OUC

The *Reliable* One

Ten-Year Site Plan

April 1999

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Executive Summary

This report documents the Ten Year Site Plan (TYSP) conducted for the Orlando Utilities Commission (OUC) electric system. Analysis for the plan included a review of existing electric supply resources, forecasts of customer peak demand and energy requirements, forecasts of fuel prices and availability, projections of fuel requirements and energy production by fuel type, and analysis of future generating reserve and resource requirements. The results of analysis are presented in the following eight main report sections:

Section 1 - Description of Utility
Section 2 - Strategic Issues
Section 3 - Forecast of Power Demand and Energy Consumption
Section 4 - Demand-Side Management Options
Section 5 - Forecast of Facilities Requirements
Section 6 - Production Simulation Results
Section 7 - Environmental and Land Use Information
Section 8 - Ten Year Site Plan Schedules

The Appendix contains additional details regarding OUC's demand-side management plan, customer demand forecasting program, and production costing program.

The existing OUC supply system includes wholly-owned generation facilities, jointly-owned generation facilities, and power sales agreements. The total installed capacity based on OUC's ownership share is 1,631 MW summer and 1,688 MW winter for 1999. The existing supply system has a broad range of fuel diversity and generation technology using several different fuel types and generation technologies. In addition, through OUC's recent agreement with the City of St. Cloud, OUC is also now responsible for managing the City's existing generation and transmission facilities as well as their existing power purchases contracts.

OUC currently employs demand-side management (DSM) to improve the efficiency of consumer electricity usage. These programs are designed to meet the conservation goals set forth by the Florida Public Service Commission (FPSC).

Forecasts of system peak demand growth and energy consumption were developed to determine future reserve and resource requirements. Based on the most likely peak demand forecast and established reserve margin criteria, the analysis indicated that OUC does not require additional supply resources over the ten year study period. As a result, OUC will not have any associated transmission system considerations or environmental and land use considerations.

Fuel price and availability forecasts were developed and used with the demand and energy forecasts to complete long term production costing simulations. These simulations are used as a planning tool to project fuel requirements and energy production by fuel type, as well as to determine the least cost production strategy.

1.0 Description of Utility

1.1 History of the Orlando Utilities Commission

Back at the turn of the century an Orlando Judge, John M. Cheney, organized the Orlando Water and Light Company and supplied electricity on a part-time basis with a 100 kilowatt generator. Twenty-four-hour service began in 1903.

By 1922, the City's population had grown to about 10,000 and the Judge, realizing a need for wider services than his company was able to supply, urged his friends to work and vote for a $97,500 bond issue to enable the citizens of Orlando to purchase and municipally operate his privately-owned utilities.

The bond issue carried almost three to one, as did a subsequent issue for additional improvements. The citizens of Orlando took over the company, with its 2,795 electricity customers and 5,000 water customers for a total original investment of $1.5 million.

The following year, 1923, the Orlando Utilities Commission (OUC) was created by an act of the State Legislature and full authority was granted to OUC to operate the plant as a municipal utility. The business was a paying venture from the start. In fact, by 1924 the number of customers had more than doubled and OUC contributed $53,000 to the City. When Orlando citizens took over operations of their utility, the population was less than 10,000. By 1925 it had grown to 23,000. In 1925 more than $165,000 was transferred to the City and in 1926 in additional $111,000 was transferred to the City. In 1928 one outside private utility offered $3 million to purchase the utility.

Between 1928 and 1931 there was a lot of talk for and against the sale of the utility. On August 18, 1931, an election was held and the people voted 1033 to 140 not to sell the utility, 1030 to 160 not to mortgage the utility, 744 to 436 not to issue tax notes, and 919 to 158 to lease the utility. However, the question as to whether or not Orlando's utility should remain under municipal ownership did not end with the vote of the people in 1931. A year later a $5 million offer was made for the plant, $2 million more than the actual physical value at the time.

Intermittent attempts were made to gain control of the utility until around 1940 when OUC instituted a study extending over 18 years of the utility's activity, and adopted a firm policy of keeping the people fully informed of operations to benefit the taxpayers and the citizens of Orlando.

The wisdom of these early Orlando citizens can be fully appreciated with a look at the magnitude of today's operation serving approximately 154,000 electric customers and 113,000 water customers including the recent addition of customers from the City of St. Cloud.

1.2 General Description of the Orlando Utilities Commission

The Orlando Utilities Commission (OUC) is a statutory commission created by the legislature of the State of Florida as a separate part of the government of the City of Orlando. OUC has the full authority over the management and control of the electric and water works plants in the City of Orlando and has recently been approved by the Florida Legislature to offer these services in Osceola County as well as Orange County. OUC's charter allows it to undertake, among other things, the construction, operation, and maintenance of electric generation, transmission and distribution systems, and water production, transmission and distribution systems in order to meet the requirements of its customers.

OUC's electric system provides power to customers within Orange County encompassing approximately 244 square miles. As of December 31, 1998, the electric system had 136,790 active services. Of these, 117,814 are residential services, 15,170 are general service nondemand services, and the remaining 3,806 are general service demand services. The recent agreement with the City of St. Cloud has essentially allowed OUC to add an additional 150 square miles of service area as well as an additional 17,495 active services.

1.3 Generation System

1.3.1 Existing Generating Facilities

OUC presently has ownership interests in the following five electric generating plants which are further described below.

- Indian River Plant Steam Turbine Units 1, 2 and 3, and Combustion Turbine Units A, B, C and D
- Stanton Energy Center Units 1 and 2
- Florida Power Corporation Crystal River Unit 3 Nuclear Generating Facility
- City of Lakeland McIntosh Unit 3

- Florida Power and Light Company St. Lucie Unit 2 Nuclear Generating Facility.

Stanton Energy Center. The Stanton Energy Center (SEC) is located twelve miles southeast of Orlando, Florida. The 3,250 acre site contains SEC Units 1 and 2 and the necessary supporting facilities. SEC 1 was placed in operation on July 1, 1987 followed by SEC Unit 2 which was placed in operation on June 1, 1996 at a cost of $464.9 million, $57 million under budget. Both units are fueled by pulverized coal and operate at emission levels that are below the Environmental Protection Agency (EPA) and the Florida Department of Environmental Protection requirement standards for SO_2, NO_x and particulates.

SEC Unit 1 is a 440 net MW coal-fired facility of which OUC has a 68.6 percent ownership share providing 304 MW of capacity to the OUC system. SEC Unit 2 is a 444 net MW coal-fired generating facility. OUC's ownership share in this facility is 71.6 percent, or 318 MW.

Indian River Plant. The Indian River Plant is located four miles south of Titusville, on U.S. Highway 1. The 160-acre Indian River Plant site contains three steam electric generating units, No. 1, 2, and 3, and four combustion turbine units, A, B, C, and D. The ages of the steam turbine units vary from 25 to 39 years, while those of the combustion turbines vary from six to nine years. The steam units are primarily fueled by natural gas and No. 6 fuel oil as an alternative. The combustion turbine units are primarily fueled by natural gas with No. 2 fuel oil as an alternative.

OUC has 100 percent ownership of the Indian River Units 1, 2, and 3 which have a total capacity of 619 MW. In addition, OUC has a partial ownership share of 48.8 percent, or 46 MW, in Indian River Units A and B as well as a partial ownership share of 79 percent, or 200 MW, in Indian River Units C and D.

McIntosh Unit 3. McIntosh Unit 3 is a 340 net MW coal-fired unit operated by the City of Lakeland. McIntosh Unit 3 has supplementary oil and refuse fuel burning capability and also capable of burning up to 20 percent petroleum coke. OUC has a 40 percent ownership share in this unit providing approximately 136 MW of capacity to the OUC system.

Crystal River Unit 3. Crystal River Unit 3 is a net 830 MW nuclear generating facility operated by the Florida Power Corporation. OUC has a 1.6015 percent ownership share in this facility providing approximately 13 MW to the OUC system.

St. Lucie Unit 2. St. Lucie Unit 2 is a net 835 MW nuclear generating facility operated by the Florida Power and Light. OUC has a 6.08951 percent ownership share in this facility providing approximately 52 MW to the OUC system.

Table 1-1 summarizes OUC's generating facilities including the capacity, commercial operation date, ownership share, etc.

Table 1-1
Summary of OUC Generation Facilities

Generating Facility	Date in Service Mo/Yr	Net Capability for Total Facility[1]	Ownership Share - %	Net Capability Available for OUC		Unit Type[2]	Fuel[3]	
				Summer MW	Winter MW		Primary	Alternate
Stanton Energy Center								
Unit No. 1	07/87	440	68.5542	302	304	FS	C	-
Unit No. 2	06/96	444	71.59	318	318	FS	C	-
Indian River								
Unit No. 1	02/60	90	100	88	90	FS	NG	HO
Unit No. 2	12/64	205	100	201	205	FS	NG	HO
Unit No. 3	02/74	324	100	319	324	FS	NG	HO
Unit A	06/89	48	48.8	18	23	CT	NG	LO
Unit B	07/89	48	48.8	18	23	CT	NG	LO
Unit C	08/92	127	79	85	100	CT	NG	LO
Unit D	10/92	127	79	85	100	CT	NG	LO
Total Indian River				814	865			
Crystal River								
Unit No. 3	03/77	830	1.6015	13	13	N	N	-
C.D. McIntosh Jr.								
Unit No. 3	09/82	340	40	133	136	FS	C/R	HO
St. Lucie								
Unit No. 2(4)	08/83	853	6.08951	51	52	N	N	-
Total				1,631[(5)]	1,688[(5)]			

1. Actual net capacity varies with auxiliary power consumption.
2. FS = Fossil Steam; N - Nuclear; CT - Combustion Turbine
3. C = Coal; C/R = Coal and Refuse; HO - Heavy Oil (#6); LO = Light Oil (#2); NG - Natural Gas; N = Nuclear
4. OUC receives 50 percent of this capacity from St. Lucie Unit No. 1 pursuant to a reliability exchange agreement with FP&L
5. The net capability available for OUC will be effectively reduced by the amounts allocated to firm power sales as shown in Tables 5-1 and 5-2.

1.3.2 Participation Agreements

OUC has entered into a series of participation agreements which convey an undivided ownership interest in units constructed and operated by OUC. Table 1-2 is a summary of those participation agreements.

Table 1-2
Summary of Generation Facility Participation Agreements

Company	Unit	Amount of Ownership MW	Percent of Ownership Percent
FMPA	SEC 1	117	26.6
KUA	SEC 1	21	4.8
FMPA	SEC 2	126	28.4
FMPA	IRP CT A&B	37	39.0
KUA	IRP CT A&B	12	12.2
FMPA	IRP CT C&D	53	21.0

FMPA - Florida Municipal Power Agency
KUA - Kissimmee Utility Authority
SEC - Stanton Energy Center
IRP - Indian River Plant

1.3.3 New Construction of Generation Facilities

OUC completed the construction of Stanton Unit 2 in June, 1996, but is not currently in the process of constructing any additional units.

1.4 Transmission System

1.4.1 Existing Transmission Facilities

OUC's existing transmission system consists of 26 substations approximately 302 miles of 230 kV and 115 kV lines and cables. OUC is fully integrated into the state transmission grid through its twelve 230 kV interconnections with other generating utilities which are members of the Florida Reliability Coordinating Council (FRCC) as summarized in Table 1-3. OUC's service area and transmission system are also shown on Figure 1-1.

In addition, OUC is also now responsible for approximately 50 miles of St. Cloud's transmission system including the 69 kV interconnection from St. Cloud's Central Substation to KUA's Carl Wall Substation and a 230 kV interconnection from the St. Cloud's East Substation to FPC's Holopaw Substation.

Table 1-3

OUC Transmission Interconnections

kV	Utility	Number of Interconnections
230	FPL	1
230	FPC	5
230	KUA	2
230	KUA/FMPA	1
230	Lakeland	1
230	TECO	1
230	TECO/RCID	1

FPL - Florida Power & Light
FPC - Florida Power Corporation
KUA - Kissimmee Utility Authority
TECO - Tampa Electric Company
RCID - Reedy Creek Improvement District
FMPA - Florida Municipal Power Agency

1.4.2 New Construction of Transmission Facilities

OUC is currently involved in the construction of a second Indian River – Cape Kennedy tie line with FPL. The line is anticipated to be in-service by June 1, 1999. The addition will ease a line loading constraint as well as increase the available transfer capability between the systems. Further discussion of OUC's on-going and planned transmission construction projects is provided in Section 5.3 of this report.

1.5 Agreement with the City of St. Cloud

The year 1997 marked a milestone for OUC as it began a new power supply partnership with the City of St. Cloud (St. Cloud). This new 25 year agreement is a precedent setting move as OUC has become the first municipal electric utility in the state to manage, operate and maintain another municipal electric utility. The agreement is OUC's first full requirements power supply contract. It is also unique because the 17,495 St. Cloud customers are paying market-based rates for power received. The agreement has also, in effect, provided a 12 percent increase in OUC's customer base and added 150 square miles of high growth service area to OUC's existing 244 square mile service area. Energy use in the St. Cloud service area has grown at an average rate of approximately 7 percent for the last decade.

1.6 Change in OUC Charter

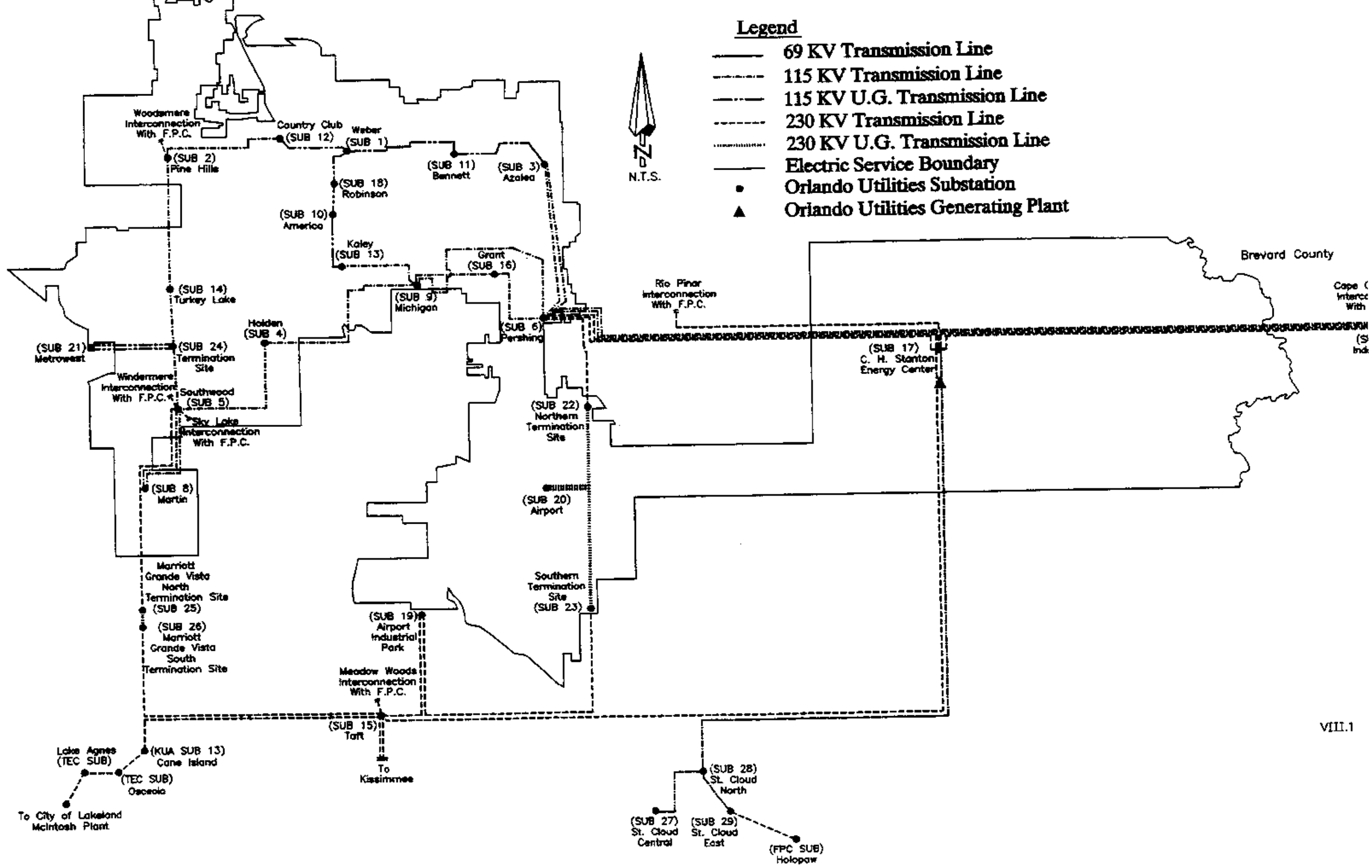
In 1997, both Houses of the Florida Legislature unanimously approved changes to the OUC charter that significantly broaden its energy business opportunities. OUC can now buy, build, maintain and/or operate power plants, power lines, and other facilities and also build and maintain facilities associated with energy services in any existing municipal electric service area in Osceola County as well as Orange County if invited to do so by those cities.

1.7 Potential Sale of Indian River Steam Units

In light of the potential for electric utility deregulation, OUC has been studying alternatives to increase flexibility and decrease costs. One of the alternatives is the potential sale of the Indian River Steam Units. OUC explored opportunities with a number of potential purchasers and is in the process of conducting negotiations in order to enter into a definitive agreement for the sale.

The potential sale only includes the Indian River Steam Units. OUC will retain joint ownership of the Indian River combustion turbine units. The potential sale will include a buy-back Power Purchase Agreement (PPA) to cover OUC's capacity and energy requirements. Since the negotiations are not yet finalized and since OUC will have a buy-back PPA, OUC has not formally reflected the potential sale in OUC's expansion planning.

Orlando Utilities Commission Transmission System



2.0 Strategic Issues

OUC incorporated a number of strategic considerations while planning for the electric system. This section provides an overview of a number of these strategic considerations.

2.1 Strategic Business Units

As the entire electric utility industry faces deregulation, OUC is aggressively developing strategies to be competitive in a deregulated environment. One strategy already implemented is to reorganize OUC into the following strategic business units, which are described below.

- Power Resource Business Unit
- Transmission Business Unit
- Electric Distribution Business Unit

2.1.1 Power Resources Business Unit

The Power Resources Business Unit (PRBU) has begun operation on a profit and loss basis. PRBU has structured its operations based on a competitive environment that assumes that even OUC's customers are not captive. PRBU will only be profitable if it can produce electricity that is competitively priced in the open market. In line with this strategy, OUC is continually studying options to improve or reposition their generating assets, such as the potential sale of the Indian River Steam Units.

OUC's generating system has been designed over the years to take advantage of fuel diversity and the resultant system reliability and economic benefits. OUC's long-standing intent to achieve diversity in its fuel mix is evidenced by its participation in other generating facilities in the State of Florida. The first such endeavor occurred in 1977 when OUC secured a share of the Crystal River Unit 3 nuclear plant, followed by the acquisition of an ownership share in the City of Lakeland's McIntosh Unit 3 coal fired unit in 1982. In 1983, OUC also acquired a share of the St. Lucie Unit 2 nuclear unit. OUC's current capacity mix is summarized in Table 2-1.

Table 2-1
Generation Capacity by Fuel Type - MW

	Winter Capacity				Summer Capacity			
Plant Name	Coal	Nuclear	Gas/Oil	Total	Coal	Nuclear	Gas/Oil	Total
Indian River			865	865			814	814
Crystal River		13		13		13		13
McIntosh	136			136	133			133
St. Lucie		52		52		51		51
Stanton	622			622	620			620
Total	758	65	865	1,688	753	64	814	1,631
Total (%)	45	4	51	100	46	4	50	100

Even though coal only represents 45 percent of OUC's capacity it provided over 65 percent of OUC's energy production in 1998. OUC's coal capacity ensures against interruptions in supply and increases in cost of oil and gas. Additional details of OUC's generating facilities are presented on Schedule 1 of Section 8.

Another example of OUC's commitment to fuel diversity is the use of alternative fuels such as refuse derived fuel (RDF) at the McIntosh Unit 3 facility. The plant is designed to burn a mix of RDF and coal. OUC's use of alternative or renewable fuels is further enhanced by burning a mix of petroleum coke in McIntosh Unit 3 along with coal and RDF. Petroleum coke is a waste by-product of the petroleum refining industry and besides the benefits of using a waste product, petroleum coke's lower prices results in significant savings over coal. Tests have been done indicating the ability to use petroleum coke for approximately 20 percent of the fuel input to McIntosh Unit 3. Permits have been modified and approved for this level of use.

OUC's diversified mix of generating units provides protection against disruption of supply while simultaneously providing economic opportunities to reduce cost to customers. The ability to burn the lowest cost fuel allows opportunities for savings when fuel prices swing. The ability to burn a variety of fuels increases OUC's opportunities to be a player in the futures market and offers greater opportunities for hedging.

2.1.2 Transmission Business Unit

TBU also continues to generate new revenues by leasing space on OUC facilities for wireless personal communications systems and leasing dark fiber to other telecommunications companies. It is also marketing its expertise to other utilities and commercial customers.

TBU is also responsible for dispatching all generation for OUC and the Florida Municipal Power Pool (FMPP). The pool consists of OUC, Lakeland, Kissimmee and the Florida Municipal Power Agency's All Requirements Project. TBU has operated the pool since its inception in 1988. Section 2.2 of this report provides additional details regarding FMPP and its strategic importance to OUC.

2.1.3 Electric Distribution Business Unit

OUC's Electric Distribution Business Unit (EDBU) is moving forward to use its superior record for reliability to develop new business and to prosper in a deregulated utility industry.

In 1997, it restructured the business unit to take it to the next level of performance. It established a new Division of Costs and Control responsible for all of the business unit's financial operations. EDBU has also added a director of business development to market its expertise to other utilities and secure other revenue-making opportunities for OUC. EDBU is also going beyond the meter to offer customers expanded power quality services.

OUC's leadership in providing reliable electric distribution service is further demonstrated by its commitment to making initial investments in high quality material and equipment, implementing aggressive preventive maintenance programs, and placing more than 40 percent of its electric distribution lines underground which reduces the potential for accidental contacts with live wires and poles and also enhances the appearance of streets, and commercial and residential areas.

During 1998, OUC continued to experience the best reliability in the State of Florida. In addition, OUC has an excellent record for the time it takes to restore outages, a measure of reliability required by the Florida Public Service Commission to be reported on a calendar year basis. That rate has improved from a three-year average of 76 minutes to 66 minutes in 1998.

2.2 Florida Municipal Power Pool

In 1988, OUC joined with the City of Lakeland and Florida Municipal Power Agency's All Requirements Project members to form the Florida Municipal Power Pool (FMPP). Later, Kissimmee Utility Authority joined FMPP. Through time, FMPA's All Requirements Project has added members as well. FMPP is an operating type electric pool, which dispatches all the pool member's generating resources in the most economical manner to meet the total load requirements of the pool. The central dispatch is providing savings to all parties because of reduced commitment costs and lower overall fuel costs. OUC serves as the FMPP dispatcher and handles all accounting for the allocation of fuel expenses and savings. The term of the pool agreement is one year and automatically renews from year to year until terminated by the consent of all participants.

OUC's participation in the FMPP provides significant savings from the joint commitment and dispatch of FMPP's units. Participation in FMPP also provides OUC with a ready market for any excess energy available from OUC's generating units.

2.3 Security of Power Supply

OUC has historically provided their customer's needs through the construction of power plants rather than from purchasing power. Generally OUC has built units that were larger than were required to meet their own customer's loads. This strategy allowed OUC to obtain greater economies of scale and reduce the per unit cost of power. Sales of excess capacity further reduced costs to OUC's customers. OUC's ownership of generating units has provided their customers with greater security of supply during periods of power shortages. OUC also currently maintains interchange agreements with other utilities in the Florida for the provision to provide electrical energy during emergency conditions.

The reliability of power supply is also enhanced by twelve 230 kV interconnections with other Florida utilities, including five interconnections with Florida Power Corporation (FPC), three with Kissimmee Utility Authority (KUA), and one each with Florida Power and Light (FP&L), Tampa Electric Company (TECO), Reedy Creek Improvement District (RCID), and the City of Lakeland. In addition to enhancing reliability, these interconnections also facilitate the marketing of electric energy by OUC to and from other electric utilities in Florida. Through its agreement with St. Cloud, OUC is also now responsible for St. Cloud's 230 kV interconnection to FPC and 69 kV interconnection to KUA.

2.4 Environmental Performance

As the quality of the environment is important to Florida and especially important to the tourist attracted economy in central Florida, OUC is committed to protecting human health and preserving the quality of life and the environment in Central Florida. To demonstrate this commitment, OUC has chosen to operate their generating units with emission levels below those required by permits and licenses by equipping its power plants with the best available environmental protection systems. As a result, even with a second unit in operation, The Stanton Energy Center is one of the cleanest coal-fired generating stations in the nation. Unit 2 is the first of its size and kind in the nation to use Selective Catalytic Reduction (SCR) to remove nitrogen oxides (NO_x). Using SCR and Low-NO_x burner technology, Stanton 2 successfully meets the stringent air quality requirements imposed upon it.

This superior environmental performance not only preserves the environment, but also results in many economic benefits, which help offset the costs associated with the superior environmental performance. For example, the high quality coal burned at Stanton contributes to the high availability of the unit was well as low heat rate.

Further demonstrating their environmental commitment to clean air, OUC has signed a contract to burn the methane gas collected from the Orange county landfill adjacent to Stanton Energy Center. Methane gas, when released into the atmosphere, is considered to be 20 times worse than carbon dioxide in terms of possible global warming effects. Both Stanton units will have the capability of burning methane. In addition to their commitment to clean air, OUC is also equally committed to minimizing the environmental and esthetic impacts on land used for and adjacent to new construction projects. In planning the new transmission line to link Stanton and St. Cloud, OUC employed the best management practices in route selection and design. OUC is using low-impact construction and clearing techniques to further minimize the environmental and esthetic impacts of the project. As a result, the state required no additional mitigation measures.

OUC has also voluntarily implemented a product substitution program not only to protect workers' health and safety but also to minimize hazardous waste generation and to prevent environmental impacts. Environmental Affairs and the Safety Division constantly review and replace products to eliminate the use of hazardous substances.

To further prevent pollution and reduce waste generation, OUC also reuses and recycles many products.

OUC is also pursuing programs demonstrating alternate fuels for transportation. OUC has purchased two minivans which have been retrofitted with battery powered motors. They will be used in the normal daily activities of OUC's Conservation and Office Services Divisions. One of the vehicles is also equipped with solar photovoltaic panels on the roof to power cooling fans. The vehicles are powered by 10 large gel cell batteries and 27 horsepower, high torque drive motors. OUC purchased these vehicles to learn as much as possible about their operating and recharge characteristics and to demonstrate the new technology to customers. OUC has also donated two vehicles to the University of Central Florida's Alternate Fuels Research Program for purposes of conducting research on alternative fuel sources for transportation.

2.5 Community Relations

Owned by the community, OUC is especially committed to being a good corporate citizen and neighbor in the areas it serves or impacts.

In Orange, Brevard and Osceola Counties in which OUC has generating units and service area, OUC gives its wholehearted support to education, diversity, the arts, and to social-service agencies. OUC is a Chamber of Commerce supporter in cities in all three counties and is committed to the economic development of these communities.

OUC is a major sponsor of many community programs such as Habitat for Humanity, the Minority/Women Business Enterprise Alliance, Inc., and the Brevard Eco-Trek youth environmental summit. Annually, OUC hosts July 4th fireworks for North Brevard at its Indian River Power Plant and is a major sponsor for St. Cloud's July 4 Lakefest and fireworks display.

A United Arts trustee, OUC has also allowed its historic Lake Ivanhoe Power Plant to be turned into a performing arts center. OUC is a corporate donor for WMFE public television and a co-sponsor of the "Power Station" exhibit at the Orlando Science Center. OUC is involved in the Orange and Osceola Foundations for Education, and is also a business partner of Brevard schools.

3.0 Forecast of Power Demand & Energy Consumption

3.1 Forecasting Methodology

Orlando Utilities Commission (OUC) uses the System for Hourly and Annual Peak and Energy Simulation (SHAPES-PC) end-use/econometric forecasting model from Energy Management Associates. The OUC staff has developed the extensive database required by the SHAPES-PC model. The SHAPES-PC model has been further enhanced to produce loads for each hour of the year in chronological order. OUC staff developed a typical weather year and calibrated this module to the SHAPES-PC model. A discussion of the SHAPES-PC model can be found in Appendix A.

3.2 Retail Sales

The SHAPES-PC model produces forecasts of energy and demand for the residential, commercial, industrial, and miscellaneous sectors (street lights and OUC use). Since OUC does not have commercial and industrial rate classes, these forecasts had to be treated in a different manner. The commercial and industrial sector sales forecasts were combined together and then allocated to the general service non-demand and demand classes based on historical ratios.

3.2.1 Residential

Historically, the average number of residential customers has increased at an average annual rate of 2.1 percent for the period from 1989 through 1998. The average number of residential customers for the period 1999 through 2008 was projected as a function of service area population, age distribution, and headship ratio.

OUC's service area population was projected using Orange County population projections developed from University of Florida population estimates. Historically, service area population has grown at an average rate of 1.9 percent for the 1989 through 1998 period. Service area population is projected to grow at an average annual rate of 1.6 percent for the period 1999 through 2008.

The SHAPES-PC model was used to project residential customers. SHAPES-PC uses the following model to estimate residential customers:

CUS_t	=	$(AGE_t^a * POP_t * BHSR^a * HSRT_t^a) * CHR_t$
Where:		
t	=	the forecast year
a	=	the age category
CUS	=	the residential customer forecast
AGE	=	the fraction of population in a given age category
POP	=	the service area population forecast
BSHR	=	the base year headship ratio
HSRT	=	the headship ratio trend
CHR	=	the customer per household ratio

The projected average number of residential customers is expected to grow at an average annual rate of 1.8 percent from 1999 to 2008.

Historically, residential sales have increased at an average annual rate of 3.4 percent for the 1989 through the 1998 period. SHAPES-PC uses the following general equation to project annual appliance usage for seventeen types of residential appliances:

AE_t^a	=	$NAP_t^a * ADJCL_t^a * AUI^a$
Where:		
t	=	the forecast year
a	=	the appliance type
AE	=	the annual energy for appliance in year t
NAP	=	the forecasted appliance stock for type a in year t
ADJCL	=	the adjusted connected load for appliance a in year t
AUI	=	the annual hours of integral use for appliance a

Projected residential sales are the summation of the individual appliance usages for a given year. Residential sales are expected to grow at an average annual rate of 1.5 percent from 1999 to 2008.

3.2.2 Commercial

SHAPES-PC defines the commercial sector as all customers dealing with the following activities: 1) forestry, fishing, and construction, 2) transportation and public utilities, 3) wholesale trade, 4) retail trade, 5) finance, insurance, and real estate and 6) services and government. Annual commercial sales are the sum of baseload, heating, and cooling components. The following equations are used to project these components of commercial sales:

$AEB_t^c = EIB_t^c * EMP_t^c * PAF_t^c$

$AEC_t^c = EIC_t^c * EMP_t^c * PAF_t^c$

$AEH_t^c = EIH_t^c * EMP_t^c * PAF_t^c$

Where:

c	=	the commercial customer category
t	=	the forecast year
AEB	=	the annual baseload energy forecast
AEC	=	the annual cooling energy forecast
AEH	=	the annual heating energy forecast
EIB	=	the baseload energy intensity for customer category c in year t
EIC	=	the cooling energy intensity for customer category c in year t
EIH	=	the heating energy intensity for customer category c in year t
EMP	=	the employment forecast for customer category in year t
PAF	=	the price adjustment factor for customer c in year t

OUC's service area commercial employment historical data and projections were developed by using Orange County commercial employment and applying a trended fraction of OUC's share of the county numbers.

SHAPES-PC was used to determine the load shape modification due to OUC's commercial efficient lighting program. To estimate the load shape impact of the programs, the commercial temperature insensitive and sensitive loads within the SHAPES database were reduced to reflect the effect of program participation. The model was also used to estimate the effect of a new chiller system for a major account.

The commercial sales sector forecast that is developed from these equations is then combined with the industrial sector sales forecast to produce the general service non-demand and general service demand sales forecasts which will be discussed later.

3.2.3 Industrial

In the SHAPES-PC model the industrial sector is defined as those customers dealing in manufacturing and mining activities. The industrial sector is not considered to be weather sensitive like the residential and commercial sectors. Annual industrial energy sales are projected using the following formula:

$$AE_t^i = EI_t^i * EMP_t^i * (I\text{-}FSG_t^i) * PAF_t^i$$

Where:

i	=	the industrial customer category
t	=	the forecast year
AE	=	the annual energy forecast
EI	=	the energy intensity per employee
EMP	=	the industrial employment forecast
FSG	=	the fraction of annual energy self-generated
PAF	=	the price adjustment factor

The history and forecast of industrial employment data for the OUC service area was developed in the same way as the commercial employment forecast.

The industrial sales sector forecast that is developed from this formula is combined with the commercial sector forecast to generate the general service non-demand and general service demand sales forecasts.

3.2.4 General Service Non-Demand

Historically, the average number of General Service Non-Demand (GSND) customers has increased at an average annual rate of 1.8 percent from 1989 through 1998. The average number of GSND customers for the 1999 through 2008 period was projected as a function of service area employment associated with GSND customers. Multiple regression analysis was used to develop an econometric model for projecting the average number of GSND customers. The following model was chosen to be used:

$$GSNDCUS = 6916.36 + 0.045256\ (EMPL)$$

Where:

GSNDCUS	=	Average number of general service non-demand customers
EMPL	=	OUC service area general service non-demand employment forecast

The projected average number of General Services Non-Demand customers is reported to grow at an average annual rate of 1.4 percent from 1999 to 2008.

The general service non-demand class is a mixture of both commercial and industrial customers as defined by the SHAPES-PC model. Therefore, GSND sales are projected as a percentage of the SHAPES-PC model sales forecast for the commercial and industrial sectors.

Historically, GSND sales have declined at an average annual rate of 0.4 percent from 1989 through 1998. During the 1999 through 2008 period, GSND sales are projected to grow at an average annual rate of 1.5 percent.

3.2.5 General Service Demand

For the historic period from 1989 through 1998, the number of General Service Demand (GSD) customers grew at a 5.4 percent average annual rate. Multiple regression analysis was used to develop an econometric model to project the average number of GSD customers. The following equation was used:

GSDCUS	=	-532.564 + 0.105467 (EMPL)
Where:		
GSDCUS	=	Average number of general service demand customers
EMPL	=	OUC service area general service demand employment forecast

For the forecast period 1999 through 2008, the number of average GSD customers is projected to increase at an annual rate of 2.5 percent. The GSD class is a mixture of commercial and industrial customers as defined by SHAPES PC model. Therefore, GSD sales are projected as a percentage of the SHAPES-PC model's sales forecast for the commercial and industrial sectors.

Historically from 1989 through 1998, GSD sales have grown at an average rate of 3.8 percent. For the forecast period, GSD sales are expected to grow at an average annual rate of 4.0 percent.

3.2.6 Street, Highway, and Traffic Lights

Total street and highway lighting use was determined from historical trends. During the forecast period, street and highway lighting is estimated to increase from 24 GWh to 26 GWh. This reflects a decrease in usage per fixture since OUC is projecting an increasing number of streetlights. Other sales to ultimate customers (traffic lights) have been projected to be 5 GWh throughout the forecast period.

3.2.7 OUC Use and Losses

OUC Use is projected to be 5 GWh at the beginning of the forecast and growing to 6 GWh by the end of the forecast period. Distribution and transmission losses are projected to be 4.1 percent of retail sales.

3.2.8 Total Retail Sales

The sum of the consumption in all of the individual classes equals total OUC retail sales. Historically from 1989 through 1998, retail sales have grown at an average annual rate of 3.2 percent. For the forecast period, retail sales are projected to grow at an average annual rate of 3.0 percent. Retail sales plus OUC Use and losses equals Net Energy for Load (NEL).

3.3 Orlando Utilities Commission Demand Forecast

Peak demand on the OUC system is highly weather sensitive with the annual peak demand occurring in both the summer and winter seasons. In six out of the last ten years, the summer peak has been the higher seasonal peak.

The SHAPES-PC model projects demand on an hour by hour basis. The demand for each of the 8,760 hours in a year is individually projected. A typical weather year is developed by choosing historical months which most closely resemble normal or typical weather. The temperature of each hour of the typical weather year is used to determine the weather sensitive portion of hourly demand.

In the residential sector, the demands of the various appliance types for a given hour are summed together to arrive at the projected residential demand. Certain appliances such as heating and air conditioning are weather sensitive. A weather sensitive portion of demand for a given temperature is added to the non-weather sensitive portion of demand equaling total demand for appliances like air conditioning and heating.

In the commercial sector, the hourly demand forecast is a function of the hourly load profile and the annual commercial energy forecast. The hourly load profile is also a function of the hourly temperature of the typical weather year.

In the industrial sector, the hourly demand is a function of the hourly load profile and the annual industrial energy forecast. The industrial sector is not felt to be weather sensitive.

The hourly demand for OUC Use and street, highway, and traffic lights are a function of their annual energy forecasts and their load profile relationships to the other sectors.

The demand forecast developed by the SHAPES-PC model is also a function of economic and demographic parameters such as the population forecast and commercial and industrial employment. Population and employment forecasts used to develop the base, low, and high demand forecasts are shown in Tables 3-1, 3-2, and 3-3 respectively. These projections were developed by using the Orange County population projections from the University of Florida's Population Bulletin.

3.3.1 Most Likely Case Load Forecast

Total peak demand is the sum of the hourly demands for all sectors adjusted for losses. Summer peak demand for the 1999 to 2008 period is the highest hourly peak demand occurring between April 1 and October 31 and is expected to grow at an average annual rate of 2.7 percent. Winter peak demand is the highest hourly demand occurring between November 1 of the prior year and March 31 of the current year, and is projected to grow at an average annual rate of 2.4 percent for the 1999/2000 to 2008/09 period. The forecasted winter and summer peaks are shown in Tables 3-4 and 3-5 respectively.

3.3.2 Low Case and High Case Load Forecast

Summer peak demand for the 1999 to 2008 period expected to grow at an average annual rate of 0.7 and 4.3 percent for the low and high demand forecasts respectively. Winter low and high peak demand forecasts are projected to grow at an average annual rate of 0.5 and 4.1 percent respectively for the 1999/2000 to 2008/09 period. The forecasted winter and summer peaks for the low and high growth rate scenarios are shown in Tables 3-4 and 3-5 respectively.

Table 3-1
Economic Forecast – Most Likely Case

Year	OUC Service Area Population	OUC Service Area Commercial Employment	OUC Service Area Industrial Employment
1999	301,100	214,000	16,100
2000	305,900	219,700	16,400
2001	310,700	225,800	16,700
2002	315,500	231,900	16,900
2003	321,000	237,800	17,200
2004	327,100	243,100	17,500
2005	331,800	249,200	17,800
2006	336,800	254,500	18,100
2007	342,400	260,400	18,400
2008	348,400	265,000	18,700
AAGR%	1.63%	2.40%	1.68%

Table 3-2
Economic Forecast – Low Case

Year	OUC Service Area Population	OUC Service Area Commercial Employment	OUC Service Area Industrial Employment
1999	293,900	202,800	15,756
2000	295,400	203,800	15,835
2001	295,700	204,800	15,910
2002	296,000	205,800	15,994
2003	296,300	206,900	16,074
2004	297,700	207,900	16,154
2005	298,000	208,900	16,235
2006	298,300	210,000	16,316
2007	298,600	211,000	16,398
2008	298,900	212,005	16,480
AAGR%	0.19%	0.49%	0.50%

Table 3-3
Economic Forecast - High Case

Year	OUC Service Area Population	OUC Service Area Commercial Employment	OUC Service Area Industrial Employment
1999	308,700	215,600	16,700
2000	319,200	223,100	17,300
2001	329,000	230,900	17,900
2002	339,000	238,900	18,500
2003	349,300	247,200	19,200
2004	361,300	255,800	19,800
2005	372,300	264,800	20,500
2006	383,600	274,000	21,300
2007	395,300	284,000	22,000
2008	407,357	294,365	22,723
AAGR%	3.13%	3.52%	3.48%

Table 3-4
Winter Peak Demand Forecasts – MW

Year	Low Growth Case	Most Likely Case	High Growth Case
99/00	902	959	999
00/01	907	984	1,042
01/02	912	1,009	1,086
02/03	915	1,033	1,129
03/04	919	1,057	1,175
04/05	924	1,082	1,223
05/06	928	1,106	1,272
06/07	935	1,132	1,326
07/08	938	1,157	1,379
08/09	941	1,183	1,434
AAGR %	0.47%	2.36%	4.10%

Table 3-5 Summer Peak Demand Forecasts - MW			
Year	Low Growth Case	Most Likely Case	High Growth Case
1999	874	916	936
2000	880	942	976
2001	886	969	1,020
2002	892	996	1,063
2003	898	1,024	1,109
2004	904	1,050	1,155
2005	911	1,079	1,205
2006	918	1,106	1,256
2007	924	1,135	1,309
2008	930	1,161	1,364
AAGR %	0.69%	2.67%	4.27%

3.3.3 Net Energy for Load

Net Energy for Load (NEL) is the sum of the total forecasted energy required to serve retail and wholesale customers, including energy for utility use and losses, less energy savings through energy conservation measures.. As shown in Table 3-6, the NEL for the most likely case is expected to increase at an average annual growth rate of 3.0 percent. The average annual growth rate for the low and high band NEL forecasts is 1.2 and 4.4 percent respectively.

Table 3-6 Forecasts of Net Energy for Load - GWh			
Year	Low Growth Case	Most Likely Case	High Growth Case
1999	4,356	4,556	4,638
2000	4,417	4,714	4,858
2001	4,454	4,850	5,061
2002	4,506	5,002	5,286
2003	4,563	5,160	5,526
2004	4,624	5,328	5,781
2005	4,668	5,477	6,026
2006	4,724	5,634	6,292
2007	4,776	5,792	6,565
2008	4,829	5,954	6,850
AAGR %	1.15%	3.02%	4.43%

3.4 St. Cloud Load Forecast

OUC has an interlocal agreement with the City of St. Cloud. As part of this agreement OUC is the total requirements supplier for St. Cloud. Therefore OUC has developed a forecast of St. Cloud's net energy for load and peak demand requirements.

The St. Cloud net energy for load forecast was developed using regression analysis. The net energy for load was projected as a function of Osceola County population. The source for the population projections was the University of Florida Bureau of Business and Economic Research's Population Bulletin. The following is the St. Cloud net energy for load equation:

STCLNEL = 21.269 * (OSPOP) - 26791.5
R-squared = 0.9839

The Variables are defined as follows:

STCLNEL = Net Energy for Load for St. Cloud in MWh
OSPOP = Osceola County population

For the historical period 1989 through 1998 St. Cloud's net energy for load has grown at a 6 percent average annual rate. For the forecast period the net energy for load is projected to grow at an average annual rate of 3.1 percent. St. Cloud's population grew at an average annual rate of 3.4 percent for the historical period. The population is projected to grow at an average rate of 3.0 percent for the forecast period.

For the forecast period the summer and winter peak demands are both projected to grow at an average annual rate of 3.1 percent. Table 3-7 provides the forecasted summer and winter peak demand for St. Cloud as well as the forecasted net energy for load.

Table 3-7
City of St. Cloud
Demand and Energy Forecast

Year	Total Summer Demand (MW)	Total Winter Demand (MW)	Net Energy for Load (NEL) (GWh)
1999	72	89	319
2000	75	93	331
2001	77	96	343
2002	80	99	354
2003	82	102	365
2004	85	105	376
2005	87	108	387
2006	90	111	398
2007	92	114	409
2008	95	117	421
AAGR%	3.1%	3.1%	3.1%

4.0 Demand-Side Management Programs

Throughout its history, the Orlando Utilities Commission (OUC) has demonstrated a strong commitment to serve its customers conservation needs. OUC has undertaken many conservation programs to meet customer needs and expectations. The demand-side management plan for OUC was approved by the Florida Public Service Commission (FPSC) in 1995. The FPSC goals for OUC, programs implemented to meet these goals, and discussion of direct load control evaluated by OUC are presented briefly in this section and in greater detail in Appendix B.

4.1 Goals

Within Order No. PSC-95-0461-FOF-EG, issued on April 10, 1995, the FPSC established numeric conservation goals for the OUC in accordance with Rules 25-17.0001-.005 of the Florida Administrative Code. OUC has designed its Demand Side Management (DSM) plan to achieve the goals approved by the FPSC. Details of these programs are contained in Appendix B. Table 4-1 presents the approved goals for OUC.

4.2 Current Programs

There have been significant changes in the market place since OUC's conservation programs were proposed and approved. Today there is much more emphasis on competition as the electric industry prepares for deregulation. Economic conditions have also changed significantly since OUC's conservation programs were proposed and approved. The cost of power plants has decreased drastically. The cost of the avoided unit has decreased from \$356/kW in 1996 dollars to \$232/kW in 1998 dollars. Likewise, fuel cost and fuels costs projections have decreased significantly. The fuel cost of the avoided unit decreased from \$0.0327/kWh with a 5.4 percent escalation rate to \$0.0301/kWh with a 2.5 percent escalation rate. As a result, conservation programs are significantly less cost effective than they were when OUC's conservation programs were proposed and approved. As OUC went about evaluation and implementing the approved conservation programs, these changing conditions became evident.

Table 4-1

Total Conservation Goals Approved by the FPSC

Year	Residential			Commercial		
	Winter kW Reduction	Summer kW Reduction	MWh Energy Reduction	Winter kW Reduction	Summer kW Reduction	MWh Energy Reduction
1996	230	155	0	0	0	0
1997	693	468	0	0	0	0
1998	1,386	938	0	0	0	0
1999	2,309	1,563	0	0	0	0
2000	2,463	2,381	0	0	38	0
2001	4,849	3,280	0	0	115	0
2002	6,465	4,374	0	0	230	0
2003	8,311	5,624	0	0	384	0
2004	10,388	7,029	0	0	576	0
2005	12,256	8,290	0	0	807	0

4.2.1 Program Descriptions

The current customer programs include:

- Residential Energy Survey Program
- Residential Heat Pump Program
- Residential Weatherization Program
- Low Income Home Energy Fixup Program
- Commercial Energy Survey Program

4.2.2 Residential Energy Survey

This program is designed to provide residential homeowners with recommended energy efficiency measures and practices. The Residential Energy Survey includes complete attic, air duct, and air return inspections. Literature on other OUC programs is also provided to the residential customers. The customer is given a choice to receive a low-flow showerhead or compact fluorescent bulb. OUC energy analysts are presently using this walk-thru type audit as a means to get OUC customers to participate in other conservation programs and to qualify for appropriate rebates.

4.2.3 Residential Heat Pump Program

Heat Pumps are marketed to the owners of existing residential strip heating systems and older, inefficient central air conditioners and heat pumps. The program requires heat pumps with a SEER of 11 (or greater) and a HSPF of 7.0 (or greater) in order to qualify for rebates. Rebates vary by equipment SEER levels. One of the main benefits of the program is the duct work and insulation level improvements made by contractors when installing the energy efficient heat pumps.

4.2.4 Residential Weatherization Program

This program is designed for existing single family homes and promotes R-19 ceiling insulation (or higher), caulking, weather-stripping, window treatment, water heater insulation and air condition/heating supply and return air duct repair. The customer can receive a \$140 rebate for installing R-19 ceiling insulation (or higher), \$100 rebate for duct repairs and up to \$110 for other conservation measures specified above. In addition, the customer is allowed to carry payments for ceiling insulation on their electric bill for 12 or 24 months. OUC directly pays the total contractor cost for insulation when OUC provides the financing.

Measure	Incentive
Insulate top floor attic level to R-19	\$100
Air seal entry door	5
Insulate electric water heater	5
Install low-flow showerhead	5
Air seal return-air plenum	(Up to) 25

The program is promoted through Residential Energy Surveys, trade shows, exhibits, and neighborhood meetings.

4.2.5 Low Income Home Energy Fixup Program

This program began in 1985 and since inception, has made more than 3,000 homes more energy efficient. This program is offered to customers whose total family annual income does not exceed \$20,000. The program will pay 85 percent of the total contract cost for home weatherization for the following measures:

a) upgrading ceiling insulation to R-19

b) exterior and interior caulking
c) weatherstripping doors and windows
d) air conditioning/heating supply and return air duct repairs
e) water heater insulation

Customers are allowed to finance the remaining 15 percent of the cost on their monthly electric bill. OUC has agreed in a Memorandum of Understanding with the Florida Department of Consumer Affairs dated March 17, 1995 to continue this program.

4.2.6 Commercial Energy Survey Program

This survey is a physical walk-through inspection of the commercial facility. The commercial customer having a Commercial Energy Survey receives a report at the time of the survey. Within 30 days of a detailed audit, the customer receives a written report. Conservation literature is provided to all customers. Customers are encouraged to participate in the CASH program that provides commercial customers CASH to spend on energy savings. This program tailors each incentive to the customers' needs on a case by case basis to increase efficiency, upgrade equipment and improve operations.

4.2.7 Program Participation

Participation in OUC's demand-side management programs remains high as shown below:

Annual Program Participation (Number of Customers Participating)				
	1995	1996	1997	1998
Residential Programs				
Residential Energy Survey	3049	2526	2124	2501
Residential Heat Pump	254	251	235	204
Weatherization	251	186	195	189
Low Income Fix Up	295	256	315	164
Commercial Energy Survey	427	199	230	218

Estimated MWh and MW impacts of current residential programs are provided on Table 4-2. Estimates of future participants are simply the average of the participants for 1996 through 1998.

Table 4-2
Residential Programs – Estimated Savings

Year	Energy MWh	Summer Demand MW	Winter Demand MW
1996	3091	1240	1385
1997	5932	2392	2695
1998	8400	3283	3713
1999	11200	4377	4951
2000	14000	5472	6189
2001	16800	6566	7427
2002	19600	7660	8665
2003	22401	8755	9903
2004	25202	9850	11141
2005	27912	10944	12379

Although OUC has not implemented the direct load control program, OUC's other residential programs are projected to exceed OUC's residential goals.

4.3 Program Revisions

DSM program elements are being reassessed in light of the changing competitive environment and changing economic factors. Additional commercial and residential projects may be added in the future and some current projects deleted.

4.3.1 Direct Load Control

Residential direct load control (DLC) was included in the OUC DSM plan approved by the FPSC in 1995. However, OUC has reevaluated the economics of direct load control and determined that it is no longer economical in light of changing economic factors such as lower generation equipment costs and interest rates. The results of the revised residential DLC are provided in Appendix B and indicate that the revised rate impact test benefit-to-cost ratios for the residential direct load control programs (DLC-1A and DLC-2) have been reduced to 0.921 and 0.800, respectively, indicating that the programs are no longer economically beneficial to rate payers. Rate impact test ratios below 1.0 are not considered economical to rate payers. The rate impact test benefit-to-cost ratios for DLC-1A and DLC-2 calculated in OUC's 1995 DSM Plan (Appendix B) were 1.084 and 1.111.

If desired by the Commission, OUC can file a petition to modify its goals under 25-17.0021(2), Fla. Admin. Code, to eliminate the impact of the direct load control program from OUC's goals since it is no longer cost effective. OUC would propose, however, to wait to develop new goals when the Commission sets goals in 2000 as required by 25-17.0021(2)FAC. OUC intends to continue to provide existing conservation programs to their customers while modifying them as appropriate for market conditions.

5.0 Forecast of Facilities Requirements

5.1 Existing Capacity Resources and Requirements

5.1.1 Existing Generating Capability

OUC's existing generating capability is 1,631 MW in the summer and 1,688 MW in the winter as summarized in Table 1-1. The existing generating capability consists of OUC's joint ownership share of Stanton Energy Center and Indian River Plants operated by OUC and OUC's joint ownership share of Crystal River 3, McIntosh 3, and St. Lucie 2 operated by Florida Power Corporation, The City of Lakeland, and Florida Power and Light, respectively.

5.1.2 Power Purchases Agreements

OUC does not currently have any firm power purchase agreements. However, through its agreement with St. Cloud, OUC now manages St. Cloud's power purchases.

5.1.3 Power Sales Agreements

OUC has several power sales agreements resulting in the contracted firm interchange shown in Tables 5-1 and 5-2. OUC has a system power sales agreement with Enron. OUC has unit power sales agreements with Florida Municipal Power Agency (FMPA), Seminole Electric Cooperative (SEC), Reedy Creek Improvement District (RCID), Kissimmee Utility Authority (KUA), and Philadelphia Electric Company (PECO) from the Indian River and Stanton Plants. In addition, OUC has the partial requirements sales agreement with St. Cloud.

Most recently, OUC signed a long-term contract to be the exclusive partial requirements power supplier to the RCID. The seven-year agreement goes into effect January 1, 1999.

5.1.4 Modifications and Retirements of Generating Facilities

OUC has not scheduled any unit modifications or retirements over the ten year forecast period, but will continue to evaluate options on an ongoing basis.

5.2 Existing Transmission System

OUC's existing transmission system consists of 26 substations and 302 miles of 230 kV and 115 kV transmission lines as well as 50 miles of St. Cloud's 230 kV and 69 kV transmission lines. Table 1-3 provides additional description of OUC's 12 transmission interconnections. Sections 1.4.2 and 5.3.2 of this report discuss OUC's ongoing and planned transmission projects.

Table 5-1
Summary of Winter Capacity, Demand, and Reserve Margin

Year	Installed Capacity (MW)	Contracted Firm Interchange (Net Export) (MW)	Projected Firm Net to Grid from NUG (MW)	Total Available Capacity (MW)	Firm Peak Demand (MW)	Required Reserves OUC (MW)	RCID (MW)	St. Cloud (MW)	Total (MW)	Reserve Margin (%)
1999	1,688	551	0	1,137	937	141	9	11	160	21.3
2000	1,688	496	0	1,192	959	144	15	12	171	24.3
2001	1,688	399	0	1,289	984	148	16	13	176	31.0
2002	1,688	382	0	1,306	1,009	151	17	13	181	29.4
2003	1,688	368	0	1,320	1,033	155	17	13	185	27.8
2004	1,688	317	0	1,371	1,057	159	18	14	191	29.7
2005	1,688	232	0	1,456	1,082	162	20	14	196	34.6
2006	1,688	81	0	1,607	1,106	166	-	14	180	45.3
2007	1,688	64	0	1,628	1,132	170	-	15	185	43.5
2008	1,688	67	0	1,621	1,157	174	-	15	189	40.1

Notes:
1. Required reserve margin is 15 percent
2. OUC partial requirements sales to the City of St.Cloud and the Reedy Creek Improvement District are included under Firm Interchange Contracts

Table 5-2 Summary of Summer Capacity, Demand, and Reserve Margin										
Year	Installed Capacity (MW)	Contracted Firm Interchange (Net Export) (MW)	Projected Firm Net to Grid from NUG (MW)	Total Available Capacity (MW)	Firm Peak Demand (MW)	Required Reserves OUC (MW)	Required Reserves RCID (MW)	Required Reserves St. Cloud (MW)	Required Reserves Total (MW)	Reserve Margin (%)
1999	1,631	534	0	1,097	916	137	9	9	155	19.8
2000	1,631	460	0	1,171	942	141	15	9	165	24.3
2001	1,631	380	0	1,251	969	145	16	9	171	29.1
2002	1,631	363	0	1,268	996	149	17	10	176	27.3
2003	1,631	328	0	1,303	1,024	154	17	10	181	27.2
2004	1,631	297	0	1,334	1,050	158	18	11	187	27.0
2005	1,631	211	0	1,420	1,079	162	20	11	193	31.6
2006	1,631	60	0	1,571	1,106	166	-	11	177	42.0
2007	1,631	42	0	1,589	1,135	170	-	12	182	40.0
2008	1,631	45	0	1,586	1,161	174	-	12	186	36.6

Notes:
1. Required reserve margin is 15 percent
2. OUC partial requirements sales to the City of St.Cloud and Reedy Creek Improvement District are included under Firm Interchange Contracts

5.3 Future Resource Needs

5.3.1 Generation Capability and Requirements Forecast

Historically, OUC has used a combination of reserve margin and Expected Unserved Energy (EUE) for determining capacity reserves. For the purpose of this Ten-Year Site Plan, OUC is using a 15 percent reserve margin for capacity planning purposes to be consistent with Florida Regional Reliability Council (FRCC) requirements and Florida Administrative Code (FAC) 25-6.035. A 15 percent reserve margin is used by many utilities in Florida and the Southeast. OUC believes this to be a reasonable criterion for use in the Ten-Year Site Plant.

OUC's reserve margin calculations are based on OUC's firm load requirements as well as OUC partial requirements sales to the RCID and St. Cloud's firm load requirements less St. Cloud's partial requirements (PR) purchases from FPC and Tampa Electric Company (TECO). OUC's winter and summer reserve margin requirements are shown in Tables 5-1 and 5-2 respectively, and St. Cloud's winter and summer reserve margin requirements are shown in Tables 5-3 and 5-4 respectively.

As shown in Tables 5-1 and 5-2, OUC's actual reserve margins significantly exceed those required by a 15 percent reserve margin criteria. The smallest reserve margin for OUC occurs during the summer season of 1999 when the system reserve margin reaches approximately 20 percent.

As OUC does not violate its reserve margin criteria in any year of the forecast period, OUC is not planning to add additional generation capacity during the 1998 to 2007 time frame. However, as noted earlier, if the pending sale of the Indian River Steam Units is finalized, the generation planning process may ultimately need to be reviewed and updated depending upon the exact term and amount of the buy back agreement.

5.3.2 Transmission Capability and Requirements Forecast

OUC continuously monitors and upgrades the bulk power transmission system as necessary to provide reliable electric service to their customers. OUC has adopted the North American Electric Reliability Council (NERC) Planning Standards as the basis for its and the City of St. Cloud's electric power transmission system planning. For the purposes of planning studies, OUC utilizes certain criteria that pertain to voltage and line and transformer loading. A criterion of 95 percent and 105 percent of nominal system voltage establishes the lower and upper limits of acceptable voltage. Transmission lines are not allowed to exceed 100 percent of their continuous ratings during normal conditions or 100 percent of their emergency ratings during contingency outages. The bus tie transformer loading guideline is 100 percent of the unit's 65 °C rating.

OUC's transmission group continually reviews the need and options for increasing the capability of the transmission system based on the following planning criteria.

During the course of a planning study, the OUC and St. Cloud transmission systems are subjected to a single contingency analysis which involves outaging each 69-230 kV transmission line respectively. Bus tie transformers, tie lines with neighboring utilities and off-system facilities known to cause internal problems are included as well. If a violation of the voltage or loading criteria occurs, the first step taken is to find an operational procedure that will relieve the problem.

If the problem cannot be adequately resolved by operational procedures, a permanent solution is determined in the form of an upgrade or new construction. The revised system containing the improvement is then subjected to the same analysis as the original to insure that no voltage or loading violations remain.

Based on the above criteria as well as economic and reliability factors, OUC has developed the following schedule of upgrades to maintain reliable and economical electric service to their customers.

- A second Indian River – Cape Kennedy 230kv tie line with FPL with an in-service date of June 1999.
- A second 230kv tie line between Stanton and FPC. Expected completion date is summer, 2001.
- Upgrade the 69 kV line from KUA to the City of St. Cloud. Expected completion date is in 2002.
- Addition of the Grant to Robinson 115 kV transmission line. Expected completion date is in 2002.
- Addition of second bus tie transformer at the Southwood substation. Expected completion date is in 2006.

None of these planned transmission system projects are subject to the Transmission Line Siting Act and none of the planned projects will be associated facilities under the Power Plant Siting Act.

Table 5-3
Summary St. Cloud Winter Loads

Year	Net Sale from OUC (MW)	FMPA[1] (MW)	TECO PR (MW)	FPC PR (MW)	Diesel (MW)	St. Cloud Total Peak Load (MW)	St. Cloud Required Reserves (MW)
1999	39	15	15	0	26	89	11
2000	43	15	15	0	26	93	12
2001	46	15	15	0	26	96	12
2002	49	15	15	0	26	99	13
2003	52	15	15	0	26	102	13
2004	55	15	15	0	26	105	14
2005	58	15	15	0	26	108	14
2006	61	15	15	0	26	111	14
2007	64	15	15	0	26	114	15
2008	67	15	15	0	26	117	15

Notes:
1. The purchase from FMPA is from Stanton Unit 2.
2. Reserves are not required on PR purchases.

Table 5-4
Summary St. Cloud Summer Loads

Year	Net Sale from OUC (MW)	FMPA[1] (MW)	TECO PR (MW)	FPC PR (MW)	Diesel (MW)	St. Cloud Total Peak Load (MW)	St. Cloud Required Reserves (MW)
1999	22	15	15	0	26	72	9
2000	25	15	15	0	26	75	9
2001	27	15	15	0	26	77	9
2002	30	15	15	0	26	80	10
2003	32	15	15	0	26	82	10
2004	35	15	15	0	26	85	11
2005	37	15	15	0	26	87	11
2006	40	15	15	0	26	90	11
2007	42	15	15	0	26	92	12
2008	45	15	15	0	26	95	12

Notes:
1. The purchase from FMPA is from Stanton Unit 2.
2. Reserves are not required on PR purchases.

6.0 Production Simulation Results

OUC conducts production cost simulation analyses of the system for use in their budgeting process and to provide fuel consumption and energy production projections for Schedules 5 and 6. The process and its results are summarized in this section.

6.1 General Inflation Rate

OUC used an annual inflation rate of 3.0 percent for the basis of forecasting fuel costs, O&M costs, and various other miscellaneous costs associated with resource and system planning analyses.

6.2 Fuel Price Forecasts

This section provides price forecasts for various fuel types used in OUC's generation facilities as well as a discussion of the various supply and demand factors that can impact price and availability. These forecasts represent OUC's best estimate of future prices based on current market conditions and as a result are subject to change as further market information is compiled and assessed.

6.2.1 Forecast of Coal Availability and Price

Coal is the primary fuel used for generation at OUC accounting for approximately 68 percent of its total energy production in 1998. The following section discusses the future demand and supply of coal as well as the price projections for coal delivered to the Stanton Energy Center and McIntosh Unit 3.

Coal Demand

Coal consumption in the region and the entire U.S. is expected to increase during the ten year forecast period. Short term trends clearly indicate that coal consumption will continue to increase, however, long term forecasts are not as clear as downward pressures on consumption could occur due to the displacement of coal by other more competitive fuels as well as the enactment of more stringent environmental regulations. It is expected, that this impact of downward pressure on consumption will be partially, if not completely, offset by the future retirement of a number of U.S. nuclear plants resulting in an overall increase in coal consumption over the long term.

Electricity generation is clearly the primary market force driving coal consumption in the U.S. as it is estimated that 80 percent of the coal demand comes from the utility sector. In fact, it is forecasted by the Energy Information Administration (EIA) in the 1998 Annual Energy Outlook (AEO98) report, that coal consumption for electricity generation will increase from 896 million tons in 1996 to 1,147 million tons in 2020. This is primarily due to increased utilization of coal in existing facilities as well as the addition of new coal fired facilities. The average utilization rate for coal-fired power plants is expected to increase from 66 to 80 percent between 1996 and 2020. Furthermore, the Department of Energy also projects that by 2015, 50 percent of all electric generation will be from coal.

Coal Supply

Coal supply in the U.S. is currently increasing at a slightly higher rate than demand which will result in downward pressure on prices. It is expected that the market supply of coal will continue to outpace demand over the long term. This trend is expected to continue over the long term, however, possible consolidation of coal producers could place some upward pressure on prices.

Stanton Energy Center. A majority of the coal requirements for the Stanton Energy Center are supplied through two long term contracts with the Blue Diamond Coal Company and the TECO Coal Corporation as well as a medium term contract with James River Coal Sales Company. James River has recently acquired the Blue Diamond Coal Company. However, this transaction will have no impact on coal deliveries. Other coal supplies will be provided from the spot market.

OUC has a long-term transportation contract with CSX Rail Transportation to transport the coal from the Blue Diamond, TECO, and James River coal suppliers to the Stanton Energy Center. The transportation contract with CSX extends through 2007. Fifteen percent of the transportation costs are fixed with the balance subject to escalation.

McIntosh Unit 3. McIntosh 3 burns a combination of RDF, petroleum coke, and coal. Lakeland is currently purchasing approximately 90 percent of the coal requirements for McIntosh 3 under 1-year contracts with the remainder of coal requirements purchased on the spot market. Lakeland's current contracts are with

Shamrock (Sun Coal) and Consol Coal. The contract with Shamrock is for the current year with the possibility of extending 2 additional years. The contract with Consol Coal is a 1-year term agreement.

Coal Price Forecast

Stanton Energy Center. In 1999, the average price for coal at Stanton is forecasted to be $1.81/MBtu. As shown in Table 6-1 this price is expected to increase at 2.7 percent annually in nominal terms (includes inflation) and reach $2.30/MBtu by 2008. This is slightly higher than the national EIA forecast provided in the 1998 annual energy (AEO98) report which predicts that the cost of coal delivered to electric generators will escalate at -1.3 percent annually in real terms, or 1.2 percent annually in nominal terms assuming a 2.5 percent annual inflation rate. The national EIA forecast is heavily influenced by Western coal and does not reflect the higher cost of Eastern coal burned at Stanton or the greater transportation costs necessary to deliver coal to Florida.

Table 6-1
Delivered Fuel Price Forecast ($/MBtu) - Base Case

Year	Coal Stanton	Coal McIntosh	Natural Gas	No. 6 Fuel Oil	Uranium	Landfill Gas	Petroleum Coke	RDF
1999	1.81	1.85	2.71	2.68	0.56	0.85	1.15	-2.42
2000	1.77	1.92	2.84	2.70	0.57	0.85	1.24	-2.54
2001	1.80	1.99	2.92	2.81	0.58	0.85	1.29	-2.67
2002	1.85	2.06	3.01	2.92	0.60	0.85	1.35	-2.79
2003	1.90	2.13	3.10	3.04	0.61	0.85	1.40	-2.93
2004	1.96	2.21	3.19	3.16	0.63	0.85	1.46	-3.07
2005	2.01	2.29	3.29	3.29	0.64	0.85	1.52	-3.22
2006	2.09	2.37	3.39	3.42	0.66	0.85	1.59	-3.37
2007	2.18	2.46	3.49	3.56	0.68	0.85	1.65	-3.53
2008	2.30	2.56	3.59	3.70	0.68	0.85	1.73	-3.70
AAGR	**2.70**	**3.68**	**3.17**	**3.65**	**2.50**	**0.00**	**4.64**	**-4.83**

OUC's forecast is based on a weighted average of the expected delivery prices of Blue Diamond, TECO, and James River coal, as well as the forecasted prices from the spot market. The forecast also assumes that coal labor and material costs will escalate at an annual rate of 3.0 percent and that spot market prices will escalate at 3.0 percent annually. No increase in productivity is assumed in developing the expected delivery prices.

McIntosh Unit 3. As operator of McIntosh Unit 3, The City of Lakeland is also responsible for the unit's fuel procurement. As a result, OUC has used Lakeland's coal price forecast as the basis for the McIntosh Unit 3 projections presented in Table 6-1. As shown in Table 6-1, the 1999 forecasted price for coal delivered to McIntosh Unit 3 is projected to be $1.85/MBtu and escalate at an average annual rate of 3.7 percent to $2.56/MBtu in 2008.

Low and High Band Coal Price Forecasts

Stanton Energy Center. Low and High band coal price forecasts were also developed and are presented in Tables 6-2 and 6-3 respectively. The average annual escalation rates for the low and high forecasts are 1.4 percent and 4.8 percent, respectively. The low and high band forecasts assume that coal labor and material costs will escalate at 2.0 and 5.0 percent respectively, and that spot market coal will escalate at 2.0 and 5.0 percent respectively.

Table 6-2
Delivered Fuel Price Forecast ($/MBtu) - Low Band Case

	Coal		Natural	No. 6		Landfill	Petroleum	
Year	Stanton	McIntosh	Gas	Fuel Oil	Uranium	Gas	Coke	RDF
1999	1.80	1.80	2.22	2.04	0.55	0.85	1.12	-2.48
2000	1.75	1.82	2.42	2.25	0.55	0.85	1.18	-2.67
2001	1.75	1.84	2.47	2.32	0.56	0.85	1.20	-2.87
2002	1.79	1.86	2.52	2.40	0.56	0.85	1.22	-3.08
2003	1.82	1.88	2.57	2.47	0.57	0.85	1.24	-3.31
2004	1.85	1.90	2.63	2.55	0.58	0.85	1.26	-3.55
2005	1.88	1.92	2.68	2.63	0.58	0.85	1.28	-3.81
2006	1.91	1.94	2.74	2.72	0.59	0.85	1.30	-4.09
2007	1.95	1.96	2.80	2.81	0.59	0.85	1.32	-4.39
2008	2.04	1.99	2.86	2.89	0.60	0.85	1.35	-4.72
AAGR	**1.40**	**1.12**	**2.85**	**3.95**	**1.00**	**0.00**	**2.10**	**-7.41**

Table 6-3
Delivered Fuel Price Forecast ($/MBtu) - High Band Case

Year	Coal Stanton	Coal McIntosh	Natural Gas	No. 6 Fuel Oil	Uranium	Landfill Gas	Petroleum Coke	RDF
1999	1.83	1.90	2.98	3.10	0.56	0.85	1.17	-2.36
2000	1.81	2.01	3.02	3.00	0.59	0.85	1.30	-2.42
2001	1.87	2.14	3.19	3.17	0.61	0.85	1.39	-2.48
2002	1.96	2.27	3.37	3.36	0.63	0.85	1.48	-2.53
2003	2.05	2.41	3.56	3.55	0.66	0.85	1.58	-2.59
2004	2.15	2.56	3.76	3.75	0.69	0.85	1.69	-2.64
2005	2.24	2.72	3.97	3.97	0.71	0.85	1.80	-2.70
2006	2.42	2.89	4.19	4.20	0.74	0.85	1.93	-2.76
2007	2.59	3.06	4.42	4.44	0.77	0.85	2.05	-2.83
2008	2.78	3.27	4.67	4.69	0.80	0.85	2.21	-2.89
AAGR	**4.76**	**6.22**	**5.12**	**4.71**	**4.00**	**0.00**	**7.32**	**-2.28**

McIntosh Unit 3. Tables 6-2 and 6-3 provide the low and high band price forecasts for McIntosh Unit 3. The low and high band forecasts are projected to escalated at average annual rates of 1.1 and 6.2 percent respectively.

6.2.2 Forecast of Natural Gas Availability and Price

Second to coal, natural gas is also responsible for a significant portion of OUC's energy production making up approximately 13 percent of its total generation in 1998. The following section discusses the future demand and supply of natural gas as well as the price projections for gas delivered to the Indian River Plant.

Natural Gas Demand

As discussed in the AEO98 report, the demand for natural gas is predicted to increase significantly on a national level over the forecast period with demand in the electricity generation sector increasing from 3.0 trillion cubic feet in 1996 to 9.9 trillion cubic feet in 2020. This demand is primarily due to the expected impacts of the restructured electricity industry which is expected to provide new opportunities for gas fired generation.

Natural Gas Supply

The lack of natural gas as a commodity is not expected to impact supply, as the level of natural gas production and storage are expected to increase in-line with demand over the forecast period. Transportation is expected to be the limiting factor determining availability.

As a result of the significant increase in consumption, it is expected that near term demand for natural gas will be greater than available transportation capacity on a national level. Consequently, it is forecasted that additional interstate transportation capacity on a national level will be brought on-line at a rate of 1.5 percent annually through the forecast period.

Florida currently has adequate transportation capacity and with the planned Phase IV upgrade to the Florida Gas Transmission (FGT) pipeline, it is expected that Florida will maintain adequate transportation capacity over the study period. FGT filed for Federal Energy Regulatory Commission (FERC) approvals of the Phase IV expansion program December 2, 1998. The filing consists of expanding services to southwest Florida with 205 miles of underground pipelines. Additionally, FGT proposes to add 48,570 hp of compression to its system. The proposed additions will add 272,000 MBtu per day of incremental firm transportation service to peninsular Florida. The estimated cost of the expansion is $350 million. FGT anticipates construction of this project will begin in March of 2000, and is scheduled for completion and placed in service by May 2001. The Phase IV expansion of the FGT system should therefore be capable of implementation at a relatively low incremental cost impact to existing and prospective customers. Phase V expansion discussions are currently under way.

OUC's Indian River Plant is supplied through two firm gas transportation contracts.

The two gas transportation contracts, FTS1 and FTS2, are with FGT and expire in 2004 and 2015 respectively. FGT requires FERC approval prior to raising rates and is also required to submit a rate case at least once every three years. The transportation capacity schedules for each contract are provided below.

Contract	October	November - April	May - September
FTS1	12,500 MBtu/D	3,193 MBtu/D	7,423 MBtu/D

Contract	October - April	May	June-September
FTS2	12,000 MBtu/D	22,200 MBtu/D	25,000 MBtu/D

Natural Gas Price Forecast

Due to the affects of supply and demand, natural gas prices are expected to remain relatively stable during the ten year forecast period. This is primarily due to lower interest rates which reduce the construction costs of new pipeline transmission and distribution facilities as well as increased competition within the gas industry. The Phase IV addition to the FGT system is also expected to lower the FTS2 transportation contract rate. The FTS2 contract price would essentially be based on an average of the Phase III and Phase IV capacity charges.

In 1999, the average forecasted price for delivered natural gas at Indian River is expected to be $2.71/MBtu. As shown in Table 6-1 this price is expected to increase at 3.2 percent annually in nominal terms to $3.59/MBtu in 2008.

The commodity cost component was assumed to escalate at 3.0 percent annually which is the same as the AEO98 forecast which predicts that wellhead natural gas prices will escalate at 0.5 percent annually in real terms. The transportation cost component of the delivery price is assumed to escalate at 4.0 percent over every three year period based on the FERC requirement that FGT submit a rate case at least once every three years. A FGT compression fuel charge of 3.0 percent is included in the total transportation charge.

Low and High Band Natural Gas Price Forecasts

Low and High band natural gas price forecasts were also developed and are presented in Tables 6-2 and 6-3 respectively. The average annual delivered price escalation rates for the low and high forecasts are 2.9 percent and 5.1 percent, respectively. The low and high band forecasts assumes annual commodity escalation rates of 2.0 percent and 6.0 percent respectively.

6.2.3 Forecast of Residual Oil Availability and Price

The steam generation units located at the Indian River Plant are designed to burn either natural gas or residual oil (No. 6 fuel oil). OUC normally uses natural gas so as to minimize the use of No. 6 oil. During 1998, generation from residual oil accounted for only 12.6 percent of OUC's energy production.

The future price of residual fuel oil is primarily driven by international influences making it difficult to forecast. Nevertheless, OUC has developed a baseline forecast based on the following assumptions.

- West Texas Intermediate (WTI) Oil is used as a basis for determining the price of gulf coast residual oil.
- The forecasted price for 1999 WTI is $17.01/bbl and escalates at 4.0 percent annually
- Total heating value per barrel of residual oil is 6.3 MBtu
- Transportation costs are based on shipping the oil to Port Canaveral and then subsequently transporting it from Port Canaveral to the Indian River Plant
- Transportation costs are escalated at 4.0 percent annually

As shown in Table 6-1, the price of residual oil is expected to increase from $2.68/MBtu in 1999 to $3.70/MBtu by 2008 which is equivalent to an average annual growth rate of 3.7 percent.

Low and High band forecasts were developed based on the following changes from the base forecast.

- Low Band - The forecasted price for 1999 WTI is $12.28/bbl and escalates at 3.0 percent annually
- High Band - The forecasted price for 1998 WTI is $20.17/bbl and escalates at 5.0 percent annually

As shown in Tables 6-2 and 6-3 the average annual escalation rates for the Low and High band forecasts, based on these assumptions, are 4.0 percent and 4.7 percent, respectively.

6.2.4 Forecast of Nuclear Fuel Price

The fuel forecast for nuclear fuel was developed based on a weighted average (weighted by energy production) of the 1996 prices at the Crystal River and St. Lucie

Plants as listed in the Research Data Institute's (RDI) POWERdat database of fuel prices. As shown in Table 6-1, the forecast assumes a 1999 nuclear fuel price of \$0.56/MBtu with an average annual increase of 2.5 percent.

The Low and high band price forecasts shown in Tables 6-2 and 6-3 are based on annual escalation rates of 1.0 and 4.0 percent respectively.

6.2.5 Forecast of Petroleum Coke Availability and Price

Petroleum coke is blended with coal and burned in the McIntosh Unit 3 plant. The petroleum coke price forecast is based upon current contracts and anticipated growth of this fuel's usage for Florida. While the domestic market is a price taker instead of a price setter, it is envisioned that usage of this fuel will increase in the future.

As operator of McIntosh Unit 3, The City of Lakeland is also responsible for the unit's fuel procurement. As a result, OUC has used Lakeland's petroleum coke price forecast as the basis for the McIntosh Unit 3 projections presented in Table 6-1. As shown in Table 6-1, the 1999 forecasted price for petroleum coke delivered to McIntosh Unit 3 is projected to be \$1.15/MBtu and escalate at an average annual rate of 4.6 percent to \$1.73/MBtu in 2008.

Tables 6-2 and 6-3 provide low and high band price projections for petroleum coke at McIntosh Unit 3. As shown in the tables, the low and high band average annual escalation rates are 2.1 and 7.3 percent respectively.

6.2.6 Forecast of Refuse Derived Fuel Availability and Price

Refuse Derived Fuel (RDF) is also burned at the McIntosh Plant. The plant receives tipping fees from local private enterprises and the City of Lakeland's Public Works Department to burn the fuel. As a result, the fuel is considered a credit. The projections for the base, low, and high band credits over the forecast period are provided in Tables 6-1, 6-2, and 6-3 respectively.

6.2.7 Forecast of Landfill Gas Availability and Price

OUC has signed a long term fixed rate contract with DTE Biomass Energy to purchase landfill gas (Methane) from the Orange County Landfill. The methane gas will primarily be burned in Stanton Unit 1 (Stanton Unit 2 is also capable of burning the landfill gas) which is located adjacent to the landfill. The projected base, low, and high band prices for landfill gas are provided in Tables 6-1, 6-2, and 6-3 respectively.

6.3 Production Costing Methodology

The utility planning and scheduling program from the P Plus Corporation (PPC) was used to complete the system production costing and unit performance simulation. The PPC program uses chronological production costing method to complete the long term (1 week to 30 years) system production simulation. The PPC production simulation program output results include optimal unit startup and shutdown times, cost impact of unit outages or derations, system production costs, expected unserved energy, hourly marginal cost, generation cost by unit, generation cost by fuel type, and emissions data as well as many others. A detailed description of the PPC program is provided in
Appendix C.

6.4 Fuel Usage Forecast

Using the projected demand and fuel price projections, forecasts of annual fuel usage and energy production by fuel type were developed using the PPC production costing program. The results of the energy production by fuel type forecasts are shown in Tables 6-4 and 6-5. Table 6-4 provides the energy production by fuel type on a total energy basis and Table 6-5 provides the energy production by fuel type on a percentage of total energy basis. As shown from the tables, coal continues to be the primary fuel for generation over the forecast period followed by natural gas which actually has a decreasing contribution over the forecast period as OUC's power sales contracts expire. The remaining fuel sources account for approximately 12 percent of the total production in 1998 and continue to provide roughly the same percentage contribution over the forecast period.

Fuel usage projections are provided in Schedule 5 of Section 8.

Since no generation facilities are planned from 1998 through 2007, it is expected that current fuel usage differential projections will not change significantly.

Table 6-4
Forecasted Energy Production by Fuel Type - GWh

Year	Coal	Natural Gas	No. 6 Fuel Oil	Uranium	Landfill Gas	RDF	Total Energy
1999	4,448	745	225	447	10	9	5,884
2000	4,602	778	125	480	10	9	6,004
2001	4,596	797	96	453	10	9	5,961
2002	4,629	839	173	434	10	10	6,095
2003	4,575	931	259	455	10	10	6,240
2004	4,716	974	185	455	10	10	6,350
2005	4,716	976	373	415	10	10	6,500
2006	4,429	946	364	401	10	10	6,160
2007	4,330	1,245	137	403	10	11	6,136
2008	4,891	872	42	489	10	11	6,315

Table 6-5
Forecasted Energy Production by Fuel Type - %

Year	Coal	Natural Gas	No. 6 Fuel Oil	Uranium	Landfill Gas	RDF	Total Energy
1999	75.6	12.7	3.8	7.6	0.2	0.2	100
2000	76.6	13.0	2.1	8.0	0.2	0.1	100
2001	77.1	13.4	1.6	7.6	0.2	0.2	100
2002	75.9	13.8	2.8	7.1	0.2	0.2	100
2003	73.3	14.9	4.2	7.3	0.2	0.2	100
2004	74.3	15.3	2.9	7.2	0.2	0.2	100
2005	72.6	15.0	5.7	6.4	0.2	0.2	100
2006	71.9	15.4	5.9	6.5	0.2	0.2	100
2007	70.6	20.3	2.2	6.6	0.2	0.2	100
2008	77.5	13.8	0.7	7.7	0.2	0.2	100

7.0 Environmental and Land Use Information

No new power generation or associated facilities are planned for the 1999 - 2008 time frame.

8.0 Ten Year Site Plan Schedules

This section contains the following schedules required for the Ten Year Site Plan.

- Schedule 1 - Existing Generation Facilities
- Schedule 2.1 - History and Forecast of Energy Consumption and Number of Customers by Customer Class
- Schedule 2.2 - History and Forecast of Energy Consumption and Number of Customers by Customer Class
- Schedule 2.3 - History and Forecast of Energy Consumption and Number of Customers by Customer Class
- Schedule 3.1 - History and Forecast of Summer Peak Demand
- Schedule 3.2 - History and Forecast of Winter Peak Demand
- Schedule 3.3 - History and Forecast of Annual Net Energy for Load
- Schedule 4 - Previous Year and 2 - Year Forecast of Retail Peak Demand and Net Energy for Load by Month
- Schedule 5 - Fuel Requirements
- Schedule 6.1 - Energy Sources
- Schedule 6.2 - Energy Sources
- Schedule 7.1 - Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak
- Schedule 7.2 - Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak
- Schedule 8 - Planned and Prospective Generating and Facility Additions and Changes
- Schedule 9 - Status Report and Specifications of Proposed Generating Facilities
- Schedule 10 - Status Report and Specifications of Proposed Directly Associated Transmission Lines

Schedule 1
Existing Generating Facilities
As of December 31, 1998

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)		(11)	(12)	(13)	(14)
				Fuel		Fuel Transport		Alt. Fuel Days	Commercial In Service		Expected Retirement	Gen. Max Nameplate	Net Capability	
Plant Name	Unit No.	Location	Unit Type	Pri	Alt	Pri	Alt	Use	Month/Year		Month/Year	kW	Summer MW	Winter MW
Indian River	1	Brevard	ST	NG	F06	PL	WA		2	60	Unknown	86,700	88	90
Indian River	2	Brevard	ST	NG	F06	PL	WA		12	64	Unknown	207,600	201	205
Indian River	3	Brevard	ST	NG	F06	PL	WA		2	74	Unknown	344,500	319	324
Indian River	A	Brevard	GT	NG	F02	PL	TK		6	89	Unknown	37,500	18	23
Indian River	B	Brevard	GT	NG	F02	PL	TK		7	89	Unknown	37,500	18	23
Indian River	C	Brevard	GT	NG	F02	PL	TK		8	92	Unknown	112,040	85	100
Indian River	D	Brevard	GT	NG	F02	PL	TK		10	92	Unknown	112,040	85	100
Stanton Energy Center	1	Orange	ST	BIT	-	RR	-		7	87	Unknown	464,580	302	304
Stanton Energy Center	2	Orange	ST	BIT	-	RR	-		6	96	Unknown	464,580	318	318
McIntosh Unit	3	Polk	ST	BIT	NG	RR	PL		9	82	Unknown	363,870	133	136
Crystal River Unit	3	Citrus	NP	UR	-	TK	-		3	77	Unknown	890,460	13	13
St. Lucie Unit	2	St. Lucie	NP	UR	-	TK	-		8	83	Unknown	850,000	51	52

Schedule 2.1
History and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		Rural and Residential				General Service Non-Demand		(See Note 1)
Year	Population	Members per Household	GWH	Average No. of Customers	Average kWh Consumption Per Customer	GWH	Average No. of Customers	Average kWh Consumption Per Customer
1989	253,900	2.59	1,187	97,923	12,122	322	12,950	24,865
1990	257,450	2.55	1,239	101,097	12,256	307	13,446	22,832
1991	262,590	2.57	1,201	102,134	11,759	320	13,758	23,259
1992	267,500	2.58	1,216	103,495	11,749	308	13,891	22,173
1993	271,500	2.58	1,256	104,978	11,964	310	14,091	22,000
1994	275,300	2.58	1,286	106,462	12,079	316	14,318	22,070
1995	278,500	2.56	1,380	108,805	12,683	316	14,590	21,659
1996	284,000	2.56	1,419	110,949	12,790	318	14,858	21,403
1997	290,600	2.55	1,377	113,977	12,081	322	14,994	21,475
1998	300,400	2.55	1,583	117,814	13,436	311	15,170	20,501
1999	301,100	2.54	1,445	118,559	12,188	328	15,412	21,282
2000	305,900	2.54	1,467	120,661	12,158	333	15,656	21,270
2001	310,700	2.53	1,484	122,793	12,085	338	15,896	21,263
2002	315,500	2.52	1,507	124,953	12,061	343	16,135	21,258
2003	321,000	2.52	1,530	127,140	12,034	349	16,369	21,321
2004	327,100	2.52	1,558	129,830	12,000	354	16,599	21,327
2005	331,800	2.52	1,576	131,648	11,971	359	16,829	21,332
2006	336,800	2.52	1,597	133,898	11,927	365	17,059	21,396
2007	342,400	2.51	1,618	136,148	11,884	370	17,289	21,401
2008	348,400	2.51	1,645	138,815	11,850	375	17,419	21,528

Notes:

1. OUC does not have commercial and industrial rate classes. As a result, commercial and industrial loads are combined together to form General Service Non-Demand and General Service Demand rate classes. The General Service Non-Demand requirements are shown on Schedule 2.1 and the General Service Demand requirements are shown on Schedule 2.2.

Schedule 2.2
History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	General Service Demand *(See Note 1)*						
Year	GWH	Average No. of Customers	Average KWH Consumption Per Customer	Railroads and Railways GWH	Street & Highway Lighting GWH	Other Sales to Public Authorities GWH	Total Sales to Ultimate Consumers GWH
1989	1,789	2,369	755,171	0	21	4	3,323
1990	1,899	2,451	774,786	0	21	4	3,470
1991	1,981	2,461	804,957	0	22	4	3,528
1992	2,004	2,542	788,356	0	23	4	3,555
1993	2,024	2,646	764,928	0	23	4	3,617
1994	2,131	2,749	775,191	0	22	5	3,760
1995	2,207	2,946	749,151	0	22	5	3,930
1996	2,259	3,116	724,968	0	23	5	4,024
1997	2,331	3,452	675,261	0	23	5	4,058
1998	2,497	3,806	656,069	0	22	5	4,418
1999	2,568	3,823	671,724	0	24	5	4,370
2000	2,693	3,926	685,940	0	24	5	4,522
2001	2,801	4,033	694,520	0	24	5	4,652
2002	2,919	4,142	704,732	0	24	5	4,798
2003	3,041	4,250	715,529	0	25	5	4,950
2004	3,169	4,358	727,168	0	25	5	5,111
2005	3,289	4,465	736,618	0	25	5	5,254
2006	3,413	4,571	746,664	0	25	5	5,405
2007	3,538	4,675	756,791	0	26	5	5,557
2008	3,661	4,779	766,060	0	26	5	5,712

Notes: 1. OUC does not have commercial and industrial rate classes. As a result, commercial and industrial loads are combined together to form General Service Non-Demand and General Service Demand rate classes. The General Service Non-Demand requirements are shown on Schedule 2.1 and the General Service Demand requirements are shown on Schedule 2.2.

Schedule 2.3
History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1) Year	(2) Sales for Resale GWH	(3) Utility Use & Losses GWH	(4) Net Energy for Load GWH	(5) Other Customers (Average No.)	(6) Total No. of Customers
1989	0	185	3,508	0	113,242
1990	0	124	3,594	0	116,994
1991	0	129	3,657	0	118,353
1992	0	118	3,673	0	119,928
1993	0	166	3,783	0	121,715
1994	0	137	3,897	0	123,529
1995	0	171	4,101	0	126,341
1996	0	162	4,186	0	128,923
1997	0	213	4,271	0	132,423
1998	0	160	4,578	0	136,790
1999	0	186	4,556	0	137,794
2000	0	192	4,714	0	140,243
2001	0	198	4,850	0	142,722
2002	0	204	5,002	0	145,230
2003	0	210	5,160	0	147,759
2004	0	217	5,328	0	150,787
2005	0	223	5,477	0	152,942
2006	0	229	5,634	0	155,528
2007	0	235	5,792	0	158,112
2008	0	242	5,954	0	161,013

Schedule 3.1
History and Forecast of Summer Peak Demand - MW
Base Case

(1) Year	(2) Total	(3) Wholesale [2]	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential [1] Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. [1] Conservation	(10) Net Firm Demand
1989	681	0	681	0	0	-	0	-	681
1990	708	0	708	0	0	-	0	-	708
1991	714	0	714	0	0	-	0	-	714
1992	763	0	763	0	0	-	0	-	763
1993	760	0	760	0	0	-	0	-	760
1994	749	0	749	0	0	-	0	-	749
1995	799	0	799	0	0	-	0	-	798
1996	788	0	788	0	0	-	0	-	788
1997	882	0	882	0	0	-	0	36	846
1998	944	0	944	1	0	-	0	37	907
1999	955	0	955	1	0	-	0	38	916
2000	982	0	982	1	0	-	0	39	942
2001	1,010	0	1,010	1	0	-	0	40	969
2002	1,038	0	1,038	1	0	-	0	41	996
2003	1,067	0	1,067	1	0	-	0	42	1,024
2004	1,094	0	1,094	1	0	-	0	43	1,050
2005	1,124	0	1,124	1	0	-	0	44	1,079
2006	1,152	0	1,152	1	0	-	0	45	1,106
2007	1,182	0	1,182	1	0	-	0	46	1,135
2008	1,209	0	1,209	1	0	-	0	47	1,161

Notes:
1. OUC does not breakout residential and commercial/industrial conservation. Data in column 9 represents total system conservation. Prior to 1997, conservation was factored into total demand (column 2).

Schedule 3.2
History and Forecast of Winter Peak Demand - MW
Base Case

(1) Year	(2) Total	(3) Wholesale [2]	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential [1] Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. [1] Conservation	(10) Net Firm Demand
1989/90	774	0	774	0	0	-	0	-	774
1990/91	636	0	636	0	0	-	0	-	636
1991/92	673	0	673	0	0	-	0	-	673
1992/93	721	0	721	0	0	-	0	-	721
1993/94	674	0	674	0	0	-	0	-	674
1994/95	800	0	800	0	0	-	0	-	800
1995/96	885	0	885	0	0	-	0	-	885
1996/97	775	0	775	0	0	-	0	-	775
1997/98	768	0	768	1	0	-	0	22	746
1998/99	962	0	962	1	0	-	0	24	937
1999/00	985	0	985	1	0	-	0	25	959
2000/01	1,011	0	1,011	1	0	-	0	26	984
2001/02	1,037	0	1,037	1	0	-	0	27	1,009
2002/03	1,062	0	1,062	1	0	-	0	28	1,033
2003/04	1,087	0	1,087	1	0	-	0	29	1,057
2004/05	1,113	0	1,113	1	0	-	0	30	1,082
2005/06	1,138	0	1,138	1	0	-	0	31	1,106
2006/07	1,165	0	1,165	1	0	-	0	32	1,132
2007/08	1,191	0	1,191	1	0	-		33	1,157
2008/09	1,218	0	1,218	1	0	-	0	34	1,183

Notes:
1. OUC does not breakout residential and commercial/industrial conservation. Data in column 9 represents total system conservation. Prior to 1997/98, conservation was factored into total demand (column 2).

Schedule 3.3
History and Forecast of Annual Net Energy for Load - GWH
Base Case

(1) Year	(2) Total	(3) Residential [1] Conservation	(4) Comm/Ind. [1] Conservation	(5) Retail	(6) Wholesale [2]	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor %
1989	3,508	-	-	3,323	-	185	3,508	58.8
1990	3,594	-	-	3,470	-	124	3,594	57.9
1991	3,657	-	-	3,528	-	129	3,657	58.5
1992	3,673	-	-	3,555	-	118	3,673	55.0
1993	3,783	-	-	3,617	-	166	3,783	56.8
1994	3,897	-	-	3,760	-	137	3,897	59.4
1995	4,101	-	-	3,930	-	171	4,101	58.7
1996	4,186	-	-	4,024	-	162	4,186	60.6
1997	4,360	-	89	4,058	-	213	4,271	57.6
1998	4,669	-	91	4,418	-	160	4,578	57.6
1999	4,649	-	93	4,370	-	186	4,556	56.8
2000	4,809	-	95	4,522	-	192	4,714	57.1
2001	4,947	-	97	4,652	-	198	4,850	57.1
2002	5,101	-	99	4,798	-	204	5,002	57.3
2003	5,261	-	101	4,950	-	210	5,160	57.5
2004	5,431	-	103	5,111	-	217	5,328	57.9
2005	5,581	-	104	5,254	-	223	5,477	57.9
2006	5,740	-	106	5,405	-	229	5,634	58.2
2007	5,900	-	108	5,557	-	235	5,792	58.3
2008	6,064	-	110	5,712	-	242	5,954	58.5

Notes:
1. OUC does not breakout residential and commercial/industrial conservation. Data in column 4 represents total system conservation. Prior to 1997, conservation was factored into total energy (column 2).

Schedule 4
Previous Year and 2 - Year Forecast of Retail
Peak Demand and Net Energy for Load by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Actual - 1998		1999		2000	
Month	Peak Demand MW	NEL GWH	Peak Demand MW	NEL GWH	Peak Demand MW	NEL GWH
January	588	321	937	380	959	393
February	672	296	777	336	907	360
March	676	326	766	357	789	369
April	721	335	807	356	833	365
May	788	400	809	374	821	392
June	900	473	914	395	940	407
July	907	471	905	428	939	438
August	870	462	916	422	942	437
September	845	412	844	402	870	416
October	780	401	826	389	868	399
November	673	340	748	343	771	356
December	618	341	822	374	844	382
Total		4,578		4,556		4,714

Schedule 5
Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel Requirements		Units	Actual 1998	1,999	2,000	2,001	2,002	2,003	2,004	2,005	2,006	2,007	2,008
(1)	Nuclear		Trillion BTU	5	5	5	5	5	5	5	5	4	4	5
(2)	Coal		1000 Ton	1,955	1,750	1,813	1,808	1,820	1,794	1,847	1,847	1,734	1,694	1,939
(3)	Residual	Total	1000 BBL	1,425	380	204	156	278	416	603	568	576	216	66
(4)		Steam	1000 BBL	1,425	380	204	156	278	416	603	568	576	216	66
(5)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(7)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	Total	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(9)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(11)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(12)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	9,445	8,638	9,268	9,282	9,683	10,530	10,837	10,742	10,389	13,399	9,312
(14)		Steam	1000 MCF	7,422	7,853	8,601	9,058	9,278	9,658	10,234	10,174	9,929	12,665	9,108
(15)		CC	1000 MCF	0	0	0	0	0	0	0	0	0	0	0
(16)		CT	1000 MCF	2,023	785	667	224	405	872	603	568	460	734	204
(17)	Refuse	Steam	BTUx106	93,177	93,177	93,177	93,177	103,530	103,530	103,530	103,530	103,530	113,883	113,883

Schedule 6.1
Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources		Units	Actual 1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
(1)	Annual Firm Interchange		GWH	-1,563	-1,328	-1,290	-1,111	-1,093	-1,080	-1,022	-1,023	-526	-344	-361
(2)	Nuclear		GWH	362	447	480	453	434	455	455	415	401	403	489
(3)	Residual	Total	GWH	774	225	125	96	173	259	185	373	364	137	42
(4)		Steam	GWH	774	225	125	96	173	259	185	373	364	137	42
(5)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0
(7)		Diesel	GWH	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	Total	GWH	0	0	0	0	0	0	0	0	0	0	0
(9)		Steam	GWH											
(10)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0
(11)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0
(12)		Diesel	GWH	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	GWH	805	755	788	807	849	941	984	986	956	1,255	882
(14)		Steam	GWH	798	705	742	789	817	870	933	938	917	1,192	863
(15)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0
(16)		CT	GWH	7	50	46	18	32	71	51	48	39	63	19
(17)	Coal	Steam	GWH	4,191	4,448	4,602	4,596	4,629	4,575	4,716	4,716	4,429	4,330	4,891
(18)	Refuse	Steam	GWH	9	9	9	9	10	10	10	10	10	11	11
(19)	Net Energy for Load		GWH	4,578	4,556	4,714	4,850	5,002	5,160	5,328	5,477	5,634	5,792	5,954

Schedule 6.2
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources		Units	Actual 1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
(1)	Annual Firm Interchange		%	-34.1	-29.1	-27.4	-22.9	-21.9	-20.9	-19.2	-18.7	-9.3	-5.9	-6.1
(2)	Nuclear		%	7.9	9.8	10.2	9.3	8.7	8.8	8.5	7.6	7.1	7.0	8.2
(3)	Residual	Total	%	16.9	4.9	2.7	2.0	3.5	5.0	3.5	6.8	6.5	2.4	0.7
(4)		Steam	%	16.9	4.9	2.7	2.0	3.5	5.0	3.5	6.8	6.5	2.4	0.7
(5)		CC	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(6)		CT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7)		Diesel	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)	Distillate	Total	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)		Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)		CC	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(11)		CT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(12)		Diesel	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(13)	Natural Gas	Total	%	17.6	16.6	16.7	16.6	17.0	18.2	18.5	18.0	17.0	21.7	14.8
(14)		Steam	%	17.4	15.5	15.7	16.3	16.3	16.9	17.5	17.1	16.3	20.6	14.5
(15)		CC	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(16)		CT	%	0.2	1.1	1.0	0.4	0.6	1.4	1.0	0.9	0.7	1.1	0.3
(17)	Coal	Steam	%	91.5	97.6	97.6	94.8	92.5	88.7	88.5	86.1	78.6	74.8	82.1
(18)	Refuse	Steam	%	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
(19)	Net Energy for Load		%	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
		Firm	Firm								
	Total	Capacity	Capacity		Total	System Firm	Reserve Margin before Maintenance		Scheduled	Reserve Margin after Maintenance	
	Installed	Import	Export	QF	Capacity	Summer Peak			Maintenance		
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
1999	1631	0	404	0	1,227	916	311	34.0	0	311	34.0
2000	1631	0	330	0	1,301	942	359	38.1	0	359	38.1
2001	1631	0	250	0	1,381	969	412	42.5	0	412	42.5
2002	1631	0	363	0	1,268	996	272	27.3	0	272	27.3
2003	1631	0	328	0	1,303	1,024	279	27.2	0	279	27.2
2004	1631	0	297	0	1,334	1,050	284	27.0	0	284	27.0
2005	1631	0	211	0	1,420	1,079	341	31.6	0	341	31.6
2006	1631	0	60	0	1,571	1,106	465	42.0	0	465	42.0
2007	1631	0	42	0	1,589	1,135	454	40.0	0	454	40.0
2008	1631	0	45	0	1,586	1,161	425	36.6	0	425	36.6

Schedule 7.2
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Winter Peak Demand	Reserve Margin before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
1999	1,688	0	421	0	1,267	937	330	35.2	0	330	35.2
2000	1,688	0	366	0	1,322	959	363	37.9	0	363	37.9
2001	1,688	0	269	0	1,419	984	435	44.2	0	435	44.2
2002	1,688	0	382	0	1,306	1,009	297	29.4	0	297	29.4
2003	1,688	0	368	0	1,320	1,033	287	27.8	0	287	27.8
2004	1,688	0	317	0	1,371	1,057	314	29.7	0	314	29.7
2005	1,688	0	232	0	1,456	1,082	374	34.6	0	374	34.6
2006	1,688	0	81	0	1,607	1,106	501	45.3	0	501	45.3
2007	1,688	0	64	0	1,624	1,132	492	43.5	0	492	43.5
2008	1,688	0	67	0	1,621	1,157	464	40.1	0	464	40.1

Schedule 8
Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const Start	Commercial In-Service	Expected Retirement	Gen Max Nameplate	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Mo/Yr	Mo/Yr	Mo/Yr	kW	Sum MW	Win MW	Status

No new generation facilities are planned for the 1999 through 2008 time period

Schedule 9 Status Report and Specifications of Proposed Generating Facilities		
(1)	Plant Name and Unit Number:	**No new generation facilities are planned during the 1999 through 2008 time period**
(2)	Capacity a. Summer: b. Winter:	
(3)	Technology Type:	
(4)	Anticipated Construction Timing a. Field construction start-date: b. Commercial in-service date:	
(5)	Fuel a. Primary fuel: b. Alternate fuel:	
(6)	Air Pollution Control Strategy:	
(7)	Cooling Method:	
(8)	Total Site Area:	
(9)	Construction Status:	
(10)	Certification Status:	
(11)	Status with Federal Agencies:	
(12)	Projected Unit Performance Data: Planned Outage Factor (POF): Forced Outage Factor (FOF): Equivalent Availability Factor (EAF): Resulting Capacity Factor (%): Average Net Operating Heat Rate (ANOHR):	
(13)	Projected Unit Financial Data Book Life (Years): Total Installed Cost (In-Service Year $/kW): Direct Construction Cost ($/kW): AFUDC Amount ($/kW): Escalation ($/kW): Fixed O&M ($/kW-Yr): Variable O&M ($/MWh): K Factor:	

Schedule 10 Status Report and Specifications of Proposed Directly Associated Transmission Lines		
(1)	Point of Origin and Termination:	**No new generation facilities or associated transmission lines are planned during the 1999 through 2008 time period**
(2)	Number of Lines:	
(3)	Right-of-Way	
(4)	Line Length:	
(5)	Voltage:	
(6)	Anticipated Construction Timing:	
(7)	Anticipated Capital Investment:	
(8)	Substations:	
(9)	Participation with Other Utilities:	

Appendix A

SHAPES Integrated Customer Demand Forecasting System

SHAPES II™

Integrated Customer Demand Forecasting System
Technical Description

NewEnergy Associates, L.L.C.

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TABLE OF CONTENTS

Introduction To SHAPES II

Over twenty-five investor-owned and public power utilities in the United States. Canada and Europe. as well as regulatory commissions in several states. now use SHAPES II to forecast energy and demand. SHAPES II is an end-use load shape forecasting system originally developed by Battelle Memorial Institute and acquired by Energy Management Associates in 1991. In 1992 Energy Management Associates merged with EDS and formed the Utilities SBU of EDS.

SHAPES II enables a user to select from an array of forecast models and to specify a level of detail within each model commensurate with available data. Thus SHAPES II makes it possible to strike a reasonable balance between the need for forecast detail and the cost of implementing a service area specific database.

The flexibility afforded by SHAPES II. coupled with its ability to forecast chronological hourly demand at the end-use. sector. and system levels. makes it a powerful tool for use by forecasters. system planners and marketing analysts.

SHAPES II's capabilities extend beyond the traditional requirements of an energy and peak demand forecast to include:

- Chronological hourly demand forecasts (8760 values per year) by end-use. class. and system.
- Consistent energy and demand forecasts for improved inputs to utility planning and forecasting systems: forecasts can be passed directly to PROMOD IV. PROSCREEN II. PROVIEW. and MAINPLAN. or in EEI format to other models.
- Explicit modeling of weather impacts. and ability to generate weather-normal. as well as extreme weather. energy and demand forecasts.
- Ability to reflect the impact on energy and demand of trends in appliance efficiency. the introduction of new end-uses. the changing mix of new end-uses over time. and the growth of one class relative to another. Through the appliance stock model. all the detail about vintaging and retirement / replacement of old stock can be tracked.

Forecast Models

SHAPES II is an integrated forecasting system which includes seven models under a common user interface:

1) System Level Model

   This model is used to define and account for the major components of the user's system. System level components can include any of the sector models listed below as well as unique components specified by the user: a large industrial customer. co-ops or municipal customers. street lighting. etc.

2) Residential Sector Model

   A bottom up methodology capable of producing a customer and appliance stock forecast as well as chronological demand forecasts for each appliance.

3) Commercial Sector SIC Model

   This model forecasts energy and demand by employment category and three end-uses: baseload, heating, and cooling.

4) Commercial Sector Building Type Model

   This model is driven by floor space projections, and forecasts energy and demand by building type and end-use. It is more data intensive than the Commercial SIC Model but is not limited to three end-uses.

5) Industrial Sector Model

   This model can forecast energy and demand at the 2-, 3- and 4-digit SIC level.

6) Miscellaneous Sector Model

   This model provides an additional methodology for accounting for sales for resale, street lighting, and other miscellaneous end-uses.

Consistent Energy and Demand Forecasts

SHAPES II provides an integrated framework for forecasting energy and hourly demand by end-use for each of the major customer classes of a utility. The level of detail associated with each type of forecast is as follows:

Forecast	Level of Detail
Annual Energy	End-Use, Sector, System
Monthly Energy	End-Use, Sector, System
Chronological Hourly Demand	End-Use, Sector, System

Hourly demand is forecasted for each hour, day, month, and year (8760 demand values per year, 365 load shapes). A typical meteorological year (8760 hourly temperatures) is used to determine demand for temperature sensitive end-uses.

SHAPES II forecasts energy by summing hourly demand. This approach ensures that the factors causing a change in demand are the same as those causing a change in energy requirements. By using different procedures to estimate energy and demand, traditional forecasting methodologies make it difficult to ensure consistent changes in energy and demand. Errors caused by inconsistent estimates can easily overwhelm the initial changes in load typically associated with demand-side management strategies.

End-Use Definitions

SHAPES II makes a distinction between two types of end-uses:

Weather Sensitive	Weather Insensitive
Usage varies by time of day, type of day, and month	Usage varies by time of day, type of day, and weather variable (temperature, temperature-humidity index, etc.)

These two types of end-uses are defined within each model as follows:

Model	End-Use Type
System Level	User specified: can include totals from sector models (Residential. Commercial. Industrial) as well as components unique to the system such as co-op or municipal customers. a large industrial customer or street lighting. Unique components can be modeled as weather sensitive and insensitive
Residential Sector	Major household appliances: weather sensitive and weather insensitive
Commercial Sector SIC	Customer categories (generally 1-digit SIC): baseload. heating. cooling by customer category
Commercial Sector Building Type	Building types (e.g. office. retail. restaurants. etc.): weather sensitive/insensitive end-uses by building type
Industrial Sector	Customer categories (generally 2-digit SIC): weather insensitive only
Miscellaneous Sector	User defined categories (e.g. street lighting. sales for resale. etc.)

The planner is free to specify which end-uses are to be included in each sector of the model: no end-uses are hard-wired in the database and there is no practical limit on the number of end-uses included in each sector.

A Flexible Database

Within the general framework outlined above. the user is free to define end-uses as required. In fact. all dimensions of a SHAPES II database can be modified by the user to reflect available data and forecast requirements. The SHAPES II software queries the database and allocates arrays of an appropriate size on a dynamic basis; database dimensions are not hard-wired in the model code. Thus. *a user can begin with a very simple database. perhaps only a few end-uses in each sector, and add end-uses as additional data become available.* Important dimensions of the database which can be specified by the user include:

- Number of day types
- Forecast horizon
- Number and type of end-uses
- Number of system level components
- Number of dwelling types in the residential sector
- Number of building types in the commercial sector
- Type of weather variable used and interval range

There are no practical limits to these dimensions.

A Flexible Approach to Forecasting

SHAPES II provides the user with three general ways to balance forecast requirements with available data and staff resources:

1) Level of Detail

At the system level. SHAPES II permits the user to specify the major components of the system. These components may include the residential. commercial. and industrial sectors as well as unique components such as a municipal utility or a large industrial customer. It is entirely up to the user which components are included at the system level: if there is no need to model the industrial sector. the user can simply omit it from the list of system level components.

This flexibility means that the user can model a system as a single component, as multiple user-defined components. or as a mix of residential. commercial. industrial. and user-defined components.

If the user includes the residential. commercial or industrial sectors among the list of system level components. the user can also specify the number (from 1 to 100) and type of end-uses included in each of these sectors.

2) Combined Endogenous and Exogenous Forecasts

SHAPES II enables the user to develop a detailed end-use energy forecast: end-use energy is summed to estimate class and system totals. The level of effort required to develop the energy forecast database is directly proportional to the number of end-uses specified by the user for each sector.

Alternatively, the user can substitute an exogenous energy forecast for one or more end-uses and/or system components. SHAPES II will use these exogenous energy forecasts to drive the chronological demand forecast for each end-use or component. This feature makes it possible to utilize the energy forecasts generated by methodologies specifically designed for unique or troublesome components of the system. One can even bypass the energy forecast models entirely, using SHAPES II to generate chronological demand forecasts which are consistent with an existing energy forecast model.

3) Residual Demand Forecasts

SHAPES II forecasts demand by combining energy and weather data with use patterns which describe usage as a function of time, day type, and weather or season. Provided adequate load research data is available, the user would normally develop one use pattern for each end-use defined in the database. Limited load research data, as well as constraints imposed by time and staff resources, may make this difficult. SHAPES II permits the user to omit a use pattern for a particular end-use or component as long as a use pattern can be specified at the next higher level. For example, a user might have adequate data to develop use patterns for a few specific appliances in the residential sector; if the user supplies a use pattern for the residential sector as a whole, SHAPES II will compute demand for the remaining appliances as the difference between the residential sector demand and the demand of the appliances for which use patterns were provided.

The options described above make it possible for the user to begin with a relatively simple database and add detail as time and resources permit. The following paragraphs suggest several possible approaches to developing a database.

1) Exogenous Energy Forecasts / Endogenous Demand Forecasts

This approach assumes that an exogenous energy forecast is available to the user; this energy forecast is then used by SHAPES II to generate a demand forecast. One of the advantages to this approach is that it permits development of a demand forecast which is consistent with the utility's existing energy forecast model. The level of detail specified by the user is determined by the level of detail associated with the energy forecast, as well as the ability of the user to develop corresponding use patterns. Options include:

- System Level Demand Forecasts

  The user can define the system as composed of one or more components: exogenous energy forecasts and weather sensitive or insensitive use patterns are used to forecast chronological demand for each component. This approach can be used to explore the sensitivity of a system to weather; it can also be used by co-ops and municipal power authorities to forecast system peak and the change in system load shape due to the relative growth of members. This approach is completely compatible with a utility's existing energy forecast methodology and the data analysis required to implement this approach is well within the means of a single staff person.

- End-Use Level Demand Forecasts

A similar approach can be taken at the end-use level: exogenous end-use energy forecasts can be combined with use patterns and weather data to forecast chronological demand at the end-use level. Demand is summed across end-uses to estimate class and system totals. This approach makes it possible to generate a detailed load shape forecast and to explore the impact of weather while maintaining compatibility with an existing energy forecast model.

2) End-Use Level Energy and Demand Forecasts

SHAPES II forecasts monthly and annual energy by end-use and sector, then sums across all sectors to estimate system energy. The level of effort required to develop the energy forecast database is directly proportional to the level of detail specified by the user for each sector. With respect to the demand forecast, SHAPES II allows the user to add use patterns for specific end-uses as time and data resources permit. Thus, the user has several options:

- No Demand Forecast

  SHAPES II permits the user to develop an energy forecast and defer the development of a demand forecast.

- System Demand Forecast Only

  The SHAPES II energy forecast is combined with weather data and a single use pattern describing system demand as a function of time, weather, and type of day to forecast chronological demand at the system level.

- Limited End-Use and System Demand Forecast

  Use patterns are developed for the system and for several significant end-uses: SHAPES II forecasts chronological demand for these end-uses and the system. This approach accounts for the influence of specific end-uses on peak and load shape.

- Full End-Use and System Demand Forecast

  Use patterns are developed for all end-uses: SHAPES II forecasts both energy and chronological demand for all end-uses and sums across end-uses to compute system totals. This approach is the most robust methodologically, and also the most data intensive.

Regional Forecasting and Scenario Modeling

Within a SHAPES II database the user can easily create multiple Data Profiles which will support the development of regional forecasts. A Data Profile specifies the input and output files that will be used in a forecast. These Data Profiles facilitate the ability to run multiple scenarios through the specification of different input and output files.

Using the Data Profile feature, the user can run several scenarios by using SHAPES II's batch run capability.

A common application of the Data Profiles is the modeling of multiple regions. One Data Profile is defined for each region. Only inputs that vary across regions such as population forecast, saturation, and weather conditions need to be uniquely defined in each region's Data Profile. SHAPES II produces forecasts for all regions individually and allows for the summation of regional results to total system outputs.

Flexible Input/Output Handling

Load data and demographic data is often stored in various spreadsheets or SAS programs. SHAPES II provides full cut and paste capabilities making the task of moving data from other Windows based software into SHAPES II easy.

A Flexible Approach to Reporting Results

SHAPES II is fully compatible with the Windows clipboard allowing complete cut-and-paste functionality with other Windows-based spreadsheet, word processing and presentation software. This provides users with complete flexibility for creating their own custom reports based on SHAPES II input and output information. For example, SHAPES II forecast output can be cut-and-pasted into a spreadsheet for the development of additional computations such as totals and averages as well as subsequent reporting.

SHAPES II facilitates the graphical reporting of your forecast information as well. SHAPES II contains powerful two- and three-dimensional graphics capabilities allowing any data to be graphed. Legends, titles, and axes labels can be specified within the program by the user. SHAPES II graphs can then be saved as files for incorporation in word processing documents; *all graphs included in this brochure were generated by SHAPES II as files and directly incorporated into this MS-Word document.*

SHAPES II System Level And Sector Forecast Models

System Level Model

At the system level, SHAPES II permits the user to specify the major components of the system. Components specified at the system level fall into one of the following categories:

1) Sector Level Models

   A component can be identified by the user as the total energy or demand estimated by any one of the sector models included in SHAPES II; these models are described below and include the following:

   - Residential Sector Model
   - Commercial Sector SIC Model
   - Commercial Sector Building Type Model
   - Industrial Sector Model
   - Miscellaneous Sector Model
   - Losses Model

2) Weather Sensitive Component

   The user can specify one or more components as weather sensitive. For each such component, the user must supply an energy forecast and a weather sensitive use pattern. The system level model uses these inputs to forecast chronological demand for the component.

3) Seasonal Component

The user can specify one or more components as seasonal or weather insensitive. For each such component. the user must supply an energy forecast and a weather insensitive use pattern. The system level model uses these inputs to forecast chronological demand for the component.

4) Total Component

This component is simply the sum of the energy and demand forecasts generated by each of the other components specified by the user.

Residential Sector Model

In the residential sector. SHAPES II is capable of forecasting energy and hourly demand for as many as 100 household end-uses. SHAPES II makes a distinction between appliances whose usage is primarily a function of time. type of day and season (weather insensitive appliances). and those for which usage is a function of weather as well as time of day and type of day (weather sensitive). Appliances typically included in the residential sector database and for which default data is supplied are:

Weather Insensitive	Weather Sensitive
Range	Room A/C
Frost-Free and Standard Refrigerators	Central A/C
Frost-Free and Standard Freezers	Resistance Heating
Washer	Heat Pump
Dryer	
Dishwasher	
Color TV	
B & W TV	
Water Heater	
Lighting	
Microwave Oven	

The Residential Sector Model forecasts energy and demand using a bottom up approach: that is. demand is forecasted first and then energy is computed by summing demand over time. A simplified formulation for this approach is as follows:

$$DEMAND^{a}_{h} = NAP^{a} * CL^{a} * USE^{a}_{h}$$

where:

a	is the appliance type
h	is the hour
DEMAND	is the demand for appliance a at hour h
NAP	is the number of appliances of type a
CL	is the connected load for appliance type a
USE	is the probability appliance a is in use at a given hour

Then energy is:

$$ENERGY^{a} = \Sigma_{h}\ DEMAND^{a}_{h}$$

SHAPES II applies an age distribution and headship ratios to an exogenous population forecast to arrive at a customer forecast: this forecast is then broken down by household type.

The number of appliances (NAP) is then computed by any of the following methodologies applied by household type:

1) Exogenous saturation rates
2) Exogenous penetration rates
3) Income-related saturation functions

A price adjustment factor is computed using a price forecast and price elasticities to account for changes in overall usage due to price reactions. This factor is applied to the connected load.

Usage (USE) is determined by use patterns for each appliance. Some appliances, such as water heaters, refrigerators and dishwashers are treated as weather insensitive: their use factors vary by time of day, type of day, and month. Other appliances such as air conditioning, resistance heating, and heat pumps are considered weather sensitive: their usage varies by time of day, type of day, and weather.

Commercial Sector SIC Model

SHAPES II includes two models for forecasting energy and demand in the commercial sector. The Commercial Sector SIC Model is similar to the Industrial Sector Model in that it generates an annual energy forecast based on a regression of historical energy intensity (kWh / employee): this regression is estimated, however, on a monthly basis using heating and cooling degree days as well as employment for the independent predictors.

Monthly and annual use integrals are computed using weather sensitive and insensitive use patterns. The ratio of monthly usage to annual usage is then used to allocate annual energy to monthly energy.

The same use patterns are then used to allocate monthly energy to hourly demand.

Commercial Sector Building Type Model

The Commercial Sector Building Type Model differs from the Commercial Sector SIC Model primarily with respect to the methodology for forecasting annual energy. The Building Type Model estimates energy intensity in units of kWh per square foot of floor space (an energy use coefficient) and then drives the energy forecast with a forecast of floor space for each building type. The user can supply an exogenous floor space forecast or develop an endogenous floor space forecast based on an employment forecast and estimates of floor space requirements per employee.

Unlike the Commercial SIC Model which is limited to base load, heating and cooling end-uses, there are no practical constraints on the number of end-uses or building types in the Building Type Model.

The procedure for estimating monthly energy and hourly demand is identical to that used by the Commercial SIC Model.

Industrial Sector Model

The Industrial Sector Model forecasts energy and demand using a top down approach: that is, annual energy is forecasted first, then allocated to the months of the year, and finally allocated on an hourly basis.

Customer categories, generally 2-digit SICs, are the "end-uses" in this sector. Greater detail can be achieved if the data available supports it: nothing in the SHAPES II software or methodology precludes the use of 3- or 4-digit customer categories or even plant-level categories.

All end-uses in the industrial sector are treated by SHAPES II as weather insensitive: that is, demand is considered to be a function of time of day, type of day, and month or season.

The Industrial Sector Model is essentially econometric in nature. It relies on regressions of energy intensity (MWh/unit of output), as well as an exogenous forecast of output, to forecast annual energy. Employment is the most common measure of output used, primarily because employment data is readily available.

The first step involved in creating an industrial sector database requires the use of historical sales data and historical measures of output to develop energy intensity regressions by customer category. A customer category is generally a 2-digit SIC, although the SHAPES II software will accommodate finer detail.

Monthly energy is obtained by allocating annual energy to the monthly level. Patterns of usage based on time, type of day, and month are used to allocate monthly energy to hourly demand.

TAUPA - Use Pattern Development Tools

SHAPES II includes tools for developing both weather sensitive and weather insensitive use patterns. These tools automate the process of developing the use patterns required to generate hourly demand forecasts.

The BUILD Function

The BUILD function reads metered demand data and creates tables of average hourly demand by time, type of day, and weather or month. Supporting statistics are also computed. The actual observations associated with each mean are also maintained and can be viewed and edited with TAUPA. Having knowledge of the actual points behind each average provides a greater understanding of the usage which leads to a higher level of confidence in the demand forecast. The examples below display only average values, but the process described can be based on actual values instead.

Temperature Associated Use Pattern Analysis (TAUPA)

A weather sensitive use pattern created by the BUILD function is usually sparse because the raw data rarely includes observations for all time and weather conditions. TAUPA provides functions for completing a weather sensitive use pattern using extrapolation, interpolation, and smoothing techniques. A graphic editor also enables the user to delete outliers and to mark the regions over which extrapolation will occur. *This tool greatly simplifies the process of creating weather sensitive use patterns.*

TAUPA's graphic editor plots load versus temperature (or other weather variable) on an hour by hour basis: Figure 1 displays load versus temperature for Hour 2 of the second day type -- in this example, Tuesday-Friday. Non-zero points are color coded to indicate the relative number of observations corresponding to each point.

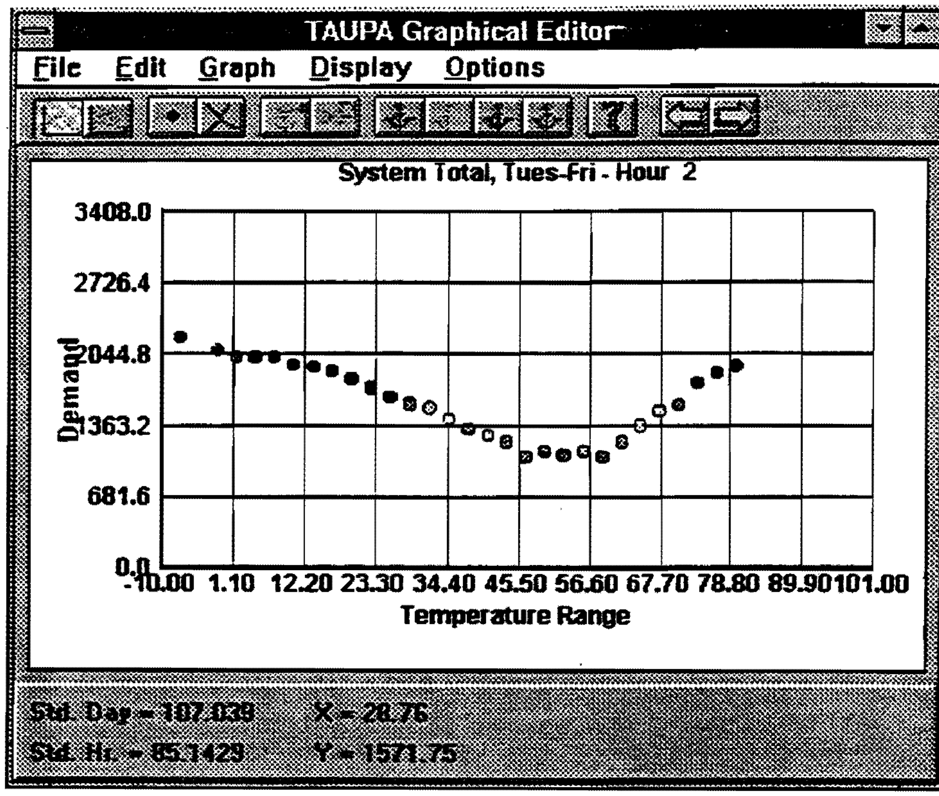

Figure 1 *Raw Data for Hour 2*

TAUPA provides interpolation, extrapolation, and smoothing functions to complete the use pattern. To use them, the user must first identify the heating and cooling range within each plot. TAUPA's MARK function marks the heating and cooling curves automatically: the end points of these curves are marked with triangular symbols as shown in Figure 2. Each plot also displays the R-Square value of each curve. The points between the heating and cooling curves are considered part of the dead band or base load.

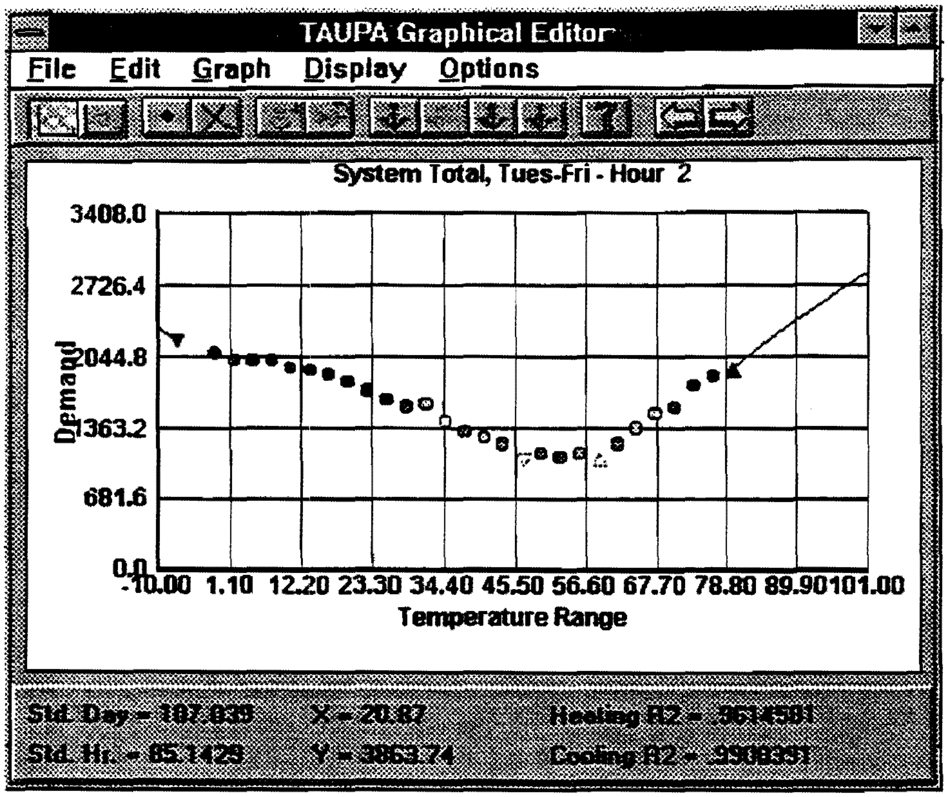

Figure 2 *Raw Data with Curves Marked*

The TAUPA graphic editor enables the user to delete outliers, insert points, and refine the choice of heating and cooling curve end points. Note that in Hour 18 of day type 2 (Figure 3), the MARK function identified a point in the 46 degree range as the end point for both the heating and cooling curves. This choice is undesirable for two reasons: this point is an outlier and choosing it as belonging to the deadband is probably inconsistent with the observations belonging to the dead band in the adjacent hours.

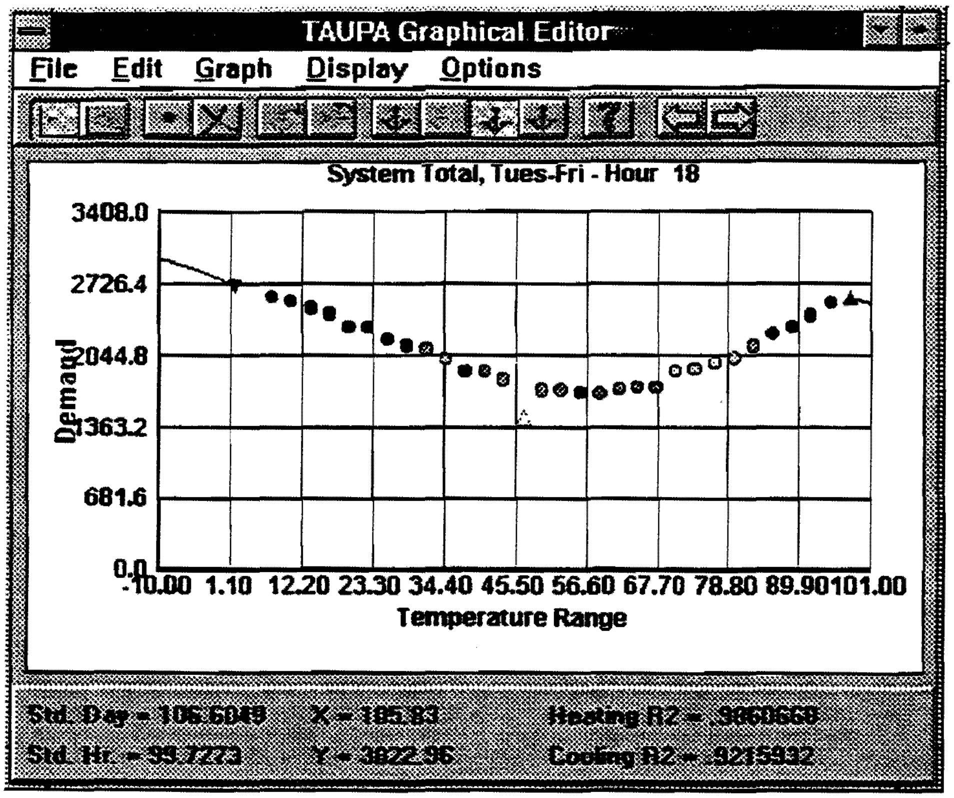

Figure 3 *Hour 18 Prior to Editing*

The graphic editor provides a cross hair cursor which can be used to re-mark the heating and cooling end points and to delete or insert points. Figure 4 displays Hour 18 after the end points have been adjusted and the outlier has been deleted. Note that the R-Square value for both curves have been updated to reflect these changes.

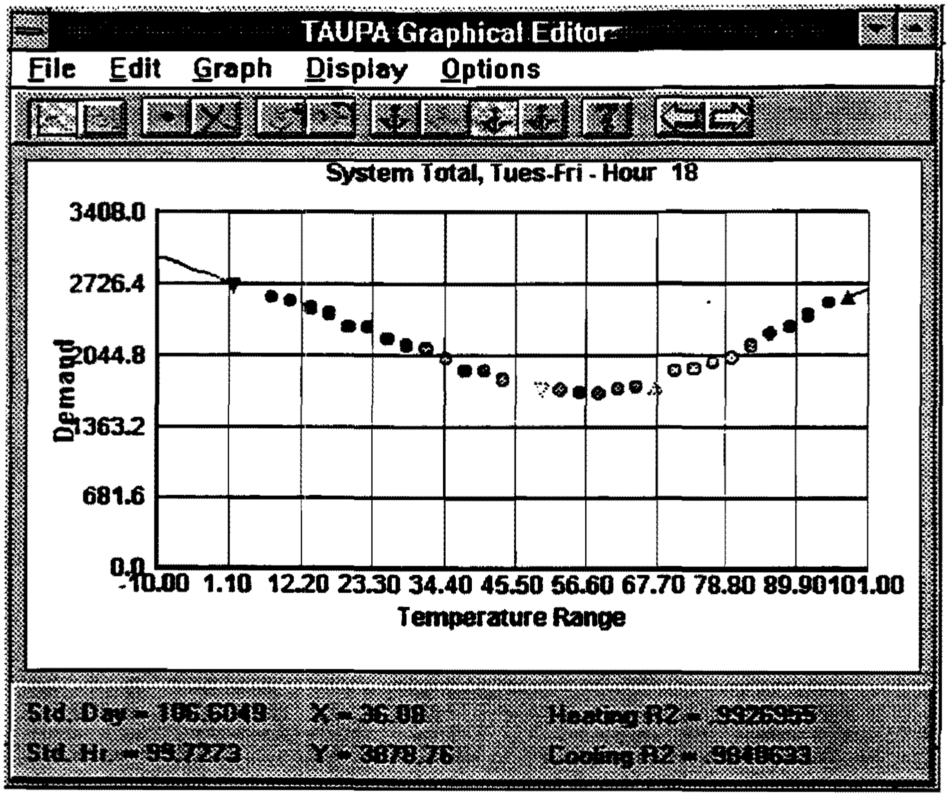

Figure 4 *Hour 18 After Editing*

After the load vs. temperature plot for each hour has been edited. TAUPA's interpolation. extrapolation. and smoothing functions can be used to complete the full use pattern.

Figure 5 displays Hour 18 after the TAUPA interpolation and extrapolation function has been invoked.

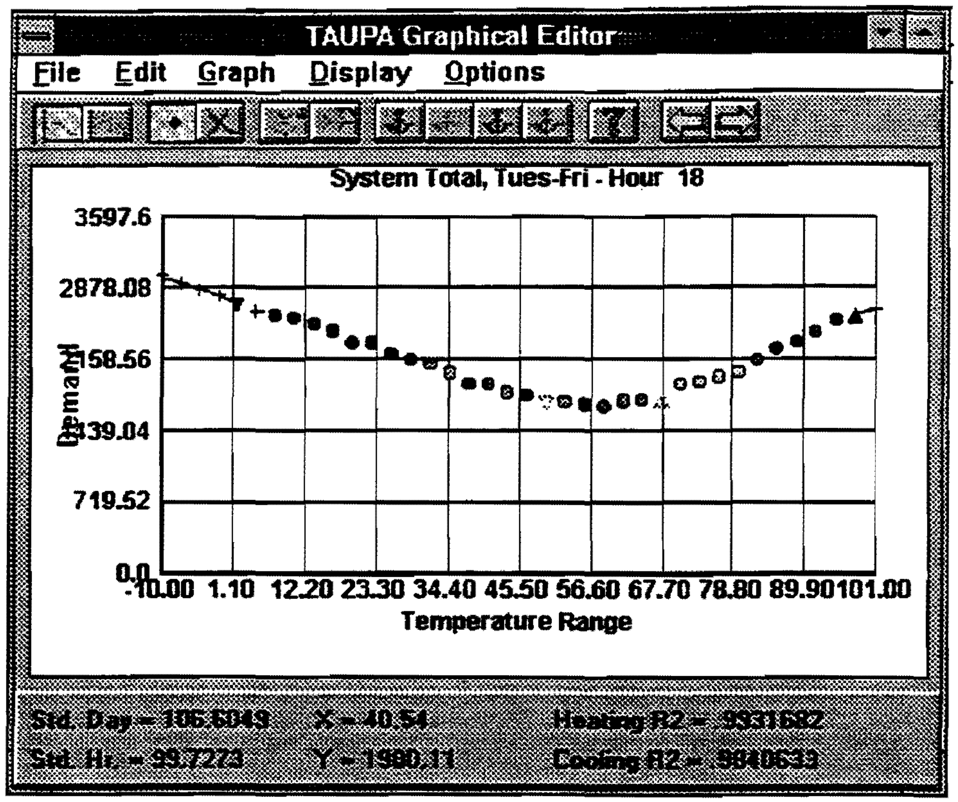

Figure 5 *Hour 18 After Interpolation/Extrapolation*

Figures 6-10 display all hours of the Tuesday-Friday use pattern at each stage of its development using TAUPA.

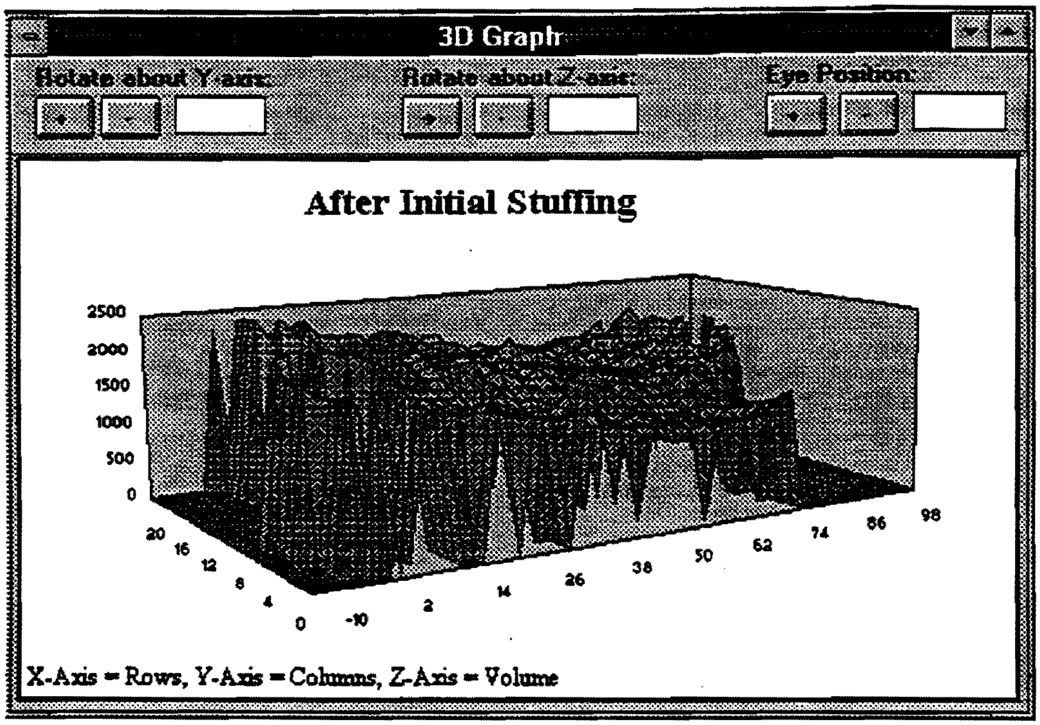

Figure 6 *After Initial Stuffing*

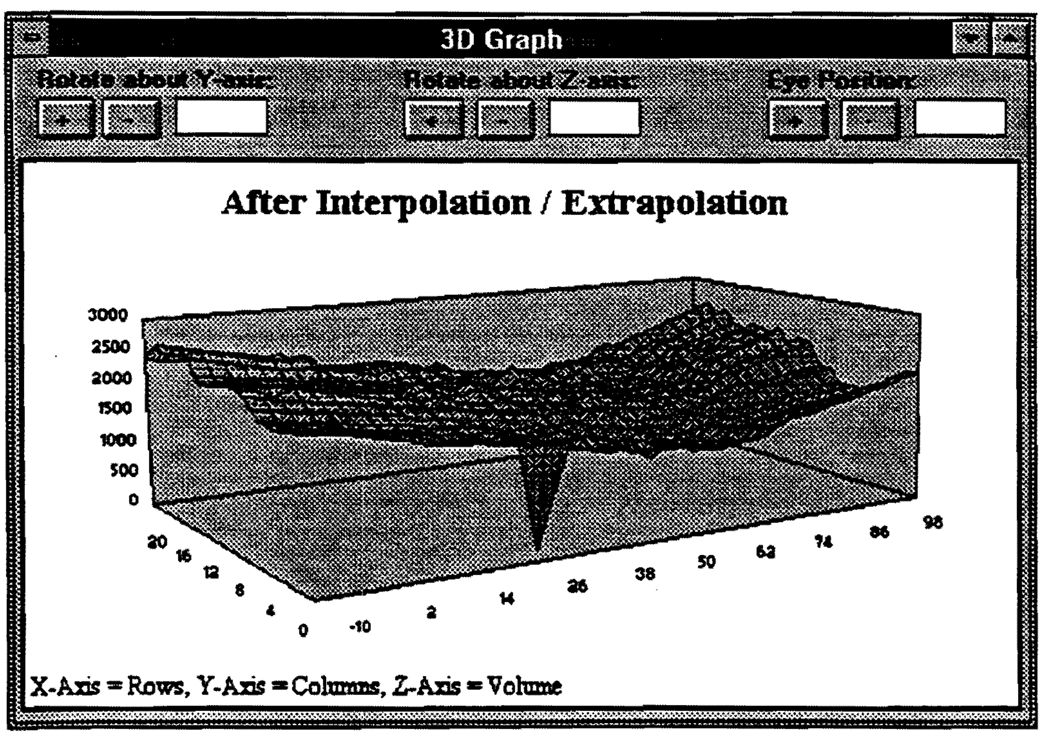

Figure 7 *After Inter/Extrapolation*

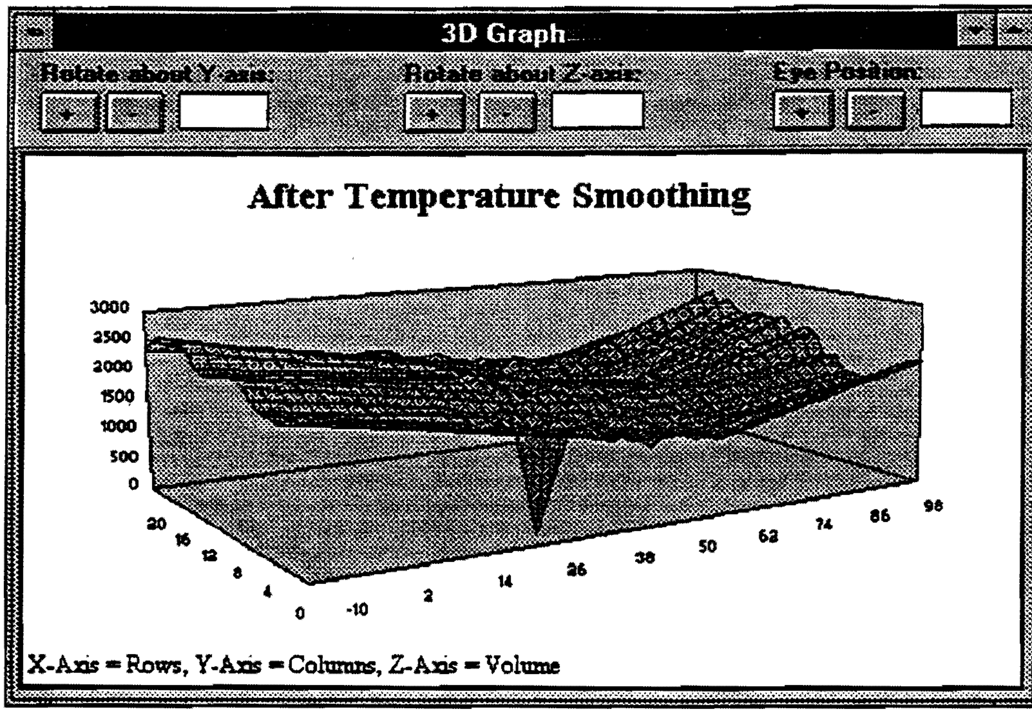

Figure 8 *After Temperature Smoothing*

Figures 9-10:

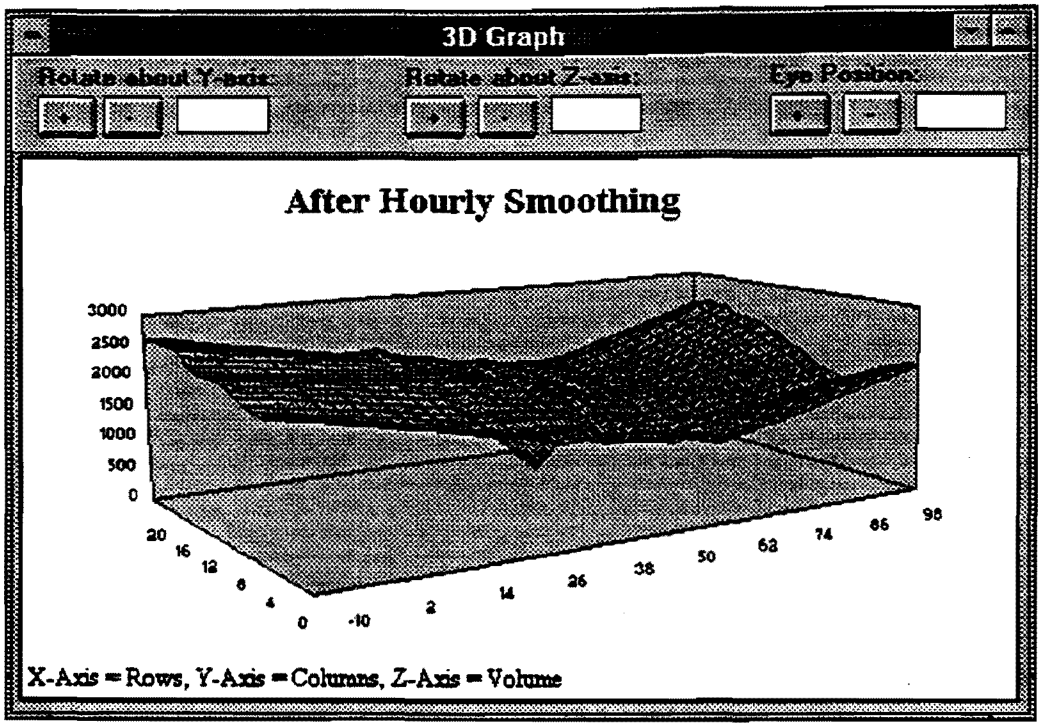

Figure 9 *After Hourly Smoothing*

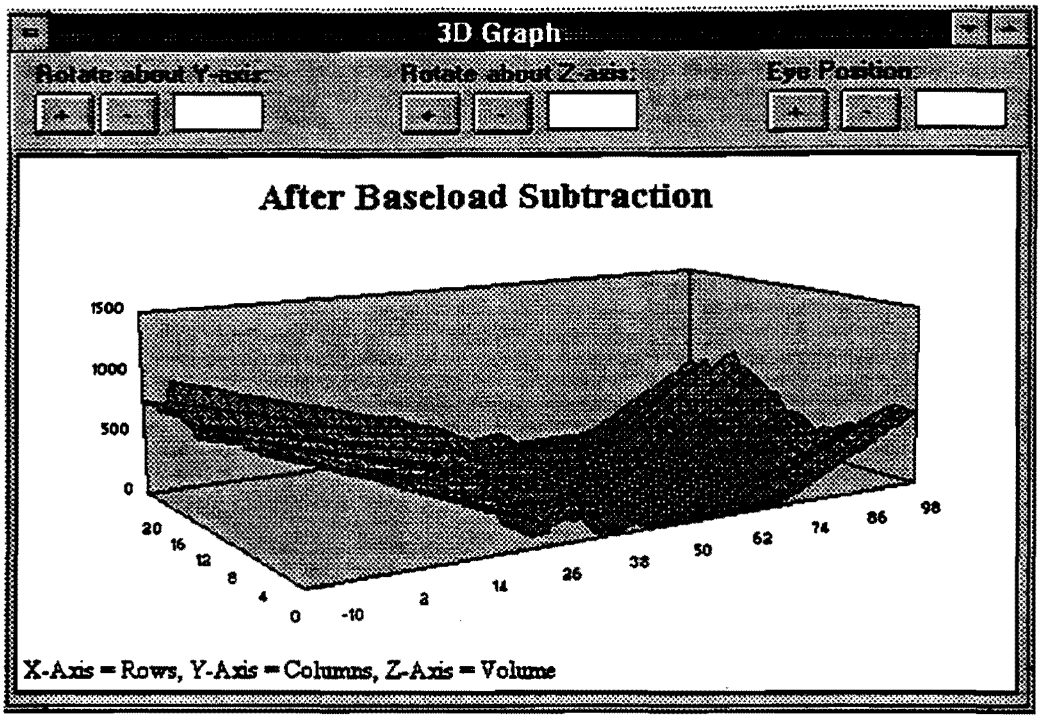

Figure 10 *After Baseload Subtraction*

SHAPES II Software System And User Group

SHAPES II features a menu driven, window-based user interface which is extremely easy to use. Specific features include:

Spreadsheet Editing

SHAPES II includes a sophisticated, full screen spreadsheet editor which enables the user to view and edit any file included in the database. The spreadsheet editor is mouse-driven and enables the user to perform the following functions:

- **Save**

  Save spreadsheet as a new file or replace the existing file

- **Modify**

  Copy, Delete or Insert rows or columns of data; alter database dimensions: number of end-uses, forecast horizon, etc.

- **Labels**

  Edit row and column labels identifying each data item

- **2-D**

  Create a two-dimensional line graph

- **3-D**

  Create a three-dimensional surface graph

- **TAUPA**

  Access the Temperature Associated Use Pattern Analysis tool kit

- **View**

  Page to a different table of a multi-table file or view other files in the database without affecting the file currently displayed.

- **Cut-and-Paste**

  Full compatible with the Windows clipboard allowing complete cut-and-paste functionality with other Windows-based spreadsheet, word processing and presentation software.

These functions enable the user to tailor a database to reflect the unique characteristics of a particular service area as well as to generate report quality graphs.

Graphics

The SHAPES II spreadsheet editor includes powerful two- and three-dimensional graphics capabilities. Any data included in the SHAPES II database can be graphed using these features. Graphs can be displayed on-screen, can be printed to a wide variety of printers or cut-and-pasted into documents. Legends, titles, colors, line styles and axes labels can be specified by the user. Examples of two- and three dimensional graphs are shown in Figures 11 and 12. Graphs can be saved to files for incorporation in word processing documents; *all* *graphs included in this brochure were generated by SHAPES II as files and directly incorporated into this MS-Word document.*

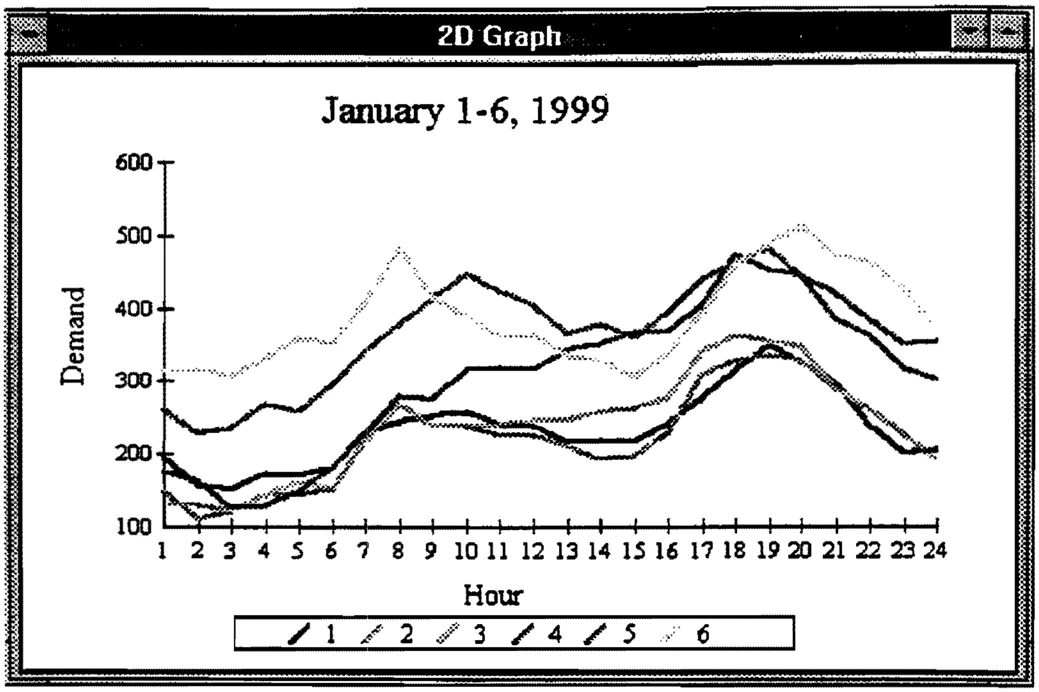

Figure 11 *2-D Graph Example*

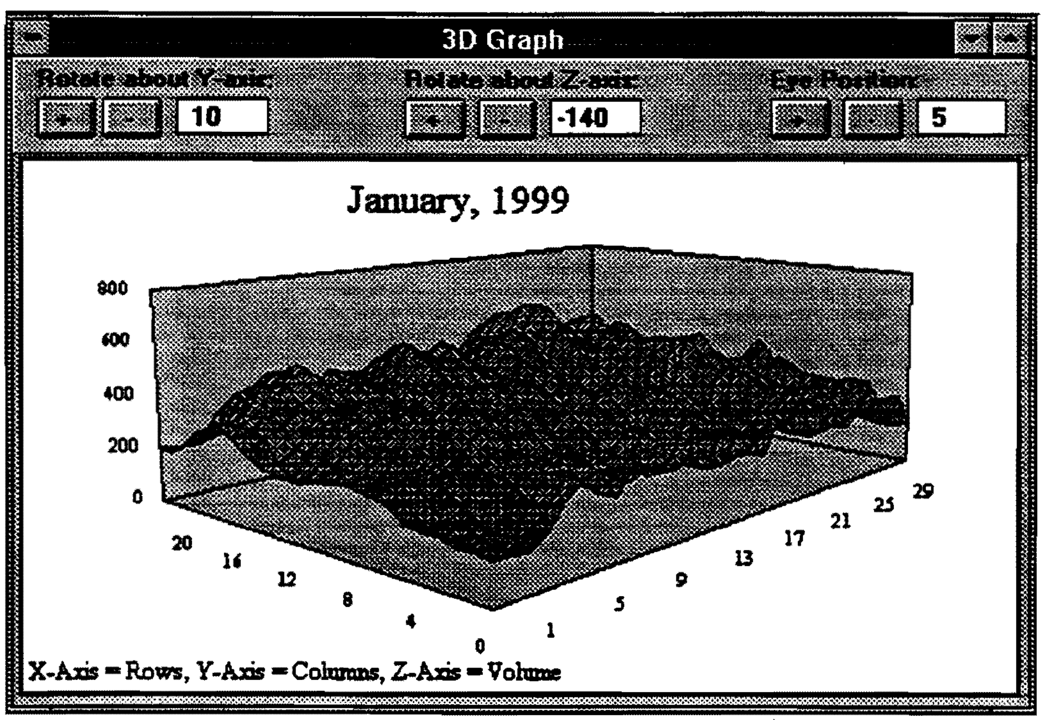

Figure 12 *3-D Graph Example*

File Formats

Many files incorporated in the SHAPES II database are formatted as simple ASCII files. If a file includes five rows and ten columns worth of data. the file will have five records each with ten values separated by blanks. These files can be viewed at the DOS command level simply by issuing a TYPE command followed by the name of the file. SHAPES II does not append any header information to the beginning of these files.

Some files in the SHAPES II database are too large to be treated in this manner. Use pattern and temperature frequency data. for instance. are stored by SHAPES II in a binary format. This format enables SHAPES II to perform input/output with these data very quickly and thus speeds execution. The creation of these files is transparent to the user and any file saved in the SHAPES II database in binary format can be translated to ASCII or DIF format using the export function described below.

Exporting/Importing Files

SHAPES II makes it easy for the user to import files to the SHAPES II database from external sources. and vice versa. Any file in the SHAPES II database can be translated to an ASCII or DIF format. Similarly. ASCII and DIF format files produced by other software packages can be read directly into the SHAPES II database. In addition. chronological data can be imported and exported in EEI format. This feature enables the user to easily transfer files from SHAPES II to other packages such as LOTUS 1-2-3 and back to SHAPES II.

Printing Files

SHAPES II enables the user to obtain a printed copy of any file in the database on a variety of printers. Print drivers are included for:

- Epson MX or FX
- IBM
- HP Laser Jet+
- Okidata

In addition. the user can specify a print driver for any printer not included in the above list.

Compressed or normal print can be specified as well as narrow or wide carriage.

Forecast Logs

Each time SHAPES II generates a forecast. a forecast log is also generated. This log includes a time and date stamp, the names of the data and forecast profiles used to create the forecast. which elements of the forecast were selected. and the names of each input and output file used during the forecast run. Warnings generated during the forecast are also written to this log file.

Database Organization

SHAPES II can be configured to use up to eight different directories: each directory has a different purpose:

1) Forecast Output Files
2) Forecast Input Files
3) Import/Export Files
4) Plot Files
5) SHAPES II Forecast Logs
6) TAUPA Working Directory
7) Print Files

SHAPES II can be directed to use a different set of directories simply by changing its setup configuration. This capability is very useful when developing separate databases for different regions of a service territory.

Documentation

The capabilities and methodology of SHAPES II are fully described in two documents provided with the software.

The SHAPES II File Documentation gives a detailed explanation of the SHAPES II forecast methodology, a definition of each file included in the database, and a description of the analyses required to create each data file.

The SHAPES II User's Guide provides a detailed guide to the use of the software.

Both documents are updated on a regular basis as changes are made to the SHAPES II methodology and software.

Performance

Run times for SHAPES II depend primarily on the number of end-uses included in the database, and the number of years, months, and end-uses included in a chronological demand forecast.

The following benchmarks were established for a database which includes a total of 45 end-uses in four sectors: Industrial, Residential, Commercial, and Miscellaneous. All runs were made using SHAPES II Version 1.0 on a 486, 33MHz PC:

Run	Description	Run Time (Sec)
1	40 year annual and monthly energy forecast	37
2	40 year annual forecast 1 year Day Type Hourly forecast (12 months, 4 day types) 1 year Chronological Demand (12 months, 365 days, 8 classes, 3 end-uses)	206
3	Hourly and Chronological Demand forecast for Residential Sector	75

Hardware Requirements

SHAPES II operates on PC 486 with the following configuration:

- 16 MB RAM
- 8 MB Available Disk Space
- Any EPSON. IBM. Okidata. Laser Jet+ or compatible printers

Users' Group

Each year EDS sponsors a users' group meeting. This three day meeting generally includes the following agenda:

- Presentations by users and industry experts
- SHAPES II / TAUPA development activities
- Feedback
- Roundtable discussions and workshop on industry and software issues

The Thirteenth Annual Users' Group will be held in June. 1998 at a site to be determined.

Appendix B

OUC Demand Side Management Plan

ORLANDO UTILITIES COMMISSION

Energy Conservation
And
Demand-Side Management Programs
Of The
Orlando Utilities Commission

August 25, 1995

ORLANDO UTILITIES COMMISSION
500 SOUTH ORANGE AVENUE • P. O. BOX 3193 • ORLANDO, FLORIDA 32802 • 407/423-9100

August 25, 1995

Commissioners:
Susan F. Clark, Chairman
J. Terry Deason
Julia L. Johnson
Diane K. Kiesling
Joe Garcia

Commissioners:

Please accept this submittal document of the Orlando Utilities Commission (OUC) Energy Conservation and Demand-Side Management Programs for your review and approval as part of the requirements under the Florida Energy Efficiency and Conservation Act (FEECA).

OUC has worked diligently since 1973 to offer all customers energy and water conservation programs with the intent to help them use our products as efficiently as possible. These programs aggressively follow through with the commitment to meet the numeric conservation goals established by the Florida Public Service Commission.

I believe energy and water conservation programs offer a positive value added service to the customers of the Orlando Utilities Commission. You can be sure OUC will continue our tradition of a public utility dedicated to energy conservation and demand-side management.

Sincerely,

Robert C. Haven P.E.
General Manager and
Chief Executive Officer

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Conservation Goals for the Orlando Utilities Commission (OUC) in accordance with Florida Administrative Code, Sections 25-17.001. 005. and the Florida Public Service Commission (FPSC), as set forth in Order No. PSC-95-0461-FOF-EG. issued April 10. 1995.	)))))	Docket No. 930558-EG Filed: August. 25. 1995

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that copies of the Energy Conservation and Demand-Side Management Program of the Orlando Utilities Commission have been sent by U. S. Mail or hand delivered this 25th day of August. 1995 to the following parties of record:

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SECTION I

PROGRAMS MEETING GOALS

INTRODUCTION

In accordance with Florida Administrative Code, Sections 25-17.001, 005, the Florida Public Service Commission (FPSC), established numeric conservation goals for the Orlando Utilities Commission (OUC), as set forth in Order No. PSC-95-0461-FOF-EG, issued April 10, 1995, in Docket No. 930558-EG. In response to this order, OUC submits these Energy Conservation and Demand-Side Management (EC-DSM) Programs to the FPSC for approval.

OUC has designed its EC-DSM Programs to achieve the conservation goals set forth by the FPSC. The total program plan provides OUC residential and commercial customers with a broad range of programs to assist them in the reduction of kWh energy and kW demand with the intent to maintain competitive electric rates.

In addition, OUC and the Florida Department of Community Affairs (DCA) have entered into a joint stipulation (Attachment #1) agreeing to a special interest in energy conservation that addresses low-income home weatherization, renewable energy sources and energy efficient residential new construction. Furthermore, the DCA and OUC have agreed to engage in cooperative activities to enhance their capacity to meet their individual goals while enabling each to pursue activities that could not be accomplished alone.

Section I - Programs Meeting Goals

The Florida Public Service Commission (FPSC) approved numeric conservation goals for the Orlando Utilities Commission (OUC) as follows:

Residential Numeric Conservation Goals

Year	Winter kW Reduction	Summer kW Reduction	mWh Energy Reduction
1996	230	155	0
1997	693	468	0
1998	1,386	938	0
1999	2,309	1,563	0
2000	2,463	2,381	0
2001	4,849	3,280	0
2002	6,465	4,374	0
2003	8,311	5,624	0
2004	10,388	7,029	0
2005	12,256	8,290	0

Commercial/Industrial Numeric Conservation Goals

Year	Winter kW Reduction	Summer kW Reduction	mWh Energy Reduction
1996	0	0	0
1997	0	0	0
1998	0	0	0
1999	0	0	0
2000	0	38	0
2001	0	115	0
2002	0	230	0
2003	0	384	0
2004	0	576	0
2005	0	807	0

The conservation goals were determined through the Cost Effectiveness Results Report (CEGRR) process. The process involved evaluating an exhaustive list of Demand Side Options (DSO) and all their different permutations. The final goals were based on those DSO's which passed the FPSC's Rate Impact Measure (RIM) test. For OUC, only two technology groups passed RIM. They were residential Direct Load Control (DLC) and commercial Thermal Energy Storage (TES). The DLC group included central air conditioning, electric furnaces (i.e. heat strips), electric water heaters and pool pumps (only as a value added service). DLC was cost effective for single family, new and existing construction.

New construction, thermal energy storage, was the only commercial DSO that passed RIM. All new construction DSO's are subject to normal, local business cycles. Numeric conservation goals, subject to unpredictable business cycles, are risky. Therefore, OUC decided to substitute the Commercial Efficient Lighting (CEL) technology group for TES. Although CEL did not pass RIM, CEL programs have a higher probably of success and in addition, offer more conservation. The existing CEL Program has proven very successful and since inception of the program, more than 140 customers have participated.

OUC is committed to meet and exceed its residential and commercial conservation goals.

A. RESIDENTIAL DIRECT LOAD CONTROL

Starting in calendar year 1996, OUC will be starting a Single Family DLC pilot program. The full program will start on January 1, 1997. OUC will be controlling central air conditioners (CAC), electric furnaces, heat pump auxiliary heat operations, electric water heaters and pool pumps. DLC services will be offered to new and existing construction customers.

As the previous Cost Effectiveness Goals Results Report (CEGRR) demonstrated, only the control of single family, new and existing construction, central air conditioners with strip heating and electric water heaters were cost effective. In addition, as a value added service, the additional control of pool pumps was also cost effective.

A recent customer opinion survey conducted by OUC, revealed that the vast majority of our single family customers desire DLC services. Therefore OUC will offer DLC to heat pump customers as well as strip heating customers. For conservation goals attainment and subsequent reporting purposes, OUC will be reporting on all of the DLC operations.

OUC plans to use a FM/VHF radio system. The DLC system will use a 50% duty cycle for CAC and strip heat equipment. The system will shed electric water heaters, heat pump auxiliary heaters and pool pumps. As a minimum, all DLC customers will have their CAC, heating systems and electric water heaters controlled.

DLC customers will receive monthly bill credits. The credits will have fixed and possibly, variable components. In addition to traditional fixed monthly credits, customers may receive monthly variable credits. The variable credit will be based on the number of control days. Therefore, the more days customers are controlled, the more credits they will receive.

B. COMMERCIAL EFFICIENT LIGHTING PROGRAM

This program is ongoing and began in 1992. This program is available to all commercial electric customers. The program is targeted to the existing customer and retrofit market. Commercial customers are encouraged to retrofit their facilities with energy efficient lighting as a part of the Commercial Energy Audit. The majority of existing commercial facilities are equipped with standard 40 or 75 watt fluorescent tubes. Most facilities still use standard core and oil (magnetic) ballasts, incandescent lamps and mercury vapor fixtures.

Magnetic ballasts can be replaced with electronic ballasts and incandescent lamps can be replaced with compact fluorescent lamps - all without appreciable loss of light. Reflectors can be installed in existing four-tube fluorescent fixtures allowing the removal of two tubes and one ballast, reducing wattage with no significant loss of light output. The program was expanded in 1992 to include rebates to qualifying customers. Participating commercial electric customers receive a rebate equal to $100 for every KW of lighting load permanently removed from the OUC system. Since 1993, the program has effectively removed more than 2.5 mW from the OUC system. More than 140 commercial customers have participated in the program.

C. MONITORING AND EVALUATION PLAN

OUC will be exercising three Demand Side Management (DSM) programs to achieve the approved conservation goals. The plan has two residential programs and one commercial program. The residential programs are DLC for single family homes with central air conditioning, strip heat (or heat pumps) and electric water heating. The second is DLC for the same plus swimming pool pumps. The one commercial program is Commercial Efficient Lighting.

OUC's approved conservation goals are only demand reductions. The residential goals are both winter and summer reductions. The commercial goals are summer demand reductions. Therefore the monitoring and evaluation plan only addresses how OUC will measure and validate the actual demand reductions.

Conservation goals attainment will be reported to FPSC in March of each year. Each utility is to report the actual reductions which are attributable to their programs. Since the DSM plans will receive FPSC approval in late 1995 or early 1996, the actual program start dates will be in late 1996 or early 1997. A 12 month post implementation period (i.e. CY 1997 or possibly CY 1998) will be required to determine the actual reductions. This will necessitate the first attainment report (with actual reductions) to be no earlier than March 1998 (or later). In addition, program evaluations will have to be performed during January and February 1998. It is extremely doubtful that program evaluations can be performed during this short period. In subsequent years, program evaluations will be occurring all the time, as post 12 month periods continually occur.

Therefore the 1997 annual report will be based on the engineering estimates listed below.

RESIDENTIAL

Direct Load Control (DLC) Monitoring and Evaluation Plan

OUC will be implementing a residential DLC program which will be controlling single family central air conditioning, strip heating, domestic water heating, heat pump auxiliary heating and pool pumps. By imposing a 50% CAC duty cycle on the peak summer day, OUC anticipates a .93 kW/participant reduction (at the meter). In addition, OUC anticipates an additional .29 kW/participant summer reduction resulting from shedding electric water heating.

By using the same load control receiver and adding an additional relay, swimming pool pumps can be controlled. OUC is anticipating a .75 kW/participant summer reduction resulting from shedding pool pumps.

Peak winter demand reductions will come from 50% cycling of heat strips and shedding heat pump auxiliary heat strips and electric water heaters. OUC anticipates 1.5 kW/participant reduction from cycling heat strips (or .76 kW/participant by shedding heat pump auxiliary heat) and .74 kW/participant reduction from shedding electric water heaters. At this time, OUC does not plan to shed or cycle pool pumps on peak winter days.

Average single family home (engineering estimates)

<u>Summer demand reduction</u> - (per participant)

central air conditioning	-	.93 kW
electric water heating	-	.29 kW
pool pumps	-	.75 kW

<u>Winter demand reduction</u> -

electric furnace	-	1.5 kW
heat pump auxiliary heat	-	.76 kW
electric water heating	-	.74 kW
pool pumps	-	0 kW

OUC will track progress toward meeting demand reduction goals by first ensuring that marketing goals are maintained, if not exceeded.

The next step will be to perform "notch" tests during near extreme conditions. Notch tests are simply comparing control day system load profiles with non-control days.

A notch test confirms if the "sum of the parts equals the whole".

As a backup to the notch test, OUC will, from time to time, install, premise level, recording meters on DLC customers. The purpose of the recording meters will be to confirm notch test results. Again, by comparing control days with non-control days, demand reductions can be determined. The random installation of 15 recording meters will yield a 75% confidence level.

COMMERCIAL

Commercial Efficient Lighting (CEL)

OUC's CEL program rebates $100 per kW (peak summer) permanently (i.e. hard wired) reduced. OUC will monitor and evaluate the CEL program for commercial goals attainment.

OUC will monitor CEL's progress by first tracking marketing goals. This will ensure that the correct number of customers with the correct demand reductions are continually brought into the program.

The next step is to develop energy equations for every new participant. This will be accomplished by using demand billing data, weather data, and other variables as appropriate. At various times during the year, a sample of all existing participants will be developed. The sample will be constructed from all customers who entered the program after January 1, 1996. The sample will be evaluated using time-series regressions. The pre and post series will be compared to determine the actual summer demand reductions. In the case of GSND customers (i.e. non-demand), monthly energies will be used. Generally, the energies will be converted to demands using the following conversions factors:

Offices	3,120 kWh/kW
Restaurants	3,650 kWh/kW
Retail	3,536 kWh/kW
Groceries	7,884 kWh/kW
Schools	2,000 kWh/kW
Colleges	2,000 kWh/kW
Hospitals	8,760 kWh/kW
Lodging	4,380 kWh/kW
Misc	3,500 kWh/kW

The above mentioned conversion factors will be modified as deemed appropriate for specific circumstances.

OUC will sample non-participating commercial customers to determine lighting trends. Randomly selected customers will receive a Commercial Energy Survey which will include a detailed lighting survey. The lighting survey data will be subdivided into common groupings and then compared with previous surveys. This qualitative approach will determine lighting trends naturally occurring within common groupings. Naturally occurring trends will be factored into the overall CEL summer demand reductions and goals attainment.

The 1997 CEL engineering estimates will be based on lighting pre and post lighting surveys.

SECTION II

MAINTENANCE OF EXISTING PROGRAMS

SECTION II- Maintenance of Existing Programs

OUC fully intends to continue existing residential and commercial programs. Executive Vice President and General Manager Bob Haven is dedicated to continue existing programs as a value added service as a means to help customers reduce the inefficient use of electricity. The Residential Energy Survey was introduced to customers in 1973. OUC was lauded by the FPSC in the early 1980's as being the original leader in Florida to offer energy conservation programs. OUC continued to expand existing programs and offer new programs in both the residential and commercial sectors. Rebates were included in some of the programs in 1992. The programs listed in SECTION II will be continued.

A. RESIDENTIAL PROGRAMS

Residential Energy Survey:

This program is designed to provide residential homeowners with recommended energy efficiency measures and practices. The Residential Energy Survey includes complete attic, air duct and air return inspections. Literature on other OUC programs is also provided to the residential customers. The customer is given a choice to receive a water heater jacket, low-flow showerhead or compact fluorescent bulb. OUC Energy Analysts are presently using this walk-thru type audit as a means to get OUC customers to participate in other conservation programs and to qualify for appropriate rebates.

Residential Heat Pump Program:

Heat Pumps are marketed to the owners of existing residential strip heating systems and older, inefficient central air conditioners and heat pumps. The program requires heat pumps with a SEER of 11 (or greater) and a HSPF of 7.0 (or greater) in order to qualify for rebates. Rebates range in terms of equipment SEER levels, tonnage and replaced equipment. The main strength of the program's success is the air conditioning contractors that now inspect customers' duct work and insulation levels. Contractors often install energy efficient heat pumps plus duct repairs and additional insulation as a part of a total energy saving package for customers.

Residential Weatherization Program:

This program is designed for existing single family homes and promotes R-19 ceiling insulation (or higher), caulking, weatherstripping, window treatment, water heater insulation and air condition/heating supply and return air duct repair. The customer will receive a $140 rebate for installing R-19 ceiling insulation (or higher), $100 rebate for duct repairs and up to $110 for other conservation measures specified above. In addition, the customer is allowed to carry payments for ceiling insulation on their electric bill for 12 or 24 months. OUC pays the total contractor cost.

Low Income Home Energy Fixup Program:

This program began in 1985 and since inception, has made more than 3,000 homes more energy efficient. This program is offered to customers whose total family annual income does not exceed $20,000. The Fix-up program will pay 85% of the total contract cost for home weatherization for the following measures: (a) upgrading ceiling insulation to R-19; (b) exterior and interior caulking; © weatherstripping doors and windows; (d) air conditioning/heating supply and return air duct repairs; (e) installation of energy efficient doors and (f) water heater insulation. Customers are allowed to carry the 15% contractor payment on their monthly electric bill. OUC pays the customer's 15% cost to the contractor. OUC has agreed in a Memorandum of Understanding with the State Department of Consumer Affairs dated March 17, 1995 to continue this program.

Residential Efficient Water Heating Program:

This program encourages residential customers in existing homes to install waste heat recovery units and to insulate older, less efficient, electric water heaters. Customers receive a $50 rebate for installing a waste heat recovery unit.

B. COMMERCIAL PROGRAMS

Commercial Energy Survey Program:

This survey is a physical walk-through inspection of the commercial facility. The commercial customer having a Commercial Energy Survey receives a report at the time of the survey. A computer program called ACES is used upon request as a tool to assist in performing economic evaluations for the smaller customers. Within 30 days of a detailed audit, the customer receives a written report. Conservation literature is provided to all customers. Customers are encouraged to participate in the Commercial Efficient Lighting and Commercial Efficient Cooling

Programs.

Commercial Cooling Program:

This survey is targeted to existing commercial customers. Customers with existing HVAC units of 20 tons or less may qualify for rebates of up to $3,000. The program started July 1, 1995.

C. EDUCATIONAL OUTREACH PROGRAM

This program is now entering the tenth year of operation. The program is very successful and has won several awards for contributions to education. The program consists of hour long classroom presentations focused on teaching students about energy and water conservation. The presenter, a former teacher, uses a display model of a generating plant, an electric meter display, and FCG "Watt-Counter," energy and water workbooks as well as videos and other attention getting devices. Students are taught how electricity is generated and are encouraged to perform mini-electric and water audits on their own homes. Many students sign their parents up for an actual OUC Residential Energy Survey. During each of the last two years, more than 8,000 Orange County school children have seen the OUC classroom presentations.

SECTION III - New Energy Conservation Programs

A. Residential New Construction Program:

This program is presently under development and expected to be fully operational in 1996. The program will target builders and developers in new subdivisions. It is projected that 500 to 600 new single family homes will be built in the OUC service area each year. OUC has entered into a Memorandum of Understanding (MOU) with the Florida Department of Consumer Affairs (DCA) dated March 17, 1995. The agreement stated in the MOU that OUC will develop an energy efficient, residential new construction program "based on features of the Building Energy Rating System ("BERS"), State of Florida Energy Code Point Indexes ("EPI") and OUC's efficiency standards.

B. Commercial Efficient Motors Program:

This program is scheduled to begin operation in 1996. The program will promote the installation of high efficiency motors to the existing commercial customer market. The program will utilize an incentive schedule based on motor size in horsepower and efficiency level. At this writing, the amount of the incentive has not been determined. The program will be promoted through the OUC Commercial Energy Survey, Commercial Cooling and Commercial Efficient Lighting Programs and a Major Accounts Program.

C. Multi-Family Weatherization Program:

This program is scheduled to begin operation in 1996. The program will promote the installation of various energy conservation measures to the existing multi-family market. This market will include commercial customers ranging in size from duplex to multi-unit apartment complexes. The program will utilize an incentive schedule based on the following measures:

Measure	Incentive
Insulate top floor attic level to R-19	$100
Air seal entry door	5
Insulate electric water heater	5
Install low-flow showerhead	5
Air seal return-air plenum	(Up to) 25

The program will be promoted through Commercial Energy Surveys and Residential Energy Surveys. The program will also be promoted through OUC membership in the Apartment Association of Greater Orlando.

D. Electric Line Extension Policy:

OUC will, subject to approval of OUC's governing Commission, amend its' Administrative Policy Manual section on Electric Line Extension Policy to allow for OUC owned, cost-effective photovoltaic ("PV") equipment, to be installed on customers' premises in lieu of a line extension. This was a mutual agreement between the Florida Department of Community Affairs (FDCA) and OUC in a Memorandum of Understanding dated 03/17/95.

SECTION IV

APPENDIX A

PROGRAM PARTICIPATION AND PERCENT ELIGIBLE CALCULATIONS

ORLANDO UTILITIES COMMISSION
RESIDENTIAL DEMAND SIDE MANAGEMENT PLAN
1995 CONSERVATION GOALS

RESIDENTIAL DIRECT LOAD CONTROL

YEAR	RESIDENTIAL SINGLE FAMILY NUMBER OF METERS	ELIGIBLE POPULATION CENTRAL A/C WITH STRIP HEAT NUMBER OF METERS	ELIGIBLE POPULATION POOL PUMPS & CAC/SH NUMBER OF METERS	DIRECT LOAD CONTROL CAC/SH CUMULATIVE PARTICIPANTS	DIRECT LOAD CONTROL CAC/SH ANNUAL PARTICIPANTS	DIRECT LOAD CONTROL POOL PUMPS & CAC/SH CUMULATIVE PARTICIPANTS	DIRECT LOAD CONTROL POOL PUMPS & CAC/SH ANNUAL PARTICIPANTS	PER CENT ELIGIBLE POPULATION DLC CAC/SH CUMULATIVE	PER CENT ELIGIBLE POPULATION DLC POOL PUMPS CUMULATIVE
1996	52,916	20,029	3,092	0	0	0	0	NA	NA
1997	53,635	20,070	3,099	337	337	196	196	1.68%	6.33%
1998	54,330	20,097	3,103	506	169	392	196	2.52%	12.63%
1999	55,015	20,113	3,105	843	337	588	196	4.19%	18.93%
2000	55,715	20,130	3,108	1,264	421	784	196	6.28%	25.22%
2001	56,316	20,106	3,104	1,770	506	981	197	8.80%	31.60%
2002	56,966	20,092	3,102	3,034	1,264	1,177	196	15.10%	37.94%
2003	57,582	20,061	3,097	3,792	758	1,373	196	18.90%	44.33%
2004	58,231	20,037	3,094	4,474	682	1,569	196	22.33%	50.72%
2005	58,872	20,005	3,089	5,081	607	1,765	196	25.40%	57.14%
2006	59,435	19,940	3,079	5,612	531	1,961	196	28.14%	63.69%

NOTES: 1. POPULATION VALUES ARE DERIVED FROM 1995 FORECAST AND OUC 1995 TEN YEAR SITE PLAN.
2. 15.44% OF ALL SINGLE FAMILY HOMES HAVE POOLS AS PER OUC 1992 RESIDNETIAL APPLIANCE INFORMATION SURVEY.
3. THE NUMBER OF ELIGIBLE POOLS WAS PRORATED FROM THE TOTAL NUMBER OF POOLS BY THE PERCENTAGE OF SINGLE FAMILY HOMES THAT HAVE CENTRAL AIR CONDITIONING WITH STRIP HEAT (CAC W/SH).
4. THE NUMBER OF PARTICIPANTS IS FROM THE OUC 1994 CEGRR.

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ORLANDO UTILITIES COMMISSION
COMMERCIAL DEMAND SIDE MANAGEMENT PLAN
1995 CONSERVATION GOALS

COMMERICAL EFFICIENT LIGHTING

YEAR	TOTAL NUMBER OF GSND METERS	TOTAL NUMBER OF GSD METERS	TOTAL NUMBER OF METERS	TOTAL ENERGY CONSUMPTION GSND GWH	TOTAL ENERGY CONSUMPTION GSD GWH	TOTAL COMMERCIAL ENERGY CONSUMPTION GWH	TOTAL COMMERCIAL LIGHTING ENERGY CONSUMPTION GWH	TOTAL COMMERCIAL LIGHTING SUMMER C. DEMAND KW	TOTAL COMMERCIAL LIGHTING C. DEMAND ELIGIBLE KW	CUMULATIVE PARTICIPANT C. DEMAND REDUCTION KW	ANNUAL PARTICIPANT C. DEMAND REDUCTION KW	PER CENT ELIGIBLE POPULATION CUMULATIVE
1996	15,114	2,962	18,076	338	2,261	2,599	706	177,002	88,501	NA	NA	NA
1997	15,354	3,009	18,363	348	2,317	2,665	724	181,497	90,748	90	90	0.10%
1998	15,628	3,064	18,692	362	2,401	2,763	750	188,171	94,085	176	86	0.19%
1999	15,965	3,131	19,096	375	2,480	2,855	775	194,436	97,218	269	93	0.28%
2000	16,307	3,200	19,507	392	2,587	2,979	809	202,881	101,441	359	90	0.35%
2001	16,655	3,269	19,924	409	2,687	3,096	841	210,850	105,425	448	89	0.42%
2002	17,011	3,340	20,351	427	2,798	3,225	876	219,635	109,817	538	90	0.49%
2003	17,372	3,412	20,784	446	2,908	3,354	911	228,420	114,210	628	90	0.55%
2004	17,740	3,486	21,226	466	3,032	3,498	950	238,227	119,114	717	89	0.60%
2005	18,099	3,558	21,657	485	3,145	3,630	986	247,241	123,621	807	90	0.65%
2006	18,465	3,631	22,096	505	3,263	3,768	1,023	256,597	128,298	897	90	0.70%

NOTES: 1. GSD AND GSND ANNUAL ENERGIES ARE FROM OUC 1995 TEN YEAR SITE PLAN.
2. COINCIDENT SUMMER DEMAND REDUCTION IS FROM OUC 1994 CEGRR.
3. HALF OF COMMERCIAL LIGHTING DEMAND IS ASSUMED ELIGIBLE FOR PROGRAM.
4. THE VALUE OF 3,988 KWH/KW IS FROM OUC 1994 CEGRR.
5. C. DEMAND - COINCIDENT SUMMER DEMHAND AT THE GENERATOR
6. THE VALUE OF 27.2% OF COMMERCIAL ENERGY IS ASSUMED TO BE INTERIOR COMMERCIAL LIGHTING. THIS IS DERIVED FROM SRC 1993 OUC SALES PROFILE.

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SECTION IV

APPENDIX B

ENERGY AND DEMAND REDUCTIONS

ORLANDO UTILITIES COMMISSION
1995 DEMAND SIDE MANAGEMENT PLAN
ENERGY AND DEMAND REDUCTIONS AT THE METER

RESIDENTIAL

	DIRECT LOAD CONTROL CAC w/SH & DWH			DIRECT LOAD CONTROL POOL PUMPS			TOTAL		
YEAR	ENERGY CUMULATIVE KWH	DEMAND WINTER CUMULATIVE KW	DEMAND SUMMER CUMULATIVE KW	ENERGY CUMULATIVE KWH	DEMAND WINTER CUMULATIVE KW	DEMAND SUMMER CUMULATIVE KW	ENERGY CUMULATIVE KWH	DEMAND WINTER CUMULATIVE KW	DEMAND SUMMER CUMULATIVE KW
1996	NA	NA	NA	NA	NA	NA	NA	NA	NA
1997	0	757	412	0	0	148	0	757	560
1998	0	1,136	619	0	0	295	0	1,136	914
1999	0	1,893	1,031	0	0	443	0	1,893	1,474
2000	0	2,839	1,546	0	0	589	0	2,839	2,135
2001	0	3,975	2,165	0	0	737	0	3,975	2,902
2002	0	5,299	2,886	0	0	884	0	5,299	3,770
2003	0	6,812	3,711	0	0	1,032	0	6,812	4,743
2004	0	8,515	4,638	0	0	1,180	0	8,515	5,817
2005	0	10,046	5,471	0	0	1,327	0	10,046	6,798
2006	0	11,409	6,214	0	0	1,475	0	11,409	7,689

NOTE: THE VALUES LISTED ARE NOT OUC'S GOALS BUT RATHER OFFERED AS PROOF THAT OUC HAS A VIABLE PLAN TO MEETS ITS GOALS.

COMMERCIAL - TOTAL

COMMERCIAL EFFICIENT LIGHTING

YEAR	ENERGY CUMULATIVE KWH	DEMAND WINTER CUMULATIVE KW	DEMAND SUMMER CUMULATIVE KW
1996	NA	NA	NA
1997	140,305	0	74
1998	421,877	0	147
1999	702,487	0	220
2000	983,097	0	294
2001	1,264,669	0	367
2002	1,545,279	0	441
2003	1,826,851	0	515
2004	2,107,461	0	588
2005	2,388,072	0	661
2006	3,793,046	0	735

NOTE: THE VALUES LISTED ARE NOT OUC'S GOALS BUT RATHER OFFERED AS PROOF THAT OUC HAS A VIABLE PLAN TO MEETS ITS GOALS.

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ORLANDO UTILITIES COMMISSION
1995 DEMAND SIDE MANAGEMENT PLAN
ENERGY AND DEMAND REDUCTIONS AT THE GENERATOR

RESIDENTIAL

	DIRECT LOAD CONTROL CAC w/SH & DWH			DIRECT LOAD CONTROL POOL PUMPS			TOTAL		
	ENERGY CUMULATIVE	DEMAND WINTER CUMULATIVE	DEMAND SUMMER CUMULATIVE	ENERGY CUMULATIVE	DEMAND WINTER CUMULATIVE	DEMAND SUMMER CUMULATIVE	ENERGY CUMULATIVE	DEMAND WINTER CUMULATIVE	DEMAND SUMMER CUMULATIVE
YEAR	KWH	KW	KW	KWH	KW	KW	KWH	KW	KW
1996	NA	NA	NA	NA	NA	NA	NA	NA	NA
1997	0	923	503	0	0	180	0	923	683
1998	0	1,386	755	0	0	360	0	1,386	1,115
1999	0	2,309	1,258	0	0	540	0	2,309	1,798
2000	0	3,463	1,886	0	0	719	0	3,463	2,605
2001	0	4,849	2,641	0	0	899	0	4,849	3,540
2002	0	6,465	3,521	0	0	1,079	0	6,465	4,600
2003	0	8,311	4,527	0	0	1,259	0	8,311	5,786
2004	0	10,388	5,658	0	0	1,439	0	10,388	7,097
2005	0	12,256	6,675	0	0	1,619	0	12,256	8,294
2006	0	13,919	7,581	0	0	1,799	0	13,919	9,380

NOTE: THE VALUES LISTED ARE NOT OUC'S GOALS BUT RATHER OFFERED AS PROOF THAT OUC HAS A VIABLE PLAN TO MEETS ITS GOALS.

COMMERCIAL - TOTAL
COMMERCIAL EFFICIENT LIGHTING

	ENERGY CUMULATIVE	DEMAND WINTER CUMULATIVE	DEMAND SUMMER CUMULATIVE
YEAR	KWH	KW	KW
1996	NA	NA	NA
1997	146,000	0	90
1998	439,000	0	179
1999	731,000	0	269
2000	1,023,000	0	359
2001	1,316,000	0	448
2002	1,608,000	0	538
2003	1,901,000	0	628
2004	2,193,000	0	717
2005	2,485,000	0	807
2006	3,947,000	0	897

NOTE: THE VALUES LISTED ARE NOT OUC'S GOALS BUT RATHER OFFERED AS PROOF THAT OUC HAS A VIABLE PLAN TO MEETS ITS GOALS.

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SECTION IV

APPENDIX C.1

DIRECT LOAD CONTROL - MAIN

COST EFFECTIVENESS CALCULATIONS

INPUT DATA -- PART 1
PROGRAM: DLC-1A CAC/SH + DWH, EC/NC,SF

I. PROGRAM DEMAND SAVINGS AND LINE LOSSES

(1) CUSTOMER KW REDUCTION AT THE METER	2.24 KW /CUST
(2) GENERATOR KW REDUCTION PER CUSTOMER	2.74 KW GEN/CUST
(3) KW LINE LOSS PERCENTAGE	3.8 %
(4) GENERATION KWH REDUCTION PER CUSTOMER	0.0 KWH/CUST/YR
(5) KWH LINE LOSS PERCENTAGE	3.9 %
(6) GROUP LINE LOSS MULTIPLIER	1.0180
(7) CUSTOMER KWH PROGRAM INCREASE AT METER	0.0 KWH/CUST/YR
(8) CUSTOMER KWH REDUCTION AT METER	0.0 KWH/CUST/YR
(9) SUMMER KW/CUST AT METER	1.22
(10) WINTER KW/CUST AT METER	2.24

II. ECONOMIC LIFE AND K FACTORS

(1) STUDY PERIOD FOR CONSERVATION PROGRAM	24 YEARS
(2) GENERATOR ECONOMIC LIFE	25 YEARS
(3) T & D ECONOMIC LIFE	32 YEARS
(4) K FACTOR FOR GENERATION	1.0790
(5) K FACTOR FOR T & D	1.0790
(6) SWITCH REV REQ(0) OR VAL-OF-DEF (1)	0

III. UTILITY AND CUSTOMER COSTS

(1) UTILITY NONRECURRING COST PER CUSTOMER	175.00 $/CUST
(2) ANNUAL UTILITY PROGRAM COST	133,000.00 $/YR
(3) UTILITY COST ESCALATION RATE	4.0 %
(4) CUSTOMER INCREMENTAL EQUIPMENT COST	0.00 $/CUST
(5) CUSTOMER EQUIPMENT ESCALATION RATE	4.0 %
(6) CUSTOMER INCREMENTAL 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	2.0 %
(10) INCREASED SUPPLY COSTS	0.00 $/CUST/YR
(11) SUPPLY COSTS ESCALATION RATE	0.0 %
(12) UTILITY DISCOUNT RATE	7.90%
(13) UTILITY CWIP RATE	7.90%
(14) UTILITY NON RECURRING REBATE/INCENTIVE ...	0.00 $/CUST
(15) UTILITY RECURRING REBATE/INCENTIVE	24.00 $/CUST/YR
(16) UTILITY REBATE/INCENTIVE ESCAL RATE	0.0 %

IV. AVOIDED GENERATOR, TRANS. AND DIST. COSTS

(1) BASE YEAR	1996
(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT	2014
(3) IN-SERVICE YEAR FOR AVOIDED T & D	2014
(4) BASE YEAR AVOIDED GENERATING UNIT COST	356.00 $/KW
(5) BASE YEAR AVOIDED TRANSMISSION COST	67.69 $/KW
(6) BASE YEAR DISTRIBUTION COST	99.16 $/KW
(7) GEN, TRAN, & DIST COST ESCALATION RATE ...	2.5 %
(8) GENERATOR FIXED O & M COST	0.00 $/KW/YR
(9) GENERATOR FIXED O&M ESCALATION RATE	4.0 %
(10) TRANSMISSION FIXED O & M COST	1.27 $/KW/YR
(11) DISTRIBUTION FIXED O & M COST	0.26 $/KW/YR
(12) T&D FIXED O&M ESCALATION RATE	4.0 %
(13) AVOIDED GEN UNIT VARIABLE O & M COSTS	1.430 CENTS/KWH
(14) GENERATOR VARIABLE O&M COST ESCALATION RATE	4.0 %
(15) GENERATOR CAPACITY FACTOR	5 %
(16) AVOIDED GENERATING UNIT FUEL COST	3.260 CENTS/KWH
(17) AVOIDED GEN UNIT FUEL ESCALATION RATE	5.4 %
(18) AVOIDED PURCHASE CAPACITY COST PER KW	0.00 $/KW/YR
(19) CAPACITY COST ESCALATION RATE	0.0 %

V. NON-FUEL ENERGY AND DEMAND CHARGES

(1) NON-FUEL COST IN CUSTOMER BILL	5.243 CENTS/KWH
(2) NON-FUEL ESCALATION RATE	3.5 %
(3) CUSTOMER DEMAND CHARGE PER KW	0.00 $/KW/MO
(4) DEMAND CHARGE ESCALATION RATE	0.0 %
(5) DIVERSITY and ANNUAL DEMAND ADJUSTMENT FACTOR FOR CUSTOMER BILL	0.0

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

CALCULATION OF CWIP AND IN-SERVICE COST OF PLANT
PLANT: 2014 AVOIDED UNIT

(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 CWIP ($/KW)	(9) YEARLY TOTAL CWIP ($/KW)	(10) INCREMENTAL YEAR-END BOOK VALUE ($/KW)	(11) CUMULATIVE YEAR-END BOOK VALUE ($/KW)
2005	-9	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2006	-8	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2007	-7	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2008	-6	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2009	-5	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2010	-4	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2011	-3	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2012	-2	50.0%	1.5000	50.0%	267.00	133.50	133.50	10.55	277.55	277.55
2013	-1	50.0%	2.2500	50.0%	400.50	467.25	477.80	37.75	438.25	715.79
2014	0			0.0%	0.00			0.00	0.00	
				1.00	667.50			48.29	715.79	

IN-SERVICE YEAR = 2014

PLANT COSTS (1996 $) $356.0
AFUDC RATE: 7.90%

INPUT DATA -- PART 2
PROGRAM: DLC-1A CAC/SH + DWH, EC/NC,SF

(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
1996	84	84	1.91	2.42	1.96	0.00	1.00	1.00
1997	253	253	2.07	2.12	1.72	0.00	1.00	1.00
1998	506	506	2.12	2.21	1.76	0.00	1.00	1.00
1999	843	843	2.17	2.26	1.82	0.00	1.00	1.00
2000	1,264	1,264	2.26	2.43	1.90	0.00	1.00	1.00
2001	1,770	1,770	2.28	2.55	1.95	0.00	1.00	1.00
2002	2,360	2,360	2.33	2.63	1.98	0.00	1.00	1.00
2003	3,034	3,034	2.43	2.82	2.13	0.00	1.00	1.00
2004	3,792	3,792	2.50	2.31	2.24	0.00	1.00	1.00
2005	4,474	4,474	2.60	3.37	2.38	0.00	1.00	1.00
2006	5,081	5,081	2.69	3.91	2.62	0.00	1.00	1.00
2007	5,612	5,612	2.80	4.04	2.73	0.00	1.00	1.00
2008	6,067	6,067	2.94	4.24	2.83	0.00	1.00	1.00
2009	6,446	6,446	3.03	4.55	3.01	0.00	1.00	1.00
2010	6,749	6,749	3.19	4.95	3.21	0.00	1.00	1.00
2011	6,976	6,976	3.36	5.61	3.53	0.00	1.00	1.00
2012	7,128	7,128	3.47	6.10	3.79	0.00	1.00	1.00
2013	7,204	7,204	3.72	6.20	3.90	0.00	1.00	1.00
2014	0	7,204	3.90	6.61	4.14	0.00	1.00	1.00
2015	0	7,204	4.04	7.07	4.40	0.00	1.00	1.00
2016	0	7,204	4.23	7.56	4.67	0.04	1.00	1.00
2017	0	7,204	4.42	8.08	4.97	0.04	1.00	1.00
2018	0	7,204	4.62	8.64	5.28	0.05	1.00	1.00
2019	0	7,204	4.83	9.25	5.61	0.05	1.00	1.00

AVOIDED GENERATION UNIT BENEFITS
PROGRAM: DLC-1A CAC/SH + DWH, EC/NC,SF

* UNIT SIZE OF AVOIDED GENERATION UNIT = 19,735 KW
* INSERVICE COSTS OF AVOIDED GEN. UNIT (000) $14,126

(1) YEAR	(1A) REVENUE REQUIREMENT 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)
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	0.000	0	0	0	0	0	0	0	0
2005	0.000	0	0	0	0	0	0	0	0
2006	0.000	0	0	0	0	0	0	0	0
2007	0.000	0	0	0	0	0	0	0	0
2008	0.000	0	0	0	0	0	0	0	0
2009	0.000	0	0	0	0	0	0	0	0
2010	0.000	0	0	0	0	0	0	0	0
2011	0.000	0	0	0	0	0	0	0	0
2012	0.000	0	0	0	0	0	0	0	0
2013	0.000	0	0	0	0	0	0	0	0
2014	0.119	1,681	6,096	0	177	512	0	0	2,370
2015	0.116	1,636	6,096	0	184	540	0	0	2,360
2016	0.113	1,592	6,096	0	191	569	2	0	2,349
2017	0.110	1,547	6,096	0	199	600	3	0	2,343
2018	0.106	1,502	6,096	0	207	632	3	0	2,338
2019	0.103	1,458	6,096	0	215	666	3	0	2,336
NOMINAL		9,417	36,579	0	1,171	3,519	11	0	14,096
NPV		2,011		0	246	738	2	0	2,993

AVOIDED T & D AND PROGRAM FUEL SAVINGS
PROGRAM: DLC-1A CAC/SH + DWH, EC/NC,SF

* INSERVICE COSTS OF AVOIDED TRANS. (000) = $2,083
* INSERVICE COSTS OF AVOIDED DIST. (000) = $2,496

(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)
1996	0	0	0	0	0	0	0
1997	0	0	0	0	0	0	0
1998	0	0	0	0	0	0	0
1999	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0
2001	0	0	0	0	0	0	0
2002	0	0	0	0	0	0	0
2003	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0
2014	230	36	266	275	6	281	0
2015	225	37	262	269	6	275	0
2016	219	39	258	263	6	269	0
2017	214	40	255	257	7	263	0
2018	209	42	251	251	7	257	0
2019	204	44	248	244	7	252	0
NOMINAL	1,301	238	1,539	1,558	39	1,598	0
NPV:	278	50	328	332	8	341	0

WORKSHEET : DSM PROGRAM FUEL SAVINGS
PROGRAM: DLC-1A CAC/SH + DWH, EC/HC,SF

(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)
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
2015	0	0	0	0	0	0
2016	0	0	0	0	0	0
2017	0	0	0	0	0	0
2018	0	0	0	0	0	0
2019	0	0	0	0	0	0
NOMINAL	0	0	0	0	0	0
NPV:		0		0	0	0

WORKSHEET: UTILITY COSTS AND PARTICIPANT COSTS AND REV LOSS/GAIN/RG
PROGRAM: DLC-1A CAC/SH + DWH, EC/NC,SF

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	<----- UTILITY PROGRAM COSTS & REBATES ------->					
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)
1996	15	133	148	0	1	1
1997	31	138	169	0	4	4
1998	48	144	192	0	9	9
1999	66	150	216	0	16	16
2000	86	156	242	0	25	25
2001	108	162	270	0	36	36
2002	131	168	299	0	50	50
2003	155	175	330	0	65	65
2004	182	182	364	0	82	82
2005	170	189	359	0	99	99
2006	157	197	354	0	115	115
2007	143	205	348	0	128	128
2008	127	213	340	0	140	140
2009	110	221	332	0	150	150
2010	92	230	322	0	158	158
2011	72	240	311	0	165	165
2012	50	249	299	0	169	169
2013	26	259	285	0	172	172
2014	0	0	0	0	0	0
2015	0	0	0	0	0	0
2016	0	0	0	0	0	0
2017	0	0	0	0	0	0
2018	0	0	0	0	0	0
2019	0	0	0	0	0	0
NOM.	1,768	3,411	5,179	0	1,585	1,585
NPV	937	1,783	2,720	0	659	659

(1)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
	<------------------ PARTICIPATING CUSTOMER COSTS & BENEFITS --------------------->										
YEAR	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)
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
2015	0	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0
NOM.	0	0	0	0	0	0	0	0	0	0	0
NPV	0	0	0		0	0	0		0	0	0

TOTAL RESOURCE COST TESTS
PROGRAM: DLC-1A CAC/SH + DWH, EC/NC,SF

(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)
1996	0	148	0	0	148	0	0	0	0	0	(148)	(148)
1997	0	169	0	0	169	0	0	0	0	0	(169)	(304)
1998	0	192	0	0	192	0	0	0	0	0	(192)	(469)
1999	0	216	0	0	216	0	0	0	0	0	(216)	(641)
2000	0	242	0	0	242	0	0	0	0	0	(242)	(819)
2001	0	270	0	0	270	0	0	0	0	0	(270)	(1,004)
2002	0	299	0	0	299	0	0	0	0	0	(299)	(1,193)
2003	0	330	0	0	330	0	0	0	0	0	(330)	(1,387)
2004	0	364	0	0	364	0	0	0	0	0	(364)	(1,585)
2005	0	359	0	0	359	0	0	0	0	0	(359)	(1,766)
2006	0	354	0	0	354	0	0	0	0	0	(354)	(1,932)
2007	0	348	0	0	348	0	0	0	0	0	(348)	(2,082)
2008	0	340	0	0	340	0	0	0	0	0	(340)	(2,219)
2009	0	332	0	0	332	0	0	0	0	0	(332)	(2,343)
2010	0	322	0	0	322	0	0	0	0	0	(322)	(2,454)
2011	0	311	0	0	311	0	0	0	0	0	(311)	(2,553)
2012	0	299	0	0	299	0	0	0	0	0	(299)	(2,642)
2013	0	285	0	0	285	0	0	0	0	0	(285)	(2,720)
2014	0	0	0	0	0	2,370	547	0	0	2,916	2,916	(1,978)
2015	0	0	0	0	0	2,360	537	0	0	2,897	2,897	(1,295)
2016	0	0	0	0	0	2,349	527	0	0	2,877	2,877	(666)
2017	0	0	0	0	0	2,343	518	0	0	2,861	2,861	(86)
2018	0	0	0	0	0	2,338	508	0	0	2,847	2,847	448
2019	0	0	0	0	0	2,336	499	0	0	2,835	2,835	941
NOMINAL	0	5,179	0	0	5,179	14,096	3,136	0	0	17,233	12,054	
NPV:	0	2,720	0	0	2,720	2,993	668	0	0	3,661	941	

Discount Rate 7.90%
Benefit/Cost Ratio: col (11) / col (6) 1.346

PARTICIPANT COSTS AND BENEFITS
PROGRAM: DLC-1A CAC/SH + DWH, EC/NC,SF

(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)
1996	0	0	1	0	1	0	0	0	0	1	1
1997	0	0	4	0	4	0	0	0	0	4	5
1998	0	0	9	0	9	0	0	0	0	9	13
1999	0	0	16	0	16	0	0	0	0	16	25
2000	0	0	25	0	25	0	0	0	0	25	44
2001	0	0	36	0	36	0	0	0	0	36	69
2002	0	0	50	0	50	0	0	0	0	50	100
2003	0	0	65	0	65	0	0	0	0	65	138
2004	0	0	82	0	82	0	0	0	0	82	183
2005	0	0	99	0	99	0	0	0	0	99	233
2006	0	0	115	0	115	0	0	0	0	115	287
2007	0	0	128	0	128	0	0	0	0	128	342
2008	0	0	140	0	140	0	0	0	0	140	399
2009	0	0	150	0	150	0	0	0	0	150	454
2010	0	0	158	0	158	0	0	0	0	158	509
2011	0	0	165	0	165	0	0	0	0	165	562
2012	0	0	169	0	169	0	0	0	0	169	612
2013	0	0	172	0	172	0	0	0	0	172	659
2014	0	0	0	0	0	0	0	0	0	0	659
2015	0	0	0	0	0	0	0	0	0	0	659
2016	0	0	0	0	0	0	0	0	0	0	659
2017	0	0	0	0	0	0	0	0	0	0	659
2018	0	0	0	0	0	0	0	0	0	0	659
2019	0	0	0	0	0	0	0	0	0	0	659
NOMINAL	0	0	1,585	0	1,585	0	0	0	0	1,585	
NPV:	0	0	659	0	659	0	0	0	0	659	

In service year of gen unit: 2014
Discount rate: 7.90%

RATE IMPACT TEST
PROGRAM:DLC-1A CAC/SH + DWH, EC/NC,SF

(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)
----	------	------	------	------	------	------	------	------	------	------	------	------	------
1996	0	148	1	0	0	149	0	0	0	0	0	(149)	(149)
1997	0	169	4	0	0	173	0	0	0	0	0	(173)	(309)
1998	0	192	9	0	0	201	0	0	0	0	0	(201)	(482)
1999	0	216	16	0	0	232	0	0	0	0	0	(232)	(666)
2000	0	242	25	0	0	267	0	0	0	0	0	(267)	(863)
2001	0	270	36	0	0	306	0	0	0	0	0	(306)	(1,073)
2002	0	299	50	0	0	348	0	0	0	0	0	(348)	(1,294)
2003	0	330	65	0	0	395	0	0	0	0	0	(395)	(1,525)
2004	0	364	82	0	0	445	0	0	0	0	0	(445)	(1,768)
2005	0	359	99	0	0	458	0	0	0	0	0	(458)	(1,999)
2006	0	354	115	0	0	469	0	0	0	0	0	(469)	(2,218)
2007	0	348	128	0	0	476	0	0	0	0	0	(476)	(2,425)
2008	0	340	140	0	0	481	0	0	0	0	0	(481)	(2,618)
2009	0	332	150	0	0	482	0	0	0	0	0	(482)	(2,797)
2010	0	322	158	0	0	480	0	0	0	0	0	(480)	(2,963)
2011	0	311	165	0	0	476	0	0	0	0	0	(476)	(3,115)
2012	0	299	169	0	0	468	0	0	0	0	0	(468)	(3,253)
2013	0	285	172	0	0	457	0	0	0	0	0	(457)	(3,379)
2014	0	0	0	0	0	0	2,370	547	0	0	2,916	2,916	(2,637)
2015	0	0	0	0	0	0	2,360	537	0	0	2,897	2,897	(1,954)
2016	0	0	0	0	0	0	2,349	527	0	0	2,877	2,877	(1,325)
2017	0	0	0	0	0	0	2,343	518	0	0	2,861	2,861	(745)
2018	0	0	0	0	0	0	2,338	508	0	0	2,847	2,847	(211)
2019	0	0	0	0	0	0	2,336	499	0	0	2,835	2,835	282
	------	------	------	------	------	------	------	------	------	------	------	------	
NOMINAL	0	5,179	1,585	0	0	6,764	14,096	3,136	0	0	17,233	10,469	
NPV:	0	2,720	659	0	0	3,379	2,993	668	0	0	3,661	282	

Discount rate: 7.90%
Benefit / Cost Ratio - Col (12)/Col (7) 1.084

SECTION IV

APPENDIX C.2

DIRECT LOAD CONTROL
POOL PUMPS

COST EFFECTIVENESS
CALCULATIONS

INPUT DATA -- PART 1
PROGRAM: DLC-2 POOL PUMPS, EC/NC,SF

I. PROGRAM DEMAND SAVINGS AND LINE LOSSES

(1) CUSTOMER KW REDUCTION AT THE METER	0.75 KW /CUST
(2) GENERATOR KW REDUCTION PER CUSTOMER	0.92 KW GEN/CUST
(3) KW LINE LOSS PERCENTAGE	3.8 %
(4) GENERATION KWH REDUCTION PER CUSTOMER	0.0 KWH/CUST/YR
(5) KWH LINE LOSS PERCENTAGE	3.9 %
(6) GROUP LINE LOSS MULTIPLIER	1.0180
(7) CUSTOMER KWH PROGRAM INCREASE AT METER	0.0 KWH/CUST/YR
(8) CUSTOMER KWH REDUCTION AT METER	0.0 KWH/CUST/YR
(9) SUMMER KW/CUST AT METER	0.75
(10) WINTER KW/CUST AT METER	0.00

II. ECONOMIC LIFE AND K FACTORS

(1) STUDY PERIOD FOR CONSERVATION PROGRAM	24 YEARS
(2) GENERATOR ECONOMIC LIFE	25 YEARS
(3) T & D ECONOMIC LIFE	32 YEARS
(4) K FACTOR FOR GENERATION	1.0790
(5) K FACTOR FOR T & D	1.0790
(6) SWITCH REV REQ(0) OR VAL-OF-DEF (1)	0

III.UTILITY AND CUSTOMER COSTS

(1) UTILITY NONRECURRING COST PER CUSTOMER	175.00 $/CUST
(2) ANNUAL UTILITY PROGRAM COST	0.00 $/YR
(3) UTILITY COST ESCALATION RATE	4.0 %
(4) CUSTOMER INCREMENTAL EQUIPMENT COST	0.00 $/CUST
(5) CUSTOMER EQUIPMENT ESCALATION RATE	4.0 %
(6) CUSTOMER INCREMENTAL 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	2.0 %
(10) INCREASED SUPPLY COSTS	0.00 $/CUST/YR
(11) SUPPLY COSTS ESCALATION RATE	0.0 %
(12) UTILITY DISCOUNT RATE	7.90%
(13) UTILITY CWIP RATE	7.90%
(14) UTILITY NON RECURRING REBATE/INCENTIVE ...	0.00 $/CUST
(15) UTILITY RECURRING REBATE/INCENTIVE	6.00 $/CUST/YR
(16) UTILITY REBATE/INCENTIVE ESCAL RATE	0.0 %

IV. AVOIDED GENERATOR, TRANS. AND DIST. COSTS

(1) BASE YEAR	1996
(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT	2014
(3) IN-SERVICE YEAR FOR AVOIDED T & D	2014
(4) BASE YEAR AVOIDED GENERATING UNIT COST	356.00 $/KW
(5) BASE YEAR AVOIDED TRANSMISSION COST	67.69 $/KW
(6) BASE YEAR DISTRIBUTION COST	99.16 $/KW
(7) GEN, TRAN, & DIST COST ESCALATION RATE ...	2.5 %
(8) GENERATOR FIXED O & M COST	0.00 $/KW/YR
(9) GENERATOR FIXED O&M ESCALATION RATE	4.0 %
(10) TRANSMISSION FIXED O & M COST	1.27 $/KW/YR
(11) DISTRIBUTION FIXED O & M COST	0.26 $/KW/YR
(12) T&D FIXED O&M ESCALATION RATE	4.0 %
(13) AVOIDED GEN UNIT VARIABLE O & M COSTS	1.430 CENTS/KWH
(14) GENERATOR VARIABLE O&M COST ESCALATION RATE	4.0 %
(15) GENERATOR CAPACITY FACTOR	5 %
(16) AVOIDED GENERATING UNIT FUEL COST	3.260 CENTS/KWH
(17) AVOIDED GEN UNIT FUEL ESCALATION RATE	5.4 %
(18) AVOIDED PURCHASE CAPACITY COST PER KW	0.00 $/KW/YR
(19) CAPACITY COST ESCALATION RATE	0.0 %

V. NON-FUEL ENERGY AND DEMAND CHARGES

(1) NON-FUEL COST IN CUSTOMER BILL	5.243 CENTS/KWH
(2) NON-FUEL ESCALATION RATE	3.5 %
(3) CUSTOMER DEMAND CHARGE PER KW	0.00 $/KW/MO
(4) DEMAND CHARGE ESCALATION RATE	0.0 %
(5) DIVERSITY and ANNUAL DEMAND ADJUSTMENT FACTOR FOR CUSTOMER BILL	0.0

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

CALCULATION OF CWIP AND IN-SERVICE COST OF PLANT
PLANT: 2014 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 CWIP ($/KW)	YEARLY TOTAL CWIP ($/KW)	INCREMENTAL YEAR-END BOOK VALUE ($/KW)	CUMULATIVE YEAR-END BOOK VALUE ($/KW)
----	----	----	-----	----	------	------	------	------	------	------
2005	-9	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2006	-8	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2007	-7	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2008	-6	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2009	-5	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2010	-4	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2011	-3	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2012	-2	50.0%	1.5000	50.0%	267.00	133.50	133.50	10.55	277.55	277.55
2013	-1	50.0%	2.2500	50.0%	400.50	467.25	477.80	37.75	438.25	715.79
2014	0			0.0%	0.00			0.00	0.00	
				----	------			------	------	
				1.00	667.50			48.29	715.79	

IN-SERVICE YEAR = 2014

PLANT COSTS (1996 $) $356.0
AFUDC RATE: 7.90%

(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
1996	33	33	1.91	2.42	1.96	0.00	1.00	1.00
1997	99	99	2.07	2.12	1.72	0.00	1.00	1.00
1998	199	199	2.12	2.21	1.76	0.00	1.00	1.00
1999	332	332	2.17	2.26	1.82	0.00	1.00	1.00
2000	498	498	2.26	2.43	1.90	0.00	1.00	1.00
2001	697	697	2.28	2.55	1.95	0.00	1.00	1.00
2002	930	930	2.33	2.63	1.98	0.00	1.00	1.00
2003	1,196	1,196	2.43	2.82	2.13	0.00	1.00	1.00
2004	1,495	1,495	2.50	2.31	2.24	0.00	1.00	1.00
2005	1,761	1,761	2.60	3.37	2.38	0.00	1.00	1.00
2006	1,994	1,994	2.69	3.91	2.62	0.00	1.00	1.00
2007	2,193	2,193	2.80	4.04	2.73	0.00	1.00	1.00
2008	2,359	2,359	2.94	4.24	2.83	0.00	1.00	1.00
2009	2,492	2,492	3.03	4.55	3.01	0.00	1.00	1.00
2010	2,592	2,592	3.19	4.95	3.21	0.00	1.00	1.00
2011	2,658	2,658	3.36	5.61	3.53	0.00	1.00	1.00
2012	2,691	2,691	3.47	6.10	3.79	0.00	1.00	1.00
2013	2,691	2,691	3.72	6.20	3.90	0.00	1.00	1.00
2014	0	2,691	3.90	6.61	4.14	0.00	1.00	1.00
2015	0	2,691	4.04	7.07	4.40	0.00	1.00	1.00
2016	0	2,691	4.23	7.56	4.67	0.04	1.00	1.00
2017	0	2,691	4.42	8.08	4.97	0.04	1.00	1.00
2018	0	2,691	4.62	8.64	5.28	0.05	1.00	1.00
2019	0	2,691	4.83	9.25	5.61	0.05	1.00	1.00

AVOIDED GENERATION UNIT BENEFITS
PROGRAM: DLC-2 POOL PUMPS, EC/NC,SF

* UNIT SIZE OF AVOIDED GENERATION UNIT = 2,468 KW
* INSERVICE COSTS OF AVOIDED GEN. UNIT (000) $1,767

(1) YEAR	(1A) REVENUE REQUIREMENT 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)
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	0.000	0	0	0	0	0	0	0	0
2005	0.000	0	0	0	0	0	0	0	0
2006	0.000	0	0	0	0	0	0	0	0
2007	0.000	0	0	0	0	0	0	0	0
2008	0.000	0	0	0	0	0	0	0	0
2009	0.000	0	0	0	0	0	0	0	0
2010	0.000	0	0	0	0	0	0	0	0
2011	0.000	0	0	0	0	0	0	0	0
2012	0.000	0	0	0	0	0	0	0	0
2013	0.000	0	0	0	0	0	0	0	0
2014	0.119	210	801	0	23	67	0	0	301
2015	0.116	205	801	0	24	71	0	0	300
2016	0.113	199	801	0	25	75	0	0	299
2017	0.110	193	801	0	26	79	0	0	298
2018	0.106	188	801	0	27	83	0	0	298
2019	0.103	182	801	0	28	88	0	0	298
NOMINAL		1,178	4,806	0	154	462	1	0	1,793
NPV		251		0	32	97	0	0	381

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AVOIDED T & D AND PROGRAM FUEL SAVINGS
PROGRAM: DLC-2 POOL PUMPS, EC/NC,SF

* INSERVICE COSTS OF AVOIDED TRANS. (000) = $261
* INSERVICE COSTS OF AVOIDED DIST. (000) = $312

(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)
1996	0	0	0	0	0	0	0
1997	0	0	0	0	0	0	0
1998	0	0	0	0	0	0	0
1999	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0
2001	0	0	0	0	0	0	0
2002	0	0	0	0	0	0	0
2003	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0
2014	29	5	33	34	1	35	0
2015	28	5	33	34	1	34	0
2016	27	5	33	33	1	34	0
2017	27	5	32	32	1	33	0
2018	26	6	32	31	1	32	0
2019	26	6	31	31	1	32	0
NOMINAL	163	31	194	195	5	200	0
NPV:	35	7	41	42	1	43	0

(1)	(2)	(3)	(4)	(5)	(6)	(7)
YEAR	REDUCTION IN KWH GENERATION NET NEW CUST KWH (000)	AVOIDED MARGINAL FUEL COST - REDUCED KWH $(000)	INCREASE IN KWH GENERATION NET NEW CUST KWH (000)	INCREASED MARGINAL FUEL COST - INCREASE KWH $(000)	NET AVOIDED PROGRAM FUEL SAVINGS $(000)	EFFECTIVE PROGRAM FUEL SAVINGS $(000)
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
2015	0	0	0	0	0	0
2016	0	0	0	0	0	0
2017	0	0	0	0	0	0
2018	0	0	0	0	0	0
2019	0	0	0	0	0	0
NOMINAL	0	0	0	0	0	0
NPV:		0		0	0	0

WORKSHEET: UTILITY COSTS AND PARTICIPANT COSTS AND REV LOSS/GAIN/RU
PROGRAM: DLC-2 POOL PUMPS, EC/NC,SF

(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)
1996	6	0	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1997	12	0	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1998	19	0	19	0	1	1	0	0	0	0	0	0	0	0	0	0	0
1999	26	0	26	0	2	2	0	0	0	0	0	0	0	0	0	0	0
2000	34	0	34	0	2	2	0	0	0	0	0	0	0	0	0	0	0
2001	42	0	42	0	4	4	0	0	0	0	0	0	0	0	0	0	0
2002	52	0	52	0	5	5	0	0	0	0	0	0	0	0	0	0	0
2003	61	0	61	0	6	6	0	0	0	0	0	0	0	0	0	0	0
2004	72	0	72	0	8	8	0	0	0	0	0	0	0	0	0	0	0
2005	66	0	66	0	10	10	0	0	0	0	0	0	0	0	0	0	0
2006	60	0	60	0	11	11	0	0	0	0	0	0	0	0	0	0	0
2007	54	0	54	0	13	13	0	0	0	0	0	0	0	0	0	0	0
2008	47	0	47	0	14	14	0	0	0	0	0	0	0	0	0	0	0
2009	39	0	39	0	15	15	0	0	0	0	0	0	0	0	0	0	0
2010	30	0	30	0	15	15	0	0	0	0	0	0	0	0	0	0	0
2011	21	0	21	0	16	16	0	0	0	0	0	0	0	0	0	0	0
2012	11	0	11	0	16	16	0	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	16	16	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
2015	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NOM.	651	0	651	0	153	153	0	0	0	0	0	0	0	0	0	0	0
NPV	354	0	354	0	64	64	0	0	0		0	0	0		0	0	0

TOTAL RESOURCE COST TESTS
PROGRAM: DLC-2 POOL PUMPS, EC/NC,SF

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	INCREASED SUPPLY COSTS	UTILITY PROGRAM COSTS	PARTICIPANT PROGRAM COSTS	OTHER COSTS	TOTAL COSTS	AVOIDED GEN UNIT BENEFITS	AVOIDED T & D BENEFITS	PROGRAM FUEL SAVINGS	OTHER BENEFITS	TOTAL BENEFITS	NET BENEFITS	CUMULATIVE DISCOUNTED NET BENEFITS
YEAR	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
1996	0	6	0	0	6	0	0	0	0	0	(6)	(6)
1997	0	12	0	0	12	0	0	0	0	0	(12)	(17)
1998	0	19	0	0	19	0	0	0	0	0	(19)	(33)
1999	0	26	0	0	26	0	0	0	0	0	(26)	(54)
2000	0	34	0	0	34	0	0	0	0	0	(34)	(79)
2001	0	42	0	0	42	0	0	0	0	0	(42)	(108)
2002	0	52	0	0	52	0	0	0	0	0	(52)	(141)
2003	0	61	0	0	61	0	0	0	0	0	(61)	(177)
2004	0	72	0	0	72	0	0	0	0	0	(72)	(216)
2005	0	66	0	0	66	0	0	0	0	0	(66)	(249)
2006	0	60	0	0	60	0	0	0	0	0	(60)	(277)
2007	0	54	0	0	54	0	0	0	0	0	(54)	(301)
2008	0	47	0	0	47	0	0	0	0	0	(47)	(319)
2009	0	39	0	0	39	0	0	0	0	0	(39)	(334)
2010	0	30	0	0	30	0	0	0	0	0	(30)	(344)
2011	0	21	0	0	21	0	0	0	0	0	(21)	(351)
2012	0	11	0	0	11	0	0	0	0	0	(11)	(354)
2013	0	0	0	0	0	0	0	0	0	0	0	(354)
2014	0	0	0	0	0	301	69	0	0	369	369	(260)
2015	0	0	0	0	0	300	67	0	0	367	367	(173)
2016	0	0	0	0	0	299	66	0	0	365	365	(94)
2017	0	0	0	0	0	298	65	0	0	363	363	(20)
2018	0	0	0	0	0	298	64	0	0	362	362	48
2019	0	0	0	0	0	298	63	0	0	360	360	110
NOMINAL	0	651	0	0	651	1,793	394	0	0	2,187	1,535	
NPV:	0	354	0	0	354	381	84	0	0	464	110	

Discount Rate 7.90%
Benefit/Cost Ratio: col (11) / col (6) 1.312

PARTICIPANT COSTS AND BENEFITS
PROGRAM: DLC-2 POOL PUMPS, EC/NC,SF

(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)
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	1	0	1	0	0	0	0	1	1
1999	0	0	2	0	2	0	0	0	0	2	3
2000	0	0	2	0	2	0	0	0	0	2	4
2001	0	0	4	0	4	0	0	0	0	4	7
2002	0	0	5	0	5	0	0	0	0	5	10
2003	0	0	6	0	6	0	0	0	0	6	14
2004	0	0	8	0	8	0	0	0	0	8	18
2005	0	0	10	0	10	0	0	0	0	10	23
2006	0	0	11	0	11	0	0	0	0	11	28
2007	0	0	13	0	13	0	0	0	0	13	34
2008	0	0	14	0	14	0	0	0	0	14	39
2009	0	0	15	0	15	0	0	0	0	15	45
2010	0	0	15	0	15	0	0	0	0	15	50
2011	0	0	16	0	16	0	0	0	0	16	55
2012	0	0	16	0	16	0	0	0	0	16	60
2013	0	0	16	0	16	0	0	0	0	16	64
2014	0	0	0	0	0	0	0	0	0	0	64
2015	0	0	0	0	0	0	0	0	0	0	64
2016	0	0	0	0	0	0	0	0	0	0	64
2017	0	0	0	0	0	0	0	0	0	0	64
2018	0	0	0	0	0	0	0	0	0	0	64
2019	0	0	0	0	0	0	0	0	0	0	64
NOMINAL	0	0	153	0	153	0	0	0	0	153	
NPV:	0	0	64	0	64	0	0	0	0	64	

In service year of gen unit: 2014
Discount rate: 7.90%

RATE IMPACT TEST
PROGRAM:DLC-2 POOL PUMPS, EC/NC,SF

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	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
YEAR	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
1996	0	6	0	0	0	6	0	0	0	0	0	(6)	(6)
1997	0	12	0	0	0	12	0	0	0	0	0	(12)	(17)
1998	0	19	1	0	0	20	0	0	0	0	0	(20)	(34)
1999	0	26	2	0	0	28	0	0	0	0	0	(28)	(57)
2000	0	34	2	0	0	36	0	0	0	0	0	(36)	(83)
2001	0	42	4	0	0	46	0	0	0	0	0	(46)	(115)
2002	0	52	5	0	0	56	0	0	0	0	0	(56)	(151)
2003	0	61	6	0	0	68	0	0	0	0	0	(68)	(190)
2004	0	72	8	0	0	80	0	0	0	0	0	(80)	(234)
2005	0	66	10	0	0	76	0	0	0	0	0	(76)	(272)
2006	0	60	11	0	0	72	0	0	0	0	0	(72)	(306)
2007	0	54	13	0	0	66	0	0	0	0	0	(66)	(334)
2008	0	47	14	0	0	60	0	0	0	0	0	(60)	(358)
2009	0	39	15	0	0	53	0	0	0	0	0	(53)	(378)
2010	0	30	15	0	0	46	0	0	0	0	0	(46)	(394)
2011	0	21	16	0	0	37	0	0	0	0	0	(37)	(406)
2012	0	11	16	0	0	27	0	0	0	0	0	(27)	(414)
2013	0	0	16	0	0	16	0	0	0	0	0	(16)	(418)
2014	0	0	0	0	0	0	301	69	0	0	369	369	(324)
2015	0	0	0	0	0	0	300	67	0	0	367	367	(237)
2016	0	0	0	0	0	0	299	66	0	0	365	365	(158)
2017	0	0	0	0	0	0	298	65	0	0	363	363	(84)
2018	0	0	0	0	0	0	298	64	0	0	362	362	(16)
2019	0	0	0	0	0	0	298	63	0	0	360	360	46
NOMINAL	0	651	153	0	0	805	1,793	394	0	0	2,187	1,382	
NPV:	0	354	64	0	0	418	381	84	0	0	464	46	

Discount rate: 7.90%
Benefit / Cost Ratio - Col (12)/Col (7) 1.111

SECTION IV

APPENDIX C.3

COMMERCIAL EFFICIENT LIGHTING

COST EFFECTIVENESS CALCULATIONS

INPUT DATA -- PART 1
PROGRAM: COMMERCIAL EFFICIENT LIGHTING

I. PROGRAM DEMAND SAVINGS AND LINE LOSSES

(1) CUSTOMER KW REDUCTION AT THE METER	1.00	KW /CUST
(2) GENERATOR KW REDUCTION PER CUSTOMER	1.22	KW GEN/CUST
(3) KW LINE LOSS PERCENTAGE	3.8	%
(4) GENERATION KWH REDUCTION PER CUSTOMER	3,988.0	KWH/CUST/YR
(5) KWH LINE LOSS PERCENTAGE	3.9	%
(6) GROUP LINE LOSS MULTIPLIER	1.0170	
(7) CUSTOMER KWH PROGRAM INCREASE AT METER	0.0	KWH/CUST/YR
(8) CUSTOMER KWH REDUCTION AT METER	3,832.5	KWH/CUST/YR
(9) SUMMER KW/CUST AT METER	1.00	
(10) WINTER KW/CUST AT METER	0.00	

II. ECONOMIC LIFE AND K FACTORS

(1) STUDY PERIOD FOR CONSERVATION PROGRAM	24	YEARS
(2) GENERATOR ECONOMIC LIFE	25	YEARS
(3) T & D ECONOMIC LIFE	32	YEARS
(4) K FACTOR FOR GENERATION	1.0790	
(5) K FACTOR FOR T & D	1.0790	
(6) SWITCH REV REQ(0) OR VAL-OF-DEF (1)	0	

III. UTILITY AND CUSTOMER COSTS

(1) UTILITY NONRECURRING COST PER CUSTOMER	4.58	$/CUST
(2) ANNUAL UTILITY PROGRAM COST	21,085.00	$/YR
(3) UTILITY COST ESCALATION RATE	4.0	%
(4) CUSTOMER INCREMENTAL EQUIPMENT COST	1,333.33	$/CUST
(5) CUSTOMER EQUIPMENT ESCALATION RATE	4.0	%
(6) CUSTOMER INCREMENTAL 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	2.0	%
(10) INCREASED SUPPLY COSTS	0.00	$/CUST/YR
(11) SUPPLY COSTS ESCALATION RATE	0.0	%
(12) UTILITY DISCOUNT RATE	7.90%	
(13) UTILITY CWIP RATE	7.90%	
(14) UTILITY NON RECURRING REBATE/INCENTIVE ...	100.00	$/CUST
(15) UTILITY RECURRING REBATE/INCENTIVE	0.00	$/CUST/YR
(16) UTILITY REBATE/INCENTIVE ESCAL RATE	0.0	%

IV. AVOIDED GENERATOR, TRANS. AND DIST. COSTS

(1) BASE YEAR	1997	
(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT	2014	
(3) IN-SERVICE YEAR FOR AVOIDED T & D	2014	
(4) BASE YEAR AVOIDED GENERATING UNIT COST	356.00	$/KW
(5) BASE YEAR AVOIDED TRANSMISSION COST	67.69	$/KW
(6) BASE YEAR DISTRIBUTION COST	99.16	$/KW
(7) GEN, TRAN, & DIST COST ESCALATION RATE ...	2.5	%
(8) GENERATOR FIXED O & M COST	0.00	$/KW/YR
(9) GENERATOR FIXED O&M ESCALATION RATE	4.0	%
(10) TRANSMISSION FIXED O & M COST	1.27	$/KW/YR
(11) DISTRIBUTION FIXED O & M COST	0.26	$/KW/YR
(12) T&D FIXED O&M ESCALATION RATE	4.0	%
(13) AVOIDED GEN UNIT VARIABLE O & M COSTS	1.430	CENTS/KWH
(14) GENERATOR VARIABLE O&M COST ESCALATION RATE	4.0	%
(15) GENERATOR CAPACITY FACTOR	5	%
(16) AVOIDED GENERATING UNIT FUEL COST	3.260	CENTS/KWH
(17) AVOIDED GEN UNIT FUEL ESCALATION RATE	5.4	%
(18) AVOIDED PURCHASE CAPACITY COST PER KW	0.00	$/KW/YR
(19) CAPACITY COST ESCALATION RATE	0.0	%

V. NON-FUEL ENERGY AND DEMAND CHARGES

(1) NON-FUEL COST IN CUSTOMER BILL	1.994	CENTS/KWH
(2) NON-FUEL ESCALATION RATE	3.5	%
(3) CUSTOMER DEMAND CHARGE PER KW	8.40	$/KW/MO
(4) DEMAND CHARGE ESCALATION RATE	0.0	%
(5) DIVERSITY and ANNUAL DEMAND ADJUSTMENT FACTOR FOR CUSTOMER BILL	0.0	

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

CALCULATION OF CWIP AND IN-SERVICE COST OF PLANT
PLANT: 2014 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 CWIP ($/KW)	YEARLY TOTAL CWIP ($/KW)	INCREMENTAL YEAR-END BOOK VALUE ($/KW)	CUMULATIVE YEAR-END BOOK VALUE ($/KW)
2005	-9	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2006	-8	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2007	-7	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2008	-6	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2009	-5	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2010	-4	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2011	-3	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2012	-2	50.0%	1.5000	50.0%	267.00	133.50	133.50	10.55	277.55	277.55
2013	-1	50.0%	2.2500	50.0%	400.50	467.25	477.80	37.75	438.25	715.79
2014	0			0.0%	0.00			0.00	0.00	
				1.00	667.50			48.29	715.79	

IN-SERVICE YEAR = 2014

PLANT COSTS (1997 $) $356.0
CWIP RATE: 7.90%

F_12

INPUT DATA -- PART 2
PROGRAM: COMMERCIAL EFFICIENT LIGHTING

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(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
1997	122	73	1.91	2.42	1.96	0.00	1.00	1.00
1998	244	147	2.07	2.12	1.72	0.00	1.00	1.00
1999	367	220	2.12	2.21	1.76	0.00	1.00	1.00
2000	489	293	2.17	2.26	1.82	0.00	1.00	1.00
2001	611	367	2.26	2.43	1.90	0.00	1.00	1.00
2002	733	440	2.28	2.55	1.95	0.00	1.00	1.00
2003	855	513	2.33	2.63	1.98	0.00	1.00	1.00
2004	978	587	2.43	2.82	2.13	0.00	1.00	1.00
2005	1,100	660	2.50	2.31	2.24	0.00	1.00	1.00
2006	1,222	733	2.60	3.37	2.38	0.00	1.00	1.00
2007	1,344	807	2.69	3.91	2.62	0.00	1.00	1.00
2008	1,466	880	2.80	4.04	2.73	0.00	1.00	1.00
2009	1,589	953	2.94	4.24	2.83	0.00	1.00	1.00
2010	1,711	1,026	3.03	4.55	3.01	0.00	1.00	1.00
2011	1,833	1,100	3.19	4.95	3.21	0.00	1.00	1.00
2012	1,955	1,173	3.36	5.61	3.53	0.00	1.00	1.00
2013	2,077	1,246	3.47	6.10	3.79	0.00	1.00	1.00
2014	2,200	1,320	3.72	6.20	3.90	0.00	1.00	1.00
2015	0	1,320	3.90	6.61	4.14	0.00	1.00	1.00
2016	0	1,320	4.04	7.07	4.40	0.00	1.00	1.00
2017	0	1,320	4.23	7.56	4.67	0.04	1.00	1.00
2018	0	1,320	4.42	8.08	4.97	0.04	1.00	1.00
2019	0	1,320	4.62	8.64	5.28	0.05	1.00	1.00
2020	0	1,320	4.83	9.25	5.61	0.05	1.00	1.00

AVOIDED GENERATION UNIT BENEFITS
PROGRAM: COMMERCIAL EFFICIENT LIGHTING

* UNIT SIZE OF AVOIDED GENERATION UNIT = 1,614 KW
* INSERVICE COSTS OF AVOIDED GEN. UNIT (000) $1,155

(1) YEAR	(1A) REVENUE REQUIREMENT 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)
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	0.000	0	0	0	0	0	0	0	0
2005	0.000	0	0	0	0	0	0	0	0
2006	0.000	0	0	0	0	0	0	0	0
2007	0.000	0	0	0	0	0	0	0	0
2008	0.000	0	0	0	0	0	0	0	0
2009	0.000	0	0	0	0	0	0	0	0
2010	0.000	0	0	0	0	0	0	0	0
2011	0.000	0	0	0	0	0	0	0	0
2012	0.000	0	0	0	0	0	0	0	0
2013	0.000	0	0	0	0	0	0	0	0
2014	0.119	137	432	0	12	34	0	0	184
2015	0.116	134	432	0	13	36	0	0	183
2016	0.113	130	432	0	13	38	0	0	181
2017	0.110	127	432	0	14	40	0	0	180
2018	0.106	123	432	0	14	42	0	0	179
2019	0.103	119	432	0	15	45	0	0	178
2020	0.100	116	432	0	15	47	0	0	178
NOMINAL		886	3,024	0	95	284	1	0	1,264
NPV		198		0	21	62	0	0	280

F_22

AVOIDED T & D AND PROGRAM FUEL SAVINGS
PROGRAM: COMMERCIAL EFFICIENT LIGHTING

* INSERVICE COSTS OF AVOIDED TRANS. (000) = $166
* INSERVICE COSTS OF AVOIDED DIST. (000) = $199

(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)
1997	0	0	0	0	0	0	4
1998	0	0	0	0	0	0	9
1999	0	0	0	0	0	0	16
2000	0	0	0	0	0	0	23
2001	0	0	0	0	0	0	32
2002	0	0	0	0	0	0	41
2003	0	0	0	0	0	0	50
2004	0	0	0	0	0	0	62
2005	0	0	0	0	0	0	57
2006	0	0	0	0	0	0	94
2007	0	0	0	0	0	0	120
2008	0	0	0	0	0	0	136
2009	0	0	0	0	0	0	155
2010	0	0	0	0	0	0	179
2011	0	0	0	0	0	0	210
2012	0	0	0	0	0	0	254
2013	0	0	0	0	0	0	294
2014	18	2	21	22	0	22	317
2015	18	3	20	21	0	22	348
2016	18	3	20	21	0	21	372
2017	17	3	20	20	0	21	398
2018	17	3	20	20	0	20	425
2019	16	3	19	19	0	20	455
2020	16	3	19	19	1	20	487
NOMINAL	120	19	139	143	3	147	4,538
NPV:	27	4	31	32	1	33	1,334

WORKSHEET : DSM PROGRAM FUEL SAVINGS
PROGRAM: COMMERCIAL EFFICIENT LIGHTING

(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)
1997	146	4	0	0	4	4
1998	439	9	0	0	9	9
1999	731	16	0	0	16	16
2000	1,023	23	0	0	23	23
2001	1,316	32	0	0	32	32
2002	1,608	41	0	0	41	41
2003	1,901	50	0	0	50	50
2004	2,193	62	0	0	62	62
2005	2,485	57	0	0	57	57
2006	2,778	94	0	0	94	94
2007	3,070	120	0	0	120	120
2008	3,363	136	0	0	136	136
2009	3,655	155	0	0	155	155
2010	3,947	179	0	0	179	179
2011	4,240	210	0	0	210	210
2012	4,532	254	0	0	254	254
2013	4,825	294	0	0	294	294
2014	5,117	317	0	0	317	317
2015	5,263	348	0	0	348	348
2016	5,263	372	0	0	372	372
2017	5,263	398	0	0	398	398
2018	5,263	425	0	0	425	425
2019	5,263	455	0	0	455	455
2020	5,263	487	0	0	487	487
NOMINAL	78,949	4,538	0	0	4,538	4,538
NPV:		1,334		0	1,334	1,334

(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)
1997	1	21	22	12	0	12	163	0	163	140	3	3	6	0	0	0	0
1998	1	22	23	12	0	12	169	0	169	421	9	9	18	0	0	0	0
1999	1	23	23	12	0	12	176	0	176	702	15	15	30	0	0	0	0
2000	1	24	24	12	0	12	183	0	183	983	22	22	43	0	0	0	0
2001	1	25	25	12	0	12	191	0	191	1,264	29	29	58	0	0	0	0
2002	1	26	26	12	0	12	198	0	198	1,545	36	37	72	0	0	0	0
2003	1	27	27	12	0	12	206	0	206	1,826	43	45	88	0	0	0	0
2004	1	28	28	12	0	12	214	0	214	2,107	52	53	106	0	0	0	0
2005	1	29	30	12	0	12	223	0	223	2,388	61	63	123	0	0	0	0
2006	1	30	31	12	0	12	232	0	232	2,669	71	73	143	0	0	0	0
2007	1	31	32	12	0	12	241	0	241	2,950	81	83	164	0	0	0	0
2008	1	32	33	12	0	12	251	0	251	3,231	92	94	186	0	0	0	0
2009	1	34	35	12	0	12	261	0	261	3,512	105	106	211	0	0	0	0
2010	1	35	36	12	0	12	271	0	271	3,793	117	118	235	0	0	0	0
2011	1	37	37	12	0	12	282	0	282	4,074	132	132	264	0	0	0	0
2012	1	38	39	12	0	12	293	0	293	4,355	149	146	294	0	0	0	0
2013	1	39	41	12	0	12	305	0	305	4,636	164	160	324	0	0	0	0
2014	0	41	41	0	0	0	317	0	317	4,917	186	176	362	0	0	0	0
2015	0	0	0	0	0	0	0	0	0	5,058	201	187	388	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	5,058	208	194	402	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	5,058	217	201	418	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	5,058	227	208	435	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	5,058	238	215	452	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	5,058	248	222	471	0	0	0	0
NOM.	13	541	554	208	0	208	4,179	0	4,179	75,870	2,704	2,589	5,293	0	0	0	0
NPV	7	283	290	121	0	121	2,184	0	2,184		851	830	1,681		0	0	0

TOTAL RESOURCE COST TESTS
PROGRAM: COMMERCIAL EFFICIENT LIGHTING

(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)
1997	0	22	163	0	185	0	0	4	0	4	(181)	(181)
1998	0	23	169	0	192	0	0	9	0	9	(183)	(350)
1999	0	23	176	0	200	0	0	16	0	16	(183)	(508)
2000	0	24	183	0	208	0	0	23	0	23	(185)	(655)
2001	0	25	191	0	216	0	0	32	0	32	(184)	(791)
2002	0	26	198	0	225	0	0	41	0	41	(184)	(916)
2003	0	27	206	0	234	0	0	50	0	50	(184)	(1,032)
2004	0	28	214	0	243	0	0	62	0	62	(181)	(1,139)
2005	0	30	223	0	253	0	0	57	0	57	(195)	(1,245)
2006	0	31	232	0	263	0	0	94	0	94	(169)	(1,330)
2007	0	32	241	0	273	0	0	120	0	120	(153)	(1,402)
2008	0	33	251	0	284	0	0	136	0	136	(148)	(1,466)
2009	0	35	261	0	296	0	0	155	0	155	(141)	(1,523)
2010	0	36	271	0	307	0	0	179	0	179	(128)	(1,570)
2011	0	37	282	0	320	0	0	210	0	210	(110)	(1,608)
2012	0	39	293	0	332	0	0	254	0	254	(78)	(1,633)
2013	0	41	305	0	346	0	0	294	0	294	(51)	(1,648)
2014	0	41	317	0	358	184	43	317	0	544	186	(1,597)
2015	0	0	0	0	0	183	42	348	0	573	573	(1,451)
2016	0	0	0	0	0	181	42	372	0	595	595	(1,311)
2017	0	0	0	0	0	180	41	398	0	619	619	(1,176)
2018	0	0	0	0	0	179	40	425	0	645	645	(1,045)
2019	0	0	0	0	0	178	39	455	0	673	673	(919)
2020	0	0	0	0	0	178	38	487	0	703	703	(797)
NOMINAL	0	554	4,179	0	4,733	1,264	285	4,538	0	6,088	1,355	
NPV:	0	290	2,184	0	2,474	280	63	1,334	0	1,677	(797)	

Discount Rate 7.90%
Benefit/Cost Ratio: col (11) / col (6) 0.678

PARTICIPANT COSTS AND BENEFITS
PROGRAM: COMMERCIAL EFFICIENT LIGHTING

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
YEAR	SAVINGS IN PARTICIPANTS BILL $(000)	TAX CREDITS $(000)	UTILITY REBATES $(000)	OTHER BENEFITS $(000)	TOTAL BENEFITS $(000)	CUSTOMER EQUIPMENT COSTS $(000)	CUSTOMER O & M COSTS $(000)	OTHER COSTS $(000)	TOTAL COSTS $(000)	NET BENEFITS $(000)	CUMULATIVE DISCOUNTED NET BENEFITS $(000)
1997	6	0	12	0	18	163	0	0	163	(145)	(145)
1998	18	0	12	0	30	169	0	0	169	(140)	(275)
1999	30	0	12	0	42	176	0	0	176	(134)	(390)
2000	43	0	12	0	56	183	0	0	183	(128)	(491)
2001	58	0	12	0	70	191	0	0	191	(120)	(580)
2002	72	0	12	0	85	198	0	0	198	(114)	(658)
2003	88	0	12	0	100	206	0	0	206	(106)	(725)
2004	106	0	12	0	118	214	0	0	214	(97)	(782)
2005	123	0	12	0	136	223	0	0	223	(87)	(829)
2006	143	0	12	0	155	232	0	0	232	(77)	(868)
2007	164	0	12	0	176	241	0	0	241	(65)	(898)
2008	186	0	12	0	198	251	0	0	251	(52)	(921)
2009	211	0	12	0	223	261	0	0	261	(38)	(936)
2010	235	0	12	0	247	271	0	0	271	(24)	(945)
2011	264	0	12	0	276	282	0	0	282	(6)	(947)
2012	294	0	12	0	307	293	0	0	293	13	(943)
2013	324	0	12	0	336	305	0	0	305	31	(934)
2014	362	0	0	0	362	317	0	0	317	45	(922)
2015	388	0	0	0	388	0	0	0	0	388	(823)
2016	402	0	0	0	402	0	0	0	0	402	(728)
2017	418	0	0	0	418	0	0	0	0	418	(637)
2018	435	0	0	0	435	0	0	0	0	435	(549)
2019	452	0	0	0	452	0	0	0	0	452	(464)
2020	471	0	0	0	471	0	0	0	0	471	(382)
NOMINAL	5,293	0	208	0	5,501	4,179	0	0	4,179	1,322	
NPV:	1,681	0	121	0	1,802	2,184	0	0	2,184	(382)	

In service year of gen unit: 2014
Discount rate: 7.90%

RATE IMPACT TEST
PROGRAM:COMMERCIAL EFFICIENT LIGHTING

(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)
1997	0	22	12	6	0	39	4	0	0	0	4	(36)	(36)
1998	0	23	12	18	0	52	9	0	0	0	9	(43)	(76)
1999	0	23	12	30	0	66	16	0	0	0	16	(50)	(118)
2000	0	24	12	43	0	80	23	0	0	0	23	(57)	(164)
2001	0	25	12	58	0	96	32	0	0	0	32	(64)	(210)
2002	0	26	12	72	0	111	41	0	0	0	41	(70)	(258)
2003	0	27	12	88	0	128	50	0	0	0	50	(78)	(308)
2004	0	28	12	106	0	146	62	0	0	0	62	(84)	(357)
2005	0	30	12	123	0	165	57	0	0	0	57	(108)	(416)
2006	0	31	12	143	0	186	94	0	0	0	94	(92)	(463)
2007	0	32	12	164	0	208	120	0	0	0	120	(88)	(504)
2008	0	33	12	186	0	232	136	0	0	0	136	(96)	(545)
2009	0	35	12	211	0	258	155	0	0	0	155	(103)	(586)
2010	0	36	12	235	0	283	179	0	0	0	179	(104)	(625)
2011	0	37	12	264	0	313	210	0	0	0	210	(104)	(661)
2012	0	39	12	294	0	346	254	0	0	0	254	(91)	(690)
2013	0	41	12	324	0	377	294	0	0	0	294	(82)	(714)
2014	0	41	0	362	0	403	501	43	0	0	544	141	(676)
2015	0	0	0	388	0	388	530	42	0	0	573	185	(629)
2016	0	0	0	402	0	402	553	42	0	0	595	193	(583)
2017	0	0	0	418	0	418	578	41	0	0	619	201	(539)
2018	0	0	0	435	0	435	605	40	0	0	645	210	(497)
2019	0	0	0	452	0	452	633	39	0	0	673	220	(455)
2020	0	0	0	471	0	471	664	38	0	0	703	232	(415)
NOMINAL	0	554	208	5,293	0	6,055	5,802	285	0	0	6,088	33	
NPV:	0	290	121	1,681	0	2,092	1,614	63	0	0	1,677	(415)	

Discount rate: 7.90%
Benefit / Cost Ratio - Col (12)/Col (7) 0.802

ATTACHMENT #1

FLORIDA DEPARTMENT OF COMMUNITY AFFAIRS

JOINT STIPULATION

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Adoption of Numeric Conservation Goals and Consideration of National Energy Policy Act Standards (Section 111)	)	Docket No. 930558-EG Filed: February 24, 1995

JOINT STIPULATION

Orlando Utilities Commission (OUC) and the Florida Department of Community Affairs ("DCA") hereby jointly stipulate and agree to the following:

1. The Florida Public Service Commission ("FPSC") is required to establish numeric conservation goals for Florida's FEECA utilities.

2. FPSC opened Docket Number 930558-EG for the purpose of establishing numeric conservation goals for OUC.

3. The DCA is a party to Docket Number 930558-E, representing the Governor of the State of Florida.

4. The parties to Docket Number 930558-EG wish to avoid an evidentiary hearing and other procedural matters by stipulating to conservation goals.

5. If the goals stipulated to herein are not approved by the FPSC, neither OUC nor the DCA will require the other to adopt or support any particular goals or other actions in any hearing before the FPSC or other proceedings, and this stipulation will be null and void.

6. If the goals stipulated to herein are approved by the FPSC, OUC will continue, for a time period to be determined by OUC's governing commission, its low Income Home Energy Fixup

Program; OUC will implement, with approval of OUC's governing commission, a Residential, single family, energy efficient, new construction program based on the Building Energy Rating System ("BERS"), the State of Florida Energy Performance Index ("EPI") and OUC energy efficiency standards; and OUC will amend, subject to approval of OUC's governing commission, its Administrative Policy Manual to allow for OUC owned, cost effective photovoltaic equipment to be installed on customer premises in lieu of line extensions.

7. The DCA and OUC have agreed that OUC's numeric conservation goals should be as follows:

Residential

Year	Winter Kw Reduction	Summer Kw Reduction	mWh Energy Reduction
1996	230	155	0
1997	693	468	0
1998	1,386	938	0
1999	2,309	1,563	0
2000	2,463	2,381	0
2001	4,849	3,280	0
2002	6,465	4,374	0
2003	8,311	5,624	0
2004	10,388	7,029	0
2005	12,256	8,290	0

Commercial/Industrial

Year	Winter Kw Reduction	Summer Kw Reduction	mWh Energy Reduction
1996	0	0	0
1997	0	0	0
1998	0	0	0
1999	0	0	0
2000	0	38	0
2001	0	115	0
2002	0	230	0
2003	0	384	0
2004	0	576	0
2005	0	807	0

IN WITNESS WHEREOF, the parties hereto have caused this Stipulation to be executed by their duly authorized representatives on the date and date indicated below.

ORLANDO UTILITIES COMMISSION

C. Laurence Keesey

CHARLES LAURENCE KEESEY
ATTORNEY

2/24/95
DATE

DEPARTMENT OF COMMUNITY AFFAIRS
STATE OF FLORIDA

Andrea England

ANDREA ENGLAND
ASSISTANT GENERAL COUNSEL

2/24/95
DATE

OUC\STIP.F24

Updated Direct Load Control Main (DLC-1A)

Cost Effectiveness Calculations

INPUT DATA -- PART 1
PROGRAM: DLC-CAC/SH + DWH, EC/NC, SF

I. PROGRAM DEMAND SAVINGS AND LINE LOSSES

(1) CUSTOMER KW REDUCTION AT THE METER	2.24	KW /CUST
(2) GENERATOR KW REDUCTION PER CUSTOMER	2.74	KW GEN/CUST
(3) KW LINE LOSS PERCENTAGE	3.8	%
(4) GENERATION KWH REDUCTION PER CUSTOMER	0.0	KWH/CUST/YR
(5) KWH LINE LOSS PERCENTAGE	3.9	%
(6) GROUP LINE LOSS MULTIPLIER	1.0180	
(7) CUSTOMER KWH PROGRAM INCREASE AT METER	0.0	KWH/CUST/YR
(8) CUSTOMER KWH REDUCTION AT METER	0.0	KWH/CUST/YR
(9) SUMMER KW/CUST AT METER	1.22	
(10) WINTER KW/CUST AT METER	2.24	

II. ECONOMIC LIFE AND K FACTORS

(1) STUDY PERIOD FOR CONSERVATION PROGRAM	24	YEARS
(2) GENERATOR ECONOMIC LIFE	25	YEARS
(3) T & D ECONOMIC LIFE	32	YEARS
(4) K FACTOR FOR GENERATION	1.0600	
(5) K FACTOR FOR T & D	1.0600	
(6) SWITCH REV REQ(0) OR VAL-OF-DEF (1)	0	

III. UTILITY AND CUSTOMER COSTS

(1) UTILITY NONRECURRING COST PER CUSTOMER	183.86	$/CUST
(2) ANNUAL UTILITY PROGRAM COST	139,733.13	$/YR
(3) UTILITY COST ESCALATION RATE	2.5	%
(4) CUSTOMER INCRMENTAL EQUIPMENT COST	0.00	$/CUST
(5) CUSTOMER EQUIPMENT ESCALATION RATE	4.0	%
(6) CUSTOMER INCREMENTAL 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	2.0	%
(10) INCREASED SUPPLY COSTS	0.00	$/CUST/YR
(11) SUPPLY COSTS ESCALATION RATE	0.0	%
(12) UTILITY DISCOUNT RATE	7.90%	
(13) UTILITY CWIP RATE	7.90%	
(14) UTILITY NON RECURRING REBATE/INCENTIVE ...	0.00	$/CUST
(15) UTILITY RECURRING REBATE/INCENTIVE	48.00	$/CUST/YR
(16) UTILITY REBATE/INCENTIVE ESCAL RATE	0.0	%

IV. AVOIDED GENERATOR, TRANS. AND DIST. COSTS

(1) BASE YEAR	1998	
(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT	2014	
(3) IN-SERVICE YEAR FOR AVOIDED T & D	2014	
(4) BASE YEAR AVOIDED GENERATING UNIT COST	232.00	$/KW
(5) BASE YEAR AVOIDED TRANSMISSION COST	71.12	$/KW
(6) BASE YEAR DISTRIBUTION COST	104.18	$/KW
(7) GEN, TRAN, & DIST COST ESCALATION RATE ...	2.5	%
(8) GENERATOR FIXED O & M COST	1.75	$/KW/YR
(9) GENERATOR FIXED O&M ESCALATION RATE	2.5	%
(10) TRANSMISSION FIXED O & M COST	1.64	$/KW/YR
(11) DISTRIBUTION FIXED O & M COST	0.27	$/KW/YR
(12) T&D FIXED O&M ESCALATION RATE	2.5	%
(13) AVOIDED GEN UNIT VARIABLE O & M COSTS	0.874	CENTS/KWH
(14) GENERATOR VARIABLE O&M COST ESCALATION RATE	2.5	%
(15) GENERATOR CAPACITY FACTOR	5	%
(16) AVOIDED GENERATING UNIT FUEL COST	3.010	CENTS/KWH
(17) AVOIDED GEN UNIT FUEL ESCALATION RATE	2.5	%
(18) AVOIDED PURCHASE CAPACITY COST PER KW	0.00	$/KW/YR
(19) CAPACITY COST ESCALATION RATE	0.0	%

V. NON-FUEL ENERGY AND DEMAND CHARGES

(1) NON-FUEL COST IN CUSTOMER BILL	5.508	CENTS/KWH
(2) NON-FUEL ESCALATION RATE	2.5	%
(3) CUSTOMER DEMAND CHARGE PER KW	0.00	$/KW/MO
(4) DEMAND CHARGE ESCALATION RATE	0.0	%
(5) DIVERSITY and ANNUAL DEMAND ADJUSTMENT FACTOR FOR CUSTOMER BILL	0.0	

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

CALCULATION OF CWIP AND IN-SERVICE COST OF PLANT
PLANT: 2014 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 CWIP ($/KW)	YEARLY TOTAL CWIP ($/KW)	INCREMENTAL YEAR-END BOOK VALUE ($/KW)	CUMULATIVE YEAR-END BOOK VALUE ($/KW)
2005	-9	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2006	-8	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2007	-7	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2008	-6	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2009	-5	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2010	-4	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2011	-3	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2012	-2	50.0%	1.5000	50.0%	174.00	87.00	87.00	6.87	180.87	180.87
2013	-1	50.0%	2.2500	50.0%	261.00	304.50	311.37	24.60	285.60	466.47
2014	0			0.0%	0.00			0.00	0.00	
				1.00	435.00			31.47	466.47	

IN-SERVICE YEAR = 2014

PLANT COSTS (1998 $) $232.0
CWIP RATE: 7.90%

(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
1998	506	506	2.12	2.21	1.76	0.00	1.00	1.00
1999	843	843	2.17	2.26	1.82	0.00	1.00	1.00
2000	1,264	1,264	2.26	2.43	1.90	0.00	1.00	1.00
2001	1,770	1,770	2.28	2.55	1.95	0.00	1.00	1.00
2002	2,360	2,360	2.33	2.63	1.98	0.00	1.00	1.00
2003	3,034	3,034	2.43	2.82	2.13	0.00	1.00	1.00
2004	3,792	3,792	2.50	2.31	2.24	0.00	1.00	1.00
2005	4,474	4,474	2.60	3.37	2.38	0.00	1.00	1.00
2006	5,081	5,081	2.69	3.91	2.62	0.00	1.00	1.00
2007	5,612	5,612	2.80	4.04	2.73	0.00	1.00	1.00
2008	6,067	6,067	2.94	4.24	2.83	0.00	1.00	1.00
2009	6,446	6,446	3.03	4.55	3.01	0.00	1.00	1.00
2010	6,749	6,749	3.19	4.95	3.21	0.00	1.00	1.00
2011	6,976	6,976	3.36	5.61	3.53	0.00	1.00	1.00
2012	7,128	7,128	3.47	6.10	3.79	0.00	1.00	1.00
2013	7,204	7,204	3.72	6.20	3.90	0.00	1.00	1.00
2014	0	7,204	3.90	6.61	4.14	0.00	1.00	1.00
2015	0	7,204	4.04	7.07	4.40	0.00	1.00	1.00
2016	0	7,204	4.23	7.56	4.67	0.00	1.00	1.00
2017	0	7,204	4.42	8.08	4.97	0.00	1.00	1.00
2018	0	7,204	4.62	8.64	5.28	0.04	1.00	1.00
2019	0	7,204	4.83	9.25	5.61	0.04	1.00	1.00
2020	0	7,204	5.04	9.89	5.97	0.05	1.00	1.00
2021	0	7,204	5.27	10.58	6.34	0.05	1.00	1.00

AVOIDED GENERATION UNIT BENEFITS
PROGRAM: DLC-CAC/SH + DWH, EC/NC, SF

* UNIT SIZE OF AVOIDED GENERATION UNIT = 19,735 KW
* INSERVICE COSTS OF AVOIDED GEN. UNIT (000) $9,206

(1) YEAR	(1A) REVENUE REQUIREMENT 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)
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	0.000	0	0	0	0	0	0	0	0
2005	0.000	0	0	0	0	0	0	0	0
2006	0.000	0	0	0	0	0	0	0	0
2007	0.000	0	0	0	0	0	0	0	0
2008	0.000	0	0	0	0	0	0	0	0
2009	0.000	0	0	0	0	0	0	0	0
2010	0.000	0	0	0	0	0	0	0	0
2011	0.000	0	0	0	0	0	0	0	0
2012	0.000	0	0	0	0	0	0	0	0
2013	0.000	0	0	0	0	0	0	0	0
2014	0.119	1,095	7,280	43	94	325	0	0	1,559
2015	0.116	1,066	7,280	44	97	333	0	0	1,541
2016	0.113	1,037	7,280	45	99	342	0	0	1,524
2017	0.110	1,008	7,280	47	102	350	0	0	1,507
2018	0.106	979	7,280	48	104	359	3	0	1,487
2019	0.103	950	7,280	49	107	368	3	0	1,471
2020	0.100	921	7,280	50	110	377	3	0	1,455
2021	0.097	892	7,280	51	112	387	4	0	1,439
NOMINAL		7,949	58,236	378	825	2,842	13	0	11,982
NPV		1,854		86	188	649	3	0	2,774

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AVOIDED T & D AND PROGRAM FUEL SAVINGS
PROGRAM: DLC-CAC/SH + DWH, EC/NC, SF

* INSERVICE COSTS OF AVOIDED TRANS. (000) = $2,083
* INSERVICE COSTS OF AVOIDED DIST. (000) = $2,496

(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)
1998	0	0	0	0	0	0	0
1999	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0
2001	0	0	0	0	0	0	0
2002	0	0	0	0	0	0	0
2003	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0
2014	230	40	270	275	5	281	0
2015	225	41	266	269	6	275	0
2016	219	42	262	263	6	269	0
2017	214	43	258	257	6	262	0
2018	209	45	254	251	6	256	0
2019	204	46	250	244	6	250	0
2020	199	47	246	238	6	244	0
2021	194	48	242	232	6	238	0
NOMINAL	1,694	353	2,046	2,029	47	2,076	0
NPV:	394	80	475	472	11	483	0

(1)	(2)	(3)	(4)	(5)	(6)	(7)
YEAR	REDUCTION IN KWH GENERATION NET NEW CUST KWH (000)	AVOIDED MARGINAL FUEL COST - REDUCED KWH $(000)	INCREASE IN KWH GENERATION NET NEW CUST KWH (000)	INCREASED MARGINAL FUEL COST - INCREASE KWH $(000)	NET AVOIDED PROGRAM FUEL SAVINGS $(000)	EFFECTIVE PROGRAM FUEL SAVINGS $(000)
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
2015	0	0	0	0	0	0
2016	0	0	0	0	0	0
2017	0	0	0	0	0	0
2018	0	0	0	0	0	0
2019	0	0	0	0	0	0
2020	0	0	0	0	0	0
2021	0	0	0	0	0	0
NOMINAL	0	0	0	0	0	0
NPV:		0		0	0	0

WORKSHEET: UTILITY COSTS AND PARTICIPANT COSTS AND REV LOSS/GAIN/RU
PROGRAM: DLC-CAC/SH + DWH, EC/NC, SF

(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)
1998	93	140	233	0	12	12	0	0	0	0	0	0	0	0	0	0	0
1999	64	143	207	0	32	32	0	0	0	0	0	0	0	0	0	0	0
2000	81	147	228	0	51	51	0	0	0	0	0	0	0	0	0	0	0
2001	100	150	251	0	73	73	0	0	0	0	0	0	0	0	0	0	0
2002	120	154	274	0	99	99	0	0	0	0	0	0	0	0	0	0	0
2003	140	158	298	0	129	129	0	0	0	0	0	0	0	0	0	0	0
2004	162	162	324	0	164	164	0	0	0	0	0	0	0	0	0	0	0
2005	149	166	315	0	198	198	0	0	0	0	0	0	0	0	0	0	0
2006	136	170	306	0	229	229	0	0	0	0	0	0	0	0	0	0	0
2007	122	175	296	0	257	257	0	0	0	0	0	0	0	0	0	0	0
2008	107	179	286	0	280	280	0	0	0	0	0	0	0	0	0	0	0
2009	91	183	275	0	300	300	0	0	0	0	0	0	0	0	0	0	0
2010	75	188	263	0	317	317	0	0	0	0	0	0	0	0	0	0	0
2011	58	193	250	0	329	329	0	0	0	0	0	0	0	0	0	0	0
2012	39	197	237	0	338	338	0	0	0	0	0	0	0	0	0	0	0
2013	20	202	223	0	344	344	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
2015	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NOM.	1,557	2,708	4,265	0	3,154	3,154	0	0	0	0	0	0	0	0	0	0	0
NPV	972	1,564	2,537	0	1,517	1,517	0	0	0		0	0	0		0	0	0

TOTAL RESOURCE COST TESTS
PROGRAM: DLC-CAC/SH + DWH, EC/NC, SF

(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)
1998	0	233	0	0	233	0	0	0	0	0	(233)	(233)
1999	0	207	0	0	207	0	0	0	0	0	(207)	(424)
2000	0	228	0	0	228	0	0	0	0	0	(228)	(620)
2001	0	251	0	0	251	0	0	0	0	0	(251)	(820)
2002	0	274	0	0	274	0	0	0	0	0	(274)	(1,022)
2003	0	298	0	0	298	0	0	0	0	0	(298)	(1,226)
2004	0	324	0	0	324	0	0	0	0	0	(324)	(1,431)
2005	0	315	0	0	315	0	0	0	0	0	(315)	(1,616)
2006	0	306	0	0	306	0	0	0	0	0	(306)	(1,783)
2007	0	296	0	0	296	0	0	0	0	0	(296)	(1,932)
2008	0	286	0	0	286	0	0	0	0	0	(286)	(2,066)
2009	0	275	0	0	275	0	0	0	0	0	(275)	(2,185)
2010	0	263	0	0	263	0	0	0	0	0	(263)	(2,291)
2011	0	250	0	0	250	0	0	0	0	0	(250)	(2,384)
2012	0	237	0	0	237	0	0	0	0	0	(237)	(2,465)
2013	0	223	0	0	223	0	0	0	0	0	(223)	(2,537)
2014	0	0	0	0	0	1,559	551	0	0	2,109	2,109	(1,912)
2015	0	0	0	0	0	1,541	540	0	0	2,081	2,081	(1,340)
2016	0	0	0	0	0	1,524	530	0	0	2,054	2,054	(818)
2017	0	0	0	0	0	1,507	520	0	0	2,027	2,027	(340)
2018	0	0	0	0	0	1,487	510	0	0	1,998	1,998	97
2019	0	0	0	0	0	1,471	500	0	0	1,971	1,971	496
2020	0	0	0	0	0	1,455	490	0	0	1,945	1,945	861
2021	0	0	0	0	0	1,439	480	0	0	1,919	1,919	1,195
NOMINAL	0	4,265	0	0	4,265	11,982	4,122	0	0	16,104	11,839	
NPV:	0	2,537	0	0	2,537	2,774	958	0	0	3,732	1,195	

Discount Rate 7.90%
Benefit/Cost Ratio: col (11) / col (6) 1.471

PARTICIPANT COSTS AND BENEFITS
PROGRAM: DLC-CAC/SH + DWH, EC/NC, SF

(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)
1998	0	0	12	0	12	0	0	0	0	12	12
1999	0	0	32	0	32	0	0	0	0	32	42
2000	0	0	51	0	51	0	0	0	0	51	86
2001	0	0	73	0	73	0	0	0	0	73	144
2002	0	0	99	0	99	0	0	0	0	99	217
2003	0	0	129	0	129	0	0	0	0	129	305
2004	0	0	164	0	164	0	0	0	0	164	409
2005	0	0	198	0	198	0	0	0	0	198	526
2006	0	0	229	0	229	0	0	0	0	229	650
2007	0	0	257	0	257	0	0	0	0	257	780
2008	0	0	280	0	280	0	0	0	0	280	911
2009	0	0	300	0	300	0	0	0	0	300	1,041
2010	0	0	317	0	317	0	0	0	0	317	1,168
2011	0	0	329	0	329	0	0	0	0	329	1,291
2012	0	0	338	0	338	0	0	0	0	338	1,407
2013	0	0	344	0	344	0	0	0	0	344	1,517
2014	0	0	0	0	0	0	0	0	0	0	1,517
2015	0	0	0	0	0	0	0	0	0	0	1,517
2016	0	0	0	0	0	0	0	0	0	0	1,517
2017	0	0	0	0	0	0	0	0	0	0	1,517
2018	0	0	0	0	0	0	0	0	0	0	1,517
2019	0	0	0	0	0	0	0	0	0	0	1,517
2020	0	0	0	0	0	0	0	0	0	0	1,517
2021	0	0	0	0	0	0	0	0	0	0	1,517
NOMINAL	0	0	3,154	0	3,154	0	0	0	0	3,154	
NPV:	0	0	1,517	0	1,517	0	0	0	0	1,517	

In service year of gen unit: 2014
Discount rate: 7.90%

RATE IMPACT TEST
PROGRAM:DLC-CAC/SH + DWH, EC/NC, SF

(1) YEAR	(2) INCREASED SUPPLY COSTS $(000)	(3) UTILITY PROGRAM COSTS $(000)	(4) INCENTIVES $(000)	(5) REVENUE LOSSES $(000)	(6) OTHER COSTS $(000)	(7) TOTAL COSTS $(000)	(8) AVOIDED GEN UNIT & FUEL BENEFITS $(000)	(9) AVOIDED T & D BENEFITS $(000)	(10) REVENUE GAINS $(000)	(11) OTHER BENEFITS $(000)	(12) TOTAL BENEFITS $(000)	(13) NET BENEFITS TO ALL CUSTOMERS $(000)	(14) CUMULATIVE DISCOUNTED NET BENEFIT $(000)
1998	0	233	12	0	0	245	0	0	0	0	0	(245)	(245)
1999	0	207	32	0	0	239	0	0	0	0	0	(239)	(467)
2000	0	228	51	0	0	279	0	0	0	0	0	(279)	(706)
2001	0	251	73	0	0	323	0	0	0	0	0	(323)	(963)
2002	0	274	99	0	0	373	0	0	0	0	0	(373)	(1,239)
2003	0	298	129	0	0	428	0	0	0	0	0	(428)	(1,531)
2004	0	324	164	0	0	487	0	0	0	0	0	(487)	(1,840)
2005	0	315	198	0	0	514	0	0	0	0	0	(514)	(2,142)
2006	0	306	229	0	0	536	0	0	0	0	0	(536)	(2,433)
2007	0	296	257	0	0	553	0	0	0	0	0	(553)	(2,712)
2008	0	286	280	0	0	566	0	0	0	0	0	(566)	(2,977)
2009	0	275	300	0	0	575	0	0	0	0	0	(575)	(3,226)
2010	0	263	317	0	0	580	0	0	0	0	0	(580)	(3,459)
2011	0	250	329	0	0	580	0	0	0	0	0	(580)	(3,674)
2012	0	237	338	0	0	575	0	0	0	0	0	(575)	(3,873)
2013	0	223	344	0	0	567	0	0	0	0	0	(567)	(4,054)
2014	0	0	0	0	0	0	1,559	551	0	0	2,109	2,109	(3,429)
2015	0	0	0	0	0	0	1,541	540	0	0	2,081	2,081	(2,858)
2016	0	0	0	0	0	0	1,524	530	0	0	2,054	2,054	(2,335)
2017	0	0	0	0	0	0	1,507	520	0	0	2,027	2,027	(1,857)
2018	0	0	0	0	0	0	1,487	510	0	0	1,998	1,998	(1,420)
2019	0	0	0	0	0	0	1,471	500	0	0	1,971	1,971	(1,021)
2020	0	0	0	0	0	0	1,455	490	0	0	1,945	1,945	(656)
2021	0	0	0	0	0	0	1,439	480	0	0	1,919	1,919	(322)
NOMINAL	0	4,265	3,154	0	0	7,419	11,982	4,122	0	0	16,104	8,685	
NPV:	0	2,537	1,517	0	0	4,054	2,774	958	0	0	3,732	(322)	

Discount rate: 7.90%
Benefit / Cost Ratio - Col (12)/Col (7) 0.921

Updated Direct Load Control Pool Pumps (DLC-2)

Cost Effectiveness Calculations

I. PROGRAM DEMAND SAVINGS AND LINE LOSSES

(1) CUSTOMER KW REDUCTION AT THE METER	0.75	KW /CUST
(2) GENERATOR KW REDUCTION PER CUSTOMER	0.92	KW GEN/CUST
(3) KW LINE LOSS PERCENTAGE	3.8	%
(4) GENERATION KWH REDUCTION PER CUSTOMER	0.0	KWH/CUST/YR
(5) KWH LINE LOSS PERCENTAGE	3.9	%
(6) GROUP LINE LOSS MULTIPLIER	1.0180	
(7) CUSTOMER KWH PROGRAM INCREASE AT METER	0.0	KWH/CUST/YR
(8) CUSTOMER KWH REDUCTION AT METER	0.0	KWH/CUST/YR
(9) SUMMER KW/CUST AT METER	0.75	
(10) WINTER KW/CUST AT METER	0.00	

II. ECONOMIC LIFE AND K FACTORS

(1) STUDY PERIOD FOR CONSERVATION PROGRAM	24	YEARS
(2) GENERATOR ECONOMIC LIFE	25	YEARS
(3) T & D ECONOMIC LIFE	32	YEARS
(4) K FACTOR FOR GENERATION	1.0600	
(5) K FACTOR FOR T & D	1.0600	
(6) SWITCH REV REQ(0) OR VAL-OF-DEF (1)	0	

III. UTILITY AND CUSTOMER COSTS

(1) UTILITY NONRECURRING COST PER CUSTOMER	183.86	$/CUST
(2) ANNUAL UTILITY PROGRAM COST	0.0	$/YR
(3) UTILITY COST ESCALATION RATE	2.5	%
(4) CUSTOMER INCRMENTAL EQUIPMENT COST	0.00	$/CUST
(5) CUSTOMER EQUIPMENT ESCALATION RATE	4.0	%
(6) CUSTOMER INCREMENTAL 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	2.0	%
(10) INCREASED SUPPLY COSTS	0.00	$/CUST/YR
(11) SUPPLY COSTS ESCALATION RATE	0.0	%
(12) UTILITY DISCOUNT RATE	7.90%	
(13) UTILITY CWIP RATE	7.90%	
(14) UTILITY NON RECURRING REBATE/INCENTIVE ...	0.00	$/CUST
(15) UTILITY RECURRING REBATE/INCENTIVE	18.00	$/CUST/YR
(16) UTILITY REBATE/INCENTIVE ESCAL RATE	0.0	%

IV. AVOIDED GENERATOR, TRANS. AND DIST. COSTS

(1) BASE YEAR	1998	
(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT	2014	
(3) IN-SERVICE YEAR FOR AVOIDED T & D	2014	
(4) BASE YEAR AVOIDED GENERATING UNIT COST	232.00	$/KW
(5) BASE YEAR AVOIDED TRANSMISSION COST	71.12	$/KW
(6) BASE YEAR DISTRIBUTION COST	104.18	$/KW
(7) GEN, TRAN, & DIST COST ESCALATION RATE ...	2.5	%
(8) GENERATOR FIXED O & M COST	1.75	$/KW/YR
(9) GENERATOR FIXED O&M ESCALATION RATE	2.5	%
(10) TRANSMISSION FIXED O & M COST	1.64	$/KW/YR
(11) DISTRIBUTION FIXED O & M COST	0.27	$/KW/YR
(12) T&D FIXED O&M ESCALATION RATE	2.5	%
(13) AVOIDED GEN UNIT VARIABLE O & M COSTS	0.874	CENTS/KWH
(14) GENERATOR VARIABLE O&M COST ESCALATION RATE	2.5	%
(15) GENERATOR CAPACITY FACTOR	5	%
(16) AVOIDED GENERATING UNIT FUEL COST	3.010	CENTS/KWH
(17) AVOIDED GEN UNIT FUEL ESCALATION RATE	2.5	%
(18) AVOIDED PURCHASE CAPACITY COST PER KW	0.00	$/KW/YR
(19) CAPACITY COST ESCALATION RATE	0.0	%

V. NON-FUEL ENERGY AND DEMAND CHARGES

(1) NON-FUEL COST IN CUSTOMER BILL	5.508	CENTS/KWH
(2) NON-FUEL ESCALATION RATE	2.5	%
(3) CUSTOMER DEMAND CHARGE PER KW	0.00	$/KW/MO
(4) DEMAND CHARGE ESCALATION RATE	0.0	%
(5) DIVERSITY and ANNUAL DEMAND ADJUSTMENT FACTOR FOR CUSTOMER BILL	0.0	

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

CALCULATION OF CWIP AND IN-SERVICE COST OF PLANT
PLANT: 2014 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 CWIP ($/KW)	YEARLY TOTAL CWIP ($/KW)	INCREMENTAL YEAR-END BOOK VALUE ($/KW)	CUMULATIVE YEAR-END BOOK VALUE ($/KW)
2005	-9	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2006	-8	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2007	-7	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2008	-6	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2009	-5	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2010	-4	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2011	-3	0.0%	1.0000	0.0%	0.00	0.00	0.00	0.00	0.00	0.00
2012	-2	50.0%	1.5000	50.0%	174.00	87.00	87.00	6.87	180.87	180.87
2013	-1	50.0%	2.2500	50.0%	261.00	304.50	311.37	24.60	285.60	466.47
2014	0			0.0%	0.00			0.00	0.00	
				1.00	435.00			31.47	466.47	

IN-SERVICE YEAR = 2014

PLANT COSTS (1998 $) $232.0
CWIP RATE: 7.90%

(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
1998	199	199	2.12	2.21	1.76	0.00	1.00	1.00
1999	332	332	2.17	2.26	1.82	0.00	1.00	1.00
2000	498	498	2.26	2.43	1.90	0.00	1.00	1.00
2001	697	697	2.28	2.55	1.95	0.00	1.00	1.00
2002	930	930	2.33	2.63	1.98	0.00	1.00	1.00
2003	1,196	1,196	2.43	2.82	2.13	0.00	1.00	1.00
2004	1,495	1,495	2.50	2.31	2.24	0.00	1.00	1.00
2005	1,761	1,761	2.60	3.37	2.38	0.00	1.00	1.00
2006	1,994	1,994	2.69	3.91	2.62	0.00	1.00	1.00
2007	2,193	2,193	2.80	4.04	2.73	0.00	1.00	1.00
2008	2,359	2,359	2.94	4.24	2.83	0.00	1.00	1.00
2009	2,492	2,492	3.03	4.55	3.01	0.00	1.00	1.00
2010	2,592	2,592	3.19	4.95	3.21	0.00	1.00	1.00
2011	2,658	2,658	3.36	5.61	3.53	0.00	1.00	1.00
2012	2,691	2,691	3.47	6.10	3.79	0.00	1.00	1.00
2013	2,691	2,691	3.72	6.20	3.90	0.00	1.00	1.00
2014	0	2,691	3.90	6.61	4.14	0.00	1.00	1.00
2015	0	2,691	4.04	7.07	4.40	0.00	1.00	1.00
2016	0	2,691	3.90	6.61	4.14	0.00	1.00	1.00
2017	0	2,691	4.04	7.07	4.40	0.00	1.00	1.00
2018	0	2,691	4.23	7.56	4.67	0.04	1.00	1.00
2019	0	2,691	4.42	8.08	4.97	0.04	1.00	1.00
2020	0	2,691	4.62	8.64	5.28	0.05	1.00	1.00
2021	0	2,691	4.83	9.25	5.61	0.05	1.00	1.00

AVOIDED GENERATION UNIT BENEFITS
PROGRAM: DLC-POOL PUMPS

* UNIT SIZE OF AVOIDED GENERATION UNIT = 2,468 KW
* INSERVICE COSTS OF AVOIDED GEN. UNIT (000) $1,151

(1) YEAR	(1A) REVENUE REQUIREMENT 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)
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	0.000	0	0	0	0	0	0	0	0
2005	0.000	0	0	0	0	0	0	0	0
2006	0.000	0	0	0	0	0	0	0	0
2007	0.000	0	0	0	0	0	0	0	0
2008	0.000	0	0	0	0	0	0	0	0
2009	0.000	0	0	0	0	0	0	0	0
2010	0.000	0	0	0	0	0	0	0	0
2011	0.000	0	0	0	0	0	0	0	0
2012	0.000	0	0	0	0	0	0	0	0
2013	0.000	0	0	0	0	0	0	0	0
2014	0.119	137	948	6	12	42	0	0	197
2015	0.116	133	948	6	13	43	0	0	195
2016	0.113	130	948	6	13	44	0	0	193
2017	0.110	126	948	6	13	46	0	0	191
2018	0.106	122	948	6	14	47	0	0	189
2019	0.103	119	948	6	14	48	0	0	187
2020	0.100	115	948	7	14	49	0	0	185
2021	0.097	112	948	7	15	50	0	0	183
NOMINAL		994	7,582	49	107	370	2	0	1,519
NPV		232		11	25	84	0	0	352

AVOIDED T & D AND PROGRAM FUEL SAVINGS
PROGRAM: DLC-POOL PUMPS

* INSERVICE COSTS OF AVOIDED TRANS. (000) = $261
* INSERVICE COSTS OF AVOIDED DIST. (000) = $312

(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)
1998	0	0	0	0	0	0	0
1999	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0
2001	0	0	0	0	0	0	0
2002	0	0	0	0	0	0	0
2003	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0
2014	29	5	34	34	1	35	0
2015	28	5	33	34	1	34	0
2016	27	6	33	33	1	34	0
2017	27	6	32	32	1	33	0
2018	26	6	32	31	1	32	0
2019	26	6	31	31	1	31	0
2020	25	6	31	30	1	31	0
2021	24	6	30	29	1	30	0
NOMINAL	212	46	258	254	6	260	0
NPV:	49	10	60	59	1	60	0

(1)	(2)	(3)	(4)	(5)	(6)	(7)
YEAR	REDUCTION IN KWH GENERATION NET NEW CUST KWH (000)	AVOIDED MARGINAL FUEL COST - REDUCED KWH $(000)	INCREASE IN KWH GENERATION NET NEW CUST KWH (000)	INCREASED MARGINAL FUEL COST - INCREASE KWH $(000)	NET AVOIDED PROGRAM FUEL SAVINGS $(000)	EFFECTIVE PROGRAM FUEL SAVINGS $(000)
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
2015	0	0	0	0	0	0
2016	0	0	0	0	0	0
2017	0	0	0	0	0	0
2018	0	0	0	0	0	0
2019	0	0	0	0	0	0
2020	0	0	0	0	0	0
2021	0	0	0	0	0	0
NOMINAL	0	0	0	0	0	0
NPV:		0		0	0	0

WORKSHEET: UTILITY COSTS AND PARTICIPANT COSTS AND REV LOSS/GAIN/RU
PROGRAM: DLC-POOL PUMPS

(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)
1998	37	0	37	0	2	2	0	0	0	0	0	0	0	0	0	0	0
1999	25	0	25	0	5	5	0	0	0	0	0	0	0	0	0	0	0
2000	32	0	32	0	7	7	0	0	0	0	0	0	0	0	0	0	0
2001	39	0	39	0	11	11	0	0	0	0	0	0	0	0	0	0	0
2002	47	0	47	0	15	15	0	0	0	0	0	0	0	0	0	0	0
2003	55	0	55	0	19	19	0	0	0	0	0	0	0	0	0	0	0
2004	64	0	64	0	24	24	0	0	0	0	0	0	0	0	0	0	0
2005	58	0	58	0	29	29	0	0	0	0	0	0	0	0	0	0	0
2006	52	0	52	0	34	34	0	0	0	0	0	0	0	0	0	0	0
2007	46	0	46	0	38	38	0	0	0	0	0	0	0	0	0	0	0
2008	39	0	39	0	41	41	0	0	0	0	0	0	0	0	0	0	0
2009	32	0	32	0	44	44	0	0	0	0	0	0	0	0	0	0	0
2010	25	0	25	0	46	46	0	0	0	0	0	0	0	0	0	0	0
2011	17	0	17	0	47	47	0	0	0	0	0	0	0	0	0	0	0
2012	9	0	9	0	48	48	0	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	48	48	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
2015	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NOM.	577	0	577	0	458	458	0	0	0	0	0	0	0	0	0	0	0
NPV	369	0	369	0	221	221	0	0	0		0	0	0		0	0	0

TOTAL RESOURCE COST TESTS
PROGRAM: DLC-POOL PUMPS

(1) YEAR	(2) INCREASED SUPPLY COSTS $(000)	(3) UTILITY PROGRAM COSTS $(000)	(4) PARTICIPANT PROGRAM COSTS $(000)	(5) OTHER COSTS $(000)	(6) TOTAL COSTS $(000)	(7) AVOIDED GEN UNIT BENEFITS $(000)	(8) AVOIDED T & D BENEFITS $(000)	(9) PROGRAM FUEL SAVINGS $(000)	(10) OTHER BENEFITS $(000)	(11) TOTAL BENEFITS $(000)	(12) NET BENEFITS $(000)	(13) CUMULATIVE DISCOUNTED NET BENEFITS $(000)
1998	0	37	0	0	37	0	0	0	0	0	(37)	(37)
1999	0	25	0	0	25	0	0	0	0	0	(25)	(60)
2000	0	32	0	0	32	0	0	0	0	0	(32)	(87)
2001	0	39	0	0	39	0	0	0	0	0	(39)	(119)
2002	0	47	0	0	47	0	0	0	0	0	(47)	(154)
2003	0	55	0	0	55	0	0	0	0	0	(55)	(191)
2004	0	64	0	0	64	0	0	0	0	0	(64)	(232)
2005	0	58	0	0	58	0	0	0	0	0	(58)	(266)
2006	0	52	0	0	52	0	0	0	0	0	(52)	(294)
2007	0	46	0	0	46	0	0	0	0	0	(46)	(317)
2008	0	39	0	0	39	0	0	0	0	0	(39)	(336)
2009	0	32	0	0	32	0	0	0	0	0	(32)	(350)
2010	0	25	0	0	25	0	0	0	0	0	(25)	(360)
2011	0	17	0	0	17	0	0	0	0	0	(17)	(366)
2012	0	9	0	0	9	0	0	0	0	0	(9)	(369)
2013	0	0	0	0	0	0	0	0	0	0	0	(369)
2014	0	0	0	0	0	197	69	0	0	266	266	(290)
2015	0	0	0	0	0	195	68	0	0	263	263	(218)
2016	0	0	0	0	0	193	67	0	0	260	260	(152)
2017	0	0	0	0	0	191	65	0	0	256	256	(91)
2018	0	0	0	0	0	189	64	0	0	253	253	(36)
2019	0	0	0	0	0	187	63	0	0	249	249	15
2020	0	0	0	0	0	185	62	0	0	246	246	61
2021	0	0	0	0	0	183	60	0	0	243	243	103
NOMINAL	0	577	0	0	577	1,519	518	0	0	2,037	1,460	
NPV:	0	369	0	0	369	352	120	0	0	472	103	

Discount Rate 7.90%
Benefit/Cost Ratio: col (11) / col (6) 1.280

PARTICIPANT COSTS AND BENEFITS
PROGRAM: DLC-POOL PUMPS

(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)
1998	0	0	2	0	2	0	0	0	0	2	2
1999	0	0	5	0	5	0	0	0	0	5	6
2000	0	0	7	0	7	0	0	0	0	7	13
2001	0	0	11	0	11	0	0	0	0	11	21
2002	0	0	15	0	15	0	0	0	0	15	32
2003	0	0	19	0	19	0	0	0	0	19	45
2004	0	0	24	0	24	0	0	0	0	24	60
2005	0	0	29	0	29	0	0	0	0	29	78
2006	0	0	34	0	34	0	0	0	0	34	96
2007	0	0	38	0	38	0	0	0	0	38	115
2008	0	0	41	0	41	0	0	0	0	41	134
2009	0	0	44	0	44	0	0	0	0	44	153
2010	0	0	46	0	46	0	0	0	0	46	171
2011	0	0	47	0	47	0	0	0	0	47	189
2012	0	0	48	0	48	0	0	0	0	48	206
2013	0	0	48	0	48	0	0	0	0	48	221
2014	0	0	0	0	0	0	0	0	0	0	221
2015	0	0	0	0	0	0	0	0	0	0	221
2016	0	0	0	0	0	0	0	0	0	0	221
2017	0	0	0	0	0	0	0	0	0	0	221
2018	0	0	0	0	0	0	0	0	0	0	221
2019	0	0	0	0	0	0	0	0	0	0	221
2020	0	0	0	0	0	0	0	0	0	0	221
2021	0	0	0	0	0	0	0	0	0	0	221
NOMINAL	0	0	458	0	458	0	0	0	0	458	
NPV:	0	0	221	0	221	0	0	0	0	221	

In service year of gen unit: 2014
Discount rate: 7.90%

RATE IMPACT TEST
PROGRAM:DLC-POOL PUMPS

(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)
1998	0	37	2	0	0	38	0	0	0	0	0	(38)	(38)
1999	0	25	5	0	0	30	0	0	0	0	0	(30)	(66)
2000	0	32	7	0	0	40	0	0	0	0	0	(40)	(100)
2001	0	39	11	0	0	50	0	0	0	0	0	(50)	(140)
2002	0	47	15	0	0	62	0	0	0	0	0	(62)	(186)
2003	0	55	19	0	0	74	0	0	0	0	0	(74)	(237)
2004	0	64	24	0	0	88	0	0	0	0	0	(88)	(292)
2005	0	58	29	0	0	87	0	0	0	0	0	(87)	(344)
2006	0	52	34	0	0	86	0	0	0	0	0	(86)	(390)
2007	0	46	38	0	0	83	0	0	0	0	0	(83)	(432)
2008	0	39	41	0	0	80	0	0	0	0	0	(80)	(470)
2009	0	32	44	0	0	76	0	0	0	0	0	(76)	(503)
2010	0	25	46	0	0	70	0	0	0	0	0	(70)	(531)
2011	0	17	47	0	0	64	0	0	0	0	0	(64)	(555)
2012	0	9	48	0	0	57	0	0	0	0	0	(57)	(574)
2013	0	0	48	0	0	48	0	0	0	0	0	(48)	(590)
2014	0	0	0	0	0	0	197	69	0	0	266	266	(511)
2015	0	0	0	0	0	0	195	68	0	0	263	263	(439)
2016	0	0	0	0	0	0	193	67	0	0	260	260	(373)
2017	0	0	0	0	0	0	191	65	0	0	256	256	(312)
2018	0	0	0	0	0	0	189	64	0	0	253	253	(257)
2019	0	0	0	0	0	0	187	63	0	0	249	249	(207)
2020	0	0	0	0	0	0	185	62	0	0	246	246	(160)
2021	0	0	0	0	0	0	183	60	0	0	243	243	(118)
NOMINAL	0	577	458	0	0	1,034	1,519	518	0	0	2,037	1,002	
NPV:	0	369	221	0	0	590	352	120	0	0	472	(118)	

Discount rate: 7.90%
Benefit / Cost Ratio - Col (12)/Col (7) 0.800

Appendix C

P+ Electric Utility Planning and Scheduling Program

P+ Family of Programs

P Plus Corporation (PPC) supplies the *P+* family of electric utility planning and scheduling program. These programs have been designed and developed by experienced utility engineers specifically for planners and operators at electric utilities to develop integrated resource plans, to determine the financial and operating impacts of various expansion plans, to evaluate in detail the resources and their impacts on system operation, and to optimize the short term scheduling of resources. These programs assist the users to quickly and effectively evaluate their system's resources and operations and to ensure that the system cost is minimized while all requirements are satisfied. These programs are applicable to all types of utility systems, including the investor owned, municipal and cooperative utilities, and under the traditional regulation or the newly restructured/ deregulated environment.

The mid-to-long-term production simulation programs are based on hourly chronological load representation and provide accurate modeling of actual power system operation. They do not require the approximations by other models using typical day/week or load-duration curves. Simulation periods can vary from 1 week to 30 years.

The short-term scheduling program provides operational strategies in system cost reduction by optimizing short-term scheduling periods of 1 day to 1 month. This model is based on well known and computationally efficient state-of-the art optimization techniques. The large scale short-term scheduling problem is decomposed into several small problems and the most appropriate approach is used to solve each of these problems in arriving at the optimal schedule.

P+ programs are easy to use and run under Microsoft Windows 3.1, Windows 95 and Windows NT. The interactive user interface, with hierarchical menus and help messages, guides the users through the model effortlessly so that no special training is necessary. This process reduces the number of commands a user needs to know and makes the models simple to use. Users can change or update information easily and quickly so that data will always be current. In addition, checks are performed on data entry for reasonable limits and consistency, thereby minimizing the data errors. Each program also produces its standard set of reports and graphical outputs.

P+ application programs run on most mainframes, minis, workstations, and personal computers. This fact makes *P+* programs convenient to implement on and portable across most computers. Under the PC environment, the user can display output using a variety of graphs, charts, and tables, review data and evaluate results. ***P+*** programs perform all the functions necessary for integrated resource planning and short-term planning and operations planning in electric utilities.

Operations Planning functions include:

- Unit commitment and resource dispatching.
- Unit cycling.
- Emission studies.
- Performance evaluations.
- Maintenance scheduling.
- Interchange analysis.
- Fuel planning and budgeting.
- Economy energy studies.
- Commission hearing and testimony support.

Integrated Resource Planning functions include:

- Production costing.
- Cogeneration pricing and impacts.
- Marginal cost calculation.
- System reliability studies.
- DSM evaluation/integration.
- Expansion planning.
- Power interchange.
- Technology assessment.
- Plant life extension.
- Emission compliance studies.

PPC provides all the necessary support services for the ***P+*** family of programs. These services include installing the programs on the customer computers, training users, customizing programs, and providing consulting and testimony services for specialized applications. PPC maintains a program update service to keep users current with the latest improvements and releases. PPC also supports an active user's group through which users discuss and exchange ideas on applications and studies. PPC will also assist users in conducting a variety of planning studies.

P+ has nine main application programs: Short-term Resource Optimization, Production Simulation, Generation Expansion, Financial Analysis, Reliability Assessment, Maintenance Optimization, Power Pool Simulation, and Pool Accounting.

The Short-term Resource Optimization program (P-COM) provides the user with the ability to minimize total system operating cost by optimizing production schedules for one day to one month. Scheduling intervals can be quarter hourly, half hourly, hourly or two hourly. Detailed system, plant and units constraints are modeled. The user can determine:

- Optimal unit startup and shutdown times.
- Dollar benefit of potential transactions.
- Cost impact of unit outages or derations.
- Impact of resource characteristics, such as ramping, on system operation.

With the Production Simulation programs, users can simulate detailed hourly electric operations from one week to 30 years. There are three basic versions of the Production Simulation programs: (1) P-WEEK or P-MONTH for simulating single company system, (2) P-POOL for simulating deregulated pool with multiple generating companies, and (3) P-MAREA for simulating systems with multiple companies. The programs will determine the full rang eof plant and system results including:

- System production cost, expected unserved energy.
- Hourly marginal cost.
- Generation and cost by generating unit, and by fuel type and class.
- NO_X, SO_2, CO_2, and other emissions
- Fuel use and allocation.
- Revenue and operating profit by generating company (P-POOL).

The Demand-Side Management Simulation program (P-DSM) is a front end processor for the production simulation programs. The P-DSM program takes the user specified demand side options characteristics and adjust the chronological load accordingly. The output chronological load data can be read by the production simulation programs directly to simulate the system with DSM options. The program has the following features which can be sued to model various types of DSM:

- Load reduction.
- Load building.
- Load clipping with payback.
- Prespecified load control pattern.

- Cost trigger.

The Reliability Analysis application (P-REL) evaluates the reliability of the utility systems by determining:

- Loss of Load Hours.
- Loss of Load Probability.
- Expected Unserved Energy.

Maintenance Optimization scheduling program (R-MAINT) helps users decide the best time for scheduling maintenance to minimize system cost or reliability index by considering:

- Unit maintenance requirement.
- System maintenance blackout periods.
- Unit maintenance blackout periods.
- Number of crews.
- Travel time between plants.
- System capacity reserve requirements.

The Power Pool program (P-LDM) simulates the operation of an electric utility system that is a member of a power pool with free flow ties. The program determines:

- Utilities total energy transaction with the pool.
- The total cost or revenue of the pool interchange for specified subperiods.
- Impact on the pool transactions by purchase/sale with non-pool members.

The Pool Accounting program (P-PAM) performs the pool accounting functions including:

- Hourly generation cost allocation.
- Cost saving to the pool member.

The Generation Expansion program (P-GEM) can execute either automatically or interactively with user selection to determine the resource expansion plan for up to 30 years.

- Resource addition in each year.
- Satisfying the system expansion criteria.

The Financial Analysis program (P-FIN) allows the user to evaluate the financial viabilities of alternate resource expansion plans by providing the following:

- Capital expenditure.
- Cash flows and income statement.
- Balance sheet.
- Revenue requirement.
- Return on investment.
- Rate impact.

There are several versions of P-FIN for use with different types of utility systems: traditionally regulated IOUs, MUNIs, COOPs, state owned, deregulated generating companies and transmission and distribution companies.

In addition, PPC supplies other programs to support integrated resource planning. These programs provide screening of alternative demand and supply-side resources by calculating the Total Resource Cost Test ratios, and the Utility Cost Test. These ratios are plotted against the levelized Utility Cost for each option.

Application programs use the same input database, therefore, the users do not need to maintain and update multiple databases for different applications. A common database and a user interface make the planning process convenient.

USERS TOOLS

A special set of user's tools is available through the interactive user interface. This set of tools helps the user to perform key operations and resource planning functions including:

- Interactive system data entry and edit.
- Interactive maintenance data entry and edit.
- Hourly load data construction from historical hourly load data and future load forecasts.
- Graphical display of simulation results.

INTERACTIVE USER'S INTERFACE

The PC based user's interface has been developed for use under Microsoft Windows 3.1, Windows 95 and Windows NT for all *P+* programs. Standard Windows features are used, such as pull-down menus, drop down lists and function or navigation buttons.

For ease of use and to ensure the integrity of the data, on-line context-sensitive help messages, data reasonability checks and selection-option descriptions are provided for each field. This eliminates the need to refer to a user manual, minimizing training.

Report and graphical output of the program results can be easily viewed on the screen and printed on a variety of laser/line printers.

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