S. for a product now made in Europe.

- o Any modifications to PP&L's marketing of RTS systems will have a major impact on the successful operation of this infrastructure, particularly local distributors and installers, and should be considered in decisions concerning storage heating.

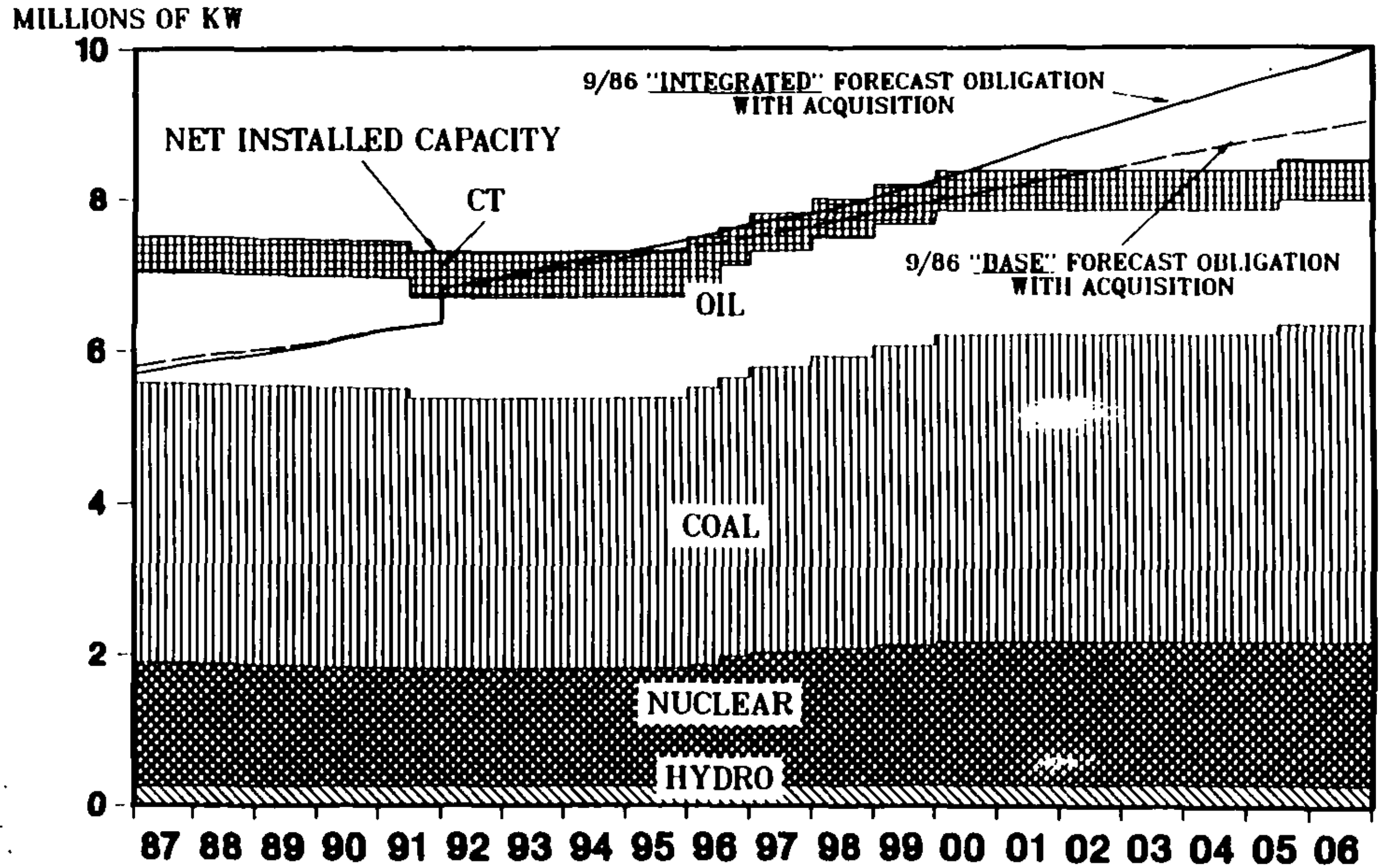
Effect of Cost Allocation

- o The addition of significant amounts of RTS systems may affect the cost of service allocation of costs to the rate classes.
  - The cost of service allocation for each rate class are, in part, determined by their contribution to the system peak demand.
  - In the later years, RTS customers may contribute more toward the system peak demand than other rate classes.
    - o Maintaining the current RTS rate relationships may cause cost of service allocation concerns for the Residential Service (RS) rate class.
    - o Rates may have to be changed to reflect new use of facilities by customer groups.

- o A description of the RTS rate and current rebates are contained in Appendix 3.

FIGURE 10

9/86 "BASE" FORECAST AND 9/86 "INTEGRATED" FORECAST OBLIGATION/CAPACITY COMPARISON INCLUDING ACE SALE EXTENSIONS AND SERVICE TERRITORY ACQUISITION



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Impact of 9/86 Integrated Forecast on PP&L's Flexibility to Employ Other Strategies

- Figure 10, on the facing page, shows the impact of extending the sale of SSES and coal capacity to Atlantic City by five years and a 400 MW service territory expansion in 1991 for both the 9/86 "Base" Forecast and the 9/86 "Integrated" Forecast. L/C/R tables are provided in Appendix 4.

- These events could require the use of NUG as capacity and/or advance the need for additional resources to 2002 for the 9/86 "Base" Forecast and to 1995 for the 9/86 "Integrated" Forecast.

- For the 9/86 "Base" Forecast:
  - PP&L could be short a small amount of capacity in 1995.
  - About 500 MW of additional resources would be needed by 2006 with the service area acquisition.

- For the 9/86 "Integrated" Forecast:
  - PP&L would need about 150 MW per year of additional resources from 1995 through 2000.
  - About 1500 MW of additional resources would be needed by 2006 with the service area acquisition.

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96

Appendix 1

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9/86 BASE CASE FORECAST

PENNSYLVANIA POWER & LIGHT COMPANY
ANNUAL SALES, OUTPUT, AND SEASONAL PEAKS
INCLUDING SUPPLY TO UGI

	SALES (GWH)	OUTPUT (GWH)	PEAKS: SUMMER (MW)	PEAKS: WINTER (MW)
1986	24,855	26,826	4,300	5,300
1987	25,435	27,500	4,380	5,390
1988	25,779	27,926	4,450	5,470
1989	26,127	28,273	4,500	5,550
1990	26,440	28,579	4,570	5,630
1991	26,880	29,054	4,640	5,720
1992	27,390	29,605	4,720	5,830
1993	27,910	30,167	4,800	5,950
1994	28,450	30,750	4,890	6,060
1995	28,890	31,225	4,960	6,150
1996	29,430	31,809	5,050	6,280
1997	30,010	32,435	5,140	6,400
1998	30,585	33,056	5,230	6,520
1999	31,170	33,688	5,320	6,650
2000	31,770	34,337	5,420	6,780
2001	32,375	34,990	5,520	6,910
2002	32,960	35,622	5,610	7,030
2003	33,550	36,260	5,700	7,170
2004	34,140	36,897	5,790	7,300
2005	34,725	37,529	5,880	7,410
2006	35,300	38,150	5,900	7,530

NOTE: SALES TO ATLANTIC ELECTRIC & JCPL ARE NOT INCLUDED.

RATES & MARKET RESEARCH
FORECASTING

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67

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9/86 INTEGRATED FORECAST

PENNSYLVANIA POWER & LIGHT COMPANY
ANNUAL SALES, OUTPUT, AND SEASONAL PEAKS
INCLUDING SUPPLY TO UGI

	SALES	OUTPUT	PEAKS	
			SUMMER	WINTER
	(GWH)	(GWH)	(MW)	(MW)
1986	24,855	26,826	4,230	5,220
1987	25,435	27,500	4,310	5,310
1988	25,990	28,096	4,400	5,410
1989	26,595	28,748	4,500	5,520
1990	27,195	29,396	4,590	5,620
1991	27,952	30,192	4,680	5,710
1992	28,728	31,053	4,780	5,830
1993	29,525	31,914	4,880	5,950
1994	30,344	32,799	4,990	6,060
1995	31,041	33,553	5,080	6,160
1996	31,852	34,429	5,180	6,350
1997	32,725	35,373	5,290	6,480
1998	33,663	36,279	5,400	6,700
1999	34,427	37,212	5,500	6,930
2000	35,306	38,163	5,620	7,180
2001	36,191	39,119	5,730	7,430
2002	37,057	40,055	5,840	7,670
2003	37,936	41,005	5,940	7,930
2004	38,806	41,946	6,050	8,190
2005	39,664	42,873	6,160	8,420
2006	40,520	43,798	6,280	8,670

NOTE: SALES TO ATLANTIC ELECTRIC & JCPL ARE NOT INCLUDED.

RATES & MARKET RESEARCH
FORECASTING

68

04/02/87

Appendix 2

Winter Load/Capacity/Reserve Summary
9/86 BASE CASE FORECAST
(MEGAWATTS)

	Peaks (1)				Purchases/Sales (3)						Capacity Obligation (4)			Reserve Over Obligation	
Year	Summer	Winter	Add/Ret.	Planned Capacity	AE(2)	ACE(2)	JCPL	Net Inst.	Actual Reserve	%	Total	Req.	Reserves		
1987	4,380	5,390	0	8,499	70	-125	-945	7,499	2,109	39.1%	5,929	539	10.0%	1,670	26.5%
1988	4,450	5,470	0	8,499	50	-125	-945	7,479	2,009	36.7%	6,017	547	10.0%	1,462	24.3%
1989	4,500	5,550	0	8,499	25	-125	-945	7,454	1,904	34.3%	6,105	555	10.0%	1,349	22.1%
1990	4,570	5,630	0	8,499	15	-125	-945	7,444	1,814	32.2%	6,277	647	11.5%	1,167	18.6%
1991	4,640	5,720	0	8,499	0	-127 (5)	-945	7,427	1,707	29.8%	6,378	658	11.5%	1,049	16.5%
1992	4,720	5,830	0	8,499	0	-127	-945	7,427	1,597	27.4%	6,500	670	11.5%	927	14.3%
1993	4,800	5,950	0	8,499	0	-127	-945	7,427	1,477	24.8%	6,634	684	11.5%	793	11.9%
1994	4,890	6,060	0	8,499	0	-127	-945	7,427	1,367	22.6%	6,757	697	11.5%	670	9.9%
1995	4,960	6,150	0	8,499	0	-127	-945	7,427	1,277	20.8%	6,857	707	11.5%	570	8.3%
1996	5,050	6,280	0	8,499	0	-127	-756	7,616	1,336	21.3%	7,002	722	11.5%	614	8.8%
1997	5,140	6,400	0	8,499	0	-127	-567	7,805	1,405	22.0%	7,136	736	11.5%	669	9.4%
1998	5,230	6,520	0	8,499	0	-127	-378	7,994	1,474	22.6%	7,302	782	12.0%	692	9.5%
1999	5,320	6,650	0	8,499	0	-127	-189	8,183	1,533	23.1%	7,448	798	12.0%	735	9.9%
2000	5,420	6,780	0	8,499	0	0	0	8,499	1,719	25.4%	7,594	814	12.0%	[illegible]	11.9%
2001	5,520	6,910	0	8,499	0	0	0	8,499	1,589	23.0%	7,739	829	12.0%	760	9.8%
2002	5,610	7,030	0	8,499	0	0	0	8,499	1,469	20.9%	7,874	844	12.0%	625	7.9%
2003	5,700	7,170	0	8,499	0	0	0	8,499	1,329	18.5%	8,030	860	12.0%	469	5.8%
2004	5,790	7,300	0	8,499	0	0	0	8,499	1,199	16.4%	8,176	876	12.0%	323	4.0%
2005	5,880	7,410	0	8,499	0	0	0	8,499	1,089	14.7%	8,299	889	12.0%	200	2.4%
2006	5,980	7,530	0	8,499	0	0	0	8,499	969	12.9%	8,434	904	12.0%	65	0.8%

Notes:

(1) Peak loads include 100% of the needs for the Luzerne Electric Division (LU) of the UGI Corporation above their owned generation throughout the study period.

(2) The Susquehanna units (1050 mw each) are jointly owned by PP&L (90%-945 mw) and Allegheny Electric Cooperative Inc. (AE) (10%-105 mw). Since AE does not require all the capacity initially, PP&L will purchase capacity and energy from them through the late 1980's as shown under purchases/sales. In addition, PP&L has entered into an agreement with Atlantic City Electric Company (ACE) under which ACE will purchase 6.6% of PP&L's share of the capacity and energy from the Susquehanna units (125 mw when both units are in-service), beginning with the in-service dates and ending in September,1991. Additionally,ACE will purchase 127 mw of the Company's coal fired units (October,1991 through September,2000).

(3) The Purchases/Sales indicated reflect the effect of capacity arrangements with AE, ACE, and JCPL. The AE and ACE arrangements are noted in (2) above. The sale to JCPL reflects the sale of 945 mw Slice of System Capacity and Energy.

(4) Estimates of capacity obligation are based on the PJM allocation method, using reserve margin of PL group (PL & LU). Obligation and reserve above obligation are customarily presented in terms of summer rated capacity. The "Winter" obligation indicated here is an equivalent capacity obligation reflecting winter capacity ratings.

(5) The Summer capacity rating is 125 MW.

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69

Appendix 3

RTS Rate

o The RTS rate and grants in 1987 are:
  - Fixed customer charge of $11.50 per month
  - Demand charges of about $6/KW for all KW in excess of 2 KW used during the on peak period
  - Energy charge of about 3 cents for all KWH
  - A one-time rebate of $800 to 1500 to install energy storage systems
  - The demand and energy changes are expected to result in an average rate of about 4-5 cents per KWH for heating residential customers with energy storage

o The average residential rate is projected to be about 8 cents per KWH for 1987.

Appendix 4

04/02/87

Winter Load/Capacity/Reserve Summary
9/86 BASE CASE FORECAST
400 MW TERRITORY EXPANSION AND EXTEND ACE SALES
(MEGAWATTS)

Year	Peaks (1) Summer	Peaks (1) Winter	Add/Ret.	Planned Capacity	Purchases/Sales (3) AE(2)	Purchases/Sales (3) ACE(2)	Purchases/Sales (3) JCPL	Net Inst.	Actual Reserve	%	Capacity Obligation (4) Total	Capacity Obligation (4) Req. Reserves		Reserve Over Obligation	
1987	4,380	5,390	0	8,499	70	-125	-945	7,499	2,109	39.1%	5,929	539	10.0%	1,570	26.5%
1988	4,450	5,470	0	8,499	50	-125	-945	7,479	2,009	36.7%	6,017	547	10.0%	1,462	24.3%
1989	4,500	5,550	0	8,499	25	-125	-945	7,454	1,904	34.3%	6,105	555	10.0%	1,349	22.1%
1990	4,570	5,630	0	8,499	15	-125	-945	7,444	1,814	32.2%	6,277	647	11.5%	1,167	18.6%
1991	5,040	6,120	0	8,499	0	-252 (5)	-945	7,302	1,182	19.3%	6,824	704	11.5%	478	7.0%
1992	5,125	6,235	0	8,499	0	-252	-945	7,302	1,067	17.1%	6,952	717	11.5%	350	5.0%
1993	5,215	6,365	0	8,499	0	-252	-945	7,302	937	14.7%	7,097	732	11.5%	205	2.9%
1994	5,315	6,485	0	8,499	0	-252	-945	7,302	817	12.6%	7,231	746	11.5%	71	1.0%
1995	5,390	6,580	0	8,499	0	-252	-945	7,302	722	11.0%	7,337	757	11.5%	-35	-0.5%
1996	5,490	6,720	0	8,499	0	-127	-756	7,616	896	13.3%	7,493	773	11.5%	123	1.6%
1997	5,585	6,845	0	8,499	0	-127	-567	7,805	960	14.0%	7,632	787	11.5%	173	2.3%
1998	5,685	6,975	0	8,499	0	-127	-378	7,994	1,019	14.6%	7,812	837	12.0%	182	2.3%
1999	5,785	7,115	0	8,499	0	-127	-189	8,183	1,068	15.0%	7,969	854	12.0%	214	2.7%
2000	5,890	7,250	0	8,499	0	-127 (6)	0	8,372	1,122	15.5%	8,120	870	12.0%	252	3.1%
2001	6,000	7,390	0	8,499	0	-127	0	8,372	982	13.3%	8,277	887	12.0%	95	1.2%
2002	6,100	7,520	0	8,499	0	-127	0	8,372	852	11.3%	8,422	902	12.0%	-50	-0.6%
2003	6,200	7,670	0	8,499	0	-127	0	8,372	702	9.2%	8,590	920	12.0%	-218	-2.5%
2004	6,300	7,810	0	8,499	0	-127	0	8,372	562	7.2%	8,747	937	12.0%	-375	-4.3%
2005	6,395	7,925	0	8,499	0	0	0	8,499	574	7.2%	8,876	951	12.0%	-377	-4.2%
2006	6,505	8,055	0	8,499	0	0	0	8,499	444	5.5%	9,022	967	12.0%	-523	-5.8%

Notes:

(1) Peak loads include 100% of the needs for the Luzerne Electric Division (LU) of the UGI Corporation above their owned generation throughout the study period.

(2) The Susquehanna units (1050 mw each) are jointly owned by PP&L (90%-945 mw) and Allegheny Electric Cooperative Inc. (AE) (10%-105 mw). Since AE does not require all the capacity initially, PP&L will purchase capacity and energy from them through the late 1980's as shown under purchases/sales. In addition, PP&L has entered into an agreement with Atlantic City Electric Company (ACE) under which ACE will purchase 6.6% of PP&L's share of the capacity and energy from the Susquehanna units (125 mw when both units are in-service), beginning with the in-service dates and ending in September,1991. Additionally,ACE will purchase 127 mw of the Company's coal fired units (October,1991 through September,2000).

(3) The Purchases/Sales indicated reflect the effect of capacity arrangements with AE, ACE, and JCPL. The AE and ACE arrangements are noted in (2) above. The sale to JCPL reflects the sale of 945 mw Slice of System Capacity and Energy.

(4) Estimates of capacity obligation are based on the PJM allocation method, using reserve margin of PL group (PL & LU). Obligation and reserve above obligation are customarily presented in terms of summer rated capacity. The "Winter" obligation indicated here is an equivalent capacity obligation reflecting winter capacity ratings.

(5) Extend nuclear sale

(6) Extend coal sale (summer capacity rating is 125 mw).

71

04/02/87

Winter Load/Capacity/Reserve Summary
9/86 INTEGRATED FORECAST
400 MW TERRITORY EXPANSION AND EXTEND ACE SALES
(MEGAWATTS)

Year	Peaks (1) Summer	Winter	Add/Ret.	Planned Capacity	Purchases/Sales (3) AE(2)	ACE(2)	JCPL	Net Inst.	Actual Reserve	%	Capacity Obligation (4) Total	Req.	Reserves	Reserve Over Obligation	
1987	4,310	5,310	0	8,499	70	-125	-945	7,499	2,189	41.2%	5,841	531	10.0%	1,658	28.4%
1988	4,400	5,410	0	8,499	50	-125	-945	7,479	2,069	38.2%	5,951	541	10.0%	1,528	25.7%
1989	4,500	5,520	0	8,499	25	-125	-945	7,454	1,934	35.0%	6,072	552	10.0%	1,382	22.8%
1990	4,590	5,620	0	8,499	15	-125	-945	7,444	1,824	32.5%	6,266	646	11.5%	1,178	18.8%
1991	5,080	6,120	0	8,499	0	-252 (5)	-945	7,302	1,182	19.3%	6,824	704	11.5%	478	7.0%
1992	5,185	6,235	0	8,499	0	-252	-945	7,302	1,067	17.1%	6,983	748	12.0%	319	4.6%
1993	5,295	6,365	0	8,499	0	-252	-945	7,302	937	14.7%	7,161	796	12.5%	141	2.0%
1994	5,415	6,485	0	8,499	0	-252	-945	7,302	817	12.6%	7,296	811	12.5%	6	0.1%
1995	5,510	6,590	0	8,499	0	-252	-945	7,302	712	10.8%	7,447	857	13.0%	-145	-1.9%
1996	5,620	6,790	0	8,499	0	-127	-756	7,616	826	12.2%	7,673	883	13.0%	-57	-0.7%
1997	5,735	6,925	0	8,499	0	-127	-567	7,805	880	12.7%	7,791	866	12.5%	14	0.2%
1998	5,855	7,155	0	8,499	0	-127	-378	7,994	839	11.7%	8,014	859	12.0%	-20	-0.2%
1999	5,965	7,395	0	8,499	0	-127	-189	8,183	788	10.7%	8,245	850	11.5%	-62	-0.8%
2000	6,090	7,650	0	8,499	0	-127 (6)	0	8,372	722	9.4%	8,492	842	11.0%	-119	-1.4%
2001	6,210	7,910	0	8,499	0	-127	0	8,372	462	5.8%	8,780	870	11.0%	-408	-4.6%
2002	6,330	8,160	0	8,499	0	-127	0	8,372	212	2.6%	9,017	857	10.5%	-645	-7.2%
2003	6,440	8,430	0	8,499	0	-127	0	8,372	-58	-0.7%	9,273	843	10.0%	-901	-9.7%
2004	6,560	8,700	0	8,499	0	-127	0	8,372	-328	-3.8%	9,527	827	9.5%	-1,155	-12.1%
2005	6,675	8,935	0	8,499	0	0	0	8,499	-436	-4.9%	9,739	804	9.0%	-1,240	-12.7%
2006	6,805	9,195	0	8,499	0	0	0	8,499	-696	-7.6%	10,023	828	9.0%	-1,524	-15.2%

Notes:

(1) Peak loads include 100% of the needs for the Luzerne Electric Division (LU) of the UGI Corporation above their owned generation throughout the study period.

(2) The Susquehanna units (1050 mw each) are jointly owned by PP&L (90%-945 mw) and Allegheny Electric Cooperative Inc. (AE) (10%-105 mw). Since AE does not require all the capacity initially, PP&L will purchase capacity and energy from them through the late 1980's as shown under purchases/sales.
In addition, PP&L has entered into an agreement with Atlantic City Electric Company (ACE) under which ACE will purchase 6.6% of PP&L's share of the capacity and energy from the Susquehanna units (125 mw when both units are in-service), beginning with the in-service dates and ending in September,1991.
Additionally,ACE will purchase 127 mw of the Company's coal fired units (October,1991 through September,2000).

(3) The Purchases/Sales indicated reflect the effect of capacity arrangements with AE, ACE, and JCPL.
The AE and ACE arrangements are noted in (2) above. The sale to JCPL reflects the sale of 945 mw Slice of System Capacity and Energy.

(4) Estimates of capacity obligation are based on the PJM allocation method, using reserve margin of PL group (PL & LU).
Obligation and reserve above obligation are customarily presented in terms of summer rated capacity.
The "Winter" obligation indicated here is an equivalent capacity obligation reflecting winter capacity ratings.

(5) Extend nuclear sale

(6) Extend coal sale (Summer capacity rating is 125 mw).

D M0136704

72

CEPFOD Exhibit No. 7

PP&L

March 26, 1985

Mr. G. E. McNair, TW-5
Mr. F. A. Long, A4-3
Mr. R. H. Ballard, A4-3
Mr. J. O. Beamer, TW-6
Mr. J. E. Brett, A4-3
Mr. H. A. Courtright, A3-3
Mr. R. A. Donia, TW-5
Mr. T. R. Dahl, A3-4

Mr. R. M. Geneczko, A4-3
Ms. H. S. L. Kekuna, A3-4
Mr. E. P. Koepcke, A3-3
Mr. J. C. Krum, A3-2
Mr. P. L. Roberts, A3-4
Mr. R. Romancheck, TW-6
Mr. J. J. Slivka, TW-5

FILE 32338400160
MEMORANDUM FOR FILE
IMPLEMENTATION OF PUC EVALUATION METHODOLOGY
FOR CONSERVATION & LOAD MANAGEMENT PROGRAMS
MONTHLY STATUS - MARCH 1985

This status report provides a summary of the remaining three DSM programs that were analyzed by using the PUC Evaluation Methodology. These programs are included in the first three attachments in the following order.

- Winter Relief Assistance Program (WRAP)
- Residential New Construction (Off-Peak SESS Heat Pump)
- Residential New Construction/Existing Conversion (Off-Peak Ceramic Heating)

A fourth program - I&C Time-of-Day rate was originally included in the list of programs to be evaluated using the PUC Evaluation Methodology. However, upon detailed review of this program, it was determined that it was not necessary to be included as a load management/conservation program in the Annual Conservation Report since it is primarily an economic development initiative program and the utility cost is zero (less than the $100,000 reporting requirement).

A summary of the Net Present Value (NPV) and Benefit-Cost Ratio (BCR) terms for these programs and the three previous programs (CACS, RCS and IS-2) is provided in Attachment 4. Definitions and Equations are again provided to aid in analysis of the program results.

Comments and questions on all programs should be directed to John Milot or George Beam prior to April 3. This information will then be included with the 1984 Annual Conservation Report.

J. M. Milot / G. E. Beam
J. M. Milot/geb　　G. E. Beam

M&CS
GEB/smm

Attachments

WINTER RELIEF ASSISTANCE PROGRAM (WRAP)

WRAP is a weatherization program for low-income residential customers, as mandated by the PUC on August 27, 1984. PP&L's program was developed in cooperation with the PUC's Bureau of Conservation, Economics and Energy Planning (CEEP) and was phased in on March 1, 1985. The annual operating budget has been set by the PUC at $2 million.

WRAP Procedures

Within PP&L, WRAP is a two-part program designed to serve low-income customers who either have electric heat or electric water heating. PP&L's goals for WRAP include:

- Activity A which would provide weatherization services to 2,000 low-income households, annually, which are headed by customers who are 18 years of age or above and have annual incomes under 175 percent of poverty; and

- Activity B which would offer up to $300,000, annually, either to reduce the interest on energy conservation loans to landlords of multi-family housing units in which over half of the tenants are low income, or to install low-cost conservation measures in approximately 1,500 multi-family low-income rental units.

Under Activity A, the Company will use Residential Consultants to conduct home energy inspections. Based on the home energy inspection, WRAP workers will install low-cost infiltration measures and arrangements will be made with private contractors to install additional weatherization measures (i.e., attic insulation, storm windows).

The intent of Activity B is to provide weatherization services by developing a partnership program with local lending institutions, community groups and private contractors. Services will include installing low-cost conservation materials, and/or encouraging landlords to obtain conservation loans from local banks. PP&L will subsidize the financing by providing interest write-downs and by utilizing Federal Solar Bank Funds.

Basic Assumptions

Tables 1a, 1b and 1c list the input data used to evaluate the individual WRAP activities. The assumptions used to develop the activity-specific data are listed on Chart A. The other data, common to all activities, was derived from the assumptions listed below:

- o Utility Avoided Energy Cost (MCE) equal to PP&L average incremental value of energy increased by 9.4% to account for losses.

- o Utility Capacity Savings (G) and Avoided Capacity Costs (MCD) are not applicable due to PP&L's sufficient capacity situation until 2000.

- o Utility costs, (UC), include all of the program's O&M costs as incurred by PP&L and are apportioned among the activities.

- o Discount rate for all parties equal to PP&L's after tax cost of money (i.e., 9.7%).

- o Uncollectible Accounts (UA) would be reduced as a result of WRAP, but the amount for each activity has not yet been defined.

Analysis of Results for WRAP

The results of applying the PUC Methodology to each of the WRAP activities are provided in the PUC's format on Tables 2a, 2b and 2c, with additional detail on tables 3a, 3b, and 3c. As expected, WRAP provides very large benefits to the participant. The benefits are so large that they far outweigh the losses to the nonparticipant and provide benefit-to-cost ratios for all ratepayers of no less than 9-to-1. This is due to the large avoided energy costs realized, as compared to the costs of the conservation measures. Activity A provides the most benefits, due to its relative size, but provides the lowest benefit-to-cost ratio for PP&L of all the activities. This is because the additional grant provided under this activity results in the installation of additional measures with lower payoffs than those high payoff measures which would be done for all activities, (i.e., the law of diminishing returns).

CHART A
WRAP ACTIVITY ASSUMPTIONS

	Activity A	Activity B (Indiv.)	Activity B (Master)
Participants Demand (D) and Energy (E) Savings	o 2000 Homes/Yr. o 15% Electric Heat (1200 KWH Savings/Home/Yr.) o 85% Non-Electric Heat (400 KWH Savings/Home/Yr.) o 5 Year Program Life o 10 Yr. Conservation Measure Life o 0.1 KW avg. demand savings per home/unit	o 1200 Units/Yr. (80% of total apart.) o 400 KWH Savings/Unit/Yr. Same	o 300 Units/Yr. o 15% Electric Heated (1200 KWH Savings/Unit/Yr.) o 85% Non-Electric Heated (400 KWH Savings/Unit/Yr.) Same
Participants Average Demand (ACD) and Energy (ACE) Payments	o 1985-1989 energy rates as per proposed RS rate schedule (7/84 filing) o 1990-1998 energy rates escalated at 5.5% annually o No demand rate for RS class.	Same as A	o 1985-1989 energy and demand rates as per proposed GS-3 rate schedule (7/84 filing). o 1990-1998 rates escalated at 5.5% annually.
Participants Costs (PC)	o No direct costs o Includes non-electric heat savings assuming - $100/savings/home - escalated at weighted oil/gas escalation rate	o No direct costs o Non-electric heat savings undetermined at present.	o Includes conservation measure cost and interest not subsidized by PP&L. o Also includes non-electric heat savings as per Activity A.
Tax Credits (TC)	o Zero since no direct costs incurred	o Same as A	o Equal to 15% of participants cost, less non-electric heat savings.
Incentive Cost (I)	o $750 grant per home o $100,000 escalations (a 6.7%) per year o 5 year program life	o $235 grant per unit o $15,000 escalation (a 5%) per year o 5 year program life	o $50 interest subsidy per unit o $750 escalation (a 5%) per year.

2000
1200
300
3500

1,340,000
480,000
156,000
1,676,000

DM 046880

17

TABLE 1a

FORM ACR-4. COST BENEFIT ANALYSIS INPUTS

COMPANY: PENNSYLVANIA POWER & LIGHT COMPANY
PROGRAM: WRAP-ACTIVITY A
YEAR FROM: 1985
YEAR TO: 1998

t	YEAR	ENERGY SAVINGS KWH (E)	PARTICIPANT AVERAGE ENERGY PRICE $ PER KWH (ACE)	UTILITY AVOIDED ENERGY COST $ PER KWH (MCE)	PARTICIPANT DEMAND SAVINGS KW (D)	UTILITY CAPACITY SAVINGS KW (G)	PARTICIPANT AVERAGE DEMAND COST $ PER KW (ACD)	UTILITY AVOIDED CAPACITY COST $ PER KW (MCD)	PARTICIPANT COST $ (PC)	TAX CREDITS $ (TC)
1	1985	1000000.00	0.0650	0.0508	200.00	200.0	0.0000	0.0000	-170000.00	0.00
2	1986	2000000.00	0.0730	0.0516	400.00	500.0	0.0000	0.0000	-340000.00	0.00
3	1987	3000000.00	0.0760	0.0564	600.00	800.0	0.0000	0.0000	-510000.00	0.00
4	1988	4000000.00	0.0760	0.0690	800.00	1100.0	0.0000	0.0000	-680000.00	0.00
5	1989	5000000.00	0.0760	0.0865	1000.00	1300.0	0.0000	0.0000	-850000.00	0.00
6	1990	5000000.00	0.0800	0.1034	1000.00	1300.0	0.0000	0.0000	-850000.00	0.00
7	1991	5000000.00	0.0850	0.1235	1000.00	1300.0	0.0000	0.0000	-850000.00	0.00
8	1992	5000000.00	0.0890	0.1489	1000.00	1300.0	0.0000	0.0000	-850000.00	0.00
9	1993	5000000.00	0.0940	0.1728	1000.00	1300.0	0.0000	0.0000	-850000.00	0.00
10	1994	5000000.00	0.0990	0.1927	1000.00	1300.0	0.0000	0.0000	-850000.00	0.00
11	1995	4000000.00	0.1050	0.2141	800.00	1100.0	0.0000	0.0000	-680000.00	0.00
12	1996	3000000.00	0.1100	0.2321	600.00	800.0	0.0000	0.0000	-510000.00	0.00
13	1997	2000000.00	0.1160	0.2517	400.00	500.0	0.0000	0.0000	-340000.00	0.00
14	1998	1000000.00	0.1230	0.2729	200.00	200.0	0.0000	0.0000	-170000.00	0.00

				DISCOUNT RATES						
t	YEAR	INCENTIVE COST $ (I)	UTILITY COST $ (UC)	PARTICIPANT % (Dp)	NON-PARTIC. % (Dnp)	UTILITY % (Du)	ESCALATION RATE % --	SYSTEM SALES OR DEMAND KWH OR KW (S)	SALES OR DEMAND RATIO % (f)	UNCOLLECTIBLE ACCOUNTS REDUCTION $ (UA)
1	1985	1500000.00	576000.00	9.70	9.70	9.70	0.00	2.394E+10	0.00	0.00
2	1986	1600000.00	256000.00	9.70	9.70	9.70	0.00	2.477E+10	0.00	0.00
3	1987	1700000.00	270000.00	9.70	9.70	9.70	0.00	2.558E+10	0.00	0.00
4	1988	1800000.00	285000.00	9.70	9.70	9.70	0.00	2.650E+10	0.00	0.00
5	1989	1900000.00	300000.00	9.70	9.70	9.70	0.00	2.707E+10	0.00	0.00
6	1990	0.00	0.00	9.70	9.70	9.70	0.00	2.768E+10	0.00	0.00
7	1991	0.00	0.00	9.70	9.70	9.70	0.00	2.837E+10	0.00	0.00
8	1992	0.00	0.00	9.70	9.70	9.70	0.00	2.906E+10	0.00	0.00
9	1993	0.00	0.00	9.70	9.70	9.70	0.00	2.974E+10	0.00	0.00
10	1994	0.00	0.00	9.70	9.70	9.70	0.00	3.036E+10	0.00	0.00
11	1995	0.00	0.00	9.70	9.70	9.70	0.00	3.097E+10	0.00	0.00
12	1996	0.00	0.00	9.70	9.70	9.70	0.00	3.159E+10	0.00	0.00
13	1997	0.00	0.00	9.70	9.70	9.70	0.00	3.220E+10	0.00	0.00
14	1998	0.00	0.00	9.70	9.70	9.70	0.00	3.282E+10	0.00	0.00

78

DM 046891

TABLE 2a

FORM ACR-5. COST BENEFIT ANALYSIS RESULTS
CUMULATIVE PRESENT WORTHED DOLLARS

COMPANY: PENNSYLVANIA POWER & LIGHT COMPANY
PROGRAM: WRAP-ACTIVITY A

PERIOD OF ANALYSIS BEGINNING YEAR	PERIOD OF ANALYSIS ENDING YEAR	TOTAL UTILITY BENEFITS $ (Bu)	TOTAL UTILITY COSTS $ (Cu)	REVENUE REDUCTION COST $ (Cr)	PARTICIPANT REVENUE REQUIREMENT $ (Rp)	TOTAL PARTICIPANT BENEFITS $ (Bp)	TOTAL PARTICIPANT COSTS $ (Cp)	TOTAL ALL RATEPAYERS BENEFITS $ (Ba)	TOTAL ALL RATEPAYERS COSTS $ (Ca)
1985	1998	3531575.63	1456767.27	2446794.28	0.00	9493442.79	-4864480.27	3531575.63	-3407713.00

DISCOUNTED PAYBACK PERIOD	CUMULATIVE NET PRESENT VALUE: PARTICIPANT $ (NPVP)	NON-PARTIC. $ (NPVNP)	UTILITY $ (NPVU)	RATEPAYERS $ (NPVA)	BENEFIT-COST RATIO: PARTICIPANT -- (BCRP)	NON-PARTIC. -- (BCRNP)	UTILITY -- (BCRU)	RATEPAYERS -- (BCRA)	RATE IMPACT NON-PARTIC. $ PER KWH (RIMnp)
.	14357923.06	-7418634.43	2074808.36	6939288.64	∞	0.3225	2.4243	∞	0.00001852

DM 046892

79

TABLE 3a

COST BENEFIT ANALYSIS RESULTS
CUMULATIVE PRESENT WORTHED DOLLARS

COMPANY: PENNSYLVANIA POWER & LIGHT COMPANY
PROGRAM: WRAP-ACTIVITY A
YEAR FROM: 1985
YEAR TO: 1998

t	YEAR	TOTAL UTILITY BENEFITS $ (SBuPV)	TOTAL UTILITY COSTS $ (SCuPV)	TOTAL INCENTIVE COSTS $ (SCiPV)	REVENUE REDUCTION COST $ (SCrPV)	PARTICIPANT REVENUE REQUIREMENT $ (SRpPV)	TOTAL PARTICIPANT BENEFITS $ (SBpPV)	TOTAL PARTICIPANT COSTS $ (SCpPV)	TOTAL RATEPAYERS BENEFITS $ (SBaPV)	TOTAL RATEPAYERS COSTS $ (SCaPV)
1	1985	50800.00	576000.00	1500000.00	65000.00	0.00	1565000.00	-170000.00	50800.00	406000.00
2	1986	144874.75	809363.72	2958523.25	198090.25	0.00	3156613.49	-479936.19	144874.75	329427.53
3	1987	285475.33	1033726.34	4371176.80	387552.02	0.00	4758728.82	-903732.26	285475.33	129994.09
4	1988	494544.11	1249612.59	5734668.89	617830.68	0.00	6352499.57	-1418829.27	494544.11	-169216.68
5	1989	793192.11	1456767.27	7046648.51	880226.61	0.00	7926875.12	-2005767.52	793192.11	-549000.25
6	1990	1118621.97	1456767.27	7046648.51	1132009.87	0.00	8178658.38	-2540806.95	1118621.97	-1084039.68
7	1991	1472943.22	1456767.27	7046648.51	1375874.69	0.00	8422523.21	-3028536.60	1472943.22	-1571769.33
8	1992	1862363.27	1456767.27	7046648.51	1608637.52	0.00	8655286.03	-3473139.75	1862363.27	-2016372.48
9	1993	2274328.65	1456767.27	7046648.51	1832739.05	0.00	8879387.57	-3878429.76	2274328.65	-2421662.50
10	1994	2693114.57	1456767.27	7046648.51	2047891.14	0.00	9094539.65	-4247882.83	2693114.57	-2791115.57
11	1995	3032435.29	1456767.27	7046648.51	2214302.51	0.00	9260951.03	-4517310.78	3032435.29	-3060543.51
12	1996	3283926.90	1456767.27	7046648.51	2333492.85	0.00	9380141.36	-4701514.02	3283926.90	-3244746.75
13	1997	3449669.32	1456767.27	7046648.51	2409877.91	0.00	9456526.42	-4813457.65	3449669.32	-3356690.38
14	1998	3531575.63	1456767.27	7046648.51	2446794.28	0.00	9493442.79	-4864480.27	3531575.63	-3407713.00

		---------- CUMULATIVE NET PRESENT VALUE ----------				*-------------- BENEFIT-COST RATIO --------------*				RATE IMPACT
t	YEAR	PARTICIPANT $ (SNPVp)	NON-PARTIC. $ (SNPVnp)	UTILITY $ (SNPVu)	RATEPAYERS $ (SNPVa)	PARTICIPANT -- (BCRp)	NON-PARTIC. -- (BCRNp)	UTILITY -- (BCRu)	RATEPAYERS -- (BCRa)	NON-PARTIC. $ PER KWH (RIMnp)
1	1985	1735000.00	-2090200.00	-525200.00	-355200.00	-9.2059	0.0237	0.0882	0.1251	0.00008731
2	1986	3636549.68	-3821102.46	-664488.97	-184552.78	-6.5772	0.0365	0.1790	0.4398	0.00007845
3	1987	5662461.07	-5506979.83	-748251.02	155481.24	-5.2656	0.0493	0.2762	2.1961	0.00007413
4	1988	7771328.83	-7107568.04	-755068.48	663760.79	-4.4773	0.0651	0.3958	-2.9225	0.00007052
5	1989	9932642.64	-8590450.28	-663575.16	1342192.36	-3.9520	0.0845	0.5445	-1.4448	0.00006719
6	1990	10719465.33	-8516803.67	-338145.30	2202661.65	-3.2189	0.1161	0.7679	-1.0319	0.00005476
7	1991	11451059.81	-8406347.25	16175.95	3044712.55	-2.7811	0.1491	1.0111	-0.9371	0.00004571
8	1992	12128425.78	-8249690.03	405596.00	3878735.75	-2.4921	0.1842	1.2784	-0.9236	0.00003874
9	1993	12757817.33	-8061826.18	817561.38	4695991.15	-2.2894	0.2200	1.5612	-0.9392	0.00003322
10	1994	13342422.48	-7858192.35	1236347.30	5484230.14	-2.1410	0.2552	1.8487	-0.9649	0.00002878
11	1995	13778261.80	-7685283.00	1575668.02	6092978.80	-2.0501	0.2829	2.0816	-0.9908	0.00002528
12	1996	14081655.38	-7552981.73	1827159.63	6528673.65	-1.9951	0.3030	2.2543	-1.0121	0.00002250
13	1997	14269984.08	-7463624.37	1992902.05	6806359.70	-1.9646	0.3161	2.3680	-1.0277	0.00002029
14	1998	14357923.06	-7418634.43	2074808.36	6939288.64	-1.9516	0.3225	2.4243	-1.0363	0.00001852

TABLE 1b

FORM ACR-4. COST BENEFIT ANALYSIS INPUTS

COMPANY: PENNSYLVANIA POWER & LIGHT COMPANY
PROGRAM: WRAP-ACTIVITY # (INDIVIDUALLY METERED)
YEAR FROM: 1985 ·B
YEAR TO: 1998

#	YEAR	ENERGY SAVINGS KWH (E)	PARTICIPANT AVERAGE ENERGY PRICE $ PER KWH (ACE)	UTILITY AVOIDED ENERGY COST $ PER KWH (WCE)	PARTICIPANT DEMAND SAVINGS KW (D)	UTILITY CAPACITY SAVINGS KW (G)	PARTICIPANT AVERAGE DEMAND COST $ PER KW (ACD)	UTILITY AVOIDED CAPACITY COST $ PER KW (WCD)	PARTICIPANT COST $ (PC)	TAX CREDITS $ (TC)
1	1985	480000.00	0.0650	0.0508	120.00	160.0	0.0000	0.0000	0.00	0.00
2	1986	960000.00	0.0730	0.0516	240.00	300.0	0.0000	0.0000	0.00	0.00
3	1987	1440000.00	0.0760	0.0564	360.00	480.0	0.0000	0.0000	0.00	0.00
4	1988	1920000.00	0.0760	0.0690	480.00	620.0	0.0000	0.0000	0.00	0.00
5	1989	2400000.00	0.0760	0.0865	600.00	780.0	0.0000	0.0000	0.00	0.00
6	1990	2400000.00	0.0800	0.1034	600.00	780.0	0.0000	0.0000	0.00	0.00
7	1991	2400000.00	0.0850	0.1235	600.00	780.0	0.0000	0.0000	0.00	0.00
8	1992	2400000.00	0.0890	0.1489	600.00	780.0	0.0000	0.0000	0.00	0.00
9	1993	2400000.00	0.0940	0.1728	600.00	780.0	0.0000	0.0000	0.00	0.00
10	1994	2400000.00	0.0990	0.1927	600.00	780.0	0.0000	0.0000	0.00	0.00
11	1995	1920000.00	0.1050	0.2141	480.00	620.0	0.0000	0.0000	0.00	0.00
12	1996	1440000.00	0.1100	0.2321	360.00	480.0	0.0000	0.0000	0.00	0.00
13	1997	960000.00	0.1160	0.2517	240.00	300.0	0.0000	0.0000	0.00	0.00
14	1998	480000.00	0.1230	0.2729	120.00	160.0	0.0000	0.0000	0.00	0.00

#	YEAR	INCENTIVE COST $ (I)	UTILITY COST $ (UC)	DISCOUNT RATES PARTICIPANT % (Dp)	NON-PARTIC. % (Dnp)	UTILITY % (Du)	ESCALATION RATE % --	SYSTEM SALES OR DEMAND KWH OR KW (S)	SALES OR DEMAND RATIO % (f)	UNCOLLECTIBLE ACCOUNTS REDUCTION $ (UA)
1	1985	285000.00	56000.00	9.70	9.70	9.70	0.00	2.394E+10	0.00	0.00
2	1986	300000.00	39000.00	9.70	9.70	9.70	0.00	2.477E+10	0.00	0.00
3	1987	315000.00	41000.00	9.70	9.70	9.70	0.00	2.558E+10	0.00	0.00
4	1988	330000.00	43000.00	9.70	9.70	9.70	0.00	2.650E+10	0.00	0.00
5	1989	345000.00	46000.00	9.70	9.70	9.70	0.00	2.707E+10	0.00	0.00
6	1990	0.00	0.00	9.70	9.70	9.70	0.00	2.768E+10	0.00	0.00
7	1991	0.00	0.00	9.70	9.70	9.70	0.00	2.837E+10	0.00	0.00
8	1992	0.00	0.00	9.70	9.70	9.70	0.00	2.906E+10	0.00	0.00
9	1993	0.00	0.00	9.70	9.70	9.70	0.00	2.974E+10	0.00	0.00
10	1994	0.00	0.00	9.70	9.70	9.70	0.00	3.036E+10	0.00	0.00
11	1995	0.00	0.00	9.70	9.70	9.70	0.00	3.097E+10	0.00	0.00
12	1996	0.00	0.00	9.70	9.70	9.70	0.00	3.159E+10	0.00	0.00
13	1997	0.00	0.00	9.70	9.70	9.70	0.00	3.220E+10	0.00	0.00
14	1998	0.00	0.00	9.70	9.70	9.70	0.00	3.282E+10	0.00	0.00

TABLE 2b

FORM ACR-5. COST BENEFIT ANALYSIS RESULTS
CUMULATIVE PRESENT WORTHED DOLLARS

COMPANY: PENNSYLVANIA POWER & LIGHT COMPANY
PROGRAM: WRAP-ACTIVITY B (INDIVIDUALLY METERED)

PERIOD OF ANALYSIS BEGINNING YEAR	ENDING YEAR	TOTAL UTILITY BENEFITS $ (Bu)	TOTAL UTILITY COSTS $ (Cu)	REVENUE REDUCTION COST $ (Cr)	PARTICIPANT REVENUE REQUIREMENT $ (Rp)	TOTAL PARTICIPANT BENEFITS $ (Bp)	TOTAL PARTICIPANT COSTS $ (Cp)	TOTAL ALL RATEPAYERS BENEFITS $ (Ba)	TOTAL ALL RATEPAYERS COSTS $ (Ca)
1985	1998	1695156.30	189957.41	1174461.25	0.00	2482892.19	0.00	1695156.30	189957.41

DISCOUNTED PAYBACK PERIOD	CUMULATIVE NET PRESENT VALUE: PARTICIPANT $ (NPVP)	NON-PARTIC. $ (NPVNP)	UTILITY $ (NPVU)	RATEPAYERS $ (NPVA)	BENEFIT-COST RATIO: PARTICIPANT -- (BCRP)	NON-PARTIC. -- (BCRNP)	UTILITY -- (BCRU)	RATEPAYERS -- (BCRA)	RATE IMPACT NON-PARTIC. $ PER KWH (RIMnp)
.	2482892.19	-977693.29	1505198.89	1505198.89	∞	0.6342	8.9239	8.9239	0.00000244

82

DM 046895

TABLE 3b

1

COST BENEFIT ANALYSIS RESULTS
CUMULATIVE PRESENT WORTHED DOLLARS

COMPANY: PENNSYLVANIA POWER & LIGHT COMPANY
PROGRAM: WRAP-ACTIVITY B (INDIVIDUALLY METERED)
YEAR FROM: 1985
YEAR TO: 1998

t	YEAR	TOTAL UTILITY BENEFITS $ (SBuPV)	TOTAL UTILITY COSTS $ (SCuPV)	TOTAL INCENTIVE COSTS $ (SCiPV)	REVENUE REDUCTION COST $ (SCrPV)	PARTICIPANT REVENUE REQUIREMENT $ (SRpPV)	TOTAL PARTICIPANT BENEFITS $ (SBpPV)	TOTAL PARTICIPANT COSTS $ (SCpPV)	TOTAL RATEPAYERS BENEFITS $ (SBaPV)	TOTAL RATEPAYERS COSTS $ (SCaPV)
1	1985	24384.00	56000.00	285000.00	31200.00	0.00	316200.00	0.00	24384.00	56000.00
2	1986	69539.88	91551.50	558473.11	95083.32	0.00	653556.43	0.00	69539.88	91551.50
3	1987	137028.16	125621.38	820229.50	186024.97	0.00	1006254.47	0.00	137028.16	125621.38
4	1988	237381.17	158193.69	1070203.05	296558.73	0.00	1366761.78	0.00	237381.17	158193.69
5	1989	380732.21	189957.41	1308430.93	422508.77	0.00	1730939.70	0.00	380732.21	189957.41
6	1990	536938.55	189957.41	1308430.93	543364.74	0.00	1851795.67	0.00	536938.55	189957.41
7	1991	707012.75	189957.41	1308430.93	660419.85	0.00	1968850.78	0.00	707012.75	189957.41
8	1992	893934.37	189957.41	1308430.93	772146.01	0.00	2080576.94	0.00	893934.37	189957.41
9	1993	1091677.75	189957.41	1308430.93	879714.75	0.00	2188145.68	0.00	1091677.75	189957.41
10	1994	1292694.99	189957.41	1308430.93	982987.75	0.00	2291418.68	0.00	1292694.99	189957.41
11	1995	1455568.94	189957.41	1308430.93	1062865.21	0.00	2371296.14	0.00	1455568.94	189957.41
12	1996	1576284.91	189957.41	1308430.93	1120076.57	0.00	2428507.50	0.00	1576284.91	189957.41
13	1997	1655841.27	189957.41	1308430.93	1156741.40	0.00	2465172.33	0.00	1655841.27	189957.41
14	1998	1695156.30	189957.41	1308430.93	1174461.25	0.00	2482892.19	0.00	1695156.30	189957.41

		---------- CUMULATIVE NET PRESENT VALUE ----------				*--------------- BENEFIT-COST RATIO ---------------*				RATE IMPACT
t	YEAR	PARTICIPANT $ (SNPVp)	NON-PARTIC. $ (SNPVnp)	UTILITY $ (SNPVu)	RATEPAYERS $ (SNPVa)	PARTICIPANT -- (BCRp)	NON-PARTIC. -- (BCRNp)	UTILITY -- (BCRu)	RATEPAYERS -- (BCRa)	NON-PARTIC. $ PER KWH (RIMnp)
1	1985	316200.00	-347816.00	-31616.00	-31616.00	0.0000	0.0655	0.4354	0.4354	0.00001453
2	1986	653556.43	-675568.05	-22011.62	-22011.62	0.0000	0.0933	0.7596	0.7596	0.00001387
3	1987	1006254.47	-994847.70	11406.77	11406.77	0.0000	0.1211	1.0908	1.0908	0.00001339
4	1988	1366761.78	-1287574.30	79187.48	79187.48	0.0000	0.1557	1.5006	1.5006	0.00001277
5	1989	1730939.70	-1540164.90	190774.80	190774.80	0.0000	0.1982	2.0043	2.0043	0.00001205
6	1990	1851795.67	-1504814.53	346981.13	346981.13	0.0000	0.2630	2.8266	2.8266	0.00000967
7	1991	1968850.78	-1451795.45	517055.33	517055.33	0.0000	0.3275	3.7220	3.7220	0.00000789
8	1992	2080576.94	-1376599.98	703976.96	703976.96	0.0000	0.3937	4.7060	4.7060	0.00000646
9	1993	2188145.68	-1286425.34	901720.34	901720.34	0.0000	0.4591	5.7470	5.7470	0.00000530
10	1994	2291418.68	-1188681.10	1102737.58	1102737.58	0.0000	0.5210	6.8052	6.8052	0.00000435
11	1995	2371296.14	-1105684.61	1265611.53	1265611.53	0.0000	0.5683	7.6626	7.6626	0.00000364
12	1996	2428507.50	-1042180.00	1386327.50	1386327.50	0.0000	0.6020	8.2981	8.2981	0.00000311
13	1997	2465172.33	-999288.47	1465883.86	1465083.86	0.0000	0.6236	8.7169	8.7169	0.00000272
14	1998	2482892.19	-977693.29	1505198.89	1505198.89	0.0000	0.6342	8.9239	8.9239	0.00000244

83

DM 046898

TABLE 1c

FORM ACR-4. COST BENEFIT ANALYSIS INPUTS

COMPANY: PENNSYLVANIA POWER & LIGHT COMPANY
PROGRAM: WRAP-ACTIVITY U (MASTER METERED)
YEAR FROM: 1985
YEAR TO: 1998

t	YEAR	ENERGY SAVINGS KWH (E)	PARTICIPANT AVERAGE ENERGY PRICE $ PER KWH (ACE)	UTILITY AVOIDED ENERGY COST $ PER KWH (MCE)	PARTICIPANT DEMAND SAVINGS KW (D)	UTILITY CAPACITY SAVINGS KW (G)	PARTICIPANT AVERAGE DEMAND COST $ PER KW (ACD)	UTILITY AVOIDED CAPACITY COST $ PER KW (MCD)	PARTICIPANT COST $ (PC)	TAX CREDITS $ (TC)
1	1985	150000.00	0.0410	0.0508	30.00	40.0	0.0000	0.0000	-23462.00	306.00
2	1986	300000.00	0.0440	0.0516	60.00	80.0	0.0000	0.0000	-46924.00	611.00
3	1987	450000.00	0.0450	0.0564	90.00	120.0	0.0000	0.0000	-70386.00	917.00
4	1988	600000.00	0.0450	0.0690	120.00	160.0	0.0000	0.0000	-93848.00	1223.00
5	1989	750000.00	0.0450	0.0865	150.00	200.0	0.0000	0.0000	-117310.00	1529.00
6	1990	750000.00	0.0470	0.1034	150.00	200.0	0.0000	0.0000	-117310.00	1529.00
7	1991	750000.00	0.0500	0.1235	150.00	200.0	0.0000	0.0000	-117310.00	1529.00
8	1992	750000.00	0.0530	0.1489	150.00	200.0	0.0000	0.0000	-117310.00	1529.00
9	1993	750000.00	0.0560	0.1728	150.00	200.0	0.0000	0.0000	-117310.00	1529.00
10	1994	750000.00	0.0590	0.1927	150.00	200.0	0.0000	0.0000	-117310.00	1529.00
11	1995	600000.00	0.0620	0.2141	120.00	160.0	0.0000	0.0000	-93848.00	1223.00
12	1996	450000.00	0.0650	0.2321	90.00	120.0	0.0000	0.0000	-70386.00	917.00
13	1997	300000.00	0.0690	0.2517	60.00	80.0	0.0000	0.0000	-46924.00	611.00
14	1998	150000.00	0.0730	0.2729	30.00	40.0	0.0000	0.0000	-23462.00	306.00

t	YEAR	INCENTIVE COST $ (I)	UTILITY COST $ (UC)	DISCOUNT RATES PARTICIPANT % (Dp)	NON-PARTIC. % (Dnp)	UTILITY % (Du)	ESCALATION RATE % --	SYSTEM SALES OR DEMAND KWH OR KW (S)	SALES OR DEMAND RATIO % (f)	UNCOLLECTIBLE ACCOUNTS REDUCTION $ (UA)
1	1985	15000.00	14000.00	9.70	9.70	9.70	0.00	2.394E+10	0.00	0.00
2	1986	15750.00	10000.00	9.70	9.70	9.70	0.00	2.477E+10	0.00	0.00
3	1987	16500.00	10000.00	9.70	9.70	9.70	0.00	2.558E+10	0.00	0.00
4	1988	17250.00	11000.00	9.70	9.70	9.70	0.00	2.650E+10	0.00	0.00
5	1989	18000.00	11000.00	9.70	9.70	9.70	0.00	2.707E+10	0.00	0.00
6	1990	0.00	0.00	9.70	9.70	9.70	0.00	2.768E+10	0.00	0.00
7	1991	0.00	0.00	9.70	9.70	9.70	0.00	2.837E+10	0.00	0.00
8	1992	0.00	0.00	9.70	9.70	9.70	0.00	2.906E+10	0.00	0.00
9	1993	0.00	0.00	9.70	9.70	9.70	0.00	2.974E+10	0.00	0.00
10	1994	0.00	0.00	9.70	9.70	9.70	0.00	3.036E+10	0.00	0.00
11	1995	0.00	0.00	9.70	9.70	9.70	0.00	3.097E+10	0.00	0.00
12	1996	0.00	0.00	9.70	9.70	9.70	0.00	3.159E+10	0.00	0.00
13	1997	0.00	0.00	9.70	9.70	9.70	0.00	3.220E+10	0.00	0.00
14	1998	0.00	0.00	9.70	9.70	9.70	0.00	3.282E+10	0.00	0.00

84

TABLE 2c

FORM ACR-5. COST BENEFIT ANALYSIS RESULTS
CUMULATIVE PRESENT WORTHED DOLLARS

COMPANY: PENNSYLVANIA POWER & LIGHT COMPANY
PROGRAM: WRAP-ACTIVITY B (MASTER METERED)

PERIOD OF ANALYSIS BEGINNING YEAR	PERIOD OF ANALYSIS ENDING YEAR	TOTAL UTILITY BENEFITS $ (Bu)	TOTAL UTILITY COSTS $ (Cu)	REVENUE REDUCTION COST $ (Cr)	PARTICIPANT REVENUE REQUIREMENT $ (Rp)	TOTAL PARTICIPANT BENEFITS $ (Bp)	TOTAL PARTICIPANT COSTS $ (Cp)	TOTAL ALL RATEPAYERS BENEFITS $ (Ba)	TOTAL ALL RATEPAYERS COSTS $ (Ca)
1985	1998	529736.34	47353.62	217930.04	0.00	295243.66	-671355.51	529736.34	-632751.04

DISCOUNTED PAYBACK PERIOD	CUMULATIVE NET PRESENT VALUE: PARTICIPANT $ (NPVP)	NON-PARTIC. $ (NPVNP)	UTILITY $ (NPVU)	RATEPAYERS $ (NPVA)	BENEFIT-COST RATIO: PARTICIPANT -- (BCRP)	NON-PARTIC. -- (BCRNP)	UTILITY -- (BCRU)	RATEPAYERS -- (BCRA)	RATE IMPACT NON-PARTIC. $ PER KWH (RIMnp)
.	966599.17	195888.21	482382.72	1162487.38	[illegible]	1.5868	11.1868	[illegible]	-0.00000049

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85

TABLE 3c

COST BENEFIT ANALYSIS RESULTS
CUMULATIVE PRESENT WORTHED DOLLARS

COMPANY: PENNSYLVANIA POWER & LIGHT COMPANY
PROGRAM: WRAP-ACTIVITY 8 (MASTER METERED)
YEAR FROM: 1985
YEAR TO: 1998

t	YEAR	TOTAL UTILITY BENEFITS $ (SBuPV)	TOTAL UTILITY COSTS $ (SCuPV)	TOTAL INCENTIVE COSTS $ (SCiPV)	REVENUE REDUCTION COST $ (SCrPV)	PARTICIPANT REVENUE REQUIREMENT $ (SRpPV)	TOTAL PARTICIPANT BENEFITS $ (SBpPV)	TOTAL PARTICIPANT COSTS $ (SCpPV)	TOTAL RATEPAYERS BENEFITS $ (SBaPV)	TOTAL RATEPAYERS COSTS $ (SCaPV)
1	1985	7620.00	14000.00	15000.00	6150.00	0.00	21456.00	-23462.00	7620.00	-9768.00
2	1986	21731.21	23115.77	29357.34	18182.82	0.00	48403.13	-66236.84	21731.21	-43984.04
3	1987	42821.30	31425.50	43068.39	35010.01	0.00	79703.38	-124725.68	42821.30	-94925.16
4	1988	74181.62	39757.95	56135.19	55462.39	0.00	114148.97	-195815.13	74181.62	-158608.57
5	1989	118978.82	47353.62	68564.47	78767.30	0.00	150938.95	-276819.52	118978.82	-233073.09
6	1990	167793.30	47353.62	68564.47	100955.70	0.00	174089.80	-350661.25	167793.30	-307877.26
7	1991	220941.48	47353.62	68564.47	122473.18	0.00	196484.62	-417973.68	220941.48	-376067.03
8	1992	279354.49	47353.62	68564.47	143264.92	0.00	218076.12	-479334.15	279354.49	-438227.26
9	1993	341149.30	47353.62	68564.47	163291.01	0.00	238831.26	-535268.94	341149.30	-494891.10
10	1994	403967.19	47353.62	68564.47	182524.30	0.00	258729.13	-586257.81	403967.19	-546544.55
11	1995	454865.29	47353.62	68564.47	197263.60	0.00	273953.00	-623442.03	454865.29	-584213.35
12	1996	492589.03	47353.62	68564.47	207828.19	0.00	284848.80	-648864.25	492589.03	-609966.77
13	1997	517450.40	47353.62	68564.47	214643.59	0.00	291865.36	-664313.78	517450.40	-625617.47
14	1998	529736.34	47353.62	68564.47	217930.04	0.00	295243.66	-671355.51	529736.34	-632751.04

		CUMULATIVE NET PRESENT VALUE				BENEFIT-COST RATIO				RATE IMPACT
t	YEAR	PARTICIPANT $ (SNPVp)	NON-PARTIC. $ (SNPVnp)	UTILITY $ (SNPVu)	RATEPAYERS $ (SNPVa)	PARTICIPANT -- (BCRp)	NON-PARTIC. -- (BCRNp)	UTILITY -- (BCRu)	RATEPAYERS -- (BCRa)	NON-PARTIC. $ PER KWH (RIMnp)
1	1985	44918.00	-27530.00	-6380.00	17388.00	-0.9145	0.2168	0.5443	-0.7801	0.00000115
2	1986	114639.97	-48924.71	-1384.56	65715.26	-0.7308	0.3076	0.9401	-0.4941	0.00000100
3	1987	204429.06	-66682.60	11395.80	137746.46	-0.6390	0.3910	1.3626	-0.4511	0.00000090
4	1988	309964.10	-77173.91	34423.67	232790.19	-0.5829	0.4901	1.8658	-0.4677	0.00000077
5	1989	427758.47	-75706.57	71625.20	352051.90	-0.5453	0.6111	2.5126	-0.5105	0.00000059
6	1990	524751.05	-49080.49	120439.68	475670.56	-0.4965	0.7737	3.5434	-0.5450	0.00000032
7	1991	614458.30	-17449.79	173587.86	597008.52	-0.4701	0.9268	4.6658	-0.5875	0.00000009
8	1992	697410.26	20171.49	232000.87	717581.75	-0.4550	1.0778	5.8993	-0.6375	-0.00000009
9	1993	774100.19	61940.20	293795.68	836040.39	-0.4462	1.2218	7.2043	-0.6893	-0.00000026
10	1994	844986.94	105524.79	356613.57	950511.73	-0.4413	1.3536	8.5309	-0.7391	-0.00000039
11	1995	897395.03	141683.61	407511.67	1039078.64	-0.4394	1.4524	9.6057	-0.7786	-0.00000047
12	1996	933713.05	168842.75	445235.41	1102555.80	-0.4390	1.5215	10.4024	-0.8076	-0.00000050
13	1997	956179.15	186888.72	470096.78	1143067.87	-0.4393	1.5654	10.9274	-0.8271	-0.00000051
14	1998	966599.17	195888.21	482382.72	1162487.38	-0.4398	1.5868	11.1868	-0.8372	-0.00000049

DM 046899

96

RESIDENTIAL NEW CONSTRUCTION–
OFF-PEAK SUPPLEMENTAL ELECTRIC STORAGE SYSTEM (SESS) HEAT PUMPS

Introduction

The Supplemental Electric Storage System (SESS) Heat Pump Program encourages application of off-peak thermal storage installations which directly contribute to the demand management portion of the corporate managed load growth objectives. The program primarily focuses on the installation of electric space and water heating systems in the new home market.

SESS Heat Pump Program Procedure

PP&L has implemented the program through the following general procedures:

New Construction

- Contact builders, developers, installers and customers to encourage installation of efficient electric space heating and water heating systems with an emphasis on off-peak applications.

- Provide a cash grant to new single home, town house and twin home customers who install a supplemental electric storage system (SESS) heat pump space heating system. This grant is intended to help offset the higher installation costs of this system.

- Support the residential new construction program by systemwide newspaper advertising, bill inserts, handout literature, participation in fairs and shows, PP&L displays and meeting with appropriate allies in the residential construction industry.

Existing Customer Conversions

- Encourage the installation of energy-efficient electric space and water heating systems, emphasize off-peak applications, with customers making a change in space or water heating equipment.

Space Heating

- Contact customers planning to replace their present fossil-fired system. Those customers with warm air furnaces needing replacement or desirous of adding central air conditioning, will be informed of the benefits of heat pumps by the consultant.

- Inform customers who do not care to continue heating via warm air or hot water distribution systems about the electric resistance space heating option.

- Encourage the installation of off-peak electric space heating systems. Those who install an SESS heat pump space heating system will be eligible to receive a cash grant. This grant is provided to help offset the higher installation costs of this system and is available only when the conversion is being made from an existing fossil-fired space heating system.

Water Heating

- Meet with dealers, installers, and customers to relate the benefits and options available by converting to electric water heating. Option include off-peak electric water heating, conventional electric water heating, a heat-pump water heater or a solar-assisted electric water heater. Customers who convert their present fossil-fired domestic water heating systems to off-peak electric water heating will be eligible for the off-peak water heating provision of the RS rate.

- Support residential conversion efforts by systemwide newspaper advertising, bill inserts, handout literature, participation in fairs and shows, PP&L displays and meetings with appropriate allies in the space heating industry.

Basic Assumptions

Table 4A lists the input data used in the SESS program analysis, which was based on the major assumptions listed below:

- Promotional period is assumed for the 1985-1989 five-year period. Participating customers fully recover the cost of their investment in the 1985-1999 period.

- Participants Demand and Energy Savings based on:

  -- Increasing the total program participation from 300 customers in 1985 to 2,475 in 1989.
  -- 1-3KW on-peak demand reduction per participant (3KW at time of winter system peak).
  -- Installing an 'SESS' system compared to a 'conventional heat pump' results in a 2,000 KWH on-peak energy reduction and a 2,900 KWH off-peak energy increase per participant, annually. The net increase of 900 KWH represents heating system losses. These weather normalized values are based on an average 1,800 square foot home.

- Participants Demand and Energy Payments (revenue reduction) based on:

  -- 1985 to 1989 energy rates as per proposed RS and RTS rate schedules as filed with the PUC on July, 1984.
  -- 1990 to 1999 energy rates escalated at 5.5% annually.
  -- Demand charge applied for RTS rate.

- Utility Avoided Energy Cost (MCE) equal to PP&L's incremental value of energy increased by 9.4% to account for losses, and represents PP&L's CSO.

- Avoided Capacity Costs (MCD) are zero due to PP&L's adequate capacity situation until 2000.
- Participants' incremental cost to install a SESS compared to a conventional heat pump is $2,310 in 1985. This amount is assumed to escalate at 5% per year.
- Utility's Cost (UC) include all costs associated with program less incentive. Incentive cost (I) starts at $1,200 in 1985 and decreases to $0 by 1990.
- Participant's 1985 annual savings under the RTS rate is approximately $220.00 and increases to approximately $300.00 by 1989. After 1989, the savings escalate at 5.5%.
- Based on heating system cost differential, the PP&L grant, and the RTS rate savings, the participant's payback period increases from five years in 1985 to eight years in 1989.
- Discount rate for all parties equal to PP&L's after tax cost of money (i.e. 9.7%).

Analysis of Results for SESS Program

The results of applying the PUC Methodology to the SESS program are provided in the PUC's format on Table 4B, with additional detail on Table 4C. As shown, the SESS program is expected to provide present worth benefits to the participant. The non-participant and PP&L, however, do not benefit. This is due to the fact that the reduction in PP&L's CSO is minimal. The increase in off-peak energy consumption significantly offsets any decrease in on-peak energy consumption due to the SESS heating storage losses. Since the non-participant's negative net present value is substantial, the program is a net cost to all ratepayers as a whole.

TABLE 4A

8:18:53 MARCH 22, 1985

FORM ACR-4. COST BENEFIT ANALYSIS INPUTS

COMPANY: PENNSYLVANIA POWER & LIGHT COMPANY
PROGRAM: SESS
YEAR FROM: 1985
YEAR TO: 1999

t	YEAR	REVENUE REDUCTION COST $ (Cr)	TOTAL UTILITY BENEFITS $ (Bu)	PARTICIPANT DEMAND SAVINGS KW (D)	UTILITY CAPACITY SAVINGS KW (G)	PARTICIPANT AVERAGE DEMAND COST $ PER KW (ACD)	UTILITY AVOIDED CAPACITY COST $ PER KW (MCD)	PARTICIPANT COST $ (PC)	TAX CREDITS $ (TC)
1	1985	66225.0000	-766.0000	0.00	0.0	0.0000	0.0000	693000.00	0.00
2	1986	196490.0000	-272.0000	0.00	0.0	0.0000	0.0000	970400.00	0.00
3	1987	360816.0000	2599.0000	0.00	0.0	0.0000	0.0000	1273000.00	0.00
4	1988	541224.0000	9224.0000	0.00	0.0	0.0000	0.0000	1604400.00	0.00
5	1989	744183.0000	37805.0000	0.00	0.0	0.0000	0.0000	1895400.00	0.00
6	1990	785120.0000	46238.0000	0.00	0.0	0.0000	0.0000	0.00	0.00
7	1991	828284.0000	91082.0000	0.00	0.0	0.0000	0.0000	0.00	0.00
8	1992	873848.0000	86304.0000	0.00	0.0	0.0000	0.0000	0.00	0.00
9	1993	921913.0000	105741.0000	0.00	0.0	0.0000	0.0000	0.00	0.00
10	1994	972626.0000	134586.0000	0.00	0.0	0.0000	0.0000	0.00	0.00
11	1995	1026110.0000	124800.0000	0.00	0.0	0.0000	0.0000	0.00	0.00
12	1996	1082540.0000	132529.0000	0.00	0.0	0.0000	0.0000	0.00	0.00
13	1997	1142089.0000	140285.0000	0.00	0.0	0.0000	0.0000	0.00	0.00
14	1998	1204904.0000	148758.0000	0.00	0.0	0.0000	0.0000	0.00	0.00
15	1999	1271160.0000	157638.0000	0.00	0.0	0.0000	0.0000	0.00	0.00

t	YEAR	INCENTIVE COST $ (I)	UTILITY COST $ (UC)	*----------- DISCOUNT RATES ----------* PARTICIPANT % (Dp)	NON-PARTIC. % (Dnp)	UTILITY % (Du)	ESCALATION RATE % --	SYSTEM SALES OR DEMAND KWH OR KW (S)	SALES OR DEMAND RATIO % (f)	UNCOLLECTIBLE ACCOUNTS REDUCTION $ (UA)
1	1985	360000.00	675000.00	9.70	9.70	9.70	0.00	2.394E+10	0.00	0.00
2	1986	320000.00	615000.00	9.70	9.70	9.70	0.00	2.477E+10	0.00	0.00
3	1987	300000.00	555000.00	9.70	9.70	9.70	0.00	2.558E+10	0.00	0.00
4	1988	240000.00	495000.00	9.70	9.70	9.70	0.00	2.650E+10	0.00	0.00
5	1989	270000.00	435000.00	9.70	9.70	9.70	0.00	2.707E+10	0.00	0.00
6	1990	0.00	0.00	9.70	9.70	9.70	0.00	2.768E+10	0.00	0.00
7	1991	0.00	0.00	9.70	9.70	9.70	0.00	2.837E+10	0.00	0.00
8	1992	0.00	0.00	9.70	9.70	9.70	0.00	2.906E+10	0.00	0.00
9	1993	0.00	0.00	9.70	9.70	9.70	0.00	2.974E+10	0.00	0.00
10	1994	0.00	0.00	9.70	9.70	9.70	0.00	3.036E+10	0.00	0.00
11	1995	0.00	0.00	9.70	9.70	9.70	0.00	3.097E+10	0.00	0.00
12	1996	0.00	0.00	9.70	9.70	9.70	0.00	3.159E+10	0.00	0.00
13	1997	0.00	0.00	9.70	9.70	9.70	0.00	3.220E+10	0.00	0.00
14	1998	0.00	0.00	9.70	9.70	9.70	0.00	3.282E+10	0.00	0.00
15	1999	0.00	0.00	9.70	9.70	9.70	0.00	3.347E+10	0.00	0.00

TABLE 48

8:18:53 MARCH 22, 1985

FORM ACR-5. COST BENEFIT ANALYSIS RESULTS
CUMULATIVE PRESENT WORTHED DOLLARS

COMPANY: PENNSYLVANIA POWER & LIGHT COMPANY
PROGRAM: SESS

PERIOD OF ANALYSIS BEGINNING YEAR	PERIOD OF ANALYSIS ENDING YEAR	TOTAL UTILITY BENEFITS $ (Bu)	TOTAL UTILITY COSTS $ (Cu)	REVENUE REDUCTION COST $ (Cr)	PARTICIPANT REVENUE REQUIREMENT $ (Rp)	TOTAL PARTICIPANT BENEFITS $ (Bp)	TOTAL PARTICIPANT COSTS $ (Cp)	TOTAL ALL RATEPAYERS BENEFITS $ (Ba)	TOTAL ALL RATEPAYERS COSTS $ (Ca)
1985	1999	500943.86	2372144.32	5640891.31	0.00	6910125.91	5159551.77	500943.86	7531696.09

DISCOUNTED PAYBACK PERIOD	CUMULATIVE NET PRESENT VALUE: PARTICIPANT $ (NPVP)	NON-PARTIC. $ (NPVNP)	UTILITY $ (NPVU)	RATEPAYERS $ (NPVA)	BENEFIT-COST RATIO: PARTICIPANT -- (BCRP)	NON-PARTIC. -- (BCRNP)	UTILITY -- (BCRU)	RATEPAYERS -- (BCRA)	RATE IMPACT NON-PARTIC. $ PER KWH (RIMnp)
11	1750574.14	-8781326.37	-1871200.46	-7030752.23	1.3393	0.0540	0.2112	0.0665	0.00002023

91

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TABLE 4C

8:18:53 MARCH 22, 1985

COST BENEFIT ANALYSIS RESULTS
CUMULATIVE PRESENT WORTHED DOLLARS

COMPANY: PENNSYLVANIA POWER & LIGHT COMPANY
PROGRAM: SESS
YEAR FROM: 1985
YEAR TO: 1999

t	YEAR	TOTAL UTILITY BENEFITS $ (SBuPV)	TOTAL UTILITY COSTS $ (SCuPV)	TOTAL INCENTIVE COSTS $ (SCiPV)	REVENUE REDUCTION COST $ (SCrPV)	PARTICIPANT REVENUE REQUIREMENT $ (SRpPV)	TOTAL PARTICIPANT BENEFITS $ (SBpPV)	TOTAL PARTICIPANT COSTS $ (SCpPV)	TOTAL RATEPAYERS BENEFITS $ (SBaPV)	TOTAL RATEPAYERS COSTS $ (SCaPV)
1	1985	-766.00	675000.00	360000.00	66225.00	0.00	426225.00	693000.00	-766.00	1368000.00
2	1986	-1013.95	1235619.87	651704.65	245340.77	0.00	897045.42	1577594.35	-1013.95	2813214.22
3	1987	1145.75	1696809.71	900996.45	545169.01	0.00	1446165.46	2635422.57	1145.75	4332232.28
4	1988	8132.89	2071770.03	1082795.40	955143.81	0.00	2037939.21	3850748.52	8132.89	5922518.55
5	1989	34237.83	2372144.32	1269234.61	1465013.77	0.00	2738248.38	5159551.77	34237.83	7531696.09
6	1990	63342.72	2372144.32	1269234.61	1963213.96	0.00	3232448.57	5159551.77	63342.72	7531696.09
7	1991	115605.53	2372144.32	1269234.61	2430432.98	0.00	3707717.59	5159551.77	115605.53	7531696.09
8	1992	160747.92	2372144.32	1269234.61	2995560.12	0.00	4164794.73	5159551.77	160747.92	7531696.09
9	1993	211166.47	2372144.32	1269234.61	3335139.10	0.00	4604373.71	5159551.77	211166.47	7531696.09
10	1994	269664.37	2372144.32	1269234.61	3757091.64	0.00	5027126.25	5159551.77	269664.37	7531696.09
11	1995	319112.32	2372144.32	1269234.61	4164454.45	0.00	5433689.06	5159551.77	319112.32	7531696.09
12	1996	366979.52	2372144.32	1269234.61	4555449.31	0.00	5924583.92	5159551.77	366979.52	7531696.09
13	1997	413167.79	2372144.32	1269234.61	4931477.51	0.00	6200712.12	5159551.77	413167.79	7531696.09
14	1998	457814.99	2372144.32	1269234.61	5293109.04	0.00	6562343.65	5159551.77	457614.99	7531696.09
15	1999	500943.86	2372144.32	1269234.61	5640891.31	0.00	6910125.91	5159551.77	500943.86	7531696.09

		--------- CUMULATIVE NET PRESENT VALUE ---------				*------------- BENEFIT-COST RATIO -------------*				RATE IMPACT
t	YEAR	PARTICIPANT $ (SNPVp)	NON-PARTIC. $ (SNPVnp)	UTILITY $ (SNPVu)	RATEPAYERS $ (SNPVa)	PARTICIPANT -- (BCRp)	NON-PARTIC. -- (BCRNp)	UTILITY -- (BCRu)	RATEPAYERS -- (BCRa)	NON-PARTIC. $ PER KWH (RIMnp)
1	1985	-266775.00	-1101991.00	-675766.00	-1368766.00	0.6150	-0.0007	-0.0011	-0.0006	0.00004603
2	1986	-680548.93	-2133679.24	-1236633.82	-2814228.17	0.5686	-0.0005	-0.0008	-0.0004	0.00004380
3	1987	-1189257.11	-3141829.42	-1695663.96	-4331086.53	0.5487	0.0004	0.0007	0.0003	0.00004229
4	1988	-1812809.31	-4101576.35	-2063637.14	-5914385.66	0.5292	0.0020	0.0039	0.0014	0.00004069
5	1989	-2421303.39	-5076154.87	-2337906.49	-7497458.26	0.5307	0.0067	0.0144	0.0045	0.00003970
6	1990	-1927103.20	-5541250.17	-2308801.60	-7468353.37	0.6265	0.0113	0.0267	0.0084	0.00003563
7	1991	-1451834.18	-5964256.37	-2256538.79	-7416090.56	0.7186	0.0190	0.0487	0.0153	0.00003243
8	1992	-994757.04	-6376191.13	-2211396.40	-7370948.17	0.8072	0.0246	0.0678	0.0213	0.00002994
9	1993	-555170.06	-6765351.55	-2160977.84	-7320529.61	0.8924	0.0303	0.0890	0.0280	0.00002787
10	1994	-132425.52	-7129606.20	-2102479.95	-7262031.72	0.9743	0.0364	0.1137	0.0358	0.00002611
11	1995	274137.29	-7486721.05	-2053032.00	-7212583.77	1.0531	0.0409	0.1345	0.0424	0.00002462
12	1996	665132.15	-7829848.71	-2005164.80	-7164716.57	1.1289	0.0448	0.1547	0.0487	0.00002333
13	1997	1041160.35	-8159688.64	-1958976.52	-7118528.29	1.2018	0.0482	0.1742	0.0549	0.00002218
14	1998	1402791.88	-8476672.98	-1914329.33	-7073881.10	1.2719	0.0512	0.1930	0.0608	0.00002116
15	1999	1750574.14	-8781326.37	-1871200.46	-7030752.23	1.3393	0.0540	0.2112	0.0665	0.00002023

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92

RESIDENTIAL NEW CONSTRUCTION/EXISTING CONVERSION-OFF-PEAK CERAMIC HEATING

Introduction

The Ceramic Storage Room Unit electric storage space heating system is an integral element of PP&L's residential electric heating options programs in the new home and conversion market. The program encourages the installation of energy efficient electric space and water heating systems, emphasizing off-peak applications which directly contribute to the demand management portion of the corporate managed load growth objectives.

Ceramic Storage Room Units - Electric Storage Space Heating Systems Program Procedure

PP&L has implemented the program through the following general procedures:

New Construction

- Contact builders, developers, installers and customers to encourage installation of efficient electric space heating and water heating systems with an emphasis on off-peak applications.
- Provide a cash grant to new single home, town house and twin home customers who install ceramic storage room units. This grant is intended to help offset the higher installation costs of this system.
- Support the residential new construction program by systemwide newspaper advertising, bill inserts, handout literature, participation in fairs and shows, PP&L displays and meeting with appropriate allies in the residential construction industry.

Existing Customer Conversions

- Encourage the installation of energy-efficient electric space and water heating systems, emphasize off-peak applications, with customers making a change in space or water heating equipment.

Space Heating

- Contact customers planning to replace their present fossil-fired system and inform those who do not care to continue heating via warm air or hot water distribution systems about the electric resistance space heating option.
- Encourage the installation of off-peak electric space heating systems. Those who install a ceramic storage space heating system will be eligible to receive a cash grant. This grant is provided to help offset the higher installation costs of this system and is available only when the conversion is being made from an existing fossil-fired space heating system.

Water Heating

- Meet with dealers, installers, and customers to relate the benefits and options available by converting to electric water heating. Option include off-peak electric water heating, conventional electric water heating, a heat-pump water heater or a solar-assisted electric water heater. Customers who convert their present fossil-fired domestic water heating systems to off-peak electric water heating will be eligible for the off-peak water heating provision of the RS rate.

- Support residential conversion efforts by systemwide newspaper advertising, bill inserts, handout literature, participation in fairs and shows, PP&L displays and meetings with appropriate allies in the space heating industry.

Basic Assumptions

Table 5A lists the input data used in the ceramic program analysis, which was based on the major assumptions listed below:

- Promotional period is assumed for the 1985-1989 five-year period. Participating customers fully recover the cost of their investment in the 1985-1999 period.

- Participants Demand and Energy Savings based on:

  -- Increasing the total program participation from 76 customers in 1985 to 1,726 in 1989.
  -- 1-6KW on-peak demand reduction per participant (6KW at time of winter system peak).
  -- Installing a 'Ceramic' system compared to a 'Baseboard Resistance' system results in a 5,500 KWH on-peak energy reduction and a 5,600 KWH off-peak energy increase per participant, annually. The net increase of 100 KWH represents heating system losses. These weather normalized values are based on an average 1,800 square foot home.

- Participants Demand and Energy Payments (revenue reduction) based on:

  -- 1985 to 1989 energy rates as per proposed RS and RTS rate schedules as filed with the PUC on July, 1984.
  -- 1990 to 1999 energy rates escalated at 5.5% annually.
  -- Demand charge applied for RTS rate.

- Utility Avoided Energy Cost (MCE) equal to PP&L's incremental value of energy increased by 9.4% to account for losses, and represents PP&L's CSO.

- Avoided Capacity Costs (MCD) are zero due to PP&L's adequate capacity situation until 2000.

- Participants' incremental cost to install a ceramic compared to a baseboard resistance is $3,150 in 1985. This amount is assumed to escalate at 5% per year.

94

- Utility's Cost (UC) include all costs associated with program less incentive. Incentive cost (I) starts at $1,000 in 1985 and decreases to $0 by 1990.

- Participant's 1985 annual savings under the RTS rate is approximately $450.00 and increases to approximately $600.00 by 1989. After 1989, the savings escalate at 5.5%.

- Based on heating system cost differential, the PP&L grant, and the RTS rate savings, the participant's payback period increases from five years in 1985 to six years in 1989.

- Discount rate for all parties equal to PP&L's after tax cost of money (i.e. 9.7%).

Analysis of Results for Ceramic Program

The results of applying the PUC Methodology to the Ceramic program provided in the PUC's format on Table 5B with additional detail on Table 5C. As shown, the Ceramic program is expected to provide present worth benefits to the participant and PP&L. The non-participant, however, does not benefit. This is due to the fact that the loss of participant revenues greatly exceeds the reduction in PP&L's CSO, which when combined with the utility's cost results in a net cost to the non-participant. However, because the non-participant's net cost is substantial, the program is a net cost to all ratepayers as a whole.

TABLE 5A

8:27:26 MARCH 22, 1985

FORM ACR-4. COST BENEFIT ANALYSIS INPUTS

COMPANY: PENNSYLVANIA POWER & LIGHT COMPANY
PROGRAM: CERAMIC
YEAR FROM: 1985
YEAR TO: 1999

t	YEAR	REVENUE REDUCTION COST $ (Cr)	TOTAL UTILITY BENEFITS $ (Bu)	PARTICIPANT DEMAND SAVINGS KW (D)	UTILITY CAPACITY SAVINGS KW (G)	PARTICIPANT AVERAGE DEMAND COST $ PER KW (ACD)	UTILITY AVOIDED CAPACITY COST $ PER KW (MCD)	PARTICIPANT COST $ (PC)	TAX CREDITS $ (TC)
1	1985	34390.0000	6339.0000	0.00	0.0	0.0000	0.0000	239400.00	0.00
2	1986	151685.0000	23308.0000	0.00	0.0	0.0000	0.0000	545820.00	0.00
3	1987	323434.0000	61713.0000	0.00	0.0	0.0000	0.0000	1059265.00	0.00
4	1988	601848.0000	145890.0000	0.00	0.0	0.0000	0.0000	1714090.00	0.00
5	1989	1022431.0000	343579.0000	0.00	0.0	0.0000	0.0000	2718590.00	0.00
6	1990	1078664.0000	403331.0000	0.00	0.0	0.0000	0.0000	0.00	0.00
7	1991	1137906.0000	555665.0000	0.00	0.0	0.0000	0.0000	0.00	0.00
8	1992	1200508.0000	631455.0000	0.00	0.0	0.0000	0.0000	0.00	0.00
9	1993	1266608.0000	722357.0000	0.00	0.0	0.0000	0.0000	0.00	0.00
10	1994	1336269.0000	849857.0000	0.00	0.0	0.0000	0.0000	0.00	0.00
11	1995	1409700.0000	904870.0000	0.00	0.0	0.0000	0.0000	0.00	0.00
12	1996	1487311.0000	973448.0000	0.00	0.0	0.0000	0.0000	0.00	0.00
13	1997	1569107.0000	1046406.0000	0.00	0.0	0.0000	0.0000	0.00	0.00
14	1998	1655407.0000	1125594.0000	0.00	0.0	0.0000	0.0000	0.00	0.00
15	1999	1746453.0000	1210662.0000	0.00	0.0	0.0000	0.0000	0.00	0.00

t	YEAR	INCENTIVE COST $ (I)	UTILITY COST $ (UC)	DISCOUNT RATES PARTICIPANT % (Dp)	DISCOUNT RATES NON-PARTIC. % (Dnp)	DISCOUNT RATES UTILITY % (Du)	ESCALATION RATE % --	SYSTEM SALES OR DEMAND KWH OR KW (S)	SALES OR DEMAND RATIO % (f)	UNCOLLECTIBLE ACCOUNTS REDUCTION $ (UA)
1	1985	76000.00	170000.00	9.70	9.70	9.70	0.00	2.394E+10	0.00	0.00
2	1986	132000.00	235000.00	9.70	9.70	9.70	0.00	2.477E+10	0.00	0.00
3	1987	183000.00	295000.00	9.70	9.70	9.70	0.00	2.558E+10	0.00	0.00
4	1988	180000.00	355000.00	9.70	9.70	9.70	0.00	2.650E+10	0.00	0.00
5	1989	284000.00	415000.00	9.70	9.70	9.70	0.00	2.707E+10	0.00	0.00
6	1990	0.00	0.00	9.70	9.70	9.70	0.00	2.768E+10	0.00	0.00
7	1991	0.00	0.00	9.70	9.70	9.70	0.00	2.837E+10	0.00	0.00
8	1992	0.00	0.00	9.70	9.70	9.70	0.00	2.906E+10	0.00	0.00
9	1993	0.00	0.00	9.70	9.70	9.70	0.00	2.974E+10	0.00	0.00
10	1994	0.00	0.00	9.70	9.70	9.70	0.00	3.036E+10	0.00	0.00
11	1995	0.00	0.00	9.70	9.70	9.70	0.00	3.097E+10	0.00	0.00
12	1996	0.00	0.00	9.70	9.70	9.70	0.00	3.159E+10	0.00	0.00
13	1997	0.00	0.00	9.70	9.70	9.70	0.00	3.220E+10	0.00	0.00
14	1998	0.00	0.00	9.70	9.70	9.70	0.00	3.282E+10	0.00	0.00
15	1999	0.00	0.00	9.70	9.70	9.70	0.00	3.347E+10	0.00	0.00

DM 046909 96

TABLE 5B

8:27:26 MARCH 22, 1985

FORM ACR-5. COST BENEFIT ANALYSIS RESULTS
CUMULATIVE PRESENT WORTHED DOLLARS

COMPANY: PENNSYLVANIA POWER & LIGHT COMPANY
PROGRAM: CERAMIC

PERIOD OF ANALYSIS		TOTAL UTILITY BENEFITS $ (Bu)	TOTAL UTILITY COSTS $ (Cu)	REVENUE REDUCTION COST $ (Cr)	PARTICIPANT REVENUE REQUIREMENT $ (Rp)	TOTAL PARTICIPANT BENEFITS $ (Bp)	TOTAL PARTICIPANT COSTS $ (Cp)	TOTAL ALL RATEPAYERS BENEFITS $ (Ba)	TOTAL ALL RATEPAYERS COSTS $ (Ca)
BEGINNING YEAR	ENDING YEAR								
1985	1999	3767149.37	1184832.45	7335060.41	0.00	8021972.18	4792821.67	3767149.37	5977654.13

DISCOUNTED PAYBACK PERIOD	CUMULATIVE NET PRESENT VALUE				BENEFIT-COST RATIO				RATE IMPACT
	PARTICIPANT $ (NPVP)	NON-PARTIC. $ (NPVNP)	UTILITY $ (NPVU)	RATEPAYERS $ (NPVA)	PARTICIPANT -- (BCRP)	NON-PARTIC. -- (BCRNP)	UTILITY -- (BCRU)	RATEPAYERS -- (BCRA)	NON-PARTIC. $ PER KWH (RIInp)
9	3229150.51	-5439655.26	2582316.92	-2210504.75	1.6737	0.4092	3.1795	0.6302	0.00001253

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97

TABLE 5C

8:27:26 MARCH 22, 1985

COST BENEFIT ANALYSIS RESULTS
CUMULATIVE PRESENT WORTHED DOLLARS

COMPANY: PENNSYLVANIA POWER & LIGHT COMPANY
PROGRAM: CERAMIC
YEAR FROM: 1985
YEAR TO: 1999

t	YEAR	TOTAL UTILITY BENEFITS $ (SBuPV)	TOTAL UTILITY COSTS $ (SCuPV)	TOTAL INCENTIVE COSTS $ (SCiPV)	REVENUE REDUCTION COST $ (SCrPV)	PARTICIPANT REVENUE REQUIREMENT $ (SRpPV)	TOTAL PARTICIPANT BENEFITS $ (SBpPV)	TOTAL PARTICIPANT COSTS $ (SCpPV)	TOTAL RATEPAYERS BENEFITS $ (SBaPV)	TOTAL RATEPAYERS COSTS $ (SCaPV)
1	1985	6339.00	170000.00	76000.00	34390.00	0.00	110390.00	239400.00	6339.00	409400.00
2	1986	27586.04	384220.60	196328.17	172662.56	0.00	368990.73	736956.97	27586.04	1121177.58
3	1987	78867.85	629357.54	348396.17	441427.38	0.00	789823.55	1617177.25	78867.85	2246534.79
4	1988	189371.31	898268.48	490805.34	897324.59	0.00	1383129.94	2915592.89	189371.31	3813861.37
5	1989	426617.97	1184832.45	686911.77	1603329.14	0.00	2290240.91	4792821.67	426617.97	5977654.13
6	1990	680497.96	1184832.45	686911.77	2282302.99	0.00	2969214.76	4792821.67	680497.96	5977654.13
7	1991	999338.31	1184832.45	686911.77	2935278.89	0.00	3622190.66	4792821.67	999338.31	5977654.13
8	1992	1329628.75	1184832.45	686911.77	3563261.48	0.00	4250173.25	4792821.67	1329628.75	5977654.13
9	1993	1674057.08	1184832.45	686911.77	4167195.10	0.00	4854106.87	4792821.67	1674057.08	5977654.13
10	1994	2043448.00	1184832.45	686911.77	4748005.32	0.00	5434917.09	4792821.67	2043448.00	5977654.13
11	1995	2401973.38	1184832.45	686911.77	5306584.91	0.00	5993496.68	4792821.67	2401973.38	5977654.13
12	1996	2753566.09	1184832.45	686911.77	5843776.11	0.00	6530687.88	4792821.67	2753566.09	5977654.13
13	1997	3098091.05	1184832.45	686911.77	6360398.27	0.00	7047310.04	4792821.67	3098091.05	5977654.13
14	1998	3435919.02	1184832.45	686911.77	6857240.64	0.00	7544152.41	4792821.67	3435919.02	5977654.13
15	1999	3767149.37	1184832.45	686911.77	7335060.41	0.00	8021972.18	4792821.67	3767149.37	5977654.13

		CUMULATIVE NET PRESENT VALUE				BENEFIT-COST RATIO				RATE IMPACT
t	YEAR	PARTICIPANT $ (SNPVp)	NON-PARTIC. $ (SNPVnp)	UTILITY $ (SNPVu)	RATEPAYERS $ (SNPVa)	PARTICIPANT -- (BCRp)	NON-PARTIC. -- (BCRNp)	UTILITY -- (BCRu)	RATEPAYERS -- (BCRa)	NON-PARTIC. $ PER KWH (RIMnp)
1	1985	-129010.00	-274051.00	-163661.00	-403061.00	0.4611	0.0226	0.0373	0.0155	0.00001145
2	1986	-367966.24	-725625.29	-356634.56	-1093591.54	0.5007	0.0366	0.0718	0.0246	0.00001490
3	1987	-827353.70	-1340313.23	-550489.69	-2167666.94	0.4834	0.0556	0.1253	0.0351	0.00001804
4	1988	-1527462.95	-2097027.10	-708897.17	-3624490.06	0.4761	0.0828	0.2108	0.0497	0.00002081
5	1989	-2502580.76	-3048455.39	-758214.48	-5551036.16	0.4778	0.1228	0.3601	0.0714	0.00002384
6	1990	-1823606.91	-3473549.26	-504334.50	-5297156.17	0.6195	0.1638	0.5743	0.1138	0.00002233
7	1991	-1170631.01	-3907684.81	-185494.15	-4978315.82	0.7558	0.2079	0.8434	0.1672	0.00002070
8	1992	-542648.42	-4105376.95	144796.30	-4648025.37	0.8868	0.2446	1.1222	0.2224	0.00001928
9	1993	61285.20	-4364882.24	489224.63	-4303597.04	1.0128	0.2772	1.4129	0.2801	0.00001798
10	1994	642095.41	-4576301.54	858615.54	-3934206.13	1.1340	0.3087	1.7247	0.3418	0.00001676
11	1995	1200675.01	-4776355.75	1217140.93	-3575680.74	1.2505	0.3346	2.0273	0.4018	0.00001571
12	1996	1737866.21	-4961954.25	1568733.63	-3224088.04	1.3626	0.3569	2.3240	0.4606	0.00001478
13	1997	2254488.36	-5134051.44	1913258.59	-2879563.08	1.4704	0.3763	2.6148	0.5183	0.00001396
14	1998	2751330.74	-5293065.84	2251086.57	-2541735.10	1.5741	0.3936	2.8999	0.5748	0.00001321
15	1999	3229150.51	-5439655.26	2582316.92	-2210504.75	1.6737	0.4092	3.1795	0.6302	0.00001253

98

Program Benefit-Cost Summary

Program	Net Present Value (1985$) Participant $B - C$ \$	Non-Participant $B_u - (C_u + C_i + C_r)$ \$	Utility $B_u - C_u$ \$	Ratepayer $B_a - C_a$ \$
CACS	925,000	(170,000)	989,000	755,000
RCS	2,138,000	(944,000)	2,023,000	1,193,000
WRAP - Act A.	14,358,000	(7,419,000)	2,075,000	6,939,000
- Act B(1)	2,483,000	(978,000)	1,505,000	1,505,000
- Act B(2)	967,000	196,000	482,000	1,162,000
SESS	1,751,000	(8,781,000)	(1,871,000)	(7,031,000)
Ceramic	3,229,000	(5,440,000)	2,582,000	(2,211,000)
IS-2	25,071,000	(27,288,000)	567,000	(2,217,000)

Program	Benefit-Cost Ratio Participant B_p/C_p	Non-Participant $(B_u/C_u + C_i + C_r)$	Utility B_u/C_u	Ratepayer B_a/C_a
CACS	4.94	.89	3.81	2.29
RCS	3.50	.76	3.01	1.65
WRAP - Act A.	∞	.32	2.42	∞
- Act B.(1)	∞	.63	8.92	8.92
- Act B.(2)	∞	1.59	11.19	∞
SESS	1.34	.05	.21	.07
Ceramic	1.67	.41	3.18	.63
IS-2	10.01	.02	∞	.20

(1) Individually Metered
(2) Master Metered

CEPFOD Exhibit No. 8

(3)

THE FUTURE IS 1994

INTRODUCTION

PP&L has committed to not filing a base rate increase until the 1993-1995 period. This commitment is based on a goal to maintain stable rates through continued cost containment efforts.

PP&L's current rates are based on cost of service information from 1984. Significant cost of service changes have occurred since then. Additional significant cost of service changes will occur by 1994.

Formulating a strategic plan for the next five years for Division Operations should include an assessment of our expenses, revenue, rates, and rate base now and also an assessment of the same items as expected in 1994. This assessment will provide insights into potential issues in a future rate case. Knowing these issues will help in formulating a strategic plan for Division Operations.

This paper attempts to provide basic fundamentals of cost of service analyses. These fundamentals are applied to PP&L data for the years 1984, 1989, and 1994. Two separate analyses have been completed:

(1) Rate of Return Analysis - This is an analysis of the rates of return by rate class for the years 1984, 1989, and 1994. Rates of return are developed from revenue and expense data—historic, current, and projected. Revenue is projected assuming that there will be no increases to base rates and that ECR increases will approximate increases to the cost of system output.

(2) Revenue, Expense, Rate Base Requirements Analysis - This is an analysis of the revenue, expense, and/or rate base requirements in 1994 needed to achieve a 13% return on common equity. This approach expands upon the traditional regulatory revenue requirements analysis. In addition to revenue increases, expense and rate base decreases required to attain a 13% return on common equity are identified.

A review of these analyses provides significant insights into the potential regulatory issues in the next base rate case filing. These insights provide a basis for further study and preparation in anticipation of the next base rate case.

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100

RATE CASE BASICS

In order to better understand the analyses presented in this paper, it is important to review and understand the fundamental formula used as a basis for all base rate cases.

The overall rate of return is monitored using the following formula:

$$\text{Rate of Return} = \frac{\text{Revenue} - \text{Expenses}}{\text{Rate Base}}$$

As sales, revenue, expenses, and rate base change, the resulting rate of return changes. Historically, when the rate of return declined to an unacceptable level, a base rate increase was requested to raise the rate of return back to an acceptable level. The increase was determined by a rearrangement of the above formula:

$$\text{Revenue Requirement} = (\text{Rate of Return} \times \text{Rate Base}) + \text{Expenses}$$

$$\text{Revenue Increase} = \text{Revenue Requirement} - \text{Current Revenue}$$

The increase in revenue is the difference between the revenue requirement and the current level of revenue. In the rate case process, the appropriate rate of return, return on common equity, expenses, and rate base items would be investigated to determine an approved revenue requirement and resulting rate of return.

The analysis that follows attempts to demonstrate that expense and rate base decreases from currently projected levels can be just as effective in attaining a target rate of return.

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TABLE 1

PPUC JURISDICTION - RATE OF RETURN ANALYSIS
(MILLIONS OF $)

	1984	1989	AVG ANNUAL CHANGE - 89/84		1994	AVG ANNUAL CHANGE - 94/89	
Revenue	$1,680	$2,110	$ 86	4.7 %	$2,497	$ 77	3.4 %
Expenses							
Net Energy							
Fuel	593	532	(12)	(2.1)	590	12	2.1
Power Purchases	63	184	24	23.9	285	20	9.1
Power Sales	(440)	(243)	39	(11.2)	(171)	14	6.8
Total - Net Energy	216	473	51	17.0	704	46	8.3
Wages & Benefits	209	266	11	4.9	331	13	4.5
Other O&M	240	285	9	3.5	330	9	3.0
Depreciation	124	175	10	7.1	268	19	8.9
Taxes - Income	226	198	(6)	(2.6)	200	0	0.2
Taxes - Other	172	158	(3)	(1.7)	182	5	2.9
Total - Expenses	1,187	1,555	74	5.5	2,015	92	5.3
Return	$ 493	$ 555	$ 12	2.4 %	$ 482	$(15)	(2.8)%
Rate Base	$4,599	$4,535	$(13)	(0.3)%	$4,638	$ 21	0.5 %
Rate of Return	10.7%	12.2%			10.4%		
Return on Common Equity	10.5%	16.4%			11.4%		
Embedded Cost of Long-term Debt	11.27%	9.92%			9.93%		
Embedded Cost of Preferred and Preference Stock	9.89%	7.57%			7.50%		

NOTE 1: For all years, the return on common equity includes a return on Susquehanna Unit 2. For 1984, the Pennsylvania Public Utility Commission allowed a return on common equity of 15.5% excluding any equity return on Susquehanna Unit 2.

NOTE 2: Revenue projections assume no base rate increase. The ECR is projected to increase at the same rate as the cost of system output.

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102

PPUC JURISDICTION - RATE OF RETURN ANALYSIS

Table 1 lists the major elements of a cost of service rate of return analysis for the years 1984, 1989, and 1994.

The following major insights are apparent for the 1984-1989 period:

- The return and rate of return improved.
  - Revenue increases exceeded expense increases.
  - Rate base actually decreased. (The net of annual depreciation accruals and plant retirements exceeded plant additions.)
- Net energy costs increased by 17% annually.
  - Fuel costs actually decreased.
  - Power purchases significantly increased reflecting NUG activity.
  - Power sales credits declined due to decreased sales at lower margins.
- The decrease in taxes (Tax Reform Act of 1986) helped keep the increase of expenses below the increase of revenue.
- Refinancing of debt, preferred, and preference securities resulted in a greater improvement in the return on common equity than the overall rate of return.
- The directly controllable expenses—Wages & Benefits and Other O&M—increased by about $20 million each year.

Major insights for projections for the 1989-1994 period include:

- The return and rate of return is expected to deteriorate.
  - Expense increases are expected to exceed revenue increases.
  - Rate base is expected to increase by about $21 million per year. (Plant additions are expected to exceed the net of annual depreciation accruals and plant retirements even though the annual depreciation accruals are expected to increase by $19 million per year.
- Net energy costs are expected to continue to increase by about $46 million per year.
  - Fuel costs increase.
  - Power purchases continue to rapidly increase.
  - Power sales credits continue to decline. (Power purchases are expected to exceed credits from power sales by 1994.)
- Taxes are expected to increase only slightly.
- The overall rate of return is expected to deteriorate to a level approximating the level achieved in 1984.
- The directly controllable expenses—Wages & Benefits and Other O&M—are expected to increase by about $22 million each year.
- Revenue projections assume no base rate increase. The ECR is projected to increase at the same rate as the cost of system output.
- The return on common equity includes a return on Susquehanna Unit 2. The Pennsylvania Public Utility Commission has disallowed a return on common associated with Susquehanna Unit 2 for ratemaking purposes.

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TABLE 2

PPUC JURISDICTION - RATE OF RETURN ANALYSIS BY RATE CLASS - SUMMARY

RATE CLASS	RATE OF RETURN 1984	1989	1994	RETURN ON COMMON 1984	1989	1994
RS	10.5%	11.0%	7.8%	9.8%	13.3%	5.6%
GS-1	11.1	13.9	15.1	11.4	20.6	21.9
GS-3	11.6	14.3	13.6	12.9	21.7	18.6
LP-4	10.8	12.2	11.3	10.7	16.4	13.6
LP-5	11.2	12.4	11.1	11.9	16.8	13.0
PPUC	10.7	12.2	10.4	10.5	16.4	11.4

SUB RATE CLASS	RATE OF RETURN 1989	1994	RETURN ON COMMON 1989	1994
GRS	12.8%	9.8%	17.8%	10.0%
EHH-X	9.4	6.7	9.4	3.2
RTS	4.3	1.9	(3.5)	(7.8)
RS	11.0	7.8	13.3	5.6
Steel	4.6	0.8	(2.7)	(10.1)
Air Reduction	14.1	10.5	21.1	11.6
LP-5-X	16.2	16.0	26.3	24.1
LP-5	12.4	11.1	16.8	13.0

NOTE: Revenue projections assume no base rate increase. The ECR is projected to increase at the same rate as the cost of system output.

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104

PPUC JURISDICTION - RATE OF RETURN ANALYSIS BY RATE CLASS - SUMMARY

As previously shown, the overall rate of return for the PPUC jurisdiction customers has improved from 1984 to 1989 and is expected to decline back to 1984 levels by 1994. However, an analysis of the overall rate of return masks the underlying activity by rate class.

Table 2 lists the rates of return and returns on common for the years 1984, 1989, and 1994 by rate class and sub rate class. Plots 1 and 2 graphically display the same information for the return on common.

In 1984, the rate class rates of return are all close to system average. Historically, the residential rate of return has been below system average (influence of the OCA) and the commercial customers in GS-1 and GS-3 have been above average (lack of a unified intervention position in the rate case process).

Currently, the same relative relationships exist—residential below system average, commercial significantly above system average, and industrial about equal to system average.

Projections to 1994 show a significant decline to residential, an increase to commercial in GS-1, and slight declines to industrial and commercial in GS-3, LP-4, and LP-5 rate classes.

A further segmentation of the RS and LP-5 rate classes is instructive.

The general residential customers are providing an adequate rate of return. The electrically heated homes customers are below system rate of return, and RTS customers are producing a negative return on common equity.

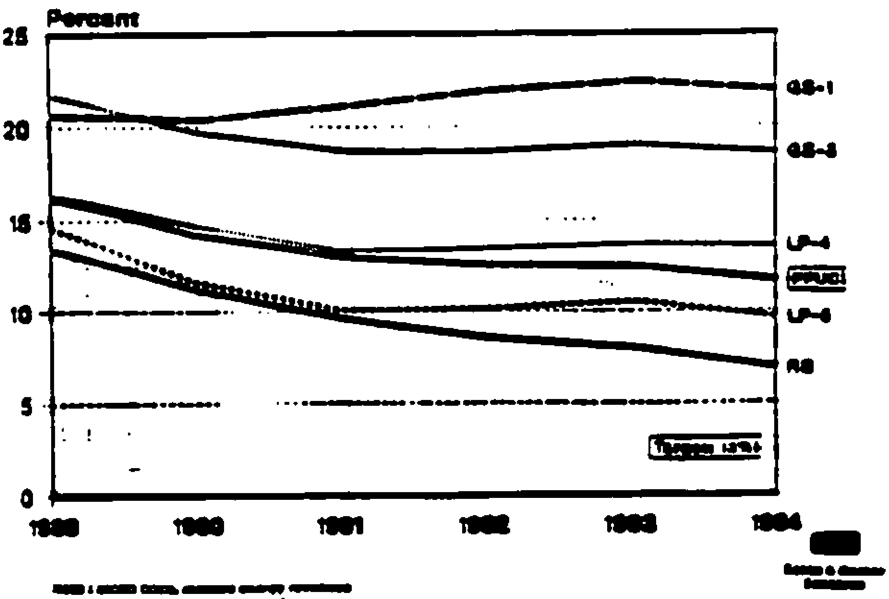
For the LP-5 rate class, air reduction companies are producing a very adequate rate of return; steel companies are barely providing any return at all; and the remaining industrials are providing excellent returns.

It is easy to surmise potential positions of intervenors in the next base rate case.

- The OCA will point out that 700,000 residential customers are providing a very adequate rate of return.
- The OCA may advocate a flat residential rate which would give a bigger share of any increase to electrically heated homes and less to other residential customers.
- If RTS is segmented by the intervenors, then the entire program, including the rate design, will be thoroughly challenged.
- The Small Business Advocate will have an outstanding opportunity to "win one" for the commercial constituents.
- Steel will argue that they are a distressed industry facing increasing mini-mill competition and need even lower rate levels to survive.
- Air reduction companies will point out the need for even lower rates to match the increasing value of their interruptible load.
- Other industrial intervenors will have an excellent opportunity to request reduced rates. They may again challenge past ECR increases and claim that there should be a recognition for lower line losses to their service.

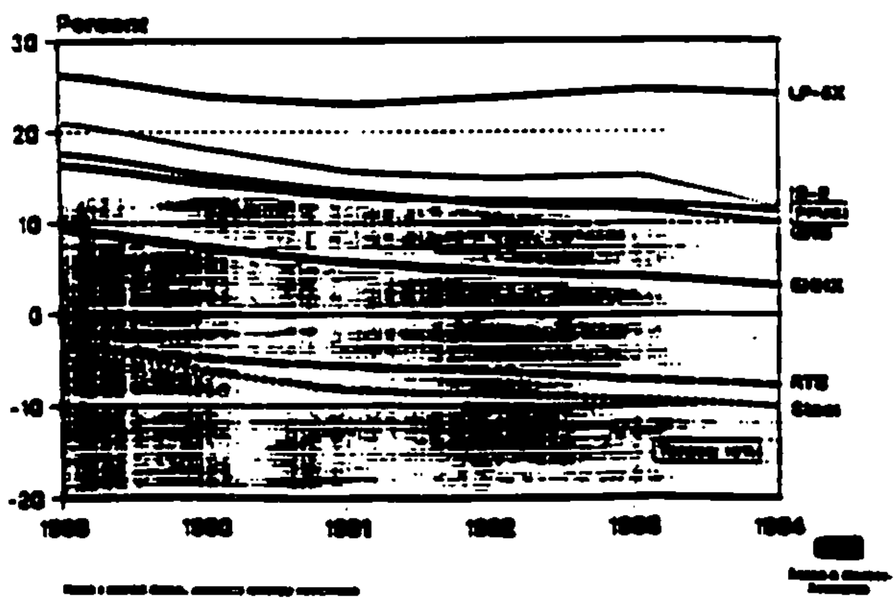
PLOT 1

Return on Common Equity Analysis



PLOT 2

Return on Common Equity Analysis



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106

REVENUE, EXPENSE, AND RATE BASE REQUIREMENTS

As mentioned in the introduction, traditional cost of service analysis develops a total revenue level required to maintain a given rate of return. The difference between this revenue requirement and the current revenue level is then used as a recommended base rate increase.

The analysis completed for this paper goes beyond a traditional cost of service revenue requirements development. This analysis has also developed expense and rate base requirements to obtain a 13% return on common equity. The results are summarized in the following table:

	PROJECTED		REQUIRED		CHANGE REQUIRED		% CHANGE REQUIRED	
	1989	1994	1989	1994	1989	1994	1989	1994
Revenue	2.110	2.496	2,003	2.554	(107)	58	(5.1)	2.3
Expense*	1,157	1.593	1.256	1.540	99	(53)	8.6	(3.3)
Rate Base	4,535	4,638	5,107	4,337	572	(301)	12.6	(6.5)

* Excluding Taxes

A 13% return on common equity can be achieved in 1994 by:

(1) Increasing total revenue by 2.3%
(2) Decreasing total expenses by 3.3%
(3) Decreasing total rate base by 6.5%
(4) Any combination of (1), (2), and (3)

There are three major insights concerning this analysis:

(1) Achieving a 13% rate of return on common equity in 1994 is attainable.
(2) Not filing a base rate case before 1994 can be achieved (assuming that the ECR is not rolled into base rates).
(3) Severe imbalances will exist by rate class and sub-rate class by 1994.

FUTURE RATE CASE ISSUES

Based on the prior information, potential rate case issues can be identified:

(1) Cross subsidies between rate classes
(2) Cross subsidies within rate classes
(3) Conservation and Load Management versus Economic Development and Marketing
(4) Prudency of costs versus attempts to shift costs to other rate classes
(5) Flat or inverted residential rate
(6) Segmentation of rate classes and their respective costs of service
(7) Value of interruptible service
(8) Justification of RTS rate
(9) Cost-based auxiliary service rates
(10) Cost-based wheeling rates
(11) Validity of ECR versus including all energy costs in base rates
(12) Impact of EDI

Recommendations

- Research and design rates which would tend to balance rates of return between and within rate classes
- Prepare to present evidence of strong conservation and load management programs
- Prepare to justify all costs (documentation of all cost containment is essential)
- Research and analyze various residential rate forms
- Prepare support for value of interruptible service
- Initiate and complete study of impact of FP&L having direct control of RTS systems for load management purposes
- Design cost-based auxiliary service rates
- Design cost-based wheeling rates
- Clearly communicate rate information to customers
  - x Expected ECR changes
  - x Expected base rate changes
  - x Customer options

CEPFOD Exhibit No. 9

Attachment 1

(2)

REVENUE REQUIREMENTS EFFECTS

- Revenue requirements are a way of expressing the costs associated with an investment or operating alternative. They can be thought of as expected revenues that would provide a minimum acceptable return to utility investors. Revenue requirements include:

  - Carrying charges, which are the annual revenues required to pay for capital investments.

  - Expenses, which include operating, maintenance and the Cost of System Output (CSO).

    - CSO is the net cost of energy for PP&L's PaPUC jurisdictional customers.

- The RTS program affects PP&L revenue requirements by changing customer energy and demand use.

  - Changes to customer energy use affect PP&L's CSO.

  - Changes to customer demand effect PP&L's capacity obligation to PJM. Although PP&L has no identified need for capacity prior to the year 2000, PP&L has been able to sell capacity to other utilities. The income from these capacity sales can reduce the amount of revenue required from PP&L's PUC jurisdictional customers.

Figure 4

IMPACT ON TOTAL REVENUE REQUIREMENTS

CHART A

ANNUAL

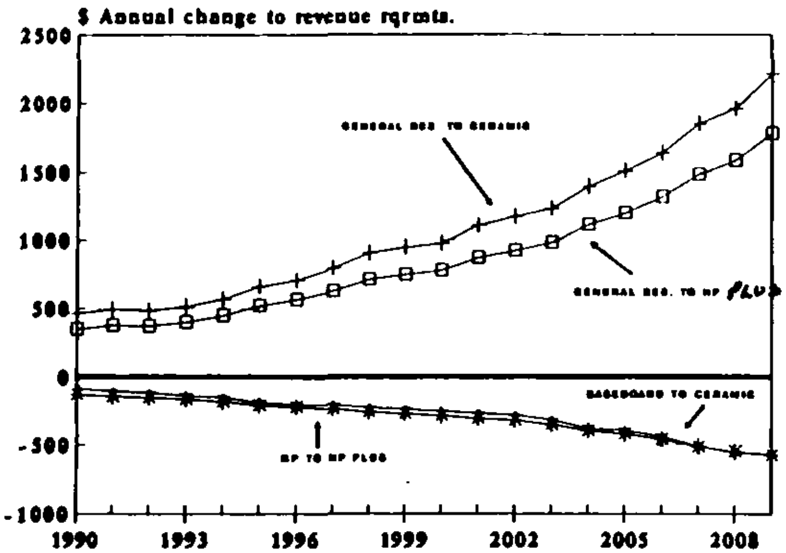
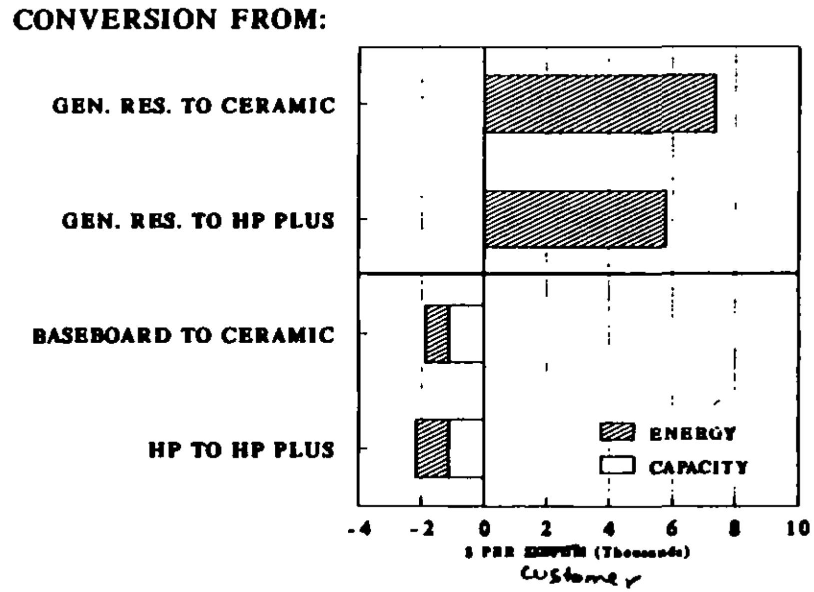


CHART B

20 YEAR PRESENT VALUE



NOTES :

ASSUMES NIGHTTIME PEAK IS CORRECTED
PROGRAM COST NOT INCLUDED

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110

- Figure 4 shows the change to PP&L's total revenue requirements resulting from adding an RTS customer. The change to revenue requirements depends on whether the customers alternative to RTS would be a fossil or electric system.

  - Chart A shows the annual change to revenue requirements.

  - Chart B shows the 20 year cumulative present value change to revenue requirements.

- When the RTS program influences customers to choose RTS rather than a fossil system, PP&L revenue requirements are increased.

  - Energy costs are increased from higher amounts of kWh sales (an average general residential customer with a single family home uses about 9000 kWh/yr compared to about 26,000 kWh for an RTS customer).

  - PP&L's capacity obligation to PJM is unchanged because an RTS customer and a general residential customer contribute about the same demand to PP&L's peak (assuming that the RTS nighttime peak problem is corrected).

- When the RTS program influences customers to choose RTS rather than an alternative electric system, revenue requirements are reduced.

  - Energy costs are reduced by transferring customer energy use from on-peak to off-peak periods when lower cost generation can meet marginal needs.

  - PP&L's capacity obligation to PJM is reduced by shifting customer demand away from PP&L peak periods.

Figure 4

IMPACT ON TOTAL REVENUE REQUIREMENTS

CHART A

ANNUAL

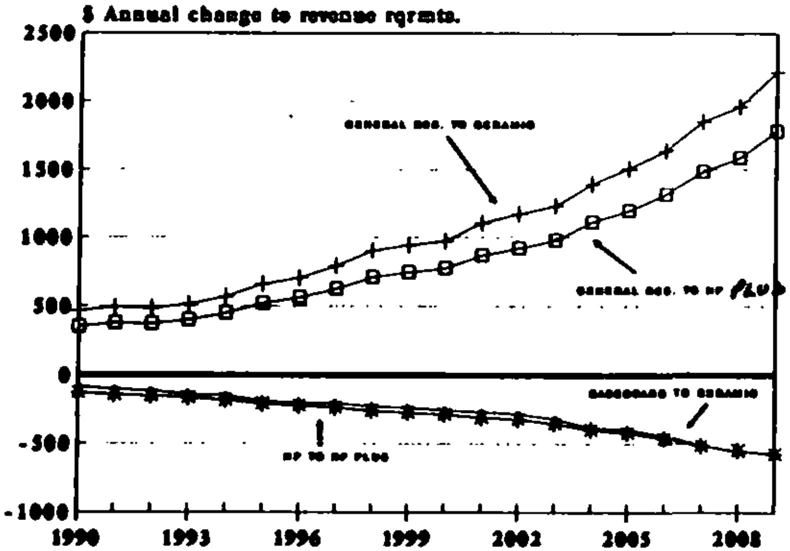
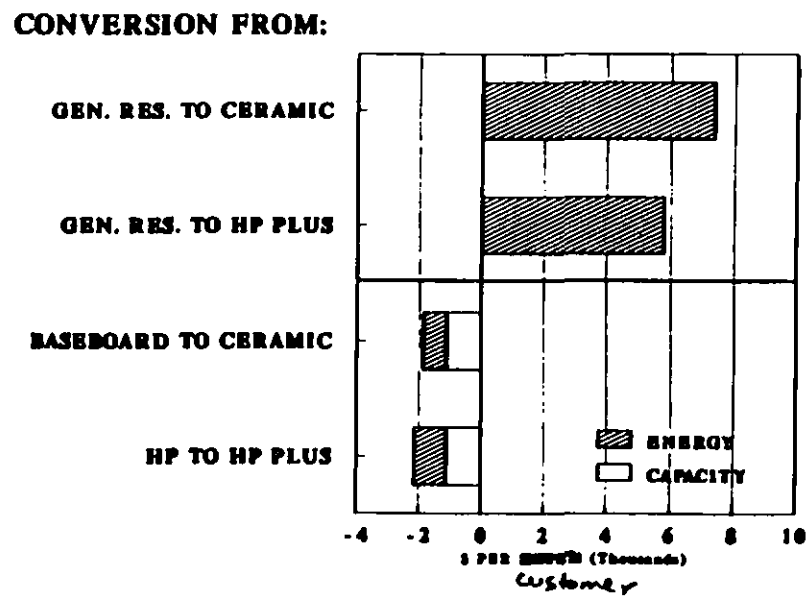


CHART B

20 YEAR PRESENT VALUE



NOTES :

ASSUMES NIGHTTIME PEAK IS CORRECTED
PROGRAM COST NOT INCLUDED

- In contrast to the analysis of incremental earnings, changes to revenue requirements are a measure of the effects of RTS on PP&L's embedded costs after a base rate case.

- When the RTS program influences customers to choose RTS instead of an electric system, PP&L can spend up to the total reduction in revenue requirements to influence customer participation. Spending includes grants, marketing costs, and lost revenues from rate incentives.

    - When the RTS program costs more than it saves, subsidies must come from either investors (in the form of lower return on investment) or other ratepayers in the form of higher rates.

    - Accordingly, PP&L can spend up to about $2000 (cumulative present value 1990-2009) per RTS customer converted from electric to RTS without exceeding the associated reduction in revenue requirements.

- When the RTS program influences customers to choose RTS instead of a fossil system, the amount of increased revenue requirements indicates the amount of additional revenues PP&L should receive.

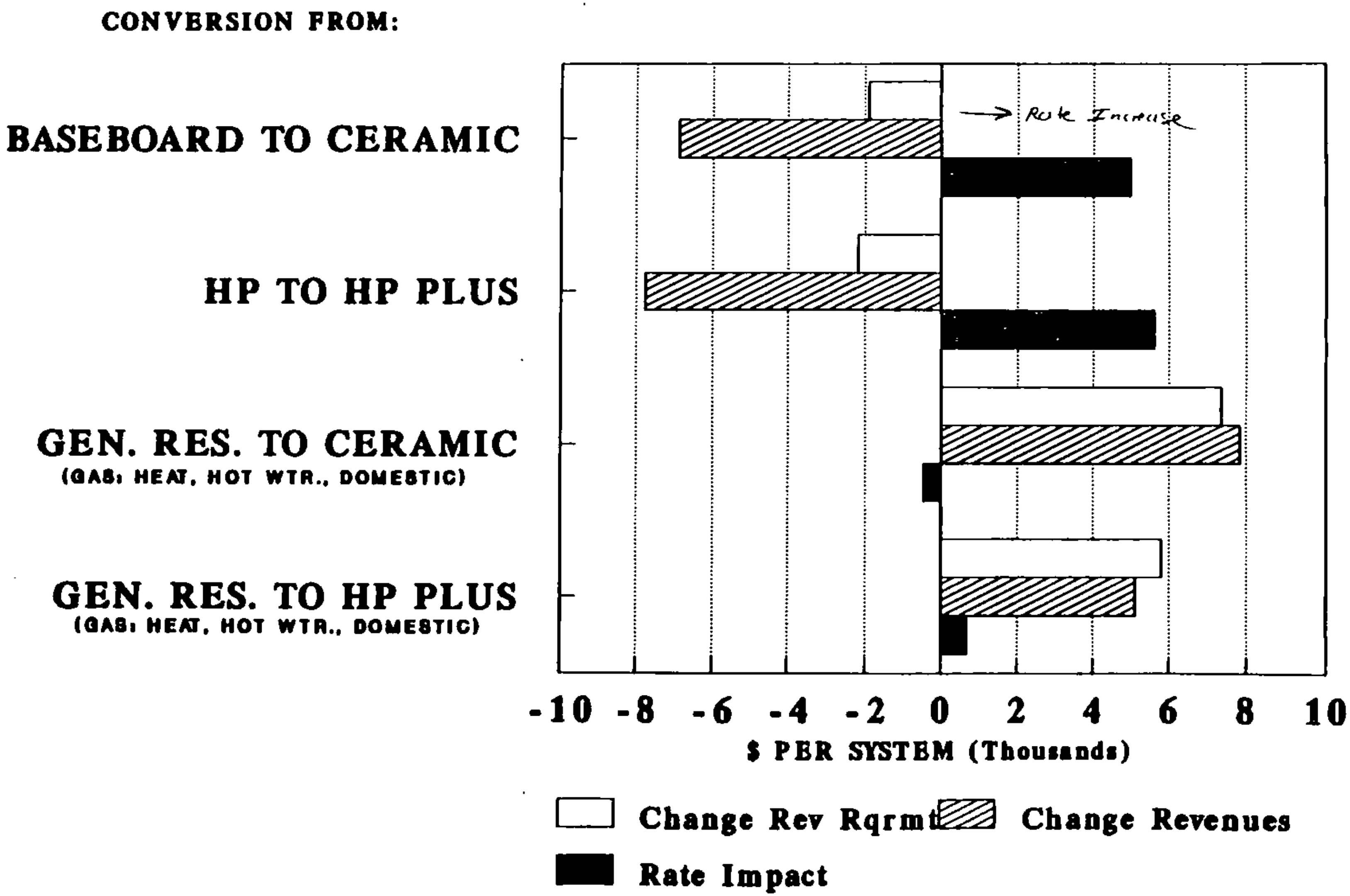
    - When costs from switching customers from fossil to RTS exceed additional revenues the excess costs must be recovered from investors or other ratepayers.

    - Accordingly, PP&L should obtain additional revenues of about $6-7 thousand (plus program costs) per RTS customer converted from fossil to RTS.

Figure 5

IMPACT ON ~~SYSTEM AVERAGE PRICE~~ NON-PARTICIPANT RATES

20 YEAR CUMULATIVE PRESENT VALUE



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414

Assumes nighttime peak is corrected

program cost not included

IMPACT ON NON-PARTICIPANT RATES

- o Figure 5 shows the effect of the RTS program on the system average price to non-RTS customers.

  - This analysis assumes that the current differential between RTS and RS rates is maintained throughout the 20 year period.

- o Adding RTS customers whose alternative was baseboard or heat pump results in the following effects:

  - PP&L revenue requirements are reduced by about $2000 per customer (20 year cumulative present value), as discussed in the previous section.

  - PP&L revenues are reduced by about $7000 per customer (20 year cumulative present value) as a result of the lower RTS rate.

  - Because the amount of lost revenues exceeds the reduction in revenue requirements, over the long-term PP&L would need to recover the difference from rate payers or reduce the rate of return to investors.

  - Consequently, when new customers are influenced to install RTS instead of baseboard or heat pump PP&L needs to recover about $5000 (present value) per RTS customer in additional rate revenue from other customers over 20 years ~~(i.e. average system price increases)~~.

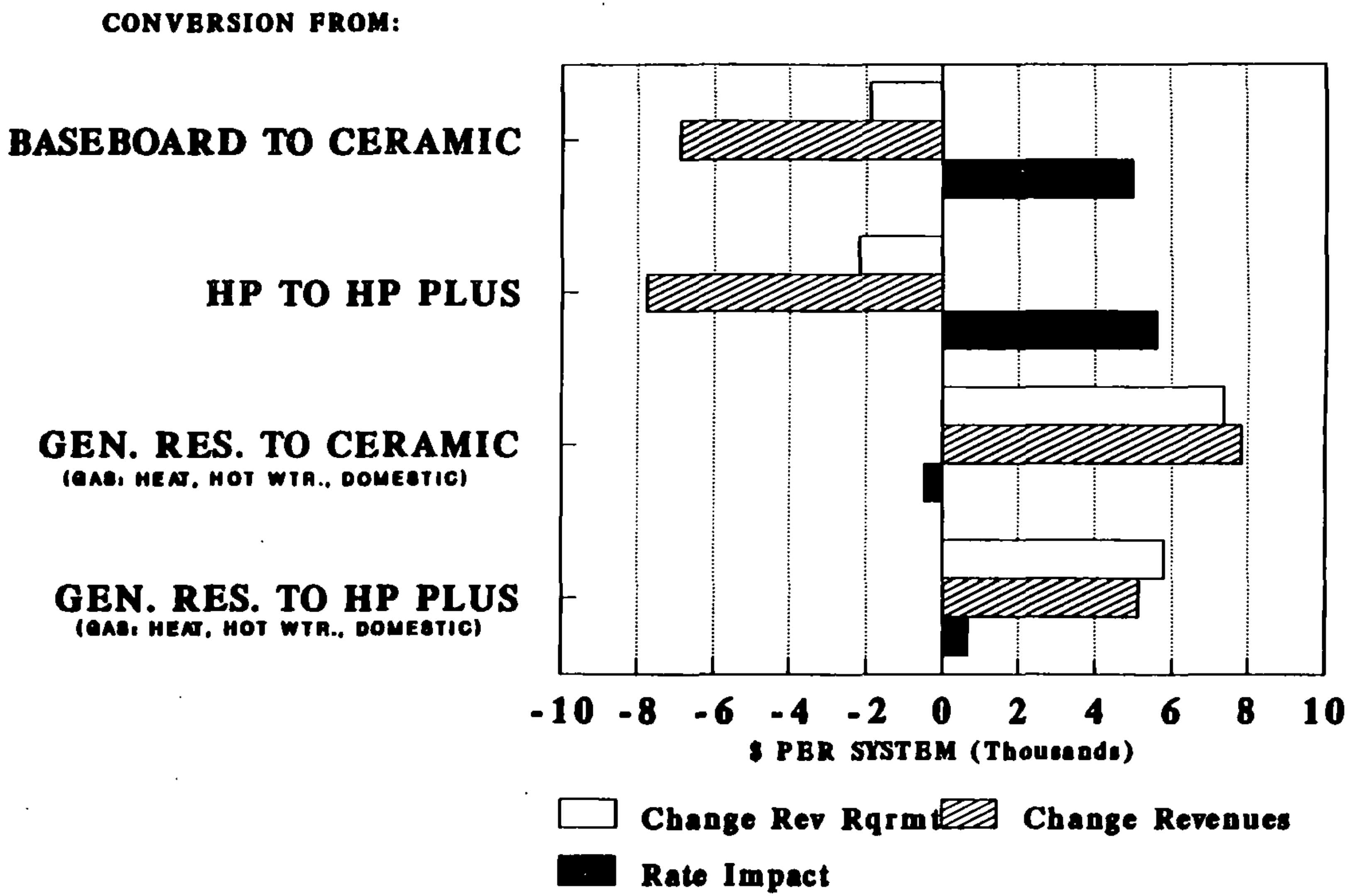
  - Figure 5 does not consider M&ED costs (advertising, grants, etc.) that ~~may~~ would also need to be recovered.

Figure 5

NON-PARTICIPANT RATES

IMPACT ON ~~SYSTEM AVERAGE PRICE~~

20 YEAR CUMULATIVE PRESENT VALUE



Assumes nighttime peak is corrected
program cost not included

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116

- o Adding RTS customers whose alternative was a fossil fueled system results in the following effects:
  - PP&L revenue requirements increase by about $6000-$7000 per customer (20 year cumulative present value), as discussed in previous section.
  - PP&L revenues increase about $5000-$8000 per customer (20 year cumulative present value) as a result of higher kWh sales.
  - Because the increased revenue requirements approximately equal the increased revenues, there is little long-term net rate impact.
  - Again, Figure 5 does not consider M&ED costs that ~~may also~~ would need to be recovered.

117

CEPFOD Exhibit No. 10

PP&L

May 6, 1987

Ms. L. C. Bartholomew	TW-17
Mr. M. J. Berish	TW-14
Mr. W. F. Hecht	TW-5
Mr. F. A. Long	A4-3
Mr. C. W. Noll	N-2
Mr. E. F. Reis	TW-15
Mr. R. J. Shovlin	TW-8

TASK TEAM #10
20 YEAR "LEAST-COST" RESOURCE PLAN"

Attached for your review and comment is a draft copy of the Task Team #10 report "PP&L's 20-Year Least-Cost Resource Plan". This report will be discussed in the PCG meeting scheduled for May 14, 1987.

The report will consist of two volumes. Only the first volume is attached to this letter. The first volume contains:

- o A summary of the Task Team approach to Least-Cost Planning.
- o Results and Conclusions.
- o The "Least-Cost Plan" which would be associated with a PaPUC filing.
- o Issues for discussion at EPC-87
- o Background information.

The second volume, not provided at this time, will contain appendices which provide all supporting data and pertinent background information.

The report is structured in a format to facilitate discussion at EPC-87. Since the PaPUC regulations implementing the "Least-Cost" Planning reporting requirements of Act 114 are not yet finalized, this report does not contain a prototype filing. The actual filing format and two-year implementation plan will be developed when the regulations are finalized.

RHB

R. H. Ballard
Chairman-Task Team #10

Attachment

Copies to:

Mr. Robert K. Campbell	TW-16	Mr. J. O. Beamer	TW-6
Mr. J. T. Kauffman	TW-16	Mr. J. C. Krum	A3-3
Mr. G. E. McNair	TW-19	Members of Task Team #10	

DS 018494

PP&L'S

20-YEAR LEAST-COST RESOURCE PLAN

A REPORT TO THE

PLANNING COORDINATION GROUP

FROM

TASK TEAM #10

May 6, 1987

119

TABLE OF CONTENTS

DS 018497

190

TASK TEAM #10
20-YEAR "LEAST-COST" RESOURCE PLAN

System Planning

Robert H. Ballard - Chairman
Robert M. Geneczko

Corporate Planning

Mike W. Snovitch

Rates & Market Research

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Marketing & Economic Development

Henry A. Courtright
Bernie J. Bujnowski

Other Major Contributors

Significant contributions to the development of this report were made by personnel from the above departments and the Financial Department

DS 018498

INTRODUCTION

- In October 1986, PCG appointed Task Team #10 (shown on the facing page), with the assignment to:
  - Develop a 20-year "Least-Cost Plan" (LCP) as required by Act 114 and the proposed regulations for discussion at EPC-87.
    - The first filing with the PaPUC is due in May, 1988.
    - Act 114 and the proposed regulations are discussed beginning on page 19.

  - Respond to CMC Action Assignment #1579 which states:

    "Evaluate and recommend strategies to deal with the nighttime peak demand issue raised by the long-term sales forecast."

- The results of the nighttime peak analysis were presented in a separate report "Response to CMC Action Assignment #1579 Issues Associated with Nighttime Peak" which was sent to CMC on April 16, 1987 following PCG review.

- This LCP Report, comprised of two volumes, presents the results of the Task Team's effort to develop a 20-year "Least-Cost Plan".
  - This volume presents a "walk-through" of the LCP process and contains:
    - A summary of the Task Team approach to Least Cost Planning
    - Results and Conclusions
    - A Least Cost Plan associated with a PaPUC filing
    - Issues associated with a PaPUC filing
    - Background information.
  - The Appendices which provide all supporting data and pertinent background information are in a separate volume.

DS 018499

123

- This report addresses the essential items to be included in the first filing with the PaPUC.
  - This report is presented in a format to facilitate discussion at EPC 87.
  - The PaPUC filing regulations are not final.
  - The actual filing format and two-year implementation plan will be developed when the regulations are finalized.
  - Refinements will be made to the Least Cost Plan following the EPC 87 review and yearly thereafter.
- The least cost plan was defined by Task Team 10 as the combination of peak demand and sales levels and resource applications that result in the lowest ¢/kwh of revenue requirements over the twenty year time frame.

DS 018500

123

FIGURE I -- OBJECTIVES OF PP&L'S LEAST COST PLANNING

- o To produce a 20-year resource plan which
  - contributes to meeting PP&L's mission and objectives
  - provides a mix of demand-side and supply-side options which, when balanced against perceived risks, is expected to result in the least cost to the customer's electricity needs as measured in ¢/kwh,,
  - is sufficiently flexible to respond to uncertainties in load/fuel forecasts and other external factors, such as regulatory environment, legislative changes, etc.,
  - provides a preferred and contingency plans to address the uncertainties
  - recognizes that competition is emerging within PP&L's environment.

OBJECTIVES OF PP&L'S LEAST COST PLANNING

- o PP&L's objectives for Least Cost Planning are shown in Figure 1 on the facing page.

    - The objectives were developed by the Task Team and were reviewed, augmented and approved by PCG.

- o The Least Cost Planning objectives are based on PP&L's goals and long-term objectives, the PaPUC regulations, and a continuation of the current utility and customer relationship.

    - PP&L's LCP objectives go beyond the PaPUC regulations which are focused primarily on economics. In addition to the ¢/KWH of revenue requirements, the following criteria were considered:

        - o Service to customers - e.g. reliability
        - o Sociopolitical - e.g. environmental
        - o Technological - e.g. maturity of technology

    - The LCP was developed absent impacts of changes such as:

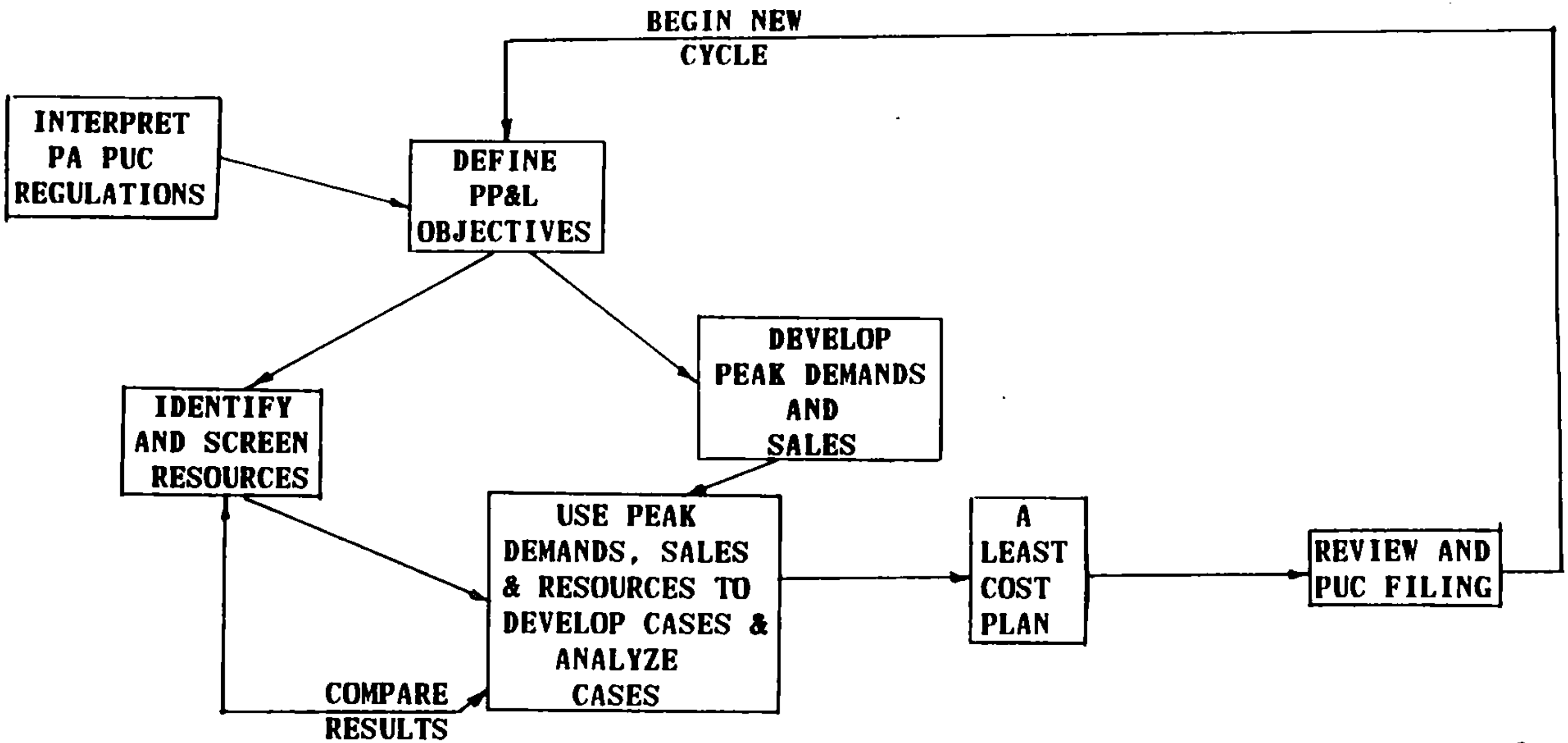
        - o Mandating transmission access or other major structural change within the electric utility industry.
        - o Modifications to PJM operation, planning or capacity scheduling.

- o The objectives of PP&L's Least Cost Planning were used as a basis for comparison of the cases reviewed. How well PP&L's representative least cost plan fits PP&L's LCP objectives is discussed beginning on page 42.

DS 018502

125

FIGURE 2
TASK TEAM APPROACH FLOW CHART



DS 018503

126

TASK TEAM APPROACH

- The Task Team #10 approach to develop the LCP for PP&L is shown in Figure 2 on the facing page.

- The Least Cost Plan, in line with the interpretation of the intent of the PUC regulations, was

  - defined by Task Team 10 as the combination of peak demand and sales levels and resource applications that result in the lowest ¢/KWH of revenue requirements over the twenty year time frame.

  - developed by comparing variations in ¢/KWH in revenue requirements over time to a peak demand and sales case from which PP&L-sponsored program impacts were eliminated.

- The no impact case, titled the Median Case, was developed for these comparison purposes.

  - It was developed by removing all impacts of PP&L's current marketing, economic development and conservation programs beginning in 1987.

  - It was also developed as a reference for evaluating feasible demand-side and supply-side options.

  - As such, the Median Case does not represent a forecast of expected future sales and peak demands.

DS 018504

127

o Demand-side and supply-side resources were identified and individually screened. The screening served to:

- provide an economic analysis of resource options applied individually as required by the proposed PaPUC regulations.

- eliminate further consideration of resources which lacked sufficient information to perform a meaningful analysis or were determined to be less promising.

- consider the overall impacts of the resources including economics, sociopolitical, technical and service to customers.

- check the results from the detailed studies of LCP Cases.

o Developing and analyzing the LCP Cases was the main thrust of the Task Team effort.

- The cases were analyzed in groups with each group building on the results of prior groups.

- A total of 14 cases were analyzed and are described beginning on page 29.

o Case analysis included all costs and benefits to the extent identifiable. For instance, the Median Case revenue requirement analysis

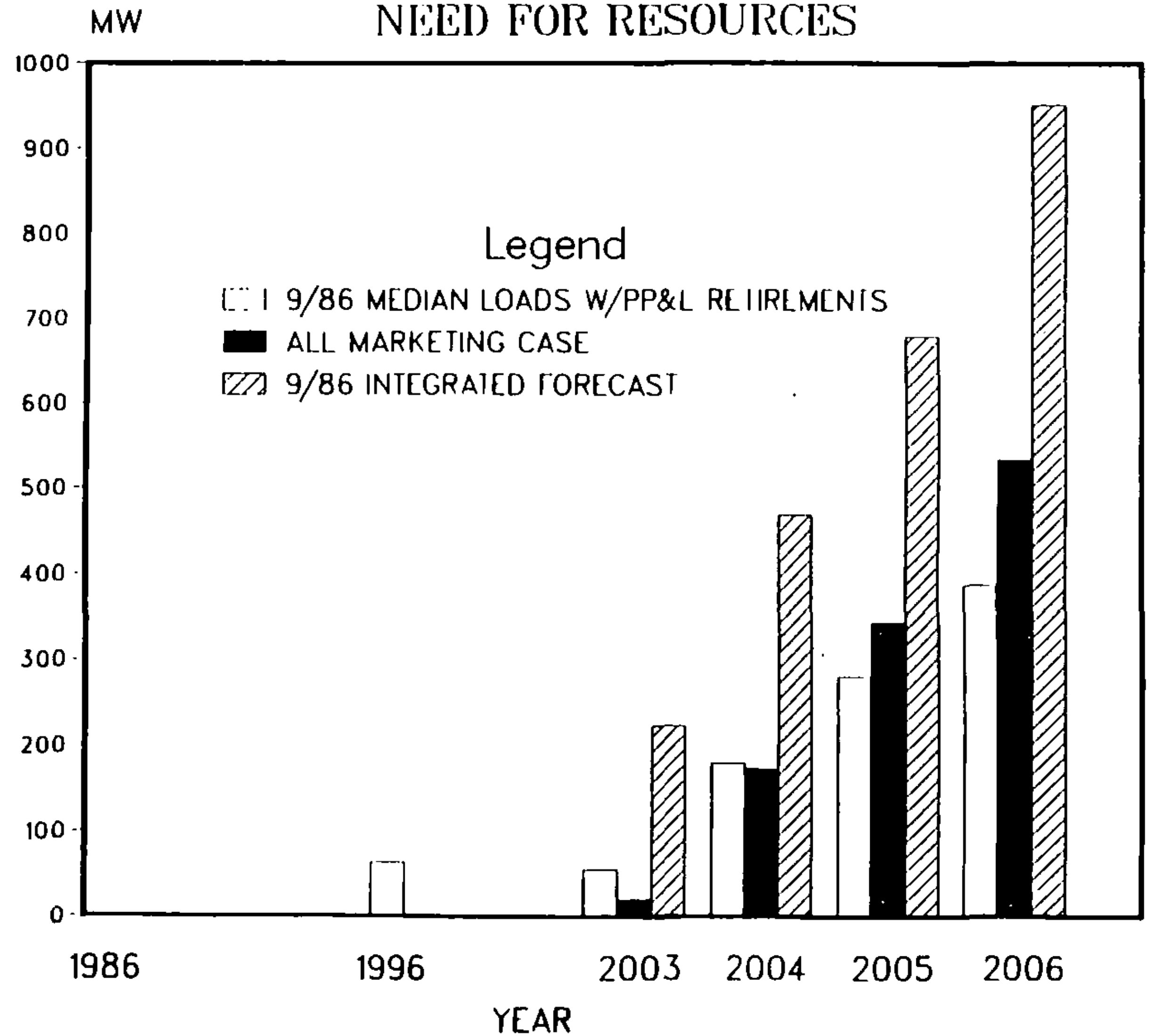
- excludes the portion of PP&L's operating budget attributable to marketing and economic development

- reduces the PP&L capital budget to reflect load-related distribution and transmission costs.

DS 018505

- o Finally, the Task Team recognizes that the LCP process is iterative and should not be based solely on a revenue requirement analysis.
  - The results of the task team will be reviewed at EPC.
  - Suggestions and comments from EPC will be used to refine the LCP and develop the two-year implementation plan that will be submitted to the PaPUC.
  - After the LCP has been submitted to the PaPUC, suggestions and comments received from the PaPUC will also be reviewed and incorporated into the development of LCP's for subsequent years.

FIGURE 3
LCP STUDY CASES
NEED FOR RESOURCES



DS 018507

130

RESULTS AND CONCLUSIONS

RESOURCE REQUIREMENTS

- Figure 3 above shows the <u>cases</u> studied by Task Team #10 in which resources <u>were required</u> to maintain reliability, and the extent of that resource need.

  - The resource need is shown before additional demand-side or new supply-side options were applied to analyze the case.

- Generally, there is no resource need prior to 2000. The three cases requiring resources after 2000 are:

  - Case 2, The Median Case assuming the retirement of about 1,000 MW of PP&L capacity.

  - Case 4, the All Marketing case in which PP&L markets to a sales level approaching the 9/86 "Integrated" Forecast, but with <u>no</u> emphasis on off-peak sales such as those from Residential Thermal Storage (RTS) heating systems.

  - Case 5, the 9/86 "Integrated" Forecast has a high concentration of RTS systems.

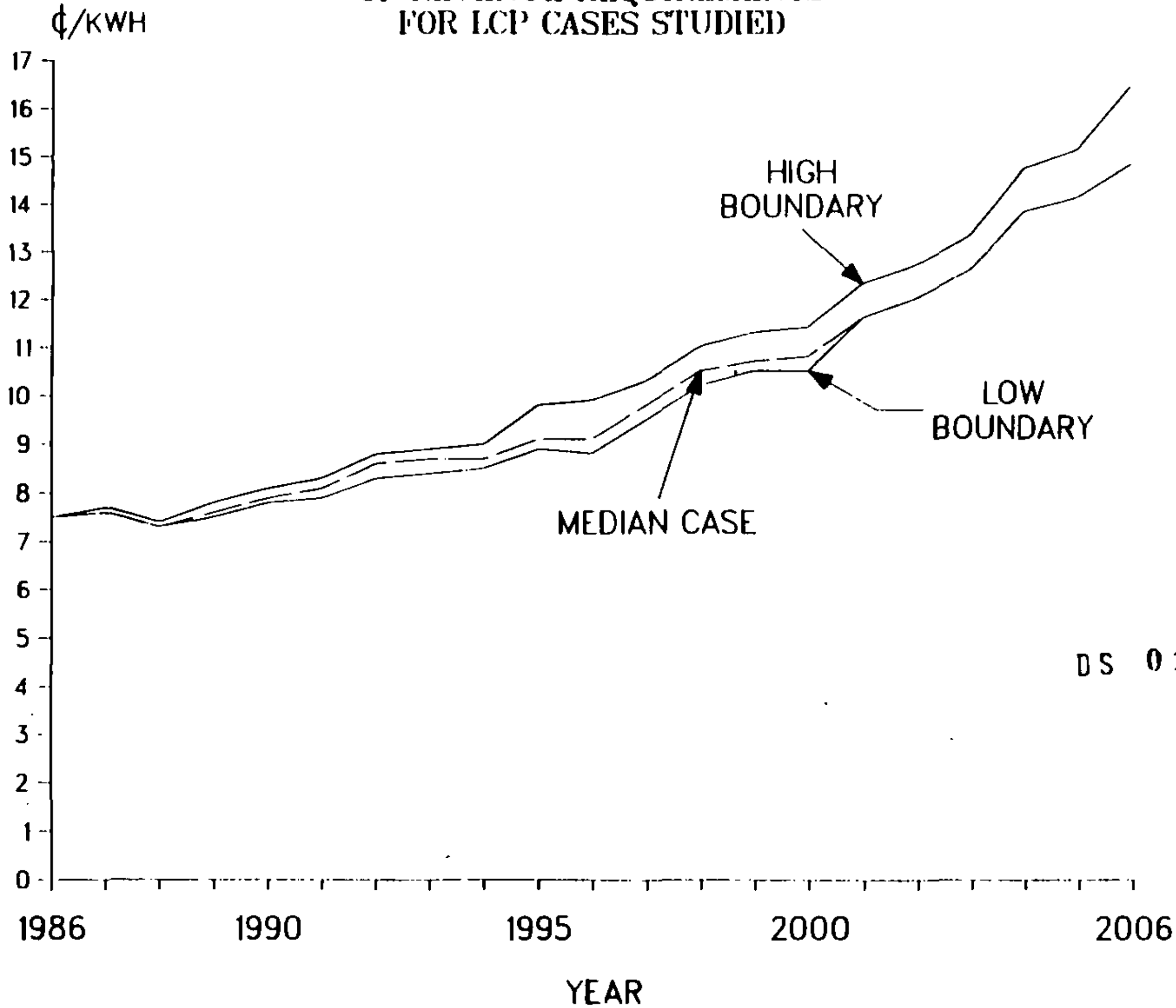
- Case 2, the Median Case assuming PP&L unit retirements has the lowest resource requirement of the three cases because the Median Case peak demand growth rate is relatively low about 1.5% per year.

o Although both marketing cases have approximately the same sales growth rates, the peak demand growth in the 9/86 "Integrated" Forecast is much greater after 1995.

- This higher peak demand growth rate in the 9/86 "Integrated" Forecast is primarily due to the nighttime peak demand contributions from RTS systems.

- The 9/86 "Integrated" Forecast peak demand growth and its specific impacts are explained in the associated Task Team #10 Report responding to CMC Action Assignment #1579, "Issues Associated with Nighttime Peak".

FIGURE 4
BANDWIDTH OF ¢/KWH
OF REVENUE REQUIREMENTS
FOR LCP CASES STUDIED



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¢/KWH OF REVENUE REQUIREMENTS

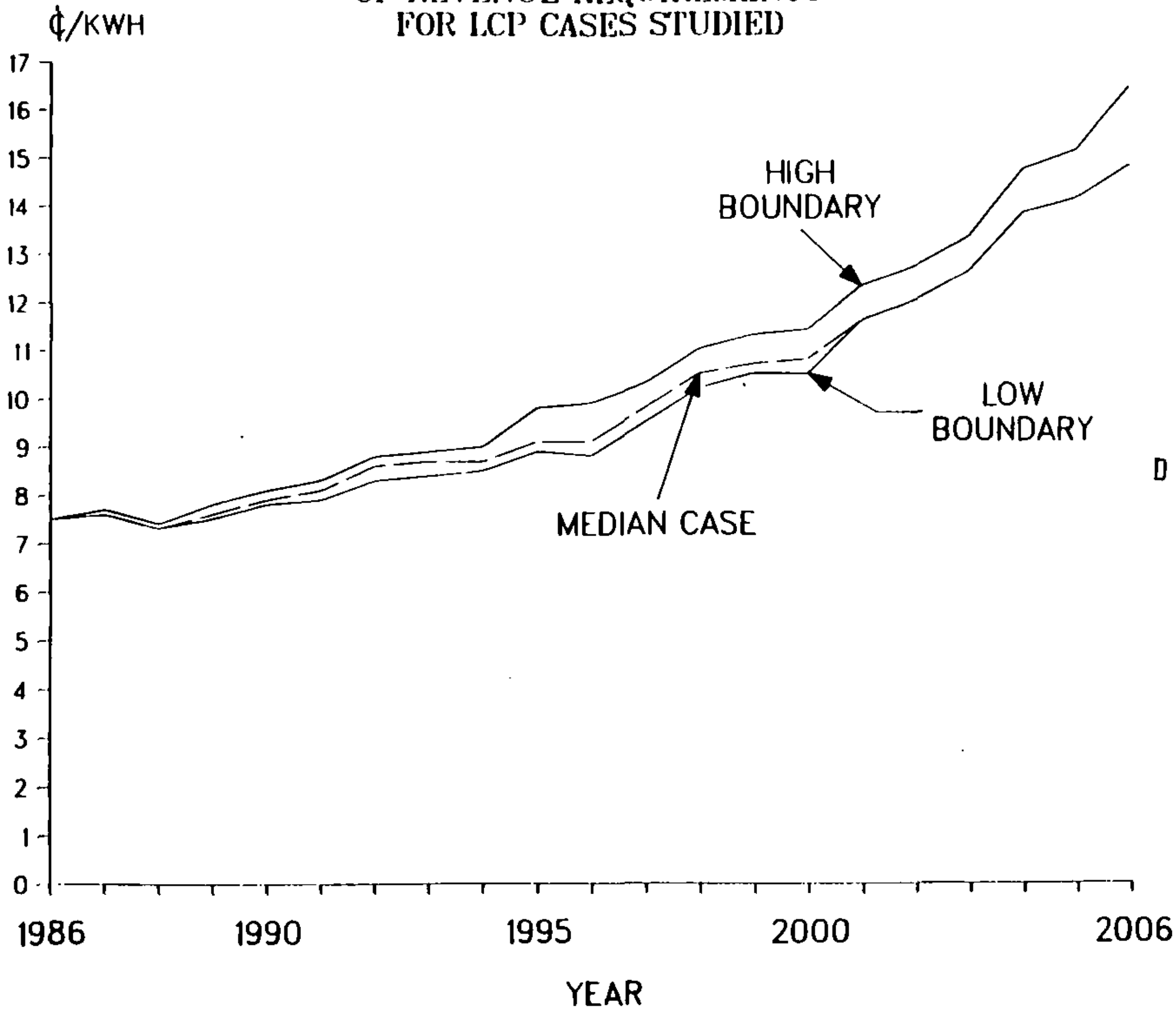
- o Figure 4 shown above presents the envelope of ¢/KWH of annual revenue requirements for all cases studied in the development of a Least Cost Plan.
  - The high and low boundaries represent the highest and lowest ¢/KWH value appearing in that year for any case studied.
  - The high and low boundaries are not reflective of any specific case.
  - Results for alternate fuel price forecasts were not included in the figure since they were structured for use in sensitivity analysis.

- o The maximum change (highest to lowest) in ¢/KWH of revenue requirement resulting from varying peak demand and sales was only about 5% in 1995 and 10% by 2006.
  - By comparison, the peak demand and sales varied by about 10% in 1995 and 20% by 2006.

- o These cases show that while total dollars of revenue requirements may increase for increases to peak demand and sales, average revenue requirements in ¢/KWH may actually decrease.
  - Even though total fixed costs may increase for changes to peak demand, fixed costs in ¢/KWH will tend to decrease since they are spread over more KWH.
    - o This is generally true as long as major new resources are not required.
  - Variable costs, primarily CSO, increase both in total and in ¢/KWH for sales additions since each KWH sold costs progressively more.
  - The net impact on ¢/KWH of revenue requirements depends on the relative change in all of these components.

(Repeated from previous page)

FIGURE 4
BANDWIDTH OF ¢/KWH
OF REVENUE REQUIREMENTS
FOR LCP CASES STUDIED



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o <u>Prior to 2000</u>, the cases with higher sales generally have <u>lower</u> ¢/KWH of revenue requirements.

- As sales are added in this period, the decrease in fixed costs per KWH is greater than the increase in variable costs per KWH.

o <u>After 2000</u>, the cases with higher sales generally have <u>higher</u> ¢/KWH of revenue requirements.

- In this period, the increase in variable costs per KWH is greater than decrease in fixed costs per KWH up to the point of the addition of new capacity.

o The extended life of about 1,000 MW of PP&L generation associated with life extension programs was projected to result in a 10% decrease in ¢/KWH of revenue requirements after 1995 primarily due to an increase in the CSO.

GENERAL OBSERVATIONS

- ¢/KWH of revenue requirements are not very different for various load and sales cases.

  - As noted, plant life extension was the only option identified by the Task Team that had a major impact on minimizing ¢/KWH of revenue requirements.
  - Other options showed this impact, but to a lower extent.

- Cases that include power plant life extension have lower ¢/KWH of revenue requirements than cases that include conservation/load control or new-supply side resources.

- Prior to 1995, PP&L should continue to apply measures to increase sales to at least the level of the 9/86 "Integrated" Forecast.
  - These sales tend to lower the ¢/KWH of revenue requirements.
  - Off-peak sales provide additional benefits since they occur at times of lower CSO.
  - Lower sales resulting from conservation increase short term ¢/KWH of revenue requirements.

- Between 1995 and 2000, PP&L should attempt to reduce sales and peak demand growth rates.

  - Higher sales increase ¢/KWH of revenue requirements and the associated peak growth causes a need for additional high cost resources.
  - Even off-peak additions to sales will have this impact if prior off-peak programs had already flattened the PP&L load shape.
  - The Median Case produces the lowest ¢/KWH during this period. However, the median case does not represent a forecast of expected future peak demand and sales.

- Fuel costs can alter the relationship of whether to market or to decrease sales growth rate.

- *Fuel costs can alter the relationship of whether to market or to decrease* sales growth rate.

  - Higher fuel costs increase CSO and can decrease or eliminate any reductions in ¢/KWH gained by marketing. However, higher electricity sales may result from the higher costs of competing fuels.
  - Conversely, low fuel costs can extend the incentive to market up to a point short of the need for new resources. However, lower electricity sales may result from the lower costs of competing fuels.

- After 2000, Load Control results in only limited reductions in the need for new supply resources for the 9/86 "Integrated" Forecast because PP&L's peak-day load shape is relatively flat.

- Non-Utility Generation (NUG) could be a preferred alternate to new conventional supply side resources if it can be used as PJM installed capacity under proposed PJM guidelines.

  - PP&L expects to have 525 MW of NUG under contract by the early 1990's.
  - *During the term of these contracts, PP&L may be able to use NUG for capacity on PJM* at no additional cost, however the need is after 2000 when existing contracts begin to expire and some of the units will have been in service about 20 years.
  - Alternatively, additional NUG when needed for capacity may command a price equal to the revenue requirement for a new PP&L power plant.

o Assuming traditional financing, the impact of adding new utility generation results in increases in ¢/KWH of revenue requirements due to the additional carrying charges which are offset to some extent by the energy benefits.

- The ¢/KWH of revenue requirements was increased about 5% in the "Integrated" Case with the addition of new utility generation.

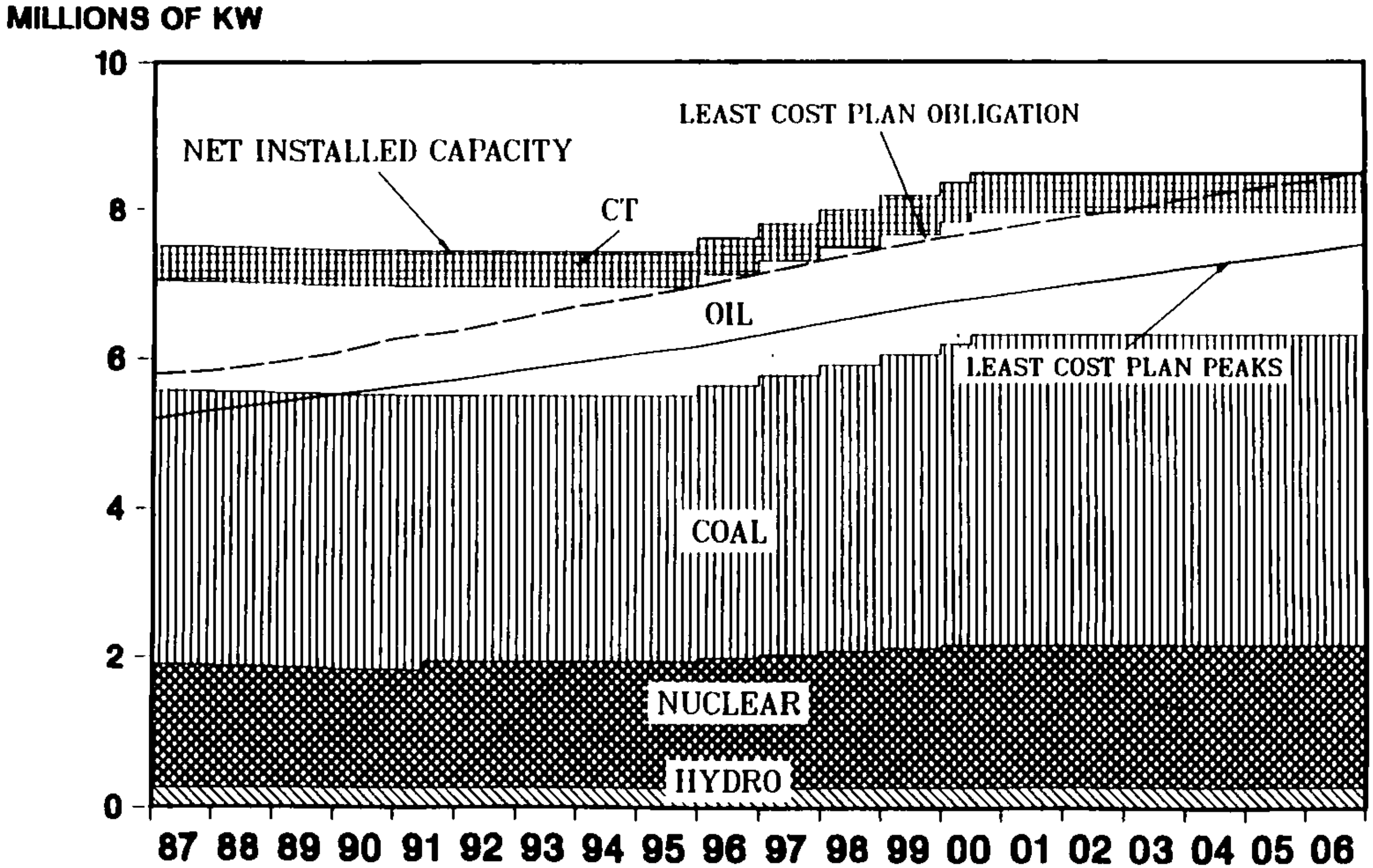
o Non-traditional methods of ownership and financing may result in different ¢/KWH of revenue requirements.

SUMMARY CONCLUSION

o PP&L's LCP should optimize the use of existing resources by controlling the sales growth rate to reduce ¢/KWH of revenue requirements while still avoiding the need for new resources.

- Financial and other concerns are also important in the development of an LCP and will be discussed in separate analyses presented at EPC 87.

FIGURE 5
PP&L LEAST COST PLAN
LOAD/CAPACITY/RESERVE



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140

A LEAST COST PLAN

- The Task Team developed a representative Least Cost Plan from the results and conclusions presented in the previous pages. Figure 5 shown above presents the resource characteristics of that case.

- This representative Least Cost Plan is as follows:

  - Market to achieve sales growth associated with the 9/86 "Integrated" Forecast through 1995 of 2.4%.
  - After 1995, annually step down marketing efforts by 20% so that there is a sales growth rate of 1.8% for the years past 2000.
  - Have a sales growth rate of about the 9/86 "Base" Forecast level after 2000.

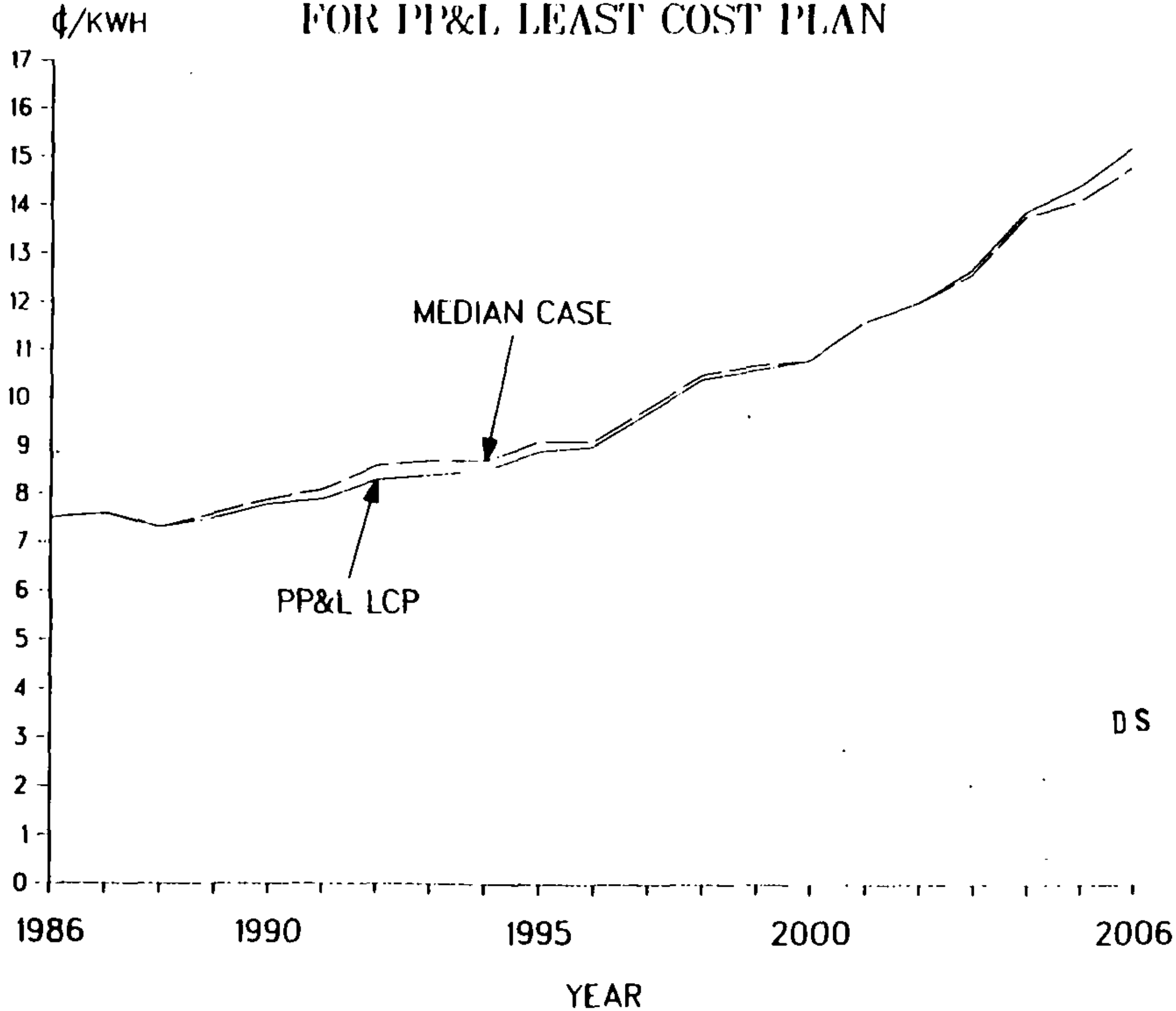
- 1995 was chosen as the starting point for decreasing the sales growth rate because:

  - it occurs at the point when PP&L's daytime and nighttime peak are about equal.
  - this allows PP&L to achieve most of the benefits of increased sales and economic development.
  - it provides sufficient time for PP&L to revise marketing before experiencing the need for new resources.

- The revision in marketing in the long term is based on the conclusion that the level of peak demand and sales in the Median Case provide the lowest ¢/KWH of revenue requirements in the later years of the study period.

  - After 2000, the 9/86 "Base" forecast rate of growth was chosen since some utility influence and market presence was thought to be desirable.

FIGURE 6
¢/KWH OF REVENUE REQUIREMENTS FOR PP&L LEAST COST PLAN



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- o Although the Least Cost Plan does not produce the lowest ¢/KWH in each and every year as shown in *Figure 6 above, it does have the lowest ¢/KWH on a levelized basis.*

- o This plan delays the need for new load control, NUG or generating capacity to the end of the study period.

- o Overall, any other combinations of loads, sales and resources are not expected to produce a plan with significantly lower ¢/KWH of revenue requirements. As a result, this plan which is discussed beginning on page 41 was chosen since it is representative of the general needs of an LCP and satisfies PP&L objectives.

  - This conclusion is based on the fact that there is only a small difference in ¢/KWH of revenue requirements for all cases studied and no one case producing consistently low ¢/KWH of revenue requirements.

  - Changes to this plan are expected from reviews of this report, the financial analysis of this plan to be presented at EPC-87 and as a result of other issues scheduled for discussion at EPC-87.

ISSUES

ISSUES REQUIRING RESOLUTION
BEFORE FILING

1) ISSUE - What rate of return on common equity should be used in the annual LCP filing?

- o The LCP is presented in terms of Revenue Requirements. Revenue Requirements analysis includes all costs of doing business including a return on common equity. Thus, the LCP results are based on achieving this full return.

  - The LCP assumes an average return on common equity of 13% for the study duration which is the same rate used for EPC 87 Long-Term Financial Analysis and for other internal PP&L studies.
  - Our current allowed rate of return for PUC customers is 15.5%.

2) ISSUE - How will regulators, legislators, intervenors, etc. react to an LCP which includes increased use of electricity?

- o The LCP chosen by Task Team #10, does not produce ¢/KWH of revenue requirements that are significantly different from a plan showing a lower sales level.
- o While this LCP conforms to PP&L's goals and objectives and while it conforms to the PP&L definition of "Least-Cost", we have no evidence that it conforms to other's definition of least cost.
- o Society attitudes towards conservation vary and often appear related to energy availability. Even in today's relative energy abundance, many, including legislators and regulators, regard conservation of energy as important. They could equate "least cost" with "less use" of electricity and not increased use.

DS 018521

144

ISSUES

3) ISSUE - Should PP&L include financial information as part of the LCP?

- o This LCP aids PP&L by increasing sales and avoiding the need for base rate proceedings.
- o Price and supply stability is a benefit to customers while maintaining earnings is a benefit to the Company.
- o Is this earnings benefit substantial enough to point out within the context of an LCP filing?
- o Can it be used as a justification for the chosen LCP?

OTHER

4) ISSUE - This LCP proposes a reduction in the sales growth rate beginning in 1995. What revisions should be made to the marketing program to accomplish this change?

5) ISSUE - How, if at all, should PP&L address external impacts on PP&L's LCP?

- o PJM conditions
- o Reregulation
- o Acid Rain Legislation

6) ISSUE - By filing an LCP, are we in effect, providing an edge to the competition who are not required to file?

- o Competitive fuels
- o NUG
- o Other utilities

DS 018522

145

7) <u>ISSUE</u> - Should PP&L attempt to influence the PUC in the development and implementation of the LCP regulation?

- o PP&L will be developing a position on these issues and could share these findings with the PaPUC.
  - For example, PP&L has expanded the capabilities of the PUC Cost/Benefit Evaluation Methodology to evaluate marketing and supply-side options.
- o PP&L, along with other Pennsylvania utilities, will be responding with comments on the LCP regulations, which are scheduled to be published in the Pennsylvania Bulletin.
  - This could provide PP&L an opportunity to influence and respond to LCP regulation decisions made by the PaPUC.

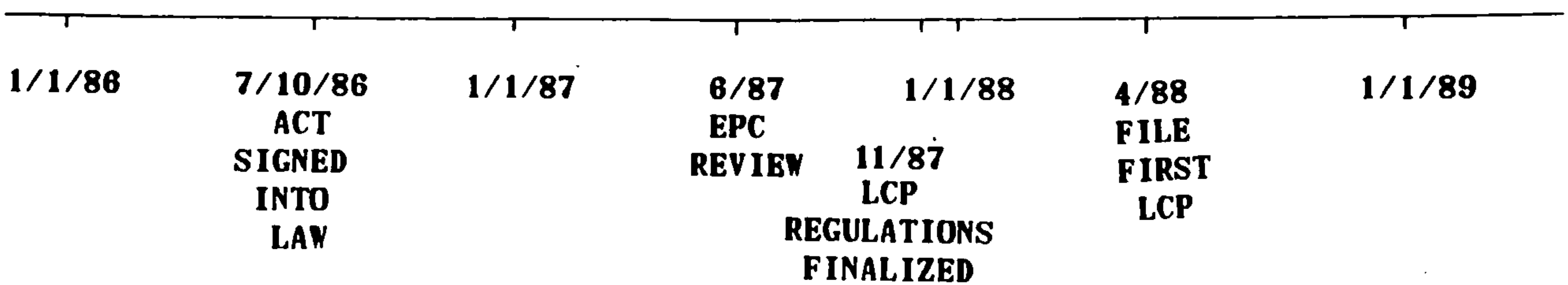
8) <u>ISSUE</u> - Existing NUG may be needed for capacity beyond the year 2000. Should PP&L do anything now to insure that the needed capacity will be in service and available when needed?

- o Existing contracts for NUG will expire:
  - between 1990 and 1995 for 50 MW of NUG
  - between 1996 and 2000 for zero MW of NUG
  - between 2001 and 2005 for 80 MW of NUG
  - between 2005 and 2010 for 360 MW of NUG.
- o These contracts allow PP&L to use NUG as capacity at no additional cost.
- o Will NUG remain viable over long term?
  - Some NUG units will be about 20 years old when needed for capacity. Maintenance practices will be important in the length of useful service life.
  - Once depreciated, will there be any benefits in NUG life extension programs?

9) <u>ISSUE</u> - Is there a potential timing conflict between the PP&L planning cycle and the date for filing the LCP?

- o What mechanism will be established to review LCP before filing?

FIGURE 7
LEAST COST PLAN TIME LINE



ACT 114 AND PAPUC LEAST-COST PLANNING (LCP) REGULATIONS

o The Public Utility Commission Sunset Bill (Act 114) was signed into law by Governor Thornburgh on July 10, 1986. The act provides:

- Continuation of the PaPUC through 12/31/92 with Sunset review at that time and every ten years thereafter.

- That electric utilities submit on an annual basis a 20-year resource plan intended to support the objective of "least-cost energy planning".

- Other requirements and restrictions in the areas of plant outages, capacity additions, management efficiency, quality of service, advertising expenses and fuel purchase audits.

o Figure 7 shown above shows the Least Cost Plan Time Line.

o In September, 1986, the PaPUC staff developed proposed regulations implementing the requirement of Act 114. The draft regulations require utilities to submit by May 1 of each year a 20-year resource plan including:

- three scenarios (low, medium and high) of annual energy and annual system peak demand by customer class.
- an evaluation of the cost effectiveness of all supply-side and demand-side resource options.
- a comparison of the potential rate impacts of all supply-side and demand-side resource options.
- an integration of all supply-side and demand-side resource options to derive the preferred, least-cost resource mix.

- o An LCP is to be developed for the most likely scenario of peak/energy growth.

- o *The documentation of the LCP is to include:*

  - a comparative evaluation of all demand-side and supply-side options (one option at a time) including a measure of attractiveness such as net present value, benefit-cost ratio, etc.
  - a discussion of non-economic factors related to the various resource options.
  - an explanation of the decision-making process used to derive the LCP including consideration of uncertainties and risks.

- o The first filing of an LCP with the PaPUC is to be made prior to May 1, 1988.

- o In addition, on or before May 1 of even-numbered years, a two-year implementation plan specifying all activities scheduled for the acquisition and development of the least-cost resources delineated in the most current annual LCP Report is to be filed.

  - Informal sessions are to be scheduled by the PaPUC to allow interested parties to participate in the review of the proposed implementation plans.

- o The least-cost planning data submitted by utilities is to be summarized in an annual report prepared by the PaPUC (due September 1st).
  - report is to be submitted to the Governor, General Assembly, Office of Consumer Advocate and *each affected utility.*

- o No specific approval or disapproval of utility plans is required by the PaPUC regulations.

149

DS 018526

MEASURE OF LEAST COST

- o The Task Team has chosen to measure "least cost" in terms of ¢/KWH of revenue requirements.
  - The proposed PaPUC regulations do not define the term "least cost".
  - Least Cost has different implications to different political, regulatory, utility and special interest groups.
  - For instance, least cost can be measured as the lowest ¢/KWH of revenue requirements, lowest total dollars of revenue requirements, lowest overall costs to society, etc.
  - ¢/KWH of revenue requirements is an appropriate measure because it recognizes that price is also a function of sales.
    - o Societal impacts are not always quantifiable but an LCP can be qualified to include such impacts.
- o The ¢/KWH of revenue requirements presented here are consistent with the proposed PPUC regulations.
  - It is also consistent with the evaluations required by the PaPUC for the Annual Conservation and Load Management Report.

150

RESOURCES AVAILABLE TO PP&L

DEMAND-SIDE OPTIONS

- o Demand-Side Management Options were broken into six categories:

  - Economic Development Initiative Rates
  - Equipment/Appliance Load Control
  - Building Envelope
  - Efficient Equipment/Appliance
  - Thermal Energy Storage Equipment
  - Cogeneration Alternative

- o The Economic Development Initiative (EDI) rate options were reviewed in the development of the LCP. The EDI rates are designed to stimulate economic activity in PP&L's service area by making favorable rates available to customers who can modify their electric demand to match off-peak periods. The specific EDI rate options evaluated in the LCP include:

  - Interruptible Service (IS-2) Rate
  - Customer Voluntary Load Curtailment Program
  - Industrial and Commercial Time-of-Day Rate
  - Demand-Free Day Program

15

DS 018528

- Equipment/Appliance Load Control techniques can be applied to a wide range of customer and end-use applications. The most common load control techniques -- "direct" and "local" -- are applied to the end-use appliances -- electric water heaters and air conditioners.

  - Direct Control is performed by sending signals via a two-way power line carrier communication system to receivers installed in customers' homes to control appliances.

  - Local Control is performed via a temperature-activated time switch, which is used to control the air conditioner.

- Building Envelope options are those that reduce building heat losses or gains. They allow customers to manage space conditioning, lighting, and to some extent water heating energy consumption and demand within buildings. Examples:

  - Higher Insulation Levels in New/Existing Buildings
  - Water Heater Blanket

- Efficient Equipment/Appliance options are those that provide a customer with the same level of service with a lower energy/demand usage pattern. Examples:

  - Space Heating Options ... Heat Pumps, Dual Fuel Heating Systems.
  - Space Cooling Option ... High Energy Efficiency Ratios (EER) Air Conditioners.
  - Water Heating Option ... Ground Source/Water Source Heat Pumps.
  - Equipment/Appliance Options ... Lighting, Motors, Refrigerators/Freezers, Industrial Process Electrotechnologies.

DS 018529

152

o Thermal Energy Storage Equipment options allow peak demand energy demands to be met with greatly reduced peak demand contributions. This is accomplished through the use of energy storage mediums, which are changed during off-peak demands. Thermal Energy Storage devices include:

- Space Heaters ... Ceramic Room, Central Hydronic, Heat Pump Plus (water storage), etc.
- Water Heaters.

o Cogeneration Alternative proposals include high efficiency electric and financial alternatives. These efforts are made to retain existing electric sales and avoid their loss by the installation of on-site cogeneration equipment.

DS 018530

153

SUPPLY-SIDE OPTIONS

o Supply-side options were divided into three categories:

- Extended Life
- New Central Station Generation
- Non-Utility Generation

o Life extension has generally been PP&L policy. To analyze the benefits of extended life, the Task Team evaluated life extension by comparing it to a case during which 1000 MW were retired. It was assumed for convenience, that base load units were retired after they had been in service for 40 years. Also, CT's which were not required for reliability were assumed to be retired.

- Holtwood 17 (73 MW), Martins Creek 1&2 (300 MW), Sunbury 1-4 (389 MW)
- 325 MW of CTs.

o Central Station Generation included most forms of base load, intermediate and peaking units.

- Nuclear, oil and gas-fired steam units were <u>not</u> included.
- Solar, wind and battery storage were eliminated because of their high cost and further need for technological development.

o Both existing NUG and new NUG facilities were considered for installed capacity purposes.

- Existing contracted NUG were paid at contract rates.
- Municipal Solid Waste Units were paid at the Pioneer Rate.
- New NUG were paid at the costs of a PP&L "avoided" capacity alternative.

157

DS 018531

SCREENING

- o Having developed the list of resources with their availability, the resources were ranked in order of most desirable to least desirable using economic and non-economic values to provide a focus on those options that best met objectives of a PP&L Least Cost Plan.

Evaluation Criteria

- o The criteria selected represent broad categories which represent a common base against which options can be measured. The categories selected are:

  - Economic
  - Sociopolitical
  - Technological
  - Service to Customers

- o Each category has criteria to allow for a more detailed screening of the options.

- o The criteria within each category are assigned weights so that the sum of the weights within a category equals 1.0.

- o Each category is assigned a weight so that the sum of the category weight equals 1.0.

APPLICATION OF CRITERIA

- o A numeric score ranging from 0 to +10 is assigned to each option with +10 being the most favorable rank.

- o The numeric score is multiplied by the weight assigned to the category.

- o The sum of the weighted numeric scores provides the overall score for each option.

- o Options with the highest weighted numeric scores have the highest rank in the screening.

SCREENING RESULTS

- o The screening process was applied several times using alternative weights for the criteria.

  - The results suggest that the weighting process is relatively insensitive to alternative weights.

- o The screening results which were generally consistent with the results of Task Team 8 indicate that:

  - Extended life, most rate options and existing NUG are the highest ranking resource options.

  - Certain marketing options e.g. energy efficient appliances, energy efficient lighting and super insulation were nearly as high ranking.

  - The lowest ranking options were new supply-side options and certain other marketing options e.g. water source heat pump and Heat Pump Plus.

- o The screening process, while not representing a complete or final evaluation of each option, is useful in developing case studies.

  - *Those options which scored high in the screening process were used in the development of the LCP case studies.*

  - In addition, Economic Development, received a low ranking in the screening because of a low score in the environmental impact criterion. However, it was included in the case studies because of positive impacts on the regional economy and to meet the short-term sales growth rate which generally result in the lowest ¢/KWH of revenue requirements.

CASE DEVELOPMENT AND ANALYSIS

- o There are two main components of the cases used for the analysis:

  - Energy use levels based on peak demand and sales.
  - Resources based on screening rank.

- o The development of the resource screening rank was reviewed in the previous section.

- o The development of energy use levels is reviewed in the following section.

PEAK DEMAND AND SALES

- o The Task Team has interpreted the PaPUC regulations to mean that each PA company should develop peak demand and sales cases that excludes any sales and associated peak demands attributed to Company-implemented programs. These peak demand and sales levels would:

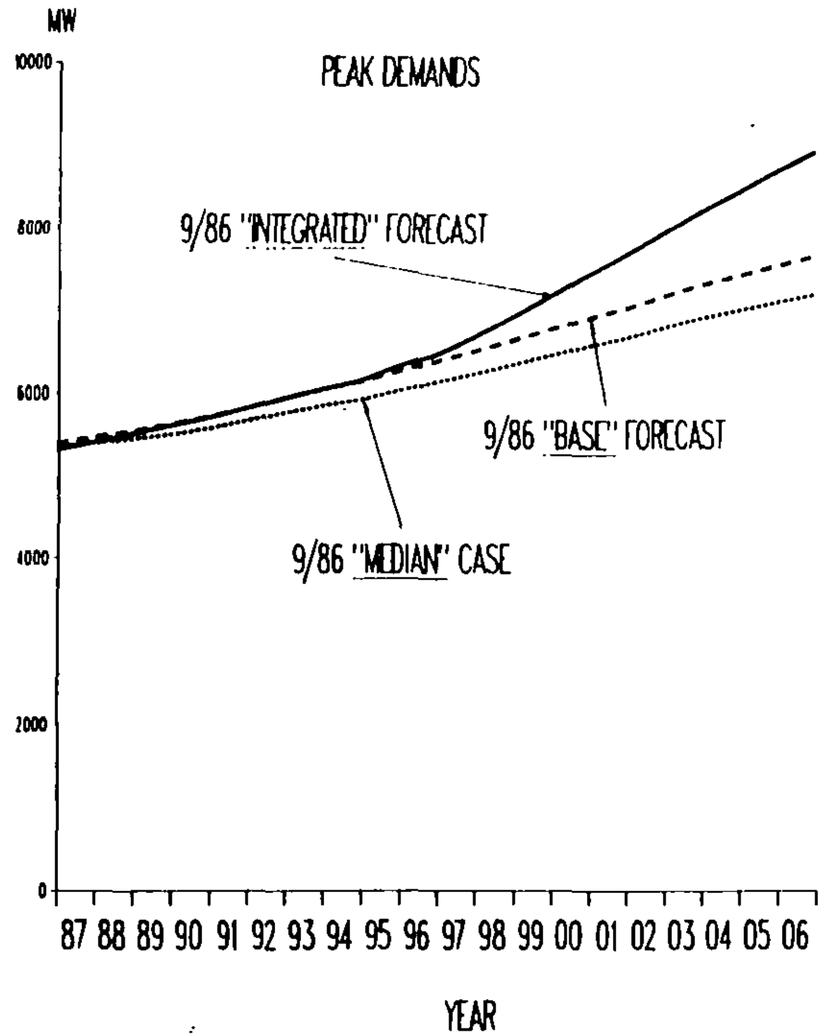
  - serve as a base from which to evaluate all feasible demand and supply-side options including NUG, marketing, load control, economic development, etc.

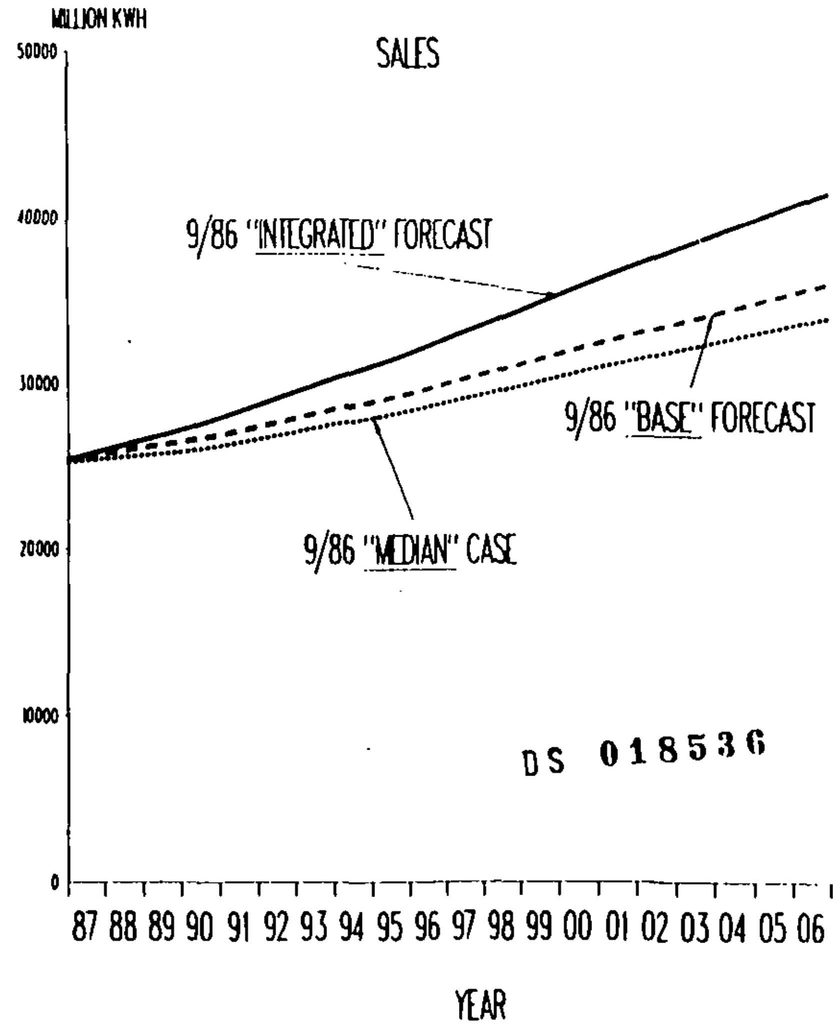
  - consist of median, high, and low energy use levels.

DS 018535

FIGURE 8

PEAK DEMANDS AND SALES COMPARISION





DS 018536

MEDIAN ENERGY USE LEVEL

- In September 1986, long term peak demand and sales forecasts were prepared by Rates and Market Research with and without long term marketing and economic development.
  - The 9/86 "Base" Forecast reflects the impact of marketing and economic development programs for the short term horizon only (1986-1987).
  - The 9/86 "Integrated" Forecast assumes the full attainment of the marketing and economic development goals for the full forecast period (1986-2006). The results of this forecast portray a higher annual peak demand growth and a shift to a nighttime winter peak beyond 1995.
- The 9/86 "Base" Forecast was chosen as the forecast from which to develop the 9/86 Median Case.
- The 9/86 Median Case, shown above, was developed by removing from the 9/86 Base Forecast the peak demand and sales contributions associated with:
  - The Residential marketing efforts aimed at increasing electric heat new dwelling unit saturation and number of RTS in both new and existing homes.
  - The successful marketing of industrial and commercial marketing and economic development activities.
  - Company sponsored conservation programs, had any been included in the base case.
- Continuing impacts of previous marketing programs were eliminated beginning at the start of 1987.

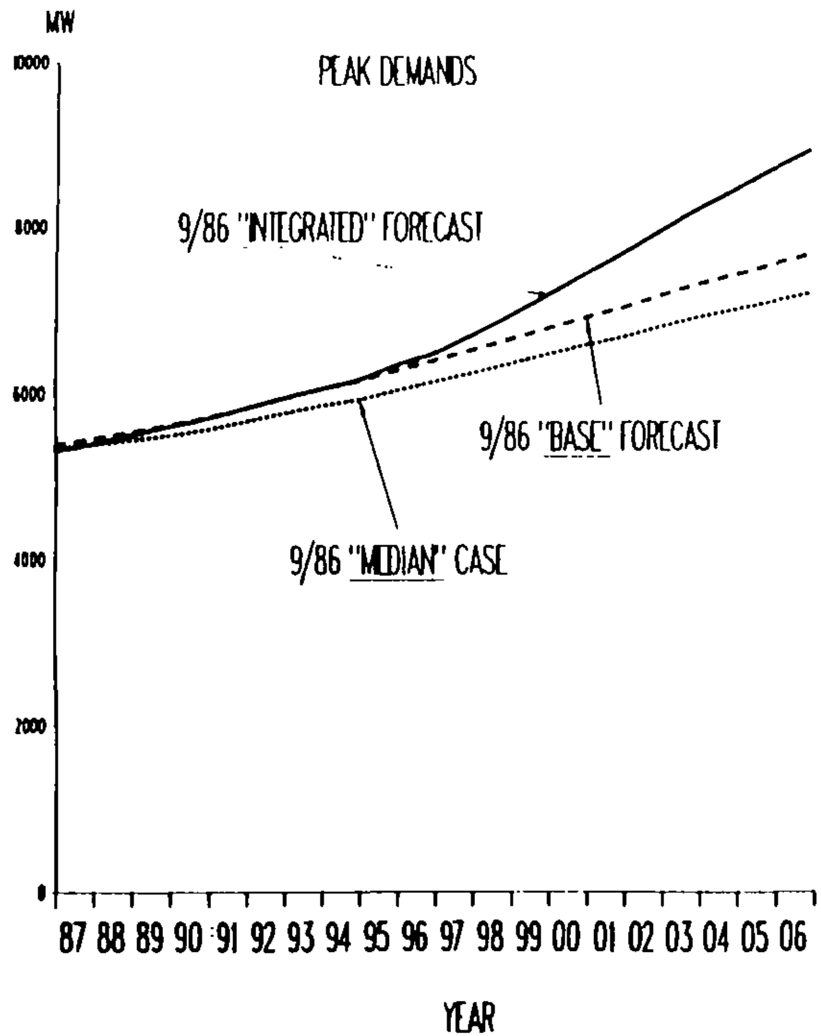
16

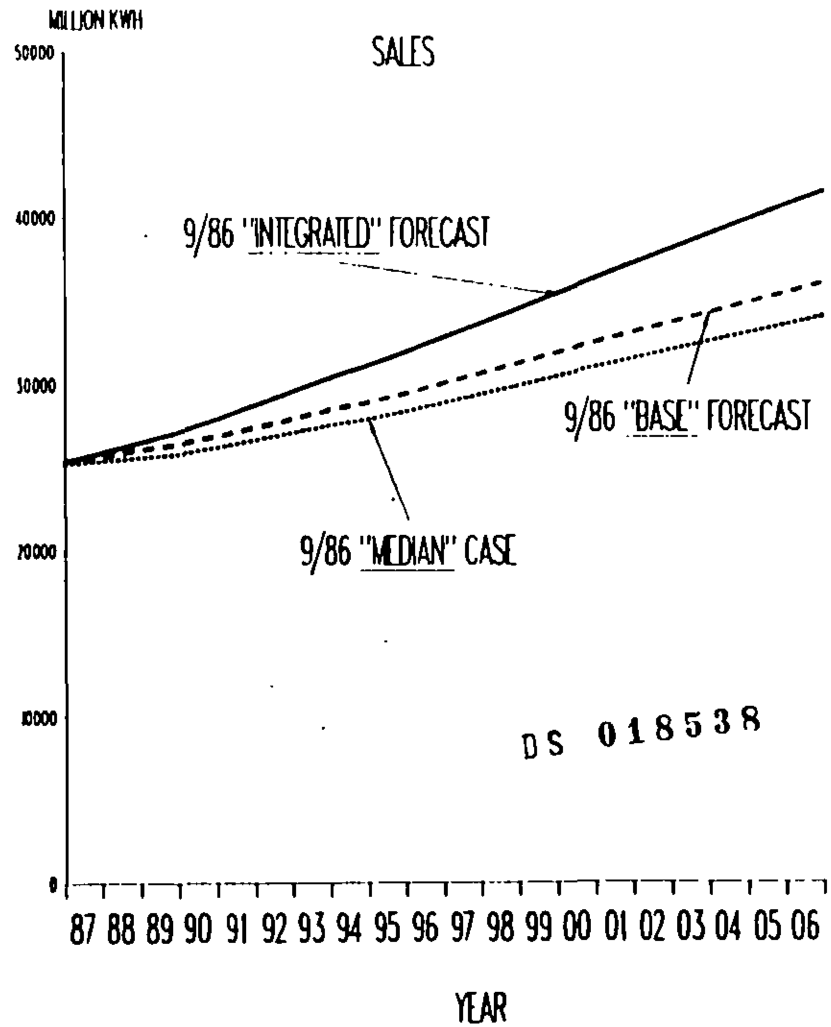
DS 018537

(REPEATED FROM PREVIOUS PAGE)

FIGURE 8

PEAK DEMANDS AND SALES COMPARISION





DS 018538

- Without these programs, both system sales and winter peaks grow at a 1.5% through 2006.

- On April 6, 1987 CMC approved the use of the projected sales from the 9/86 "Integrated" Forecast and the system winter peak demands from the 9/85 Forecast for external reporting and internal Corporate planning.

    - The Least Cost Plan will be compared to that reference case elsewhere within the context of EPC-87.

162

DS 018539

PROBABLE HIGH AND PROBABLE LOW ENERGY USE LEVELS

- o The Probable High and Low energy use levels were developed from the Median energy use level.

- o The Probable High energy use level includes:
  - Higher average electricity use by residential customers
  - Increased electricity use by agricultural on interruptible rates such as greenhouses
  - Revitalization of steel industry
  - No reductions in sales to textile, apparel or coal mining industries
  - Faster population growth
  - An additional FERC customer
  - The retirement of Hunlock
  - Reductions in self-generation
  - Termination of the NYPA allocation to FERC customers.
  - Resort expansion in Poconos

- o The Probable Low energy use level includes:
  - Lower average electricity use by residential customers and lower market share for electric residential heating
  - Reductions in sales to Commercial customers
  - Reductions in sales to textile, apparel and coal mining industries
  - Termination of UGI contract in 1999
  - Slower population growth
  - Termination of Citizens Electric and one other FERC customer contracts
  - Lighting efficiency improvements
  - Increase in self-generation
  - Increased NYPA allocation to FERC customers.

163

- o The peak demand and sales levels together with the resource list were than used to develop various cases. The results of these cases provided information to develop the LCP.

- o In general, groups of two to four cases were developed and analyzed at a time before proceeding to develop additional cases.

  - The results of each analysis were used to develop the next group of cases.

  - The number of cases developed and analyzed was reduced through this process.

FIGURE 9 -- CASES STUDIED

	Median Cases		
Case Number	1	2	3
Case Description	Median Case	Median Case With Retirement of PP&L Capacity	Median Case With Life Extension and Measures to Reduce Peak Demand
Peak Demand	Median	Median	Median
Energy Sales	Median	Median	Median
Measures to Reduce Peak Demand	No	Yes	Yes
Measures to Increase Sales	No	No	No
PP&L Capacity	No Change	About 1,000 MW Retired	No Change
NUG as Capacity	No	No	No

MEDIAN CASE

- o The intent of the Task Team approach was to examine all resource options by building up, or down, from the Median Case which is shown as case 1 above.

- o The Median Case is designed to exclude any utility sponsored programs which influence peak demand or sales from either marketing or conservation.

- o The Median Case assumes that no PP&L power plant will be retired for the study period and thus, all capital and operating costs associated with life extension are embedded within this case.

- o This first set of comparisons determines the importance of power plant life extension instead of, and in conjunction with, measures to reduce the peak demand.

  - Case 2 eliminates the cost of life extension but includes costs for measures to reduce the peak demand.
  - Case 3 continues the life extension costs and adds costs of measures to reduce the peak demand.

- o The general observations available from these comparisons are as follows:

  - PP&L power plant life extension is economically desirable.
  - In the near term, lower sales tends to increase ¢/KWH of revenue requirements
  - Measures to reduce peak demand may make sense as additional resources required to satisfy PP&L's Installed Capacity Obligation.

- o Since life extension is economically desirable, it is included in all subsequent cases.

196

DS 018543

FIGURE 10 -- CASES STUDIED

	Median Cases			Marketing Cases	
Case Number	1	2	3	4	5
Case Descrip.	Median Case	Median Case With Retirement of PP&L Capacity	Median Case With Life Extension and Measures to Reduce Peak Demand	All Marketing Case	9/86 "Integrated" Forecast
Peak Demand	Median	Median	Median	All Marketing	9/86 "Integrated"
Energy Sales	Median	Median	Median	9/86 Integrated	9/86 Integrated
Measures to Reduce Peak Demand	No	Yes	Yes	No	No
Measures to Increase Sales	No	No	No	Yes	Yes
PP&L Capacity	No Change	About 1,000 MW	No Change	No Change	No Change
NUG as Capacity	No	No	No	No	No

DS 018544

MARKETING CASES

- The next set of cases were developed to investigate if higher levels of sales achieve lower ¢/KWH than the Median Case.

- Case 4, the All Marketing Case, investigates the addition of sales through a marketing program that does not specifically include measures to control peak demand growth rates.

- Case 5 is PP&L's 9/86 "Integrated" Forecast. Marketing efforts are directed at increasing sales, but, these sales are concentrated in the winter nighttime hours.

- PP&L's costs for both of these cases were increased to include capital, operating and manpower costs for marketing and economic development, and additional load-related transmission/distribution costs.

- The observations available from these cases are:

  - Higher sales levels, when compared to the Median case, tend to reduce ¢/KWH of revenue requirements prior to 2000.
  - Concentrating these sales in the nighttime tends to further reduce ¢/KWH of revenue requirements prior to 2000.
  - The need for additional resources is advanced compared to the Median Case for both cases but still occurs after 2000.
  - The need for additional resources is much greater for the 9/86 "Integrated" Forecast than for Case 4, the All Marketing Case.
  - After 2000, both sales cases result in a higher level of ¢/KWH than the Median case level.

DS 018545

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FIGURE 10 -- CASES STUDIED

	Median Cases			Marketing Cases	
Case Number	1	2	3	4	5
Case Descrip.	Median Case	Median Case With Retirement of PP&L Capacity	Median Case With Life Extension and Measures to Reduce Peak Demand	All Marketing Case	9/86 "Integrated" Forecast
Peak Demand	Median	Median	Median	All Marketing	9/86 "Integrated"
Energy Sales	Median	Median	Median	9/86 Integrated	9/86 Integrated
Measures to Reduce Peak Demand	No	Yes	Yes	No	No
Measures to Increase Sales	No	No	No	Yes	Yes
PP&L Capacity	No Change	About 1,000 MW	No Change	No Change	No Change
NUG as Capacity	No	No	No	No	No

DS 018546

- o These cases were developed without adding resources to maintain ICO since their purpose was only to determine, in general, if higher sales were superior to lower sales.
  - These cases also provided the magnitude of PP&L's ICO shortfall.
- o The Task Team did not investigate the Probable High energy use level since the All Marketing Case resulted in higher peak demand and energy sales.

FIGURE 11 -- CASES STUDIED

	Median Cases			Marketing Cases				Resource Cases	
Case Number	1	2	3	4	5	6	7	8	14
Case Descrip.	Median Case	Median Case With Retirement of PPAI Capacity	Median Case With Life Extension and Measures to Reduce Peak Demand	All Marketing Case	9/86 "Integrated" Forecast	9/86 Base	9/86 Probable Low	9/86 Integrated With New Capacity	9/86 Integrated With Direct-Load Control and NUG
Peak Demand	Median	Median	Median	All Marketing	9/86 "Integrated"	9/86 Base	Probable Low	9/86 Integrated	9/86 Integrated With Direct-Load Control and NUG
Energy Sales	Median	Median	Median	9/86 Integrated	9/86 Integrated	9/86 Base	Probable Low	9/86 Integrated	9/86 Integrated With Direct-Load Control and NUG
Measures to Reduce Peak Demand	No	Yes	Yes	No	No	No	No	Yes	Yes
Measures to Increase Sales	No	No	No	Yes	Yes	No	Short Term	Yes	Yes
PPAI Capacity	No Change	About 1,000 MW	No Change	No Change	No Change	No Change	No Change	Add 1000 MW New Coal	No Change
NUG as Capacity	No	No	No	No	No	No	No	No	Yes

RESOURCE CASES

- o Case 6, The 9/86 "Base" Forecast, shown above, was developed as part of the Task Team #10 assignment to identify the issues associated with PP&L going to a nighttime peak. It is useful here to confirm that the trend toward sales greater than the Median Case is desirable prior to 2000.

- o Case 7 corresponds to the 9/86 Probable Low Case and was developed for two reasons:

  - To confirm that sales lower than the Median Case do result in higher ¢/KWH prior to 2000.

    - o It is possible that decreasing sales below the Median Case could also reduce ¢/KWH if the Median sales level had the highest average of total fixed and variable costs.

  - To satisfy the reporting requirement of the preliminary PUC regulations.

- o These cases demonstrate that:

  - Sales at a level higher than the Median Case are desirable prior to 2000 since they tend to reduce ¢/KWH.

  - However, sales lower than the Median Case tend to further increase ¢/KWH for the entire period.

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FIGURE 11 -- CASES STUDIED

	Median Cases			Marketing Cases		Resource Cases			
Case Number	1	2	3	4	5	6	7	8	14
Case Descrip.	Median Case	Median Case With Retirement of PP&L Capacity	Median Case With Life Extension and Measures to Reduce Peak Demand	All Marketing Case	9/86 "Integrated" Forecast	9/86 Base	9/86 Probable Low	9/86 Integrated With New Capacity	9/86 Integrated With Direct-Load Control and NUG
Peak Demand	Median	Median	Median	All Marketing	9/86 "Integrated"	9/86 Base	Probable Low	9/86 Integrated	9/86 Integrated With Direct-Load Control and NUG
Energy Sales	Median	Median	Median	9/86 Integrated	9/86 Integrated	9/86 Base	Probable Low	9/86 Integrated	9/86 Integrated With Direct-Load Control and NUG
Measures to Reduce Peak Demand	No	Yes	Yes	No	No	No	No	Yes	Yes
Measures to Increase Sales	No	No	No	Yes	Yes	No	Short Term	Yes	Yes
PP&L Capacity	No Change	About 1,000 MW	No Change	No Change	No Change	No Change	No Change	Add 1000 MW New Coal	No Change
NUG as Capacity	No	No	No	No	No	No	No	No	Yes

DS 018550

173

- Cases 8 and 14 were developed to determine if, with the addition of alternate resources, the effect of lowering ¢/KWH with respect to the Median Case, is beneficial past 2000.

- Case 8 is based on the 9/86 "Integrated" Forecast, and adds a 500 MW coal fired unit in both 2003 and 2005.

  - Peaking generation was not added since there was an apparent need to reduce energy costs.

- Case 14 is also based on the 9/86 "Integrated" Forecast and uses Direct Load Control to stagger the RTS recharge throughout the on-peak and off-peak hours to clip peaks and NUG for installed capacity. There is limited potential for Direct Load Control since PP&L's winter daily load shape is already relatively flat. Thus, load control alone is not sufficient to delay the need for capacity to the end of the period.

  - 525 MW of NUG is presently projected to be in-service on the PP&L system in the early 1990's.

  - The 525 MW of NUG was designated as installed capacity for PJM purposes at no additional cost to PP&L.

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FIGURE 11 -- CASES STUDIED

	Median Cases			Marketing Cases		Resource Cases			
Case Number	1	2	3	4	5	6	7	8	14
Case Descrip.	Median Case	Median Case With Retirement of PP&L Capacity	Median Case With Life Extension and Measures to Reduce Peak Demand	All Marketing Case	9/86 "Integrated" Forecast	9/86 Base	9/86 Probable Low	9/86 Integrated With New Capacity	9/86 Integrated With Direct-Load Control and NUG
Peak Demand	Median	Median	Median	All Marketing	9/86 "Integrated"	9/86 Base	Probable Low	9/86 Integrated	9/86 Integrated With Direct-Load Control and NUG
Energy Sales	Median	Median	Median	9/86 Integrated	9/86 Integrated	9/86 Base	Probable Low	9/86 Integrated	9/86 Integrated With Direct-Load Control and NUG
Measures to Reduce Peak Demand	No	Yes	Yes	No	No	No	No	Yes	Yes
Measures to Increase Sales	No	No	No	Yes	Yes	No	Short Term	Yes	Yes
PP&L Capacity	No Change	About 1,000 MW	No Change	No Change	No Change	No Change	No Change	Add 1000 MW New Coal	No Change
NUG as Capacity	No	No	No	No	No	No	No	No	Yes

DS 018552

- The observations from this investigation are as follows:

  - Additional resources, whether demand or supply side, will increase ¢/KWH of revenue requirements with respect to the Median Case after 2000.

  - Load Control and using 525 MW of today's NUG, assuming that NUG will continue to be in service, to satisfy ICO tend to be favored when compared to new capacity.

- For this analysis, it was assumed that additional NUG, if needed for capacity reasons, would likely require some form of capacity credit.

  - There should be no difference in new NUG and new PP&L capacity from a revenue requirements standpoint.

176

DS 018553

FIGURE 12 -- CASES STUDIED

	Median Cases			Marketing Cases		Resource Cases			
Case Number	1	2	3	4	5	6	7	8	14
Case Descrip.	Median Case	Median Case With Retirement of PP&L Capacity	Median Case With Life Extension and Measures to Reduce Peak Demand	All Marketing Case	9/86 "Integrated" Forecast	9/86 Base	9/86 Probable Low	9/86 Integrated With New Capacity	9/86 Integrated With Direct-Load Control and NUG
Peak Demand	Median	Median	Median	All Marketing	9/86 "Integrated"	9/86 Base	Probable Low	9/86 Integrated	9/86 Integrated With Direct-Load Control and NUG
Energy Sales	Median	Median	Median	9/86 Integrated	9/86 Integrated	9/86 Base	Probable Low	9/86 Integrated	9/86 Integrated With Direct-Load Control and NUG
Measures to Reduce Peak Demand	No	Yes	Yes	No	No	No	No	Yes	Yes
Measures to Increase Sales	No	No	No	Yes	Yes	No	Short Term	Yes	Yes
PP&L Capacity	No Change	About 1,000 MW	No Change	No Change	No Change	No Change	No Change	Add 1000 MW New Coal	No Change
NUG as Capacity	No	No	No	No	No	No.	No	No	Yes

	Fuel Price Sensitivity			
Case Number	9	10	11	12
Case Descrip.	Median High Fuel Prices	Median Low Fuel Prices	9/86 "Integrated" High Fuel Prices	9/86 "Integrated" Low Fuel Prices
Peak Demand	Median	Median	9/86 Integrated	9/86 Integrated
Energy Sales	Median	Median	9/86 Integrated	9/86 Integrated
Measures to Reduce Peak Demand	No	Median	Yes	9/86 Integrated
Measures to Increase Sales	No	Median	No	9/86 Integrated
PP&L Capacity	No Change	Median	No Change	9/86 Integrated
NUG as Capacity	No	Median	No	9/86 Integrated

DS 018554

FUEL PRICE SENSITIVITY

- The final set of cases shown in Figure 12 involved a fuel price sensitivity. Cases 9 through 12 investigate the impacts of extremely low and high coal and oil prices.

- These fuel price bounds which correspond to the low and high cases presented in the 11/86 Long-Term Fossil Fuel forecast are:

	Low		Base		High	
	Coal $/Ton	#6 Oil $/bbl	Coal $/Ton	#6 Oil $/bbl	Coal $/Ton	#6 Oil $/bbl
1990	30.00	8.50	35.50	19.00	41.00	59.50
1995	42.00	11.00	53.00	44.50	72.50	100.00
2000	56.50	15.00	75.50	68.50	109.50	146.50
2005	77.50	20.50	108.50	106.00	165.50	214.50

Values in Current Dollars.

- These are sensitivities, not cases, and are intended only to investigate trends.

- High coal and oil prices cause an increase in ¢/KWH of revenue requirements for higher sales beginning in about 1995.

- Low coal and oil prices would extend the incentive to market past 2000, but only up to the point that new resources are required.

178

DS 018555

FIGURE 13 -- CASES STUDIED

	Median Cases			Marketing Cases		Resource Cases			
Case Number	1	2	3	4	5	6	7	8	14
Case Descrip.	Median Case	Median Case With Retirement of PP&L Capacity	Median Case With Life Extension and Measures to Reduce Peak Demand	All Marketing Case	9/86 "Integrated" Forecast	9/86 Base	9/86 Probable Low	9/86 Integrated With New Capacity	9/86 Integrated With Direct-Load Control and NUG
Peak Demand	Median	Median	Median	All Marketing	9/86 "Integrated"	9/86 Base	Probable Low	9/86 Integrated	9/86 Integrated With Direct-Load Control and NUG
Energy Sales	Median	Median	Median	9/86 Integrated	9/86 Integrated	9/86 Base	Probable Low	9/86 Integrated	9/86 Integrated With Direct-Load Control and NUG
Measures to Reduce Peak Demand	No	Yes	Yes	No	No	No	No	Yes	Yes
Measures to Increase Sales	No	No	No	Yes	Yes	No	Short Term	Yes	Yes
PP&L Capacity	No Change	About 1,000 MW	No Change	No Change	No Change	No Change	No Change	Add 1000 MW New Coal	No Change
NUG as Capacity	No	No	No	No	No	No	No	No	Yes

	Fuel Price Sensitivity				Least Cost Plan
Case Number	9	10	11	12	13
Case Descrip.	Median High Fuel Prices	Median Low Fuel Prices	9/86 "Integrated" High Fuel Prices	9/86 "Integrated" Low Fuel Prices	A Least Cost Plan
Peak Demand	Median	Median	9/86 Integrated	9/86 Integrated	See Writeup
Energy Sales	Median	Median	9/86 Integrated	9/86 Integrated	See Writeup
Measures to Reduce Peak Demand	No	Median	Yes	9/86 Integrated	Yes
Measures to Increase Sales	No	Median	No	9/86 Integrated	No
PP&L Capacity	No Change	Median	No Change	9/86 Integrated	No Change
NUG as Capacity	No	Median	No	9/86 Integrated	No

LEAST COST PLAN

o Case 13, a Least Cost Plan, shown in Figure 13, was developed based on the conclusions of the foregoing analysis.

o This case is aimed at achieving sales higher than the Median Case prior to 2000, yet still avoid the need for capacity throughout the study period.

o This case also recognizes the value of promoting off-peak sales.

o Thus, the case is as follows:

  - Market to achieve sales growth associated with the 9/86 "Integrated" Forecast through 1995.

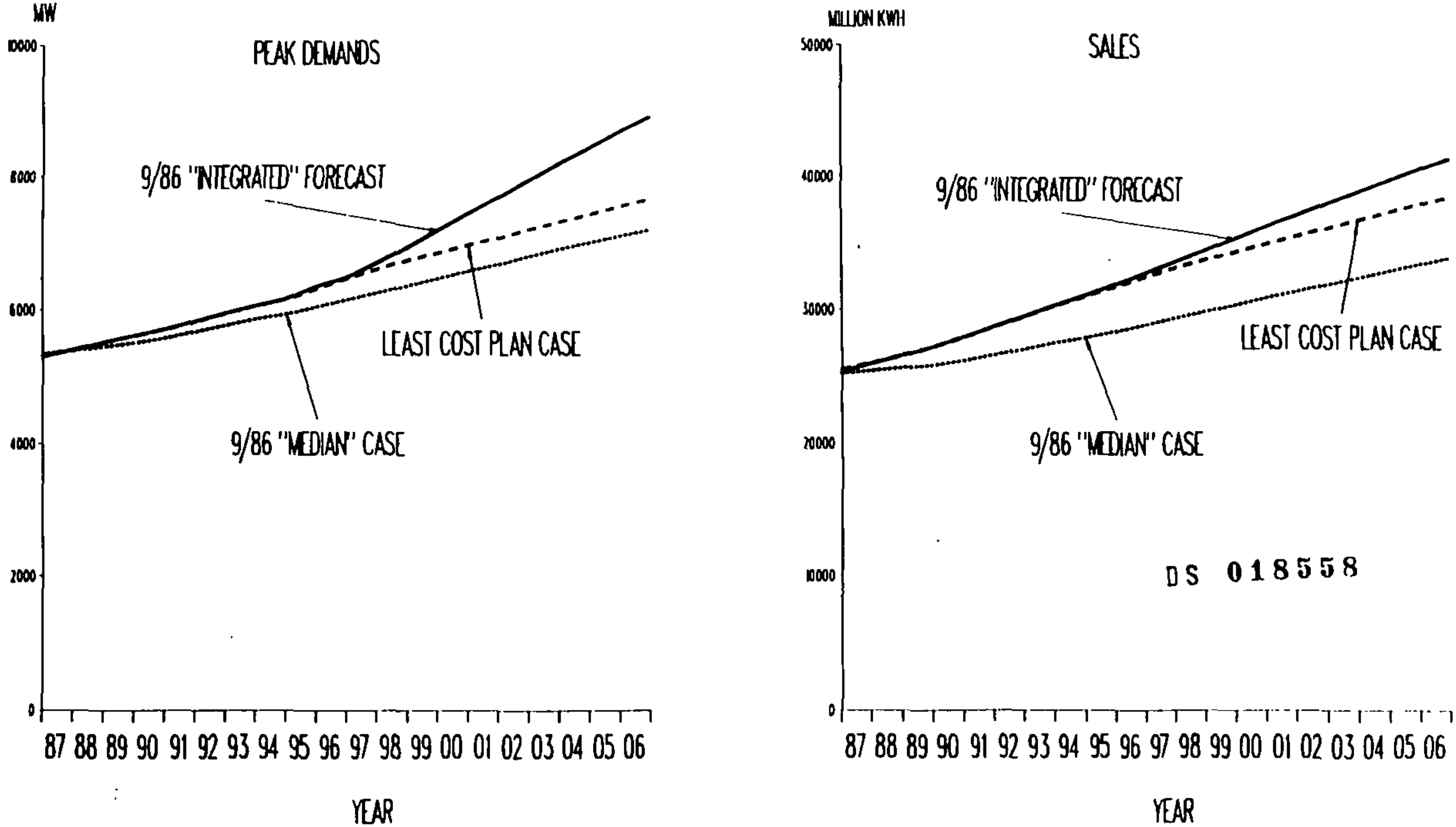
  - After 1995, annually stepdown marketing efforts by 20% so that there is a sales growth rate of 1.8 for the years past 2000.

  - Continue to increase peak demand and sales after 2000 at about the level of the 9/86 "Base" Forecast, to recognize that some utility market presence and influence is desirable.

o While this case does not produce the lowest ¢/KWH in each and every year, it does produce the lowest ¢/KWH in levelized terms.

FIGURE 14

PEAK DEMANDS AND SALES COMPARISION



DS 018558

HOW DOES THIS LEAST COST PLAN FIT PP&L LCP OBJECTIVES?

PP&L LCP OBJECTIVES

To produce a 20-year resource plan which ...

1) ... contributes to meeting PP&L's mission and objectives. This Least Cost Plan

- o Provides for reliable and economical service throughout the study period.
- o Maintains the rise in average price for electricity (average revenue requirement) below the general rate of inflation (3.6% vs. 4.8%) for the 1986 - 2006 period.
- o Holds peak demand growth to a level that defers the need for new generation into the 21st century as shown in Figure 14.
- o Is not evaluated here for financial objectives which are addressed separately in EPC-87.

2) ... provides a mix of demand-side and supply-side options which, when balanced against perceived risks, is expected to result in the least cost to the customer's electricity needs as measured in ¢/KWH.

- o This Least Cost Plan does result in the lowest ¢/KWH of revenue requirement when levelized over the period. Generally, customer needs are met without the need for additional costly resources.

3) ... is sufficiently flexible to respond to uncertainties in load/fuel forecasts and other external factors, such as regulatory environment, legislative changes, etc. This Least Cost Plan

- o Is sufficiently flexible in that sales levels are not so high to cause ¢/KWH of revenue requirements to rise dramatically due to fuel price disruptions.

- o Produces an acceptable level of revenue requirement in the event of low sales.

- o Has a low average revenue requirement and a reduced need for base rate increases which could minimize legislative/regulatory concerns.

- o However, has little additional opportunity for direct control of loads because the LCP already includes high levels of load control such as interruptible load and off-peak storage heating.

  - PP&L's peak day load shape is relatively flat for this case.

4) ... provides a preferred and contingency plans to address uncertainties.

- o These uncertainties include:

  - Competition levels from other energy supplies.
  - Significant changes in fuel costs.
  - Regulation action such as acid rain legislation.
  - Loss of major customer load.

DS 018560

- o This Least Cost Plan can be quickly altered to continue marketing in the event of lower or higher than expected sales.

HOW DOES THIS LEAST COST PLAN
CONFORM TO THE PROPOSED PAPUC REGULATIONS?

- PaPUC proposed regulations provide guidelines for both developing and reporting a utility's Least Cost Plan.

- This LCP addresses the PPUC guidelines for developing LCP as enumerated below. This report is not presented in the PPUC reporting format since regulations are preliminary and subject to change. The PPUC guidelines for developing an LCP include:
  - Consideration of three load growth scenarios: low, median, and high.
  - Development of preferred least cost resource mix for the likely load growth scenario and determination of modifications to this mix if either of the other two load growth scenarios occur.
  - Determination of the potential and cost effectiveness of all available supply-side and demand-side options including:
    - Existing capacity uprating and extension of useful life.
    - Non-Utility Generation (NUG) and the sensitivity of the amount of NUG to purchase price.
    - Energy conservation and demand management.
    - Strategic marketing.
    - Both conventional and non-conventional supply-side options.

  - Consideration of system reliability, uncertainties, and risk associated with above resource options.

- Information to fulfill the current PPUC reporting guidelines is available from PP&L's Least Cost Planning procedure.

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CEPFOD Exhibit No. 11

DRAFT

RTS TASK FORCE

RTS RATE ECONOMIC ANALYSIS AND ~~NEW~~ LOAD MANAGEMENT OPTIONS FOR RESIDENTIAL THERMAL STORAGE SYSTEMS

APRIL 1991

RTS TASK FORCE

RTS RATE ECONOMIC ANALYSIS AND ~~NEW~~ LOAD MANAGEMENT OPTIONS FOR RESIDENTIAL THERMAL STORAGE SYSTEMS

SYSTEM PLANNING

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RATES & MARKET RESEARCH

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DISTRIBUTION

R. E. LEE

TABLE OF CONTENTS

TABLE OF FIGURES

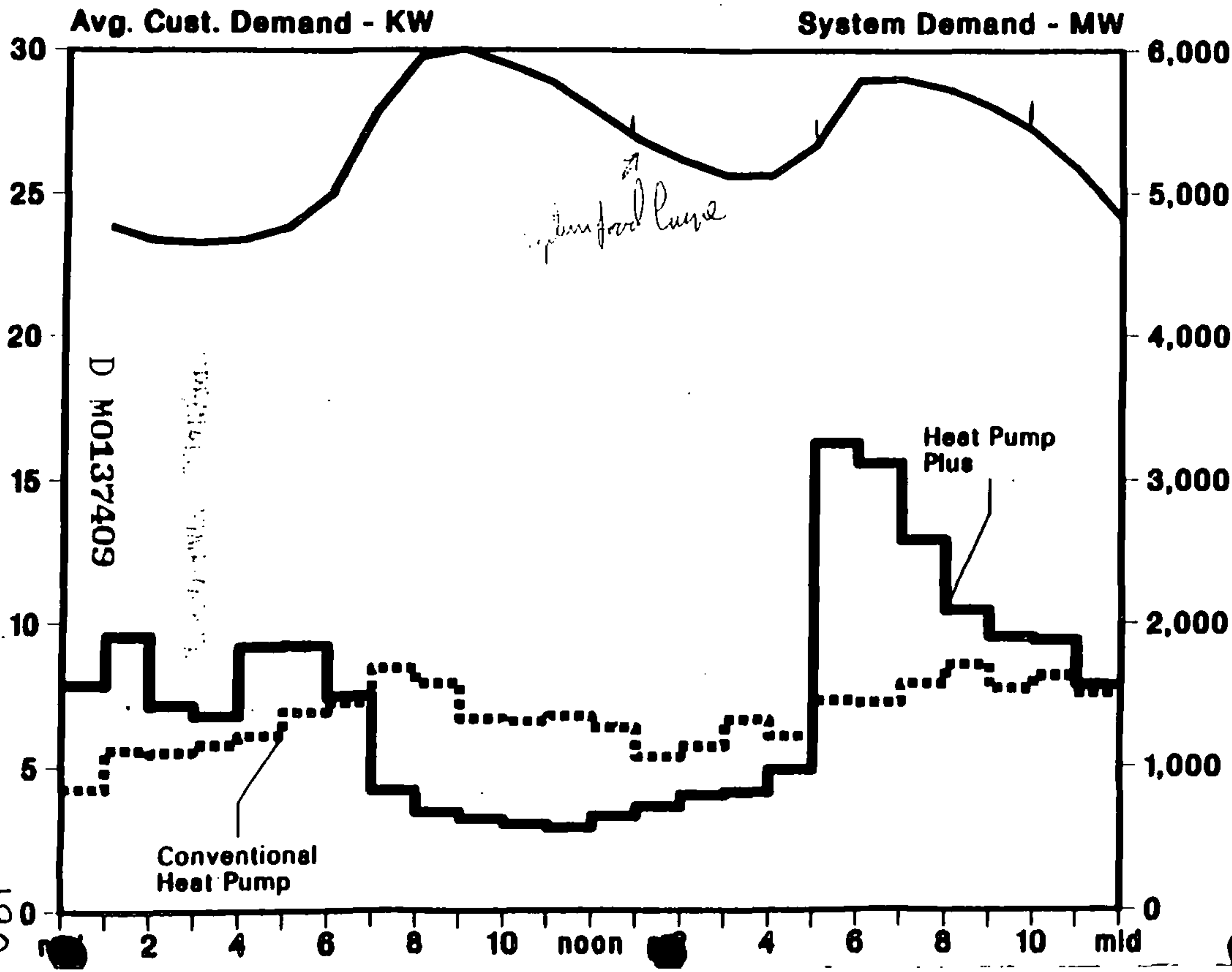
INTRODUCTION

Figure 1

13,200 customers
19KW
230

Heat Pump Plus vs. Conventional Heat Pump

System Peak Day: Dec. 22, 1989



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190

- The RTS Task Force was established in July 1990 to ~~accomplish~~ the following objective:

  - Identify, test and evaluate ~~new~~ options for controlling the operation of Residential Thermal (RTS) Storage Systems to improve their load management capabilities. & to perform an economic evaluation of the RTS Rate.

  - RTS systems currently operate in a fashion that contributes ~~significant~~ load to PP&L's 5 pm to 9 pm evening peak period. Continued promotion of RTS Systems could contribute to a more frequent occurrence of the system peak hour within this time period. New options identified by the RTS Task Force are to shift RTS system loads out of the 5 pm to 9 pm evening peak time period.

  - Figure 1 illustrates the increased load contributed from an RTS System (represented by a Heat Pump Plus system) as compared to a conventional heat pump during the 5 pm to 9 pm evening peak period.

- To perform a more complete evaluation of RTS Systems, the RTS Task Force expanded it ~~activities in the~~ Fall of 1990 to include:

  - Performing an ~~economic evaluation~~ of the RTS Rate.

- Heat Pump Plus and Ceramic Room Heater System are representing RTS Systems throughout the report. These two systems were used as they constitute approximately 96% of all RTS systems installed in our service territory.

Add Dave's Paragraph

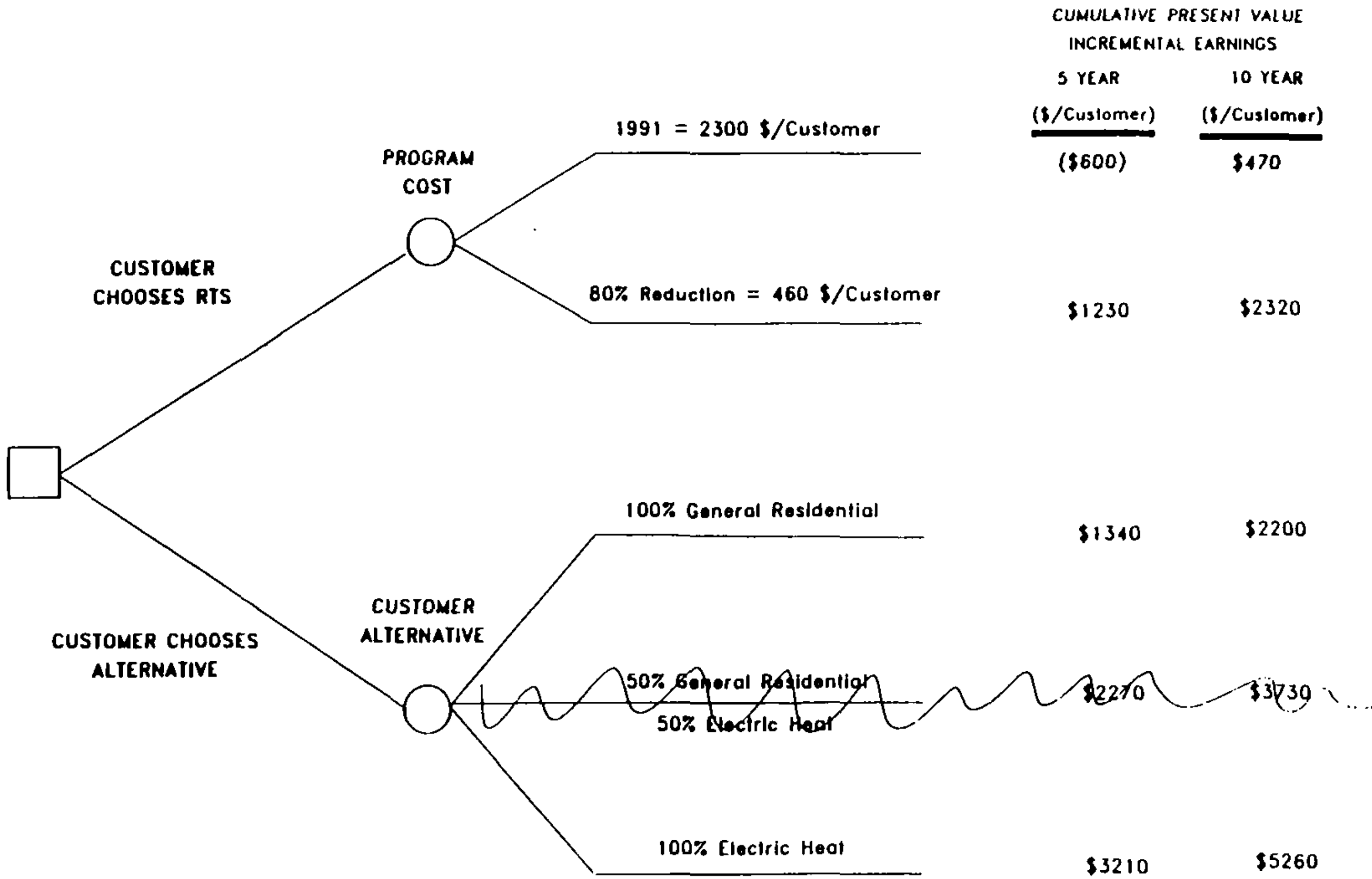
SUMMARY

This section highlights the key findings of the Task Force in three areas:

- Economics of RTS -- P~~re Rate Case~~ (Incremental Earnings)
- Economics of RTS -- P~~ost Rate Case~~
- Load Management Options for RTS Systems

FIGURE 2

INCREMENTAL EARNINGS EFFECTS



Editorial Changes

ECONOMICS OF RTS -- ~~PRE-RATE CASE~~ (INCREMENTAL EARNINGS)

- o Incremental earnings represent the portion of revenue resulting from adding a customer that will flow to PP&L earnings.

- o Projections of incremental earnings are affected by uncertainties associated with program costs and the RTS customer's alternative to RTS.

- o Figure 2 depicts the uncertainties associated with RTS and the resulting effect on incremental earnings. Uncertainties include:

  - Program Costs -- 1991 costs for RTS are estimated at about $2,300 per customer (promotional expenditures, residential grants, etc.). However, these costs could decrease about 80 percent to $460 per customer by 1995 assuming a phasing out of residential grants and shifting of advertising and manpower costs to focus on other programs.

  - Customer Alternative -- If RTS was not offered, customers would select an alternative system (fossil or electric). The amount of earnings that PP&L would receive without RTS depends on the customer's alternative selection.

- o The net effect on earnings equals the incremental earnings from the RTS customer, less program costs, less the earnings PP&L would have received had the customer selected an alternative system.

- o If program costs remain at 1991 levels ($2,300 per customer), the net effect of the RTS program on earnings is negative regardless of the customer's alternative.

  - For example, earnings over a 10 year period decrease by $ 1,730 ($ 470 less $ 2,200) if a customer choosing only general residential service is influenced to choose an RTS System.

  - Earnings over a 10 year period decrease by $ 4,790 if a customer choosing an electric heating system is influenced to choose an RTS System.

194

- The RTS Program enhances net incremental earnings only if 1991 program costs are reduced by about 80 percent to $ 460 per customer, and only for general residential customers that are influenced to select an RTS system.

  - Earnings over a 10 year period amount to $ 120 ($ 2,320 - $ 2,200) per customer.

- PP&L's 1988 market research results indicate that about 50 percent of PP&L's RTS customers would have chosen electric heat if RTS was not available.

  - Converting these customers from an alternate electric heating system to an RTS System decreases earnings over a 10 year period by $ 3,260 ($ 470 - 3,730) per customer.

Reword to clearly state

ECONOMICS OF RTS -- ~~POST-RATE CASE~~ Rate of Return

- o Currently, the RTS rate reflects a lower rate of return than the Residential Service (RS) rate.

  - Based on 1989 data, the RTS rate earns a rate of return of about 2.1 percent if the nighttime peak contribution is unchanged or about 3.6 percent if the contribution nighttime peak is reduced.

  - The rate of return for the RS rate is about 9.5 percent.

- o If the RTS rate is simply increased to achieve the same rate of return as the RS rate ~~(based on 1989 data)~~, then the average RTS rate changes from about 4.8 cents per kwh to about:

  - 7.4 cents per kwh (+54 percent) if the contribution to the evening peak is unchanged or

  - 6.5 cents per kwh (+35 percent) if the RTS contribution to the evening peak is reduced.

- o ~~PP&L's rate policy of making gradual changes to customer rates would not allow a sudden increase to the RTS rate of 30 percent to 50 percent.~~

- o If RTS rates were adjusted to achieve the same rate of return as RS rates, the total estimated cost for RTS systems becomes higher than that of alternative electric or fossil heating systems.

LOAD MANAGEMENT OPTIONS FOR RTS SYSTEMS

o Testing of three new control schemes has demonstrated the ability to shift significant *heat storage and water heater loads out of the 5 pm to 9 pm evening peak period.*

- Test #1 Mid-Day Full Boost
  - o This control scheme shows the most promise for shifting the greatest amount of heat storage and water heater loads out of the 5 pm to 9 pm period for all weather conditions.
  - o Between KW and KW will be added per RTS system to each hour of the 12 noon to 4 pm time period.

- Test #2 Mid-Day Half Boost
  - o This control scheme should eliminate heat storage and water heater loads from the 5 pm to 8 pm period. However, the 9 pm time period load will be higher than that of current RTS Systems.
  - o Between KW and KW will be added per RTS System to each hour of the 12 noon to 4 pm time period.

- Test # 3 Hydrokinetix "Smart" System
  - o This control scheme can shift heat storage loads out of the 5 pm to 9 pm time period until late evening and early morning hours under most weather conditions. When weather conditions approach the system's design criteria, very little if any shifting of load will occur. Should a system peak occur concurrently with design day weather conditions, minimal load management benefit is attained.

o All three control schemes can be easily applied to future RTS System installations.

Existing Systems?

- o All three scenarios are not easily applied to existing RTS system installations. Therefore, load management improvements may be limited to the future installations.
  - New control schemes have to be investigated if load improvements are desired from the existing 10,000 systems in our service territory.
  - Establishing Direct, One-Way Radio Control of RTS Systems represents one possible method to gain control of existing RTS Systems.
    - o ~~Direct Control would be cheaper.~~
    - o Direct Control ~~can~~ provide additional benefits such as "load clipping", control over "groups" of RTS System or customers and control of air conditioning operation.
    - o Direct Control can substitute as the methodology for implementing one of the three control schemes on future RTS System installations.

- o Additional testing is required to determine the optimal RTS System control scheme for shifting loads away from the evening peak. The RTS Task Force was limited in the number of tests that could be performed and did not establish statistically significant ~~results~~.

- o Additional market research is required to determine if an alternate RTS System control schemes will be accepted and are compatible with customer needs.

- o Approximately 50 percent of <u>future</u> RTS Systems will exhibit improved load management capabilities based on the results of Test #3. No action by PP&L is required to attain this benefit. The RTS System manufacturer who developed load management capability within their system currently has 50 percent of the RTS market. Note, the benefit is provided under <u>most</u> weather conditions but <u>not</u> design day conditions.

Add Test #4

Maybe add after Test #3

198

RECOMMENDATIONS

① o Three potential systems proved successful at ~~shifting~~ load out of 5-7 p.m. evening peak period (from equip. perspective) $\boxed{\text{demonstrated}}$

o The economic implications of the RTS Rate outweigh the need to improve the load management capabilities of these systems at this point in time.

③ Rate is not economically feasible

o Near-term efforts should focus on improving the economics of the RTS Rate. Additional testing to identify the optimal RTS system control scheme depends on the outcome of the economic analysis.

④ o Utilize the findings in this report to conduct a more detailed evaluation of the future direction of the RTS Rate. Consideration should be given to the following possible courses of action:

back into ↓ improve ... alternate actions

- Redefine marketing programs to use the RTS Rate strictly for influencing customers who would choose fossil fuel heating systems to choose the RTS Program.
- Reduce RTS Program related costs such as grants and advertising to minimize the negative earnings associated with the RTS Rate.
- Continue to promote the RTS Rate recognizing the negative earnings associated with the rate.
- Modify the RTS Rate to boost earnings and rate of return.
- Gradually phaseout the RTS Rate while protecting those customers currently on the rate.
- Evaluate the benefits of PP&L owning the RTS storage system and offering a customer rate which reflects the costs to amortize the installation while providing an incentive to the customer.

② o Selecting an optimal RTS System control scheme requires a review of the following issues:

make these more general

- o Economics of adding load in the 12 noon to 4 pm time period vs. off-peak hours.
- o Rate modifications to permit boosting during the 12 noon to 4 pm period.
- o Economics associated with the "Smart" System shifting loads out of the evening peak for most weather conditions but possibly not for weather conditions when a system peak day could occur.
- o Extend testing statistically representative sample.

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200

SECTION I

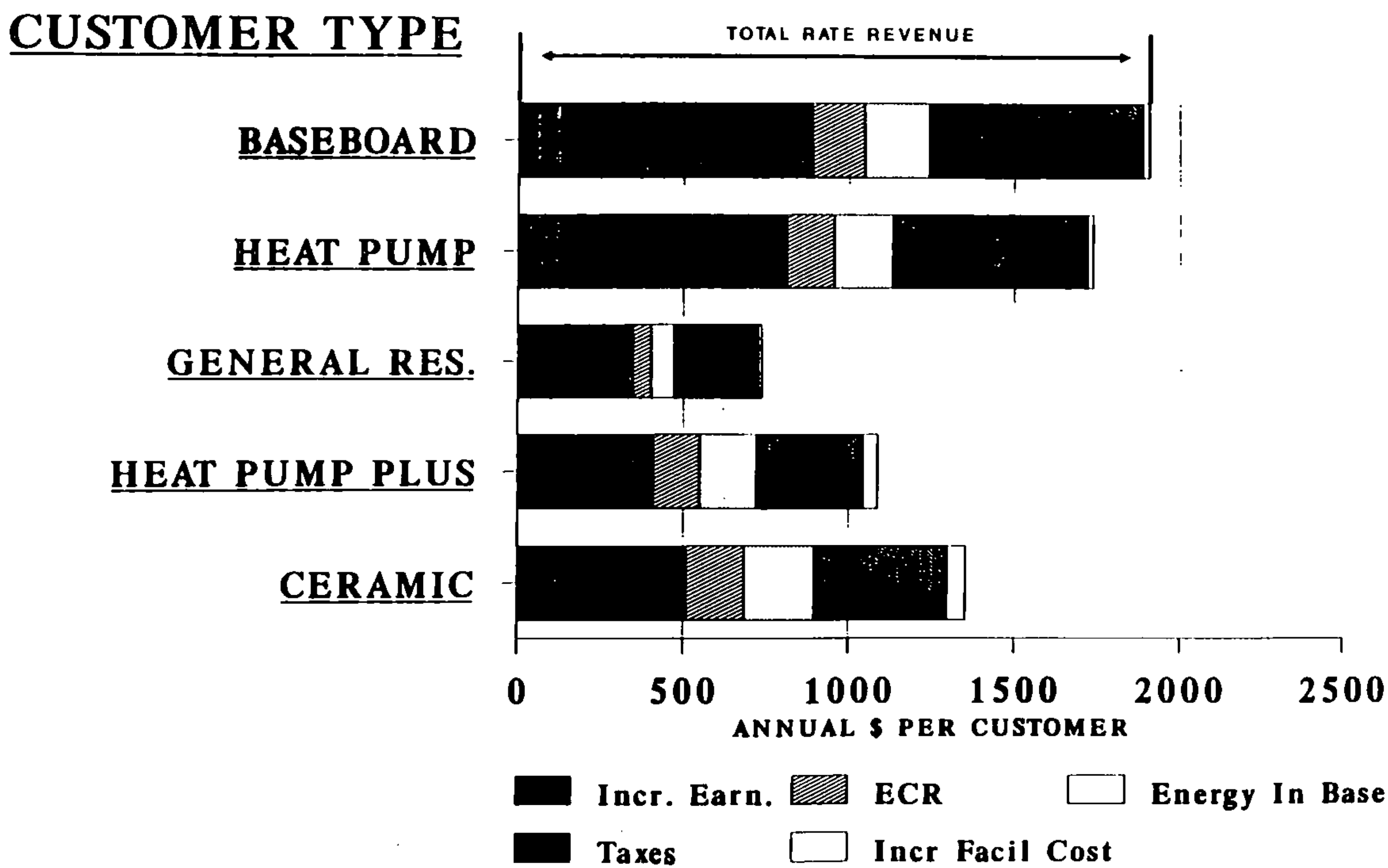
ECONOMIC ANALYSIS OF THE RTS RATE

This section presents an economic evaluation of the Residential Thermal Storage (RTS) Program, including pre-rate case effects (earnings) and post-rate case effects (customer rates).

The evaluation is based on estimates of energy use and demand profiles for the "average" RTS customer (see appendix for data assumptions).

FIGURE 3

INCREMENTAL EARNINGS
FIRST YEAR



Program cost not included

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202

DISCUSSION

PRE-RATE CASE EFFECTS -- INCREMENTAL EARNINGS

- o Incremental earnings are the portion of revenue resulting from adding an additional customer that will flow to PP&L earnings.

- o Evaluation of incremental earnings is for the period between base rate cases when earnings can be enhanced by adding new customers. After the base rate case, the new customer sales and revenue requirements are reflected in the rates and a new rate of return is established.

- o The following discussion first shows the incremental earnings PP&L receives from different types of customers (not considering incremental marketing costs), and then describes the net effect on PP&L earnings resulting from influencing customers to choose RTS.

- o Figure 3 shows the annual incremental earnings for five types of PP&L customers.

  - Annual incremental earnings equals the total annual revenue from the customer less incremental costs.

  - Incremental costs include taxes, energy costs (ECR and energy costs in base rates), and any incremental facility costs.

  - Marketing costs are not included in this figure.

  - For example, had a customer with baseboard heat connected to the PP&L system in 1990, PP&L would have received about $1,900 of additional revenue. After subtracting taxes, energy costs, and incremental facility costs, PP&L's earnings would have increased by about $900.

- * o Discussion on incremental facility costs for RTS will be included here ______________ ________.

Effect on earnings
Value of equity not included

Effect of equity only on incremental earnings is not included.

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203

- RTS customers contribute more incremental earnings than average general residential customers but less incremental earnings than electric baseboard or heat pump customers.

- The <u>net</u> effect on PP&L's earnings resulting from the RTS program depends on:

  - Program costs (grants, and other marketing costs).

  - The customer alternative (i.e., the amount of earnings PP&L would receive from the customer if RTS was not offered).

  - Number of years between rate cases.

- M&ED expects RTS program costs to decrease from about $2,300 per customer in 1991 to about $460 per customer by 1996.

- PP&L's 1988 market research results indicate that about 50 percent of PP&L's RTS customers would have chosen electric heat if RTS was not available (about 15 percent baseboard, 35 percent heat pump).

  - The choice of the remaining 50 percent of PP&L's RTS customers include gas (about 15 percent), oil (about 25 percent) and other systems (10 percent).

  - Historically, about 35 percent of PP&L's RTS customers have ceramic systems and about 65 percent have Heat Pump Plus.

- Figure 4 shows the sensitivity of net effect incremental earnings (5 and 10-year cumulative present value) to program cost and the customer's alternative.

  - For example, if program cost equals $ 460 per customer and 100 percent of all RTS customers would choose a fossil heating system if RTS was not offered, then the 5-year cumulative present value of incremental earnings equals negative $ 110 per RTS customer, the 10-year cumulative present value equals $ 120 per RTS customer.

- The net effect on earnings is equal to:

  - incremental earnings from RTS,

  - less program cost,

  - less earnings PP&L would have received from the customer's alternative.

- If PP&L can reduce RTS program cost to about $460 per customer and influence only customers that would have chosen a fossil system, then the program cost can be recovered with increased earnings in about seven years. Otherwise, the net effect on the cumulative present value of earnings is negative.

FIGURE 4

RTS PROGRAM NET EFFECT ON EARNINGS

COST UNCERTAINTY	CUSTOMER ALTERNATIVE	EARNINGS EFFECT CUMULATIVE PRESENT VAL $ PER RTS CUSTOMER 5 YEAR	10 YEAR
2300 $/Customer	100% GENERAL RESIDENTIAL	($1,940)	($1,730)
	50% GEN. RES/ 50% ELECTRIC	($2,870)	($3,260)
	100% ELECTRIC	($3,810)	($4,780)
460 $/Customer	100% GENERAL RESIDENTIAL	($110)	$120
	50% GEN. RES/ 50% ELECTRIC	($1,040)	($1,410)
	100% ELECTRIC	($1,980)	($2,940)

NOTES:
o Does not include earnings effects from bulk power sales of additional capacity

206

rate of return -- Residential Customers

POST-RATE CASE EFFECTS -- RTS CUSTOMER RATES

- Figure 5 shows the rate of return reflected in the RS and RTS rates based on 1989 data.
  - The RTS contribution to the evening peak affects the amount of fixed costs that are allocated to the RTS rate class.
  - Therefore, if the RTS contribution to the evening peak is reduced, the rate of return increases from about 2.1 percent to 3.6 percent.
- If the RTS rate was adjusted to earn the same rate of return as the RS rate (using 1989 data), the average RTS rate would change from about 4.8 cents per kwh to about:
  - 7.4 cents per kwh if the contribution to the evening peak is unchanged or
  - 6.5 cents per kwh if the RTS contribution to the evening peak is reduced.

Indicate how percentages were derived (2.1 & 3.6%) (what was the procedure

used in removing the evening contribution

Provide reference documents

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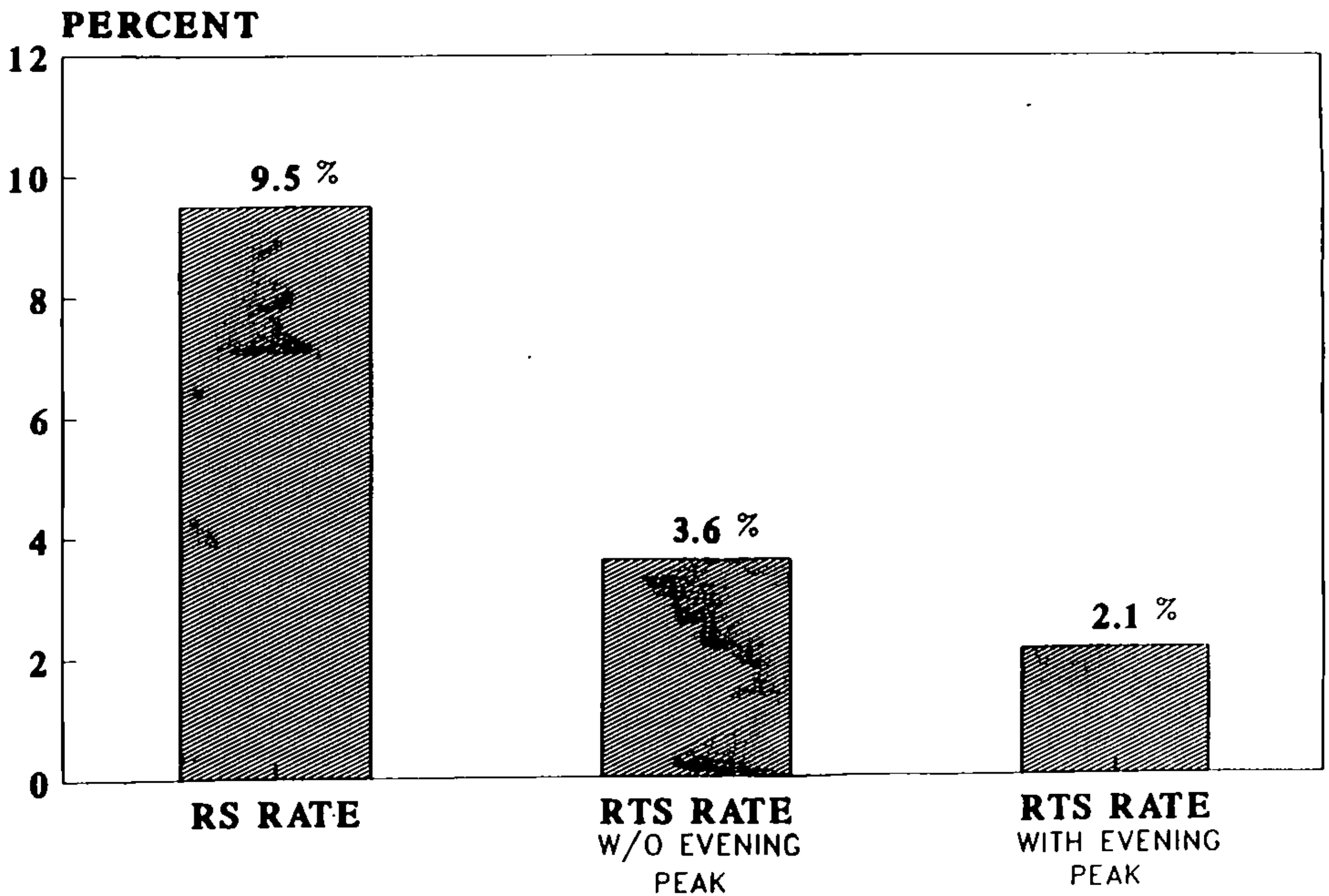
207

FIGURE 5

RATE OF RETURN
FROM RESIDENTIAL RATES
BASED ON 1989 DATA



- Figure 6 compares total annual costs in 1991 for an RTS system with alternative systems from the customers perspective. Both current RTS rates and rates adjusted to achieve equivalent rates of return for RS and RTS are shown.

  - *The adjusted RTS rate assumes that the evening peak contribution is reduced.*

  - Fixed costs are based on the annual costs for a 15-year mortgage. Installed costs for RTS systems are reduced by the amount of PP&L grants (about $820 per system in 1991).

  - Maintenance costs are an estimate of annual levelized costs over system life.

  - Operating costs include electric plus any fossil fuel costs.

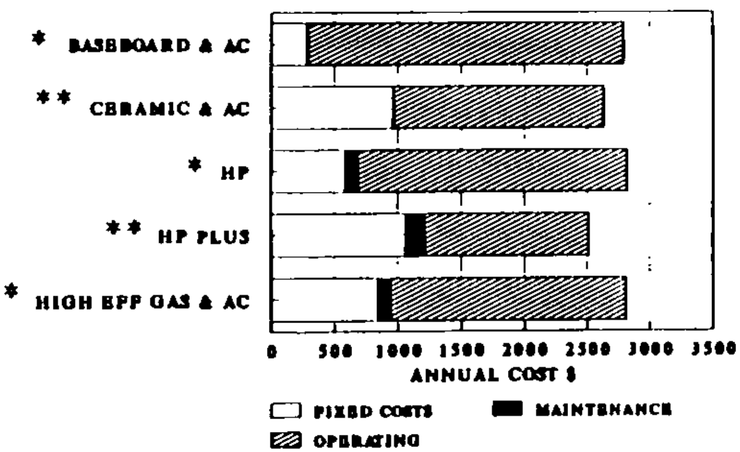
- Based on the current RTS rate, the total annual estimated costs for RTS systems are less than alternative systems.

- However, total annual estimated costs for RTS are higher than alternative systems if the RTS rate is adjusted to reflect a rate of return equivalent to the RS rate. Customers will shift to alternate heating systems if the adjustment is made.

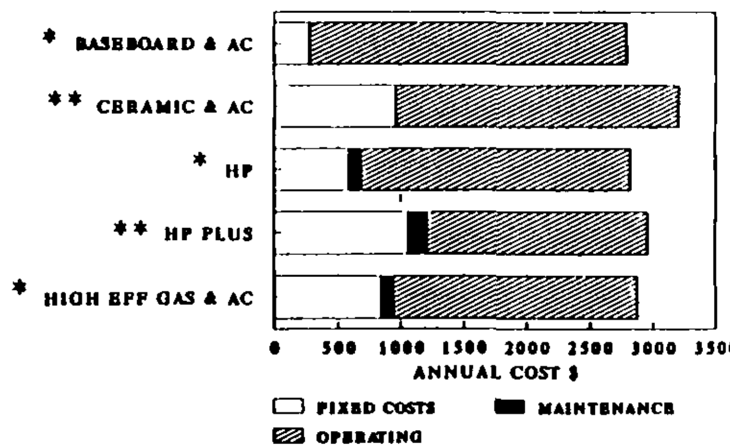
FIGURE 6

CUSTOMER PERSPECTIVE
15 YEAR LEVELIZED VALUES

CURRENT RATES



EQUAL RATES OF RETURN



Assumes evening peak corrected

NOTES:

** RTS RATE

* RS RATE

Fixed cost based on 15 yr. mortgage at 10%

Operating includes elec. & fossil fuel cost

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210

SECTION II

LOAD MANAGEMENT OPTIONS FOR RTS SYSTEMS

This section presents the results of testing on four new control schemes for RTS Systems.

Data was collected for each of the four control schemes from mid-January 1991 through the end of March 1991.

DESCRIPTION OF RTS TASK FORCE TESTING PLAN

- o Four tests were defined has having the greatest potential for improving the load management capabilities of RTS systems and shifting heat storage and water heater KW loads out of the 5 pm to 9 pm PP&L evening peak time period. Descriptions of these four tests are as follows:

TEST # 1 -- MID-DAY FULL BOOST

- o OBJECTIVE

Utilize the 400 to 500 MW valley in PP&L's system load curve between the 12 noon to 4 pm time period to boost or charge heat storage and water heater equipment. Quantify the benefit of a full charge in delaying equipment recharging beyond the 5 pm to 9 pm evening peak.

One Heat Pump Plus and one Ceramic Room Heater systems were monitored.

EQUIPMENT	ON-PEAK PERIOD	OFF-PEAK PERIOD
HEAT STORAGE	7 AM TO 12 NOON 4 PM TO 10 PM	12 NOON TO 4 PM 10 PM TO 7 AM
WATER HEATER	7 AM TO 12 NOON 4 PM TO 10 PM	12 NOON TO 4 PM 10 PM TO 7 AM
HOUSE LOADS	7 AM TO 5 PM	5 PM TO 7 AM

212

TEST #2 -- MID-DAY HALF BOOST

o OBJECTIVE

Utilize the 400 to 500 MW valley in PP&L's system load curve between the 12 noon to 4 pm time period to boost or charge heat storage and water heater equipment. Quantify the benefit of a half charge in delaying equipment charging beyond the 5 pm to 9 pm evening peak.

One Heat Pump Plus and one Ceramic Room Heater systems were monitored.

EQUIPMENT	ON-PEAK PERIOD	OFF-PEAK PERIOD
HEAT STORAGE	7 AM TO 12 NOON 4 PM TO 8 PM	12 NOON TO 4 PM 8 PM TO 7 AM
WATER HEATER	7 AM TO 12 NOON 4 PM TO 8 PM	12 NOON TO 4 PM 8 PM TO 7 AM
HOUSE LOADS	7 AM TO 5 PM	5 PM TO 7 AM

TEST #3 - HYDROKINETIX "SMART" SYSTEM

o OBJECTIVE

Quantify the benefits of one RTS system manufacturer's load management software for delaying charging of the water storage tank. The "Smart" system analyzes energy remaining in the tank, outdoor temperature, heating requirements of the home for the next day and delays charging until the last moment when the system must charge to meet the next day's heating requirements.

Two scenarios were reviewed. First, system performance with a minimum of excess storage (10%) in the tank. Second, system performance with a larger amount of excess storage (25%) in the tank.

EQUIPMENT	ON-PEAK PERIOD	OFF-PEAK PERIOD
HEAT STORAGE	7 AM TO 5 PM	5 PM TO 7 AM
WATER HEATER	7 AM TO 5 PM	5 PM TO 7 AM
HOUSE LOADS	7 AM TO 5 PM	5 PM TO 7 AM

- TEST #4 - DEMAND LIMITING TEST

o OBJECTIVE

Quantify the benefits of allowing heat storage charging during the current on-peak period in delaying system charging beyond the 5 pm to 9 pm evening peak. Software was developed to permit heat storage charging during the on-peak period provided a predetermined whole house demand level was not exceeded.

EQUIPMENT	ON-PEAK PERIOD	OFF-PEAK PERIOD
HEAT STORAGE	NONE	7 AM TO 5 PM (LIMITED CHARGING UP TO A PREDETERMINED KW LIMIT) 5 PM TO 7 AM
WATER HEATER	7 AM TO 5 PM	5 PM TO 7 AM
HOUSE LOADS	7 AM TO 5 PM	5 PM TO 7 AM

TEST RESULTS

- To quantify the load management benefits of the four new control schemes, system performance on 1/22/91 (coldest day of the test period) is compared against average system performance on 1/5/88 (system peak day). Weather conditions on 1/22/91 and 1/5/88 are essentially identical. This allows a "true" comparison of system performance under the new control schemes. Avg. Heat Pump Plus and Avg. Ceramic Room system data was taken from the Least Impact System Metering Program (LISMP).

- Test Home #1 and Test Home #6 use test data gathered on 2/12/91. Metering equipment was not operating at these test locations on 1/22/91. 2/12/91 was the coldest day for these test locations although weather conditions were significantly warmer than 1/22/91.

- Test #1 MID-DAY FULL BOOST

  - Success at shifting heat storage and water heater load out of the 5 pm to 9 pm for the heat pump plus test location.

    Home owner modified the operation of the water storage tank at this location. Test data collected does not provide any insight into true performance of the system under the test scenario.

  - Success at shifting heat storage and water heater load out of the 5 pm to 9 pm period for the ceramic room heater test location.

HOUR ENDED	TEST HOME KW (2/12/91)	AVG. CER. SYS. KW (1/5/88)	KW SHIFTED
6 PM	1.4	17.9	16.5
7 PM	0.5	17.8	17.3
8 PM	2.2	17.0	14.8
9 PM	3.6	12.9	9.3

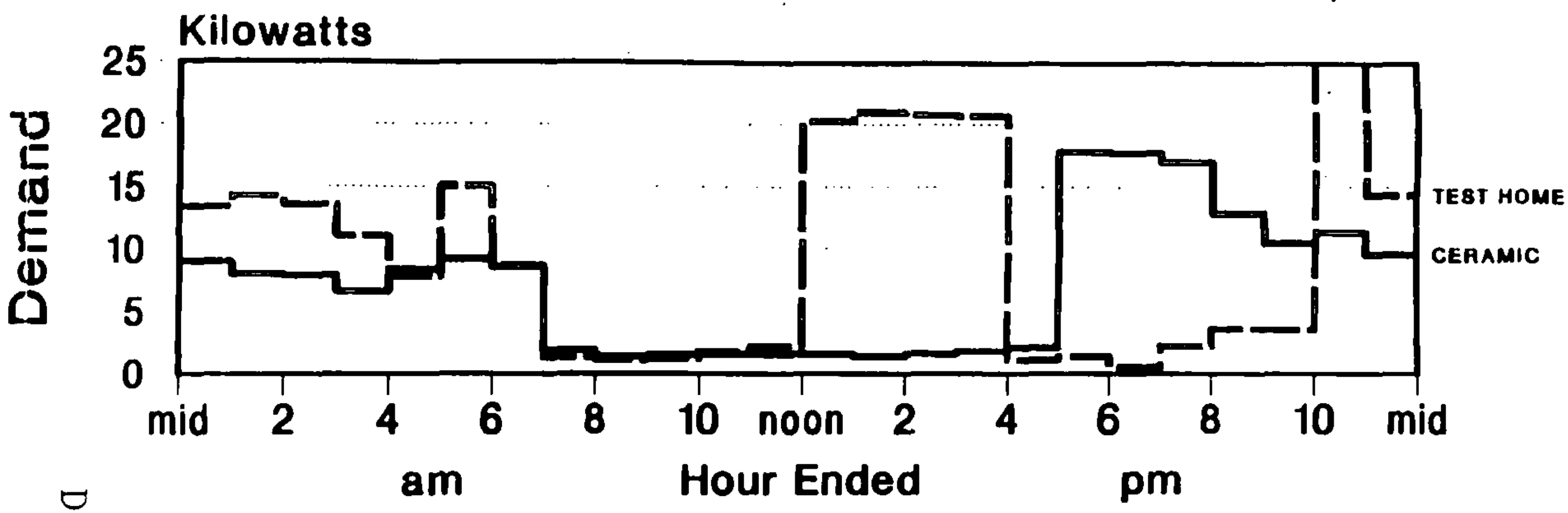
  - OBSERVATIONS   In an expanded test similar results could be expected

    - The mid-day full boost scenario deferred significant loads out of the 5 pm to 9 pm time period. Similar results are expected for the Heat Pump Plus system that did not provide any test results.
    - Additional loads would be incurred during the 12 noon to 4 pm time period during heat storage and water heater charging as follows:

      Hour Ended 1 pm: 18.7 KW Ceramic Sys.
      Hour Ended 2 pm: 19.6 KW Ceramic Sys.
      Hour Ended 3 pm: 19.2 KW Ceramic Sys.
      Hour Ended 4 pm: 18.9 KW Ceramic Sys.

FIGURE 7

2/12/91 Test Home #1 vs. 1/5/88 Avg Ceramic Customer



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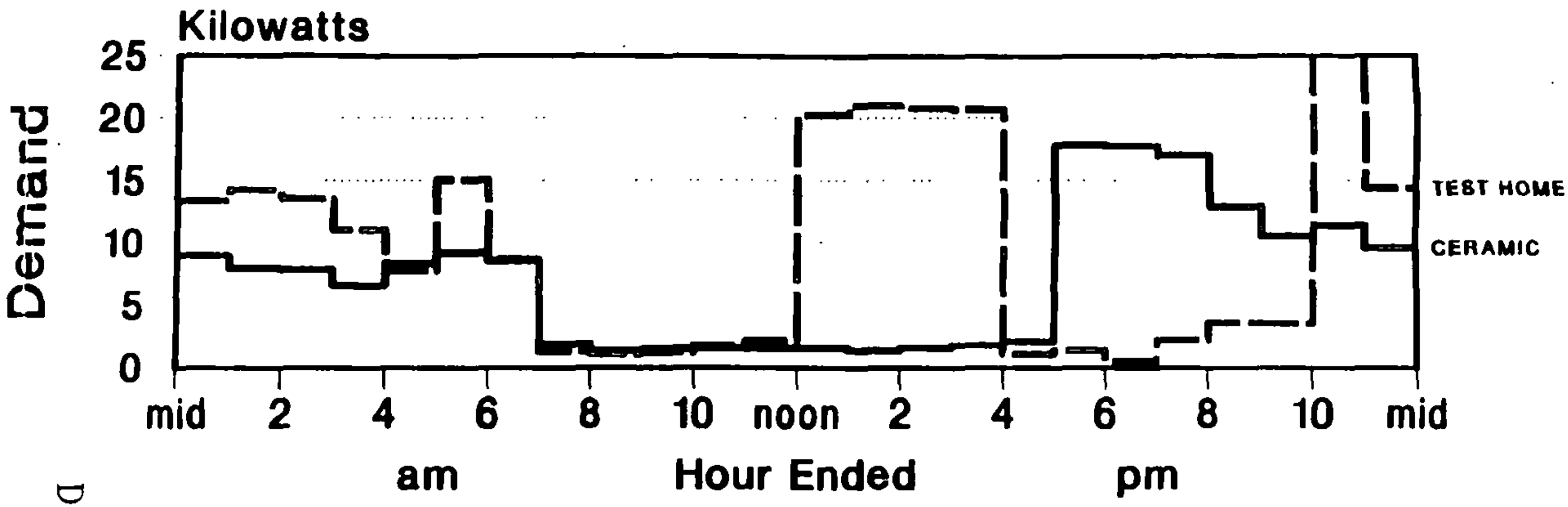
217

FIGURE 7

2/12/91 Test Home #1 vs. 1/5/88 Avg Ceramic Customer



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217

- Excluding other changes to the system load curve, approximately _____ RTS Systems could be given a <u>full</u> boost during the 12 noon to 4 pm time period without developing a new mid-day peak.
- See Figures 7 for a graphical presentation of the load curves for Test #1.

- ADVANTAGES OF THE MID-DAY FULL BOOST SCENARIO

- All heat storage and water heater loads are deferred out of the 5 pm to 9 pm time period for all weather conditions including design day conditions.
- Heat storage and water heater mid-day full boost operation can be controlled from one meter outside the home. No significant additional cost is incurred for this meter. for future systems.

- DISADVANTAGES OF THE MID-DAY FULL BOOST SCENARIO

- Modification to the RTS Rate is required to permit the boost during the 12 noon to 4 pm time period.
- A new evening peak in the 9 pm to 10 pm will develop over time as the number of systems using this control scheme increase.
- Retro-fitting new outside meters to existing RTS Systems will take approximately 10 years to complete, the useful service life of the meters. Significant costs will be incurred to perform an accelerated changeout.
- Potential exists for water heater energy to be exhausted during the 4 pm to 8 pm time frame. This scenario did not occur in this test but additional testing is required before the water heater is allowed to operate in this fashion.

o Test #2 MID-DAY HALF BOOST

- Success at shifting heat storage and water heater load out of the 5 pm to 9 pm for the heat pump plus test location.

HOUR ENDED	TEST HOME KW (1/22/91)	AVG. HP+ SYSTEM KW (1/5/88)	KW SHIFTED
6 PM	3.3	16.3	13.0
7 PM	3.1	15.6	12.5
8 PM	3.0	12.9	9.9
9 PM	13.9	10.4	- 3.5

- Success at shifting heat storage and water heater load out of the 5 pm to 9 pm period for the ceramic room heater test location.

HOUR ENDED	TEST HOME KW (1/22/91)	AVG. CER SYS. KW (1/5/88)	KW SHIFTED
6 PM	3.1	17.9	14.8
7 PM	4.9	17.8	12.9
8 PM	3.6	17.0	13.4
9 PM	15.7	12.9	- 2.8

- OBSERVATIONS

  - The mid-day half boost scenario deferred significant loads out of the 5 pm to 8 pm time period.
  - The mid-day half boost scenario created an increased KW load in the 9 pm time period.
  - Excluding other changes to the system load curve, approximately ______ RTS Systems could be given a half boost during the 12 noon to 4 pm time period without developing a new mid-day peak.
  - Additional KW loads would be incurred during the 12 noon to 4 pm time period during heat storage and water heater charging as follows:

Hour Ended 1 pm:	6.1 KW	HP+ Sys.	4.9 KW	Ceramic Sys.
Hour Ended 2 pm:	3.5 KW	HP+ Sys.	3.7 KW	Ceramic Sys.
Hour Ended 3 pm:	4.3 KW	HP+ Sys.	5.3 KW	Ceramic Sys.
Hour Ended 4 pm:	2.5 KW	HP+ Sys.	5.3 KW	Ceramic Sys.

  - See Figures 8 and 9 for a graphical presentation of the load curves for Test #2.

- ADVANTAGES OF THE MID-DAY HALF BOOST SCENARIO

  - All heat storage and water heater loads are deferred out of the 5 pm to 8 pm time period for all weather conditions including design day conditions.
  - Heat storage and water heater mid-day boost operation can be controlled from one meter outside the home. No significant additional cost is incurred for this meter. for future RTS System installations.

- DISADVANTAGES OF THE MID-DAY HALF BOOST SCENARIO

  - Increased heat storage and water heater KW loads will occur in the 9 pm time frame.
  - Modification to the RTS Rate is required to permit the boost during the 12 noon to 4 pm time period.
  - A new evening peak will develop over time as the number of systems using this control scheme increases.
  - Retro-fitting new outside meters to existing RTS System will take approximately 10 years to complete, the useful service life of the meters. Significant costs would be incurred to perform an accelerated changeout.

FIGURE 8

1/22/91 Test Home #2 vs. 1/5/88 Avg HP+ Customer

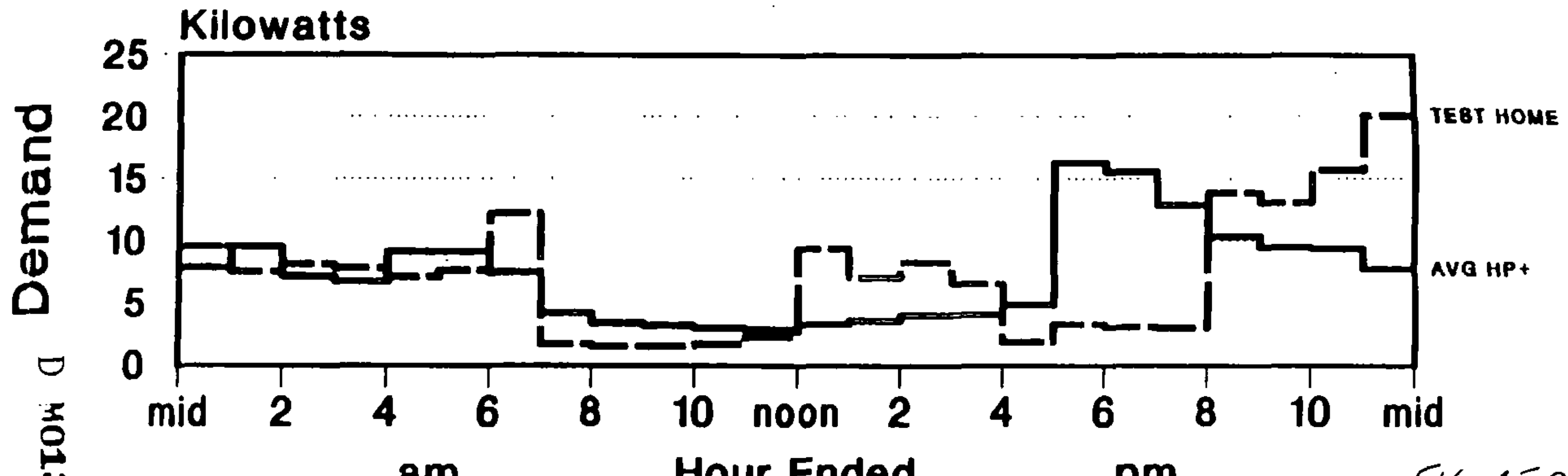
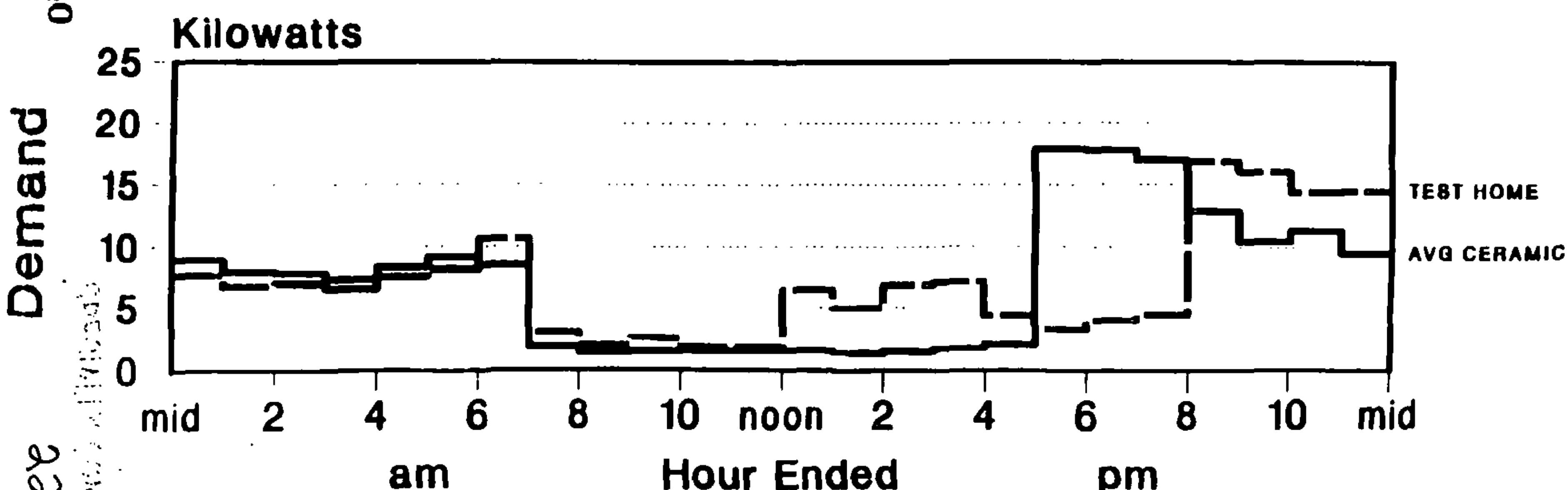


FIGURE 9

1/22/91 Test Home #3 vs. 1/5/88 Avg Ceramic Customer



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o Test #3 HYDROKINETIX "SMART" SYSTEM
TEST LOCATION HAS 30 GALLONS OF EXCESS STORAGE CAPACITY

- Success at shifting heat storage load out of the 5 pm to 9 pm for the heat pump plus test location.

HOUR ENDED	TEST HOME KW (1/22/91)	AVG. HP+ SYSTEM KW (1/5/88)	KW SHIFTED
6 PM	5.3	16.3	11.0
7 PM	4.0	15.6	11.6
8 PM	10.4	12.9	2.5
9 PM	8.7	10.4	- 1.7

o Test #3 HYDROKINETIX "SMART" SYSTEM
TEST LOCATION HAS 60 GALLONS OF EXCESS STORAGE CAPACITY

- Success at shifting heat storage load out of the 5 pm to 9 pm for the heat pump plus test location.

HOUR ENDED	TEST HOME KW (1/22/91)	AVG. HP+ SYSTEM KW (1/5/88)	KW SHIFTED
6 PM	4.6	16.3	11.7
7 PM	3.6	15.6	12.0
8 PM	3.0	12.9	9.9
9 PM	3.7	10.4	4.1

FIGURE 10

2/12/91 Test Home #4 vs. 1/5/88 Avg HP+ Customer

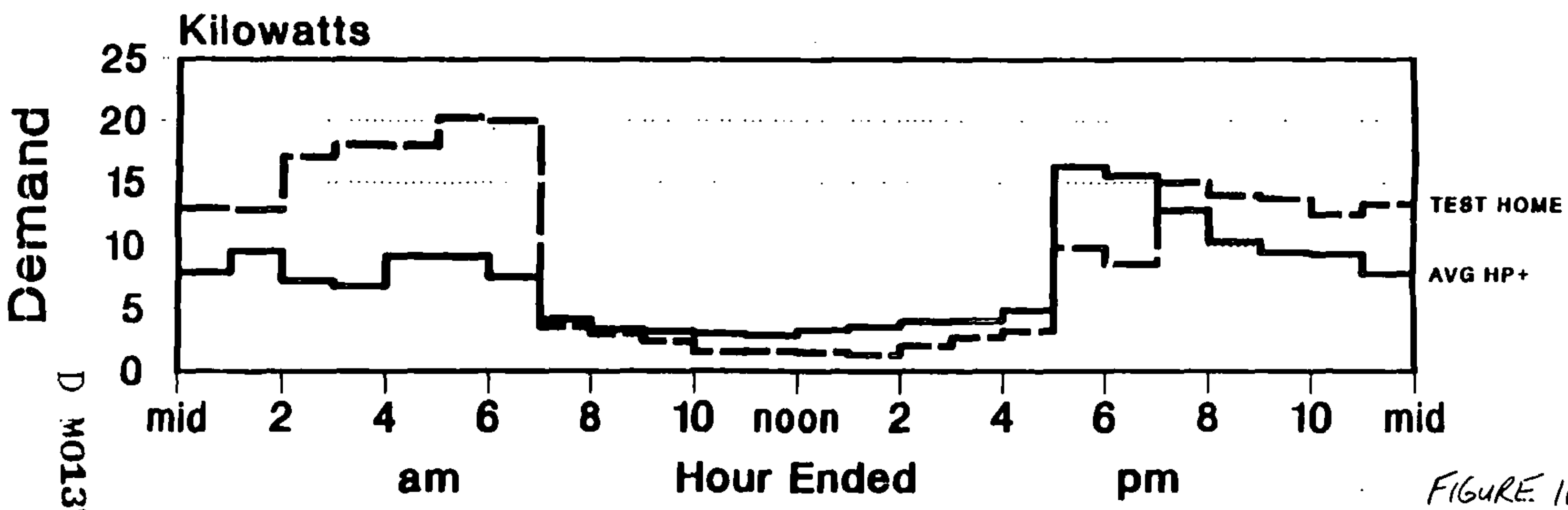
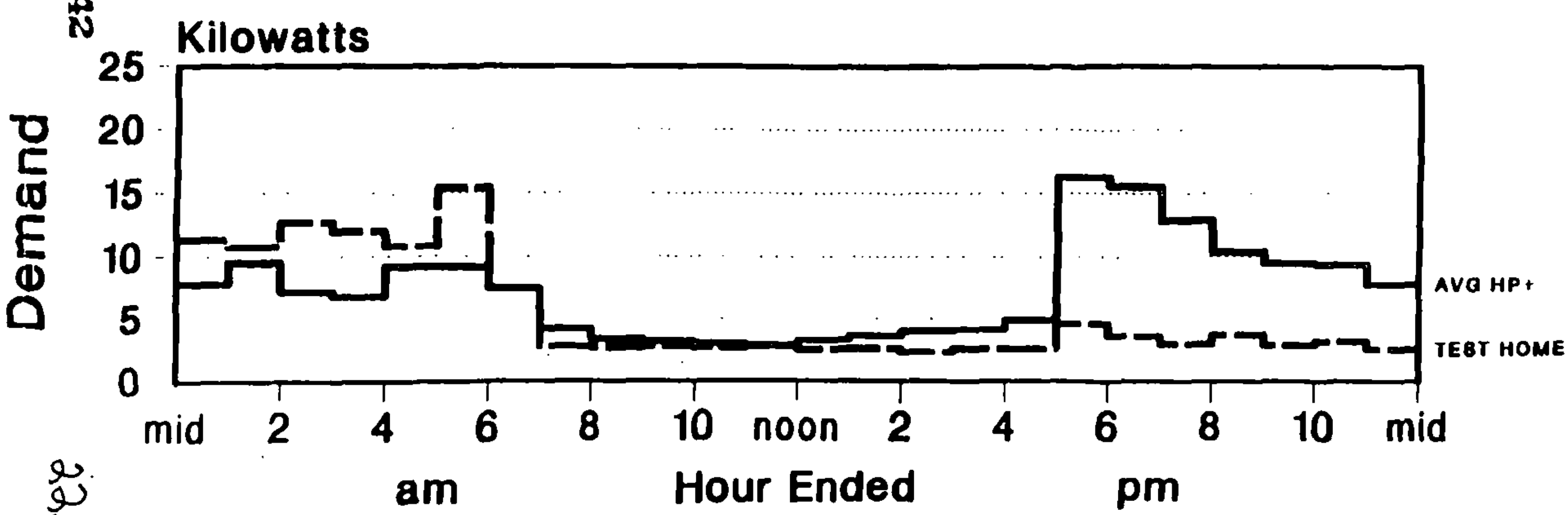


FIGURE 11

1/22/91 Test Home #5 vs. 1/5/88 Avg HP+ Customer



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233

- OBSERVATIONS

  - o The Hydrokinetix "Smart" System control does defer significant heat storage KW loads later into the evening as designed. Significant KW load savings were realized except for the 9 pm time period where only 30 gallons of excess storage existed.
  - o Oversizing of the water storage tank by 25% (60 excess gallons) prevented system charging in the 5 pm to 9 pm time period.
  - o See Figures 10 and 11 for a graphical presentation of the load curves for Test #3.

- ADVANTAGES OF THE HYDROKINETIX "SMART" SYSTEM

  - o Hydrokinetix has made the "Smart" System a standard feature of their equipment. Future installations, representing approximately 50% of all RTS system installations, will provide this load management benefit without any action by PP&L.
  - o No RTS rate modification is required to attain the load management benefits. The system does not charge during the current on-peak time period.
  - o The "Smart" System will help flatten out PP&L's load curve over the late evening and early morning hours. This system maximizes the diversity between RTS systems by fully utilizing the excess capacity within each system.

- DISADVANTAGES OF THE HYDROKINETIX "SMART" SYSTEM

  - o No heat storage KW load savings will be realized at or near design day conditions. The system can not defer charging of the water tank without a mid-day boost under these weather conditions.
  - o Hydrokinetix is the only RTS system manufacturer with this load management capability. Other manufacturers have not developed and are not close to developing this technology.
  - o Retrofit of existing Hydrokinetix systems would be difficult and costly. New control panels with the load management capability cost approximately $ 800.
  - o Oversizing of water storage capacity by 25% will require some customers to spend between an additional $ 200 to $ 300.

224

- Test #4 DEMAND LIMITING TEST

  - Success at shifting heat storage load out of the 5 pm to 9 pm for the heat pump plus test location.

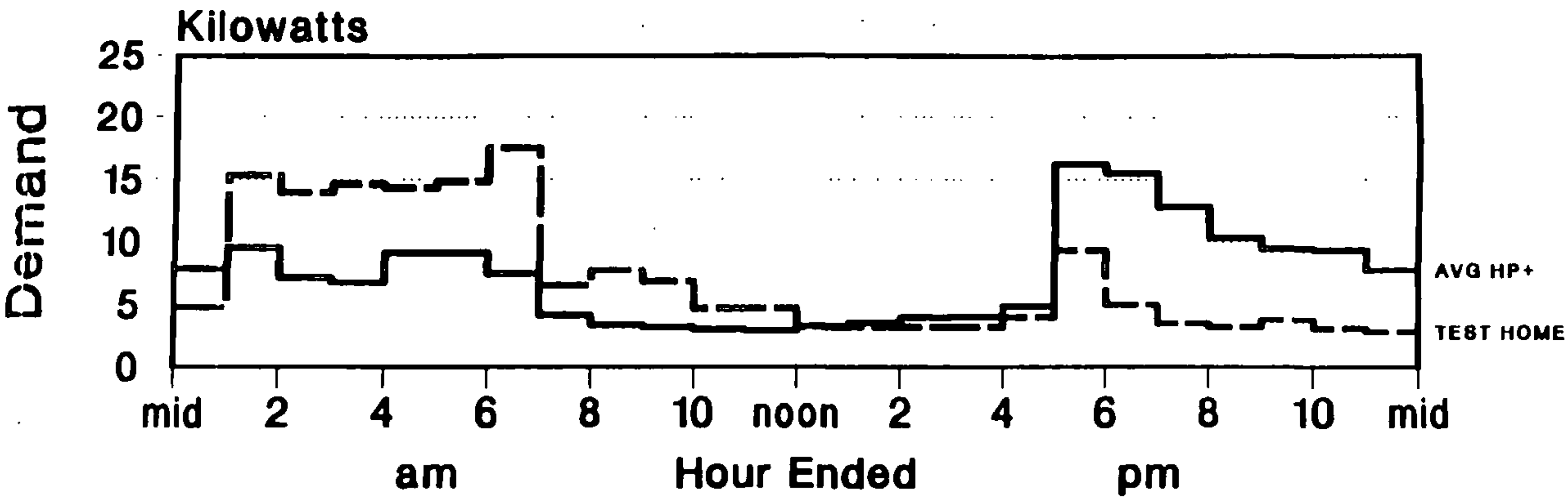
HOUR ENDED	DEMAND LIMITED KW (2/12/91)	AVG. HP+ SYSTEM KW (1/5/88)	KW SHIFTED
6 PM	9.4	16.3	6.9
7 PM	5.0	15.6	10.6
8 PM	3.5	12.9	9.4
9 PM	3.2	10.4	7.2

  - OBSERVATIONS

    - The Hydrokinetix "Smart" System with limited boosting during the current 7 am to 5 pm does shift significant heat storage loads out of the 5 pm to 9 pm evening peak period.
    - This control scheme will add heat storage loads to the system's load curve morning peak period (8 am to 11 am). This increased load will occur during design day conditions and mild weather conditions as evidenced by outdoor conditions on the day the above information was collected.
    - This control scheme is not recommended for further consideration due to the increased loads that would occur during morning peak hours.
    - The demand limiting test can prove beneficial when used to boost storage during the 12 noon to 4 pm period. This system is beneficial because the amount of load added can be managed based on a whole house approach.
    - See Figure 12 for a graphical presentation of the load curves for Test #4.

FIGURE 12

2/12/91 Test Home #6 vs. 1/5/88 Avg HP+ Customer



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336

- ADVANTAGES

  o See Advantages listed under Test #3 - Hydrokinetix "Smart" System.

- DISADVANTAGES

  o This load control option will act to increase the 8 am to 11 am morning peak load. Therefore, no further consideration is warranted on the option unless it is used to limit or control the amount of a mid-day boost during the 12 noon to 4 pm period.

RTS LOAD MANAGEMENT OPTIONS NOT TESTED

- The RTS Task Force considered several other options for shifting storage system loads out of the 5 pm to 9 pm evening peak period. Options listed below were reviewed and found to be inconsistent with our objective.

- Utilize the full 12 hour on-peak, 12 hour off-peak design of RTS Systems.

  - RTS systems are designed to meet a home's heating needs during an on-peak period of 12 hours without any charging of the system. During the next 12 hour off-peak period, the system provides sufficient heating for the next 12 hour on-peak period while storing energy for the next on-peak period.
  - RTS systems currently operate on a 10 hour on-peak period and 14 hour off-peak period.
  - Each system has two hours of storage capacity that is not being used.
  - Implementing a 12 hour on-peak, 12 hour off-peak schedule will not resolve the RTS system contribution to the evening peak:

    - Systems will begin to charge at the hour ended 7 pm.
    - The system peak between the hours of 7 pm to 9 pm will continue to increase (See Figure 1 - System Load Curve).
    - Potential exists for some storage systems to be depleted before 7 pm on design days. There is no research on the amount of time required for a storage system to recover from design day conditions and still meet the home's heating needs. Storage capacity may only be sufficient for a 11 hour vs. 12 hour period.
    - Potential exists for water heaters to be depleted over a 12 hour period. Present requirements call for a minimum 80 gallon water in an RTS home. This storage capacity may not be sufficient to meet demands between 6 am to 8 am and 5 pm to 7 pm.

      - A mid-day boost may be required.
      - Larger volume water heaters may be required.

328

- DESIGN RTS SYSTEMS TO SPAN A 14 HOUR ON-PEAK PERIOD

  - Utilizing a 14 hour on-peak period would delay heat storage loads until the hour ended 9 pm.

    - Potential exists for some storage systems to be depleted before 9 pm per the explanation stated above.
    - Storage capacity must be increased between 17% and 20 % for a 14 hour on-peak period.
    - Some customers will incur an additional $ 200 to $300 cost to install larger than presently needed storage tanks.

      - The additional cost decreases the marketability of RTS systems.
      - Customers may object to larger storage tanks in their homes.

    - Water heaters can not remain off for a 14 hour period. A mid-day boost will be required or installation of larger volume water heaters (another cost increase for the customer).

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229

APPENDIX I

ECONOMIC ANALYSIS ASSUMPTIONS

ECONOMIC ANALYSIS ASSUMPTIONS

- Annual customer energy useand peak demand contributions for electric heat customers were calculated by M&ED assuming:
  - 2,000 sq. ft. House Meeting Act 222 Standards
  - House located in Harrisburg Division

- Hourly energy and demand profiles are based on Least Impact System Metering Program (LISMP) data.

- Annual energy use for general residential customers is based on average use of 9,000 kwh per customer.

- Energy value is based on PP&L's incremental value of energy from the 1990 Least Cost Plan (LCP) production cost model.

- Capacity value is assumed to equal 50 percent of the PJM installed capacity rate ($ 31 per kw-year in 1990).

- Incremental earning values are based on the R&MR report "Analysis of New Customer Incremental Earnings Contribution By Rate Class" (1/90).

APPENDIX II

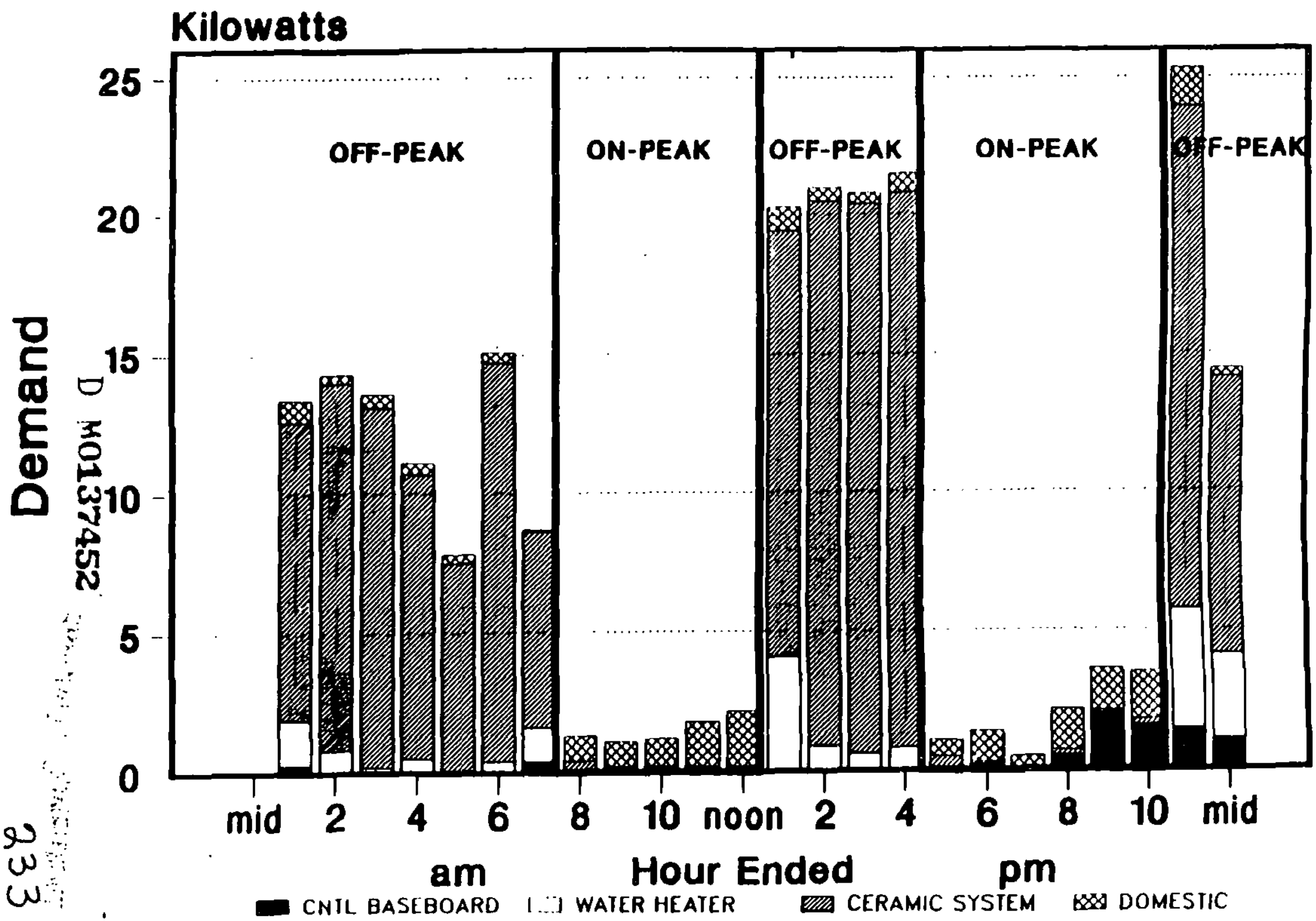
TEST #1 - MID-DAY FULL BOOST

Remove II & III

TEST HOME #1 - DEMAND AND TEMPERATURE PROFILE FOR THE HP+ SYSTEM

TEST HOME #2 - DEMAND AND TEMPERATURE PROFILE FOR THE CERAMIC ROOM HEATER SYSTEM

RTS Task Force - Mid-Day Full Boost
Test Home #1 - Ceramic Room Heaters
Tuesday, 2/12/91



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233

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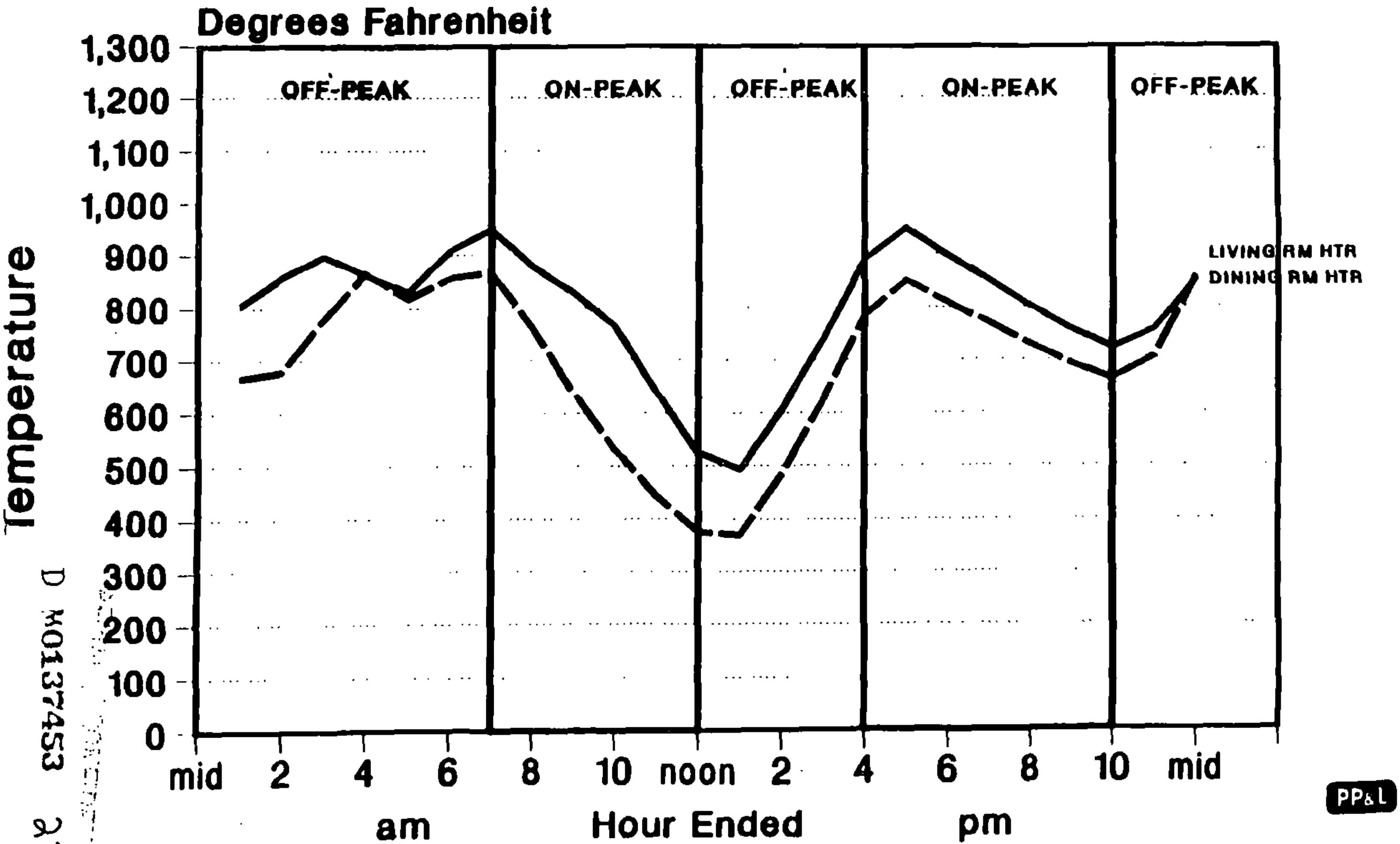
RTS Task Force - Mid-Day Full Boost
Test Home #1 - Ceramic Room Heaters
Tuesday, 2/12/91



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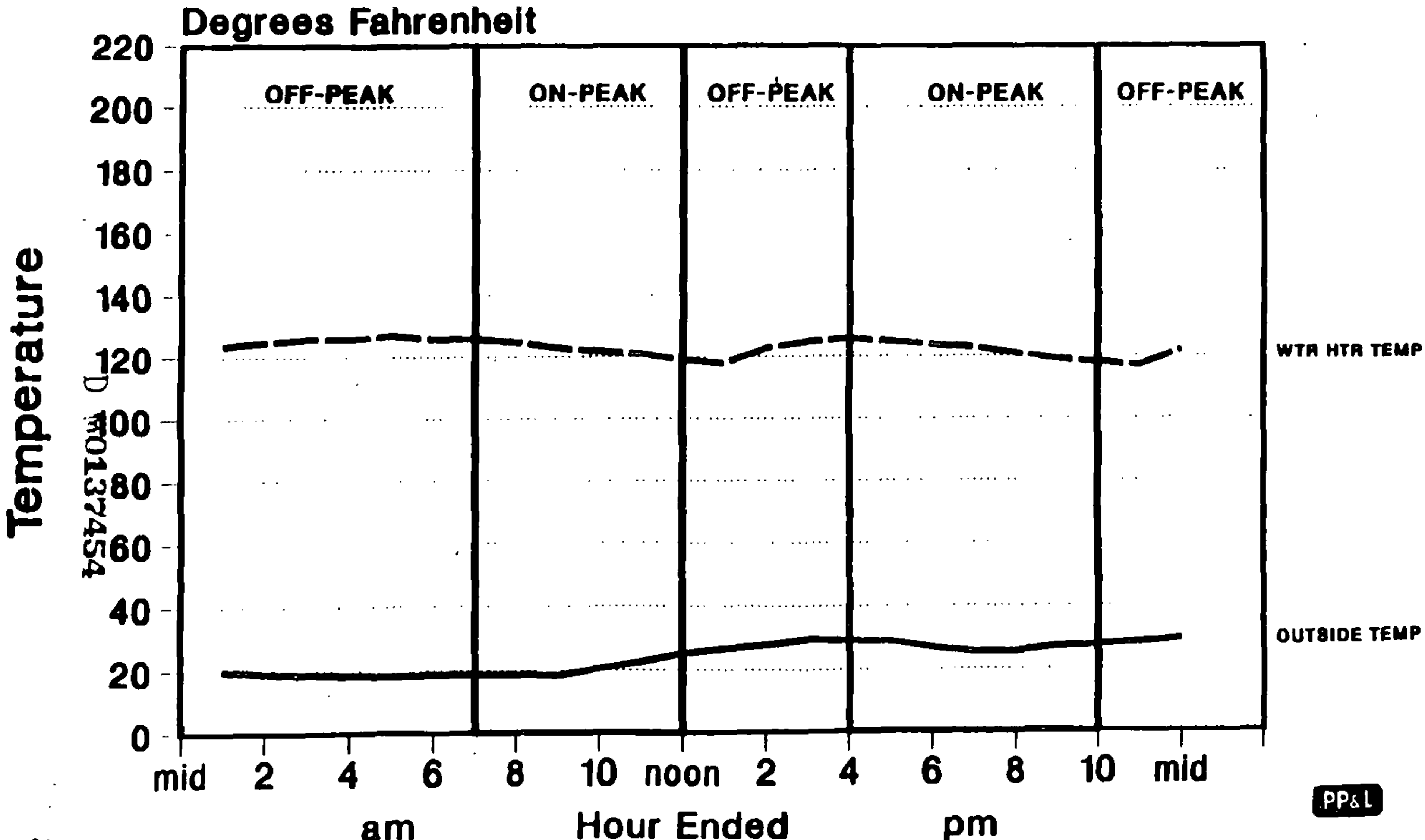
234

RTS Task Force - Mid-Day Full Boost
Test Home #1 - Ceramic Room Heaters
Tuesday, 2/12/91



235

APPENDIX III

TEST #2 - MID-DAY HALF BOOST

TEST HOME # 2 - DEMAND AND TEMPERATURE PROFILE FOR THE HP+ SYSTEM

TEST HOME #3 - DEMAND AND TEMPERATURE PROFILE FOR THE CERAMIC ROOM HEATER SYSTEM