1994 DEMAND SIDE MANAGEMENT
BASE PLANNING STUDY

**** DOCUMENTATION OUTLINE ****
VOLUME I
THE VALUE OF CONSERVATION FOR GAINESVILLE REGIONAL UTILITIES

GAINESVILLE REGIONAL UTILITIES
DECEMBER 6, 1994

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

I. METHODOLOGICAL OVERVIEW

BENEFITS AND COSTS OF CONSERVATION

In fulfilling its obligations to the community that it serves, Gainesville Regional Utilities (GRU) has historically and continues to explore opportunities to enhance the services provided to customers. This self-imposed obligation, along with existing City policies and State legislative and regulatory requirements, have compounded in a manner that compels GRU to be proactive in achieving cost effective energy conservation for the customers that it serves.

Ascertaining the optimal level of resources to commit to conservation, or more appropriately determining the value of demand-side management (DSM), requires careful consideration of relevant associated costs and benefits. Thus, the initial effort focuses on identifying, in a general sense, the relevant impacts of DSM and how such impacts are manifested as either additional costs or benefits for utility customers.

Clearly, the consequence of successful DSM is a reduction, within some delineated time period, in energy consumption. The obvious and immediate impacts of the reduction in energy consumption are corresponding reductions in both the revenue that GRU receives to cover fuel costs (for fuel that won't be used) and the revenue GRU receives to cover the fixed costs that GRU incurs in order to assure the ability to provide service (regardless of whether energy conservation occurs). Over short periods of time, GRU is not able to reduce its fixed costs to a level comparable to the reduction in revenue. As a consequence, this short term insufficiency in revenue available to cover fixed costs, caused by energy conservation, has to be made-up by all customers via higher rates. Thus, this revenue insufficiency or "lost sales" revenue is one of the most prominent <u>costs</u> of DSM.

On the other hand, over longer time periods, GRU has some ability to adjust plant expansion and operations plans. As a result, less plant investment will be made and fixed costs can be lowered in the future, in anticipation of energy savings generated by conservation implemented presently. Since energy savings in the future have definite value presently, energy conservation can result in less fixed costs for GRU and this is the most prominent <u>benefit</u> of DSM. The conventionally accepted and all inclusive list of costs and benefits of DSM are listed in Table I-1.

PURPOSE AND SCOPE

This report is the first volume of the five volumes comprising GRU's 1994 Demand Side Management Base Planning Study. The five volumes include:

I. The Value of Conservation for Gainesville Regional Utilities

II. Patterns of Energy Use in Gainesville
III. Technical and Achievable Potential
IV. Energy Conservation Measures
V. Market Segment Characterizations

The purpose of this report is to summarize the methodologies and data sources used to develop the end use models and appliance saturation information employed in the 1994 Demand Side Management Base Planning Study. Volume V of the series contains full listings of the data bases into which the results of the studies described here were assembled, and upon which the overall study is based.

COST EFFECTIVENESS - THREE PERSPECTIVES

Cost effective means simply that benefits exceed costs i.e., (Benefits / Costs) > 1. Before attempting to quantify costs or benefits, it becomes important to distinguish where the impact of costs or benefits of DSM is borne. For example, the previous section described how lost revenues caused by energy conservation is a cost to all utility ratepayers. However, even though rates for all customers are increased, customers that adopt energy conservation will actually see a lower energy bill than they would have had without energy conservation if the "adopting" customer's energy reduction is substantial enough to exceed the billing impact caused by lost revenues. (This is generally the case when there are more "non-adopting" customers than "adopting" customers).

Regardless of the level of impact, the point of the example is that the burden of costs of DSM or the virtue of benefits from DSM lies in the eye of the beholder and as a consequence they are not universal but are determined as a matter of perspective.

There are three generally accepted perspectives from which to evaluate the costs and benefits of DSM. The three perspectives have given rise to three different, but methodologically consistent, tests for cost effectiveness. The three tests are the Participant (PAR) Test, the Rate Impact (RIM) Test and the Total Resource Cost (TRC) Test. A cursory comparison of the three tests is presented in Figure I-1.

The differences in the tests all obviously stem from the specific costs and benefits that are considered respectively in each test. The PAR Test assesses the impact of DSM from the perspective of the "participating" or "adopting" customer. Consequently, the DSM benefit of most concern is that from savings that will occur in the energy bill. Other benefits may include: utility rebates that may be offered; tax credits that various taxing jurisdictions may offer; and, any other quantifiable benefits that accrue to the customer as a consequence of implementing DSM. Relevant participant costs include: hardware purchase costs, if required; operating and maintenance costs on any acquired hardware; and, any other quantifiable costs that are incurred by the customer as a consequence of implementing DSM.

The RIM Test is designed to measure the impact on the rates that GRU must charge to all customers because of DSM. Thus, the RIM Test assesses DSM from the perspectives commonly referred to as of both the utility and of "all ratepayers." The most important benefit of DSM from this perspective is avoiding plant expansion and operations costs. These "avoidable" costs include: avoided investment in generating units; avoided generating unit operations and maintenance costs; avoided fuel costs, net of fuel cost savings foregone as a consequence of not constructing a more efficient generating unit than utilized; transmission and distribution system costs; and, any other quantifiable benefits that accrue to GRU as a consequence of implementing DSM. When DSM results in a shifting of energy consumption, additional potential for benefit exists if there are revenue gains due to "off-peak" sales. Relevant utility costs include: lost sales revenues, explained previously; the cost of inducements or incentives the utility may have to offer; costs of overheads and program administration; and, any other quantifiable costs that are incurred by the utility as a consequence of implementing DSM.

Finally, the TRC Test is an overall general measure of cost effectiveness without specific regard as to where the respective impacts of costs and benefits lie. The TRC can be said to measure the cost effectiveness of DSM in regards to total resources retained within GRU's service area as a consequence of DSM. DSM is cost effective from this perspective if more resources, specifically financial resources, remain within the service area because of the DSM, regardless of how those extra resources are distributed among customers within the service area and regardless of how the costs for that DSM is allocated to customers within the service area. Consequently, the TRC Test considers many of the same costs and benefits listed previously. Specifically, benefits include: all the avoided generation, transmission, distribution and fuel costs relevant to GRU and any other quantifiable benefits realized by the service area as a consequence of implementing DSM. Relevant costs of DSM include: all the hardware costs relevant to the DSM participant; program costs relevant to GRU; and, any other quantifiable costs that are incurred by the service area population as a consequence of implementing DSM.

METHODOLOGY FOR COST EFFECTIVENESS TESTS - THE DSM/FIRE MODEL

To facilitate analyses that gave consistent and valid treatment to all relevant parameters in the tests, an automated analytical computer model was employed for the analysis. The model utilized was the Florida Integrated Resource Evaluator (FIRE), made available to GRU by Florida Power Corporation (FPC). Some modification was required and completed by GRU staff in order to appropriately represent the differences in ownership status and financial structure that exists between GRU and FPC.

FIRE is a spread-sheet based computer program developed particularly to assist in determining the cost-effectiveness of demand-side programs in the reporting format that was specified by the Florida Public Service Commission (FPSC) in the amended Rule 25-17.008 issued July 2, 1991.

This methodology evolved from deliberate and intense discussions between the State's utility industry, FPSC staff and the general public of issues and dynamics germane to the various perspectives on DSM. Pursuant to FPSC direction, and as is embodied in FIRE, the methodology for conducting the tests requires a "value-of-deferral" methodology. This means that immediate consideration be given, as a benefit of DSM, for conservation occurring presently, even though the facilities that may be avoided by that conservation will not be installed for many years in the future. Appropriately, the model relies upon discounted cash-flow techniques, where money is adjusted for "time value," and upon reasonable assumptions about other relevant economic conditions. Some other very basic and imperative premises of the model are:

1. System load is increasing due to load growth. Therefore, reductions in load due to DSM will result in reduced need for system expansion.

2. Finite load reductions, regardless of magnitude, can be directly related to reduced need for finite and equal amounts of system capacity expansion.

3. Decreases or increases in revenue due to DSM will impact rate levels and will be passed on to all customers.

There are three sections of the computer program: a section for data input; a section that calculates costs and benefits; and, a section that shows the cost effectiveness from the three required perspectives. More detail on model assumptions as well as model results will be presented subsequently. Figure I-2 provides a summary overview of the relevant cost and benefit components while juxtaposing the three perspectives.

MODELLING APPROACH

Even though FIRE is sufficiently robust to the extent that it is able to discern relative cost effectiveness from all three perspectives for virtually any DSM measure, it also generates intermediate results that are equally useful in determining the value of "generic" energy conservation from each of the three perspectives.

In the final step of FIRE, under its ultimate application, the model computes cost effectiveness for a DSM measure by dividing its total benefits by its total costs. Thus, the model obviously computes total costs and total benefits for respective DSM measures as an intermediate result, for each perspective. As a result, the net value (or net cost) of DSM can be indicated for each perspective. This feature of the model and the fact that value of DSM is dependent upon the time upon which it occurs, prompted application of the model in a manner that ascertained the value of a kW and the value of a kWh in regards to <u>when</u> the DSM occurs. This was accomplished by evaluating or "testing" DSM programs that had savings of 1 kW and 1 kWh savings in each of the time periods of consequence (summer peak, winter peak, and off-peak). More discussion on the application and assumptions in the model is presented in Section IV. A discussion on the relevance of the time periods follows in the next Section.

FIGURE I-1

COST EFFECTIVENESS

BENEFITS EXCEED COSTS

i.e. BENEFITS ÷ COSTS > 1

THREE PERSPECTIVES

1. PARTICIPANT TEST:

PARTICIPANT BENEFITS ÷ PARTICIPANT COSTS > 1

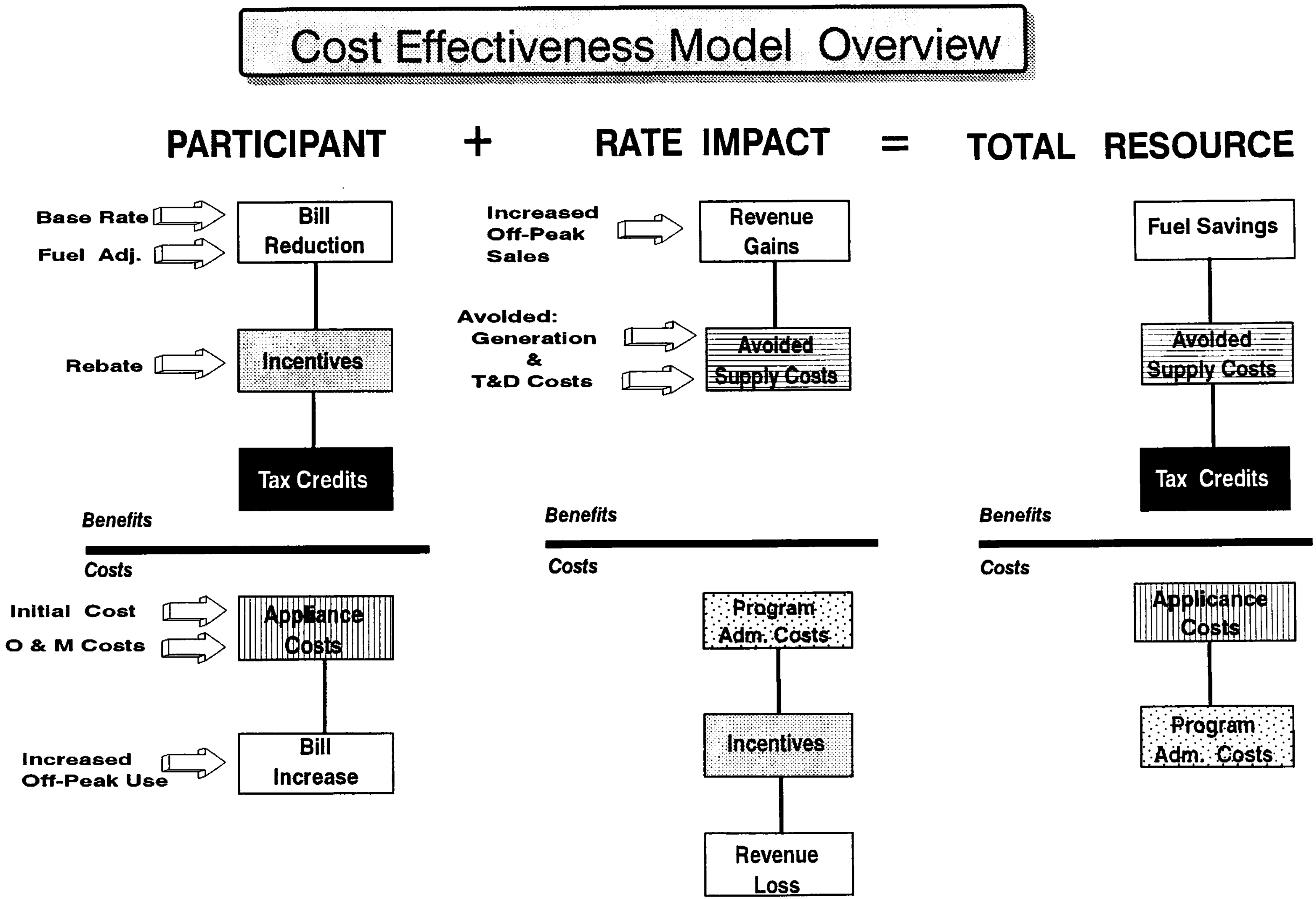
2. RATE IMPACT MEASURE (RIM):

UTILITY BENEFITS ÷ UTILITY COSTS > 1

3. TOTAL RESOURCE COST (TRC):

RESOURCE SAVINGS ÷ RESOURCE COSTS > 1

FIGURE I-2



W:\U1500\DSMPL\V1\FIG.1_2

TABLE I-1

BENEFITS AND COSTS OF ENERGY CONSERVATION

BENEFITS	COSTS
Savings in Utility Bill	Lost Utility Sales Revenue
Fuel Cost Savings	Costs of Utility Rebates and Incentives
Utility Rebates Offered	Utility Program Administration Costs
Tax Credits	Purchase of Energy Saving Hardware
Avoided Generating Costs	O&M Cost of Energy Saving Hardware
Avoided T&D Costs	Any Other Quantifiable Costs
Revenue from Additional Sales	
Any Other Quantifiable Benefits	

II DETERMINATION OF GAINESVILLE REGIONAL UTILITIES "ON" AND "OFF" PEAK POWER DEMAND PERIODS

INTRODUCTION

In order to evaluate the potential economic impacts of demand side management (DSM) and energy conservation programs the peak power demand periods on the GRU system had to be identified. Two factors were looked at to establish these peak periods; the hourly system Megawatt (MW) loads and the hourly system production cost.

HISTORICAL DATA PLOTS

The GRU daily maximum loads from 1970 through 1993 were examined to determine the seasons in which the peak demand for power on the GRU system occurred.

The daily maximum loads were normalized for each year's maximum load and plotted on a Per-Unit (PU) versus day-of-the-year basis as shown by Figure II-1. Peak seasons were defined as the dates between which the system load consistently exceeded 0.9 PU. The summer season spanned May 15 - Oct 15 while the winter season spanned Jan 1 - Jan 31.

The hourly loads for each day of the winter season (Jan 1 - Jan 31 shown by Figure II-2) and the hourly loads for each day of the summer season (May 15 - Oct 15 shown by Figure II-3), for four typical weather years ('78, '87, '91, & '92), were plotted to help identify the hours that should be assigned as the daily peak demand times for the two seasons.

OPTIMIZATION OF PERIODS

A peak day in 1995 for both the cooling and heating seasons was simulated using historical production data in a production simulation model. The quantities examined were: hour-of-day, MW demand, and hourly incremental production cost. A plot of the incremental cost ($/MWH) versus hour-of-day assisted in determining the peak periods of the day. Hourly incremental cost are shown for the summer period by Figure II-4 and for the winter period by Figure II-5.

These values were also simulated for each year of the next decade and beyond to determine variances in peak periods. The results of these simulations were very similar to the peak day for 1995. A substantial reduction in production costs is expected to occur when a new base-load coal generation unit is added. When the mixture of generators in the GRU System changes a re-evaluation of peak times will be required.

RESULTS AND DISCUSSION

The winter peak demand season covers the month of January. This short winter period may be due to a continuing trend related to the increasing saturation of natural gas for heating in the GRU service area and a reduction of the use of electric resistance heating.

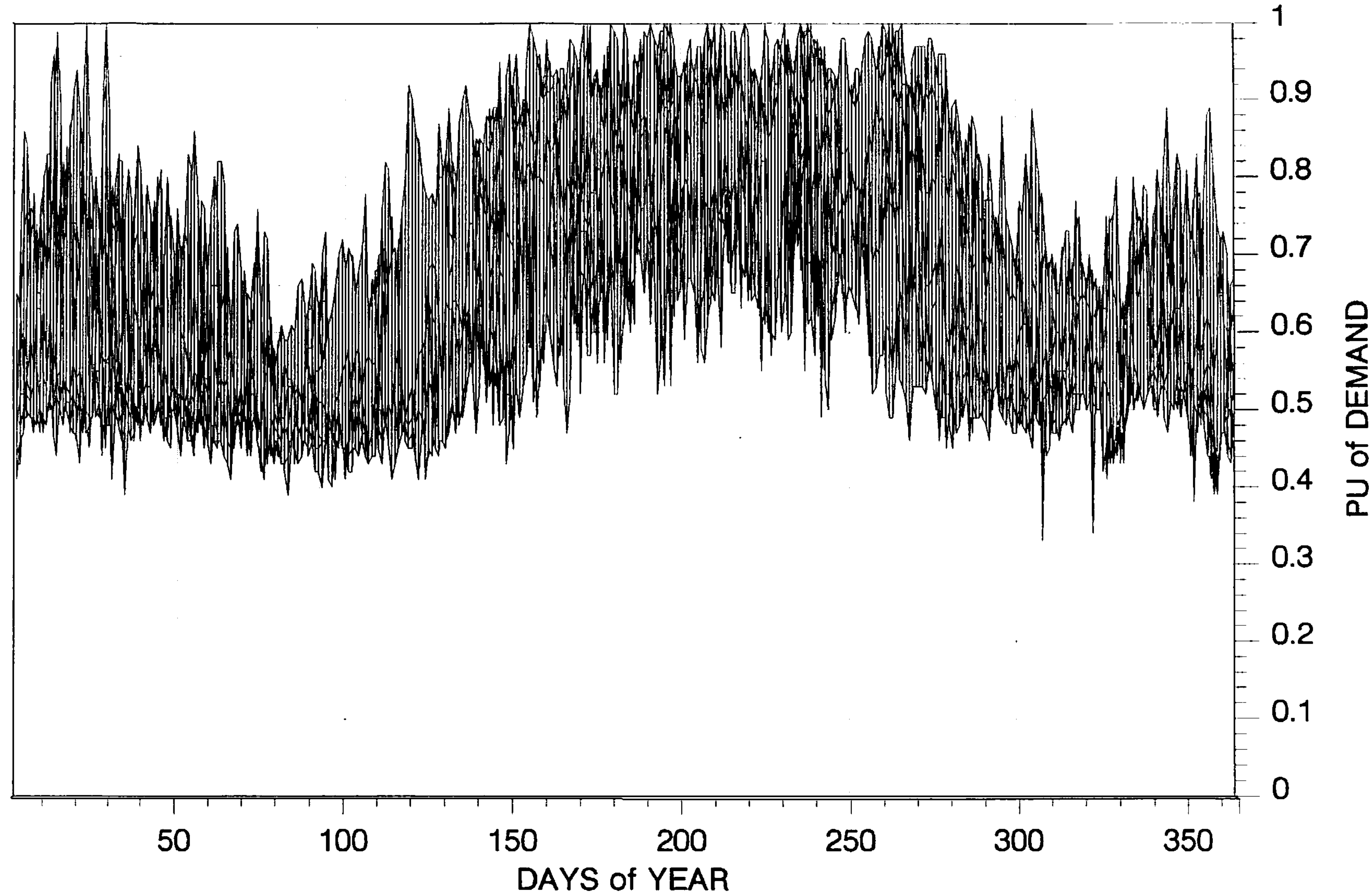
The summer peak season identified the peak demand period of May 15 - Oct 15 as appropriate. The hours of the daily peak period for both summer and winter are summarized below:

Peak Demand Periods:

Winter
January 1 - January 31
6:00 a.m. through 11:00 a.m.
5:00 p.m. through 10:00 p.m.
Weekends and Jan 1 excluded

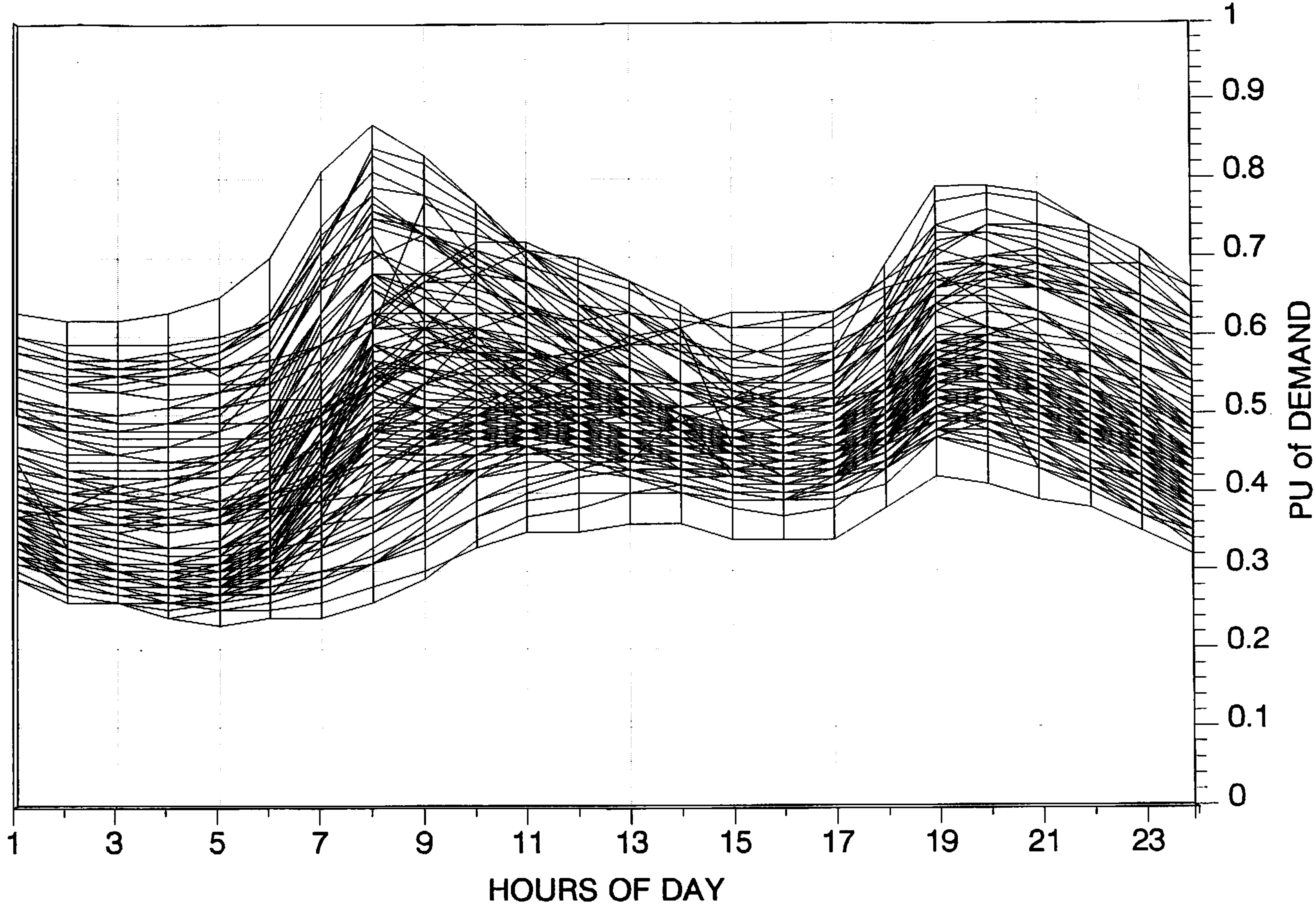
Summer
May 15 - October 15
11:00 a.m. through 10:00 p.m.
Weekends and Holidays included

w:\u1500\dsmpl\v1\s2pabc

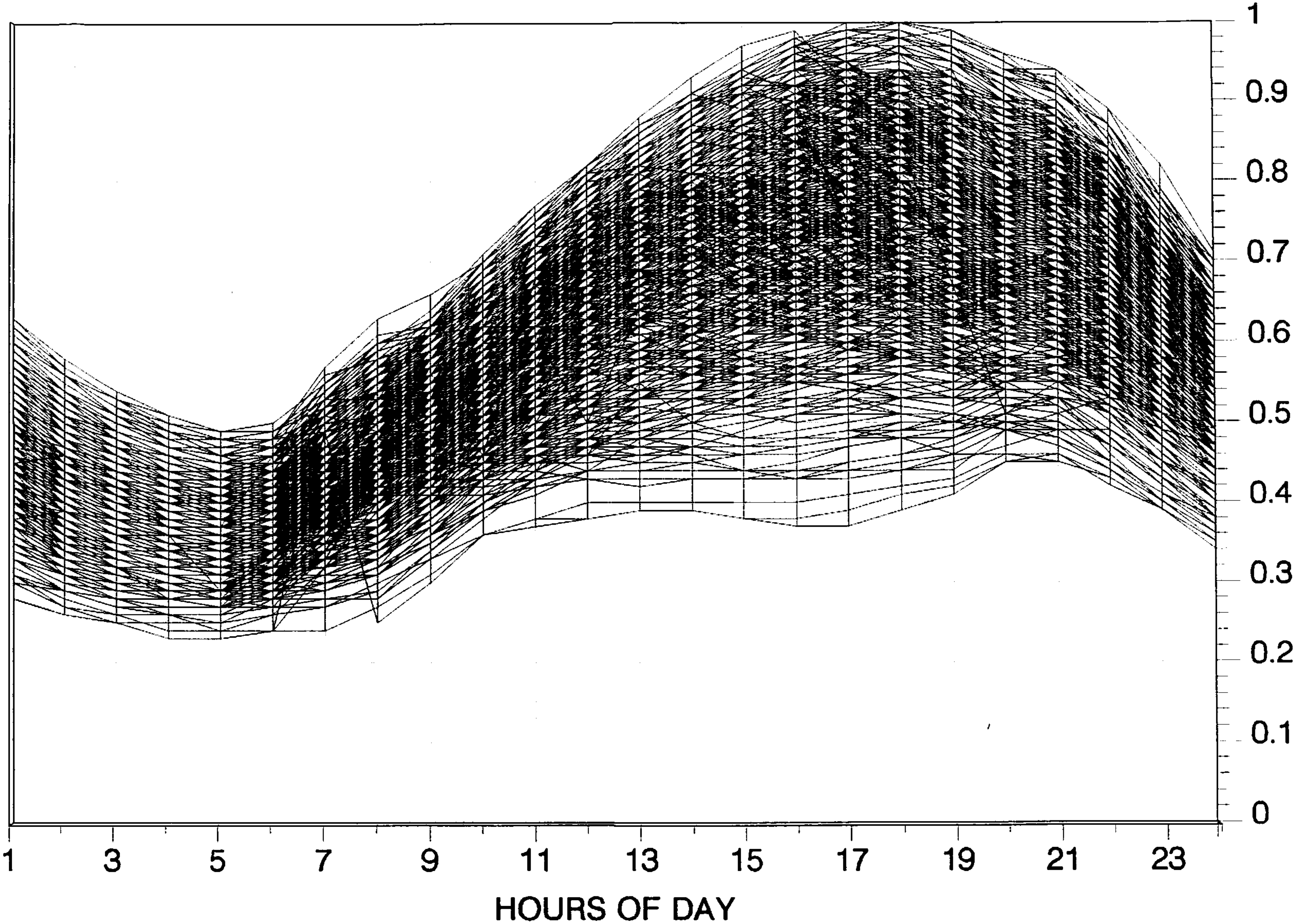


GAINESVILLE DAILY MAXIMUM LOADS
1970 - 1993

FIGURE II-1



GRU WINTER LOAD SHAPE
1978 / 1987 / 1991 / 1992
Data Points (Hour Ending Data)
FIGURE II-2



GRU SUMMER LOAD SHAPE
1978 / 1987 / 1991 / 1992
Data Points (Hour Ending Data)
FIGURE II-3

FIGURE II-4

HOURLY SUMMER INCREMENTAL COST

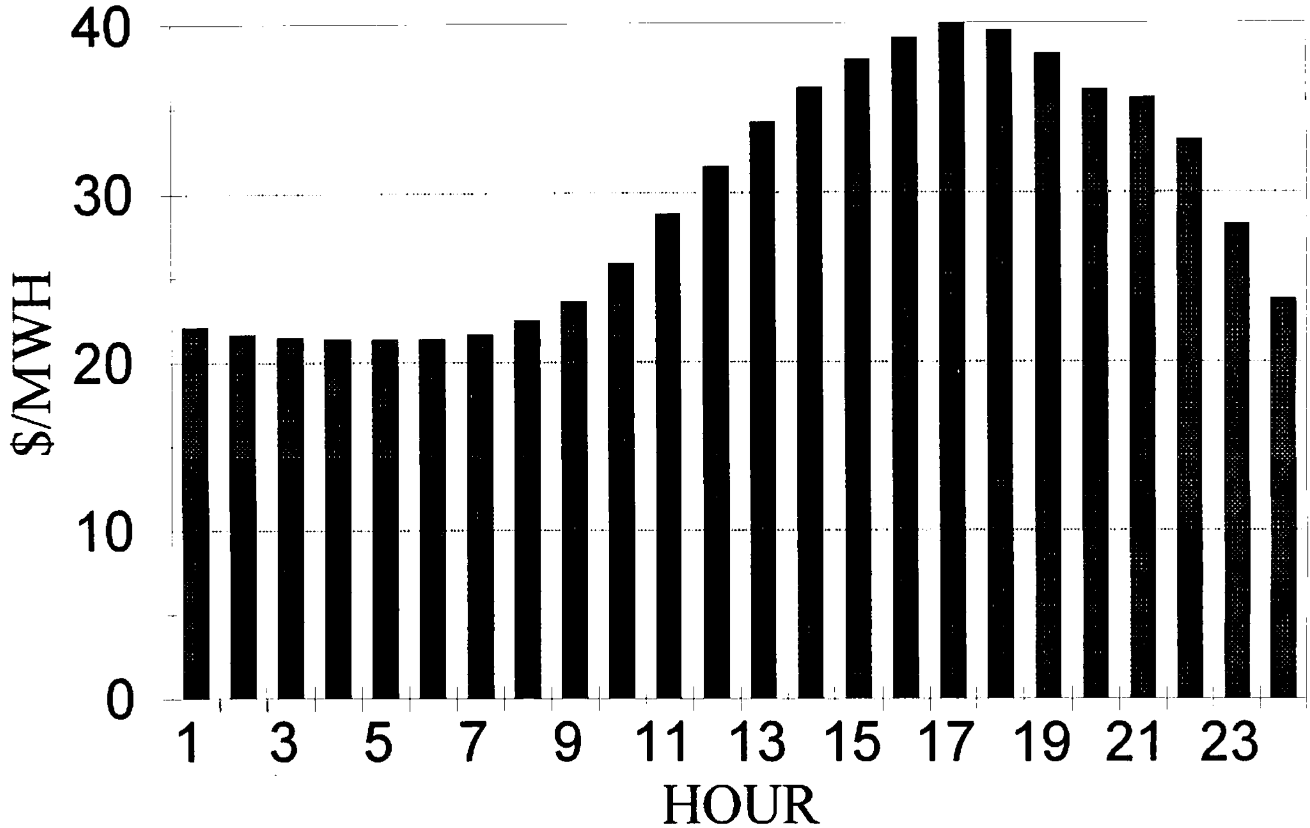
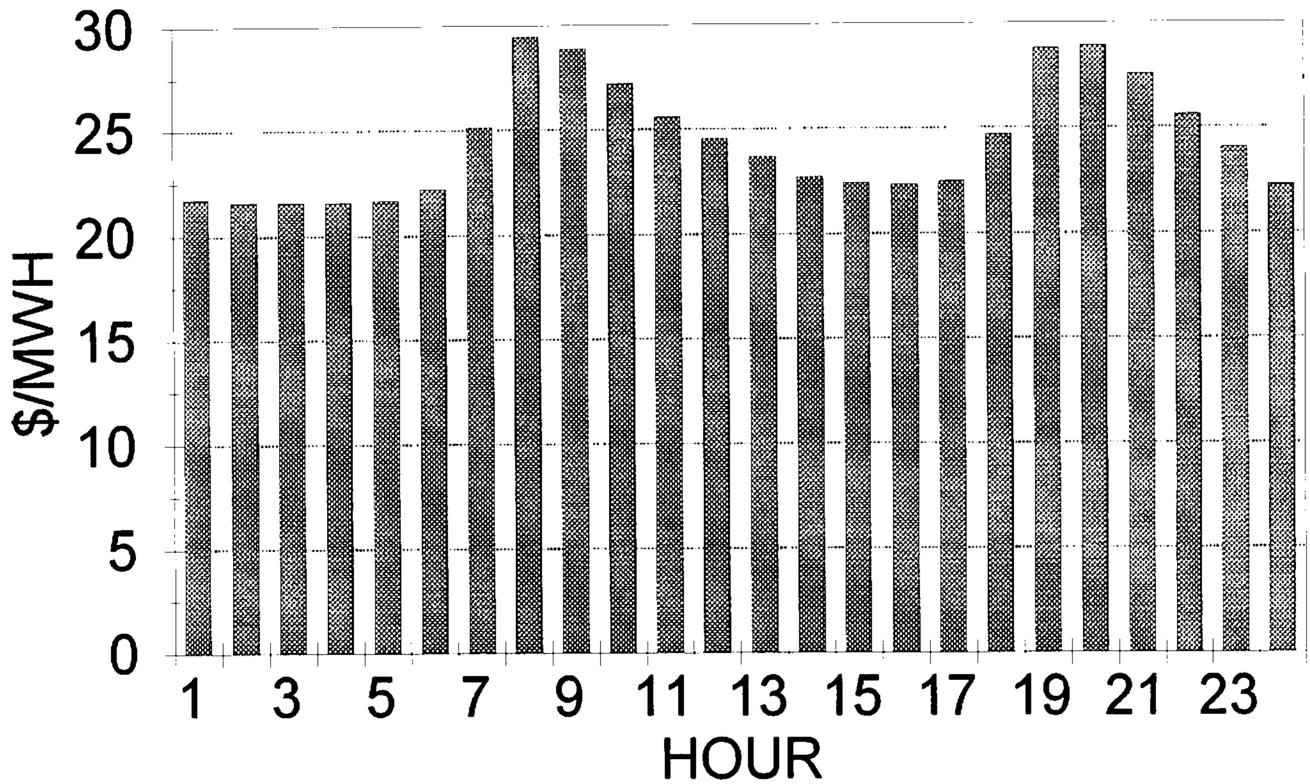


FIGURE II-5

HOURLY WINTER INCREMENTAL COST



III GENERATION BASE CASE

OVERVIEW OF INTEGRATED RESOURCE PLANNING

GRU performed an integrated resource planning study Gainesville Regional Utilities: Integrated Resource Least-Cost Planning Study, which was completed March, 1992.

Since the value of conservation is indicated by the costs it avoids and the most prominent avoided costs are generating facilities, an evaluation of the generation expansion scenarios wherein units could be deferred or eliminated was necessary. This evaluation was accommodated by state-of-the-art modeling software for integrated resource planning studies (developed by the Electric Power Research Institute), called "Electric Generation Expansion Analysis System" (EGEAS). Figure III-1 shows the primary inputs required by EGEAS. Table III-1 summarizes the yearly base case load forecast, showing MWh and winter and summer MW demands for GRU. Complete documentation of the load forecast is presented in Appendix A. The peak MW demands showing historical years as well as projections for the base and the no new conservation (CPF: conservation planning and forecasting) forecasts are plotted for summer in Figure III-2 with the winter peaks plotted in Figure III-3. Table III-2 summarizes the load reductions resulting from current conservation plan. Refer to Appendix A for a Table of historical and projected conservation savings by measure. GRU's fuel department develops an intermediate fuel price forecast based on current trends and known costs associated with current contracts. This forecast is extended for the planning horizon by applying U.S. Department of Energy escalators for the Southeast United States. Figure III-4 shows the historical and forecasted fuel prices and their escalators. A comprehensive evaluation of the potential of conservation was begun by using the methods and procedures outlined in the IRP document on a new 'no new conservation case' so as to permit the evaluation of current programs as well as possible future programs.

NO NEW CONSERVATION CASE

Table III-3 summarizes the yearly 'no new conservation' load forecast, showing MWh and winter and summer MW demands for GRU. The peak MW demands showing historical years as well as the base and the no new conservation (CPF: conservation planning and forecasting) forecasts are plotted for summer in Figure III-2 with the winter peaks plotted in Figure III-3.

RESULTS OF NO NEW CONSERVATION CASE

Table III-4 compares GRU's current generation expansion plan with the 'no new conservation' plan developed for evaluating conservation measures. GRU's next supply side resource (GRU's 'avoided unit') is shown to be a 100 MW circulating-fluidized-bed coal unit in the year 2004. Using the 'no new conservation' case, detailed hourly production runs were made for the study years. Table III-5 displays the results from the production runs including the summer peak avoided fuel cost, the winter peak avoided fuel cost and the off-peak avoided fuel cost.

FUEL COST FOR THE REPLACEMENT ENERGY

One of the values needed to evaluate demand side measures is the replacement fuel cost for GRU's "avoided unit". This is the production cost of the energy that would have been served by a new unit but must now be served by GRU's current units due to the new unit being "avoided". It is the cost of serving the "avoided unit's" energy with current gas fired generation rather than the "avoided unit's" lower coal cost and thus actually increases system production cost if the unit is avoided. Figure III-5 shows the energy that would be served by the current generating units if enough conservation could be implemented to avoid the need for the next unit. Figure III-6 indicates the energy that would be served by the avoided unit if it were not avoided. The replacement energy fuel cost is shown in Table III-6.

W:\u1500\dsmpl\v1\s3pabcd

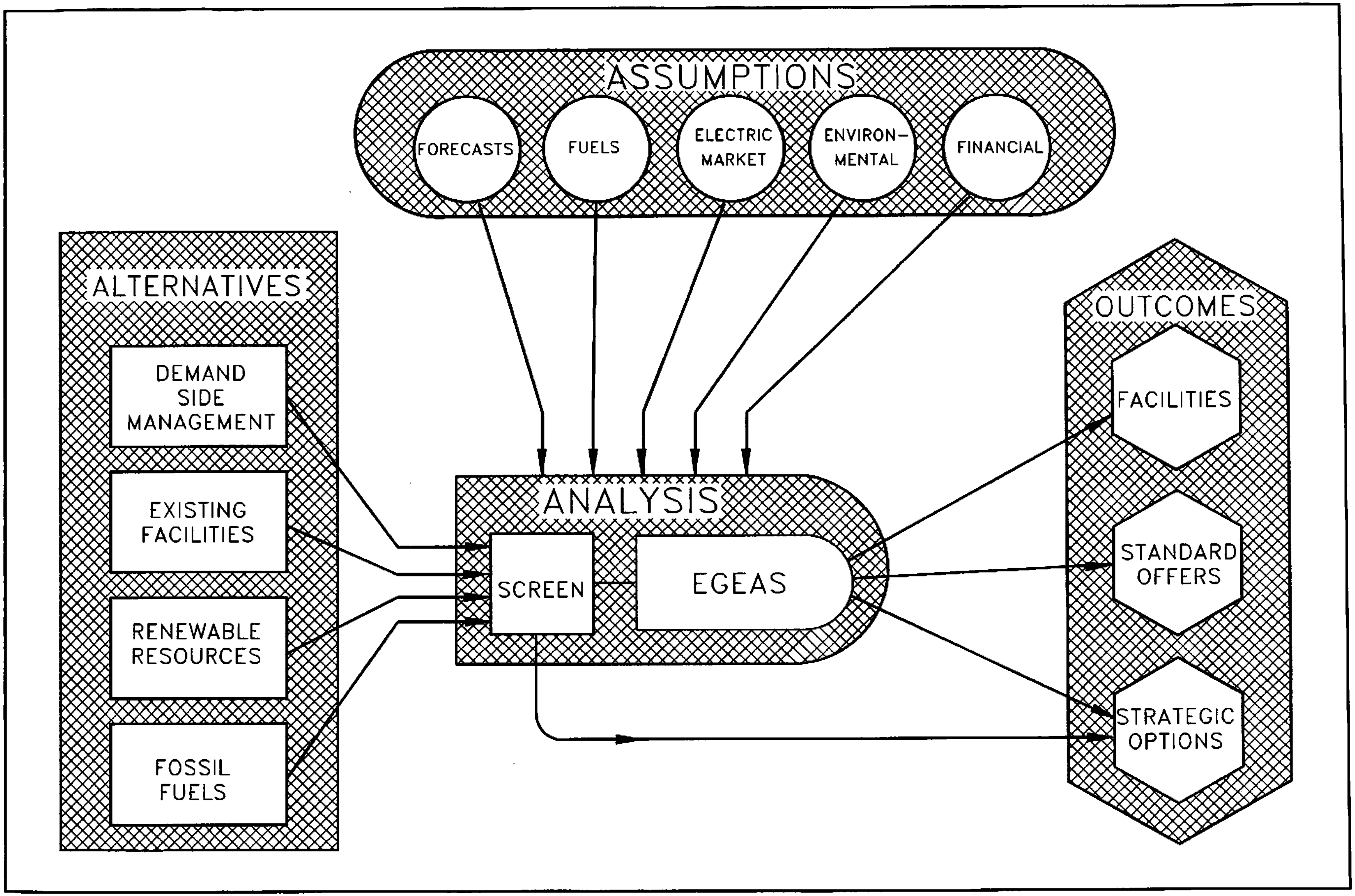


FIGURE III-1 Overview of Alternatives Analysis.

Figure III-2
Summer Peak Demand

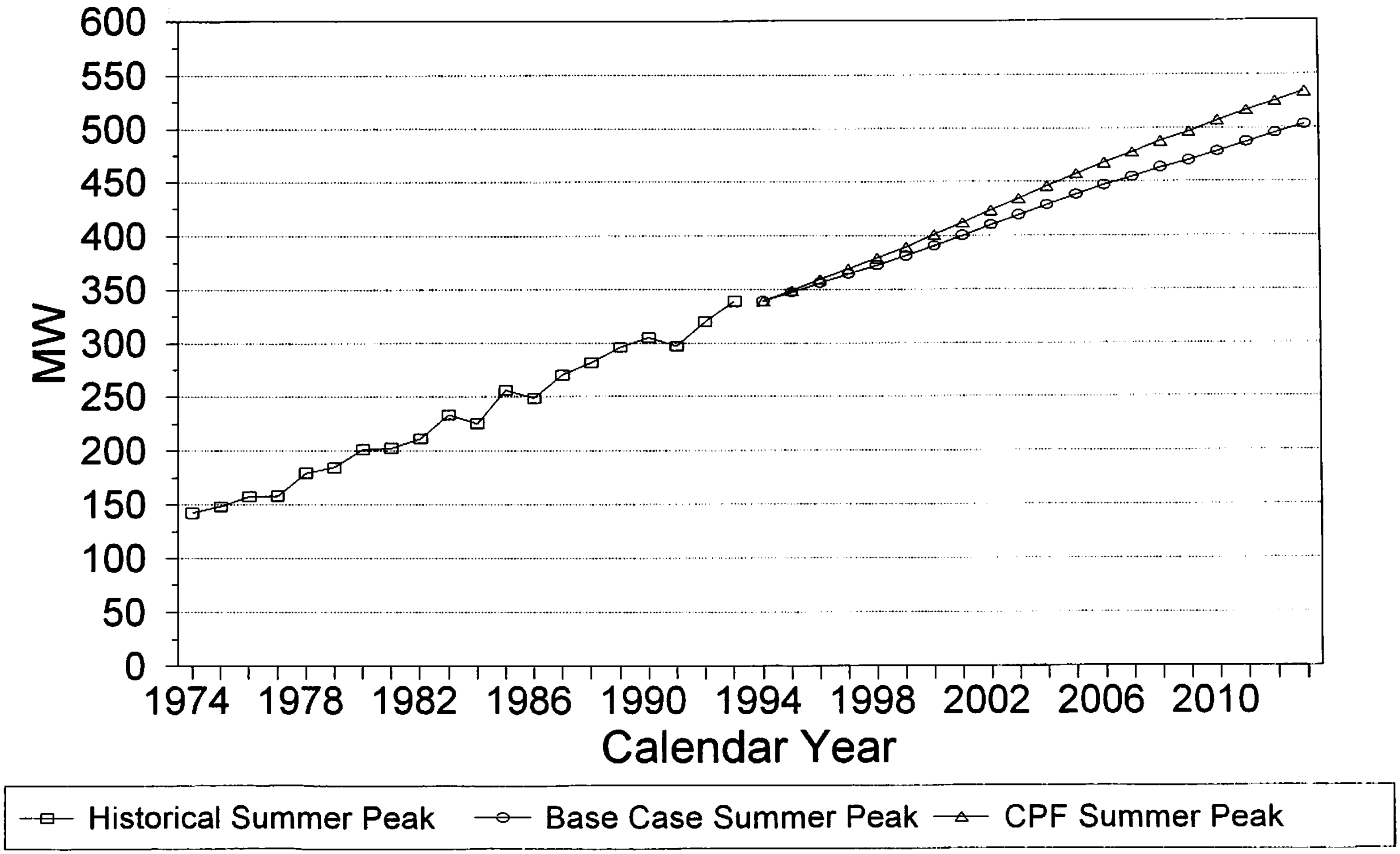


Figure III-3
Winter Peak Demand

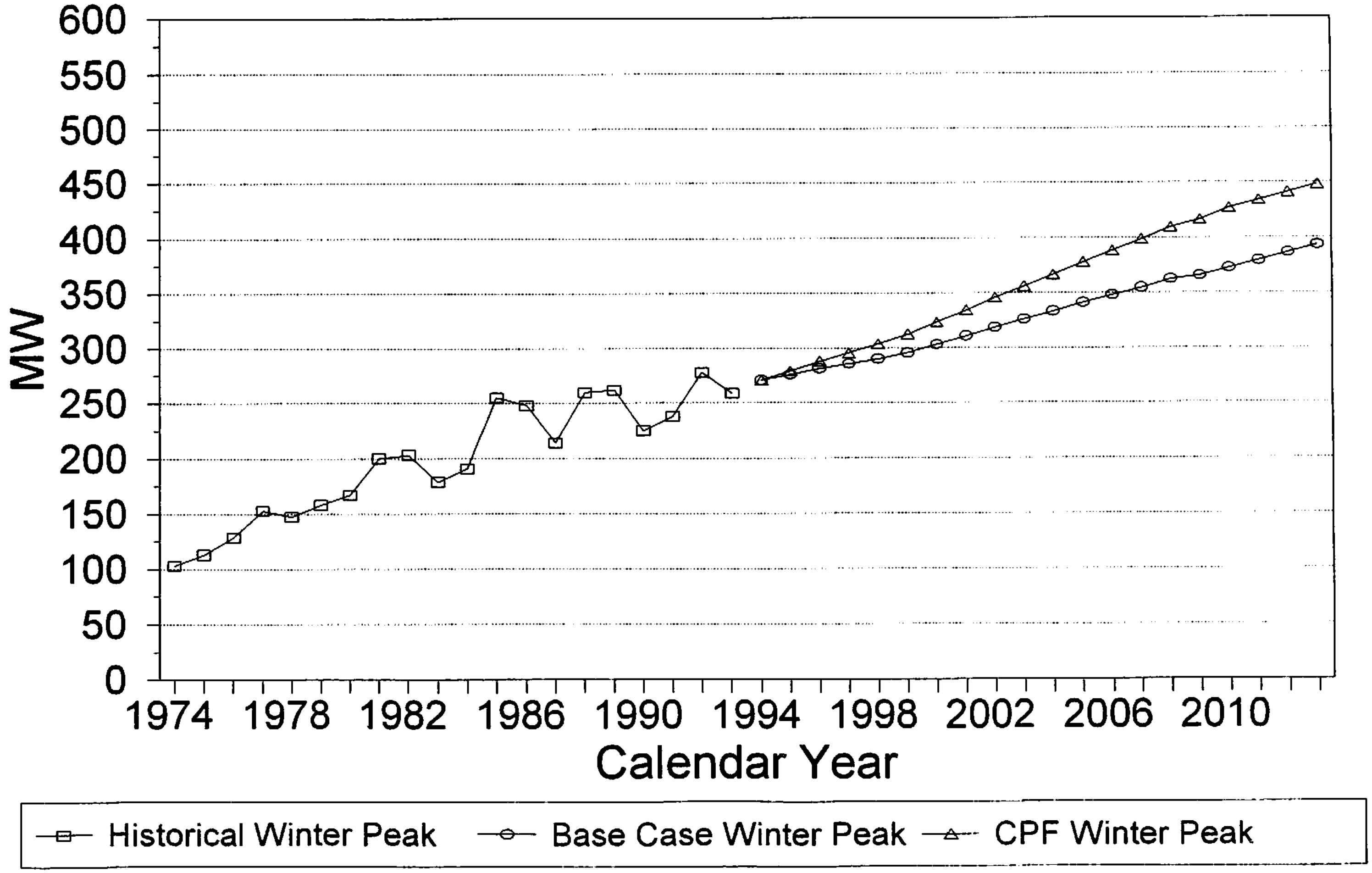
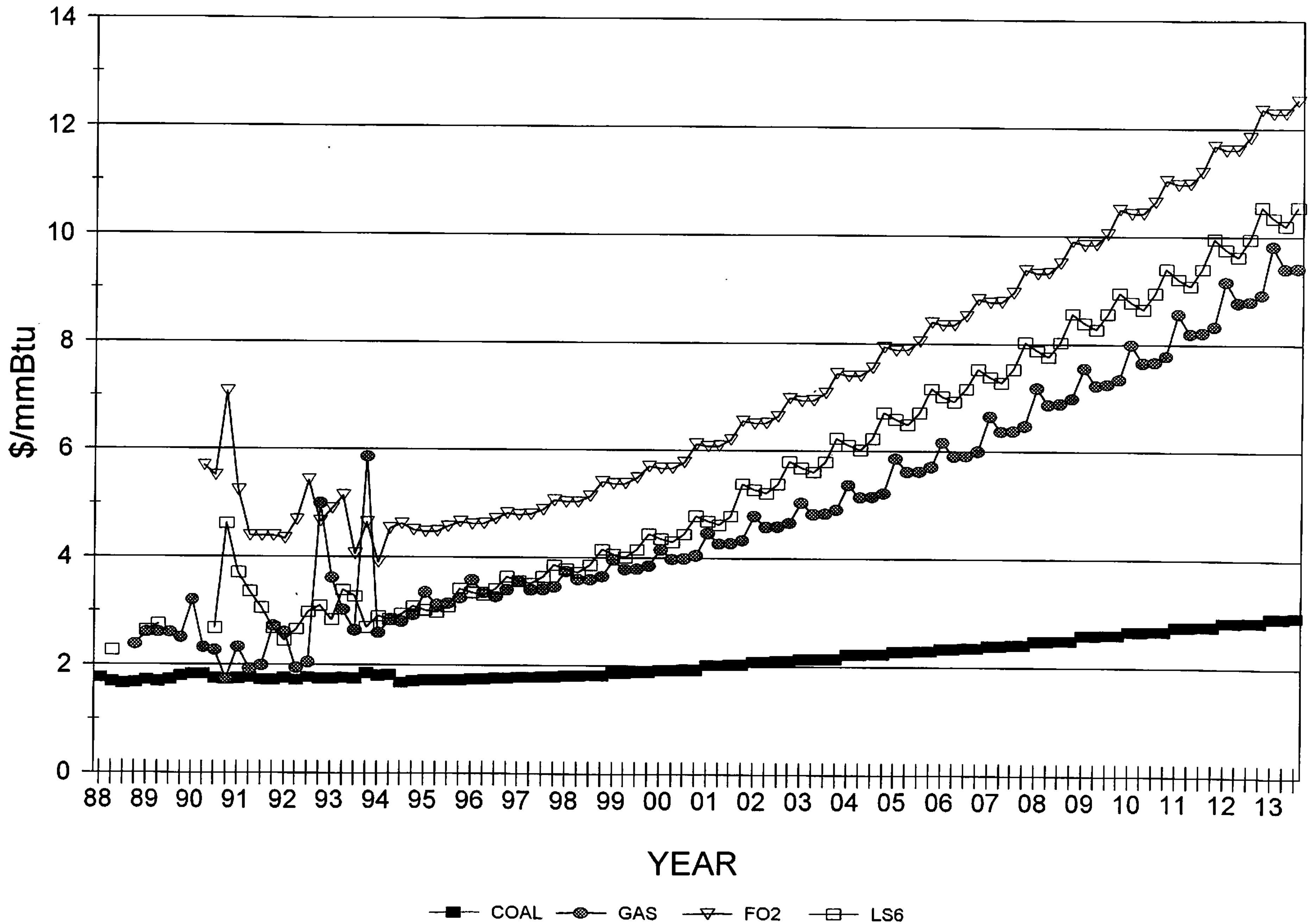


FIGURE III - 4
GRU Fuel Comparison History & Forecst



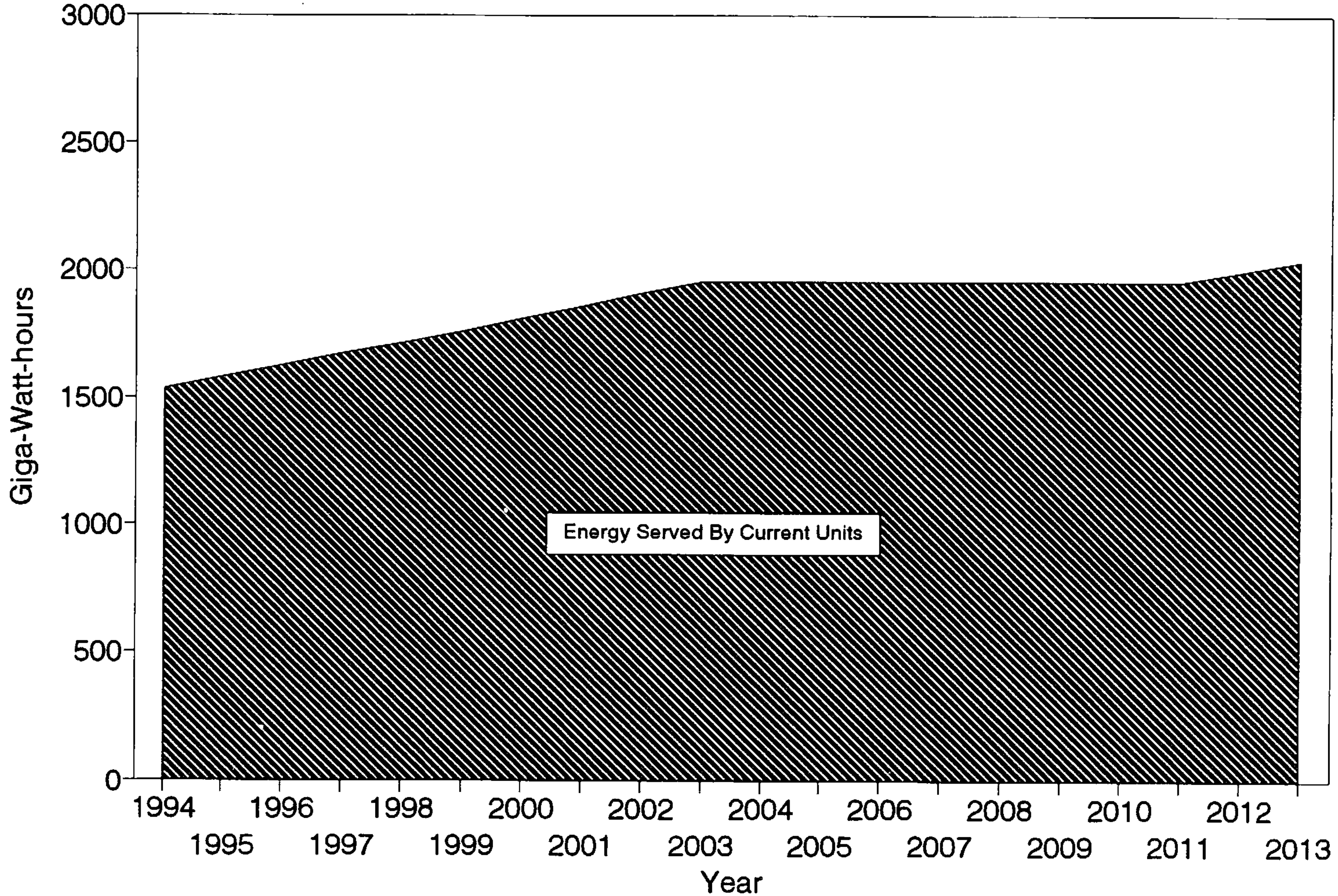
12/02/94

W:\U1500\JOSE\FUEL\FCST94\COAL_B.WB1

FIGURE III-5

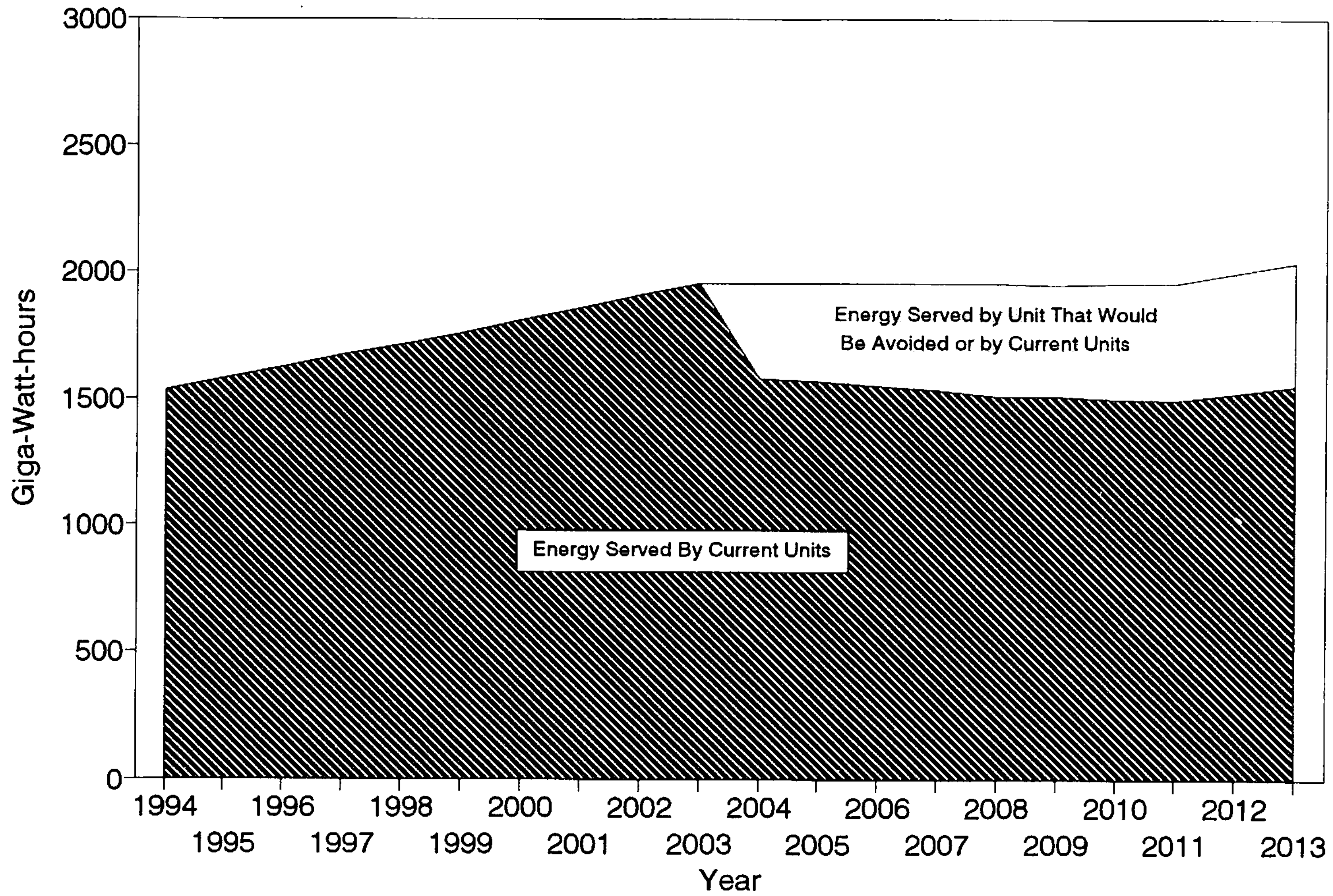
REPLACEMENT ENERGY ANALYSIS

Old Units Energy w/o Avoided Unit



d:\ssheetd\dsm\rfcncm.wq1\eswoau

FIGURE III-6
REPLACEMENT ENERGY ANALYSIS
Old Units Energy with Avoided Unit



d:\ssheetd\dsm\rfcncm.wq1\eswau

TABLE III-1

1994 "Base Case" Electric Forecast

Calendar Year	Net Energy for Load (MWh)	Winter Peak (MW)	Summer Peak (MW)
1974	604,000	103	142
1975	652,000	113	148
1976	671,876	129	158
1977	743,003	153	158
1978	797,582	147	179
1979	827,312	158	184
1980	859,591	167	201
1981	895,023	200	202
1982	896,596	203	211
1983	954,428	179	234
1984	983,002	191	225
1985	1,070,363	255	256
1986	1,105,995	248	249
1987	1,151,042	214	270
1988	1,246,015	260	282
1989	1,323,303	262	296
1990	1,362,705	225	305
1991	1,410,927	238	297
1992	1,423,592	278	320
1993	1,501,843	259	339
1994	1,533,641	271	339
1995	1,573,026	276	347
1996	1,613,900	281	356
1997	1,650,116	285	364
1998	1,685,980	290	372
1999	1,725,080	295	381
2000	1,769,161	303	390
2001	1,811,539	311	400
2002	1,856,507	318	410
2003	1,899,443	326	419
2004	1,942,546	333	428
2005	1,988,245	341	438
2006	2,027,841	348	447
2007	2,065,461	354	455
2008	2,105,551	362	463
2009	2,137,292	365	470
2010	2,176,743	372	478
2011	2,215,591	379	486
2012	2,253,919	386	495
2013	2,293,414	393	503

TABLE III-2

Load Reductions Resulting from DSM

Calendar Year	Net Energy for Load (MWh)	Winter Peak (kW)	Summer Peak (kW)
1994	1,119	2,160	556
1995	2,690	4,513	1,212
1996	3,679	6,760	1,713
1997	8,580	9,605	2,827
1998	13,468	12,272	3,883
1999	18,048	14,726	4,766
2000	19,547	15,066	5,208
2001	20,805	15,308	5,270
2002	22,451	15,881	5,787
2003	24,109	16,595	6,359
2004	26,594	17,586	7,147
2005	28,329	18,205	7,806
2006	29,522	18,432	8,480
2007	30,227	18,477	8,991
2008	30,387	18,044	9,460
2009	36,963	21,472	11,367
2010	38,152	21,889	11,866
2011	39,161	22,181	12,343
2012	40,113	22,430	12,805
2013	40,989	22,626	13,251

TABLE III-3

1994 "No New Conservation" Electric Forecast

Calendar Year	Net Energy for Load (MWh)	Winter Peak (MW)	Summer Peak (MW)
1974	604,000	103	142
1975	652,000	113	148
1976	671,876	129	158
1977	743,003	153	158
1978	797,582	147	179
1979	827,312	158	184
1980	859,591	167	201
1981	895,023	200	202
1982	896,596	203	211
1983	954,428	179	234
1984	983,002	191	225
1985	1,070,363	255	256
1986	1,105,995	248	249
1987	1,151,042	214	270
1988	1,246,015	260	282
1989	1,323,303	262	296
1990	1,362,705	225	305
1991	1,410,927	238	297
1992	1,423,592	278	320
1993	1,501,843	259	339
1994	1,533,641	271	339
1995	1,579,061	279	349
1996	1,626,127	288	359
1997	1,668,670	295	369
1998	1,710,926	303	379
1999	1,756,597	312	389
2000	1,807,274	323	400
2001	1,856,018	334	412
2002	1,907,474	345	423
2003	1,956,959	356	434
2004	2,006,662	366	446
2005	2,059,065	378	457
2006	2,105,439	388	468
2007	2,149,901	398	478
2008	2,196,911	409	488
2009	2,235,650	416	496
2010	2,282,175	427	507
2011	2,322,097	434	516
2012	2,361,438	441	525
2013	2,401,865	448	533

B:\FCSTTABL.WB1

TABLE III-4
1994 20-YEAR DEMAND & ENERGY FORECAST CASE versus NO NEW CONSERVATION FORECAST CASE

Case Designation		'94F Base Case	NC No New Conservation
Dynamic Optimization		Full	Full
Forced Options		71CT'95	71CT'95
EXPANSION CHOICES	1994		
	1995	CT 71	CT 71
	1996		
	1997		
	1998		
	1999		
	2000		
	2001		
	2002		
	2003		
	2004		CFB 100
	2005	FGD 40	
	2006		
	2007		
	2008		
	2007		
	2010	CFB 100	
	2011		
	2012		CFB 100
	2013		
OPTIONS AVAILABLE TO PLAN CC 112.3 converts CT 71 to CC Operation 100/160 is 100MW of a 160MW Unit		CT 40 CT 71 CFB 100/160 CFB 160 PC 40/300 DLC 5 CC 112.3	CT 40 CT 71 CFB 100/160 CFB 160 PC 40/300 DLC 5 CC 112.3

LEGEND
(Numbers after letter represent size)

CC = Combined Cycle
CT = Combustion Turbine
CFB = Circulating Fluidized Bed Coal
FGD = Flue Gas Desulfurization Pulverized Coal
DLC = Direct Load Control

CASE DESCRIPTIONS

Present Worth Revenue Requirements:
'94F - 1994 20-Year Demand & Energy Forecast Base Case
NC - Needed Additions if No Further Conservation Is Done

d:\ssheetd\genplan\T-1.wq1

TABLE III-5
YEARLY COST ANALYSIS

YEAR 95	avg 5 runs
Winter on-peak avg inc. =	$22.02
Winter off-peak avg inc. =	$18.08
Summer on-peak avg inc. =	$32.95
Summer off-peak avg inc. =	$19.06
Total off-peak avg inc. =	$20.78
Total on-peak avg inc. =	$31.69
System avg inc. =	$23.15
System avg prod. cost =	$21.44
YEAR 96	
Winter on-peak avg inc. =	$22.83
Winter off-peak avg inc. =	$18.94
Summer on-peak avg inc. =	$35.13
Summer off-peak avg inc. =	$19.75
Total off-peak avg inc. =	$21.37
Total on-peak avg inc. =	$33.70
System avg inc. =	$24.04
System avg prod. cost =	$22.18
YEAR 97	
Winter on-peak avg inc. =	$24.23
Winter off-peak avg inc. =	$19.50
Summer on-peak avg inc. =	$36.44
Summer off-peak avg inc. =	$20.96
Total off-peak avg inc. =	$22.95
Total on-peak avg inc. =	$35.03
System avg inc. =	$25.57
System avg prod. cost =	$23.02
YEAR 98	
Winter on-peak avg inc. =	$24.70
Winter off-peak avg inc. =	$20.05
Summer on-peak avg inc. =	$38.29
Summer off-peak avg inc. =	$21.44
Total off-peak avg inc. =	$23.71
Total on-peak avg inc. =	$36.72
System avg inc. =	$26.54
System avg prod. cost =	$24.00
YEAR 99	
Winter on-peak avg inc. =	$24.73
Winter off-peak avg inc. =	$19.80
Summer on-peak avg inc. =	$39.71
Summer off-peak avg inc. =	$21.88
Total off-peak avg inc. =	$23.46
Total on-peak avg inc. =	$37.98
System avg inc. =	$26.62
System avg prod. cost =	$24.32
YEAR 100	
Winter on-peak avg inc. =	$25.45
Winter off-peak avg inc. =	$20.68
Summer on-peak avg inc. =	$41.31
Summer off-peak avg inc. =	$22.32
Total off-peak avg inc. =	$24.14
Total on-peak avg inc. =	$39.47
System avg inc. =	$27.47
System avg prod. cost =	$25.26

02-Dec-94
c:\qpw\conservq.wb1

YEAR 101	
Winter on-peak avg inc. =	$28.38
Winter off-peak avg inc. =	$22.58
Summer on-peak avg inc. =	$45.21
Summer off-peak avg inc. =	$24.26
Total off-peak avg inc. =	$26.21
Total on-peak avg inc. =	$43.27
System avg inc. =	$29.92
System avg prod. cost =	$26.87
YEAR 102	
Winter on-peak avg inc. =	$32.39
Winter off-peak avg inc. =	$23.79
Summer on-peak avg inc. =	$49.66
Summer off-peak avg inc. =	$26.54
Total off-peak avg inc. =	$28.47
Total on-peak avg inc. =	$47.66
System avg inc. =	$32.64
System avg prod. cost =	$28.73
YEAR 103	
Winter on-peak avg inc. =	$34.71
Winter off-peak avg inc. =	$24.96
Summer on-peak avg inc. =	$52.87
Summer off-peak avg inc. =	$28.52
Total off-peak avg inc. =	$30.38
Total on-peak avg inc. =	$50.77
System avg inc. =	$34.81
System avg prod. cost =	$29.99
YEAR 104	
Winter on-peak avg inc. =	$23.74
Winter off-peak avg inc. =	$22.14
Summer on-peak avg inc. =	$38.91
Summer off-peak avg inc. =	$22.95
Total off-peak avg inc. =	$26.50
Total on-peak avg inc. =	$37.16
System avg inc. =	$28.81
System avg prod. cost =	$27.56
YEAR 105	
Winter on-peak avg inc. =	$24.02
Winter off-peak avg inc. =	$22.16
Summer on-peak avg inc. =	$43.47
Summer off-peak avg inc. =	$23.79
Total off-peak avg inc. =	$28.08
Total on-peak avg inc. =	$41.22
System avg inc. =	$30.93
System avg prod. cost =	$28.73
YEAR 106	
Winter on-peak avg inc. =	$27.28
Winter off-peak avg inc. =	$23.89
Summer on-peak avg inc. =	$48.23
Summer off-peak avg inc. =	$25.34
Total off-peak avg inc. =	$29.65
Total on-peak avg inc. =	$45.80
System avg inc. =	$33.16
System avg prod. cost =	$30.15

GENERATION ADDITIONS

71 MW CT in 1995
100 MW CFB in 2004
100 MW CFB in 2012

YEAR 107	
Winter on-peak avg inc. =	$28.07
Winter off-peak avg inc. =	$25.91
Summer on-peak avg inc. =	$53.43
Summer off-peak avg inc. =	$26.75
Total off-peak avg inc. =	$31.69
Total on-peak avg inc. =	$50.50
System avg inc. =	$35.77
System avg prod. cost =	$31.62
YEAR 108	
Winter on-peak avg inc. =	$30.58
Winter off-peak avg inc. =	$25.77
Summer on-peak avg inc. =	$59.33
Summer off-peak avg inc. =	$28.19
Total off-peak avg inc. =	$33.73
Total on-peak avg inc. =	$56.00
System avg inc. =	$38.55
System avg prod. cost =	$33.48
YEAR 109	
Winter on-peak avg inc. =	$32.40
Winter off-peak avg inc. =	$26.91
Summer on-peak avg inc. =	$63.70
Summer off-peak avg inc. =	$30.28
Total off-peak avg inc. =	$36.01
Total on-peak avg inc. =	$60.08
System avg inc. =	$41.24
System avg prod. cost =	$35.21
YEAR 110	
Winter on-peak avg inc. =	$38.20
Winter off-peak avg inc. =	$29.48
Summer on-peak avg inc. =	$70.74
Summer off-peak avg inc. =	$32.03
Total off-peak avg inc. =	$38.29
Total on-peak avg inc. =	$66.97
System avg inc. =	$44.52
System avg prod. cost =	$37.27
YEAR 111	
Winter on-peak avg inc. =	$40.41
Winter off-peak avg inc. =	$30.67
Summer on-peak avg inc. =	$77.35
Summer off-peak avg inc. =	$34.64
Total off-peak avg inc. =	$41.17
Total on-peak avg inc. =	$73.08
System avg inc. =	$48.10
System avg prod. cost =	$39.24
YEAR 112	
Winter on-peak avg inc. =	$28.87
Winter off-peak avg inc. =	$27.87
Summer on-peak avg inc. =	$54.82
Summer off-peak avg inc. =	$28.86
Total off-peak avg inc. =	$33.35
Total on-peak avg inc. =	$51.82
System avg inc. =	$37.35
System avg prod. cost =	$35.70
YEAR 113	
Winter on-peak avg inc. =	$33.08
Winter off-peak avg inc. =	$29.95
Summer on-peak avg inc. =	$59.25
Summer off-peak avg inc. =	$30.45
Total off-peak avg inc. =	$34.53
Total on-peak avg inc. =	$56.23
System avg inc. =	$39.25
System avg prod. cost =	$36.71

TABLE III-6

Replacement Fuel Price
No New Conservation Case

Year	($/MWh)
1994	0.000
1995	0.000
1996	0.000
1997	0.000
1998	0.000
1999	0.000
2000	0.000
2001	0.000
2002	0.000
2003	0.000
2004	41.714
2005	45.584
2006	47.360
2007	51.762
2008	54.553
2009	55.969
2010	59.035
2011	60.674
2012	43.281
2013	46.990

IV. FIRE MODEL DATA, ASSUMPTIONS AND RESULTS

INTRODUCTION

In addition to developing and assimilating the large amounts of data previously described, the FIRE model requires supplemental assumptions pertinent to assessing impact from each of the three cost effectiveness perspectives (participating customer's, GRU's, and GRU service area's perspective). Regardless of perspective, there are three types of assumptions: economic, technical, and rate assumptions. The following describes key assumptions made and presents summarized results of the analyses.

ECONOMIC ASSUMPTIONS

The economic assumptions used in the model are outlined in Table IV-1. In assuring that this analytical process was consistent with other planning and decision making exercises, whenever possible, economic assumptions made during those efforts were also used in FIRE. In some cases, special analysis were necessary to determine certain economic parameters not previously developed. The following discussion explains those special analyses.

Since FIRE was used to determine generic values of energy conservation rather than evaluate specific DSM measures, utility program costs, customer hardware costs and tax credits were not relevant. However, the costs associated with production or avoided production were relevant and are summarized below.

AVOIDED TRANSMISSION AND DISTRIBUTION FACILITIES COST - Developed from the average investment in T&D facilities installed, over three-year period (FY 1991-93), that could have been avoided if conservation equalled load growth.

AVOIDED TRANSMISSION O & M COSTS - Developed by dividing FY 1993 Transmission O&M costs of approximately $607,000, by estimated Transmission capacity of 650 MW.

AVOIDED DISTRIBUTION O&M COSTS - Estimated to be 5% of T&D Facilities cost.

AVOIDED GENERATING UNIT COST - Estimated 1995 cost of constructing pulverized coal generating unit provided by Stone & Webster from data compiled by the Electric Power Research Institute (EPRI).

AVOIDED GENERATOR FIXED AND VARIABLE OPERATING COSTS - Estimated unit operating costs provided by Stone & Webster from data compiled by the EPRI.

AVOIDED GENERATOR FUEL COSTS - Based upon delivered coal costs in 1995 being comparably priced to coal delivered under current GRU terms and conditions.

AVOIDED FUEL COST ESCALATION RATE - Based upon FY 1995 GRU Fuel Price Forecast.

INFLATION RATE - Assumed inflation rate for GRU's long and short term planning.

UTILITY COST OF CAPITAL - Weighted average cost of funds available to GRU. Based upon 70% debt funded at 6.5% annual interest and 30% equity (customer/owner contributed) at 14.0% annual cost.

TECHNICAL AND UTILITY RATE ASSUMPTIONS

Assumptions regarding load impact, in-service dates and facility lives are shown in Table IV-2 and are based upon current planning projections and historical experience. Rate assumptions are presented in Table IV-3 and are based upon current rates, less fuel cost recovered through fuel adjustment rates. Rate escalation is based upon Corporate Model results developed for the FY 1995-2001 budgetary planning horizon.

NATURAL GAS SYSTEM IMPACTS

Since GRU also owns and operates a natural gas distribution system, and potential energy savings are available through "fuel-switching" programs, the value of 1 therm of natural gas had to be considered parallel to the value of 1 kW and/or 1 kWh. Consequently, a simple procedure was developed to determine the value of natural gas from the three cost effectiveness perspectives. This procedure considered the current cost of 1 therm of natural gas currently and over the next twenty years. Since a fuel-switching program would result in consumption of that 1 therm (compared to none previously), the cost of the therm, $0.617/therm in 1995, is a cost borne entirely by the participating customer. Accordingly, the utility (GRU) receives $0.617 sales revenue for this therm, of which it pays $0.328 to its natural gas supplier for the gas GRU sold. Thus, the value of that 1 therm sale is a benefit of $0.289 for GRU, a cost of $0.617 to the participant, and a cost of $0.328 to the GRU service area since that amount is not retained within the service area. Table IV-4 shows the annual values of 1 therm over the study period and their cumulative present values for each of the three cost effectiveness perspectives.

DEVELOPMENT OF "TIME SENSITIVITY" CASES, 1995 AND 2002 DSM IMPLEMENTATIONS

The base case FIRE model has a twenty-year study horizon and evaluates DSM assuming 1995 implementation. Because it was recognized that "value-of-deferral" methodology employed by the model discounts, somewhat, the value of DSM when the DSM occurs far in advance of the in-service date of the avoided unit, it was decided that DSM should also be evaluated wherein DSM implementation could be designed to occur closer to the in-service date of the avoided unit. For this iteration, the model was run with an assumption of DSM implementation in 2002, two years before the in-service date of the avoided unit. These results will be presented, along with the base case results, later in this chapter.

DESCRIPTION OF FIRE OUTPUT

As mentioned previously, significant intermediate results are available from FIRE's output. The availability of these intermediate results affords the ability for analyses more extensive than is available through FIRE, as demonstrated in this application, and it also provides a traceable path to final results which enhances verification and validation. These "results" include:

Generating costs avoided on an annual basis and present valued.

T&D costs avoided on an annual basis and present valued.

Energy savings on an annual basis and totalled.

Fuel costs on an annual basis and totalled.

Fuel savings on an annual basis and totalled.

Total costs and benefits from each perspective.

FIRE output, in its entirety, is presented in Appendices B and C for the separate cases evaluating the value of 1 kW of DSM, for non-demand billed customers, during the summer peak and evaluating 1 kWh of DSM, for non-demand billed customers, also during the summer peak.

FIRE RESULTS

The results of the two cases mentioned above, along with results from all the runs of FIRE conducted as part of this study, are summarized in Table IV-5.

TABLE IV-1

ECONOMIC ASSUMPTIONS

ECONOMIC PARAMETER	ASSUMED VALUE
Utility Program Costs	0
Customer Hardware Costs	0
Customer Tax Credit	0
Avoided T&D Facilities Costs	$ 104.49/kW
Avoided Transmission O&M Costs	$ 0.93/kW/Year
Avoided Distribution O&M Costs	$ 5.22/kW/Year
Avoided Generating Unit Costs	$ 1,452.00/kW
Avoided Generator Fixed Costs	$ 5.52/kW/Year
Avoided Generator Variable Costs	$ 0.00490/kWh
Avoided Generator Fuel Cost (1994)	$ 0.01864/kWh
Avoided Fuel Cost Escalation Rate	3.90%/Year
Inflation Rate for All Other Parameters	4.00%/Year
Utility Cost of Capital	8.75%

TABLE IV-2

TECHNICAL ASSUMPTIONS

TECHNICAL ELEMENT	ASSUMED VALUE
Load Reduction at Meter	1 kW, 1 MWh[1]
Participating Customers	1,000[2]
Line Loss Percentage	6.00%
Line Loss Multiplier	1.0042
Generator Life	40 Years
T&D Life	40 Years
Base Year of Study	1995
In-Service Year of T&D	1995
In-Service Year of Generator	2004

[1] *kW evaluated to assess demand (facility) impacts over the respective time periods while kWh evaluated energy impacts over the time periods.*

[2] *Impact of 1,000 participating customers evaluated to overcome problems of rounding and scale.*

TABLE IV-3

UTILITY ELECTRIC RATE ASSUMPTIONS

RATE COMPONENT	ASSUMED VALUE
NON-DEMAND BILLED CUSTOMERS	
Non-Fuel Energy Cost in Bill	\$ 0.050/kWh
Demand Charge in Bill	\$ 0
Projected Escalation Rate	2.00%/Year
DEMAND-BILLED CUSTOMERS	
Non-Fuel Energy Cost in Bill	\$ 0.030/kWh
Demand Charge in Bill	\$ 4.900/kW
Projected Escalation Rate	2.00%/Year

TABLE IV-4

PRESENT WORTH OF 1 THERM OF NATURAL GAS

Year	Participant Cost ($/Th)	Value to GRU Custs Cost ($/Th)	Cost to Community Cost ($/Th)
1995	($0.617)	$0.289	($0.328)
1996	(0.642)	0.301	(0.341)
1997	(0.667)	0.313	(0.354)
1998	(0.694)	0.326	(0.369)
1999	(0.722)	0.339	(0.383)
2000	(0.751)	0.352	(0.399)
2001	(0.781)	0.366	(0.415)
2002	(0.812)	0.381	(0.431)
2003	(0.845)	0.396	(0.448)
2004	(0.878)	0.412	(0.466)
2005	(0.913)	0.428	(0.485)
2006	(0.950)	0.446	(0.504)
2007	(0.988)	0.463	(0.525)
2008	(1.028)	0.482	(0.546)
2009	(1.069)	0.501	(0.567)
2010	(1.111)	0.521	(0.590)
2011	(1.156)	0.542	(0.614)
2012	(1.202)	0.564	(0.638)
2013	(1.250)	0.586	(0.664)
2014	(1.300)	0.610	(0.690)
Present Value	(7.674)	3.599	(4.075)

TABLE IV-5

FIRE MODEL RESULTS

	REGULAR (1995) PROGRAMS		DELAYED (2002) PROGRAMS	
	NonDemand	Demand	NonDemand	Demand
PARTICIPANT VALUES				
1 kW Summer ($/Kw)	$0.000	$655.000	$0.000	$323.000
1 kWh Summer ($/kWh)	0.855	0.633	0.432	0.323
1 kWh Winter ($/kWh)	0.855	0.633	0.432	0.323
1 kWh Off-Peak ($/kWh)	0.855	0.633	0.432	0.323
SERVICE AREA VALUES				
1 kW Summer ($/Kw)	$801.000	$801.000	$801.000	$801.000
1 kWh Summer ($/kWh)	0.470	0.470	0.251	0.251
1 kWh Winter ($/kWh)	0.282	0.282	0.142	0.142
1 kWh Off-Peak ($/kWh)	0.279	0.279	0.147	0.147
UTILITY VALUES				
1 kW Summer ($/Kw)	$801.000	$146.000	$801.000	$478.000
1 kWh Summer ($/kWh)	-0.385	-0.163	-0.181	-0.072
1 kWh Winter ($/kWh)	-0.573	-0.351	-0.290	-0.181
1 kWh Off-Peak ($/kWh)	-0.576	-0.354	-0.285	-0.176

APPENDIX A
HISTORICAL AND PROJECTED DSM SAVINGS FROM EXISTING PROGRAMS

Conservation Program Implementations Accounted for in Electric Sales Forecast

Cumulative Implementations

	Residential Programs												Commercial Programs		
	Audit Installations				Rebates			Loans			Gas Rebates				
Year	Audits	WH Jackets	Low-Flow Heads	Refrig	Heat Pump	Window Trtmt	Weather-ization	GRU	Prime Cash	Builder	Water Heating	Space Heating	Audits	CLS	Street Light Conv.
1980	1108	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1981	2347	0	0	0	0	0	0	0	0	0	0	0	4	0	34
1982	4019	0	0	0	0	0	0	54	0	0	0	0	9	0	291
1983	5553	322	631	0	70	0	0	109	0	0	0	0	51	0	548
1984	8015	2885	9572	0	152	0	0	224	0	0	0	0	110	0	852
1985	10845	6117	14328	163	162	117	0	563	0	371	221	138	182	0	1625
1986	14600	9558	20984	397	185	295	10	1057	0	574	383	297	318	12	2204
1987	16150	9851	21939	475	256	518	327	1178	0	844	560	430	468	45	2237
1988	17728	9906	22508	501	271	657	542	1183	48	1141	735	531	633	85	2290
1989	19494	9995	22959	501	271	657	542	1183	79	1404	829	663	751	143	2658
1990	21259	10078	23787	501	271	657	542	1183	114	1765	955	768	881	227	3017
1991	22755	10147	24195	501	271	657	542	1183	141	2260	1066	861	982	358	3453
1992	24390	10208	24694	501	271	657	542	1183	141	2770	1175	939	1144	478	3453
1993	26264	9934	24359	501	271	657	542	1183	141	3424	1262	1004	1342	540	3453
1994	28050	7372	15441	501	271	657	542	1183	141	3779	1411	1123	1550	644	3453
1995	28763	4140	10699	501	271	540	542	1183	141	4164	1555	1237	1765	752	3453
1996	29380	699	4051	501	271	362	532	1183	141	4533	1734	1380	1983	863	3453
1997	29600	406	3101	501	271	139	215	1129	141	4902	1920	1529	2207	977	3453
1998	29993	351	2535	501	201	0	0	1074	141	5271	2099	1672	2400	1095	3453
1999	29492	262	2086	501	119	0	0	959	141	5640	2271	1810	2582	1215	3453
2000	28657	179	1259	338	109	0	0	620	141	5638	2229	1815	2757	1339	3453
2001	26931	110	852	104	86	0	0	126	141	5752	2239	1794	2873	1453	3453
2002	27445	49	353	26	15	0	0	5	141	5799	2241	1804	2981	1549	3453
2003	27964	1	57	0	0	0	0	0	93	5819	2238	1841	3080	1641	3453
2004	28328	1	57	0	0	0	0	0	62	5873	2309	1841	3231	1717	3453
2005	28726	0	34	0	0	0	0	0	27	5829	2355	1874	3375	1770	3453
2006	29427	0	20	0	0	0	0	0	0	5651	2416	1919	3553	1779	3453
2007	30021	0	12	0	0	0	0	0	0	5458	2472	1973	3676	1801	3453
2008	30408	0	7	0	0	0	0	0	0	5121	2550	2040	3768	1884	3453
2009	32701	0	4	0	0	0	0	0	0	5438	2715	2172	4063	2032	3453
2010	33240	0	2	0	0	0	0	0	0	5400	2731	2185	4155	2078	3453
2011	33775	0	1	0	0	0	0	0	0	5332	2746	2198	4245	2123	3453
2012	34307	0	0	0	0	0	0	0	0	5280	2732	2187	4333	2167	3453
2013	34834	0	0	0	0	0	0	0	0	5228	2705	2165	4419	2210	3453

APPENDIX B
FIRE MODEL 1995-VALUE OF KW, SUMMER PEAK
(NON-DEMAND BILLED)

I-A - Value of 1 MW-Summer, No Demand Billing Impact

F_11

PSC FORM CE 1.1
PAGE 1 OF 1
Run date: 18-Nov-94
02:41 PM

INPUT DATA -- PART 1
PROGRAM: CONS. EX.1 vs PC Unit - DSM FIRE PROGRAM (Data Rev. 7/23/92)

I. PROGRAM DEMAND SAVINGS AND LINE LOSSES

(1) CUSTOMER KW REDUCTION AT THE METER	1.00	KW /CUST
(2) GENERATOR KW REDUCTION PER CUSTOMER	1.06	KW GEN/CUST
(3) KW LINE LOSS PERCENTAGE	6.0	%
(4) GENERATION KWH REDUCTION PER CUSTOMER	0.0	KWH/CUST/YR
(5) KWH LINE LOSS PERCENTAGE	6.0	%
(6) GROUP LINE LOSS MULTIPLIER	1.0042	
(7) CUSTOMER KWH PROGRAM INCREASE AT METER	0.0	KWH/CUST/YR
(8)* CUSTOMER KWH REDUCTION AT METER	0.0	KWH/CUST/YR

II. ECONOMIC LIFE AND K FACTORS

(1) STUDY PERIOD FOR CONSERVATION PROGRAM	20	YEARS
(2) GENERATOR ECONOMIC LIFE	40	YEARS
(3) T & D ECONOMIC LIFE	40	YEARS
(4) K FACTOR FOR ALL PLANT	1.1102	
(5) OTH FIXED CHGS FACTOR	0.0050	
(6)* SWITCH REV REQ(0) G.R.U. REV REQ (1)	1	

III. UTILITY AND CUSTOMER COSTS

(1)** UTILITY NONRECURRING COST PER CUSTOMER	0.00	$/CUST
(2)** UTILITY RECURRING COST PER CUSTOMER	0.00	$/CUST/YR
(3) UTILITY COST ESCALATION RATE	4.0	%
(4) CUSTOMER EQUIPMENT COST	0.00	$/CUST
(5) CUSTOMER EQUIPMENT ESCALATION RATE	4.0	%
(6) CUSTOMER O & M COST	0.00	$/CUST/YR
(7) CUSTOMER O & M ESCALATION RATE	4.0	%
(8)* CUSTOMER TAX CREDIT PER INSTALLATION	0.00	$/CUST
(9)* CUSTOMER TAX CREDIT ESCALATION RATE	4.0	%
(10)* INCREASED SUPPLY COSTS	0.00	$/CUST/YR
(11)* SUPPLY COSTS ESCALATION RATE	4.0	%
(12)* UTILITY DISCOUNT RATE	8.75%	
(13)* UTILITY AFUDC RATE	8.75%	
(14)* UTILITY NON RECURRING REBATE/INCENTIVE	0.00	$/CUST
(15)* UTILITY RECURRING REBATE/INCENTIVE	0.00	$/CUST/YR
(16)* UTILITY REBATE/INCENTIVE ESCAL RATE	4.0	%

IV. AVOIDED GENERATOR, TRANS. AND DIST. COSTS

(1) BASE YEAR	1995	
(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT	2004	
(3) IN-SERVICE YEAR FOR AVOIDED T & D	1995	
(4) BASE YEAR AVOIDED GENERATING UNIT COST	1,452.00	$/KW
(5) BASE YEAR AVOIDED TRANSMISSION COST	0.00	$/KW
(6) BASE YEAR DISTRIBUTION COST	104.49	$/KW
(7) GEN, TRAN, & DIST COST ESCALATION RATE	4	%
(8) GENERATOR FIXED O & M COST	5.52	$/KW/YR
(9) GENERATOR FIXED O&M ESCALATION RATE	4.0	%
(10) TRANSMISSION FIXED O & M COST	0.93	$/KW/YR
(11) DISTRIBUTION FIXED O & M COST	5.22	$/KW/YR
(12) T&D FIXED O&M ESCALATION RATE	4.0	%
(13) AVOIDED GEN UNIT VARIABLE O & M COSTS	0.490	CENTS/KWH
(14) GENERATOR VARIABLE O&M COST ESCALATION RATE	4.0	%
(15) GENERATOR CAPACITY FACTOR	75	%
(16) AVOIDED GENERATING UNIT FUEL COST	1.864	CENTS/KWH
(17) AVOIDED GEN UNIT FUEL ESCALATION RATE	3.9	%
(18)* AVOIDED PURCHASE CAPACITY COST PER KW	0.00	$/KW/YR
(19)* CAPACITY COST ESCALATION RATE	4.0	%

V. NON-FUEL ENERGY AND DEMAND CHARGES

(1) NON-FUEL COST IN CUSTOMER BILL	5.000	CENTS/KWH
(2) NON-FUEL ESCALATION RATE	2.0	%
(3) CUSTOMER DEMAND CHARGE PER KW	0.00	$/KW/MO
(4) DEMAND CHARGE ESCALATION RATE	2.0	%
(5)* DIVERSITY and ANNUAL DEMAND ADJUSTMENT FACTOR FOR CUSTOMER BILL	1.0	

* Computer Program Rev. Date: 9/17/92

* SUPPLEMENTAL INFORMATION NOT SPECIFIED IN WORKBOOK

** NONRECURRING & RECURRING COSTS IN INPUTS III.(1 & 2) DO NOT INCLUDE CUSTOMER REBATES PAID BY THE UTILITY. UTILITY REBATES ARE INPUT IN III.(14 & 15).

F_11B

CALCULATION OF AFUDC AND IN-SERVICE COST OF PLANT
PLANT: 2004 AVOIDED UNIT

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
YEAR	NO. YEARS BEFORE INSERVICE	PLANT ESCALATION RATE (%)	CUMULATIVE ESCALATION FACTOR	YEARLY EXPENDITURE (%)	ANNUAL SPENDING ($/KW)	CUMULATIVE AVERAGE SPENDING ($/KW)	CUMULATIVE SPENDING WITH AFUDC ($/KW)	YEARLY TOTAL AFUDC ($/KW)	INCREMENTAL YEAR-END BOOK VALUE ($/KW)	CUMULATIVE YEAR-END BOOK VALUE ($/KW)
----	----	----	-----	----	------	------	------	------	------	------
1995	-9	4.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
1996	-8	4.0%	1.0400	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
1997	-7	4.0%	1.0816	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
1998	-6	4.0%	1.1249	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
1999	-5	4.0%	1.1699	5.0%	84.93	42.47	42.47	3.72	88.65	88.65
2000	-4	4.0%	1.2167	20.0%	353.32	261.59	265.31	23.21	376.53	465.18
2001	-3	4.0%	1.2653	40.0%	734.90	805.70	832.63	72.85	807.75	1,272.93
2002	-2	4.0%	1.3159	20.0%	382.15	1,364.22	1,464.00	128.10	510.25	1,783.18
2003	-1	4.0%	1.3686	15.0%	298.07	1,704.33	1,932.21	169.07	467.14	2,250.32
2004	0			0.0%	0.00			0.00	0.00	
				----	------			------	------	
				1.00	1853.37			396.95	2250.32	

IN-SERVICE YEAR = 2004

PLANT COSTS (1995 $) $1,452.0
AFUDC RATE: 8.75%

F_12

INPUT DATA -- PART 2
PROGRAM: CONS. EX.1 vs PC Unit - DSM FIRE PROGRAM (Data Rev. 7/23/

PSC FORM CE 1.2

18-Nov-94

(1) YEAR	(2) CUMULATIVE TOTAL PARTICIPATING CUSTOMERS	(3) ADJUSTED CUMULATIVE PARTICIPATING CUSTOMERS	(4) UTILITY AVERAGE SYSTEM FUEL COSTS (C/KWH)	(5) AVOIDED MARGINAL FUEL COST (C/KWH)	(6) INCREASED MARGINAL FUEL COST (C/KWH)	(7) REPLACEMENT FUEL COST (C/KWH)	(8) PROGRAM KW EFFECTIVENESS FACTOR	(9) PROGRAM KWH EFFECTIVENESS FACTOR
1995	1,000	1,000	2.32	3.30	1.91	0.00	1.00	1.00
1996	1,000	1,000	2.40	3.51	1.98	0.00	1.00	1.00
1997	1,000	1,000	2.56	3.64	2.10	0.00	1.00	1.00
1998	1,000	1,000	2.65	3.83	2.14	0.00	1.00	1.00
1999	1,000	1,000	2.66	3.97	2.19	0.00	1.00	1.00
2000	1,000	1,000	2.75	4.13	2.23	0.00	1.00	1.00
2001	1,000	1,000	2.99	4.52	2.43	0.00	1.00	1.00
2002	1,000	1,000	3.26	4.97	2.65	0.00	1.00	1.00
2003	1,000	1,000	3.48	5.29	2.85	0.00	1.00	1.00
2004	1,000	1,000	2.88	3.89	2.30	4.17	1.00	1.00
2005	1,000	1,000	3.09	4.35	2.38	4.56	1.00	1.00
2006	1,000	1,000	3.32	4.82	2.53	4.74	1.00	1.00
2007	1,000	1,000	3.58	5.34	2.68	5.18	1.00	1.00
2008	1,000	1,000	3.86	5.93	2.82	5.46	1.00	1.00
2009	1,000	1,000	4.12	6.37	3.03	5.60	1.00	1.00
2010	1,000	1,000	4.45	7.07	3.20	5.90	1.00	1.00
2011	1,000	1,000	4.81	7.74	3.46	6.07	1.00	1.00
2012	1,000	1,000	3.74	5.48	2.89	4.33	1.00	1.00
2013	1,000	1,000	3.93	5.93	3.05	4.70	1.00	1.00
2014	1,000	1,000	4.12	6.40	3.21	5.10	1.00	1.00

F_21

AVOIDED GENERATION UNIT BENEFITS
PROGRAM: CONS. EX.1 vs PC Unit - DSM FIRE PROGRAM (Data Rev. 7/23/92)

* UNIT SIZE OF AVOIDED GENERATION UNIT = 1,060.0 KW
* INSERVICE COSTS OF AVOIDED GEN. UNIT (000) $2,385.3

(1) YEAR	(1A)* FIXED REV REQ FACTOR	(2) AVOIDED GEN UNIT CAPACITY COST $(000)	(2A)* AVOIDED ANNUAL UNIT KWH GEN (000)	(3) AVOIDED UNIT FIXED O&M COST $(000)	(4) AVOIDED GEN UNIT VARIABLE O&M COST $(000)	(5) AVOIDED GEN UNIT FUEL COST $(000)	(6) REPLACEMENT FUEL COST $(000)	(6A)* AVOIDED PURCHASED CAPACITY COSTS $(000)	(7) AVOIDED GEN UNIT BENEFITS $(000)
1995	0.000	0	0	0	0	0	0	0	0
1996	0.000	0	0	0	0	0	0	0	0
1997	0.000	0	0	0	0	0	0	0	0
1998	0.000	0	0	0	0	0	0	0	0
1999	0.000	0	0	0	0	0	0	0	0
2000	0.000	0	0	0	0	0	0	0	0
2001	0.000	0	0	0	0	0	0	0	0
2002	0.000	0	0	0	0	0	0	0	0
2003	0.000	0	0	0	0	0	0	0	0
2004	0.100	239	6,964	8	49	183	291	0	188
2005	0.100	239	6,964	9	51	190	317	0	171
2006	0.100	239	6,964	9	53	198	330	0	168
2007	0.100	239	6,964	9	55	205	360	0	148
2008	0.100	239	6,964	10	57	213	380	0	139
2009	0.100	239	6,964	10	59	222	390	0	140
2010	0.100	239	6,964	11	61	230	411	0	130
2011	0.100	239	6,964	11	64	239	423	0	131
2012	0.100	239	6,964	11	66	249	301	0	264
2013	0.100	239	6,964	12	69	258	327	0	251
2014	0.100	239	6,964	12	72	269	355	0	236
NOMINAL		2,628	76,606	112	655	2,458	3,886	0	1,967
NPV		841		35	203	762	1,229	0	611

* SUPPLEMENTAL INFORMATION NOT SPECIFIED IN WORKBOOK

F_22

AVOIDED T & D AND PROGRAM FUEL SAVINGS
PROGRAM: CONS. EX.1 vs PC Unit - DSM FIRE PROGRAM (Data Rev. 7/23/92)

* INSERVICE COSTS OF AVOIDED TRANS. (000) = $0.0
* INSERVICE COSTS OF AVOIDED DIST. (000) = $104.5

(1) YEAR	(2) AVOIDED TRANSMISSION CAPACITY COST $(000)	(3) AVOIDED TRANSMISSION O&M COST $(000)	(4) TOTAL AVOIDED TRANSMISSION COST $(000)	(5) AVOIDED DISTRIBUTION CAPACITY COST $(000)	(6) AVOIDED DISTRIBUTION O&M COST $(000)	(7) TOTAL AVOIDED DISTRIBUTION COST $(000)	(8) PROGRAM FUEL SAVINGS $(000)
1995	0	1	1	10	5	16	0
1996	0	1	1	10	5	16	0
1997	0	1	1	10	6	16	0
1998	0	1	1	10	6	16	0
1999	0	1	1	10	6	17	0
2000	0	1	1	10	6	17	0
2001	0	1	1	10	7	17	0
2002	0	1	1	10	7	17	0
2003	0	1	1	10	7	18	0
2004	0	1	1	10	7	18	0
2005	0	1	1	10	8	18	0
2006	0	2	2	10	8	19	0
2007	0	2	2	10	8	19	0
2008	0	2	2	10	9	19	0
2009	0	2	2	10	9	20	0
2010	0	2	2	10	9	20	0
2011	0	2	2	10	10	20	0
2012	0	2	2	10	10	21	0
2013	0	2	2	10	11	21	0
2014	0	2	2	10	11	21	0
NOMINAL	0	29	29	209	156	365	0
NPV:	0	13	13	106	71	176	0

* SUPPLEMENTAL INFORMATION NOT SPECIFIED IN WORKBOOK

I-A - Value of 1 MW-Summer, No Demand Billing Impact

p_5 * WORKSHEET : DSM PROGRAM FUEL SAVINGS WORKSHEET FOR FORM CE 2.2
PROGRAM: CONS. EX.1 vs PC Unit - DSM FIRE PROGRAM (Data Rev. 7/23/92 Page 1 of 2
18-Nov-94

(1) YEAR	(2) REDUCTION IN KWH GENERATION NET NEW CUST KWH (000)	(3) AVOIDED MARGINAL FUEL COST - REDUCED KWH $(000)	(4) INCREASE IN KWH GENERATION NET NEW CUST KWH (000)	(5) INCREASED MARGINAL FUEL COST - INCREASE KWH $(000)	(6) NET AVOIDED PROGRAM FUEL SAVINGS $(000)	(7) EFFECTIVE PROGRAM FUEL SAVINGS $(000)
1995	0	0	0	0	0	0
1996	0	0	0	0	0	0
1997	0	0	0	0	0	0
1998	0	0	0	0	0	0
1999	0	0	0	0	0	0
2000	0	0	0	0	0	0
2001	0	0	0	0	0	0
2002	0	0	0	0	0	0
2003	0	0	0	0	0	0
2004	0	0	0	0	0	0
2005	0	0	0	0	0	0
2006	0	0	0	0	0	0
2007	0	0	0	0	0	0
2008	0	0	0	0	0	0
2009	0	0	0	0	0	0
2010	0	0	0	0	0	0
2011	0	0	0	0	0	0
2012	0	0	0	0	0	0
2013	0	0	0	0	0	0
2014	0	0	0	0	0	0
NOMINAL	0	0	0	0	0	0
NPV:		0		0	0	0

* SUPPLEMENTAL INFORMATION NOT SPECIFIED IN WORKBOOK

P_6 * WORKSHEET: UTILITY COSTS AND PARTICIPANT COSTS AND REV LOSS/GAIN
PROGRAM: CONS. EX.1 vs PC Unit - DSM FIRE PROGRAM (Data Rev. 7/23/92)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
	<----- UTILITY PROGRAM COSTS & REBATES ------->						<------------------ PARTICIPATING CUSTOMER COSTS & BENEFITS --------------------->										
YEAR	UTIL NONREC. COSTS $(000)	UTIL RECUR COSTS $(000)	TOTAL UTIL PGM COSTS $(000)	UTIL NONREC. REBATES $(000)	UTIL RECUR. REBATES $(000)	TOTAL REBATE/ INCENT. COSTS $(000)	PARTIC. CUST EQUIP COSTS $(000)	PARTIC. CUST O & M COSTS $(000)	TOTAL COSTS PARTIC. CUST $(000)	REDUCT. IN CUST. KWH (000)	RED. REV. - FUEL PORTION $(000)	RED. REV. NONFUEL PORTION $(000)	EFFECT. REV. REDUCT. IN BILL $(000)	INC. IN CUST. KWH (000)	INC. REV. - FUEL PORTION $(000)	INC. REV. NONFUEL PORTION	EFFECT. REVENUE INC. IN BILL $(000)
1995	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1996	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1997	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1998	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1999	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2001	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2002	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2003	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0		0	0	0		0	0	0

* SUPPLEMENTAL INFORMATION NOT SPECIFIED IN WORKBOOK

F_23

TOTAL RESOURCE COST TESTS
PROGRAM: CONS. EX.1 vs PC Unit - DSM FIRE PROGRAM (Data Rev. 7/23/92)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
YEAR	INCREASED SUPPLY COSTS $(000)	UTILITY PROGRAM COSTS $(000)	PARTICIPANT PROGRAM COSTS $(000)	OTHER COSTS $(000)	TOTAL COSTS $(000)	AVOIDED GEN UNIT BENEFITS $(000)	AVOIDED T & D BENEFITS $(000)	PROGRAM FUEL SAVINGS $(000)	OTHER BENEFITS $(000)	TOTAL BENEFITS $(000)	NET BENEFITS $(000)	CUMULATIVE DISCOUNTED NET BENEFITS $(000)
1995	0	0	0	0	0	0	17	0	0	17	17	17
1996	0	0	0	0	0	0	17	0	0	17	17	32
1997	0	0	0	0	0	0	17	0	0	17	17	47
1998	0	0	0	0	0	0	17	0	0	17	17	60
1999	0	0	0	0	0	0	18	0	0	18	18	73
2000	0	0	0	0	0	0	18	0	0	18	18	85
2001	0	0	0	0	0	0	18	0	0	18	18	96
2002	0	0	0	0	0	0	19	0	0	19	19	106
2003	0	0	0	0	0	0	19	0	0	19	19	116
2004	0	0	0	0	0	188	19	0	0	208	208	214
2005	0	0	0	0	0	171	20	0	0	191	191	296
2006	0	0	0	0	0	168	20	0	0	188	188	371
2007	0	0	0	0	0	148	20	0	0	168	168	432
2008	0	0	0	0	0	139	21	0	0	160	160	486
2009	0	0	0	0	0	140	21	0	0	161	161	536
2010	0	0	0	0	0	130	22	0	0	152	152	579
2011	0	0	0	0	0	131	22	0	0	153	153	619
2012	0	0	0	0	0	264	23	0	0	287	287	688
2013	0	0	0	0	0	251	23	0	0	274	274	748
2014	0	0	0	0	0	236	24	0	0	260	260	801
NOMINAL	0	0	0	0	0	1,967	394	0	0	2,361	2,361	
NPV:	0	0	0	0	0	611	190	0	0	801	801	

Discount Rate 8.75%
Benefit/Cost Ratio: col (11) / col (6) ERR

I-A - Value of 1 MW-Summer, No Demand Billing Impact

F_24

PARTICIPANT COSTS AND BENEFITS
PROGRAM: CONS. EX.1 vs PC Unit - DSM FIRE PROGRAM (Data Rev. 7/23/92)

(1) YEAR	(2) SAVINGS IN PARTICIPANTS BILL $(000)	(3) TAX CREDITS $(000)	(4) UTILITY REBATES $(000)	(5) OTHER BENEFITS $(000)	(6) TOTAL BENEFITS $(000)	(7) CUSTOMER EQUIPMENT COSTS $(000)	(8) CUSTOMER O & M COSTS $(000)	(9) OTHER COSTS $(000)	(10) TOTAL COSTS $(000)	(11) NET BENEFITS $(000)	(12) CUMULATIVE DISCOUNTED NET BENEFITS $(000)
1995	0	0	0	0	0	0	0	0	0	0	0
1996	0	0	0	0	0	0	0	0	0	0	0
1997	0	0	0	0	0	0	0	0	0	0	0
1998	0	0	0	0	0	0	0	0	0	0	0
1999	0	0	0	0	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0	0	0	0	0
2001	0	0	0	0	0	0	0	0	0	0	0
2002	0	0	0	0	0	0	0	0	0	0	0
2003	0	0	0	0	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0	0
NOMINAL	0	0	0	0	0	0	0	0	0	0	
NPV:	0	0	0	0	0	0	0	0	0	0	

In service year of gen unit: 2004
Discount rate: 8.75%

I-A - Value of 1 MW-Summer, No Demand Billing Impact

F_25

RATE IMPACT TEST
PROGRAM:CONS. EX.1 vs PC Unit - DSM FIRE PROGRAM (Data Rev. 7/23/92)

PSC FORM CE 2.5
Page 1 of 1
18-Nov-94

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
YEAR	INCREASED SUPPLY COSTS	UTILITY PROGRAM COSTS	INCENTIVES	REVENUE LOSSES	OTHER COSTS	TOTAL COSTS	AVOIDED GEN UNIT & FUEL BENEFITS	AVOIDED T & D BENEFITS	REVENUE GAINS	OTHER BENEFITS	TOTAL BENEFITS	NET BENEFITS TO ALL CUSTOMERS	CUMULATIVE DISCOUNTED NET BENEFIT
	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
1995	0	0	0	0	0	0	0	17	0	0	17	17	17
1996	0	0	0	0	0	0	0	17	0	0	17	17	32
1997	0	0	0	0	0	0	0	17	0	0	17	17	47
1998	0	0	0	0	0	0	0	17	0	0	17	17	60
1999	0	0	0	0	0	0	0	18	0	0	18	18	73
2000	0	0	0	0	0	0	0	18	0	0	18	18	85
2001	0	0	0	0	0	0	0	18	0	0	18	18	96
2002	0	0	0	0	0	0	0	19	0	0	19	19	106
2003	0	0	0	0	0	0	0	19	0	0	19	19	116
2004	0	0	0	0	0	0	188	19	0	0	208	208	214
2005	0	0	0	0	0	0	171	20	0	0	191	191	296
2006	0	0	0	0	0	0	168	20	0	0	188	188	371
2007	0	0	0	0	0	0	148	20	0	0	168	168	432
2008	0	0	0	0	0	0	139	21	0	0	160	160	486
2009	0	0	0	0	0	0	140	21	0	0	161	161	536
2010	0	0	0	0	0	0	130	22	0	0	152	152	579
2011	0	0	0	0	0	0	131	22	0	0	153	153	619
2012	0	0	0	0	0	0	264	23	0	0	287	287	688
2013	0	0	0	0	0	0	251	23	0	0	274	274	748
2014	0	0	0	0	0	0	236	24	0	0	260	260	801
NOMINAL	0	0	0	0	0	0	1,967	394	0	0	2,361	2,361	
NPV:	0	0	0	0	0	0	611	190	0	0	801	801	

Discount rate: 8.75%
Benefit / Cost Ratio - Col (12)/Col (7) ERR

APPENDIX C
FIRE MODEL 1995-VALUE OF KWH, SUMMER PEAK (NON-DEMAND BILLED)

I-B - Value of 1 GWh-Summer, No Demand Billing Impact

F_11

PSC FORM CE 1.1
PAGE 1 OF 1
Run date: 18-Nov-94
02:53 PM

INPUT DATA -- PART 1
PROGRAM: CONS. EX.1 vs PC Unit - DSM FIRE PROGRAM (Data Rev. 7/23/92)

I. PROGRAM DEMAND SAVINGS AND LINE LOSSES

(1) CUSTOMER KW REDUCTION AT THE METER	0.00	KW /CUST
(2) GENERATOR KW REDUCTION PER CUSTOMER	0.00	KW GEN/CUST
(3) KW LINE LOSS PERCENTAGE	6.0	%
(4) GENERATION KWH REDUCTION PER CUSTOMER	1,063.8	KWH/CUST/YR
(5) KWH LINE LOSS PERCENTAGE	6.0	%
(6) GROUP LINE LOSS MULTIPLIER	1.0042	
(7) CUSTOMER KWH PROGRAM INCREASE AT METER	0.0	KWH/CUST/YR
(8)* CUSTOMER KWH REDUCTION AT METER	1,000.0	KWH/CUST/YR

II. ECONOMIC LIFE AND K FACTORS

(1) STUDY PERIOD FOR CONSERVATION PROGRAM	20	YEARS
(2) GENERATOR ECONOMIC LIFE	40	YEARS
(3) T & D ECONOMIC LIFE	40	YEARS
(4) K FACTOR FOR ALL PLANT	1.1102	
(5) OTH FIXED CHGS FACTOR	0.50%	
(6)* SWITCH REV REQ(0) G.R.U. REV REQ (1)	1	

III. UTILITY AND CUSTOMER COSTS

(1)** UTILITY NONRECURRING COST PER CUSTOMER	0.00	$/CUST
(2)** UTILITY RECURRING COST PER CUSTOMER	0.00	$/CUST/YR
(3) UTILITY COST ESCALATION RATE	4.0	%
(4) CUSTOMER EQUIPMENT COST	0.00	$/CUST
(5) CUSTOMER EQUIPMENT ESCALATION RATE	4.0	%
(6) CUSTOMER O & M COST	0.00	$/CUST/YR
(7) CUSTOMER O & M ESCALATION RATE	4.0	%
(8)* CUSTOMER TAX CREDIT PER INSTALLATION	0.00	$/CUST
(9)* CUSTOMER TAX CREDIT ESCALATION RATE	4.0	%
(10)* INCREASED SUPPLY COSTS	0.00	$/CUST/YR
(11)* SUPPLY COSTS ESCALATION RATE	4.0	%
(12)* UTILITY DISCOUNT RATE	8.75%	
(13)* UTILITY AFUDC RATE	8.75%	
(14)* UTILITY NON RECURRING REBATE/INCENTIVE	0.00	$/CUST
(15)* UTILITY RECURRING REBATE/INCENTIVE	0.00	$/CUST/YR
(16)* UTILITY REBATE/INCENTIVE ESCAL RATE	4.0	%

IV. AVOIDED GENERATOR, TRANS. AND DIST. COSTS

(1) BASE YEAR	1995	
(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT	2004	
(3) IN-SERVICE YEAR FOR AVOIDED T & D	1995	
(4) BASE YEAR AVOIDED GENERATING UNIT COST	1,452.00	$/KW
(5) BASE YEAR AVOIDED TRANSMISSION COST	0.00	$/KW
(6) BASE YEAR DISTRIBUTION COST	104.49	$/KW
(7) GEN, TRAN, & DIST COST ESCALATION RATE	4	%
(8) GENERATOR FIXED O & M COST	5.52	$/KW/YR
(9) GENERATOR FIXED O&M ESCALATION RATE	4.0	%
(10) TRANSMISSION FIXED O & M COST	0.93	$/KW/YR
(11) DISTRIBUTION FIXED O & M COST	5.22	$/KW/YR
(12) T&D FIXED O&M ESCALATION RATE	4.0	%
(13) AVOIDED GEN UNIT VARIABLE O & M COSTS	0.490	CENTS/KWH
(14) GENERATOR VARIABLE O&M COST ESCALATION RATE	4.0	%
(15) GENERATOR CAPACITY FACTOR	75	%
(16) AVOIDED GENERATING UNIT FUEL COST	1.864	CENTS/KWH
(17) AVOIDED GEN UNIT FUEL ESCALATION RATE	3.9	%
(18)* AVOIDED PURCHASE CAPACITY COST PER KW	0.00	$/KW/YR
(19)* CAPACITY COST ESCALATION RATE	4.0	%

V. NON-FUEL ENERGY AND DEMAND CHARGES

(1) NON-FUEL COST IN CUSTOMER BILL	5.000	CENTS/KWH
(2) NON-FUEL ESCALATION RATE	2.0	%
(3) CUSTOMER DEMAND CHARGE PER KW	0.00	$/KW/MO
(4) DEMAND CHARGE ESCALATION RATE	2.0	%
(5)* DIVERSITY and ANNUAL DEMAND ADJUSTMENT FACTOR FOR CUSTOMER BILL	1.0	

* Computer Program Rev. Date: 9/17/92

* SUPPLEMENTAL INFORMATION NOT SPECIFIED IN WORKBOOK

** NONRECURRING & RECURRING COSTS IN INPUTS III.(1 & 2) DO NOT INCLUDE CUSTOMER REBATES PAID BY THE UTILITY. UTILITY REBATES ARE INPUT IN III.(14 & 15).

F_11B

CALCULATION OF AFUDC AND IN-SERVICE COST OF PLANT
PLANT: 2004 AVOIDED UNIT

18-Nov-94

(1) YEAR	(2) NO. YEARS BEFORE INSERVICE	(3) PLANT ESCALATION RATE (%)	(4) CUMULATIVE ESCALATION FACTOR	(5) YEARLY EXPENDITURE (%)	(6) ANNUAL SPENDING ($/KW)	(7) CUMULATIVE AVERAGE SPENDING ($/KW)	(8) CUMULATIVE SPENDING WITH AFUDC ($/KW)	(9) YEARLY TOTAL AFUDC ($/KW)	(10) INCREMENTAL YEAR-END BOOK VALUE ($/KW)	(11) CUMULATIVE YEAR-END BOOK VALUE ($/KW)
----	----	----	-----	----	------	------	------	------	------	------
1995	-9	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
1996	-8	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
1997	-7	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
1998	-6	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
1999	-5	4.0%	1.0400	5.0%	75.50	37.75	37.75	3.30	78.81	78.81
2000	-4	4.0%	1.0816	20.0%	314.10	232.55	235.86	20.64	334.73	413.54
2001	-3	4.0%	1.1249	40.0%	653.32	716.26	740.20	64.77	718.09	1,131.63
2002	-2	4.0%	1.1699	20.0%	339.73	1,212.79	1,301.49	113.88	453.61	1,585.24
2003	-1	4.0%	1.2167	15.0%	264.99	1,515.14	1,717.73	150.30	415.29	2,000.53
2004	0			0.0%	0.00			0.00	0.00	
				----	------			------	------	
				1.00	1647.64			352.89	2000.53	

IN-SERVICE YEAR = 2004

PLANT COSTS (1995 $) $1,452.0
AFUDC RATE: 8.75%

I-B - Value of 1 GWh-Summer, No Demand Billing Impact

F_12

INPUT DATA -- PART 2 PSC FORM CE 1.2
PROGRAM: CONS. EX.1 vs PC Unit - DSM FIRE PROGRAM (Data Rev. 7/23/ PAGE 1 OF 1
18-Nov-94

(1) YEAR	(2) CUMULATIVE TOTAL PARTICIPATING CUSTOMERS	(3) ADJUSTED CUMULATIVE PARTICIPATING CUSTOMERS	(4) UTILITY AVERAGE SYSTEM FUEL COSTS (C/KWH)	(5) AVOIDED MARGINAL FUEL COST (C/KWH)	(6) INCREASED MARGINAL FUEL COST (C/KWH)	(7) REPLACEMENT FUEL COST (C/KWH)	(8) PROGRAM KW EFFECTIVENESS FACTOR	(9) PROGRAM KWH EFFECTIVENESS FACTOR
1995	1,000	1,000	2.32	3.30	1.91	0.00	1.00	1.00
1996	1,000	1,000	2.40	3.51	1.98	0.00	1.00	1.00
1997	1,000	1,000	2.56	3.64	2.10	0.00	1.00	1.00
1998	1,000	1,000	2.65	3.83	2.14	0.00	1.00	1.00
1999	1,000	1,000	2.66	3.97	2.19	0.00	1.00	1.00
2000	1,000	1,000	2.75	4.13	2.23	0.00	1.00	1.00
2001	1,000	1,000	2.99	4.52	2.43	0.00	1.00	1.00
2002	1,000	1,000	3.26	4.97	2.65	0.00	1.00	1.00
2003	1,000	1,000	3.48	5.29	2.85	0.00	1.00	1.00
2004	1,000	1,000	2.88	3.89	2.30	4.17	1.00	1.00
2005	1,000	1,000	3.09	4.35	2.38	4.56	1.00	1.00
2006	1,000	1,000	3.32	4.82	2.53	4.74	1.00	1.00
2007	1,000	1,000	3.58	5.34	2.68	5.18	1.00	1.00
2008	1,000	1,000	3.86	5.93	2.82	5.46	1.00	1.00
2009	1,000	1,000	4.12	6.37	3.03	5.60	1.00	1.00
2010	1,000	1,000	4.45	7.07	3.20	5.90	1.00	1.00
2011	1,000	1,000	4.81	7.74	3.46	6.07	1.00	1.00
2012	1,000	1,000	3.74	5.48	2.89	4.33	1.00	1.00
2013	1,000	1,000	3.93	5.93	3.05	4.70	1.00	1.00
2014	1,000	1,000	4.12	6.40	3.21	5.10	1.00	1.00

I-B - Value of 1 GWh-Summer, No Demand Billing Impact

F_21

AVOIDED GENERATION UNIT BENEFITS
PROGRAM: CONS. EX.1 vs PC Unit - DSM FIRE PROGRAM (Data Rev. 7/23/92)

18-Nov-94

* UNIT SIZE OF AVOIDED GENERATION UNIT = 0.0 KW
* INSERVICE COSTS OF AVOIDED GEN. UNIT (000) $0.0

(1) YEAR	(1A)* FIXED REV REQ FACTOR	(2) AVOIDED GEN UNIT CAPACITY COST $(000)	(2A)* AVOIDED ANNUAL UNIT KWH GEN (000)	(3) AVOIDED UNIT FIXED O&M COST $(000)	(4) AVOIDED GEN UNIT VARIABLE O&M COST $(000)	(5) AVOIDED GEN UNIT FUEL COST $(000)	(6) REPLACEMENT FUEL COST $(000)	(6A)* AVOIDED PURCHASED CAPACITY COSTS $(000)	(7) AVOIDED GEN UNIT BENEFITS $(000)
1995	0.000	0	0	0	0	0	0	0	0
1996	0.000	0	0	0	0	0	0	0	0
1997	0.000	0	0	0	0	0	0	0	0
1998	0.000	0	0	0	0	0	0	0	0
1999	0.000	0	0	0	0	0	0	0	0
2000	0.000	0	0	0	0	0	0	0	0
2001	0.000	0	0	0	0	0	0	0	0
2002	0.000	0	0	0	0	0	0	0	0
2003	0.000	0	0	0	0	0	0	0	0
2004	0.100	0	0	0	0	0	0	0	0
2005	0.100	0	0	0	0	0	0	0	0
2006	0.100	0	0	0	0	0	0	0	0
2007	0.100	0	0	0	0	0	0	0	0
2008	0.100	0	0	0	0	0	0	0	0
2009	0.100	0	0	0	0	0	0	0	0
2010	0.100	0	0	0	0	0	0	0	0
2011	0.100	0	0	0	0	0	0	0	0
2012	0.100	0	0	0	0	0	0	0	0
2013	0.100	0	0	0	0	0	0	0	0
2014	0.100	0	0	0	0	0	0	0	0
NOMINAL		0	0	0	0	0	0	0	0
NPV		0		0	0	0	0	0	0

* SUPPLEMENTAL INFORMATION NOT SPECIFIED IN WORKBOOK

F_22

AVOIDED T & D AND PROGRAM FUEL SAVINGS
PROGRAM: CONS. EX.1 vs PC Unit - DSM FIRE PROGRAM (Data Rev. 7/23/92)

* INSERVICE COSTS OF AVOIDED TRANS. (000) = $0.0
* INSERVICE COSTS OF AVOIDED DIST. (000) = $0.0

(1) YEAR	(2) AVOIDED TRANSMISSION CAPACITY COST $(000)	(3) AVOIDED TRANSMISSION O&M COST $(000)	(4) TOTAL AVOIDED TRANSMISSION COST $(000)	(5) AVOIDED DISTRIBUTION CAPACITY COST $(000)	(6) AVOIDED DISTRIBUTION O&M COST $(000)	(7) TOTAL AVOIDED DISTRIBUTION COST $(000)	(8) PROGRAM FUEL SAVINGS $(000)
1995	0	0	0	0	0	0	18
1996	0	0	0	0	0	0	37
1997	0	0	0	0	0	0	39
1998	0	0	0	0	0	0	41
1999	0	0	0	0	0	0	42
2000	0	0	0	0	0	0	44
2001	0	0	0	0	0	0	48
2002	0	0	0	0	0	0	53
2003	0	0	0	0	0	0	56
2004	0	0	0	0	0	0	41
2005	0	0	0	0	0	0	46
2006	0	0	0	0	0	0	51
2007	0	0	0	0	0	0	57
2008	0	0	0	0	0	0	63
2009	0	0	0	0	0	0	68
2010	0	0	0	0	0	0	75
2011	0	0	0	0	0	0	82
2012	0	0	0	0	0	0	58
2013	0	0	0	0	0	0	63
2014	0	0	0	0	0	0	68
NOMINAL	0	0	0	0	0	0	1,051
NPV:	0	0	0	0	0	0	470

* SUPPLEMENTAL INFORMATION NOT SPECIFIED IN WORKBOOK

p_5

* WORKSHEET : DSM PROGRAM FUEL SAVINGS — WORKSHEET FOR FORM CE 2.2

PROGRAM: CONS. EX.1 vs PC Unit - DSM FIRE PROGRAM (Data Rev. 7/23/92 —

18-Nov-94

(1) YEAR	(2) REDUCTION IN KWH GENERATION NET NEW CUST KWH (000)	(3) AVOIDED MARGINAL FUEL COST - REDUCED KWH $(000)	(4) INCREASE IN KWH GENERATION NET NEW CUST KWH (000)	(5) INCREASED MARGINAL FUEL COST - INCREASE KWH $(000)	(6) NET AVOIDED PROGRAM FUEL SAVINGS $(000)	(7) EFFECTIVE PROGRAM FUEL SAVINGS $(000)
1995	532	18	0	0	18	18
1996	1,064	37	0	0	37	37
1997	1,064	39	0	0	39	39
1998	1,064	41	0	0	41	41
1999	1,064	42	0	0	42	42
2000	1,064	44	0	0	44	44
2001	1,064	48	0	0	48	48
2002	1,064	53	0	0	53	53
2003	1,064	56	0	0	56	56
2004	1,064	41	0	0	41	41
2005	1,064	46	0	0	46	46
2006	1,064	51	0	0	51	51
2007	1,064	57	0	0	57	57
2008	1,064	63	0	0	63	63
2009	1,064	68	0	0	68	68
2010	1,064	75	0	0	75	75
2011	1,064	82	0	0	82	82
2012	1,064	58	0	0	58	58
2013	1,064	63	0	0	63	63
2014	1,064	68	0	0	68	68
NOMINAL	20,745	1,051	0	0	1,051	1,051
NPV:		470		0	470	470

* SUPPLEMENTAL INFORMATION NOT SPECIFIED IN WORKBOOK

P_6

* WORKSHEET: UTILITY COSTS AND PARTICIPANT COSTS AND REV LOSS/GAIN
PROGRAM: CONS. EX.1 vs PC Unit - DSM FIRE PROGRAM (Data Rev. 7/23/92)

WORKSHEET FOR FORM CE 2.2

Nov-94

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
	<----- UTILITY PROGRAM COSTS & REBATES ------->						<------------------ PARTICIPATING CUSTOMER COSTS & BENEFITS ---------------------->										
YEAR	UTIL NONREC. COSTS $(000)	UTIL RECUR COSTS $(000)	TOTAL UTIL PGM COSTS $(000)	UTIL NONREC. REBATES $(000)	UTIL RECUR. REBATES $(000)	TOTAL REBATE/ INCENT. COSTS $(000)	PARTIC. CUST EQUIP COSTS $(000)	PARTIC. CUST O & M COSTS $(000)	TOTAL COSTS PARTIC. CUST $(000)	REDUCT. IN CUST. KWH (000)	RED. REV. - FUEL PORTION $(000)	RED. REV. NONFUEL PORTION $(000)	EFFECT. REV. REDUCT. IN BILL $(000)	INC. IN CUST. KWH (000)	INC. REV. - FUEL PORTION $(000)	INC. REV. NONFUEL PORTION	EFFECT. REVENUE INC. IN BILL $(000)
1995	0	0	0	0	0	0	0	0	0	500	12	25	37	0	0	0	0
1996	0	0	0	0	0	0	0	0	0	1,000	24	51	75	0	0	0	0
1997	0	0	0	0	0	0	0	0	0	1,000	26	52	78	0	0	0	0
1998	0	0	0	0	0	0	0	0	0	1,000	27	53	80	0	0	0	0
1999	0	0	0	0	0	0	0	0	0	1,000	27	54	81	0	0	0	0
2000	0	0	0	0	0	0	0	0	0	1,000	28	55	83	0	0	0	0
2001	0	0	0	0	0	0	0	0	0	1,000	30	56	86	0	0	0	0
2002	0	0	0	0	0	0	0	0	0	1,000	33	57	90	0	0	0	0
2003	0	0	0	0	0	0	0	0	0	1,000	35	59	94	0	0	0	0
2004	0	0	0	0	0	0	0	0	0	1,000	29	60	89	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	1,000	31	61	92	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	1,000	33	62	95	0	0	0	0
2007	0	0	0	0	0	0	0	0	0	1,000	36	63	99	0	0	0	0
2008	0	0	0	0	0	0	0	0	0	1,000	39	65	103	0	0	0	0
2009	0	0	0	0	0	0	0	0	0	1,000	41	66	107	0	0	0	0
2010	0	0	0	0	0	0	0	0	0	1,000	45	67	112	0	0	0	0
2011	0	0	0	0	0	0	0	0	0	1,000	48	69	117	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	1,000	38	70	108	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	1,000	39	71	111	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	1,000	41	73	114	0	0	0	0
	0	0	0	0	0	0	0	0	0	19,500	661	1,190	1,851	0	0	0	0
	0	0	0	0	0	0	0	0	0		298	557	855		0	0	0

* SUPPLEMENTAL INFORMATION NOT SPECIFIED IN WORKBOOK

I-B - Value of 1 GWh-Summer, No Demand Billing Impact

F_23

TOTAL RESOURCE COST TESTS
PROGRAM: CONS. EX.1 vs PC Unit - DSM FIRE PROGRAM (Data Rev. 7/23/92)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
YEAR	INCREASED SUPPLY COSTS $(000)	UTILITY PROGRAM COSTS $(000)	PARTICIPANT PROGRAM COSTS $(000)	OTHER COSTS $(000)	TOTAL COSTS $(000)	AVOIDED GEN UNIT BENEFITS $(000)	AVOIDED T & D BENEFITS $(000)	PROGRAM FUEL SAVINGS $(000)	OTHER BENEFITS $(000)	TOTAL BENEFITS $(000)	NET BENEFITS $(000)	CUMULATIVE DISCOUNTED NET BENEFITS $(000)
1995	0	0	0	0	0	0	0	18	0	18	18	18
1996	0	0	0	0	0	0	0	37	0	37	37	52
1997	0	0	0	0	0	0	0	39	0	39	39	85
1998	0	0	0	0	0	0	0	41	0	41	41	116
1999	0	0	0	0	0	0	0	42	0	42	42	147
2000	0	0	0	0	0	0	0	44	0	44	44	175
2001	0	0	0	0	0	0	0	48	0	48	48	205
2002	0	0	0	0	0	0	0	53	0	53	53	234
2003	0	0	0	0	0	0	0	56	0	56	56	263
2004	0	0	0	0	0	0	0	41	0	41	41	282
2005	0	0	0	0	0	0	0	46	0	46	46	302
2006	0	0	0	0	0	0	0	51	0	51	51	322
2007	0	0	0	0	0	0	0	57	0	57	57	343
2008	0	0	0	0	0	0	0	63	0	63	63	364
2009	0	0	0	0	0	0	0	68	0	68	68	385
2010	0	0	0	0	0	0	0	75	0	75	75	407
2011	0	0	0	0	0	0	0	82	0	82	82	428
2012	0	0	0	0	0	0	0	58	0	58	58	442
2013	0	0	0	0	0	0	0	63	0	63	63	456
2014	0	0	0	0	0	0	0	68	0	68	68	470
NOMINAL	0	0	0	0	0	0	0	1,051	0	1,051	1,051	
NPV:	0	0	0	0	0	0	0	470	0	470	470	

Discount Rate 8.75%
Benefit/Cost Ratio: col (11) / col (6) ERR

I-B - Value of 1 GWh-Summer, No Demand Billing Impact

F_24

PARTICIPANT COSTS AND BENEFITS
PROGRAM: CONS. EX.1 vs PC Unit - DSM FIRE PROGRAM (Data Rev. 7/23/92)

PSC FORM CE 2.4
Page 1 of 1
18-Nov-94

(1) YEAR	(2) SAVINGS IN PARTICIPANTS BILL $(000)	(3) TAX CREDITS $(000)	(4) UTILITY REBATES $(000)	(5) OTHER BENEFITS $(000)	(6) TOTAL BENEFITS $(000)	(7) CUSTOMER EQUIPMENT COSTS $(000)	(8) CUSTOMER O & M COSTS $(000)	(9) OTHER COSTS $(000)	(10) TOTAL COSTS $(000)	(11) NET BENEFITS $(000)	(12) CUMULATIVE DISCOUNTED NET BENEFITS $(000)
1995	37	0	0	0	37	0	0	0	0	37	37
1996	75	0	0	0	75	0	0	0	0	75	106
1997	78	0	0	0	78	0	0	0	0	78	171
1998	80	0	0	0	80	0	0	0	0	80	233
1999	81	0	0	0	81	0	0	0	0	81	291
2000	83	0	0	0	83	0	0	0	0	83	346
2001	86	0	0	0	86	0	0	0	0	86	398
2002	90	0	0	0	90	0	0	0	0	90	448
2003	94	0	0	0	94	0	0	0	0	94	496
2004	89	0	0	0	89	0	0	0	0	89	537
2005	92	0	0	0	92	0	0	0	0	92	577
2006	95	0	0	0	95	0	0	0	0	95	615
2007	99	0	0	0	99	0	0	0	0	99	651
2008	103	0	0	0	103	0	0	0	0	103	686
2009	107	0	0	0	107	0	0	0	0	107	719
2010	112	0	0	0	112	0	0	0	0	112	751
2011	117	0	0	0	117	0	0	0	0	117	782
2012	108	0	0	0	108	0	0	0	0	108	808
2013	111	0	0	0	111	0	0	0	0	111	832
2014	114	0	0	0	114	0	0	0	0	114	855
NOMINAL	1,851	0	0	0	1,851	0	0	0	0	1,851	
NPV:	855	0	0	0	855	0	0	0	0	855	

In service year of gen unit: 2004
Discount rate: 8.75%

I-B - Value of 1 GWh-Summer, No Demand Billing Impact

F_25

RATE IMPACT TEST
PROGRAM:CONS. EX.1 vs PC Unit - DSM FIRE PROGRAM (Data Rev. 7/23/92)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
YEAR	INCREASED SUPPLY COSTS $(000)	UTILITY PROGRAM COSTS $(000)	INCENTIVES $(000)	REVENUE LOSSES $(000)	OTHER COSTS $(000)	TOTAL COSTS $(000)	AVOIDED GEN UNIT & FUEL BENEFITS $(000)	AVOIDED T & D BENEFITS $(000)	REVENUE GAINS $(000)	OTHER BENEFITS $(000)	TOTAL BENEFITS $(000)	NET BENEFITS TO ALL CUSTOMERS $(000)	CUMULATIVE DISCOUNTED NET BENEFIT $(000)
1995	0	0	0	37	0	37	18	0	0	0	18	(19)	(19)
1996	0	0	0	75	0	75	37	0	0	0	37	(38)	(54)
1997	0	0	0	78	0	78	39	0	0	0	39	(39)	(87)
1998	0	0	0	80	0	80	41	0	0	0	41	(39)	(117)
1999	0	0	0	81	0	81	42	0	0	0	42	(39)	(145)
2000	0	0	0	83	0	83	44	0	0	0	44	(39)	(170)
2001	0	0	0	86	0	86	48	0	0	0	48	(38)	(193)
2002	0	0	0	90	0	90	53	0	0	0	53	(37)	(214)
2003	0	0	0	94	0	94	56	0	0	0	56	(37)	(233)
2004	0	0	0	89	0	89	41	0	0	0	41	(47)	(255)
2005	0	0	0	92	0	92	46	0	0	0	46	(46)	(275)
2006	0	0	0	95	0	95	51	0	0	0	51	(44)	(293)
2007	0	0	0	99	0	99	57	0	0	0	57	(42)	(308)
2008	0	0	0	103	0	103	63	0	0	0	63	(40)	(322)
2009	0	0	0	107	0	107	68	0	0	0	68	(40)	(334)
2010	0	0	0	112	0	112	75	0	0	0	75	(37)	(344)
2011	0	0	0	117	0	117	82	0	0	0	82	(35)	(354)
2012	0	0	0	108	0	108	58	0	0	0	58	(49)	(365)
2013	0	0	0	111	0	111	63	0	0	0	63	(48)	(376)
2014	0	0	0	114	0	114	68	0	0	0	68	(46)	(385)
NOMINAL	0	0	0	1,851	0	1,851	1,051	0	0	0	1,051	(799)	
NPV:	0	0	0	855	0	855	470	0	0	0	470	(385)	

Discount rate: 8.75%
Benefit / Cost Ratio - Col (12)/Col (7) 0.5