Progress Energy Florida
Petition for Need - Levy 1 & 2
Docket No. 080148-EI
Exhibit No. ________ (JBC-1)
Appendix

APPENDIX
Need Determination Study

IN SUPPORT OF PROGRESS ENERGY FLORIDA, INC.'S PETITION FOR DETERMINATION OF NEED FOR LEVY UNITS 1 AND 2 NUCLEAR POWER PLANTS

Progress Energy

APPENDICES

FIGURE 1.1

PROGRESS ENERGY FLORIDA

Service Area Map

BEFORE THE PUBLIC SERVICE COMMISSION

In re: Petition for approval of numeric conservation goals by Progress Energy Florida, Inc.	DOCKET NO. 040031-EG ORDER NO. PSC-04-0769-PAA-EG ISSUED: August 9, 2004

The following Commissioners participated in the disposition of this matter:

BRAULIO L. BAEZ, Chairman
J. TERRY DEASON
LILA A. JABER
RUDOLPH "RUDY" BRADLEY
CHARLES M. DAVIDSON

NOTICE OF PROPOSED AGENCY ACTION
ORDER APPROVING NUMERIC CONSERVATION GOALS AND DEMAND-SIDE MANAGEMENT PLAN FOR PROGRESS ENERGY FLORIDA

BY THE COMMISSION:

NOTICE is hereby given by the Florida Public Service Commission that the action discussed herein is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for a formal proceeding, pursuant to Rule 25-22.029, Florida Administrative Code.

Case Background

Section 366.82, Florida Statutes, part of the Florida Energy Efficiency and Conservation Act (FEECA), requires us to adopt goals to increase the efficiency of energy consumption, increase the development of cogeneration, and reduce and control the growth rates of electric consumption and weather-sensitive peak demand. Pursuant to Section 366.82(2), Florida Statutes, we must review a utility's conservation goals not less than every five years. These statutes are implemented by Rules 25-17.001 and 25-17.0021, Florida Administrative Code.

We first established numeric conservation goals for Progress Energy Florida, Inc. (PEF) in Order No. PSC-94-1313-FOF-EG, issued October 25, 1994, in Docket No. 930549-EG, In Re: Adoption of Numeric Conservation Goals and Consideration of National Energy Policy Act Standards (Section 111) by Florida Power Corporation, aff'd, Legal Environmental Assistance Foundation, Inc. v. Susan F. Clark, et al. as Florida Pub. Serv. Comm'n, 668 So. 2d 982 (Fla. 1996). In that order, we found:

> We will set overall conservation goals for each utility based on measures that pass both the participant and RIM tests. The record in this docket reflects that the difference in demand and energy saving between RIM and TRC portfolios are negligible. We find that goals based on measures that pass TRC but not RIM would result in increased rates and would cause customers who do not participate in a utility DSM measure to subsidize customers who do participate. Since the record reflects that the benefits of adopting a TRC goal are minimal, we do not believe that increasing rates, even slightly, is justified.

We set numeric conservation goals for PEF a second time in Order No. PSC-99-1942-FOF-EG, issued October 1, 1999 in Docket No. 971005-EG, In Re: Adoption of Numeric Conservation Goals by Florida Power Corporation. In setting PEF's numeric goals, we accepted a stipulation between PEF and the Legal Environmental Assistance Foundation. Again, PEF's numeric goals were based on measures that passed the participant and Rate Impact Measure (RIM) tests.

The instant docket, opened on January 13, 2004, represents the third time that we will set numeric conservation goals for PEF. On June 1, 2004, PEF timely filed its new numeric goals.

Rule 25-17.0021(4), Florida Administrative Code, requires that, within 90 days of a final order establishing goals, a utility shall submit a demand-side management (DSM) plan which contains conservation and DSM programs designed to meet its numeric goals. As part of its numeric goals filing, PEF filed its DSM Plan. PEF also filed testimony and exhibits in support of its proposed numeric goals and DSM Plan.

This Order addresses PEF's petition for approval of its numeric conservation goals and approval of its DSM Plan. We have jurisdiction over this matter pursuant to Sections 366.81 and 366.82, Florida Statutes.

Numeric Conservation Goals

In developing its numeric conservation goals, PEF evaluated the measures identified by us when we set goals in 1994 and again in 1999. In addition, PEF separately identified and evaluated promising new measures. The evaluation considered the issues and end-use categories specified in Rule 25-17.0021(3), Florida Administrative Code. All potential measures were evaluated against a base case, supply-side only expansion plan for cost-effectiveness using the RIM, Total Resource Cost (TRC), and participant tests. From PEF's analysis, twenty-nine residential and nineteen commercial/industrial measures passed the RIM test. The seasonal demand and annual energy savings associated with these cost-effective measures were summed by market segment to arrive at PEF's proposed goals.

PEF's goals are as follows:

PROPOSED CONSERVATION GOALS - CUMULATIVE

Year	Residential			Commercial / Industrial		
	Summer MW	Winter MW	Annual GWh	Summer MW	Winter MW	Annual GWh
2005	13	43	21	4	3	3
2006	21	75	35	7	7	6
2007	30	108	50	11	10	9
2008	38	142	65	14	14	12
2009	47	175	80	18	17	15
2010	55	210	95	21	20	18
2011	65	248	112	25	24	20
2012	74	287	128	29	28	23
2013	83	324	144	32	31	26
2014	92	366	161	36	34	29

According to its most recent FEECA report, PEF has been successful in surpassing all six of its current numeric demand and energy conservation goals that were set by us in 1999. Nonetheless, five of the six numeric goals proposed by PEF are slightly lower than the current goals. The primary reasons for this reduction are: (1) the forecasted impact of more stringent energy codes, particularly on residential air conditioning systems; and, (2) decreased participation in certain existing DSM programs due to saturation. A comparison of PEF's current and proposed conservation goals is shown below.

COMPARISON OF CURRENT AND PROPOSED CONSERVATION GOALS

Year	Residential			Commercial / Industrial		
	Summer MW	Winter MW	Annual GWh	Summer MW	Winter MW	Annual GWh
Current (*cumulative 2000-2009*)	125	389	185	38	37	19
Proposed (*cumulative 2005-2014*)	92	366	161	36	34	29

We have reviewed the programs, assumptions, and evaluation methodology used by PEF and find them to be reasonable. The DSM measures evaluated are based on an adequate assessment of the market segments and major end-use categories in accordance with Rule 25-17.0021(3), Florida Administrative Code. In addition, as required by the rule, PEF's analysis adequately reflects consideration of overlapping measures, rebound effects, free riders, interactions with building codes and appliance efficiency standards, and PEF's latest monitoring and evaluation of conservation programs and measures. PEF's chosen avoided units and the associated assumptions reflect the information provided in PEF's latest Ten-Year Site Plan and is reasonable. PEF appropriately used the RIM and participant tests to determine the cost-effective level of achievable DSM goals. Therefore, PEF's proposed conservation goals are hereby approved.

Demand-Side Management Plan

PEF's DSM Plan contains five residential programs, seven commercial and industrial (C/I) programs, a qualifying facilities program, and a research and development program. These programs are summarized in Attachment A to this Order. Tables illustrating each DSM program's projected demand and energy savings and contribution towards PEF's numeric conservation goals are also included in Attachment A. Demand and energy savings from PEF's DSM Plan are expected to meet or exceed the summer demand, winter demand, and energy savings goals approved for both the residential and commercial/industrial segments.

Pursuant to Order No. 22176, issued November 14, 1989 in Docket No. 890737-PU, In Re: Implementation of Section 366.80-.85, F.S., Conservation Activities of Electric and Natural Gas Utilities, we stated that conservation programs will be evaluated using the following criteria:

- Whether the program advances the policy objectives of Rule 25-17.001, Florida Administrative Code, and Sections 366.80 through 366.85, Florida Statutes, also known as the "Florida Energy Efficiency and Conservation Act" (FEECA);

- Whether the program is directly monitorable and yields measurable results; and

- Whether the program is cost-effective.

PEF's DSM programs are designed to minimize free riders, minimize rate impacts, and meet our prescribed conservation goals. The programs contained in PEF's DSM plan appear to meet the policy objectives of Rule 25-17.001, Florida Administrative Code, and FEECA. PEF's measurement plan to evaluate assumed demand and energy savings for each program appears reasonable. Each program included in PEF's DSM plan is cost-effective under the RIM, TRC, and participant tests. However, it must be emphasized that we are not addressing the prudence of expenditures for the programs contained in PEF's DSM plan; such a review is performed annually in the Energy Conservation Cost Recovery Clause docket.

All fourteen programs contained in PEF's DSM Plan are existing programs we approved in 2000 as part of PEF's current DSM Plan. Ten of these programs remain unchanged from that time. The remaining four programs have been modified because, due to small demand or energy savings and historically low participation rates, certain components of these four programs were no longer cost-effective. Two of the four modified programs also contain new measures to replace those that were removed. The modifications are:

- Residential New Construction program -- no longer includes the high efficiency alternate water heating component.

- Home Energy Improvement program -- no longer includes the high efficiency alternate water heating component.

- Better Business program -- no longer includes the high-efficiency motors or window film components, but now includes energy recovery ventilation (installation of high-efficiency energy recovery ventilation units that remove heat and humidity from conditioned space) and cool roofs (installation of "cool roof" coating which reflects heat).

- C/I New Construction program -- no longer includes the high-efficiency motors or heat recovery equipments, but now includes energy recovery ventilation and cool roofs.

PEF's Qualifying Facilities program is essentially unchanged from what we approved in 1995 and again in 2000. This program allows PEF to meet its obligations under Section

366.051, Florida Statutes, and Chapter 25-17, Florida Administrative Code, regarding the purchase of as-available energy and firm capacity and energy from qualifying facilities. Under the program, PEF develops standard offer contracts and administers existing standard offer and negotiated contracts.

PEF's Technology Development program, a research & development program, is essentially unchanged from what we approved in 1995 and again in 2000. Under this program, PEF will research, develop, and demonstrate potential cost-effective conservation programs. Program expenses are again capped at $800,000 per year, with a $100,000 annual cap on expenditures for any single project. PEF does not count any kW and kWh savings from its proposed Technology Development program toward its numeric conservation goals. If a legitimate DSM program results from PEF's research efforts, the program would be incorporated into the DSM Plan and its kW and kWh savings would be applied toward the goals. Examples of potential projects under the Technology Development program include demand reduction energy efficiency techniques, market transformation initiatives, indoor air quality measures, thermal energy storage technologies, and innovative metering techniques. PEF will provide a final report on each demonstration project or file and offer a permanent conservation program for each program investigated.

The programs contained in PEF's DSM Plan meet the policy objectives of Rule 25-17.001, Florida Administrative Code, and FEECA. The programs are cost-effective and are expected to allow PEF to meet the conservation goals approved in this Order. Therefore, we hereby approve PEF's DSM Plan, including approval for cost recovery.

PEF shall file program participation standards with the Division of Economic Regulation within 30 days of the issuance of the Consummating Order in this docket. PEF's program standards shall clearly state the requirements for participation in the programs, customer eligibility requirements, details on how rebates or incentives will be processed, technical specifications on equipment eligibility, and necessary reporting requirements. Our staff shall administratively approve PEF's program participation standards if they conform to the description of the programs contained in PEF's DSM Plan.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Progress Energy Florida, Inc.'s proposed annual numeric residential winter demand, summer demand, and annual energy conservation goals for the period 2005 through 2014 shall be approved as set forth in the body of this Order. It is further

ORDERED that Progress Energy Florida, Inc.'s proposed annual numeric commercial/industrial winter demand, summer demand, and annual energy conservation goals for the period 2005 through 2014 shall be approved as set forth in the body of this Order. It is further

ORDERED that Progress Energy Florida, Inc.'s demand-side management plan is hereby approved as set forth in the body of this Order. It is further

ORDERED that Progress Energy Florida, Inc. shall file program participation standards with the Division of Economic Regulation within 30 days of the issuance of the Consummating Order in this docket. It is further

ORDERED that the Commission staff shall have administrative authority to approve Progress Energy Florida, Inc.'s program participation standards if they conform to the description of the programs contained in Progress Energy Florida, Inc.'s demand-side management plan. It is further

ORDERED that Attachment A to this Order is hereby incorporated by reference. It is further

ORDERED that the provisions of this Order, issued as proposed agency action, shall become final and effective upon the issuance of a Consummating Order unless an appropriate petition, in the form provided by Rule 28-106.201, Florida Administrative Code, is received by the Director, Division of the Commission Clerk and Administrative Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on the date set forth in the "Notice of Further Proceedings" attached hereto. It is further

ORDERED that this docket shall be closed.

By ORDER of the Florida Public Service Commission this 9th day of August, 2004.

BLANCA S. BAYÓ, Director
Division of the Commission Clerk
and Administrative Services

By: Marcia Sharma
Marcia Sharma, Assistant Director
Division of the Commission Clerk
and Administrative Services

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NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing that is available under Section 120.57, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing will be granted or result in the relief sought.

Mediation may be available on a case-by-case basis. If mediation is conducted, it does not affect a substantially interested person's right to a hearing.

The action proposed herein is preliminary in nature. Any person whose substantial interests are affected by the action proposed by this order may file a petition for a formal proceeding, in the form provided by Rule 28-106.201, Florida Administrative Code. This petition must be received by the Director, Division of the Commission Clerk and Administrative Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on August 30, 2004.

In the absence of such a petition, this order shall become final and effective upon the issuance of a Consummating Order.

Any objection or protest filed in this/these docket(s) before the issuance date of this order is considered abandoned unless it satisfies the foregoing conditions and is renewed within the specified protest period.

ATTACHMENT A

PROGRESS ENERGY FLORIDA / DEMAND-SIDE MANAGEMENT PLAN

RESIDENTIAL DEMAND-SIDE MANAGEMENT PROGRAMS

Home Energy Check: Residential energy audit program. Company auditor examines home and makes recommendations on low-cost or no-cost energy-saving practices and measures. Offers six types of audits: free walk-through, customer-completed (mail-in), customer-completed (online), phone-assisted customer survey, paid walk-through ($15 cost), and home energy rating (BERS audit promoted by DCA).

Home Energy Improvement: Umbrella program for existing homes. Combines thermal envelope efficiency improvements with upgraded equipment and appliances. Offers choice of rebates, as described below, or interest-free installment billing over 12 months. Promotes the following energy-efficiency measures:

Attic Insulation Upgrade: Encourages customers who have electric space heat to add ceiling insulation. PEF pays portion of the installed cost. Specific incentive amount based on increase in insulation amount above a maximum of R-12, with maximum incentive amount of $100 per customer.

Duct Test and Repair: Promotes energy efficiency through improved duct system sealing. Program helps identify and reduce energy loss by measuring air leakage rate through the central duct system. Customer must have electric heating and centrally-ducted cooling system to participate. PEF pays up to $30 for the first unit ($20 for each additional unit at same address) for duct leakage test and up to $100 per unit for duct repair.

High Efficiency Electric Heat Pumps: Pays financial incentive, not exceeding $350 per unit, to replace existing electric heating equipment with high-efficiency electric heat pumps. Specific incentive based on minimum heating and/or cooling efficiency levels. Indoor air handler and outdoor condenser must both be replaced with new equipment to qualify for this rebate.

Supplemental Incentive Bonus: Encourages adoption of several energy-efficiency measures through an additional incentive of up to $50. Incentive is paid to a participant in PEF's high efficiency electric heat pump program who also implements the ceiling insulation upgrade, duct leakage repair, or both, within 90 days.

Residential New Construction: Umbrella program for new home construction, multi-family, and manufactured homes. Promotes energy-efficient construction which exceeds the building code. Provides information, education, and advice to home builders and contractors on energy-related issues and efficiency measures. Promotes energy-efficient electric heat pumps with an incentive identical to that offered in the Home Energy Improvement program for existing homes.

Low Income Weatherization Assistance (LIWAP): Umbrella program to improve the energy efficiency of low-income family homes. Efficiency measures and incentives are identical to those offered in PEF's Home Energy Improvement Program, with the following additions:

Reduced Air Infiltration: A $75 incentive is paid for work which reduces air infiltration by a minimum specified amount.

Water Heater Wrap / Replacement: Provides wrap for water heater and associated piping near the tank. A $25 incentive may be paid towards the purchase of a high-efficiency water heater in lieu of an insulating jacket.

High-Efficiency Alternate Water Heating: Promotes installation of high-efficiency alternative electric water heating equipment. Provides incentive of $100 for each heat recovery unit and $200 per unit for each dedicated heat pump water heater unit.

Heating and Air Conditioning Maintenance: A $40 incentive is paid for service/tune-up maintenance on an existing electric central heating and air conditioning system.

Residential Energy Management: Voluntary load control program in which PEF reduces winter peak demand by interrupting electric service to water heaters and central electric heating units. Program is offered only during winter months (November through March). Maximum monthly bill credit is $11.50, but is paid only during winter months when customer usage exceeds 600 kWh per month.

RESIDENTIAL DEMAND-SIDE MANAGEMENT PROGRAMS

DSM PROGRAM	Summer Peak Demand		Winter Peak Demand		Annual Energy Consumption		Benefit / Cost Ratio (RIM)
	Savings (MW)	% of Goal	Savings (MW)	% of Goal	Savings (GWh)	% of Goal	
Home Energy Check	11.186	12.2%	11.186	3.1%	36.550	22.7%	N/A
Home Energy Improvement	51.948	56.5%	157.298	43.0%	82.920	51.5%	1.05
Residential New Construction	31.700	34.5%	111.962	30.6%	46.548	28.9%	1.28
Low Income Weatherization Assistance	1.032	1.1%	2.814	0.8%	1.967	1.2%	1.01
Residential Energy Management	0.000	0.0%	95.872	26.2%	0.000	0.0%	1.51
TOTAL SAVINGS	95.866	104.2%	379.132	103.6%	167.985	104.3%	
GOAL	92.0		366.0		161.0		

COMMERCIAL / INDUSTRIAL DEMAND-SIDE MANAGEMENT PROGRAMS

Business Energy Check: C/I energy audit program. Offers a free walk-through audit (inspection), a paid walk-through audit (energy analysis), and an online business energy check (customer-completed internet audit).

Better Business: Umbrella efficiency program for existing C/I buildings. Gives customers information and advice on energy-related issues and efficiency measures. Offers choice of rebates, as described below, or interest-free installment billing over 12 months. Promotes the following energy-efficiency measures:

> HVAC Equipment: Pays financial incentive, of up to $100 per kW reduced, for the purchase of high-efficiency HVAC equipment such as packaged terminal heat pumps, packaged rooftop units, water-cooled and air-cooled chillers, and unitary heat pumps and air conditioners.
>
> Energy Recovery Ventilation: Pays financial incentive of up to $1,500 for the installation of high-efficiency energy recovery ventilation units that remove heat and humidity from conditioned space. Customer must have electric heating and cooling system to participate.
>
> Duct Leakage Test and Repair: Promotes energy efficiency through improved duct system sealing. Program helps identify and reduce energy loss by measuring air leakage rate through the central duct system. Customer must have electric heating and centrally-ducted cooling system to participate. PEF pays up to $30 per unit for duct leakage test and up to $100 per unit for duct repair.
>
> Roof Insulation Upgrade: Encourages customers who have electric space heat to add roof insulation. PEF pays portion of the installed cost. Eligibility based on demonstration that additional insulation results in heating and/or cooling use reductions. Specific incentive amount based on increase in insulation amount above a maximum of R-12, with maximum incentive amount of $100 per customer.
>
> Cool Roof: Promotes the installation of "cool roof" coating which reflects heat and sun. Customer must have electric cooling system to participate. PEF pays $50 per 1,000 square foot of cool roof coating installed up to a maximum of $1,000.

C/I New Construction: Umbrella efficiency program for new C/I buildings. Provides information, education, and advice on energy-related issues and efficiency measures. Allows PEF to be involved early in the building's design process. Also provides incentives for energy-efficient equipment, such as HVAC equipment, energy recovery ventilation, and cool roof coating. Incentive levels are identical to those offered in the Better Business program for existing buildings.

<u>**Innovation Incentive**</u>: Provides incentives for customer-specific demand and energy conservation projects, on a case-by-case basis, where cost-effective to all PEF customers. To be eligible, projects must reduce or shift a minimum of 10 kW of peak demand. Rebates will be limited to $150 per kW reduced or shifted. Focuses on measures not offered in PEF's other DSM programs. Examples include refrigeration equipment replacement, thermal energy storage, microwave drying systems, and inductive heating (to replace resistance heat).

<u>**Standby Generation**</u>: Voluntary demand control program available to all C/I customers having on-site generation capability. Customer controls the equipment but operates it when needed by PEF. Incentive based on the load served by the customer's generator and is based on PEF's GSLM-2 rate schedule.

<u>**Interruptible Service**</u>: Direct load control program. PEF interrupts service by disconnecting electric service at the breaker during peak or emergency conditions. Offered under PEF's IS-2 and IST-2 tariffs. Available to any non-residential customer with an average billing demand of at least 500 kW. Monthly credit paid based on level of billing demand and load factor.

<u>**Curtailable Service**</u>: Direct load control program that is similar to interruptible service, only the customer's entire load is not shed. Offered under the CS-2 and CST-2 tariffs. Available to any non-residential customer with an average billing demand of at least 500 kW. Customer must be willing to reduce 25% of its average monthly billing demand upon request by PEF. Monthly credit paid to customer based on level of curtailable demand.

COMMERCIAL / INDUSTRIAL DEMAND-SIDE MANAGEMENT PROGRAMS

DSM PROGRAM	Summer Peak Demand		Winter Peak Demand		Annual Energy Consumption		Benefit / Cost Ratio (RIM)
	Savings (MW)	% of Goal	Savings (MW)	% of Goal	Savings (GWh)	% of Goal	
Business Energy Check	2.345	6.5%	2.345	6.9%	5.000	17.2%	N/A
Better Business	6.912	19.2%	5.926	17.4%	11.948	41.2%	1.20
C/I New Construction	4.685	13.0%	6.321	18.6%	10.407	35.9%	1.20
Innovation Incentive	0.840	2.3%	0.840	2.5%	1.441	5.0%	N/A
Standby Generation	18.600	51.7%	17.760	52.2%	0.250	0.9%	1.22
Interruptible Service	0.880	2.4%	1.000	2.9%	0.009	0.0%	1.04
Curtailable Service	0.880	2.4%	1.000	2.9%	0.017	0.1%	1.27
TOTAL SAVINGS	35.142	97.6%	35.192	103.5%	29.072	100.2%	
GOAL	36.0		34.0		29.0		

BEFORE THE PUBLIC SERVICE COMMISSION

In re: Petition for approval of numeric conservation goals by Progress Energy Florida, Inc.	DOCKET NO. 040031-EG ORDER NO. PSC-04-0852-CO-EG ISSUED: September 1, 2004

CONSUMMATING ORDER

BY THE COMMISSION:

By Order No. PSC-04-0769-PAA-EG, issued August 9, 2004, this Commission proposed to take certain action, subject to a Petition for Formal Proceeding as provided in Rule 25-22.029, Florida Administrative Code. No response has been filed to the order, in regard to the above mentioned docket. It is, therefore,

ORDERED by the Florida Public Service Commission that Order No. PSC-04-0769-PAA-EG has become effective and final. It is further

ORDERED that this docket shall be closed.

By ORDER of the Florida Public Service Commission this 1st day of September, 2004.

BLANCA S. BAYÓ, Director
Division of the Commission Clerk
and Administrative Services

By: Kay Flynn
Kay Flynn, Chief
Bureau of Records

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NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any judicial review of Commission orders that is available pursuant to Section 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Director, Division of the Commission Clerk and Administrative Services and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

BEFORE THE PUBLIC SERVICE COMMISSION

In re: Petition for approval of modifications to demand-side management programs by Progress Energy Florida, Inc.	DOCKET NO. 060647-EG ORDER NO. PSC-06-1018-TRF-EG ISSUED: December 11, 2006

The following Commissioners participated in the disposition of this matter:

LISA POLAK EDGAR, Chairman
J. TERRY DEASON
ISILIO ARRIAGA
MATTHEW M. CARTER II
KATRINA J. TEW

ORDER GRANTING APPROVAL OF MODIFICATIONS TO DEMAND-SIDE MANAGEMENT PROGRAMS

BY THE COMMISSION:

Background

Progress Energy Florida, Inc.'s (PEF) current Demand Side Management (DSM) Plan is comprised of 14 individual programs, including five residential programs, seven commercial/industrial (C/I) programs, a qualifying facilities (cogeneration and small power production) program, and a research and development program.

On September 27, 2006, PEF petitioned this Commission for approval to add two new residential conservation programs to its DSM plan, and to modify three of its residential and three of its C/I conservation programs. PEF stated in its petition that its objectives are to cost-effectively reduce the growth rate of weather sensitive peak demand, reduce and control the growth rate of energy consumption, increase the conservation of expensive resources and increase the efficiency of the electric system. The two new conservation programs are the Neighborhood Energy Saver and Renewable Energy programs. The three residential programs that PEF is proposing to modify are the Home Energy Improvement, Residential New Construction, and Residential Energy Management programs. The three C/I programs that PEF is proposing to modify are the Better Business, C/I New Construction and Standby Generation programs. PEF's petition for modifications also includes the tariffs and tariff revisions (see Attachment 2) that are needed to implement the proposed additions and modifications.

We have jurisdiction over this matter pursuant to the Florida Energy Efficiency and Conservation Act (FEECA) Sections 366.80 - 366.85, Florida Statutes.

Modifications to Demand-Side Management Programs

PEF lists five residential programs (three modified programs and two new programs) and three modified commercial/industrial (C/I) programs for approval as part of its DSM plan. Because of the recent increases in avoided costs (Generation, Transmission, O&M, Transmission, and Reserve Gas), these proposed program modifications and additions are cost-effective. PEF anticipates that the implementation of these proposed DSM programs will increase the penetration of demand-side management in the future. PEF has provided the cost-effectiveness analysis of each of the proposed DSM programs using this Commission's cost-effective methodology. PEF will monitor the proposed programs to evaluate the result of the energy and demand impacts and cost-effectiveness of each program. The Program descriptions, modifications or additions are discussed below.

Residential Conservation Programs

Neighborhood Energy Saver (NES) Program – This is a new program designed to assist low-income families with escalating energy costs. The goal of the program is to implement a comprehensive package of electric conservation measures at no cost to the customer. This program supplements PEF's existing Low-income Weatherization Assistance (LIWA) Program that consists of fifteen (15) measures and incentives. Customers who participate in the LIWA program are expected to pay some of the costs. In addition to the installation of new conservation measures, an important component of the NES program is educating families on energy efficiency techniques and the promotion of behavioral changes to help customers control their energy usage. The NES program consists of twelve (12) new measures and incentives. Participation in the program is free to eligible customers (PEF pays all of the cost to implement each measure). This program is projected to reduce consumption by approximately 31 GWH and demand by approximately 7 MW winter - 11 MW summer over the next eight years. The proposed measures are discussed in Attachment 1.

Renewable Energy Program – This new program is designed to provide an incentive for renewable energy technology used in conjunction with energy management. Renewable energy technology supplements a portion of consumer demand, while peak demand is reduced by interrupting service to selected electrical equipment with radio controlled switches installed on the customer's premises. The program consists of two measures:

1. Solar Water Heater with Energy Management - PEF has bundled these two programs together in order to make installations of solar water heaters cost effective. Eligible customers can enroll in either the Year Round Energy Management or Winter Only Energy Management measures and agree to have their water heater, central electric heating system and (or) central electric cooling system placed on Energy Management. PEF provides eligible customers with incentives of $450 plus a percentage of the associated Energy Management program credit (25% of water heater, central electric heating system and central electric cooling system credits). The customer can also elect to have the pool pump placed on Energy Management and receive 100% of the credit for that appliance. PEF requires that the customer stay on the tariff for a minimum of three years.

2. Solar Photovoltaics with Energy Management - PEF has bundled this program with the previous program in order to provide a cost-effective green energy program. PEF proposes to fund this program by allowing customers participating in the Winter-Only Energy Management or Year Round Energy Management Plan to donate their monthly credits toward the Solar Photovoltaics with Energy Management Fund. Once the fund has accumulated enough credits, these credits will be used for renewable energy education (10%) and the installation of solar energy systems at schools within PEF's service territory (90%). PEF has indicated that it will record the contributed monthly credits as a deferred credit and escrow the monies collected.

This program is projected to reduced consumption by approximately .342 GWH and demand by approximately .015 MW winter - .101 MW summer over the next eight years.

Home Energy Improvement Program – This umbrella program is designed to increase energy efficiency for existing residential homes by combining efficiency improvements to the thermal envelope with upgraded electric appliances. The existing Home Energy Improvement program includes incentives for six (6) measures (Duct Test, Duct Leakage Repair, Attic Insulation, High Efficiency Heat Pump Replacing Resistance Heat, High Efficiency Heat Pump Replacing Heat Pump, and Supplemental Bonuses). PEF proposes to modify this program by adding ten (10) new measures and incentives. The modified program is projected to reduce consumption by approximately 83 GWH and demand by approximately 164 MW winter - 54 MW summer over the next eight years. The proposed measures are discussed in Attachment 1.

New Construction Program – This program is for new construction, single family, multi-family, and manufactured home building segments. The New Construction program promotes energy efficient construction in order to provide customers with more efficient dwellings combined with improved environmental comfort. The existing New Construction program includes five (5) measures consisting of a free Duct Test and promotional literature, the choice to install one of two high efficiency electric heat pumps plus one of two attic insulation measures, installation of high performance windows, and qualifying the home for the EPA's Energy Star Program. According to the petition, PEF proposes to modify the program by adding seven (7) new measures and incentives to the existing measures listed above. This program is projected to reduce consumption by approximately 52 GWH and demand by approximately 124 MW winter - 60 MW summer over the next eight years. The proposed measures are discussed in Attachment 1.

Residential Year Round Energy Management – PEF closed the Residential Year Round Energy Management in 2001 because it was no longer cost effective but continued to offer a Residential Energy Management program for the winter only. The Winter Only measure allows PEF to reduce winter peak demand and defer generation construction. Peak demand is reduced by interrupting service to selected electrical equipment (water heaters, central electric heating systems, and pool pumps) with radio controlled switches installed on the customers' premises. These controlled interruptions are at PEF's option during specified time periods and coincident with hours of winter peak demand. According to PEF, it has recently determined that the Residential Year Round Energy Management is currently cost-effective to add new participants. The increase in the avoided costs due to recent increases in the costs of installed generation, O&M, transmission, and reserve gas have made this measure cost effective. The proposed Year Round Energy Management program credits to interrupt service to selected electrical equipment (water heater, central electric heating system, central electric cooling system, and pool pump) of eligible customers are: $14.00 maximum for each of the five (5) winter months and $11.00 maximum for each of the seven (7) summer months. PEF will continue to offer the Winter Only measure. Eligible customers participating in the Winter Only measure will receive a maximum credit of $14.00 for each of the five (5) winter months. This program is projected to reduce consumption by approximately 1 GWH and demand by approximately 131 MW winter - 63 MW summer over the next eight years.

Commercial and Industrial Conservation Programs

Standby Generation Program – This is a demand control program that will reduce PEF's demand based upon the indirect control of customer equipment. This is a voluntary program available to all of PEF's C/I customers who have on-site generation capability and are willing to reduce their demand when PEF deems it necessary. PEF proposes to modify this program by adding an additional credit based on the kWh the customer provides. The credits will be based upon the load served by the customer's generator, which would have been served by PEF if the Standby Generation program were not in operation. PEF proposes to increase the present incentive from $2.10 to $2.30 per kW per month plus an additional compensation of $0.05 per kWh to support the customer's O&M associated with the run time requested by the company. This program is offered through the General Service Load Management-2 (GSLM-2) rate schedule. This program is projected to reduce consumption by approximately .603 GWH and demand by approximately 75 MW winter - 75 MW summer over the next eight years.

Better Business Program – This program is an umbrella efficiency program for existing commercial, industrial, and government customers who want to retrofit with high efficiency improvements. The current program includes incentives for ten (10) measures (high efficient heat pumps less than or equal to 65,000 Btu/h replacing electric resistance heat, high efficient heat pumps less than or equal to 65,000 Btu/h replacing heat pumps, high efficient package terminal heat pump, high efficient unitary A/C and heat pumps greater than 65,000 Btu/h, air-cooled and water-cooled electric chillers, cool roof, ceiling insulation upgrade, duct test, and duct repair). PEF proposes to make some changes to several existing measures and add eleven (11) new measures and incentives. This program is projected to reduce consumption by approximately 99 GWH and demand by approximately 32 MW winter - 53 MW summer over the next eight years. The proposed measures are discussed in Attachment 1.

Commercial /Industrial New Construction Program – This umbrella program is designed to encourage the construction of energy efficient commercial buildings. The current program consists of six measures and incentives (high efficient heat pumps less than or equal to 65,000 Btu/h, high efficient package terminal heat pump, high efficient unitary A/C and heat pumps greater than 65,000 Btu/h, air-cooled and water-cooled electric chillers, energy recovery ventilation, and cool roof). PEF proposes to make changes to several existing measures and add nine (9) new measures and incentives. This program is projected to reduce consumption by approximately 48 GWH and demand by approximately 17 MW winter - 26 MW summer over the next eight years. The proposed measures are discussed in Attachment 1.

PEF projects that the eight (8) programs listed above (two new and six modified), including existing and new measures, will reduce energy consumption by 314 GWH over the next eight years. PEF also projects that these programs will reduce electric demand by 551 MW winter and 344 MW summer over the next eight years.

All modified and new programs passed the rate impact measure (RIM) test and Participant test where applicable. The analyses are shown in the table below.

Cost Effectiveness Analysis

Program	Rate Impact Measure (RIM) Test	Total Resource Cost (TRC)Test	Participant Test
Home Energy Improvement	1.68	4.86	3.07
Residential New Construction	2.27	4.80	2.48
Neighborhood Energy Saver	1.14	21.40	N/A
Renewable Energy	1.51	1.53	1.02
Residential Year Round Energy Management	2.73	7.80	N/A
Dispatchable Standby	4.91	60.88	N/A
Better Business	1.47	3.33	2.29
C/I New Construction	1.43	2.58	1.83

N/A – not applicable because there is no cost to the participant

Conclusion

PEF's proposed modifications will cost-effectively increase the number of the customers eligible to participate in these programs. PEF's proposed Attic Insulation R15 to R30 upgrade is one example. This new measure, proposed under the Home Energy Improvement program, will allow customers that have attic insulation greater that R11 but less than R16 to qualify for an attic insulation upgrade (PEF's customers that have attic insulation greater that R11 but less than R16 do not qualify under the existing Home Energy Improvement program). These modifications and new programs will also make it easier for PEF's customers to participate by increasing the number of conservation programs and measures available, and by providing additional incentives. The proposed modifications to the six programs as well as the addition of two new programs should accomplish PEF's objectives to encourage participation while cost-effectively reducing the growth rate of weather sensitive peak demand, reducing and controlling the growth rate of energy consumption, increasing the conservation of expensive resources and increasing the efficiency of the electric system. PEF has used the Commission-approved cost-effectiveness methodologies required by Rule 25-17.008, Florida Administrative Code, and the planning assumptions in PEF's 2006 – 2015 Ten-Year Site Plan to determine the cost effectiveness of the modified and new programs.

We find that the modifications and program additions will cost-effectively increase energy efficiency in homes and businesses, reduce PEF's coincident peak load, and reduce customers' energy consumption. PEF shall file detailed program standards within 60 days from the date of this order. These standards shall be filed for all new and revised DSM programs for administrative approval by the staff. Therefore, the six program modifications and the two program additions discussed herein are hereby approved. The tariffs and tariff revisions needed to implement these proposed program additions and modifications are also approved. PEF shall recover all reasonable and prudent costs for these programs through the energy conservation cost recovery clause (ECCR).

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Progress Energy Florida, Inc.'s proposed modifications to its Demand-Side Management Programs are hereby approved as set forth herein. It is further

ORDERED that all attachments appended hereto are incorporated herein by reference. It is further

ORDERED that the tariffs are hereby approved August 31, 2007. It is further

ORDERED that Progress Energy Florida, Inc. shall file detailed program standards within 60 days from the date of this order. It is further

ORDERED that if a timely protest is filed within 21 days from issuance of this Order, the tariffs shall remain in effect with any increase held subject to refund, pending resolution of the protest. It is further

ORDERED that if no timely protest is filed, this docket shall be closed upon the issuance of a Consummating Order.

By ORDER of the Florida Public Service Commission this 11th day of December, 2006.

Blanca S. Bayó
BLANCA S. BAYÓ, Director
Division of the Commission Clerk
and Administrative Services

(S E A L)

KEF

NOTICE OF FURTHER PROCEEDINGS

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Mediation may be available on a case-by-case basis. If mediation is conducted, it does not affect a substantially interested person's right to a hearing.

The Commission's decision on this tariff is interim in nature and will become final, unless a person whose substantial interests are affected by the proposed action files a petition for a formal proceeding, in the form provided by Rule 28-106.201, Florida Administrative Code. This petition must be received by the Director, Division of the Commission Clerk and Administrative Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on January 1, 2007.

In the absence of such a petition, this Order shall become final and effective upon the issuance of a Consummating Order.

Any objection or protest filed in this docket before the issuance date of this order is considered abandoned unless it satisfies the foregoing conditions and is renewed within the specified protest period.

Attachment 1

Descriptions of Select New Programs and Modifications to Existing Programs

HOME ENERGY IMPROVEMENT PROGRAM

PEF proposes to add the following measures to its previously approved program as follows:

Attic Insulation R15 to R30 Upgrade

This portion of the program encourages customers having existing insulation level greater than R11 but less than R16 to increase there attic insulation to R30 by paying a portion of the installed cost. PEF's current Attic Insulation program does not allow this group of customers to participate. The incentive will be $75 per residence up to 1500 sq. ft.; an additional incentive of 7 cents per square foot is paid for larger homes.

Spray-In Wall Insulation

This portion of the program encourages customers to add insulation to the block wall area by paying a portion of the installed cost. The proposed incentive will be 20 cents per square foot for the installation of wall insulation adjacent to conditioned space with a maximum incentive of $300 per residence. PEF's benefit/cost analyses have shown that the installation of insulation in existing homes have had more value (demand savings are higher) than in new homes.

Central Electric Air Conditioning with Existing Non-Electric Heat

This portion of the program encourages customers with existing non-electric heat to install high efficiency electric air conditioners. PEF will provide an incentive of $50 per unit with a seasonal energy efficiency ratio (SEER) rating of 14 or higher.

Supply and Return Plenum Duct Seal

This measure encourages the sealing of the supply and return portion of the plenum to the air handler. This incentive applies only for new heating/cooling systems with a qualifying SEER rating of 14 or higher. The proposed incentive for plenum sealing is $50 per system.

Proper Sizing of High Efficiency Air Conditioners

This portion of the program encourages the customer to have the air conditioning unit properly sized using an approved sizing software. This incentive applies only for heating/cooling systems when installing a new air handler and condensing unit. The proposed incentive for the proper sizing of high efficiency heating/cooling systems is $75 per system.

HVAC Commissioning

This portion of the program encourages the evaluation and optimization of heating/cooling systems using approved software. To qualify for the $50 incentive per system the customer must complete the specified recommendations as listed in the program standards.

Reflective Roof Manufactured Homes

This measure will provide incentives to install an approved Energy Star Roofing Product. The residence must have whole house electric cooling to be eligible for an incentive of $40 per residence.

Reflective Roof Single Family Homes

This measure provides an incentive to install light colored roofs on the residence. The residence must have whole house electric cooling to be eligible for this measure. The incentive will be 15 cents per square foot over conditioned space with a maximum incentive of $150. PEF's benefit/cost analyses have shown that the installations of reflective roofs on existing homes have had more value (demand savings are higher) than on new homes

Window Film and Window Screen

This portion of the program encourages customers to install qualifying film or screening on their windows facing east, west, and south. The residence must have whole house electric cooling to be eligible for this measure. The proposed maximum incentive is half the cost up to $100.

Replacement Windows

This measure encourages the installation of new high performance windows when replacing existing windows. The customer must have whole house electric cooling and heating to be eligible for this measure. Windows of the residence qualify for the incentive of $1.00 per square foot of the window area with a maximum incentive of $250 per residence.

RESIDENTIAL NEW CONSTRUCTION

PEF proposes to add the following measures to its previously approved program as follows:

HVA C Commissioning

This measure uses approved software to evaluate and insure proper refrigerant charge and air flow per manufacture specifications. The proposed incentive is $50 per unit.

Window Film and Window Screen

This portion of the program involves the installation of qualifying shading coefficient film or screen on the windows facing east, west, and south. The proposed incentive is $100 for installing window film or window screen. Only one incentive would apply per home.

Reflective Roof Single Family

This portion of the program provides an incentive for the installation of reflective roof material on the home. The proposed incentive is $100 per home.

Attic Spray-On Foam Insulation

This portion of the program provides an incentive for adding foam insulation above the ceiling area by paying a portion of the installed cost. The proposed incentive will be $100 per home.

Wall Insulation

This portion of the program provides an incentive to add insulation to the block wall area adjacent to conditioned space beyond code requirements by paying a portion of the installed cost. The proposed incentive is $200 per home.

Conditioned Space Air Handler

This portion of the program will provide a $50 incentive for locating the air handler in conditioned space. The proposed incentive would apply upon conversion of the design plan to accommodate the location of the air handler to conditioned space.

Energy Recovery Ventilation

This program measure promotes the installation of high efficiency energy recovery ventilation (ERV) units in the conditioned air stream for homes with whole house electric heat pump systems. The proposed incentive will be $150 per home.

NEIGHBORHOOD ENERGY SAVER

New program proposed by PEF.

Compact Fluorescent Bulb

This measure will provide the resident with five (5) compact fluorescent bulbs to replace incandescent bulbs with the identical lumens output.

Water Heater Wrap and Insulation for Water Pipes

This portion of the program will furnish and install a hot water heater wrap and pipe insulation as identified by the Neighborhood Energy Saver Program Home Energy Evaluation form.

Water Heater Temperature Check and Adjustment

The portion of the program will provide a temperature check of the hot water heater and inform the customer of the possibility for turn-down adjustment.

Low Flow Faucet Aerator

This measure will allow for the installation of a maximum of three (3) aerators per household.

Low Flow Showerhead

This measure will allow for the installation of a maximum of two (2) low flow showerheads per household.

Refrigerator Coil Brush

This portion of the program will provide the customer with a coil brush.

Refrigerator Thermometer

This measure will provide for the installation of one (1) thermometer in the food compartment and one (1) thermometer in the freezer of the refrigerator.

Wall Plate Thermometer

This portion of the program will provide the installation of one (1) wall plate thermometer per home.

HVAC Winterization Kit

This measure will provide for the installation of a winterization HVAC kit for wall/window AC units if seasonably applicable. The resident will receive or have installed a maximum of three (3) kits. The customer will be educated on the proper use and value of the weatherization kit as a method of stopping air infiltration in the home.

HVAC Filters

This portion of the program will allow each customer to receive a one year supply (12) of filters.

Change Filter Calendar

This portion of the program will provide each homeowner a Progress Energy magnetic calendar to help remind them to clean or change filter monthly.

Weatherization Measures

This portion of the program will provide weather stripping, door sweeps, caulk, foam sealant, clear patch tape which will be used to reduce or stop air infiltration around doors, windows, attic doors, and where pipes enter the home. Air infiltration reduction is key to saving energy and customer comfort.

BETTER BUSINESS PROGRAM

PEF proposes to make some changes to several existing measures and add the following measures to its previously approved program as follows:

Roof Insulation Upgrade

This measure encourages customers who have electric space heat to add insulation to the roof area by paying for a portion of the installed cost. The facility must have an existing roof insulation level less than R12 to participate and upgrade to a minimum value of R19 to receive the incentive. The incentive amount will be 7 cents per square foot of conditioned space with a maximum of $5,000 per building.

Thermal Energy Storage w/ Time-of-Use Rate

This measure will provide an incentive to encourage existing business customers to utilize thermal energy storage (TES) systems to reduce the size and cost of replacement chillers and lower energy costs. To generate maximum cost savings, customers should enter into the Time-of-Use Rate. The proposed incentive for the new measure will be up to $300 per kW of reduced cooling load at peak times.

Green Roof

A green roof – also known as a vegetated or eco-roof – is a lightweight, engineered roofing system that allows for the propagation of rooftop vegetation while protecting the integrity of the underlying roof. While conventional roof gardens rely on heavy pots and planters, green roof systems allow for much more extensive cultivation of plant life across wide expanses of a given rooftop. This measure is designed to encourage business customers to increase the thermal efficiency of their buildings by utilizing Green Roof designs and resulting in reduced peak kW. The proposed incentive will be 25 cents per square foot over conditioned space for the installation of an approved Green Roof.

Efficient Compressed Air System

This measure will provide an incentive to encourage business customers to utilize a proactive approach to increase the efficiency of compressed air systems. Proposed incentives will be calculated based on $50 per kW reduction.

Occupancy Sensors

This measure will provide an incentive to encourage business customers to install occupancy sensors in any areas where indoor lights would be used on peak. The proposed incentive will be $50 per kW of lighting load controlled with approved controls.

Roof Top Unit Recommission

This measure will provide an incentive to encourage existing business customers to perform recommissioning to Rooftop Air Conditioning units (RTU). Recommissioning will consist of performing maintenance to assure the unit is operating at optimal efficiency. The proposed incentive for the new measure will be $15 per ton of RTU.

HVAC Steam Cleaning

This measure will provide an incentive to encourage existing business customers who utilize Packaged Terminal Air Conditioning (PTAC) and Packaged Terminal Heat Pump (PTHP) units to have the coils steam cleaned. This steam cleaning process will improve the efficiency of the HVAC equipment. The proposed incentive is $15 per unit on a one-time basis.

Efficient Indoor Lighting

This measure is intended to promote energy efficiency through the retrofit of older inefficient lamp and ballast technology in indoor lighting fixtures with more energy efficient technologies. The proposed incentives will be $50 per kW reduced.

Demand Control Ventilation

This measure will provide incentives for the installation of Demand Control Ventilation (DCV) using *C02* sensors. DCV saves energy by automatically adjusting building ventilation rates in real time based on occupancy. This measure provides incentives of $50 per ton with properly designed and installed DCV control programming.

Efficient Motors

This measure promotes the installation of high efficiency polyphase motors through a simple incentive structure based on the motor size and a specified $/hp. The incentive amount will be from $1.75 to $2.75 per hp. The specific incentive amount will be a function of the motor size and efficiency.

Window Film

Progress Energy Florida will provide customers with an incentive to install window film on new windows having east, west, and south exposures. The maximum incentive will be 75 cents per square-foot of window film installed. An exception to this limitation will be made for facilities with multiple guest rooms, such as hotels, motels, hospitals, and assisted-care living facilities, which may receive incentives up to a maximum of $55 per room.

COMMERCIAL/INDUSTRIAL NEW CONSTRUCTION PROGRAM

PEF proposes to make some changes to several existing measures and add the following measures to its previously approved program as follows:

Roof Insulation

This measure encourages customers whose facilities will have electric space heat to increase insulation to the roof area. The facility must increase their roof insulation level above minimum code to participate and must be planning to heat by electricity in order to receive the incentive. The customer must upgrade their roof insulation to R-19 or higher. The incentive amount will be 7 cents per square foot of conditioned space with a maximum of $5,000 per building.

Thermal Energy Storage w/ Time-of-Use Rate

This measure will provide an incentive to encourage new business customer facilities to utilize thermal energy storage (TES) systems to reduce the initial size and cost of chillers and lower energy costs. To generate maximum cost savings, customers, should enter into the Time-of-Use Rate. The proposed incentive for the new measure will be up to $300 per kW of reduced cooling load at peak times.

Green Roof

A green roof – also known as a vegetated or eco-roof – is a lightweight, engineered roofing system that allows for the propagation of rooftop vegetation while protecting the integrity of the underlying roof. While conventional roof gardens rely on heavy pots and planters, green roof systems allow for much more extensive cultivation of plant life across wide expanses of a given rooftop. This measure is designed to encourage business customers building new facilities to increase the thermal efficiency of their buildings by utilizing Green Roof designs and resulting in reduced kW. The proposed incentive will be 25 cents per square foot over conditioned space for the installation of an approved Green Roof.

Efficient Compressed Air System

This measure will provide an incentive to encourage business customers to design a system that optimizes the energy efficiency of compressed air systems. Proposed incentives will be calculated based on $50 per kW reduction.

Occupancy Sensors

This measure will provide an incentive to encourage business customers to install occupancy sensors in any areas where indoor lights would be used on peak. The proposed incentive will be $50 per kW of lighting load controlled with approved controls.

Efficient Indoor Lighting

This measure is intended to promote energy efficiency through the specification of energy efficient indoor lighting technology through a range of options. The proposed incentives will be $50 per kW reduced.

Demand Control Ventilation

This measure will provide incentives for the installation of Demand Control Ventilation (DCV) using CO2 sensors. DCV saves energy by automatically adjusting building ventilation rates in real time based on occupancy. This program provides incentives of $50 per ton with properly designed and installed DCV control programming.

Efficient Motors

This measure promotes the installation of high efficiency polyphase motors through a simple incentive structure based on the motor size and a specified $/hp. The maximum incentive amount will be from $1.75 to $2.75 per hp. The specific incentive amount will be a function of the motor size and efficiency.

Window Film

PEF will provide customers with an incentive to install window film on new windows having east, west, and south exposures. The maximum incentive will be 75 cents per square-foot of window film installed. An exception to this limitation will be made for facilities with multiple guest rooms, such as hotels, motels, hospitals, and assisted-care living facilities, which may receive incentives up to a maximum of $55 per room.

Attachment 2

Tariff Revisions

RATE SCHEDULE RSL-1
RESIDENTIAL LOAD MANAGEMENT

Availability:

Available only within the range of the Company's Load Management System.
Available to customers whose premises have active load management devices installed prior to [date TBD].
Available to customers whose premises have load management devices installed after [date TBD] that have and are willing to submit to load control of, at a minimum, central electric cooling and heating systems.

Applicable:

To customers eligible for Residential Service under Rate Schedule RS-1 or RSS-1 having a minimum average monthly usage of 600 kWh (based on the most recent 12 months, or, where not available, a projection for 12 months), and utilizing any of the following electrical equipment:

1. Water Heater
2. Central Electric Heating System
3. Central Electric Cooling System
4. Swimming Pool Pump

Character of Service:

Continuous service, alternating current, 60 cycle, single-phase, at the Company's standard distribution secondary voltage available. Three-phase service, if available, will be supplied only under the conditions set forth in the Company's booklet "Requirements for Electric Service and Meter Installations."

Limitation of Service:

Service to the electrical equipment specified above may be interrupted at the option of the Company by means of load management devices installed on the customer's premises.

For new service requests after [date TBD] customers with a central electric heating system that is a heat pump will be installed on Interruption Schedule S. All other new service requests will be installed on Interruption Schedule B. Interruption Schedule C shall be at the option of the customer.

For new service requests after April 1, 1995, and before [date TBD], customers who select the swimming pool pump schedule must also select at least one other schedule.

An installation of an alternative thermal storage heating system under Special Provision No. 7 of this rate schedule is not available after April 1, 1995.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:	$ 8.03
Energy and Demand Charges:	
Non-Fuel Energy Charges:	
First 1,000 kWh	3.315¢ per kWh
All additional kWh	4.315¢ per kWh
Plus the Cost Recovery Factors listed in Rate Schedule BA-1, *Billing Adjustments*, except the Fuel Cost Recovery Factor:	See Sheet No. 6.105 and 6.106

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Load Management Monthly Credit Amounts:[1,2]

Interruptible Equipment	Interruption Schedule A	B	C	D	S
Water Heater	-	-	$3.50	-	-
Central Heating System[3]	$2.00	$8.00	-	-	$8.00
Central Heating System w/Thermal Storage[3]	-	-	-	$8.00	-
Central Cooling System[4]	$1.00	$5.00	-	-	$5.00
Swimming Pool Pump	-	-	$2.50	-	-

(Continued on Page No. 2)

Progress Energy

SECTION NO. VI
TENTH REVISED SHEET NO. 6.131
CANCELS NINTH REVISED SHEET NO. 6.131

RATE SCHEDULE RSL-1
RESIDENTIAL LOAD MANAGEMENT
(Continued from Page No. 1)

Any customer with a heat pump not taking service under Schedule S who requests a change under this tariff will be required to take service under Schedule S.
Premises taking service under this tariff and controlled by load management devices will remain on the existing schedule until such time as the current customer affirmatively requests a change.
See also Special Provisions 10 and 11 below for further customer optional adjustments to the above credits.

Notes: (1) Load Management credits shall not exceed 40% of the Non-Fuel Energy Charge associated with kWh consumption in excess of 600 kWh per month.

(2) Premises that have load management devices installed prior to [date TBD] may remain on the existing schedule until such time as the customer requests a change under this tariff. When a change is requested, customers may take service only *under Schedule B or Schedule S if the customer has a heat pump. Customers may also opt for* Schedule C if taking service under another Schedule. Customers whose premises have load management devices installed after [date TBD] will be subject to the Limitations of Service above.

(3) For the billing months of November through March only.

(4) For the billing months of April through October only.

Interruption Schedules:

Schedule A — Equipment interruptions will not exceed an accumulated total of 10 minutes during any 30 minute interval within the Company's designated Peak Periods.

Schedule B — Equipment interruptions will not exceed an accumulated total of 16.5 minutes during any 30 minute interval within the Company's designated Peak Periods.

Schedule C — Equipment may be interrupted continuously, not to exceed 300 minutes, and during the Company's designated Peak Periods. Where a thermal storage system has been installed hereunder, additional interruptions to the water heater will *be made during periods of charging thermal the storage system.*

Schedule D — The regular heating system may be interrupted continuously and alternative heating provided by means of a thermal *storage system installed hereunder.*

Schedule S — Equipment interruptions will not exceed an accumulated total of 16.5 minutes during any 30 minute interval within the Company's designated Peak Periods. *Heat pump back-up strip may be interrupted* continuously, not to exceed 300 minutes, during the Company's designated Peak. When the heat pump back-up strip is being interrupted, the heat pump will not be interrupted.

Peak Periods:

The Peak Periods expressed in terms of prevailing clock time shall be, but are not limited to these as follows:

(1) For the calendar months of November through March, All Days:	6:00 a.m. to 11:00 a.m., and 6:00 p.m. to 10:00 p.m.
(2) For the calendar months of April through October, All Days:	1:00 p.m. to 10:00 p.m.

Terms and Conditions:

All terms and conditions of Rate Schedule RS-1, Residential Service, (i.e. Fuel Charges and other Billing Adjustments, Minimum Monthly Bill, Terms of Payment, Term of Service and Average Billing Plan), shall apply to service under this rate schedule.

(Continued on Page No. 3)

RATE SCHEDULE RSL-1
RESIDENTIAL LOAD MANAGEMENT
(Continued from Page No. 2)

Special Provisions:

1. The Company shall be allowed reasonable access to the customer's premises to install, maintain, inspect, test and remove load management devices on the electrical equipment specified above.
2. Prior to the installation of load management devices, the Company may inspect the customer's electrical equipment to ensure good repair and working condition, but the Company shall not be responsible for the repair or maintenance of the electrical equipment.
3. The Company shall not be required to install load management devices on electrical equipment which would not be economically justified for reasons, such as, excessive installation costs, insufficient load, oversized equipment or abnormal utilization of equipment, including but not limited to, vacation or other limited occupancy residences or qualifying common use facilities.
4. Multiple units of any electrical equipment specified above must all be installed with load management devices to qualify for the credit attributable to that equipment type at that premise.
5. The limitation on interruptible schedules shall not apply during critical capacity conditions on the Company's system; nor shall limitations apply at times the Company requires additional generating resources to maintain firm power sales commitments or supply emergency interchange service to another utility for its firm load obligations only. The Company may also exercise equipment interruptions at any time for purposes of testing and performance evaluation of its Load Management System.
6. If the Company determines that the load management devices have been tampered with, the Company may discontinue service under this rate schedule and bill for all prior load management credits received by the customer, unless an earlier tampering date can be established, plus applicable investigative charges.
7. An alternative thermal storage heating system is available to customers who (a) have resistance strip heating solely as their central electric heating system, (b) have adequate space and provide access for installation and maintenance of a thermal storage system, (c) have an electric water heater circuit which can be utilized for charging a thermal storage system and (d) have normal residential water heating and central heating requirements. The Company shall not be required to provide a thermal storage system where the Company deems the installation to be economically unjustified.

   For qualifying customers, the Company will install, maintain and operate a thermal storage system consisting of a thermal storage (water) tank, a pump, and a heat exchanging coil. The storage tank will be charged at the option and under the control of the Company. When this option is exercised, heating from this system will be available in place of the customer's regular heating system. During periods that the storage tank is being charged, electric service to the customer's regular water heater will be interrupted. An initial incentive payment of $50.00 shall be made to a participating customer.
8. Billing under this Rate Schedule will commence with the first complete billing period following installation of the load management devices. A customer may change interruption schedules or the selection of elelctrical equipment installed with load management devices or transfer to another rate schedule by notifying the Company forty-five days in advance. However, in the event of any revision to the interruption schedules which may affect customer, the Customer shall be allowed ninety days from the effective date of the revision to change schedules or equipment or transfer to another rate schedule.
9. If the Company determines that the effect of equipment interruptions has been offset by the customer's use of supplementary or alternative electrical equipment, or if access cannot be obtained by the Company to inspect, maintain, or remove load management devices, service under this rate schedule may be discontinued and the customer billed for all prior load management credits received over a period not in excess of six months.
10. For customers at premises taking service under Interruption Schedule B or S, and C for electric water heating, for which the premise at any time received the solar thermal water heating incentive, the monthly credit amount will be 25% of the above credit values for Interruption Schedules B, S and C, except for the pool pump. The pool pump credit amount will be at 100%.
11. A customer may elect to have all their credits contributed to the Progress Energy "Photovoltaics for Schools" green program. No partial contributions will be allowed. This program installs photovoltaic panels on schools as funds become available.

Progress Energy

RATE SCHEDULE RSL-2
RESIDENTIAL LOAD MANAGEMENT – WINTER ONLY

Availability:

Available only within the range of the Company's Load Management System.

Applicable:

To customers eligible for Residential Service under Rate Schedule RS-1 or RSS-1 having a minimum average monthly usage of 600 kWh for the months of November through March (based on the most recent billings, where not available, a projection for those months) and utilizing both electric water heater and central electric heating systems.

Character of Service:

Continuous service, alternating current, 60 cycle, single-phase, at the Company's standard distribution secondary voltage available. Three-phase service, if available, will be supplied only under the conditions set forth in the Company's booklet "Requirements for Electric Service and Meter Installations."

Limitation of Service:

Service to the electrical equipment specified above may be interrupted at the option of the Company by means of load management devices installed on the customer's premises.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:	$ 8.03
Energy and Demand Charges:	
Non-Fuel Energy Charges:	
First 1,000 kWh	3.315¢ per kWh
All additional kWh	4.315¢ per kWh
Plus the Cost Recovery Factors listed in Rate Schedule BA-1, *Billing Adjustments*, except the Fuel Cost Recovery Factor:	See Sheet No. 6.105 and 6.106

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Load Management Credit Amount:[1]

<u>Interruptible Equipment</u>	<u>Monthly Credit</u>[2]
Water Heater and Central Heating System	$11.50

Notes: (1) Load management credit shall not exceed 40% of the Non-Fuel Energy Charge associated with kWh consumption in excess of 600 kWh/month.

(2) For billing months of November through March only.

Appliance Interruption Schedule:

Heating — Equipment interruptions will not exceed an accumulated total of 16.5 minutes during any 30 minute interval within the Company's designated Peak Periods. Heat pump back-up strip may be interrupted continuously, not to exceed 300 minutes, during the Company's designated Peak. When the heat pump back-up strip is being interrupted, the heat pump will not be interrupted.

Water Heater — Equipment may be interrupted continuously, not to exceed 300 minutes, and during the Company's designated Peak Periods.

(Continued on Page No. 2)

Progress Energy

RATE SCHEDULE RSL-2
RESIDENTIAL LOAD MANAGEMENT – WINTER ONLY
(Continued from Page No. 1)

Peak Periods:

The Peak Periods expressed in terms of prevailing clock time shall be, but are not limited to these as follows:

(1) For the calendar months of November through March - All Days: 6:00 a.m. to 11:00 a.m., and 6:00 p.m. to 10:00 p.m.

Terms and Conditions:

All terms and conditions of Rate Schedule RS-1, Residential Service (i.e. Fuel Charges and other Billing Adjustments, Minimum Monthly Bill, Terms of Payment, Term of Service and Budget Billing Plan), shall apply to service under this rate schedule.

Special Provisions:

1. The Company shall be allowed reasonable access to the customer's premises to install, maintain, inspect, test and remove load management devices on the electrical equipment specified above.

2. Prior to the installation of load management devices, the Company may inspect the customer's electrical equipment to ensure good repair and working condition, but the Company shall not be responsible for the repair or maintenance of the electrical equipment.

3. The Company shall not be required to install load management devices on electrical equipment which would not be economically justified for reasons, such as, excessive installation costs, insufficient load, oversized equipment, or abnormal utilization of equipment, including but not limited to, vacation or other limited occupancy residences or qualifying common use facilities.

4. Multiple units of any electrical equipment specified above must all be installed with load management devices to qualify for the credit attributable to that equipment at that premise.

5. The limitation on interruptible schedules shall not apply during critical capacity conditions on the Company's system; nor shall limitations apply at times the Company requires additional generating resources to maintain firm power sales commitments or supply emergency interchange service to another utility for its firm load obligations only. The Company may also exercise equipment interruptions at any time for purposes of testing and performance evaluation of its Load Management System.

6. If the Company determines that the load management devices have been tampered with, the Company may discontinue service under this rate schedule and bill for all prior load management credits received by the customer, unless an earlier tampering date can be established, plus applicable investigative charges.

7. Billing under this Rate Schedule will commence with the first complete billing period following installation of the load management devices. A customer may transfer to another rate schedule by notifying the Company forty-five (45) days in advance. If a customer tranfers to another rate schedule they are not eligible for service under this rate schedule for 12 months from the date of transfer.

8. If the Company determines that the effect of equipment interruptions has been offset by the customer's use of supplementary or alternative electrical equipment, or if access cannot be obtained by the Company to inspect, maintain, or remove load management devices, service under this rate schedule may be discontinued and the customer billed for all prior load management credits received over a period not in excess of six (6) months.

9. A customer may elect to have all their credits contributed to the Progress Energy "Photovoltaics for Schools" green program. No partial contributions will be allowed. This program installs photovoltaic panels on schools as funds become available.

Progress Energy

RATE SCHEDULE GSLM-1
GENERAL SERVICE - LOAD MANAGEMENT

Availability:

Available only within the range of the Company's Load Management System.

Applicable:

To customers who are eligible for service under Rate Schedules GS-1, GST-1, GSD-1, or GSDT-1, excluding those customers served under the General Service transition rates, and who elect service under this rate schedule and have electric space cooling equipment suitable for interruptible operation. Also applicable to those customers who have any of the following electrical equipment installed on permanent residential structures and utilized for domestic (household) purposes: (1) water heater(s), (2) central electric heating system(s), (3) central electric cooling system(s), and/or (4) swimming pool pump(s).

Limitation of Service:

Service to specified electrical equipment may be interrupted at the option of the Company by means of load management devices installed on the customer's premises.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

The rates and all other terms and conditions of Company Rate Schedules GS-1, GST-1, GSD-1 or GSDT-1 (whichever shall otherwise be applicable) shall be applicable to service under this rate schedule, subject to the following:

LOAD MANAGEMENT MONTHLY CREDIT AMOUNT

Interruptible Equipment	Interruption Schedule	Credit Based on Installed Capacity[1]	Applicable Billing Months
Electric Space Cooling[3]	A	$ 0.26 Per kW	April thru October
Electric Space Cooling[3]	B	$ 0.56 Per kW	April thru October
Domestically Utilized Equipment[2,3]	[Availability, Schedules and Credits of the otherwise applicable Rate Schedule RSL-1or RSL-2 shall apply]		

Notes:

(1) Credit shall not exceed 50% of the Non-Fuel Energy and Demand Charges; nor, for otherwise applicable Rate Schedule GSDT-1, shall the credit exceed the On-Peak and Base Demand Charges.

(2) Equipment includes water heaters, central heating systems, central cooling systems and swimming pool pumps when such equipment is installed on permanent residential structures and utilized for domestic purposes.

(3) Restricted to existing customers as of July 20, 2000.

Interruption Schedules:

Schedule A Interruptions will not exceed an accumulated total of 10 minutes during any 30-minute interval within the designated Peak Periods.

Schedule B Interruptions will not exceed an accumulated total of 16.5 minutes during any 30-minute interval within the designated Peak Periods.

(Continued on Page No. 2)

Progress Energy

RATE SCHEDULE GSLM-1
GENERAL SERVICE – LOAD MANAGEMENT
(Continued from Page No. 1)

Peak Periods:

The designated Peak Periods expressed in terms of prevailing clock time shall be as follows:

(1) For the calendar months of November through March, All Days:	6:00 a.m. to 11:00 a.m., and 6:00 p.m. to 10:00 p.m.
(2) For the calendar months of April through October, All Days:	1:00 p.m. to 10:00 p.m.

Special Provisions:

1. The Company shall be allowed reasonable access to the customer's premises to install, maintain, inspect, test and remove load management devices on the electrical equipment specified above.

2. Prior to the installation of load management devices, the Company may inspect the customer's electrical equipment to ensure good repair and working condition, but the Company shall not be responsible for the repair or maintenance of the electrical equipment. The Company may, at its option, require a commercial energy audit as a prerequisite to receiving service under this rate. The audit may be used to establish or confirm equipment capacity, operating hours, or to determine the ability of the Company to control electric demand.

3. The Company shall not be required to install load management devices on electrical equipment, which would not be economically justified, for reasons such as excessive installation costs, oversized equipment or abnormal utilization of equipment, including operating hours which are not considered within the designated Peak Periods.

4. If the Company determines that equipment operating schedules and/or business hours have reduced the ability of the Company to control electric demand during the above designated peak periods, then service under this rate will be discontinued.

5. Where multiple units (including standby or multi-stage) of space conditioning equipment are used to heat or cool a building, all of these units must be equipped with load management devices and normally must be controlled on the same interruption cycle.

6. Billing under this rate schedule will commence with the first complete billing period following installation of the load management devices. During the first year of service, a customer may transfer to another rate schedule by notifying the Company forty-five (45) days in advance. After the first year of service, the customer may transfer to another rate schedule by notifying the Company twelve (12) months in advance. However, in the event of any revision to the interruption schedules which may affect customer, the customer shall be allowed ninety (90) days from the effective date of the revision to change schedules or equipment or transfer to another rate schedule.

7. The limitations on Interruptible Schedules shall not apply during critical capacity conditions on the Company's system; nor shall limitations apply at times the Company requires additional generating resources to maintain firm power sales comittments or supply emergency interchange service to another utility for its firm load obligations only. The Company may also exercise equipment interruptions at any time for purposes of testing and performance evaluation of its Load Management System.

8. If the Company determines that the load management devices have been tampered with or disconnected without notice, the Company may discontinue service under this rate schedule and bill for prior load mangement credits received by the customer, plus applicable investigative charges.

9. If the Company determines that the effect of equipment interruptions have been offset by the customer's use of supplementary or alternative electrical equipment, service under this rate schedule may be discontinued and the customer billed for all prior load management credits received over a period not in excess of six (6) months.

10. For purposes of determining eligible credits related to domestically utilized equipment, the customer shall provide the Company actual occupancy rates of permanent residential structures containing each type of equipment for the previous winter (November through March) and summer (April through October) periods. Credits for the current billing period shall apply to the number of items of each installed type of equipment multiplied by the corresponding previous seasonal period's occupancy rate.

Progress Energy

RATE SCHEDULE GSLM-2
GENERAL SERVICE LOAD MANAGEMENT – STANDBY GENERATION

Availability:

Available only within the range of the Company's radio switch communications capability.

Applicable:

To customers who are eligible for service under Rate Schedules GS-1, GST-1, GSD-1, or GSDT-1 who have standby generation that will allow facility demand reduction at the request of the Company. The customer's Standby Generation Capacity calculation must be at lease 50 kW in order to remain eligible for the rate. Customers cannot be on this rate schedule and also the General Service Load Management (GSLM-1) rate schedule. Customers cannot use the standby generation for peak shaving.

Limitation of Service:

Operation of the customer's equipment will occur at the Company's request. Power to the facility from the Company will normally remain as back up power for the standby generation. The Customer will be given fifteen (15) minutes to initiate the demand reduction before the capacity calculation (see Definitions) is impacted.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

The rates and all other terms and conditions of Company Rate Schedules GS-1, GST-1, GSD-1 or GSDT-1 (whichever shall otherwise be applicable) shall be applicable to service under this rate schedule, subject to the following:

GSLM-2 MONTHLY CREDIT AMOUNT
STANDBY GENERATION

Credit	Cumulative Fiscal Year Hours
$2.30 x *C* + $0.05[1] x kWh monthly	$0 \le CRH \le 200$
$2.76 x *C* + $0.05[1] x kWh monthly	$200 < CRH$

Immediately upon going on the rate, the customer's Capacity (*C*) is set to a value equivalent to the load the customer's standby generator carries during testing observed by the Customer and a Company representative. The *C* will remain at that value until the equipment is requested to run by the Company. The *C* for that month and subsequent months will be a calculated value based upon the following formula:

$$C = \frac{\text{kWh annual}}{[\text{CAH} - (\#\text{ of Requests} \times 1/4\text{ hour})]}$$

Definitions:

kWh annual = Actual measured kWh generated by the standby generator during the previous twelve (12) months during Company control periods (rolling total).

CAH = Cumulative hours requested by the Company for the standby generation to operate for the previous twelve (12) months (rolling total).

CRH = Cumulative standby generator running hours during request periods of the Company for the current fiscal year (the fiscal year begins on the month the customer goes on the GSLM-2 rate).

\# of Requests = The cumulative number of times the Company has requested the standby generation to be operated for the previous twelve (12) months (rolling total).

kWh monthly = Actual measured kWh generated by the standby generator for the current month during Company control periods.

[1] This $ per kWh rate represents an incentive credit to support Customer O&M associated with run time requested by the Company. PEF will periodically review this incentive rate and request changes as deemed appropriate.

(Continued on Page No. 2)

Progress Energy

RATE SCHEDULE GSLM-2
GENERAL SERVICE LOAD MANAGEMENT – STANDBY GENERATION
(Continued from Page No. 1)

Schedules:

Requests by the Company for the customer to reduce facility demand by operation of the standby generation can occur at any time during the day. The GSLM-2 will not be operated more than twice each day with the total operation not exceeding twelve (12) hours. Under extreme emergency conditions, the Company may request the Customer to voluntarily operate their standby generation for longer than twelve (12) hours a day.

Special Provisions:

1. The Company shall be allowed reasonable access to the customer's premises to install, maintain, inspect, test and remove the equipment associated with this rate.
2. Prior to the installation of the equipment, the Company may inspect the customer's electrical equipment (including standby generator) to ensure good repair and working condition, but the Company shall not be responsible for the repair or maintenance of the electrical equipment (including standby generator). The Company may, at its option, require a commercial energy audit as a prerequisite to receiving service under this rate. The audit may be used to establish or confirm equipment capacity, operating hours, or to determine the ability of the Company to control electric demand.
3. If the Company determines that the equipment installed as part of this rate by the Company has been tampered with, the Company may discontinue service under this rate and bill the customer for prior credits received under this rate for that fiscal year.

No changes have been made to this tariff sheet

BEFORE THE PUBLIC SERVICE COMMISSION

In re: Petition for approval of modifications to demand-side management programs by Progress Energy Florida, Inc.	DOCKET NO. 060647-EG ORDER NO. PSC-07-0017-CO-EG ISSUED: January 5, 2007

CONSUMMATING ORDER

BY THE COMMISSION:

By Order No. PSC-06-1018-TRF-EG, issued December 11, 2006, this Commission proposed to take certain action, subject to a Petition for Formal Proceeding as provided in Rule 25-22.029, Florida Administrative Code. No response has been filed to the order, in regard to the above mentioned docket. It is, therefore,

ORDERED by the Florida Public Service Commission that Order No. PSC-06-1018-TRF-EG has become effective and final. It is further

ORDERED that this docket shall be closed.

By ORDER of the Florida Public Service Commission this 5th day of January, 2007.

Blanca S. Bayó

BLANCA S. BAYÓ, Director
Division of the Commission Clerk
and Administrative Services

(S E A L)

KEF

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any judicial review of Commission orders that is available pursuant to Section 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Director, Division of the Commission Clerk and Administrative Services and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

Demand Side Management Plan

June 1, 2004

Progress Energy Florida Inc.
John Masiello
Manager, Program Development
& Administration
3300 Exchange Place
Lake Mary FL 32746

Progress Energy

TABLE OF CONTENTS

INTRODUCTION

In accordance with Sections 25-17.001-.005, Florida Administrative Code, the Florida Public Service Commission (FPSC) requested numeric conservation goals, testimony and Plan for Progress Energy Florida (PEF), in Docket No. 040031-EG. In response to this Order, Progress Energy submits this Demand Side Management (DSM) Plan to the FPSC for approval.

Progress Energy has designed its DSM Plan to achieve the conservation goals set forth by the FPSC. This plan provides Progress Energy's customers with comprehensive DSM services while resulting in electric rates that are lower than they would have been if this Plan were not implemented. The DSM Plan consists of five (5) residential programs, seven (7) commercial and industrial (C/I) programs, a technology research and development program, and a qualifying (small power production or cogeneration) facilities program.

This document is organized into seven sections:

Section I presents an overview of Progress Energy's proposed DSM Plan, summarizing the goals and cumulative impacts of the plan.

Section II discusses some general issues associated with demand-side management planning and implementation, including program operation, cost-effectiveness, program monitoring and evaluation, and cost-recovery.

Section III presents Progress Energy's proposed residential programs.

Section IV presents Progress Energy's proposed commercial/industrial programs.

Section V presents Progress Energy's Technology Development program.

Section VI presents Progress Energy's Qualifying Facilities program.

I. PROGRAM GOALS

AND

CUMULATIVE IMPACT

I. PROGRAM GOALS AND CUMULATIVE IMPACT

Progress Energy Florida's DSM Plan has specifically been designed to efficiently acquire all cost-effective DSM resources necessary to meet the conservation goals proposed in FPSC Docket 040031-EG. The DSM Plan consists of five (5) residential programs, seven (7) commercial and industrial (C/I) programs, a technology research and development program, and a qualifying (small power production or cogeneration) facilities program:

RESIDENTIAL PROGRAMS	COMMERCIAL/INDUSTRIAL PROGRAMS
Home Energy Check	Business Energy Check
Home Energy Improvement	Better Business
New Construction	C/I New Construction
Low Income Weatherization Assistance	Innovation Incentive
Residential Energy Management	Standby Generation
	Interruptible Service
	Curtailable Service
Technology Development	
Qualifying Facilities	

These DSM programs have been designed to achieve the conservation goals proposed in Docket 040031 while minimizing the rate impacts on all PEF customers. In designing these DSM programs, the following multiple objectives were addressed:

- Achieve the annual conservation goals established in Docket 040031-EG for 2005-2014
- Minimize rate impacts to all PEF customers
- Base program designs on customer needs
- Implement mechanisms to minimize free ridership
- Capture all cost-effective DSM resources, including cost-effective lost opportunities
- Provide customers with added value -- efficiency, convenience, productivity, comfort and reliability
- Utilize market involvement, such as dealers and home builders, where appropriate.

Tables I-1 and I-2 present the cumulative demand and energy impacts projected to be achieved by this DSM Plan as compared to the Commission-established goals for each year during the planning period 2005-2014, for the residential and C/I sectors, respectively. PEF's DSM Plan is designed to meet or exceed the Commission-established energy and demand goals.

Table I-1
Progress Energy Florida, Inc.
Residential Market Segment Demand and Energy Data

Proposed Residential Plan 2004 DSM Filing						
	Projected Summer Demand Savings (MW)		Projected Winter Demand Savings (MW)		Projected Annual Energy Savings (GWh)	
Year	Incremental	Cumulative	Incremental	Cumulative	Incremental	Cumulative
2005	13	13	43	43	21	21
2006	8	21	33	75	14	35
2007	9	30	33	108	15	50
2008	8	38	33	142	15	65
2009	9	47	34	175	15	80
2010	8	55	35	210	15	95
2011	10	65	38	248	17	112
2012	9	74	38	287	17	128
2013	9	83	38	324	16	144
2014	9	92	42	366	16	161

Table I-2
Progress Energy Florida, Inc.
Commercial/Industrial Segment Demand and Energy Data

Proposed Commercial Plan 2004 DSM Filing						
	Projected Summer Demand Savings (MW)		Projected Winter Demand Savings (MW)		Projected Annual Energy Savings (GWh)	
Year	Incremental	Cumulative	Incremental	Cumulative	Incremental	Cumulative
2005	4	4	3	3	3	3
2006	3	7	4	7	3	6
2007	4	11	4	10	3	9
2008	4	14	3	14	3	12
2009	3	18	3	17	3	15
2010	3	21	3	20	3	18
2011	4	25	4	24	3	20
2012	3	29	3	28	3	23
2013	3	32	3	31	3	26
2014	4	36	3	34	3	29

II. PROGRAM INTRODUCTION

II. PROGRAM INTRODUCTION

A. PROGRAM OPERATION

The focal point for both the residential and the C/I sector programs is an energy audit program (Home Energy Check for residential and Business Energy Check for C/I). The energy audit programs serve multiple purposes to satisfy the needs of PEF, its customers, and the Commission:

1. Educate customers by providing an overview of typical energy use.
2. Identify opportunities for improving energy efficiency at the customer's home or facility.
3. Serve as the marketing tool to introduce customers to PEF's other conservation programs.
4. Assist PEF in minimizing free ridership in the other DSM programs.
5. Satisfy the Commission's mandate to offer energy audit services to all customers.

For the residential sector, PEF has consolidated most measures into two "umbrella" programs -- the Home Energy Improvement program for existing customers and the New Construction program for new home builders. The creation of these comprehensive programs provides significant benefits over implementing measure-specific programs, including the following:

- Increased program cost-effectiveness through lower program administration, implementation, monitoring, and evaluation costs by minimizing redundant functions.
- More efficient program delivery because each customer can be more comprehensively addressed.
- Improved marketability to customers through concise, consistent, and comprehensive program packaging.

For the C/I sector, PEF has also consolidated most of the measures into "umbrella" programs -- the Better Business program for existing customers and the C/I New Construction program for new commercial buildings. These "umbrella" programs provide the same benefits as described above. But in the commercial and industrial sectors, because the facilities and systems are more complex than in the residential sector, there are additional opportunities for conservation from customer-specific technology improvements, as well as from alternative rates. Thus, for the C/I sector, PEF's DSM Plan also includes the Innovation Incentive program for customized efficiency improvements, as well as the Standby Generation, Interruptible Service, and Curtailable Service programs.

Technology Development pursues research, development and demonstration projects, individual projects as well as partnerships, of potential energy saving technologies to help determine new possible cost-effective measures.

Under the Qualifying Facilities program, Progress Energy develops standard offer contracts, negotiates, enters into, amends and restructures firm energy and capacity contracts entered into with qualifying cogeneration and small power production facilities, and administers all such contracts.

B. COST-EFFECTIVENESS

All programs submitted in this DSM Plan have been analyzed for cost-effectiveness using the Commission-approved tests described in Rule 25-17.008, Florida Administrative Code. PEF's DSM Plan has specifically been designed to efficiently acquire all cost-effective DSM resources necessary to meet the Commission-established goals for PEF. The programs were evaluated based on the Rate Impact Measure (RIM) test to ensure that the DSM programs result in lower electric rates than supply-side alternatives.

In order to conduct the cost-effectiveness analysis, the DSView model (produced by New Energy Associates) was used to evaluate the DSM programs against potentially avoidable supply-side capacity. In contrast to static models such as the Florida Integrated Resource Evaluator (FIRE) model, DSView is a more sophisticated dynamic model which more nearly simulates the operation of the power system. For example, DSView is directly integrated with other supply-side planning models, thereby allowing variables such as marginal fuel costs, hourly production costs, and generation equivalency to be computed and applied more accurately than under the FIRE model. Because of this fundamental modeling concept difference, DSView will produce different results from the FIRE model.

A summary of the cost-effectiveness results for each of the DSM programs included in this DSM Plan are shown in Table II-1. In addition, detailed program cost-effectiveness results are presented at the end of each program discussion in Sections III and IV of this document. These detailed results consist of one page each for the RIM, Participant, and Total Resource Cost (TRC) Tests.

Table II-1
Summary of Demand Side Management Programs
Included in Proposed Plan
Period 2005-2014

DSM Measure	Rate Impact Measure Test			Participant Test			Total Resource Cost Test			
	PV Total Benefits ($000)	PV Total Costs ($000)	B / C Ratio	PV Total Benefits ($000)	PV Total Costs ($000)	B / C Ratio	PV Total Benefits ($000)	PV Total Costs ($000)	B / C Ratio	Program Status
Home Energy Check	NA	NA	NA	NA	NA	NA	NA	NA	NA	Existing
Home Energy Improvement	95,438	90,520	1.05	86,790	20,377	4.26	95,438	24,107	3.96	Modified
Residential New Construction	33,885	26,410	1.28	22,269	10,891	2.04	33,885	15,032	2.25	Modified
Low Income Weatherization	1,484	1,472	1.01	1,292	NA	NA	1,484	180	8.24	Existing
Residential Winter-Only Energy Management	31,320	20,728	1.51	10,050	360	28	30,960	10,678	2.90	Existing
Business Energy Check	NA	NA	NA	NA	NA	NA	NA	NA	NA	Existing
Better Business	8,283	6,904	1.20	6,826	4,414	1.55	8,283	4,492	1.84	Modified
C/I New Construction	7,129	5,944	1.20	5,899	3,866	1.53	7,129	3,911	1.82	Modified
Innovation Incentive	NA	NA	NA	NA	NA	NA	NA	NA	NA	Existing
Standby Generation	6,602	5,403	1.22	4,768	0	NA	6,602	634	10.40	Existing
Interruptible Service	253	242	1.04	170	0	NA	253	72	3.51	Existing
Curtailable Service	466	367	1.27	145	0	NA	466	222	2.09	Existing
Technology Development	NA	NA	NA	NA	NA	NA	NA	NA	NA	Existing
Qualifying Facilities	NA	NA	NA	NA	NA	NA	NA	NA	NA	Existing

NOTES:

(1) Home Energy Check and Business Energy Check are FPSC mandated programs; therefore, no cost-effectiveness analysis was conducted for these programs.
(2) Innovation Incentive projects are individually evaluated for cost-effectiveness; only projects that pas both the RIM and Participant tests are approved.
(3) Technology Development projects are individually evaluated for cost-effectiveness.

C. PROGRAM MONITORING AND EVALUATION

Program monitoring and evaluation are important components of DSM implementation. They serve the purpose of ensuring that all DSM resources are acquired in a cost-effective manner. Specifically, program monitoring includes tracking program data and ensuring quality control. Program evaluation results document the energy and demand impacts and cost-effectiveness of the program, as well as suggest ways that the program can be improved by increasing savings, reducing costs, or increasing participation.

While there is a great need to regularly evaluate programs to ensure their cost-effectiveness, there is an equally great need to utilize the evaluation method that is most cost-effective. Imprudent expenditures on evaluation can significantly affect the overall cost-effectiveness of a program to its detriment. Just as PEF's DSM Plan is limited to cost-effective programs, only cost-effective evaluation efforts should be used to evaluate these programs. The level of evaluation effort must be balanced with the need for evaluation. For example, the programs that provide the largest portion of the total DSM impact should be given the greatest evaluation emphasis. Programs (or measures) that provide small per unit impacts or which have had relatively low levels of participation should be evaluated using approaches that can be justified given their relative contribution to the total net benefits.

Therefore, while there are many methods available to evaluate the impacts of these programs, PEF will determine on a program-by-program basis the most cost-effective evaluation method based on factors such as participation levels, program performance, dollars invested, the level of uncertainty of measure performance, etc.

D. Cost-Recovery

PEF submits the programs herein described for approval and for inclusion as cost recoverable Conservation and Energy Efficiency Programs under current FPSC-approved procedures pursuant to Rule 25-17.015, and requests permission to recover all costs associated with the development and administration of this DSM Plan.

In addition, PEF intends to maintain its work toward administering and negotiating cogeneration contracts, and will continue to seek recovery of all associated administrative costs through the Energy Conservation Cost Recovery (ECCR) Clause.

PEF will make every effort toward the most appropriate transition from its existing DSM programs to any new or modified programs submitted in this Plan. As such, PEF seeks to recover all costs incurred through the implementation of those existing programs during the transition period. This is in accordance with approved Program Participation Standards which allow, in the event of program discontinuance, the extension of current recommendations and rebate amounts for up to two years from the date of program discontinuance or until the rebate is paid, whichever is sooner.

PEF has designed each of the DSM programs to pass the RIM test; therefore, each program is cost-effective on its own merit. This should not rule out the possibility that the Company may request incentives or recovery of lost revenues in the future.

III. RESIDENTIAL

CONSERVATION PROGRAMS

III. RESIDENTIAL CONSERVATION PROGRAMS

Progress Energy Florida's DSM Plan includes five (5) residential programs:

A. **Home Energy Check** - residential energy audits

B. **Home Energy Improvement** - "umbrella" program for existing homes

C. **New Construction** - "umbrella" program for new residential construction, multi-family, and manufactured homes

D. **Low Income Weatherization Assistance Program** - "umbrella" program for the weatherization of low income family homes

E. **Residential Energy Management** - residential load control

Each program is described in detail in the following sections.

A. HOME ENERGY CHECK PROGRAM

Program Start Date: 1995

Policies and Procedures

The Home Energy Check is PEF's residential energy audit program, which provides its customers with an analysis of their current energy use and recommendations on how they can save on their electricity bill through low-cost or no-cost energy-saving practices and measures. It also serves as the foundation of the Home Energy Improvement program in that it serves as a prerequisite for participation in any of the retrofit-type components of the Home Energy Improvement program. The exception is an emergency replacement of high efficient heat pump(s). This requirement exists so that PEF can: 1) provide the customer with an overview of typical energy use, 2) verify that the action requested (e.g., additional attic insulation) will address the customer's problem, and 3) help to minimize free ridership in the Home Energy Improvement program.

The Home Energy Check program offers PEF customers the following types of audits:

Type 1: Free Walk-Through Audit (Home Energy Check)

Type 2: Customer-completed Mail In Audit (Do It Yourself Home Energy Check)

Type 3: Online Home Energy Check (Internet Option)-a customer-completed audit

Type 4: Phone Assisted Audit –A customer assisted survey of structure and appliance use

Type 5: Paid Walk-Through Audit (Computer Assisted Audit)

Type 6: Home Energy Rating Audit (Class I, II, III).

All residential customers of PEF are eligible to receive any of the above energy audits. There is no charge for Type 1 through Type 4 audits, while there is a $15 customer charge for the Type 5 audit. When a customer requests a Home Energy Check, they will be given the option of either receiving a Type 2 audit survey in the mail or scheduling a Type 1 or Type 5 walk-through audit. A PEF auditor will usually conduct the audit, although PEF may also work with other agencies and/or utilities as an extension of PEF's services, in which case an approved auditor from another organization may conduct the audit. The Home Energy Rating as outlined in PEF's "Florida Energy Gauge Ratings" rate tariff (Section II, sheet number 2.6) is available to all eligible PEF customers upon request.

Cumulative participation estimates for the program are shown in the following table.

Year	Total Number of Customers [1]	Total Number of Eligible Customers	Annual Number of Program Participants [2]	Cumulative Penetration Level (%) Calculated
2005	1,382,699	1,382,699	27,500	2%
2006	1,406,712	1,406,712	54,500	4%
2007	1,431,102	1,431,102	81,500	6%
2008	1,455,971	1,455,971	108,000	7%
2009	1,481,124	1,481,124	134,000	9%
2010	1,505,866	1,505,866	154,000	10%
2011	1,529,665	1,529,665	174,000	11%
2012	1,552,660	1,552,660	194,500	13%
2013	1,575,153	1,575,153	216,000	14%
2014	1,597,449	1,597,449	238,000	15%

1. *Total Number of Customers is the forecast of all residential customers, from the November 2003 Forecast.*
2. *Annual Number of Program Participants is the projected number of cumulative energy audits that will be conducted.*

Savings Estimates

The total program savings were developed by estimating impacts for each audit level and for low-cost energy efficiency measures promoted through the program. The total program savings are shown in the following table.

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2005	155	0.047	0.047	4,258,500	1,304	1,304
2006	156	0.048	0.048	8,475,500	2,595	2,595
2007	156	0.048	0.048	12,692,500	3,886	3,886
2008	155	0.047	0.047	16,744,500	5,126	5,126
2009	154	0.047	0.047	20,631,500	6,315	6,315
2010	155	0.048	0.048	23,897,000	7,315	7,315
2011	156	0.048	0.048	27,162,500	8,316	8,316
2012	156	0.048	0.048	30,346,000	9,290	9,290
2013	155	0.047	0.047	33,489,000	10,251	10,251
2014	154	0.047	0.047	36,550,000	11,186	11,186

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2005	165	0.051	0.051	4,550,509	1,393	1,393
2006	166	0.051	0.051	9,056,672	2,772	2,772
2007	166	0.051	0.051	13,562,835	4,152	4,152
2008	166	0.051	0.051	17,892,684	5,477	5,477
2009	165	0.051	0.051	22,046,219	6,747	6,747
2010	166	0.051	0.051	25,535,637	7,817	7,817
2011	167	0.051	0.051	29,025,055	8,886	8,886
2012	167	0.051	0.051	32,426,851	9,927	9,927
2013	166	0.051	0.051	35,785,369	10,954	10,954
2014	164	0.051	0.051	39,056,264	11,953	11,953

Per customer impacts vary from year to year because of the changing mix of audit participants in the various audit levels, as well as the mix of low-cost measures assumed to be installed in any given year.

Impact Evaluation Plan

The range of possible recommendations resulting from the audit, and the inclusion of both technological and behavioral recommendations suggests the need to survey Home Energy Check participants to determine what specific conservation actions have been implemented within each market segment due to the completed audit. These impacts are currently being evaluated, and these survey results, combined with the participant-specific data gathered during the audit, will be used to determine the savings that can be directly attributable to the Home Energy Check program.

B. HOME ENERGY IMPROVEMENT PROGRAM

Program Start Date:
- 1995
- Program modified in 2000
- Proposed modification for 2005

Policies and Procedures

The Home Energy Improvement program is the umbrella program to increase energy efficiency for existing residential homes. It combines efficiency improvements to the thermal envelope with upgraded electric appliances. The program seeks to meet the following overall goals:

- Improve customer comfort levels through efficient equipment and home thermal integrity upgrades.
- Obtain energy and demand impacts that are accurate, sustainable, and measurable.
- Enhance contractor awareness of new technologies.
- Educate customers about additional opportunities associated with an energy efficient home.
- Obtain cost effective resources from the marketplace.
- Minimize "lost opportunities" in the existing home market.

The program provides incentives for attic insulation upgrades, duct testing and repair, and high efficiency heat pumps. The program eligibility requirements to qualify for participation are as follows:

- The home must be metered by Progress Energy Florida, Inc.
- The home is required to have a residential energy audit prior to participation for the attic insulation and duct test and repair.
- Duct repairs must be sealed with mastic meeting UL 181 specifications consistent with duct manufacturer's requirements.
- New construction homes do not qualify under this program.
- High efficiency heat pump incentives will be paid for replacing existing electric heat pumps and/or electric resistance heat.

Incentive Levels and specific eligibility requirements for each measure promoted in this program will be presented in the "Program Participation Standards."

Attic Insulation Upgrade

This portion of the program encourages customers to add insulation to the ceiling area by paying a portion of the installed cost. The home must have an existing insulation level of less than R-12 to participate. The customer must have either whole house electric cooling or whole house electric heating to be eligible for this program. The maximum incentive available will be $100 per residence; the specific incentive is determined by the resulting insulation level.

Duct Test and Repair

This portion of the program is designed to encourage eligible customers to improve their central duct system by reducing the air leakage rate. This is accomplished by performing a duct leakage test, then offering to repair the leakage that is discovered by the duct test. The home must have centrally-ducted electric cooling and electric heat to participate in this measure. For a duct test, PEF will pay up to a maximum of $30 for the first unit and $20 for each additional unit at the same address. For the duct repair, PEF will pay an incentive of up to $100 per unit. For multi-family rental units, PEF will pay all the costs up to $100 per unit (top floor only) and no test is required.

High Efficiency Electric Heat Pumps

For high efficiency electric heat pumps, PEF will provide an incentive up to $350 per unit. The specific incentive available is dependent upon the efficiency level of the unit installed and the type of electric heat the new equipment is replacing. In order to qualify for an incentive both the air handler and the outdoor condensing unit shall be replaced, and both units shall be new. This program seeks to accommodate emergency replacement situations by allowing a participant to have a Home Energy Check conducted after the installation and still be eligible for the incentive.

High Efficiency Alternate Water Heating

Progress Energy has determined that it is no longer cost-effective under the RIM test to continue offering incentives for alternate water heating. These measures have relatively low rates of participation and have small overall impacts.

Supplemental Incentive Bonus

To maximize the implementation of energy efficiency measures per participant, an incentive bonus is provided to high efficiency electric heat pump participants who also implement ceiling insulation upgrade, duct leakage repair, or both, within 90 days, before or after, of the installation date of the high efficiency electric heat pump. The purpose of this incentive is to offset some of the customer's large capital outlay to install more than one energy efficiency measure. The maximum incentive bonus a customer can receive is $50.

Financing

PEF is offering as an alternative to the incentives, a financing option. The financing option is an interest free (12 Month) installment-billing plan. As an alternative to receiving an incentive, the customer may choose to finance their energy efficient measure for up to one-year interest free.

Cumulative participation estimates for the program are shown in the following table.

Year	Total Number of Customers [1]	Total Number of Eligible Customers [2]	Annual Number of Measure Participants [3]	Cumulative Penetration Level (%)
2005	1,382,699	69,135	14,530	21%
2006	1,406,712	139,471	24,475	18%
2007	1,431,102	211,026	34,746	16%
2008	1,455,971	283,824	45,669	16%
2009	1,481,124	357,880	59,985	17%
2010	1,505,866	433,174	69,279	16%
2011	1,529,665	509,657	83,203	16%
2012	1,552,660	587,290	97,127	17%
2013	1,575,153	666,048	110,531	17%
2014	1,597,449	745,920	123,935	17%

1. *Total Number of Customers is the forecast of all residential customers, from the November 2003 Forecast.*
2. *Total number of Eligible Customers is based on an estimate of the cumulative number of central heat pumps and air conditioners that are replaced each year.*
3. *Annual number of Measure Participants is the projected number of cumulative measure installations from all measures promoted through this program. Because customers can install multiple measures, the actual number of participants will be less.*

Savings Estimates

Total program savings were developed by first estimating the total savings for each individual measure based on each measure's (1) per customer savings and, (2) annual projected participation. The total program savings were then computed as the sum of the individual measure savings, and are shown in the following tables.

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2005	824	1.311	0.580	11,971,615	19,052	8,424
2006	656	1.234	0.422	16,048,091	30,211	10,335
2007	643	1.202	0.427	22,352,961	41,780	14,820
2008	640	1.194	0.428	29,227,729	54,522	19,531
2009	643	1.202	0.427	36,648,374	68,503	24,330
2010	648	1.216	0.425	44,923,866	84,243	29,468
2011	657	1.237	0.423	54,624,103	102,912	35,171
2012	662	1.252	0.421	64,324,340	121,582	40,875
2013	666	1.262	0.420	73,622,097	139,440	46,411
2014	669	1.269	0.419	82,919,854	157,298	51,948

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2005	880	1.4011	0.6195	12,792,519	20,358	9,002
2006	701	1.3190	0.4512	17,148,522	32,282	11,043
2007	687	1.2849	0.4558	23,885,722	44,645	15,836
2008	684	1.2757	0.4570	31,231,899	58,261	20,870
2009	687	1.2846	0.4562	39,161,384	73,201	25,998
2010	693	1.2994	0.4545	48,004,333	90,019	31,488
2011	702	1.3217	0.4517	58,369,723	109,969	37,583
2012	708	1.3376	0.4497	68,735,114	129,919	43,678
2013	712	1.3481	0.4487	78,670,426	149,002	49,594
2014	715	1.3562	0.4479	88,605,738	168,085	55,510

Impact Evaluation Plan

The impact evaluation plan for an "umbrella" program such as this requires a varied approach given the number and type of measures being promoted. Some measures provide large per unit impacts while other yield relatively smaller impacts. The total impact from all smaller-impact measures could be potentially less than the uncertainty around an impact estimate of just one large measure. Consequently, the impact evaluation will place greater emphasis on the larger impact measures. The method of impact evaluation may vary depending on the participation levels actually achieved for each measure. Engineering analysis and statistical billing analysis represents the primary methods that will be used to estimate demand and energy impacts. These analyses will be supported by residential end-use metering data.

Cost-Effectiveness

The economic results of the program are as follows:

Cost-Effectiveness Test	NPV Benefits $(000)	NPV Costs $(000)	NPV Net Benefits $(000)	B/C Ratio
Rate Impact Measure	95,438	90,520	4,917	1.05
Participant	86,790	20,377	66,414	4.26
Total Resource Cost	95,438	24,107	71,331	3.96

PROGRAM: HOME ENERGY IMPROVEMENT PROGRAM

RATE IMPACT MEASURE TEST

	BENEFITS					COSTS							
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
YEAR	TOTAL FUEL & O&M SAVINGS $(000)	AVOIDED T&D CAP. COSTS $(000)	AVOIDED GEN. CAP. COSTS $(000)	REVENUE GAINS $(000)	**TOTAL BENEFITS** $(000)	TOTAL FUEL & O&M INCREASE $(000)	INCREASED T&D CAP. COSTS $(000)	INCREASED GEN. CAP. COSTS $(000)	UTILITY PROGRAM COSTS $(000)	INCENTIVE PAYMENTS $(000)	REVENUE LOSSES $(000)	**TOTAL COSTS** $(000)	**NET BENEFITS** $(000)
2004	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	576	370	0	0	946	0	0	0	590	2,579	795	3,964	-3,018
2006	830	614	0	0	1,445	0	0	0	381	1,698	1,292	3,372	-1,927
2007	1,478	860	579	0	2,916	0	0	0	380	1,700	1,719	3,799	-882
2008	1,920	1,118	813	0	3,850	0	0	0	389	1,778	2,251	4,418	-568
2009	2,635	1,526	1,033	0	5,194	0	0	0	631	2,818	3,107	6,556	-1,362
2010	2,391	1,959	2,328	0	6,677	0	0	0	652	2,968	4,122	7,742	-1,064
2011	2,620	2,440	2,497	0	7,557	0	0	0	703	3,286	5,191	9,181	-1,623
2012	3,540	2,925	3,201	0	9,666	0	0	0	707	3,312	6,373	10,392	-727
2013	3,848	3,398	3,561	0	10,807	0	0	0	692	3,228	7,509	11,429	-622
2014	4,698	3,871	3,337	0	11,905	0	0	0	692	3,227	8,739	12,659	-754
2015	5,064	3,871	3,614	0	12,548	0	0	0	0	0	8,964	8,964	3,584
2016	5,058	3,871	3,546	0	12,474	0	0	0	0	0	9,181	9,181	3,292
2017	5,371	3,871	3,840	0	13,081	0	0	0	0	0	9,406	9,406	3,675
2018	5,376	3,871	3,765	0	13,012	0	0	0	0	0	9,657	9,657	3,355
2019	5,677	3,871	4,087	0	13,634	0	0	0	0	0	9,860	9,860	3,775
2020	5,624	3,871	3,984	0	13,478	0	0	0	0	0	10,112	10,112	3,366
2021	5,723	3,871	4,084	0	13,678	0	0	0	0	0	10,393	10,393	3,284
2022	5,869	3,871	4,186	0	13,925	0	0	0	0	0	10,655	10,655	3,271
2023	5,972	3,871	4,291	0	14,133	0	0	0	0	0	10,923	10,923	3,210
2024	6,067	3,871	4,398	0	14,335	0	0	0	0	0	11,156	11,156	3,180
2025	6,169	3,871	4,508	0	14,547	0	0	0	0	0	11,474	11,474	3,073
2026	6,291	3,871	4,621	0	14,782	0	0	0	0	0	11,762	11,762	3,020
2027	6,350	3,871	4,735	0	14,956	0	0	0	0	0	12,058	12,058	2,898
2028	6,489	3,871	4,854	0	15,214	0	0	0	0	0	12,327	12,327	2,887
2029	6,543	3,871	4,957	0	15,370	0	0	0	0	0	12,656	12,656	2,714
2030	6,722	3,871	5,100	0	15,693	0	0	0	0	0	12,968	12,968	2,725
2031	6,779	3,871	5,208	0	15,857	0	0	0	0	0	13,312	13,312	2,545
2032	6,967	3,871	5,358	0	16,195	0	0	0	0	0	13,643	13,643	2,553
2033	7,020	3,871	5,471	0	16,362	0	0	0	0	0	13,988	13,988	2,374
NOMINAL	139,663	92,621	101,955	0	334,239	0	0	0	5,817	26,596	255,593	288,006	46,233
NPV	39,721	27,803	27,913	0	95,438	0	0	0	3,730	16,969	69,821	90,520	4,917

Utility Discount Rate: **8.16**
Benefit Cost Ratio: **1.05**

PROGRAM: HOME ENERGY IMPROVEMENT PROGRAM

TOTAL RESOURCE COST TEST

	BENEFITS					COSTS						
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) **TOTAL BENEFITS** $(000)	(6) PARTICIPANT'S COST $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) **TOTAL COSTS** $(000)	(12) **NET BENEFITS** $(000)
2004	0	0	0	0	0	0	0	0	0	0	0	0
2005	576	370	0	0	946	3,169	0	0	0	590	3,759	-2,813
2006	830	614	0	0	1,445	1,859	0	0	0	381	2,240	-796
2007	1,478	860	579	0	2,916	1,867	0	0	0	380	2,247	670
2008	1,920	1,118	813	0	3,850	1,973	0	0	0	389	2,362	1,488
2009	2,635	1,526	1,033	0	5,194	3,502	0	0	0	631	4,133	1,061
2010	2,391	1,959	2,328	0	6,677	3,686	0	0	0	652	4,338	2,340
2011	2,620	2,440	2,497	0	7,557	4,038	0	0	0	703	4,742	2,816
2012	3,540	2,925	3,201	0	9,666	4,061	0	0	0	707	4,769	4,897
2013	3,848	3,398	3,561	0	10,807	3,970	0	0	0	692	4,662	6,145
2014	4,698	3,871	3,337	0	11,905	3,970	0	0	0	692	4,662	7,244
2015	5,064	3,871	3,614	0	12,548	0	0	0	0	0	0	12,548
2016	5,058	3,871	3,546	0	12,474	0	0	0	0	0	0	12,474
2017	5,371	3,871	3,840	0	13,081	0	0	0	0	0	0	13,081
2018	5,376	3,871	3,765	0	13,012	0	0	0	0	0	0	13,012
2019	5,677	3,871	4,087	0	13,634	0	0	0	0	0	0	13,634
2020	5,624	3,871	3,984	0	13,478	0	0	0	0	0	0	13,478
2021	5,723	3,871	4,084	0	13,678	0	0	0	0	0	0	13,678
2022	5,869	3,871	4,186	0	13,925	0	0	0	0	0	0	13,925
2023	5,972	3,871	4,291	0	14,133	0	0	0	0	0	0	14,133
2024	6,067	3,871	4,398	0	14,335	0	0	0	0	0	0	14,335
2025	6,169	3,871	4,508	0	14,547	0	0	0	0	0	0	14,547
2026	6,291	3,871	4,621	0	14,782	0	0	0	0	0	0	14,782
2027	6,350	3,871	4,735	0	14,956	0	0	0	0	0	0	14,956
2028	6,489	3,871	4,854	0	15,214	0	0	0	0	0	0	15,214
2029	6,543	3,871	4,957	0	15,370	0	0	0	0	0	0	15,370
2030	6,722	3,871	5,100	0	15,693	0	0	0	0	0	0	15,693
2031	6,779	3,871	5,208	0	15,857	0	0	0	0	0	0	15,857
2032	6,967	3,871	5,358	0	16,195	0	0	0	0	0	0	16,195
2033	7,020	3,871	5,471	0	16,362	0	0	0	0	0	0	16,362
NOMINAL	139,663	92,621	101,955	0	334,239	32,096	0	0	0	5,817	37,913	296,325
NPV	39,721	27,803	27,913	0	95,438	20,377	0	0	0	3,730	24,107	71,331

Utility Discount Rate: **8.16**
Benefit Cost Ratio: **3.96**

PROGRAM: HOME ENERGY IMPROVEMENT PROGRAM

PARTICIPANT TEST

	BENEFITS				COSTS			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
YEAR	SAVINGS IN PARTICIPANT'S BILL $(000)	INCENTIVE PAYMENTS $(000)	OTHER PARTICIPANT'S BENEFITS $(000)	TOTAL BENEFITS $(000)	PARTICIPANT'S COST $(000)	PARTICIPANT'S BILL INCREASE $(000)	TOTAL COSTS $(000)	NET BENEFITS TO PARTICIPANTS $(000)
2004	0	0	0	0	0	0	0	0
2005	795	2,579	0	3,374	3,169	0	3,169	205
2006	1,292	1,698	0	2,991	1,859	0	1,859	1,132
2007	1,719	1,700	0	3,419	1,867	0	1,867	1,552
2008	2,251	1,778	0	4,029	1,973	0	1,973	2,056
2009	3,107	2,818	0	5,925	3,502	0	3,502	2,423
2010	4,122	2,968	0	7,090	3,686	0	3,686	3,404
2011	5,191	3,286	0	8,477	4,038	0	4,038	4,439
2012	6,373	3,312	0	9,685	4,061	0	4,061	5,624
2013	7,509	3,228	0	10,737	3,970	0	3,970	6,767
2014	8,739	3,227	0	11,967	3,970	0	3,970	7,997
2015	8,964	0	0	8,964	0	0	0	8,964
2016	9,181	0	0	9,181	0	0	0	9,181
2017	9,406	0	0	9,406	0	0	0	9,406
2018	9,657	0	0	9,657	0	0	0	9,657
2019	9,860	0	0	9,860	0	0	0	9,860
2020	10,112	0	0	10,112	0	0	0	10,112
2021	10,393	0	0	10,393	0	0	0	10,393
2022	10,655	0	0	10,655	0	0	0	10,655
2023	10,923	0	0	10,923	0	0	0	10,923
2024	11,156	0	0	11,156	0	0	0	11,156
2025	11,474	0	0	11,474	0	0	0	11,474
2026	11,762	0	0	11,762	0	0	0	11,762
2027	12,058	0	0	12,058	0	0	0	12,058
2028	12,327	0	0	12,327	0	0	0	12,327
2029	12,656	0	0	12,656	0	0	0	12,656
2030	12,968	0	0	12,968	0	0	0	12,968
2031	13,312	0	0	13,312	0	0	0	13,312
2032	13,643	0	0	13,643	0	0	0	13,643
2033	13,988	0	0	13,988	0	0	0	13,988
NOMINAL	241,605	26,596	0	268,201	32,096	0	32,096	236,105
NPV	69,821	16,969	0	86,790	20,377	0	20,377	66,414

Utility Discount Rate: 8.16
Benefit Cost Ratio: 4.26

C. New Construction

Program Start Date:

- 1995
- Program modified in 2000
- Program modified in 2004

Policies and Procedures

The New Construction program is an "umbrella" program for the New Construction, Multi-family, and Manufactured Home building segments.

The New Construction program promotes energy efficient construction in order to provide customers with more efficient dwellings combined with improved environmental comfort.

The objectives of the program include the following goals:

- Educate builders and builder/owners and property managers[1] about energy efficient construction design to increase the supply of energy efficient homes.
- Educate customers and realtors about energy efficient construction design to increase the demand for energy efficient homes.
- Obtain energy and demand impacts that are accurate, sustainable, and measurable.
- Enhance contractor awareness of new technologies.
- Obtain cost effective resources from the marketplace.
- Minimize "lost opportunities" in the new home market.

The program provides education and information to the design community on energy efficient equipment and construction. The program provides the following:

- Financial incentives for energy efficient equipment.
- "Third party" endorsement/certification and PEF's seal of approval.
- Cooperative advertising for the most energy efficient builders.

[1] Contractors, builders, builder/owners, and property managers are synonymous.

The program facilitates the design and construction of energy efficient homes by working directly with the builders to comply with program requirements. Builders that express interest in participating in this program will be required to fulfill pre-qualification requirements. Then, as builders inform PEF regarding their plans to design and build additional homes, PEF representatives will provide assistance to ensure that the design and construction of the home(s) meet program requirements. Home certification criteria include the following:

- The home must be metered by Progress Energy Florida, Inc. .
- The builder must meet requirements listed in the Program Participation Standards.
- The heating source must be an all electric heat pump. No resistance heat is allowed except as back up heat. Straight air with electric strip is not allowed to participate.[2]
- Duct sealing integrity, insulation levels, and equipment efficiencies, sizing and installations must meet specific program requirements.

This program has three levels of participation with various options within each level. The builder is offered a choice of energy efficiency measures that more closely meet the home's design criteria. Program details such as builder qualification criteria, home certification requirements and incentive levels for high efficient equipment promoted by this program will be presented in the Program Participation Standards.

High Efficiency Electric Heat Pumps

For electric heat pumps, PEF will provide an incentive up to a maximum of $300 per unit. The specific incentive amount is dependent on the energy efficiency of the equipment. The Program Participation Standards will specify additional qualifying criteria for incentive eligibility.

High Efficiency Alternate Electric Water Heating

Progress Energy has determined that it is no longer cost-effective under the RIM test to continue offering incentives for alternate water heating. These measures have relatively low rates of participation and have small overall impacts.

[2] Exception would be for multi-family housing above three stories in height.

Program Participation

Cumulative participation estimates for the program are shown in the following table.

Year	Total Number of Customers [1]	Total Number of Eligible Customers [2]	Annual Number of Measure Participants [3]	Cumulative Penetration Level (%)
2005	1,382,699	27,654	11,718	42%
2006	1,406,712	55,788	22,927	41%
2007	1,431,102	84,410	34,286	41%
2008	1,455,971	113,530	44,796	39%
2009	1,481,124	143,152	55,311	39%
2010	1,505,866	173,270	65,832	38%
2011	1,529,665	203,863	76,358	37%
2012	1,552,660	234,916	86,891	37%
2013	1,575,153	266,419	97,430	37%
2014	1,597,449	298,368	107,972	36%

1. *Total Number of Customers is the forecast of all residential customers, from the November 2003 Forecast.*
2. *Total number of eligible new homes constructed in PEF's territory.*
3. *Annual Number of Measure Participants is the projected number of cumulative measure applications from all measures promoted by this program. Because customer can install multiple measures, the actual number of participants will be less.*

Savings Estimates

Total program savings were developed by first estimating the total savings for each individual measure based on each measure's (1) per customer savings and, (2) annual projected participation. The total program savings were then computed as the sum of the individual measure savings, and are shown in the following tables.

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2005	401	0.963	0.283	4,704,138	11,287	3,314
2006	408	0.982	0.278	9,350,301	22,523	6,370
2007	410	0.986	0.279	14,067,143	33,796	9,579
2008	416	1.000	0.283	18,638,492	44,785	12,691
2009	419	1.007	0.285	23,172,852	55,676	15,777
2010	421	1.011	0.287	27,708,806	66,568	18,864
2011	423	1.017	0.288	32,307,809	77,626	21,995
2012	426	1.023	0.290	36,984,156	88,887	25,181
2013	428	1.029	0.292	41,718,930	100,300	28,407
2014	431	1.037	0.294	46,548,436	111,962	31,700

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2005	429	1.0292	0.3022	5,026,705	12,061	3,542
2006	436	1.0497	0.2969	9,991,459	24,067	6,807
2007	438	1.0533	0.2985	15,031,739	36,114	10,236
2008	445	1.0683	0.3027	19,916,549	47,856	13,561
2009	448	1.0756	0.3048	24,761,834	59,493	16,858
2010	450	1.0805	0.3062	29,608,822	71,133	20,157
2011	452	1.0863	0.3078	34,523,183	82,949	23,503
2012	455	1.0931	0.3097	39,520,191	94,982	26,907
2013	458	1.1000	0.3116	44,579,632	107,177	30,355
2014	461	1.1081	0.3137	49,740,301	119,640	33,874

Impact Evaluation Plan

The Residential New Construction program includes the installation of varied types of measures. As such, the impact evaluation plan should address interactive effects of multiple measures. In order to capture the impacts of these measures, engineering simulations and statistical billing analysis will represent the primary methods used to estimate demand and energy impacts, although the specific method may vary depending on measure-specific participation levels. These analyses may be supported by residential end-use metering data, where feasible.

Cost-Effectiveness

The economic results of the program are as follows:

Cost-Effectiveness Test	NPV Benefits $(000)	NPV Costs $(000)	NPV Net Benefits $(000)	B/C Ratio
Rate Impact Measure	33,885	26,410	7,475	1.28
Participant	22,269	10,891	11,379	2.04
Total Resource Cost	33,885	15,032	18,854	2.25

PROGRAM: RESIDENTIAL NEW CONSTRUCTION PROGRAM

RATE IMPACT MEASURE TEST

	BENEFITS					COSTS						
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) REVENUE GAINS $(000)	(5) **TOTAL BENEFITS** $(000)	(6) TOTAL FUEL & O&M INCREASE $(000)	(7) INCREASED T&D CAP. COSTS $(000)	(8) INCREASED GEN. CAP. COSTS $(000)	(9) UTILITY PROGRAM COSTS $(000)	(10) INCENTIVE PAYMENTS $(000)	(11) REVENUE LOSSES $(000)	(12) **TOTAL COSTS** $(000)
2004	0	0	0	0	0	0	0	0	0	0	0	0
2005	206	210	0	0	416	0	0	0	662	192	279	1,132
2006	344	389	0	0	733	0	0	0	640	200	516	1,355
2007	610	567	238	0	1,415	0	0	0	644	198	712	1,553
2008	786	737	318	0	1,840	0	0	0	604	198	935	1,737
2009	962	906	367	0	2,235	0	0	0	604	198	1,147	1,949
2010	819	1,075	670	0	2,565	0	0	0	604	198	1,406	2,209
2011	854	1,245	761	0	2,860	0	0	0	604	199	1,655	2,458
2012	1,088	1,414	919	0	3,421	0	0	0	605	200	1,933	2,738
2013	1,139	1,584	1,021	0	3,744	0	0	0	605	201	2,189	2,995
2014	1,348	1,754	969	0	4,070	0	0	0	605	201	2,489	3,295
2015	1,449	1,754	1,058	0	4,260	0	0	0	0	0	2,550	2,550
2016	1,447	1,754	1,036	0	4,237	0	0	0	0	0	2,612	2,612
2017	1,540	1,754	1,111	0	4,405	0	0	0	0	0	2,680	2,680
2018	1,539	1,754	1,090	0	4,383	0	0	0	0	0	2,748	2,748
2019	1,625	1,754	1,183	0	4,561	0	0	0	0	0	2,803	2,803
2020	1,610	1,754	1,158	0	4,521	0	0	0	0	0	2,875	2,875
2021	1,637	1,754	1,188	0	4,578	0	0	0	0	0	2,955	2,955
2022	1,680	1,754	1,217	0	4,651	0	0	0	0	0	3,029	3,029
2023	1,710	1,754	1,248	0	4,711	0	0	0	0	0	3,107	3,107
2024	1,739	1,754	1,278	0	4,770	0	0	0	0	0	3,177	3,177
2025	1,766	1,754	1,311	0	4,830	0	0	0	0	0	3,264	3,264
2026	1,802	1,754	1,344	0	4,900	0	0	0	0	0	3,348	3,348
2027	1,821	1,754	1,356	0	4,931	0	0	0	0	0	3,431	3,431
2028	1,861	1,754	1,411	0	5,026	0	0	0	0	0	3,516	3,516
2029	1,874	1,754	1,428	0	5,055	0	0	0	0	0	3,603	3,603
2030	1,923	1,754	1,483	0	5,160	0	0	0	0	0	3,690	3,690
2031	1,939	1,754	1,501	0	5,193	0	0	0	0	0	3,786	3,786
2032	1,992	1,754	1,557	0	5,303	0	0	0	0	0	3,880	3,880
2033	2,009	1,754	1,577	0	5,339	0	0	0	0	0	3,979	3,979
NOMINAL	41,117	43,199	29,796	0	114,113	0	0	0	6,177	1,984	74,295	82,456
NPV	12,165	13,451	8,269	0	33,885	0	0	0	4,141	1,319	20,950	26,410

Utility Discount Rate: **8.16**
Benefit Cost Ratio: **1.28**

PROGRAM: RESIDENTIAL NEW CONSTRUCTION PROGRAM

TOTAL RESOURCE COST TEST

	BENEFITS					COSTS						
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) **TOTAL BENEFITS** $(000)	(6) PARTICIPANT'S COST $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) **TOTAL COSTS** $(000)	(12) **NET BENEFITS** $(000)
2004	0	0	0	0	0	0	0	0	0	0	0	0
2005	206	210	0	0	416	1,630	0	0	0	662	2,292	-1,876
2006	344	389	0	0	733	1,697	0	0	0	640	2,336	-1,603
2007	610	567	238	0	1,415	1,727	0	0	0	644	2,371	-956
2008	786	737	318	0	1,840	1,602	0	0	0	604	2,206	-365
2009	962	906	367	0	2,235	1,602	0	0	0	604	2,207	29
2010	819	1,075	670	0	2,565	1,604	0	0	0	604	2,208	356
2011	854	1,245	761	0	2,860	1,605	0	0	0	604	2,209	650
2012	1,088	1,414	919	0	3,421	1,607	0	0	0	605	2,212	1,209
2013	1,139	1,584	1,021	0	3,744	1,609	0	0	0	605	2,214	1,530
2014	1,348	1,754	969	0	4,070	1,610	0	0	0	605	2,215	1,855
2015	1,449	1,754	1,058	0	4,260	0	0	0	0	0	0	4,260
2016	1,447	1,754	1,036	0	4,237	0	0	0	0	0	0	4,237
2017	1,540	1,754	1,111	0	4,405	0	0	0	0	0	0	4,405
2018	1,539	1,754	1,090	0	4,383	0	0	0	0	0	0	4,383
2019	1,625	1,754	1,183	0	4,561	0	0	0	0	0	0	4,561
2020	1,610	1,754	1,158	0	4,521	0	0	0	0	0	0	4,521
2021	1,637	1,754	1,188	0	4,578	0	0	0	0	0	0	4,578
2022	1,680	1,754	1,217	0	4,651	0	0	0	0	0	0	4,651
2023	1,710	1,754	1,248	0	4,711	0	0	0	0	0	0	4,711
2024	1,739	1,754	1,278	0	4,770	0	0	0	0	0	0	4,770
2025	1,766	1,754	1,311	0	4,830	0	0	0	0	0	0	4,830
2026	1,802	1,754	1,344	0	4,900	0	0	0	0	0	0	4,900
2027	1,821	1,754	1,356	0	4,931	0	0	0	0	0	0	4,931
2028	1,861	1,754	1,411	0	5,026	0	0	0	0	0	0	5,026
2029	1,874	1,754	1,428	0	5,055	0	0	0	0	0	0	5,055
2030	1,923	1,754	1,483	0	5,160	0	0	0	0	0	0	5,160
2031	1,939	1,754	1,501	0	5,193	0	0	0	0	0	0	5,193
2032	1,992	1,754	1,557	0	5,303	0	0	0	0	0	0	5,303
2033	2,009	1,754	1,577	0	5,339	0	0	0	0	0	0	5,339
NOMINAL	41,117	43,199	29,796	0	114,113	16,292	0	0	0	6,177	22,469	91,644
NPV	12,165	13,451	8,269	0	33,885	10,891	0	0	0	4,141	15,032	18,854

Utility Discount Rate: **8.16**
Benefit Cost Ratio: **2.25**

PROGRAM: RESIDENTIAL NEW CONSTRUCTION PROGRAM

PARTICIPANT TEST

	BENEFITS				COSTS			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
YEAR	SAVINGS IN PARTICIPANT'S BILL $(000)	INCENTIVE PAYMENTS $(000)	OTHER PARTICIPANT'S BENEFITS $(000)	**TOTAL BENEFITS** $(000)	PARTICIPANT'S COST $(000)	PARTICIPANT'S BILL INCREASE $(000)	**TOTAL COSTS** $(000)	**NET BENEFITS TO PARTICIPANTS** $(000)
2004	0	0	0	0	0	0	0	0
2005	279	192	0	471	1,630	0	1,630	-1,160
2006	516	200	0	716	1,697	0	1,697	-981
2007	712	198	0	909	1,727	0	1,727	-817
2008	935	198	0	1,134	1,602	0	1,602	-468
2009	1,147	198	0	1,345	1,602	0	1,602	-257
2010	1,406	198	0	1,605	1,604	0	1,604	1
2011	1,655	199	0	1,854	1,605	0	1,605	249
2012	1,933	200	0	2,133	1,607	0	1,607	526
2013	2,189	201	0	2,390	1,609	0	1,609	781
2014	2,489	201	0	2,690	1,610	0	1,610	1,080
2015	2,550	0	0	2,550	0	0	0	2,550
2016	2,612	0	0	2,612	0	0	0	2,612
2017	2,680	0	0	2,680	0	0	0	2,680
2018	2,748	0	0	2,748	0	0	0	2,748
2019	2,803	0	0	2,803	0	0	0	2,803
2020	2,875	0	0	2,875	0	0	0	2,875
2021	2,955	0	0	2,955	0	0	0	2,955
2022	3,029	0	0	3,029	0	0	0	3,029
2023	3,107	0	0	3,107	0	0	0	3,107
2024	3,177	0	0	3,177	0	0	0	3,177
2025	3,264	0	0	3,264	0	0	0	3,264
2026	3,348	0	0	3,348	0	0	0	3,348
2027	3,431	0	0	3,431	0	0	0	3,431
2028	3,516	0	0	3,516	0	0	0	3,516
2029	3,603	0	0	3,603	0	0	0	3,603
2030	3,690	0	0	3,690	0	0	0	3,690
2031	3,786	0	0	3,786	0	0	0	3,786
2032	3,880	0	0	3,880	0	0	0	3,880
2033	3,979	0	0	3,979	0	0	0	3,979
NOMINAL	70,316	1,984	0	72,300	16,292	0	16,292	56,008
NPV	20,950	1,319	0	22,269	10,891	0	10,891	11,379

Utility Discount Rate: **8.16**
Benefit Cost Ratio: **2.04**

D. LOW INCOME WEATHERIZATION ASSISTANCE PROGRAM

Program Start Date: 2000

Policies and Procedures

The Low-Income Weatherization Assistance program (LIWAP) is the umbrella program to improve energy efficiency for low-income customers in existing residential housing. It combines efficiency improvements to the thermal envelope with upgraded electric appliances. The program seeks to meet the following goals:

- Integrate PEF's LIWAP procedures with the Department of Community Affairs (DCA) and local weatherization providers to deliver energy efficiency measures to low-income families.

- Identify and educate contractors and low income customers about energy saving opportunities to improve home energy efficiency.

- Increase low-income families' participation in PEF's DSM programs.

- Minimize "lost opportunities" in the existing marketplace.

The program provides incentives for attic insulation upgrades, duct testing and repair, reduced air infiltration, water heater wrap, HVAC maintenance, high efficiency heat pumps, heat recovery units, and dedicated heat pump water heaters. The program eligibility requirements to qualify for participation are as follows:

- The residence must be in PEF's service area and be a residential PEF metered customer.

- Must meet Florida's weatherization low-income criteria in addition to income requirements required by DCA.

- Homes must be greater than two years old.

- Homes having previously received PEF incentives for listed measures are not eligible for the same measure. Attic insulation and duct repairs have special exemptions as outlined in the Home Energy Improvement Program.

- A DCA approved provider or their approved contractors must perform all work. PEF approved contractors may be used.

Incentive levels and specific eligibility requirements for each measure promoted in this program will be presented in the Program Participation Standards.

Attic Insulation Upgrade

This portion of the program encourages customers to add insulation to the ceiling area by paying a portion of the installed cost. The home must have an existing insulation level of less than R-12 to participate. The customer must have either whole house electric cooling or electric heating to be eligible for this program. The maximum incentive available will be $100 per residence, the specific incentive is determined by the resulting insulation level.

Duct Test and Repair

This portion of the program is designed to encourage eligible customers to improve their central duct system by reducing the air leakage rate. This is accomplished by performing a duct leakage test, then offering to repair the leakage that is discovered by the duct test. The home must have central ducted electric cooling and electric heat to participate in this measure. For a duct test, PEF will pay up to a maximum of $30 for the first unit and $20 for each additional unit at the same address. For the duct repair, PEF will pay an incentive of up to $100 per unit.

Reduced Air Infiltration

The weatherization provider must demonstrate a minimum reduction of air infiltration into the home of 1500 cfm at 50 pascals to receive a $75 incentive. The home must not exceed ASHRAE Standard 92.2-1989 for acceptable indoor air quality.

Water Heater Wrap/Replacement

The weatherization provider will wrap the water heater with an insulation value of at least R-6 side and R-8 top and insulate the pipes a minimum of 3 feet extending from the tank. The temperature will be set down to 120 degrees. To defray the cost of purchasing a high efficiency water heater, in lieu of installing an insulating jacket, the same $25 incentive would apply.

High Efficiency Electric Heat Pumps

For high efficient electric heat pumps, PEF will provide an incentive up to $350 per unit. The specific incentive available is dependent upon the efficiency level of the unit installed and the type of electric heat the new equipment is replacing. In order to qualify for an incentive, both the air handler and the outdoor condensing unit shall be replaced, and both units shall be new. This program seeks to accommodate emergency replacement situations by allowing a participant to have a home energy audit conducted after the installation and still be eligible for the incentive.

High Efficiency Alternate Water Heating

The high efficiency water heating portion of this program promotes technologies that heat water more efficiently than a standard electric water heater and save energy. The incentive depends on the type of technology being installed. For heat recovery units, PEF will provide an incentive of $100 per residence. For dedicated heat pump water heaters, PEF will provide an incentive of $200 per unit.

Heating and Air Conditioning Maintenance

To maximize efficiency a $40 incentive will be provided for a Heating & Air Conditioning contractor to perform service/tune-up maintenance on existing electric central heating and air conditioning systems.

Program Participation

Cumulative participation estimates for the program are shown in the following table.

Year	Total Number of Customers [1]	Total Number of Eligible Customers [2]	Annual Number of Measure Participants [3]	Cumulative Penetration Level (%)
2005	1,382,699	1500	416	28%
2006	1,406,712	3026	832	27%
2007	1,431,102	4579	1248	27%
2008	1,455,971	6158	1664	27%
2009	1,481,124	7765	2080	27%
2010	1,505,866	9398	2496	27%
2011	1,529,665	11058	2912	26%
2012	1,552,660	12742	3328	26%
2013	1,575,153	14451	3744	26%
2014	1,597,449	16184	4160	26%

1. *Total Number of Customers is the forecast of all residential customers, from the November 2003 Forecast.*
2. *Total number of Eligible Customers that are weatherized by local weatherization assistance providers.*
3. *Annual Number of Measure Participants is the projected number of cumulative measure installations from all measures promoted by this program. Because customers can install multiple measures, the actual number of participants will be less.*

Savings Estimates

Total program savings were developed by first estimating the total savings for each individual measure based on each measure's (1) per customer savings and, (2) annual projected participation. The total program savings were then computed as the sum of the individual measure savings, and are shown in the following tables.

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2005	473	0.677	0.248	196,669	281	103
2006	473	0.677	0.248	393,338	563	206
2007	473	0.677	0.248	590,007	844	310
2008	473	0.677	0.248	786,676	1,126	413
2009	473	0.677	0.248	983,345	1,407	516
2010	473	0.677	0.248	1,180,014	1,689	619
2011	473	0.677	0.248	1,376,683	1,970	723
2012	473	0.677	0.248	1,573,352	2,252	826
2013	473	0.677	0.248	1,770,021	2,533	929
2014	473	0.677	0.248	1,966,690	2,814	1,032

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2005	505	0.7229	0.2652	210,155	301	110
2006	505	0.7229	0.2652	420,310	601	221
2007	505	0.7229	0.2652	630,464	902	331
2008	505	0.7229	0.2652	840,619	1,203	441
2009	505	0.7229	0.2652	1,050,774	1,504	552
2010	505	0.7229	0.2652	1,260,929	1,804	662
2011	505	0.7229	0.2652	1,471,083	2,105	772
2012	505	0.7229	0.2652	1,681,238	2,406	883
2013	505	0.7229	0.2652	1,891,393	2,707	993
2014	505	0.7229	0.2652	2,101,548	3,007	1,103

Impact Evaluation Plan

The impact evaluation plan for an "umbrella" program such as this requires a varied approach given the number and type of measures being promoted. Some measures provide large per unit impacts while other yield relatively smaller impacts. The total impact from all smaller-impact measures could be potentially less than the uncertainty around an impact estimate of just one large measure. Consequently, the impact evaluation will place greater emphasis on the larger impact measures. The method of impact evaluation may vary depending on the participation levels actually achieved for each measure. Engineering analysis and statistical billing analysis represents the primary methods that will be used to estimate demand and energy impacts. These analyses will be supported by residential end-use metering data.

Cost-Effectiveness

The economic results of the program are as follows:

Cost-Effectiveness Test	NPV Benefits $(000)	NPV Costs $(000)	NPV Net Benefits $(000)	B/C Ratio
Rate Impact Measure	1,484	1,472	12	1.01
Participant	1,292	0	1,292	NA
Total Resource Cost	1,484	1,180	1,304	8.24

PROGRAM: LOW INCOME WEATHERIZATION PROGRAM

RATE IMPACT MEASURE TEST

	BENEFITS					COSTS							
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) REVENUE GAINS $(000)	(5) **TOTAL BENEFITS** $(000)	(6) TOTAL FUEL & O&M INCREASE $(000)	(7) ICREASE T&D CAP. COSTS $(000)	(8) INCREASED GEN. CAP. COSTS $(000)	(9) UTILITY PROGRAM COSTS $(000)	(10) INCENTIVE PAYMENTS $(000)	(11) REVENUE LOSSES $(000)	(12) **TOTAL COSTS** $(000)	(13) **NET BENEFITS** $(000)
2004	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	8	6	0	0	14	0	0	0	27	34	11	73	-59
2006	14	12	0	0	26	0	0	0	27	34	22	84	-58
2007	29	18	11	0	58	0	0	0	27	34	34	95	-38
2008	38	24	15	0	78	0	0	0	27	34	46	107	-30
2009	46	30	18	0	94	0	0	0	27	34	57	118	-24
2010	32	36	34	0	102	0	0	0	27	34	59	121	-18
2011	44	42	39	0	125	0	0	0	27	34	85	146	-21
2012	55	48	48	0	152	0	0	0	27	34	99	160	-8
2013	59	54	52	0	165	0	0	0	27	34	114	175	-10
2014	71	60	48	0	180	0	0	0	27	34	129	191	-11
2015	75	60	53	0	189	0	0	0	0	0	132	132	56
2016	71	60	52	0	183	0	0	0	0	0	129	129	53
2017	80	60	56	0	197	0	0	0	0	0	139	139	58
2018	80	60	55	0	195	0	0	0	0	0	143	143	53
2019	85	60	60	0	205	0	0	0	0	0	146	146	59
2020	84	60	58	0	203	0	0	0	0	0	150	150	53
2021	85	60	60	0	205	0	0	0	0	0	154	154	51
2022	87	60	61	0	209	0	0	0	0	0	157	157	51
2023	88	60	63	0	211	0	0	0	0	0	160	160	51
2024	91	60	65	0	216	0	0	0	0	0	165	165	50
2025	92	60	66	0	218	0	0	0	0	0	170	170	48
2026	93	60	68	0	221	0	0	0	0	0	174	174	47
2027	94	60	69	0	224	0	0	0	0	0	178	178	46
2028	96	60	71	0	228	0	0	0	0	0	183	183	45
2029	97	60	72	0	230	0	0	0	0	0	187	187	43
2030	100	60	75	0	235	0	0	0	0	0	192	192	43
2031	101	60	76	0	237	0	0	0	0	0	197	197	41
2032	104	60	79	0	243	0	0	0	0	0	201	201	41
2033	105	60	80	0	245	0	0	0	0	0	207	207	39
NOMINAL	2,101	1,480	1,505	0	5,086	0	0	0	270	344	3,819	4,433	653
NPV	610	457	417	0	1,484	0	0	0	180	229	1,062	1,472	12

Utility Discount Rate: **8.16**
Benefit Cost Ratio: **1.01**

PROGRAM: LOW INCOME WEATHERIZATION PROGRAM

TOTAL RESOURCE COST TEST

	BENEFITS					COSTS						
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) **TOTAL BENEFITS** $(000)	(6) PARTICIPANT'S COST $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) **TOTAL COSTS** $(000)	(12) **NET BENEFITS** $(000)
2004	0	0	0	0	0	0	0	0	0	0	0	0
2005	8	6	0	0	14	0	0	0	0	27	27	-13
2006	14	12	0	0	26	0	0	0	0	27	27	-1
2007	29	18	11	0	58	0	0	0	0	27	27	31
2008	38	24	15	0	78	0	0	0	0	27	27	51
2009	46	30	18	0	94	0	0	0	0	27	27	67
2010	32	36	34	0	102	0	0	0	0	27	27	75
2011	44	42	39	0	125	0	0	0	0	27	27	98
2012	55	48	48	0	152	0	0	0	0	27	27	125
2013	59	54	52	0	165	0	0	0	0	27	27	138
2014	71	60	48	0	180	0	0	0	0	27	27	153
2015	75	60	53	0	189	0	0	0	0	0	0	189
2016	71	60	52	0	183	0	0	0	0	0	0	183
2017	80	60	56	0	197	0	0	0	0	0	0	197
2018	80	60	55	0	195	0	0	0	0	0	0	195
2019	85	60	60	0	205	0	0	0	0	0	0	205
2020	84	60	58	0	203	0	0	0	0	0	0	203
2021	85	60	60	0	205	0	0	0	0	0	0	205
2022	87	60	61	0	209	0	0	0	0	0	0	209
2023	88	60	63	0	211	0	0	0	0	0	0	211
2024	91	60	65	0	216	0	0	0	0	0	0	216
2025	92	60	66	0	218	0	0	0	0	0	0	218
2026	93	60	68	0	221	0	0	0	0	0	0	221
2027	94	60	69	0	224	0	0	0	0	0	0	224
2028	96	60	71	0	228	0	0	0	0	0	0	228
2029	97	60	72	0	230	0	0	0	0	0	0	230
2030	100	60	75	0	235	0	0	0	0	0	0	235
2031	101	60	76	0	237	0	0	0	0	0	0	237
2032	104	60	79	0	243	0	0	0	0	0	0	243
2033	105	60	80	0	245	0	0	0	0	0	0	245
NOMINAL	2,101	1,480	1,505	0	5,086	0	0	0	0	270	270	4,816
NPV	610	457	417	0	1,484	0	0	0	0	180	180	1,304

Utility Discount Rate: **8.16**
Benefit Cost Ratio: **8.24**

PROGRAM: LOW INCOME WEATHERIZATION PROGRAM

PARTICIPANT TEST

	BENEFITS				COSTS			
YEAR	(1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT'S BENEFITS $(000)	(4) TOTAL BENEFITS $(000)	(5) PARTICIPANT'S COST $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) TOTAL COSTS $(000)	(8) NET BENEFITS TO PARTICIPANTS $(000)
2004	0	0	0	0	0	0	0	0
2005	11	34	0	46	0	0	0	46
2006	22	34	0	57	0	0	0	57
2007	34	34	0	68	0	0	0	68
2008	46	34	0	80	0	0	0	80
2009	57	34	0	91	0	0	0	91
2010	59	34	0	94	0	0	0	94
2011	85	34	0	119	0	0	0	119
2012	99	34	0	133	0	0	0	133
2013	114	34	0	148	0	0	0	148
2014	129	34	0	164	0	0	0	164
2015	132	0	0	132	0	0	0	132
2016	129	0	0	129	0	0	0	129
2017	139	0	0	139	0	0	0	139
2018	143	0	0	143	0	0	0	143
2019	146	0	0	146	0	0	0	146
2020	150	0	0	150	0	0	0	150
2021	154	0	0	154	0	0	0	154
2022	157	0	0	157	0	0	0	157
2023	160	0	0	160	0	0	0	160
2024	165	0	0	165	0	0	0	165
2025	170	0	0	170	0	0	0	170
2026	174	0	0	174	0	0	0	174
2027	178	0	0	178	0	0	0	178
2028	183	0	0	183	0	0	0	183
2029	187	0	0	187	0	0	0	187
2030	192	0	0	192	0	0	0	192
2031	197	0	0	197	0	0	0	197
2032	201	0	0	201	0	0	0	201
2033	207	0	0	207	0	0	0	207
NOMINAL	3,613	344	0	3,957	0	0	0	3,957
NPV	1,062	229	0	1,292	0	0	0	1,292

Utility Discount Rate: 8.16
Benefit Cost Ratio: NA

E. Residential Energy Management Program

Program Start Date:
- 1981
- Program modified in 1995
- Program modified in 2000

Policies and Procedures

Residential Energy Management is a voluntary customer program that allows PEF to reduce peak demand and defer generation construction. Peak demand is reduced by interrupting service to selected electrical equipment with radio controlled switches installed on the customers' premises. These controlled interruptions are at PEF's option, during specified time periods, and coincident with hours of peak demand.

Winter-Only Energy Management

The Winter-Only Energy Management component of the program represents a modified, cost-effective version of the previous year-round Residential Energy Management program. It provides for winter only (November through March) direct load control of customer's electric water heating and central electric heating appliances. Eligible participants must have both appliances on the program and will receive monthly credits during the potential control months. The amount of the credits are identical to those under the previous year-round Residential Energy Management program (rate schedule RSL-1) except that they are payable only during the winter months.

The winter Only Energy Management component will enable PEF to continue to provide customers a cost-effective alternative to standard residential service that can help lower their electric bills as well as reduce PEF's winter peak demand.

Program Participation

Cumulative program participation estimates beginning in the year 2000 are shown in the following table, and reflect new equipment installations under the Winter-Only Energy Management component of the program. There are no new participants (i.e., new Energy Management installations) projected for the Year-Round Energy Management component.

Year	Total Number of Customers [1]	Total Number of Eligible Customers [2]	Annual Number of Program Participants	Cumulative Penetration Level (%)
2005	1,382,699	1,030,016	5,000	0.49%
2006	1,406,712	1,065,266	9,500	0.89%
2007	1,431,102	1,098,861	14,000	1.27%
2008	1,455,971	1,131,190	18,300	1.62%
2009	1,481,124	1,162,301	22,600	1.94%
2010	1,505,866	1,191,704	26,900	2.26%
2011	1,529,665	1,219,697	31,200	2.56%
2012	1,552,660	1,246,468	35,500	2.85%
2013	1,575,153	1,272,359	39,800	3.13%
2014	1,597,449	1,297,713	44,800	3.45%

1. *Total Number of Customers is the forecast of all residential customers, from the November 2003 Forecast.*
2. *Total numbers of eligible customers are all residential customers not already on the Residential Energy Management program.*

Revised 7/8/04

Savings Estimates

The total program savings shown in the following tables reflect the demand and energy savings associated with the new program participants projected for the Winter-Only Energy Management Program.

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Summer kW Reduction	Annual kWh Reduction	Winter kW Reduction	Total Annual Summer kW Reduction
2005		2.14	0.00	0.00	10,700	0.00
2006		2.14	0.00	0.00	20,330	0.00
2007		2.14	0.00	0.00	29,960	0.00
2008		2.14	0.00	0.00	38,520	0.00
2009		2.14	0.00	0.00	47,080	0.00
2010		2.14	0.00	0.00	55,640	0.00
2011		2.14	0.00	0.00	64,200	0.00
2012		2.14	0.00	0.00	72,760	0.00
2013		2.14	0.00	0.00	85,172	0.00
2014		2.14	0.00	0.00	95,872	0.00

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction			Total Annual Summer kW Reduction
2005		2.29	0.00	0.00	11,434	0.00
2006		2.29	0.00	0.00	21,724	0.00
2007		2.29	0.00	0.00	32,014	0.00
2008		2.29	0.00	0.00	41,161	0.00
2009		2.29	0.00	0.00	50,308	0.00
2010		2.29	0.00	0.00	59,455	0.00
2011		2.29	0.00	0.00	68,602	0.00
2012		2.29	0.00	0.00	77,749	0.00
2013		2.29	0.00	0.00	91,012	0.00
2014		2.29	0.00	0.00	102,446	0.00

Impact Evaluation Plan

PEF is in the process of conducting a residential end-use metering study that will be used to estimate the appliance level, and duty-cycle impacts of residential load control. This end-use metering data will be used to perform engineering and statistical analysis to estimate the impacts of the program.

Cost-Effectiveness

The following economic results for the current winter-only Residential Energy Management program:

Cost-Effectiveness Test	NPV Benefits $(000)	NPV Costs $(000)	NPV Net Benefits $(000)	B/C Ratio
Rate Impact Measure	31,320	20,728	10,591	1.51
Participant	10,050	360	9,690	28
Total Resource Cost	30,960	10,678	20,281	2.90

Residential Energy Management - Winter Only DLC
Vintage: Existing

RATE IMPACT MEASURE TEST

	BENEFITS					COSTS							
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
YEAR	TOTAL FUEL & O&M SAVINGS $(000)	AVOIDED T&D CAP. COSTS $(000)	AVOIDED GEN. CAP. COSTS $(000)	REVENUE GAINS $(000)	**TOTAL BENEFITS** $(000)	TOTAL FUEL & O&M INCREASE $(000)	INCREASED T&D CAP. COSTS $(000)	INCREASED GEN. CAP. COSTS $(000)	UTILITY PROGRAM COSTS $(000)	INCENTIVE PAYMENTS $(000)	REVENUE LOSSES $(000)	**TOTAL COSTS** $(000)	**NET BENEFITS** $(000)
2004	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	8	0	0	0	8	0	0	0	500	124	4	627	-620
2006	15	0	0	0	15	0	0	0	523	248	9	780	-765
2007	617	0	822	0	1,439	0	0	0	548	372	29	949	490
2008	722	0	1,009	0	1,731	0	0	0	574	496	23	1,092	638
2009	1,013	0	1,369	0	2,382	0	0	0	600	620	123	1,342	1,040
2010	0	0	2,350	74	2,424	253	0	0	627	744	0	1,624	800
2011	0	0	2,825	0	2,825	866	0	0	655	868	72	2,461	364
2012	0	0	3,292	111	3,403	534	0	0	684	992	0	2,210	1,194
2013	0	0	3,923	0	3,923	1,068	0	0	714	1,116	98	2,996	927
2014	0	0	3,519	0	3,519	777	0	0	745	1,240	117	2,879	640
2015	10	0	3,510	0	3,520	0	0	0	569	1,240	229	2,039	1,481
2016	0	0	3,617	0	3,617	455	0	0	580	1,240	74	2,348	1,268
2017	189	0	3,885	0	4,075	0	0	0	591	1,240	240	2,072	2,003
2018	0	0	3,773	87	3,860	481	0	0	603	1,240	0	2,324	1,537
2019	333	0	4,091	0	4,424	0	0	0	615	1,240	217	2,072	2,352
2020	0	0	3,964	134	4,098	513	0	0	628	1,240	0	2,381	1,718
2021	0	0	4,063	143	4,207	584	0	0	641	1,240	0	2,465	1,741
2022	0	0	4,165	144	4,309	558	0	0	655	1,240	0	2,453	1,856
2023	0	0	4,269	146	4,415	604	0	0	669	1,240	0	2,513	1,903
2024	0	0	4,383	161	4,544	639	0	0	684	1,240	0	2,563	1,981
2025	0	0	4,485	132	4,617	706	0	0	699	1,240	0	2,646	1,972
2026	0	0	4,605	70	4,676	634	0	0	715	1,240	0	2,589	2,087
2027	0	0	4,720	61	4,782	758	0	0	732	1,240	0	2,730	2,052
2028	0	0	4,830	0	4,830	652	0	0	750	1,240	9	2,651	2,179
2029	0	0	5,173	0	5,173	738	0	0	770	1,240	172	2,919	2,254
2030	0	0	5,195	0	5,195	679	0	0	790	1,240	128	2,837	2,358
2031	0	0	5,409	0	5,409	877	0	0	811	1,240	182	3,110	2,300
2032	0	0	5,508	0	5,508	781	0	0	833	1,240	168	3,022	2,487
2033	0	0	5,723	0	5,723	992	0	0	856	1,240	238	3,326	2,397
NOMINAL	2,906	0	104,479	1,263	108,649	14,146	0	0	19,362	30,380	2,130	66,018	42,631
NPV	1,894	0	29,066	360	31,320	3,827	0	0	6,852	9,387	662	20,728	10,591

Utility Discount Rate: 8.16
Benefit Cost Ratio: 1.51

Residential Energy Management - Winter Only DLC
Vintage: Existing

TOTAL RESOURCE COST TEST

	BENEFITS					COSTS						
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) **TOTAL BENEFITS** $(000)	(6) PARTICIPANT'S COST $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) **TOTAL COSTS** $(000)	(12) **NET BENEFITS** $(000)
2004	0	0	0	0	0	0	0	0	0	0	0	0
2005	8	0	0	0	8	0	0	0	0	500	500	-492
2006	15	0	0	0	15	0	0	0	0	523	523	-509
2007	617	0	822	0	1,439	0	0	0	0	548	548	891
2008	722	0	1,009	0	1,731	0	0	0	0	574	574	1,157
2009	1,013	0	1,369	0	2,382	0	0	0	0	600	600	1,782
2010	0	0	2,350	0	2,350	0	253	0	0	627	880	1,470
2011	0	0	2,825	0	2,825	0	866	0	0	655	1,521	1,303
2012	0	0	3,292	0	3,292	0	534	0	0	684	1,218	2,075
2013	0	0	3,923	0	3,923	0	1,068	0	0	714	1,782	2,141
2014	0	0	3,519	0	3,519	0	777	0	0	745	1,522	1,997
2015	10	0	3,510	0	3,520	0	0	0	0	569	569	2,951
2016	0	0	3,617	0	3,617	0	455	0	0	580	1,035	2,582
2017	189	0	3,885	0	4,075	0	0	0	0	591	591	3,483
2018	0	0	3,773	0	3,773	0	481	0	0	603	1,084	2,690
2019	333	0	4,091	0	4,424	0	0	0	0	615	615	3,809
2020	0	0	3,964	0	3,964	0	513	0	0	628	1,141	2,824
2021	0	0	4,063	0	4,063	0	584	0	0	641	1,225	2,838
2022	0	0	4,165	0	4,165	0	558	0	0	655	1,213	2,952
2023	0	0	4,269	0	4,269	0	604	0	0	669	1,273	2,997
2024	0	0	4,383	0	4,383	0	639	0	0	684	1,323	3,060
2025	0	0	4,485	0	4,485	0	706	0	0	699	1,406	3,080
2026	0	0	4,605	0	4,605	0	634	0	0	715	1,349	3,256
2027	0	0	4,720	0	4,720	0	758	0	0	732	1,490	3,231
2028	0	0	4,830	0	4,830	0	652	0	0	750	1,402	3,428
2029	0	0	5,173	0	5,173	0	738	0	0	770	1,507	3,665
2030	0	0	5,195	0	5,195	0	679	0	0	790	1,469	3,726
2031	0	0	5,409	0	5,409	0	877	0	0	811	1,687	3,722
2032	0	0	5,508	0	5,508	0	781	0	0	833	1,614	3,894
2033	0	0	5,723	0	5,723	0	992	0	0	856	1,847	3,875
NOMINAL	2,906	0	104,479	0	107,385	0	14,146	0	0	19,362	33,507	73,878
NPV	1,894	0	29,066	0	30,960	0	3,827	0	0	6,852	10,678	20,281

Utility Discount Rate: **8.16**
Benefit Cost Ratio: **2.90**

Residential Energy Management - Winter Only DLC
Vintage: Existing

PARTICIPANT TEST

YEAR	BENEFITS (1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT'S BENEFITS $(000)	(4) TOTAL BENEFITS $(000)	COSTS (5) PARTICIPANT'S COST $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) TOTAL COSTS $(000)	(8) NET BENEFITS TO PARTICIPANTS $(000)
2004	0	0	0	0	0	0	0	0
2005	4	124	0	128	0	0	0	128
2006	9	248	0	257	0	0	0	257
2007	29	372	0	401	0	0	0	401
2008	23	496	0	519	0	0	0	519
2009	123	620	0	743	0	0	0	743
2010	0	744	0	744	0	74	74	670
2011	72	868	0	940	0	0	0	940
2012	0	992	0	992	0	111	111	881
2013	98	1,116	0	1,214	0	0	0	1,214
2014	117	1,240	0	1,357	0	0	0	1,357
2015	229	1,240	0	1,469	0	0	0	1,469
2016	74	1,240	0	1,314	0	0	0	1,314
2017	240	1,240	0	1,480	0	0	0	1,480
2018	0	1,240	0	1,240	0	87	87	1,153
2019	217	1,240	0	1,457	0	0	0	1,457
2020	0	1,240	0	1,240	0	134	134	1,106
2021	0	1,240	0	1,240	0	143	143	1,097
2022	0	1,240	0	1,240	0	144	144	1,096
2023	0	1,240	0	1,240	0	146	146	1,094
2024	0	1,240	0	1,240	0	161	161	1,079
2025	0	1,240	0	1,240	0	132	132	1,108
2026	0	1,240	0	1,240	0	70	70	1,170
2027	0	1,240	0	1,240	0	61	61	1,179
2028	9	1,240	0	1,249	0	0	0	1,249
2029	172	1,240	0	1,412	0	0	0	1,412
2030	128	1,240	0	1,368	0	0	0	1,368
2031	182	1,240	0	1,422	0	0	0	1,422
2032	168	1,240	0	1,408	0	0	0	1,408
2033	238	1,240	0	1,478	0	0	0	1,478
NOMINAL	1,892	29,140	0	31,032	0	1,263	1,263	29,768
NPV	662	9,387	0	10,050	0	360	360	9,690

Utility Discount Rate: 8.16
Benefit Cost Ratio: 27.94

IV. COMMERCIAL/INDUSTRIAL

CONSERVATION PROGRAMS

IV. COMMERCIAL/INDUSTRIAL CONSERVATION PROGRAMS

Progress Energy Florida, Inc.'s (PEF) DSM Plan includes seven (7) commercial/industrial programs:

A. **Business Energy Check** - C/I energy audits

B. **Better Business** - "umbrella" program for existing facilities

C. **C/I New Construction** - "umbrella" program for new construction facilities

D. **Innovation Incentive** - custom measures

E. **Standby Generation** - Rate Tariff GSLM-2

F. **Interruptible Service** - Rate Tariff IS-2

G. **Curtailable Service** - Rate Tariff CS-2

Each program is described in detail in the following sections.

A. BUSINESS ENERGY CHECK PROGRAM

Program Start Date: • 1995

Policies and Procedures

The Business Energy Check is Progress Energy Florida's (PEF) energy audit program. It provides commercial and industrial (C/I) customers with an assessment of the current energy usage at their facility and information on low-cost energy efficiency measures. This program serves as the foundation for PEF's other DSM programs targeted toward existing C/I construction and, in most cases, it is a prerequisite for participation in the other C/I programs.

The Business Energy Check consists of the following types of audits:

Type 1: Free On-site Walk-Through Audit (Inspection)

Type 2: Paid Walk-Through Audit (Energy Analysis)

Type 3: On-line Business Energy Check (A Customer-completed Internet audit)

All commercial, industrial, and governmental retail customers of PEF are eligible to have either type conducted on any of their buildings located in PEF's service territory. There is no charge for Type 1 or Type 3 audits, while there is a nominal customer charge for the Type 2 energy analysis. When a customer requests a Business Energy Check, they will be given the option of scheduling a Type 1 inspection or a Type 2 energy analysis, and will be informed of the On-line audit option. The specific details on the procedures for each type of audit will be presented in the Program Participation Standards.

Program Participation

Cumulative participation estimates for the program are shown in the following table.

Year	Total Number of Customers[1]	Total Number of Eligible Customers	Annual Number of On-site Audit Participants	Annual Number of On-line Audit Participants	Cumulative Penetration Level (%)
2005	184,973	166,476	1,500	150	1%
2006	188,338	169,504	3,000	300	2%
2007	191,917	172,725	4,500	450	3%
2008	195,622	176,060	6,000	600	4%
2009	199,361	179,425	7,500	750	5%
2010	203,048	182,743	9,000	900	5%
2011	206,613	185,952	10,500	1,050	6%
2012	210,080	189,072	12,000	1,200	7%
2013	213,480	192,132	13,500	1,350	8%
2,014	216,855	195,170	15,000	1,500	8%

1. *Total Number of Customers is the April 2004 forecast of all commercial and industrial customers.*

Savings Estimates

The total program savings were developed based on historical PEF audits and a review of C/I audit impacts. These estimates include impacts directly resulting from the standard audit recommendations, including the installation of low-cost energy efficiency measures. In addition, customer-specific savings may result from site-specific recommendations that the auditor makes at the time of the audit, but which are not included in the standard audit form. These impacts will be calculated on a case-by-case basis and added to the standard impacts. The total program savings are shown in the following tables.

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2005	291	0.136	0.136	480,000	225	225
2006	291	0.136	0.136	960,000	450	450
2007	291	0.136	0.136	1,440,000	675	675
2008	291	0.136	0.136	1,920,000	900	900
2009	291	0.136	0.136	2,400,000	1,125	1,125
2010	291	0.136	0.136	2,920,000	1,369	1,369
2011	290	0.136	0.136	3,440,000	1,613	1,613
2012	290	0.136	0.136	3,960,000	1,857	1,857
2013	290	0.136	0.136	4,480,000	2,101	2,101
2014	290	0.136	0.136	5,000,000	2,345	2,345

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2005	311	0.1457	0.1457	512,914	240	240
2006	311	0.1457	0.1457	1,025,828	481	481
2007	311	0.1457	0.1457	1,538,742	721	721
2008	311	0.1457	0.1457	2,051,656	962	962
2009	311	0.1457	0.1457	2,564,570	1,202	1,202
2010	310	0.1456	0.1456	3,120,227	1,463	1,463
2011	310	0.1455	0.1455	3,675,884	1,724	1,724
2012	310	0.1454	0.1454	4,231,541	1,984	1,984
2013	310	0.1453	0.1453	4,787,197	2,245	2,245
2014	310	0.1453	0.1453	5,342,854	2,506	2,506

Impact Evaluation Plan

The range of possible recommendations resulting from the audit, and the inclusion of both technological and behavioral recommendations suggests the need to carefully survey participants to determine what specific actions have been undertaken due to the completed audit. Initially, the use of site-specific engineering estimates is likely to be the most cost-effective method of estimating program impacts, although the use of statistical analysis technique may also be considered, depending on the participation levels actually achieved.

B. BETTER BUSINESS PROGRAM

Program Start Date:
- 1995
- Proposed modification for 2005

Policies and Procedures

The Better Business program is the umbrella efficiency program for existing commercial and industrial customers. Better Business builds on the Business Energy Check by using the audit to initiate PEF involvement in the customer's facility (participating in Business Energy Check is a prerequisite for receiving most of the incentives). This program provides customers with information, education, and advice on energy-related issues and incentives on efficiency measures that are cost-effective to PEF and its customers. Better Business promotes energy efficient heating, ventilation, air conditioning, high efficiency energy recovery ventilation, and some building retrofit measures (in particular, ceiling insulation upgrade, duct leakage test and repair, and cool roof coatings).

The general eligibility requirements are as follows:

- The participant must be a PEF commercial, industrial, or governmental customer.
- Equipment must be installed in facilities located in the PEF service territory and served by a metered PEF account.
- A Business Energy Check audit (Type 1, 2, or 3) must be completed prior to the purchase or installation of all measures (with the exception of emergency HVAC replacements).
- The participant must be willing to allow PEF to inspect the installation of all measures and equipment prior to receiving any incentive payments.
- All equipment installations shall meet manufacturers' instructions and specifications.

Incentive levels and specific eligibility requirements for each measure promoted in this program will be presented in the Program Participation Standards and will be subject to revision based on changes in market conditions, such as baseline or code revisions, evaluation findings, or technological advances.

HVAC Equipment

The HVAC equipment component of Better Business provides customers with information on high efficiency HVAC equipment and financial incentives for the purchase of high efficiency unitary heat pumps and air conditioners, packaged rooftop units, packaged terminal heat pumps (PTHP's), and water-cooled and air-cooled chillers. The incentive is calculated for each unit based on the kW difference between the high efficiency unit and the program-specified baseline efficiency (at ARI Standard Test Rating Conditions) and is calculated using a dollar per kW reduced incentive up to a maximum of $100/kW reduced. The maximum incentive is $50,000 per installation for a chiller project.

Energy Recovery Ventilation

The program promotes the installation of high efficiency energy recovery ventilation (ERV) units in the conditioned air stream for customers using electric cooling and heating. These units are capable of removing over 70% of the sensible heat and over 60% of the latent heat when properly sized and installed. To qualify for PEF's incentive of $0.75 per CFM, the ERV must be at least a 450 cfm unit and have a total efficiency greater than 65% per ARI 1060-2000 test standards. As an example, a qualifying 450 cfm ERV will earn a $337 incentive. The maximum incentive is $1,500 per installation.

Duct Leakage Test and Repair

This portion of the program is designed to promote energy efficiency through improved duct system sealing. Through the use of an inspection tool, such as a blower-door, duct leaks can be identified and repaired. This program component applies to HVAC equipment and systems that are no larger than 65,000 Btu/h. A customer must have electric heating and a centrally-ducted cooling system, either air conditioning or heat pump, to be eligible for this program. If a building has excess ventilation such that the building can not be pressurized, the building may not be eligible for participation. For the duct test, PEF will pay an incentive of up to a maximum of $30 for the first unit tested and $20 for each additional unit tested. For the duct repair, PEF will pay an incentive of up to a maximum of $100 per unit. The duct repair incentive amount is dependent on the type of electric heating system.

Ceiling Insulation Upgrade

This portion of the program encourages customers who have electric space heat to add insulation to the ceiling area by paying for a portion of the installed cost. The facility must have an existing ceiling insulation level less than R-12 to participate and must be heated by electricity in order to receive the incentive. Heat loss and heat gain calculations must show that the additional insulation would result in heating and/or cooling energy use reductions in order to be eligible for an incentive. The maximum incentive amount will be $100 per customer and the specific incentive amount that a customer is eligible to receive will be a function of the resulting insulation level.

Cool Roof

This program will provide customers with an incentive to install an Energy Star Roof Products approved "*cool roof*" coating providing the facility has electric cooling. Energy Star allows manufacturers to use the Energy Star label on reflective roof products that meet the US EPA's specifications for solar reflectance and reliability, having an initial reflectance greater than or equal to .65. The incentive will be $ 50 per 1,000 square-foot of *cool roof* coating installed with a maximum incentive of $1,000 per installation.

Motors and Window Film removed

Progress Energy has determined that it is no longer cost-effective under the RIM test to continue offering incentives for motors and window film. These measures have low rates of participation and have small overall impacts.

Program Participation

Cumulative participation estimates for the program are shown in the following table.

Year	Total Number of Customers[1]	Total Number of Eligible Customers	Annual Number of Measure Participants [2]	Cumulative Penetration Level (%)
2005	184,973	166,476	489	0.3%
2006	188,338	169,504	987	0.6%
2007	191,917	172,725	1,467	0.9%
2008	195,622	176,060	1,956	1.1%
2009	199,361	179,425	2,445	1.4%
2010	203,048	182,743	2,934	1.6%
2011	206,613	185,952	3,423	1.9%
2012	210,080	189,072	3,912	2.1%
2013	213,480	192,132	4,401	2.3%
2,014	216,855	195,170	4,890	2.5%

1. *Total Number of Customers is the April 2004 forecast of all commercial and industrial customers.*
2. *This total is larger than the number of actual customers anticipated installing eligible measures and earning an incentive since many customers install multiple measures at one account.*

Savings Estimates

Total program savings were developed by first estimating the total savings for each individual measure based on each measure's (1) per customer savings and, (2) annual projected participation. The total program savings were then computed as the sum of the individual measure savings, and are shown in the following tables.

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2005	2414	1.197	1.396	1,194,756	593	691
2006	2414	1.197	1.396	2,389,512	1,185	1,382
2007	2414	1.197	1.396	3,584,268	1,778	2,074
2008	2414	1.197	1.396	4,779,024	2,371	2,765
2009	2414	1.197	1.396	5,973,780	2,963	3,456
2010	2414	1.197	1.396	7,168,536	3,556	4,147
2011	2414	1.197	1.396	8,363,292	4,148	4,839
2012	2414	1.197	1.396	9,558,049	4,741	5,530
2013	2414	1.197	1.396	10,752,805	5,334	6,221
2014	2414	1.197	1.396	11,947,561	5,926	6,912

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2005	2579	1.2793	1.4922	1,276,681	633	739
2006	2579	1.2793	1.4922	2,553,363	1,267	1,477
2007	2579	1.2793	1.4922	3,830,044	1,900	2,216
2008	2579	1.2793	1.4922	5,106,726	2,533	2,955
2009	2579	1.2793	1.4922	6,383,407	3,166	3,693
2010	2579	1.2793	1.4922	7,660,089	3,800	4,432
2011	2579	1.2793	1.4922	8,936,770	4,433	5,170
2012	2579	1.2793	1.4922	10,213,452	5,066	5,909
2013	2579	1.2793	1.4922	11,490,133	5,699	6,648
2014	2579	1.2793	1.4922	12,766,815	6,333	7,386

Per measure impacts for 2005-2014., assuming no overlap.

Per measure impacts vary from year to year because of the changing mix of measures assumed to be installed in any given year.

Impact Evaluation Plan

The impact evaluation plan for an "umbrella" program such as this requires a varied approach given the number and type of measures being promoted. Some measures provide large per unit impacts while others yield relatively smaller impacts. The total impact from all smaller-impact measures could potentially be less than the uncertainty around an impact estimate of just one large-impact measure. Consequently, the impact evaluation will place greater emphasis on the larger-impact measures. The method of impact evaluation may vary depending on the participation levels actually achieved for each measure. Engineering analysis and statistical billing analysis will represent the primary methods used to estimate demand and energy impacts. On-site metering may also be used where feasible and cost-effective.

Cost Effectiveness

The economic results of the program are as follows:

Cost-Effectiveness Test	NPV Benefits (000$)	NPV Costs (000$)	NPV Net Benefits (000$)	B/C Ratio
Rate Impact	8,283	6,904	1,379	1.20
Participant	6,826	4,414	2,412	1.55
Total Resource Cost	8,283	4,492	3,791	1.84

Program: **Better Business**

Existing **Rate Impact Measure Test**

YEAR	BENEFITS (1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) REVENUE GAINS $(000)	(5) **TOTAL BENEFITS** $(000)	COSTS (6) TOTAL FUEL & O&M INCREASE $(000)	(7) INCREASED T&D CAP. COSTS $(000)	(8) INCREASED GEN. CAP. COSTS $(000)	(9) UTILITY PROGRAM COSTS $(000)	(10) INCENTIVE PAYMENTS $(000)	(11) REVENUE LOSSES $(000)	(12) **TOTAL COSTS** $(000)	(13) **NET BENEFITS** $(000)
2004	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	60	22	0	0	82	0	0	0	12	136	65	213	-131
2006	93	44	0	0	138	0	0	0	12	136	121	269	-131
2007	185	66	61	0	312	0	0	0	12	136	186	333	-21
2008	244	88	85	0	417	0	0	0	12	136	252	400	18
2009	307	110	104	0	522	0	0	0	12	136	313	460	62
2010	271	132	231	0	635	0	0	0	12	136	381	529	106
2011	304	155	232	0	691	0	0	0	12	136	469	616	75
2012	380	177	284	0	840	0	0	0	12	136	548	695	145
2013	413	199	311	0	923	0	0	0	12	136	630	777	145
2014	486	221	285	0	991	0	0	0	12	136	715	863	128
2015	514	221	304	0	1,039	0	0	0	0	0	733	733	306
2016	513	221	299	0	1,032	0	0	0	0	0	745	745	287
2017	542	221	320	0	1,083	0	0	0	0	0	770	770	313
2018	544	221	315	0	1,080	0	0	0	0	0	789	789	291
2019	571	221	335	0	1,126	0	0	0	0	0	809	809	317
2020	572	221	330	0	1,123	0	0	0	0	0	829	829	293
2021	581	221	338	0	1,140	0	0	0	0	0	850	850	290
2022	593	221	346	0	1,161	0	0	0	0	0	868	868	293
2023	604	221	355	0	1,180	0	0	0	0	0	890	890	290
2024	619	221	364	0	1,204	0	0	0	0	0	915	915	288
2025	628	221	373	0	1,222	0	0	0	0	0	938	938	284
2026	640	221	382	0	1,243	0	0	0	0	0	962	962	281
2027	650	221	392	0	1,262	0	0	0	0	0	986	986	277
2028	664	221	402	0	1,287	0	0	0	0	0	1,010	1,010	276
2029	673	221	408	0	1,301	0	0	0	0	0	1,036	1,036	266
2030	689	221	422	0	1,332	0	0	0	0	0	1,062	1,062	271
2031	698	221	429	0	1,347	0	0	0	0	0	1,087	1,087	260
2032	716	221	444	0	1,380	0	0	0	0	0	1,115	1,115	265
2033	725	221	450	0	1,396	0	0	0	0	0	1,143	1,143	253
NOMINAL	14,477	5,409	8,601	0	28,487	0	0	0	118	1,357	21,216	22,691	5,796
NPV	4,201	1,671	2,411	0	8,283	0	0	0	78	904	5,922	6,904	1,379

Utility Discount Rate: **8.16**
Benefit Cost Ratio: **1.20**

Program: **Better Business**

Existing

Total Resource Cost Test

	BENEFITS					COSTS						
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) **TOTAL BENEFITS** $(000)	(6) PARTICIPANT'S COST $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) **TOTAL COSTS** $(000)	(12) **NET BENEFITS** $(000)
2004	0	0	0	0	0	0	0	0	0	0	0	0
2005	60	22	0	0	82	663	0	0	0	12	674	-592
2006	93	44	0	0	138	663	0	0	0	12	674	-537
2007	185	66	61	0	312	663	0	0	0	12	674	-362
2008	244	88	85	0	417	663	0	0	0	12	674	-257
2009	307	110	104	0	522	663	0	0	0	12	674	-152
2010	271	132	231	0	635	663	0	0	0	12	674	-40
2011	304	155	232	0	691	663	0	0	0	12	674	17
2012	380	177	284	0	840	663	0	0	0	12	674	165
2013	413	199	311	0	923	663	0	0	0	12	674	248
2014	486	221	285	0	991	663	0	0	0	12	674	317
2015	514	221	304	0	1,039	0	0	0	0	0	0	1,039
2016	513	221	299	0	1,032	0	0	0	0	0	0	1,032
2017	542	221	320	0	1,083	0	0	0	0	0	0	1,083
2018	544	221	315	0	1,080	0	0	0	0	0	0	1,080
2019	571	221	335	0	1,126	0	0	0	0	0	0	1,126
2020	572	221	330	0	1,123	0	0	0	0	0	0	1,123
2021	581	221	338	0	1,140	0	0	0	0	0	0	1,140
2022	593	221	346	0	1,161	0	0	0	0	0	0	1,161
2023	604	221	355	0	1,180	0	0	0	0	0	0	1,180
2024	619	221	364	0	1,204	0	0	0	0	0	0	1,204
2025	628	221	373	0	1,222	0	0	0	0	0	0	1,222
2026	640	221	382	0	1,243	0	0	0	0	0	0	1,243
2027	650	221	392	0	1,262	0	0	0	0	0	0	1,262
2028	664	221	402	0	1,287	0	0	0	0	0	0	1,287
2029	673	221	408	0	1,301	0	0	0	0	0	0	1,301
2030	689	221	422	0	1,332	0	0	0	0	0	0	1,332
2031	698	221	429	0	1,347	0	0	0	0	0	0	1,347
2032	716	221	444	0	1,380	0	0	0	0	0	0	1,380
2033	725	221	450	0	1,396	0	0	0	0	0	0	1,396
NOMINAL	14,477	5,409	8,601	0	28,487	6,625	0	0	0	118	6,743	21,744
NPV	4,201	1,671	2,411	0	8,283	4,414	0	0	0	78	4,492	3,791

Utility Discount Rate: **8.16**
Benefit Cost Ratio: **1.84**

Program: **Better Business**

Existing **Participant Test**

	BENEFITS				COSTS			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
YEAR	SAVINGS IN PARTICIPANT'S BILL $(000)	INCENTIVE PAYMENTS $(000)	OTHER PARTICIPANT'S BENEFITS $(000)	**TOTAL BENEFITS** $(000)	PARTICIPANT'S COST $(000)	PARTICIPANT'S BILL INCREASE $(000)	**TOTAL COSTS** $(000)	**NET BENEFITS TO PARTICIPANTS** $(000)
2004	0	0	0	0	0	0	0	0
2005	65	136	0	201	663	0	663	-462
2006	121	136	0	257	663	0	663	-405
2007	186	136	0	321	663	0	663	-341
2008	252	136	0	388	663	0	663	-275
2009	313	136	0	449	663	0	663	-214
2010	381	136	0	517	663	0	663	-146
2011	469	136	0	605	663	0	663	-58
2012	548	136	0	683	663	0	663	21
2013	630	136	0	765	663	0	663	103
2014	715	136	0	851	663	0	663	188
2015	733	0	0	733	0	0	0	733
2016	745	0	0	745	0	0	0	745
2017	770	0	0	770	0	0	0	770
2018	789	0	0	789	0	0	0	789
2019	809	0	0	809	0	0	0	809
2020	829	0	0	829	0	0	0	829
2021	850	0	0	850	0	0	0	850
2022	868	0	0	868	0	0	0	868
2023	890	0	0	890	0	0	0	890
2024	915	0	0	915	0	0	0	915
2025	938	0	0	938	0	0	0	938
2026	962	0	0	962	0	0	0	962
2027	986	0	0	986	0	0	0	986
2028	1,010	0	0	1,010	0	0	0	1,010
2029	1,036	0	0	1,036	0	0	0	1,036
2030	1,062	0	0	1,062	0	0	0	1,062
2031	1,087	0	0	1,087	0	0	0	1,087
2032	1,115	0	0	1,115	0	0	0	1,115
2033	1,143	0	0	1,143	0	0	0	1,143
NOMINAL	20,073	1,357	0	21,430	6,625	0	6,625	14,805
NPV	5,922	904	0	6,826	4,414	0	4,414	2,412

Utility Discount Rate: ***8.16***
Benefit Cost Ratio: **1.55**

C. Commercial/Industrial New Construction Program

Program Start Date:

- 1995
- Program modified in 2000
- Proposed modification for 2005

Policies and Procedures

The primary goal of the PEF's Commercial/Industrial (C/I) New Construction program is to foster the design and construction of energy efficient buildings. The new construction program will: 1) provide education and information to the design community on all aspects of energy efficient building design; 2) require that the building design, at a minimum, surpass the state energy code; 3) provide financial incentives for specific energy efficient equipment; and 4) provide energy design awards to building design teams. The program will simultaneously target building developers/owners and the building design community and will work one-on-one with them throughout a new construction project. PEF will focus on developing relationships with the key decision-makers of commercial and industrial new construction so as to be able to get involved early in the design process.

The general eligibility requirements are as follows:

- The new construction project location must be established within PEF's service territory.
- The new construction building must be served by a PEF account prior to the issuance of any incentive payment.
- The participant must be willing to allow PEF to inspect the installation of all measures and equipment prior to receiving any incentive payments.
- All equipment installations shall meet manufacturers' instructions and specifications.

Incentives will be provided for high efficiency HVAC equipment, high efficiency energy recovery ventilation, and coot roof coatings. Incentive levels and specific eligibility requirements for each of the measures promoted in this program will be presented in the Program Participation Standards and will be subject to revision based on changes in market conditions, such as baseline or code revisions, evaluation findings, or technological advances.

HVAC Equipment

The HVAC equipment component of C/I New Construction provides customers with information on high efficiency HVAC equipment and financial incentives for the purchase of high efficiency unitary heat pumps and air conditioners, packaged rooftop units, packaged terminal heat pumps (PTHPs), and water-cooled and air-cooled chillers. The incentive is calculated for each unit based on the kW difference between the high efficiency unit and the program-specified baseline efficiency (at ARI Standard Test Rating Conditions) and is calculated using a dollar per kW reduced incentive up to $100/kW reduced. The maximum incentive is $50,000 per installation for a chiller project.

Energy Recovery Ventilation

The program promotes the installation of high efficiency energy recovery ventilation (ERV) units in the conditioned air stream for customers using electric cooling and heating. These units are capable of removing over 70% of the sensible heat and over 60% of the latent heat when properly sized and installed. To qualify for PEF's incentive of $0.75 per CFM, the ERV must be at least a 450 cfm unit and have a total efficiency greater than 65% per ARI 1060-2000 test standards. As an example, a 450 cfm ERV will earn a $337 incentive and there is a maximum incentive of $1,500 per installation.

Cool Roof

This program will provide customers with an incentive to install an Energy Star Roof Products approved "*cool roof*" coating providing the facility has electric cooling. Energy Star allows manufacturers to use the Energy Star label on reflective roof products that meet the US EPA's specifications for solar reflectance and reliability, having an initial reflectance greater than or equal to .65. The incentive will be $ 50 per 1,000 square-foot of *cool roof* coating installed with a maximum incentive of $1,000 per installation.

Motors and Heat Recovery removed

Progress Energy has determined that it is no longer cost-effective under the RIM test to continue offering incentives for motors and heat recovery. These measures have low rates of participation and have small overall impacts.

Program Participation

Cumulative participation estimates for the program are shown in the following table.

Year	Total Number of Customers[1]	Total Number of Eligible Customers	Annual Number of Measure Participants [2]	Cumulative Penetration Level (%)
2005	184,973	3,365	189	0.6%
2006	188,338	6,944	368	0.5%
2007	191,917	10,649	547	0.5%
2008	195,622	14,388	726	0.5%
2009	199,361	18,075	905	0.5%
2010	203,048	21,640	1,084	0.5%
2011	206,613	25,107	1,263	0.5%
2012	210,080	28,500	1,442	0.5%
2013	213,480	31,882	1,621	0.5%
2,014	216,855	35,182	1,800	0.5%

1. *Total Number of Customers is the April 2004 forecast of all commercial and industrial customers.*
2. *This total is larger than the number of actual customers anticipated installing eligible measures and earning an incentive since many customers install multiple measures at one account.*

Savings Estimates

Total program savings were developed by first estimating the total savings for each individual measure based on each measure's (1) per customer savings and, (2) annual projected participation. The total program savings were then computed as the sum of the individual measure savings, and are shown in the following tables.

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2005	4248	2.580	1.912	1,040,735	632	468
2006	4248	2.580	1.912	2,081,469	1,264	937
2007	4248	2.580	1.912	3,122,204	1,896	1,405
2008	4248	2.580	1.912	4,162,938	2,528	1,874
2009	4248	2.580	1.912	5,203,673	3,160	2,342
2010	4248	2.580	1.912	6,244,408	3,792	2,811
2011	4248	2.580	1.912	7,285,142	4,424	3,279
2012	4248	2.580	1.912	8,325,877	5,057	3,748
2013	4248	2.580	1.912	9,366,612	5,689	4,216
2014	4248	2.580	1.912	10,407,346	6,321	4,685

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2005	4539	2.7568	2.0434	1,112,099	675	501
2006	4539	2.7568	2.0434	2,224,197	1,351	1,001
2007	4539	2.7568	2.0434	3,336,296	2,026	1,502
2008	4539	2.7568	2.0434	4,448,395	2,702	2,002
2009	4539	2.7568	2.0434	5,560,493	3,377	2,503
2010	4539	2.7568	2.0434	6,672,592	4,052	3,004
2011	4539	2.7568	2.0434	7,784,691	4,728	3,504
2012	4539	2.7568	2.0434	8,896,789	5,403	4,005
2013	4539	2.7568	2.0434	10,008,888	6,079	4,506
2014	4539	2.7568	2.0434	11,120,987	6,754	5,006

Per measure impacts for 2005-2014., assuming no overlap.

Per measure impacts vary from year to year because of the changing mix of measures assumed to be installed in any given year.

Impact Evaluation Plan

The impact evaluation plan for an "umbrella" program such as this requires a varied approach, given the number and type of measures being promoted. Some measures provide large per unit impacts while others yield relatively smaller impacts. The total impact from all smaller-impact measures could potentially be less than the uncertainty around an impact estimate of just one large-impact measure. Consequently, the impact evaluation will place greater emphasis on the larger-impact measures. The method of impact evaluation may vary depending on the participation levels actually achieved for each measure. Engineering analysis and statistical billing analysis will represent the primary methods used to estimate demand and energy impacts. On-site metering may also be used, where feasible and cost-effective.

Cost Effectiveness

The economic results of the program are as follows:

Cost-Effectiveness Test	NPV Benefits (000$)	NPV Costs (000$)	NPV Net Benefits (000$)	B/C Ratio
Rate Impact Measure	7,129	5,944	1,185	1.20
Participant	5,899	3,866	2,033	1.53
Total Resource Cost	7,129	3,911	3,218	1.82

Program: **Commercial New Construction**

Rate Impact Measure Test

	BENEFITS					COSTS							
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) REVENUE GAINS $(000)	(5) **TOTAL BENEFITS** $(000)	(6) TOTAL FUEL & O&M INCREASE $(000)	(7) INCREASED T&D CAP. COSTS $(000)	(8) INCREASED GEN. CAP. COSTS $(000)	(9) UTILITY PROGRAM COSTS $(000)	(10) INCENTIVE PAYMENTS $(000)	(11) REVENUE LOSSES $(000)	(12) **TOTAL COSTS** $(000)	(13) **NET BENEFITS** $(000)
2004	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	54	18	0	0	72	0	0	0	7	104	58	169	-96
2006	83	37	0	0	120	0	0	0	7	104	106	218	-98
2007	162	55	51	0	267	0	0	0	7	104	163	274	-7
2008	214	73	70	0	358	0	0	0	7	104	221	333	25
2009	269	92	87	0	448	0	0	0	7	104	274	385	62
2010	243	110	170	0	523	0	0	0	7	104	334	445	78
2011	276	128	193	0	596	0	0	0	7	104	412	523	73
2012	340	147	235	0	722	0	0	0	7	104	481	593	129
2013	374	165	258	0	796	0	0	0	7	104	553	665	132
2014	436	183	236	0	856	0	0	0	7	104	629	740	116
2015	460	183	252	0	895	0	0	0	0	0	644	644	250
2016	459	183	248	0	890	0	0	0	0	0	654	654	236
2017	484	183	265	0	932	0	0	0	0	0	677	677	255
2018	488	183	262	0	933	0	0	0	0	0	694	694	239
2019	509	183	278	0	969	0	0	0	0	0	711	711	258
2020	511	183	274	0	968	0	0	0	0	0	729	729	239
2021	520	183	281	0	983	0	0	0	0	0	747	747	236
2022	530	183	288	0	1,000	0	0	0	0	0	762	762	238
2023	540	183	295	0	1,018	0	0	0	0	0	782	782	237
2024	553	183	302	0	1,039	0	0	0	0	0	805	805	234
2025	563	183	310	0	1,056	0	0	0	0	0	825	825	231
2026	573	183	318	0	1,074	0	0	0	0	0	845	845	229
2027	583	183	325	0	1,092	0	0	0	0	0	867	867	225
2028	596	183	334	0	1,113	0	0	0	0	0	888	888	225
2029	603	183	339	0	1,125	0	0	0	0	0	910	910	215
2030	619	183	350	0	1,152	0	0	0	0	0	933	933	219
2031	626	183	356	0	1,166	0	0	0	0	0	955	955	210
2032	644	183	369	0	1,195	0	0	0	0	0	980	980	215
2033	652	183	374	0	1,209	0	0	0	0	0	1,005	1,005	204
NOMINAL	12,960	4,491	7,117	0	24,568	0	0	0	68	1,045	18,645	19,758	4,810
NPV	3,755	1,388	1,987	0	7,129	0	0	0	45	696	5,203	5,944	1,185

Utility Discount Rate: **8.16**

Benefit Cost Ratio: **1.20**

Program: Commercial New Construction

Total Resource Cost Test

	BENEFITS					COSTS						
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) **TOTAL BENEFITS** $(000)	(6) PARTICIPANT'S COST $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) **TOTAL COSTS** $(000)	(12) **NET BENEFITS** $(000)
2004	0	0	0	0	0	0	0	0	0	0	0	0
2005	54	18	0	0	72	580	0	0	0	7	587	-515
2006	83	37	0	0	120	580	0	0	0	7	587	-467
2007	162	55	51	0	267	580	0	0	0	7	587	-320
2008	214	73	70	0	358	580	0	0	0	7	587	-229
2009	269	92	87	0	448	580	0	0	0	7	587	-140
2010	243	110	170	0	523	580	0	0	0	7	587	-64
2011	276	128	193	0	596	580	0	0	0	7	587	9
2012	340	147	235	0	722	580	0	0	0	7	587	135
2013	374	165	258	0	796	580	0	0	0	7	587	209
2014	436	183	236	0	856	580	0	0	0	7	587	269
2015	460	183	252	0	895	0	0	0	0	0	0	895
2016	459	183	248	0	890	0	0	0	0	0	0	890
2017	484	183	265	0	932	0	0	0	0	0	0	932
2018	488	183	262	0	933	0	0	0	0	0	0	933
2019	509	183	278	0	969	0	0	0	0	0	0	969
2020	511	183	274	0	968	0	0	0	0	0	0	968
2021	520	183	281	0	983	0	0	0	0	0	0	983
2022	530	183	288	0	1,000	0	0	0	0	0	0	1,000
2023	540	183	295	0	1,018	0	0	0	0	0	0	1,018
2024	553	183	302	0	1,039	0	0	0	0	0	0	1,039
2025	563	183	310	0	1,056	0	0	0	0	0	0	1,056
2026	573	183	318	0	1,074	0	0	0	0	0	0	1,074
2027	583	183	325	0	1,092	0	0	0	0	0	0	1,092
2028	596	183	334	0	1,113	0	0	0	0	0	0	1,113
2029	603	183	339	0	1,125	0	0	0	0	0	0	1,125
2030	619	183	350	0	1,152	0	0	0	0	0	0	1,152
2031	626	183	356	0	1,166	0	0	0	0	0	0	1,166
2032	644	183	369	0	1,195	0	0	0	0	0	0	1,195
2033	652	183	374	0	1,209	0	0	0	0	0	0	1,209
NOMINAL	12,960	4,491	7,117	0	24,568	5,803	0	0	0	68	5,870	18,698
NPV	3,755	1,388	1,987	0	7,129	3,866	0	0	0	45	3,911	3,218

Utility Discount Rate: ***8.16***

Benefit Cost Ratio: **1.82**

Program: Commercial New Construction

Participant Test

	BENEFITS				COSTS			
YEAR	(1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT'S BENEFITS $(000)	(4) **TOTAL BENEFITS** $(000)	(5) PARTICIPANT'S COST $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) **TOTAL COSTS** $(000)	(8) **NET BENEFITS TO PARTICIPANTS** $(000)
2004	0	0	0	0	0	0	0	0
2005	58	104	0	162	580	0	580	-418
2006	106	104	0	211	580	0	580	-369
2007	163	104	0	267	580	0	580	-313
2008	221	104	0	326	580	0	580	-254
2009	274	104	0	378	580	0	580	-202
2010	334	104	0	438	580	0	580	-142
2011	412	104	0	517	580	0	580	-64
2012	481	104	0	586	580	0	580	6
2013	553	104	0	658	580	0	580	78
2014	629	104	0	733	580	0	580	153
2015	644	0	0	644	0	0	0	644
2016	654	0	0	654	0	0	0	654
2017	677	0	0	677	0	0	0	677
2018	694	0	0	694	0	0	0	694
2019	711	0	0	711	0	0	0	711
2020	729	0	0	729	0	0	0	729
2021	747	0	0	747	0	0	0	747
2022	762	0	0	762	0	0	0	762
2023	782	0	0	782	0	0	0	782
2024	805	0	0	805	0	0	0	805
2025	825	0	0	825	0	0	0	825
2026	845	0	0	845	0	0	0	845
2027	867	0	0	867	0	0	0	867
2028	888	0	0	888	0	0	0	888
2029	910	0	0	910	0	0	0	910
2030	933	0	0	933	0	0	0	933
2031	955	0	0	955	0	0	0	955
2032	980	0	0	980	0	0	0	980
2033	1,005	0	0	1,005	0	0	0	1,005
NOMINAL	17,640	1,045	0	18,685	5,803	0	5,803	12,882
NPV	5,203	696	0	5,899	3,866	0	3,866	2,033

Utility Discount Rate: **8.16**

Benefit Cost Ratio: **1.53**

D. Innovation Incentive Program

Program Start Date:

- 1992
- Modified in 1995

Policies and Procedures

The Innovation Incentive program promotes a reduction in kW and kWh by subsidizing energy conservation projects for customers in the PEF service territory. The intent of the program is to encourage legitimate energy efficiency measures that reduce peak kW demand and/or kWh energy, but which are not addressed by other programs.

Energy efficiency opportunities are identified by PEF representatives during a Business Energy Check audit and are presented to the customer as part of the Business Energy Check report. Requirements for participation in this program are also explained to the customer at that time. If the customer chooses to implement modifications to effect energy efficiency improvements that are not addressed in other PEF energy efficiency programs, the modifications would be eligible for consideration under this program.

Representative examples of energy efficient technologies that would be considered under this program include, but are not limited to, refrigeration equipment replacements to improve efficiency, thermal energy storage systems, microwave drying systems, and inductive heating systems to replace resistance heating systems.

The program is available to all business customers in PEF's territory for projects that reduce peak demand by a minimum of 10 kW.

Program eligibility requirements to qualify for participation are as follows:

- Participant must be located in the PEF service territory and be a metered business customer.
- The customer is required to have an audit (any level) completed by PEF prior to participation in the program, except in the case of new construction projects.
- Projects must reduce or shift peak demand by a minimum of 10 kW.
- The participant must be willing to allow PEF to inspect the installations of all measures and equipment.

If the described project meets the program specifications, PEF will provide project approval and projected incentive payment amounts. Engineering designs, cost estimates, and energy savings projections must be submitted under a professional seal, when necessary. The customer may be required to monitor the project after completion to verify kW and kWh savings. Monitoring methods shall be approved by PEF. Costs for monitoring equipment should be included in the overall project cost estimate.

PEF will perform a customer-specific cost-effectiveness analysis for each project being considered under the Innovation Incentive program, using the Commission-approved cost-effectiveness tests described in Rule 25-17.008, Florida Administrative Code. To receive an incentive, each project must pass the Rate Impact Measure (RIM) and Participant tests of cost-effectiveness. The customer's incentive shall be based upon the RIM results, with the maximum allowable rebate being $150 per peak kW reduced or shifted to an off peak period.

After PEF has reviewed and approved the project, a contract will be executed between PEF and the customer, in which PEF agrees to subsidize the customer upon completion of the project.

Program Participation

Cumulative participation estimates for the program are shown in the following table.

Year	Total Number of Customers[1]	Total Number of Eligible Customers	Annual Number of Measure Participants [2]	Cumulative Penetration Level (%)
2005	184,973	166,476	1	0%
2006	188,338	169,504	2	0%
2007	191,917	172,725	-3	0%
2008	195,622	176,060	4	0%
2009	199,361	179,425	5	0%
2010	203,048	182,743	6	0%
2011	206,613	185,952	7	0%
2012	210,080	189,072	8	0%
2013	213,480	192,132	9	0%
2,014	216,855	195,170	10	0%

1. *Total Number of Customers is the April 2004 forecast of all commercial and industrial customers.*
2. *This total is larger than the number of actual customers anticipated installing eligible measures and earning an incentive since many customers install multiple measures at one account.*

Savings Estimates

The total program savings are shown in the following tables.

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2005	120,047	70	70	120,047	70	70
2006	120,047	70	70	360,141	210	210
2007	120,047	70	70	480,188	280	280
2008	120,047	70	70	720,282	420	420
2009	120,047	70	70	840,329	490	490
2010	120,047	70	70	960,376	560	560
2011	120,047	70	70	1,080,423	630	630
2012	120,047	70	70	1,200,470	700	700
2013	120,047	70	70	1,320,517	770	770
2014	120,047	70	70	1,440,564	840	840

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2005	126,157	73	73	126,157	73	74
2006	126,157	73	73	378,472	220	222
2007	126,157	73	73	504,630	293	295
2008	126,157	73	73	456,944	439	443
2009	126,157	73	73	883,102	513	517
2010	126,157	73	73	1,009,259	586	591
2011	126,157	73	73	1,135,417	659	665
2012	126,157	73	73	1,261,574	732	739
2013	126,157	73	73	1,387,731	806	813
2014	126,157	73	73	1,513,889	879	886

Impact Evaluation Plan

To verify the estimated savings for each project, an engineering/billing analysis based on customer-specific site and usage data will be performed. Monitoring will continue until PEF has reasonable assurance that the project will remain in place and produce cost-effective energy savings for its estimated life. An incentive will not be issued to the customer until PEF is reasonably sure of the projected savings.

Cost Effectiveness

Each individual project will be analyzed for cost-effectiveness at the time of project submittal to PEF, using the Commission-approved tests of cost-effectiveness. Therefore, total program cost-effectiveness results are not shown. All projects must achieve a benefit-cost ratio of at least 1.0 on the RIM and Participant tests to receive an incentive under this program.

E. STANDBY GENERATION PROGRAM

Program Start Date:
- 1993
- Modified in 1995

Policies and Procedures

The Standby Generation program is a demand control program that will reduce PEF's demand based upon the indirect control of customer equipment. The program is a voluntary program available to all commercial and industrial customers who have on-site generation capability and are willing to reduce their PEF demand when PEF deems it necessary. The program is offered through the General Service Load Management-2 (GSLM-2) rate schedule.

PEF will have no direct control of the customer's equipment, but will rely upon the customer to initiate the generation upon being notified by PEF and continue running it until PEF notifies the customer that the generation is no longer needed. PEF does not restrict other use of the equipment by the customer.

Standby Generation program participants will receive a monthly credit on their energy bill according to the demonstrated ability of the customer to reduce demand at PEF's request. The credit will be based upon the load served by the customer's generator, which would have been served by PEF if the Standby Generation program were not in operation. By compensating the customer for the use of their on-site generation, PEF can impact the commercial and industrial market while minimizing rate impacts.

The general program eligibility requirements to qualify for participation are as follows:

- Customer must be eligible for service under the GS-1, GST-1, GSD-1 or GSDT-1 Rate Schedules.
- Customer must have standby generation that will allow facility demand reduction at the request of PEF.
- Customer's Standby Generation Capacity calculation must be at least 50 kW.
- Customer must be within the range of PEF's load management system.

Program Participation

Cumulative participation estimates for the program are shown in the following table.

Year	Total Number of Customers[1]	Total Number of Eligible Customers	Annual Number of Program Participants	Cumulative Penetration Level (%)
2005	184,973	590	4	0.7%
2006	188,338	599	8	1.3%
2007	191,917	608	12	2.0%
2008	195,622	618	16	2.6%
2009	199,361	627	20	3.2%
2010	203,048	636	24	3.8%
2011	206,613	645	28	4.3%
2012	210,080	654	32	4.9%
2013	213,480	663	36	5.4%
2,014	216,855	672	40	6.0%

1. *Total Number of Customers is the April 2004 forecast of all commercial and industrial customers.*
2. *Total Number of Eligible Customers is based on the total number of customers having on-site generation.*

Savings Estimates

The kW and kWh savings estimates for this program were determined from historical data and are presented below.

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2005	6260	444.000	465.000	25,040	1,776	1,860
2006	6260	444.000	465.000	50,080	3,552	3,720
2007	6260	444.000	465.000	75,120	5,328	5,580
2008	6260	444.000	465.000	100,160	7,104	7,440
2009	6260	444.000	465.000	125,200	8,880	9,300
2010	6260	444.000	465.000	150,240	10,656	11,160
2011	6260	444.000	465.000	175,280	12,432	13,020
2012	6260	444.000	465.000	200,320	14,208	14,880
2013	6260	444.000	465.000	225,360	15,984	16,740
2014	6260	444.000	465.000	250,400	17,760	18,600

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2005	6689	474.4455	496.8854	26,757	1,898	1,988
2006	6689	474.4455	496.8854	53,514	3,796	3,975
2007	6689	474.4455	496.8854	80,271	5,693	5,963
2008	6689	474.4455	496.8854	107,028	7,591	7,950
2009	6689	474.4455	496.8854	133,785	9,489	9,938
2010	6689	474.4455	496.8854	160,542	11,387	11,925
2011	6689	474.4455	496.8854	187,299	13,284	13,913
2012	6689	474.4455	496.8854	214,056	15,182	15,900
2013	6689	474.4455	496.8854	240,813	17,080	17,888
2014	6689	474.4455	496.8854	267,570	18,978	19,875

Impact Evaluation Plan

PEF uses on-site metering to measure the generation capability of each Standby Generation program participant to reduce load at the time they join the program. The customer and a PEF representative will observe the metering tests to determine the load that the standby generator carries. This system testing will also determine the initial readings that will be recorded in order to determine the incentive that the customer will receive on their bill each month. Engineering analysis is used to estimate on-going program savings for each participant based upon monitoring their generator usage.

Cost Effectiveness

The economic results of the program are as follows.

Cost-Effectiveness Test	NPV Benefits (000$)	NPV Costs (000$)	NPV Net Benefits (000$)	B/C Ratio
Rate Impact Measure	6,602	5,403	1,200	1.22
Participant	4,768	0	4,768	NA
Total Resource Cost	6,602	634	5,968	10.40

Program: **Standby Generation**

Rate Impact Measure Test

	BENEFITS					COSTS							
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
YEAR	TOTAL FUEL & O&M SAVINGS $(000)	AVOIDED T&D CAP. COSTS $(000)	AVOIDED GEN. CAP. COSTS $(000)	REVENUE GAINS $(000)	**TOTAL BENEFITS** $(000)	TOTAL FUEL & O&M INCREASE $(000)	INCREASED T&D CAP. COSTS $(000)	INCREASED GEN. CAP. COSTS $(000)	UTILITY PROGRAM COSTS $(000)	INCENTIVE PAYMENTS $(000)	REVENUE LOSSES $(000)	**TOTAL COSTS** $(000)	**NET BENEFITS** $(000)
2004	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	7	0	0	0	7	0	0	0	10	59	4	72	-65
2006	11	0	0	0	11	0	0	0	10	117	7	134	-123
2007	133	0	163	0	296	0	0	0	10	176	10	196	100
2008	184	0	231	0	415	0	0	0	10	235	14	259	156
2009	218	0	272	0	489	0	0	0	10	293	18	321	168
2010	0	0	494	0	494	29	0	0	10	352	21	412	82
2011	0	0	595	0	595	138	0	0	10	410	27	585	11
2012	0	0	692	0	692	75	0	0	10	469	31	585	106
2013	0	0	840	0	840	164	0	0	10	528	36	737	103
2014	0	0	744	0	744	98	0	0	10	586	41	735	10
2015	72	0	795	0	867	0	0	0	10	586	43	640	227
2016	0	0	756	0	756	76	0	0	10	586	43	715	41
2017	90	0	780	0	870	0	0	0	10	586	42	638	232
2018	0	0	788	0	788	63	0	0	10	586	45	704	84
2019	115	0	814	0	929	0	0	0	10	586	44	640	289
2020	0	0	828	0	828	31	0	0	10	586	47	674	153
2021	0	0	848	0	848	56	0	0	10	586	46	698	150
2022	0	0	869	0	869	45	0	0	10	586	47	688	182
2023	0	0	891	0	891	48	0	0	10	586	48	692	199
2024	0	0	921	0	921	103	0	0	10	586	49	749	172
2025	0	0	936	0	936	118	0	0	10	586	51	765	171
2026	0	0	967	0	967	99	0	0	10	586	52	747	221
2027	0	0	992	0	992	175	0	0	10	586	53	824	167
2028	0	0	1,008	0	1,008	91	0	0	10	586	54	741	267
2029	0	0	1,097	0	1,097	86	0	0	10	586	58	740	357
2030	0	0	1,098	0	1,098	78	0	0	10	586	56	731	367
2031	0	0	1,158	0	1,158	109	0	0	10	586	61	766	392
2032	0	0	1,113	0	1,113	120	0	0	10	586	59	775	338
2033	0	0	1,227	0	1,227	123	0	0	10	586	64	783	444
NOMINAL	830	0	21,916	0	22,746	1,922	0	0	290	14,364	1,170	17,746	5,000
NPV	501	0	6,101	0	6,602	524	0	0	110	4,438	330	5,403	1,200

Utility Discount Rate: **8.16**

Benefit Cost Ratio: **1.22**

Program: Standby Generation

Total Resource Cost Test

	BENEFITS					COSTS						
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
YEAR	TOTAL FUEL & O&M SAVINGS $(000)	AVOIDED T&D CAP. COSTS $(000)	AVOIDED GEN. CAP. COSTS $(000)	OTHER PARTICIPANT BENEFITS $(000)	**TOTAL BENEFITS** $(000)	PARTICIPANT'S COST $(000)	TOTAL FUEL & O&M INCREASE $(000)	INCREASED T&D CAP. COSTS $(000)	INCREASED GEN. CAP. COSTS $(000)	UTILITY PROGRAM COSTS $(000)	**TOTAL COSTS** $(000)	**NET BENEFITS** $(000)
2004	0	0	0	0	0	0	0	0	0	0	0	0
2005	7	0	0	0	7	0	0	0	0	10	10	-3
2006	11	0	0	0	11	0	0	0	0	10	10	1
2007	133	0	163	0	296	0	0	0	0	10	10	286
2008	184	0	231	0	415	0	0	0	0	10	10	405
2009	218	0	272	0	489	0	0	0	0	10	10	479
2010	0	0	494	0	494	0	29	0	0	10	39	455
2011	0	0	595	0	595	0	138	0	0	10	148	448
2012	0	0	692	0	692	0	75	0	0	10	85	606
2013	0	0	840	0	840	0	164	0	0	10	174	667
2014	0	0	744	0	744	0	98	0	0	10	108	636
2015	72	0	795	0	867	0	0	0	0	10	10	857
2016	0	0	756	0	756	0	76	0	0	10	86	670
2017	90	0	780	0	870	0	0	0	0	10	10	860
2018	0	0	788	0	788	0	63	0	0	10	73	715
2019	115	0	814	0	929	0	0	0	0	10	10	919
2020	0	0	828	0	828	0	31	0	0	10	41	786
2021	0	0	848	0	848	0	56	0	0	10	66	782
2022	0	0	869	0	869	0	45	0	0	10	55	815
2023	0	0	891	0	891	0	48	0	0	10	58	833
2024	0	0	921	0	921	0	103	0	0	10	113	808
2025	0	0	936	0	936	0	118	0	0	10	128	808
2026	0	0	967	0	967	0	99	0	0	10	109	859
2027	0	0	992	0	992	0	175	0	0	10	185	807
2028	0	0	1,008	0	1,008	0	91	0	0	10	101	907
2029	0	0	1,097	0	1,097	0	86	0	0	10	96	1,001
2030	0	0	1,098	0	1,098	0	78	0	0	10	88	1,010
2031	0	0	1,158	0	1,158	0	109	0	0	10	119	1,040
2032	0	0	1,113	0	1,113	0	120	0	0	10	130	983
2033	0	0	1,227	0	1,227	0	123	0	0	10	133	1,094
NOMINAL	830	0	21,916	0	22,746	0	1,922	0	0	290	2,212	20,534
NPV	501	0	6,101	0	6,602	0	524	0	0	110	634	5,968

Utility Discount Rate: **8.16**

Benefit Cost Ratio: **10.41**

Program: **Standby Generation**

Participant Test

	BENEFITS				COSTS			
YEAR	(1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT'S BENEFITS $(000)	(4) **TOTAL BENEFITS** $(000)	(5) PARTICIPANT'S COST $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) **TOTAL COSTS** $(000)	(8) **NET BENEFITS TO PARTICIPANTS** $(000)
2004	0	0	0	0	0	0	0	0
2005	4	59	0	62	0	0	0	62
2006	7	117	0	124	0	0	0	124
2007	10	176	0	186	0	0	0	186
2008	14	235	0	249	0	0	0	249
2009	18	293	0	311	0	0	0	311
2010	21	352	0	373	0	0	0	373
2011	27	410	0	437	0	0	0	437
2012	31	469	0	500	0	0	0	500
2013	36	528	0	563	0	0	0	563
2014	41	586	0	627	0	0	0	627
2015	43	586	0	630	0	0	0	630
2016	43	586	0	629	0	0	0	629
2017	42	586	0	628	0	0	0	628
2018	45	586	0	631	0	0	0	631
2019	44	586	0	630	0	0	0	630
2020	47	586	0	633	0	0	0	633
2021	46	586	0	632	0	0	0	632
2022	47	586	0	633	0	0	0	633
2023	48	586	0	634	0	0	0	634
2024	49	586	0	636	0	0	0	636
2025	51	586	0	637	0	0	0	637
2026	52	586	0	638	0	0	0	638
2027	53	586	0	639	0	0	0	639
2028	54	586	0	640	0	0	0	640
2029	58	586	0	644	0	0	0	644
2030	56	586	0	643	0	0	0	643
2031	61	586	0	647	0	0	0	647
2032	59	586	0	646	0	0	0	646
2033	64	586	0	650	0	0	0	650
NOMINAL	1,106	13,778	0	14,884	0	0	0	14,884
NPV	330	4,438	0	4,768	0	0	0	4,768

Utility Discount Rate: **8.16**

Benefit Cost Ratio: **#DIV/0!**

F. INTERRUPTIBLE SERVICE PROGRAM

Program Start Date: • 1996 for the IS-2 and IST-2 rate schedules.

Policies and Procedures

The Interruptible Service (IS) program is a direct load control program that reduces PEF's demand at times of capacity shortage during peak or emergency conditions. The program is available throughout the entire territory served by PEF to any non-residential customer who is willing to have their power interrupted. The program is currently offered through the Interruptible General Service (IS-2) and Interruptible General Service Time of Use (IST-2) rate schedules. The IS-1 and IST-1 rate schedules were closed to new customers in 1996, but remain active for those customers that were grand fathered onto the rate.

PEF will have remote control of the circuit breaker or disconnect switch supplying the customer's equipment. If purchased power is available at the time of potential interruption, customers who choose not to have their load interrupted will be assessed at the price of that purchased power supplied. Customers participating in the Interruptible Service program will receive a monthly interruptible demand credit based on their billing demand and billing load factor. The general program eligibility requirements to qualify for participation are as follows:

- Customer must be eligible for service under the IS-2 or IST-2 Rate Schedules.
- Average billing demand must be 500 kW or more.
- Available at primary, transmission and secondary service voltages.

Program Participation

Cumulative participation estimates for the program are shown in the following table.

Year	Total Number of Customers[1]	Total Number of Eligible Customers	Annual Number of Program Participants	Cumulative Penetration Level (%)
2005	184,973	983	0	0
2006	188,338	1,008	0	0
2007	191,917	1,033	1	0
2008	195,622	1,059	1	0
2009	199,361	1,086	1	0
2010	203,048	1,113	1	0
2011	206,613	1,141	2	0
2012	210,080	1,169	2	0
2013	213,480	1,198	2	0
2,014	216,855	1,228	2	0

1. *Total Number of Customers is the April 2004 forecast of all commercial and industrial customers.*

Savings Estimates

Savings estimate for the Interruptible Service program are shown in the following tables.

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2005	na	na	na	na	na	na
2006	na	na	na	na	na	na
2007	4250	500.000	440.000	4,250	500	440
2008	4250	500.000	440.000	4,250	500	440
2009	4250	500.000	440.000	4,250	500	440
2010	4250	500.000	440.000	4,250	500	440
2011	4250	500.000	440.000	8,500	1,000	880
2012	4250	500.000	440.000	8,500	1,000	880
2013	4250	500.000	440.000	8,500	1,000	880
2014	4250	500.000	440.000	8,500	1,000	880

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2005	na	na	na	na	na	na
2006	na	na	na	na	na	na
2007	4541	534.2854	470.1712	4,541	534	470
2008	4541	534.2854	470.1712	4,541	534	470
2009	4541	534.2854	470.1712	4,541	534	470
2010	4541	534.2854	470.1712	4,541	534	470
2011	4541	534.2854	470.1712	9,083	1,069	940
2012	4541	534.2854	470.1712	9,083	1,069	940
2013	4541	534.2854	470.1712	9,083	1,069	940
2014	4541	534.2854	470.1712	9,083	1,069	940

Impact Evaluation Plan

Program impacts are evaluated through on-site interval metering data of all Interruptible Service customers.

Cost-Effectiveness

The cost-effectiveness results of the Interruptible Service program are as follows:

Cost-Effectiveness Test	NPV Benefits (000$)	NPV Costs (000$)	NPV Net Benefits (000$)	B/C Ratio
Rate Impact Measure	253	242	11	1.04
Participant	170	0	170	NA
Total Resource Cost	253	72	181	3.51

Program: **IS2**

Rate Impact Measure Test

	BENEFITS					COSTS							
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
YEAR	TOTAL FUEL & O&M SAVINGS $(000)	AVOIDED T&D CAP. COSTS $(000)	AVOIDED GEN. CAP. COSTS $(000)	REVENUE GAINS $(000)	**TOTAL BENEFITS** $(000)	TOTAL FUEL & O&M INCREASE $(000)	INCREASED T&D CAP. COSTS $(000)	INCREASED GEN. CAP. COSTS $(000)	UTILITY PROGRAM COSTS $(000)	INCENTIVE PAYMENTS $(000)	REVENUE LOSSES $(000)	**TOTAL COSTS** $(000)	**NET BENEFITS** $(000)
2004	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	5	0	0	5	-5
2006	0	0	0	0	0	0	0	0	5	0	0	5	-5
2007	8	0	10	0	19	0	0	0	6	10	0	17	2
2008	8	0	11	0	19	0	0	0	5	10	0	16	3
2009	8	0	11	0	18	0	0	0	5	10	0	16	3
2010	0	0	16	0	16	1	0	0	5	10	0	16	-1
2011	0	0	21	0	21	4	0	0	6	21	1	31	-10
2012	0	0	34	0	34	2	0	0	5	21	1	28	6
2013	0	0	33	0	33	8	0	0	5	21	1	34	-1
2014	0	0	27	0	27	5	0	0	5	21	1	32	-5
2015	0	0	30	0	30	0	0	0	5	21	1	27	3
2016	0	0	36	0	36	3	0	0	5	21	1	30	6
2017	0	0	28	0	28	3	0	0	5	21	1	29	-1
2018	0	0	25	0	25	0	0	0	5	21	1	27	-2
2019	3	0	33	0	36	0	0	0	5	21	1	27	9
2020	1	0	27	0	28	0	0	0	5	21	1	27	1
2021	4	0	27	0	31	0	0	0	5	21	2	27	4
2022	1	0	27	0	28	0	0	0	5	21	2	27	1
2023	0	0	27	0	27	1	0	0	5	21	2	28	-1
2024	0	0	37	0	37	0	0	0	5	21	2	27	9
2025	0	0	30	0	30	1	0	0	5	21	2	28	2
2026	0	0	38	0	38	2	0	0	5	21	2	30	9
2027	0	0	47	0	47	4	0	0	5	21	2	31	16
2028	0	0	40	0	40	2	0	0	5	21	2	29	11
2029	0	0	40	0	40	5	0	0	5	21	1	32	7
2030	0	0	32	0	32	3	0	0	5	21	1	30	2
2031	0	0	42	0	42	5	0	0	5	21	2	33	9
2032	0	0	33	0	33	4	0	0	5	21	1	30	3
2033	0	0	52	0	52	0	0	0	5	21	1	27	25
NOMINAL	33	0	813	0	846	51	0	0	147	515	34	747	99
NPV	20	0	233	0	253	15	0	0	56	161	9	242	11

Utility Discount Rate: **8.16**

Benefit Cost Ratio: **1.04**

Program: IS2

Total Resource Cost Test

	BENEFITS					COSTS						
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
YEAR	TOTAL FUEL & O&M SAVINGS $(000)	AVOIDED T&D CAP. COSTS $(000)	AVOIDED GEN. CAP. COSTS $(000)	OTHER PARTICIPANT BENEFITS $(000)	**TOTAL BENEFITS** $(000)	PARTICIPANT'S COST $(000)	TOTAL FUEL & O&M INCREASE $(000)	INCREASED T&D CAP. COSTS $(000)	INCREASED GEN. CAP. COSTS $(000)	UTILITY PROGRAM COSTS $(000)	**TOTAL COSTS** $(000)	**NET BENEFITS** $(000)
2004	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	5	5	-5
2006	0	0	0	0	0	0	0	0	0	5	5	-5
2007	8	0	10	0	19	0	0	0	0	6	6	13
2008	8	0	11	0	19	0	0	0	0	5	5	14
2009	8	0	11	0	18	0	0	0	0	5	5	13
2010	0	0	16	0	16	0	1	0	0	5	6	10
2011	0	0	21	0	21	0	4	0	0	6	10	12
2012	0	0	34	0	34	0	2	0	0	5	7	28
2013	0	0	33	0	33	0	8	0	0	5	13	20
2014	0	0	27	0	27	0	5	0	0	5	10	17
2015	0	0	30	0	30	0	0	0	0	5	5	25
2016	0	0	36	0	36	0	3	0	0	5	8	28
2017	0	0	28	0	28	0	3	0	0	5	8	21
2018	0	0	25	0	25	0	0	0	0	5	5	20
2019	3	0	33	0	36	0	0	0	0	5	5	31
2020	1	0	27	0	28	0	0	0	0	5	5	23
2021	4	0	27	0	31	0	0	0	0	5	5	26
2022	1	0	27	0	28	0	0	0	0	5	5	23
2023	0	0	27	0	27	0	1	0	0	5	6	21
2024	0	0	37	0	37	0	0	0	0	5	5	31
2025	0	0	30	0	30	0	1	0	0	5	6	24
2026	0	0	38	0	38	0	2	0	0	5	7	31
2027	0	0	47	0	47	0	4	0	0	5	9	39
2028	0	0	40	0	40	0	2	0	0	5	7	34
2029	0	0	40	0	40	0	5	0	0	5	10	29
2030	0	0	32	0	32	0	3	0	0	5	8	24
2031	0	0	42	0	42	0	5	0	0	5	10	31
2032	0	0	33	0	33	0	4	0	0	5	9	25
2033	0	0	52	0	52	0	0	0	0	5	5	47
NOMINAL	33	0	813	0	846	0	51	0	0	147	198	648
NPV	20	0	233	0	253	0	15	0	0	56	72	181

Utility Discount Rate: 8.16

Benefit Cost Ratio: 3.52

Program: IS2

Participant Test

	BENEFITS				COSTS			
YEAR	(1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT'S BENEFITS $(000)	(4) **TOTAL BENEFITS** $(000)	(5) PARTICIPANT'S COST $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) **TOTAL COSTS** $(000)	(8) **NET BENEFITS TO PARTICIPANTS** $(000)
2004	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0
2007	0	10	0	11	0	0	0	11
2008	0	10	0	11	0	0	0	11
2009	0	10	0	11	0	0	0	11
2010	0	10	0	11	0	0	0	11
2011	1	21	0	22	0	0	0	22
2012	1	21	0	22	0	0	0	22
2013	1	21	0	22	0	0	0	22
2014	1	21	0	21	0	0	0	21
2015	1	21	0	22	0	0	0	22
2016	1	21	0	22	0	0	0	22
2017	1	21	0	22	0	0	0	22
2018	1	21	0	22	0	0	0	22
2019	1	21	0	22	0	0	0	22
2020	1	21	0	22	0	0	0	22
2021	2	21	0	22	0	0	0	22
2022	2	21	0	22	0	0	0	22
2023	2	21	0	22	0	0	0	22
2024	2	21	0	22	0	0	0	22
2025	2	21	0	22	0	0	0	22
2026	2	21	0	22	0	0	0	22
2027	2	21	0	22	0	0	0	22
2028	2	21	0	22	0	0	0	22
2029	1	21	0	22	0	0	0	22
2030	1	21	0	22	0	0	0	22
2031	2	21	0	22	0	0	0	22
2032	1	21	0	22	0	0	0	22
2033	1	21	0	22	0	0	0	22
NOMINAL	32	494	0	526	0	0	0	526
NPV	9	161	0	170	0	0	0	170

Utility Discount Rate: 8.16

Benefit Cost Ratio: #DIV/0!

G. CURTAILABLE SERVICE PROGRAM

Program Start Date: • 1996 for the CS-2 and CST-2 rate schedules.

Policies and Procedures

The Curtailable Service (CS) program is a direct load control program that will reduce PEF's demand at times of capacity shortage during peak or emergency conditions. The program is available throughout the entire territory served by PE to any non-residential customer who agrees to curtail 25% of their average monthly billing demand. The program is currently offered through the Curtailable General Service (CS-2) and Curtailable General Service Time of Use (CST-2) rate schedules. The CS-1 and CST-1 rate schedules were closed to new customers in 1996, but remain active for those customers that were grand fathered onto the rate.

PEF will have remote control of the circuit breaker or disconnect switch supplying the customer's equipment. If purchased power is available at the time of potential curtailment, customers who choose not to reduce their load will be assessed at the price of that purchased power. Customers participating in the Curtailable Service program receive a monthly curtailable demand credit based on their curtailable demand and billing load factor. The general program eligibility requirements to qualify for participation are as follows:

- Customer must be eligible for service under the CS-2 or CST-2 Rate Schedules.
- Average billing demand must be 500 kW or more.
- Available at primary, transmission and secondary service voltages.

Program Participation

Cumulative participation estimates for the program are shown in the following table.

Year	Total Number of Customers[1]	Total Number of Eligible Customers	Annual Number of Program Participants	Cumulative Penetration Level (%)
2005	184,973	983	1	0
2006	188,338	1,008	1	0
2007	191,917	1,033	1	0
2008	195,622	1,059	2	0
2009	199,361	1,086	2	0
2010	203,048	1,113	2	0
2011	206,613	1,141	3	0
2012	210,080	1,169	3	0
2013	213,480	1,198	3	0
2,014	216,855	1,228	4	0

1. *Total Number of Customers is the April 2004 forecast of all commercial and industrial customers.*

Savings Estimates

Savings estimate for the Curtailable Service program are shown in the following tables.

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2005	4,250	250	220	4,250	250	220
2006	4,250	250	220	4,250	250	220
2007	4,250	250	220	4,250	250	220
2008	4,250	250	220	8,500	500	440
2009	4,250	250	220	8,500	500	440
2010	4,250	250	220	8,500	500	440
2011	4,250	250	220	12,750	750	660
2012	4,250	250	220	12,750	750	660
2013	4,250	250	220	12,750	750	660
2014	4,250	250	220	17,000	1,000	880

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2005	4,541	267	235	4,541	267	235
2006	4,541	267	235	4,541	267	235
2007	4,541	267	235	4,541	267	235
2008	4,541	267	235	9,083	534	470
2009	4,541	267	235	9,083	534	470
2010	4,541	267	235	9,083	534	470
2011	4,541	267	235	13,624	801	705
2012	4,541	267	235	13,624	801	705
2013	4,541	267	235	13,624	801	705
2014	4,541	267	235	18,166	1,069	940

Impact Evaluation Plan

Program impacts are evaluated through on-site interval metering data of all Curtailable Service customers.

Cost-Effectiveness

PEF is projecting slow growth for the Curtailable Service Program. In order to evaluate the program for cost-effectiveness a minimal level of participation was assumed. The cost-effectiveness results of the Curtailable Service program are as follows:

Cost-Effectiveness Test	NPV Benefits (000$)	NPV Costs (000$)	NPV Net Benefits (000$)	B/C Ratio
Rate Impact Measure	466	367	98	1.27
Participant	145	0	145	NA
Total Resource Cost	466	222	243	2.09

Program: **CS2**

Rate Impact Measure Test

	BENEFITS					COSTS							
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
YEAR	TOTAL FUEL & O&M SAVINGS $(000)	AVOIDED T&D CAP. COSTS $(000)	AVOIDED GEN. CAP. COSTS $(000)	REVENUE GAINS $(000)	**TOTAL BENEFITS** $(000)	TOTAL FUEL & O&M INCREASE $(000)	INCREASED T&D CAP. COSTS $(000)	INCREASED GEN. CAP. COSTS $(000)	UTILITY PROGRAM COSTS $(000)	INCENTIVE PAYMENTS $(000)	REVENUE LOSSES $(000)	**TOTAL COSTS** $(000)	**NET BENEFITS** $(000)
2004	0	0	0	0	0	0	0	0	15	0	0	15	-15
2005	1	0	0	0	1	0	0	0	15	4	0	20	-19
2006	1	0	0	0	1	0	0	0	15	4	0	20	-19
2007	8	0	10	0	18	0	0	0	15	4	0	20	-2
2008	17	0	22	0	39	0	0	0	15	9	1	24	14
2009	15	0	20	0	35	0	0	0	15	9	1	24	11
2010	0	0	31	0	31	1	0	0	15	9	1	25	6
2011	0	0	36	0	36	8	0	0	15	13	1	37	-1
2012	0	0	49	0	49	2	0	0	15	13	2	32	17
2013	0	0	49	0	49	12	0	0	15	13	1	41	8
2014	0	0	53	0	53	11	0	0	15	17	1	45	9
2015	7	0	72	0	79	0	0	0	15	17	2	34	45
2016	0	0	55	0	55	21	0	0	15	17	1	55	0
2017	0	0	56	0	56	0	0	0	15	17	2	34	22
2018	0	0	53	0	53	2	0	0	15	17	2	36	17
2019	8	0	59	0	66	0	0	0	15	17	2	34	32
2020	0	0	57	0	57	1	0	0	15	17	2	35	22
2021	2	0	58	0	60	0	0	0	15	17	2	34	26
2022	2	0	56	0	58	0	0	0	15	17	2	34	24
2023	0	0	59	0	59	2	0	0	15	17	2	36	24
2024	0	0	67	0	67	8	0	0	15	17	2	42	24
2025	0	0	64	0	64	3	0	0	15	17	2	37	27
2026	0	0	73	0	73	5	0	0	15	17	2	39	35
2027	0	0	72	0	72	39	0	0	15	17	2	73	-2
2028	0	0	69	0	69	4	0	0	15	17	2	38	30
2029	0	0	78	0	78	9	0	0	15	17	3	43	35
2030	0	0	72	0	72	7	0	0	15	17	2	42	31
2031	0	0	83	0	83	12	0	0	15	17	3	46	36
2032	0	0	85	0	85	9	0	0	15	17	3	44	41
2033	0	0	95	0	95	6	0	0	15	17	3	41	54
NOMINAL	59	0	1,553	0	1,612	161	0	0	450	423	45	1,080	531
NPV	36	0	430	0	466	42	0	0	180	132	13	367	98

Utility Discount Rate: 8.16

Benefit Cost Ratio: 1.27

Program: CS2

Total Resource Cost Test

	BENEFITS					COSTS						
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
YEAR	TOTAL FUEL & O&M SAVINGS $(000)	AVOIDED T&D CAP. COSTS $(000)	AVOIDED GEN. CAP. COSTS $(000)	OTHER PARTICIPANT BENEFITS $(000)	**TOTAL BENEFITS** $(000)	PARTICIPANT'S COST $(000)	TOTAL FUEL & O&M INCREASE $(000)	INCREASED T&D CAP. COSTS $(000)	INCREASED GEN. CAP. COSTS $(000)	UTILITY PROGRAM COSTS $(000)	**TOTAL COSTS** $(000)	**NET BENEFITS** $(000)
2004	0	0	0	0	0	0	0	0	0	15	15	-15
2005	1	0	0	0	1	0	0	0	0	15	15	-14
2006	1	0	0	0	1	0	0	0	0	15	15	-14
2007	8	0	10	0	18	0	0	0	0	15	15	3
2008	17	0	22	0	39	0	0	0	0	15	15	24
2009	15	0	20	0	35	0	0	0	0	15	15	20
2010	0	0	31	0	31	0	1	0	0	15	16	16
2011	0	0	36	0	36	0	8	0	0	15	23	13
2012	0	0	49	0	49	0	2	0	0	15	17	31
2013	0	0	49	0	49	0	12	0	0	15	27	22
2014	0	0	53	0	53	0	11	0	0	15	26	27
2015	7	0	72	0	79	0	0	0	0	15	15	64
2016	0	0	55	0	55	0	21	0	0	15	36	18
2017	0	0	56	0	56	0	0	0	0	15	15	41
2018	0	0	53	0	53	0	2	0	0	15	17	36
2019	8	0	59	0	66	0	0	0	0	15	15	51
2020	0	0	57	0	57	0	1	0	0	15	16	41
2021	2	0	58	0	60	0	0	0	0	15	15	45
2022	2	0	56	0	58	0	0	0	0	15	15	43
2023	0	0	59	0	59	0	2	0	0	15	17	43
2024	0	0	67	0	67	0	8	0	0	15	23	43
2025	0	0	64	0	64	0	3	0	0	15	18	46
2026	0	0	73	0	73	0	5	0	0	15	20	54
2027	0	0	72	0	72	0	39	0	0	15	54	18
2028	0	0	69	0	69	0	4	0	0	15	19	50
2029	0	0	78	0	78	0	9	0	0	15	24	55
2030	0	0	72	0	72	0	7	0	0	15	22	50
2031	0	0	83	0	83	0	12	0	0	15	27	56
2032	0	0	85	0	85	0	9	0	0	15	24	61
2033	0	0	95	0	95	0	6	0	0	15	21	74
NOMINAL	59	0	1,553	0	1,612	0	161	0	0	450	612	1,000
NPV	36	0	430	0	466	0	42	0	0	180	222	243

Utility Discount Rate: 8.16

Benefit Cost Ratio: 2.09

Program: CS2

Participant Test

	BENEFITS				COSTS			
YEAR	(1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT'S BENEFITS $(000)	(4) **TOTAL BENEFITS** $(000)	(5) PARTICIPANT'S COST $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) **TOTAL COSTS** $(000)	(8) **NET BENEFITS TO PARTICIPANTS** $(000)
2004	0	0	0	0	0	0	0	0
2005	0	4	0	5	0	0	0	5
2006	0	4	0	5	0	0	0	5
2007	0	4	0	5	0	0	0	5
2008	1	9	0	9	0	0	0	9
2009	1	9	0	9	0	0	0	9
2010	1	9	0	9	0	0	0	9
2011	1	13	0	14	0	0	0	14
2012	2	13	0	15	0	0	0	15
2013	1	13	0	14	0	0	0	14
2014	1	17	0	19	0	0	0	19
2015	2	17	0	19	0	0	0	19
2016	1	17	0	19	0	0	0	19
2017	2	17	0	19	0	0	0	19
2018	2	17	0	19	0	0	0	19
2019	2	17	0	19	0	0	0	19
2020	2	17	0	19	0	0	0	19
2021	2	17	0	19	0	0	0	19
2022	2	17	0	19	0	0	0	19
2023	2	17	0	19	0	0	0	19
2024	2	17	0	19	0	0	0	19
2025	2	17	0	19	0	0	0	19
2026	2	17	0	19	0	0	0	19
2027	2	17	0	19	0	0	0	19
2028	2	17	0	19	0	0	0	19
2029	3	17	0	20	0	0	0	20
2030	2	17	0	19	0	0	0	19
2031	3	17	0	20	0	0	0	20
2032	3	17	0	20	0	0	0	20
2033	3	17	0	20	0	0	0	20
NOMINAL	43	406	0	449	0	0	0	449
NPV	13	132	0	145	0	0	0	145

Utility Discount Rate: **8.16**

Benefit Cost Ratio: **#DIV/0!**

V. TECHNOLOGY DEVELOPMENT PROGRAM

V. TECHNOLOGY DEVELOPMENT PROGRAM

Program Start Date: 1995

Policies and Procedures

The purpose of this program is to establish a system for meeting the goals in Section 366.82(2), Florida Statutes, and Rule 25-17, Florida Administrative Code. Specifically, the following is stated in Rule 25-17.001, {5}(f): "Aggressively pursue research, development, and demonstration projects jointly with others as well as individual projects in individual service areas."

Progress Energy will undertake certain development and demonstration projects which have promise to become cost-effective demand and energy efficiency programs. In general, each research and development project that is proposed and investigated will proceed as follows:

1. Project concept or idea development
2. Project research and design, including estimated costs and benefits
3. Conduct field test or pilot program
4. Evaluation of field test or pilot program, including cost-effectiveness
5. Acceptance or rejection of project for continuation as a program
6. If accepted in Item #5 above, application to the FPSC for approval to implement the program

Eligible customers will be determined during the project research and design phase, which will be dependent on the type of project being proposed and investigated. However, it is anticipated that only retail customers will be involved.

Each project that is proposed and investigated will have to meet one or more of the goals identified in Section 366.82(2), Florida Statutes, and Rule 25-17, Florida Administrative Code. If not, it will not proceed beyond the project concept or idea phase in Item #1 above.

Program Participation

In most cases, each demand reduction and energy efficiency project that is proposed and investigated under this program will require field testing with actual customers. These projects will offer services or products to eligible customers, after being defined in the project research and design phase, on a voluntary basis.

Examples of potential projects that may be funded under this program include demand reduction energy efficiency techniques, market transformation initiatives, indoor air quality measures, thermal energy storage technologies, and innovative metering approaches. All costs including incentives and rebates that are offered will be included as part of the pre-approved project expenditures under this program.

At the discretion of the Company, expenditures up to $800,000 annually may be made and recovered through the conservation cost recovery clause for all energy efficiency and conservation projects that are proposed and investigated. If any single project's expenditures exceed $100,000, a status report will be filed as a component of the Conservation Cost Recovery Projection and True-Up filings. The status report will identify each project under investigation with disbursements exceeding $100,000, the scope and purpose of the project, its development schedule identifying accomplishments and projections, and the project's actual and proposed expenditures for FPSC staff review. If any project (or combination of projects) expenditures are projected to exceed the $800,000 annual limit available under this program and are sufficiently worthy of special consideration, the Company will apply to the FPSC staff for approval to proceed.

Finally, the Company will account for and maintain records of all expenses for each project in accordance with Rule 25-17.015, Florida Administrative Code.

Savings Estimates

This program makes it possible to obtain and use actual data from field tests, instead of relying heavily on engineering assumptions, model results, estimates, and so forth. Benefit and cost figures derived from these projects will be more reliable and projectable, allowing better assessment of future demand reduction and energy efficiency programs submitted to the FPSC for approval.

A second benefit resulting from this development program is that the procedure uncovers benefits, costs, and disadvantages that may be overlooked by an engineering estimate or evaluation. During field tests, not only planned elements, but also unplanned elements are encountered. Actual experience on a small scale is obtained. This should facilitate the decision-making process and improve the success rate of approved programs.

Consequently, program savings were not estimated during the planning stage and are not included in the DSM Plan totals. Any impacts obtained by this program will be calculated for each individual project and will be reported to the FPSC to be counted toward achieving Progress Energy's conservation goals.

Impact Evaluation Plan

The methodology for monitoring and evaluating a project that is submitted to the FPSC for approval as a program shall be determined during the project research and design phase and shall be refined during the field test or pilot program phase. Since projects will normally include a field test or pilot program, the data will be actual rather than estimated. In the event a project does not involve a field test or pilot program, the estimated or modeled savings will be fully documented with the methodology used.

Cost-Effectiveness

The cost-effectiveness of each project submitted to the FPSC for approval to be implemented as a program shall be analyzed and reported using the Commission-approved cost-effectiveness tests.

VI. QUALIFYING FACILITIES PROGRAM

VI. QUALIFYING FACILITIES PROGRAM

Policies and Procedures

The purpose of this program is to meet the objectives and the Company's obligations established by Section 366.051, Florida Statutes, and the Commission's rules contained within Part III of Chapter 25-17, Florida Administrative Code, regarding the purchase of as-available energy and firm energy and capacity from qualifying facilities pursuant to standard offer and negotiated contracts.

Under the Qualifying Facilities program, Progress Energy develops standard offer contracts, negotiates, enters into, amends and restructures firm energy and capacity contracts entered into with qualifying cogeneration and small power production facilities, and administers all such contracts.

ORIGINAL

Progress Energy

RECEIVED-FPSC

06 SEP 27 PM 1:20

COMMISSION
CLERK

September 27, 2006

Ms. Blanca S. Bayó, Director
Division of Commission Clerk and
Administrative Services
Florida public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Petition for Approval of Demand Side Management Programs; Docket No. 060647-EG

Dear Ms. Bayó:

Please find enclosed for filing on behalf of Progress Energy Florida, Inc. ("PEF") the original and seven (7) copies of its petition for approval of Demand Side Management programs.

Thank you for your assistance in this matter.

Sincerely,

John T. Burnett LMS

John T. Burnett

JTB/lms
Enclosure

Original Tariff forwarded to ECR

Progress Energy Florida, Inc.
106 E. College Avenue
Suite 800
Tallahassee, FL 32301

RECEIVED & FILED

FPSC-BUREAU OF REC

DOCUMENT NUMBER-DATE
08949 SEP 27 06
FPSC-COMMISSION CLERK

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Approval of Demand Side Management Programs	))))	Docket No. 06-0647-EG Filed: September 27, 2006

PETITION FOR APPROVAL OF
DEMAND SIDE MANAGEMENT PROGRAMS

Progress Energy, Florida, Inc. ("PEF"), pursuant to Sections 366.82 and 366.06(1), Florida Statutes (2006), and Florida Administrative Code Rule 25-17.0021 petitions the Florida Public Service Commission ("Commission") for approval of modifications to Demand Side Management ("DSM") programs as described in this petition, and to authorize PEF to recover through its Energy Conservation Cost Recovery ("ECCR") clause reasonable and prudent expenditures associated with implementation of such programs.

Approval of the proposed programs will help further the objectives of the Florida Energy Efficiency Conservation Act ("FEECA") by cost-effectively reducing the growth rate of weather sensitive peak demand, reducing and controlling the growth rate of energy consumption, increasing the conservation of expensive resources and increasing the efficiency of the electrical system. See Section 366.81, Florida Statutes (2006); Rule 25-17.001(2), Florida Administrative Code (2006). Reducing the growth rate of weather sensitive peak demand will benefit not only PEF's individual customers who reduce their demand through participation in the new and modified DSM programs, but also all other customers on PEF's system. See Rule 25-17.001(3), Florida Administrative Code. PEF respectfully requests expedited consideration and approval of these proposed DSM programs in order that customers may receive the conservation benefits of its proposed programs in the near term. In support of this petition PEF states:

1. PEF is a public utility subject to the jurisdiction of the Commission pursuant to Chapter 366 of the Florida Statutes. PEF's General Offices are located at 100 Central Avenue, St. Petersburg, Florida 33701.

2. The names and addresses of PEF's representatives to receive communications regarding this docket are:

Paul Lewis, Jr.
Director, Regulatory Affairs
Progress Energy
106 East College Avenue, Suite 800
Tallahassee, Florida 32301
Telephone: (850) 222-8738

John T. Burnett
Associate General Counsel
Progress Energy
100 Central Avenue
St. Petersburg, Florida 33701
Telephone: (727) 820-5184

3. PEF is subject to FEECA, Sections 366.80-366.85 and 403.519, Florida Statutes (2006), and its Energy Conservation Cost Recovery clause is subject to the Commission's jurisdiction. Pursuant to FEECA and Commission rules implementing FEECA, PEF is required to seek the Commission's approval of DSM programs and is entitled to seek recovery of associated expenditures. PEF has a substantial interest in whether the Commission approves PEF's requested new programs and authorizes cost recovery for plan implementation expenditures.

4. In this petition, PEF is proposing modifications to the programs noted below:

Residential	Commercial
Home Energy Improvement	Better Business
Residential New Construction	Commercial/Industrial New Construction
Residential Energy Management	Standby Generation
Neighborhood Energy Saver	
Renewable Energy Programs	

Appendix A to this petition contains the cost-effectiveness analysis for each program. Appendix B includes program descriptions for the proposed modifications to the programs as well as a description of the measures included in the Neighborhood Energy Saver Program. Appendix C contains the Tariff revisions that are necessary to implement PEF's proposed programs in clean and legislative format.

5. The program changes are summarized in Appendix B and detailed in the various sections. The company is proposing to continue the following programs with no modifications.

Residential	Commercial
Home Energy Check	Business Energy Check
Low Income Weatherization	Innovation Incentive
	Curtailable Service
	Interruptible Service
Technology Development	
Qualifying Facilities	

6. The purpose of PEF's proposed programs is to maximize the availability of cost-effective demand-side management opportunities to PEF's customers. It is anticipated that the implementation of these proposed DSM programs will increase the penetration of demand-side management in the future. PEF proposes to initiate the new programs after they have been approved and there has been an opportunity to train personnel regarding the programs. PEF will work with the Commission and its Staff regarding the effective date of the proposed programs.

7. The proposed DSM programs will further help PEF achieve the goals set forth in the FEECA and Florida Administrative Code Rule 25-17.001. The proposed programs are designed to cost-effectively reduce the growth rate of weather-sensitive peak demand, reduce

and control the growth rate of energy consumption, increase the conservation of expensive resources and increase the efficiency of the electrical system.

8. PEF's proposed programs are cost-effective. In Appendix A, PEF has shown, using the Commission's cost-effectiveness methodology, the cost-effectiveness of each of the proposed programs for which cost-effectiveness can be meaningfully calculated.

9. PEF's proposed programs are reasonably monitorable. PEF's monitoring efforts for each of its programs are set forth in the detailed program and project summaries in Section II "Program Administration & Monitoring and Evaluation".

10. PEF is not aware of any disputed issues of material fact.. PEF's proposed programs, as reflected in Appendix B, should be approved, including the Tariff revisions to sheet nos. 6.130, 6.131, 6132, 6.135, 6.136, 6.220, 6.221, 6.225, and 6.226. (Appendix C), which are needed to implement the proposed plans. The Commission should authorize recovery of the reasonable and prudent expenditures associated with PEF's proposed programs through PEF's ECCR clause. The statutes and rule which entitle PEF to relief are Sections 366.82(2), 366.06(1), Florida Statutes (2006), and Florida Administrative Code Rule 25-17.0021 (2006).

11. There has not been agency action in this proceeding. Therefore, PEF cannot provide a statement of when and how PEF received notice of agency action.

WHEREFORE, PEF respectfully requests that the Commission: (1) approve PEF's proposed DSM programs, as reflected in Appendix B to this petition, as well as the Tariff revisions reflected in Appendix C, (2) authorize PEF to recover through its ECCR clause reasonable and prudent expenditures associated with the implementation of the proposed programs, and (3) grant such other relief as may be appropriate. Further, PEF respectfully requests expedited treatment of this petition so that PEF's customers may realize the benefits of the proposed plans in the near term.

Respectfully submitted,

John T. Burnett LMS

John T. Burnett

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Appendix A

COST-EFFECTIVE ANALYSIS

Appendix A

Cost Effectiveness Analysis

Summary of Demand Side Management Programs Included in Proposed Plan Period 2007-2014

	Rate Impact Measure Test			Participant Test			Total Resource Cost Test			
DSM Programs	PV Total Benefits ($000)	PV Total Costs ($000)	B/ C Ratio	PV Total Benefits ($000)	PV Total Costs ($000)	B/ C Ratio	PV Total Benefits ($000)	PV Total Costs ($000)	B/ C Ratio	Program Status
Home Energy Improvement	193,895	115,644	1.68	112,362	36,584	3.07	193,895	39,867	4.86	Modified
Residential New Construction	140,833	61,998	2.27	54,742	22,062	2.48	140,833	29,318	4.80	Modified
Neighborhood Energy Saver	26,266	23,106	1.14	21,878	0	N/A	26,266	1,228	21.40	New
Renewable Energy	1,116	737	1.51	483	474	1.02	1,116	728	1.53	New
Residential Year Round Energy Management	147,032	53,946	2.73	35,102	0	N/A	147,032	18,844	7.80	Modified
Dispatchable Standby	99,480	20,266	4.91	18,632	0	N/A	99,480	1,634	60.88	Modified
Better Business	113,209	76,838	1.47	75,965	33,172	2.29	113,209	34,044	3.33	Modified
C/I New Construction	53,743	37,659	1.43	37,212	20,357	1.83	53,743	20,803	2.58	Modified

AVOIDABLE GENERATION ASSUMPTIONS	
CTF G – SIMPLE CYCLE COMBUSTION TURBINE	
(1) BASE YEAR	2006
(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT	Jun-08
(3) WINTER CAPACITY	191 MW
(4) BASE YEAR AVOIDED GENERATING UNIT COST (including transmission upgrade cost)	591.62 $/KW
(5) GENERATOR COST ESCALATION RATE	2.75 %
(7) GENERATOR FIXED O&M COST (including nonescalating gas pipeline reservation cost)	35.58 $/KW-YR
(8) GENERATOR FIXED O&M ESCALATION RATE	3.0 THROUGH 2008, 2.75 BEYOND %
(10) AVOIDED GEN UNIT VARIABLE O&M COSTS	1.158 ¢/KWH
(11) GENERATOR VARIABLE O&M COST ESCALATION RATE	3.0 THROUGH 2008, 2.75 BEYOND %
(12) GENERATOR CAPACITY FACTOR	6 %
(13) AVOIDED GENERATING UNIT FUEL COST	13.16 ¢/KWH
(14) AVOIDED GEN UNIT FUEL ESCALATION RATE	2.75 %
CTF G (2 Units) – 2 SIMPLE CYCLE COMBUSTION TURBINES	
(1) BASE YEAR	2006
(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT	Jun-10
(3) WINTER CAPACITY	191 MW
(4) BASE YEAR AVOIDED GENERATING UNIT COST (including transmission upgrade cost)	591.62 $/KW
(5) GENERATOR COST ESCALATION RATE	2.75 %
(7) GENERATOR FIXED O&M COST (including nonescalating gas pipeline reservation cost)	35.58 $/KW-YR
(8) GENERATOR FIXED O&M ESCALATION RATE	3.0 THROUGH 2008, 2.75 BEYOND %
(10) AVOIDED GEN UNIT VARIABLE O&M COSTS	1.158 ¢/KWH
(11) GENERATOR VARIABLE O&M COST ESCALATION RATE	3.0 THROUGH 2008, 2.75 BEYOND %
(12) GENERATOR CAPACITY FACTOR	4 %
(13) AVOIDED GENERATING UNIT FUEL COST	11.91 ¢/KWH
(14) AVOIDED GEN UNIT FUEL ESCALATION RATE	2.75 %
CCM F – COMBINED CYCLE	
(1) BASE YEAR	2006
(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT	Jun-11
(3) WINTER CAPACITY	523 MW
(4) BASE YEAR AVOIDED GENERATING UNIT COST (including transmission upgrade cost)	771.18 $/KW
(5) GENERATOR COST ESCALATION RATE	2.75 %
(7) GENERATOR FIXED O&M COST (including nonescalating gas pipeline reservation cost)	37.86 $/KW-YR
(8) GENERATOR FIXED O&M ESCALATION RATE	3.0 THROUGH 2008, 2.75 BEYOND %
(10) AVOIDED GEN UNIT VARIABLE O&M COSTS	0.335 ¢/KWH
(11) GENERATOR VARIABLE O&M COST ESCALATION RATE	3.0 THROUGH 2008, 2.75 BEYOND %
(12) GENERATOR CAPACITY FACTOR	56 %
(13) AVOIDED GENERATING UNIT FUEL COST	6.19 ¢/KWH
(14) AVOIDED GEN UNIT FUEL ESCALATION RATE	2.75 %
CTF G (2 Units) – 2 SIMPLE CYCLE COMBUSTION TURBINES	
(1) BASE YEAR	2006
(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT	Dec-11
(3) WINTER CAPACITY	191 MW
(4) BASE YEAR AVOIDED GENERATING UNIT COST (including transmission upgrade cost)	591.62 $/KW
(5) GENERATOR COST ESCALATION RATE	2.75 %
(7) GENERATOR FIXED O&M COST (including nonescalating gas pipeline reservation cost)	35.58 $/KW-YR
(8) GENERATOR FIXED O&M ESCALATION RATE	3.0 THROUGH 2008, 2.75 BEYOND %
(10) AVOIDED GEN UNIT VARIABLE O&M COSTS	1.158 ¢/KWH
(11) GENERATOR VARIABLE O&M COST ESCALATION RATE	3.0 THROUGH 2008, 2.75 BEYOND %
(12) GENERATOR CAPACITY FACTOR	5 %
(13) AVOIDED GENERATING UNIT FUEL COST	11.31 ¢/KWH
(14) AVOIDED GEN UNIT FUEL ESCALATION RATE	2.75 %

AVOIDABLE TRANSMISSION AND DISTRIBUTION ASSUMPTIONS	
(1) BASE YEAR	2006
(2) IN-SERVICE YEAR FOR AVOIDED T&D	2006
(3) AVOIDED TRANSMISSION AND DISTRIBUTION COST	
– Non-dispatchable Programs	29.72 $/KW-YR
– Dispatchable Programs	0 $/KW-YR
(4) T&D COST ESCALATION RATE	0 %

Appendix B

PROGRAM DESCRIPTIONS

Appendix B

PROGRAM ADMINISTRATION

PEF's modifications will create awareness of all of its Demand Side Management offerings for existing and new residential and commercial customers. These programs and measures encourage high energy efficiencies in both new and existing structures. Participation will be encouraged by utilizing appropriate advertising, radio, bill inserts, direct mail, dealers, distributors, contractors, and other trade allies. The Company will continue to aggressively promote its DSM programs through educational opportunities. Energy efficiency specialists are conducting educational seminars with civic and community groups including outreach programs and home owner associations in order to increase awareness of the programs. An area of potential growth is the inclusion of students and parents in energy efficiency awareness through the development of lesson plans and home energy audits. Partnerships with large retail firms are being identified and included as well. Additional process improvements are being investigated to further encourage participation and ease of tracking success and measures of each of the programs. A history of all incentive payments made to customers will be monitored for accuracy and tracked electronically. PEF will file Program Participation Standards for the program. Program Participation Standards will be subject to revisions based upon changes in market conditions, such as but not limited to, technological advances, operational needs, program results, application assumptions and incentive amounts.

PROGRAM MONITORING AND EVALUATION

Program monitoring and evaluation are important components of DSM implementation. They serve the purpose of ensuring that all DSM resources are acquired in a cost-effective manner. Specifically, program monitoring includes tracking program data and ensuring quality control. Program evaluation results document the energy and demand impacts and cost-effectiveness of the program, as well as suggest ways that the program can be improved by increasing savings, reducing costs, or increasing participation.

To ensure quality control of the measures the Company recommends, PEF will conduct a minimum of 10 percent inspections of each measure type as required in Chapter 25.17.003.10.b. Additionally, periodic end use metering studies are conducted to validate assumptions. Evaluation is conducted on an on-going basis through the modeling of billing data to evaluate the impacts of various measures.

PEF will determine the most cost-effective evaluation method based on factors such as participation levels and program performance.

Proposed Modifications to Progress Energy Demand-Side Management Programs

Home Energy Improvement

- Attic Insulation R15 to R30 - $75 per residence; if greater than 1500 sq. ft. 7¢ per sq. ft. for every ft. above 1500 sq. ft.
- Spray-In Wall Insulation - will be 20¢ per sq. ft. for insulation added to block wall area adjacent to conditioned space (maximum incentive of $300)
- Central Electric Air Conditioning with Existing Non-Electric Heat - $50 per unit equal to or greater than 14 SEER
- Supply and Return Plenum Duct Seal - $50 per system with SEER rating of 14 or greater
- Proper sizing of High Efficiency Air Conditioner - $75 per system
- HVAC Commissioning - $50 per system based upon software evaluation and completion of specified recommendation
- Reflective Roof Manufactured Homes - $40 for roof coating per residence
- Reflective Roof Single Family Homes - 15¢ per sq. ft. with a maximum of $150 for light colored roofs per residence
- Window Film & Window Screen - 1/2 of cost up to $100 for window film and window screen per residence
- Replacement Windows - $1 per sq. ft. per window area with maximum incentive of $250 per residence

Residential New Construction

- HVAC Commissioning - $50 per system based upon software evaluation and completion of specified recommendation
- Window Film & Window Screen - Incentive $100 per residence
- Reflective Roof Single Family - $100 for reflective roof material per residence
- Attic Spray-on Foam Insulation - $100 per residence
- Wall Insulation - $200 per residence for insulation to block wall area adjacent to conditioned space
- Conditioned Space Air Handler - $50 per air handler
- Energy Recovery Ventilation - $150 per residence

Neighborhood Energy Saver

This program includes the following measures:

- Compact fluorescent bulb
- Water heater wrap and insulation for water pipes

- Water heater temperature check and adjustment
- Low flow faucet aerators
- Low flow showerhead
- Water closet leak detection tablets
- Refrigerator coil brush
- Refrigerator thermometer
- Wall plate thermometer
- HVAC winterization kit
- HVAC filters
- Change filter calendar
- Weatherization Measures

Renewable Energy

- Solar Water Heater with Energy Management - $450 per residence plus energy management program credit
- Solar Photovoltaics with Energy Management - A fund to promote environmental stewardship and renewable energy education

Residential Year Round Energy Management

- Year Round Energy Management

Dispatchable Stand By

- Stand By Generation - Incentive will be $2.30 per kW per month plus an additional compensation of 5¢ per kWh

Better Business

- Roof Insulation Upgrade - 7¢ per sq. ft. with a maximum of $5,000 per building
- Thermal Energy Storage w/Time-of-Use Rate (TES w/TOU) - $300 per kW of reduced cooling load at peak times
- Green Roof - 25¢ per sq. ft. for the installation of an approved Green Roof
- Efficient Compressed Air System - $50 per kW reduction
- Occupancy Sensors - $50 per kW of lighting load controlled
- Roof Top Unit recommission - $15 per ton
- HVAC Steam Cleaning - $15 per unit one-time
- Efficient Indoor Lighting - $50 per kW reduced, minimum of 1kW lighting reduction per incentive application
- Demand Control Ventilation - $50 per ton reduction
- Efficient Motors - $1.75 - $2.75 per hp based upon motor size, minimum number of motors 25 hp and smaller

- Window film - 75¢ per sq. ft. of window film installed per building, exception incentives for facilities with multiple rooms, up to $55 maximum per room

Commercial New Construction

- Roof Insulation - 7¢ per sq. ft. with a maximum of $5,000 per building
- Thermal Energy Storage with Time-of-Use Rate - $300 per kW of reduced cooling load at peak times
- Green Roof - 25¢ per sq. ft. for the installation of an approved Green Roof
- Efficient Compressed Air System - $50 per kW reduction
- Occupancy Sensors - $50 per kW of lighting load controlled
- Efficient Indoor Lighting - $50 per kW reduced, minimum of 1kW lighting reduction per incentive application
- Demand Control Ventilation - $50 per ton reduction
- Efficient Motors - $1.75 - $2.75 per hp based upon motor size, minimum number of motors 25 hp and smaller
- Window film - 75¢ per sq. ft. of window film installed per building, exception incentives for facilities with multiple rooms, up to $55 maximum per room

RESIDENTIAL CONSERVATION PROGRAMS

Progress Energy Florida's DSM Plan includes five (5) residential programs which the company seeks to modify:

A. Home Energy Improvement – Program designed for existing homes

B. Residential New Construction – Program for new residential construction, single family, multi-family, and manufactured homes

C. Neighborhood Energy Saver – Program for the weatherization of low income family homes

D. Renewable Energy Program – Program for alternative energy efficient systems for existing and new residential construction

E. Residential Year Round Energy Management – Residential load management

Each program is described in detail in the following sections.

HOME ENERGY IMPROVEMENT PROGRAM

Program Start Date: 1995
Program modified 2006
Proposed modification for 2007

Program Description

The Home Energy Improvement program is an "umbrella" program designed to increase energy efficiency for existing residential homes. It combines efficiency improvements to the thermal envelope with upgraded electric appliances.

Specific eligibility requirements for each measure promoted in this program will be presented in the "Program Participation Standards."

PEF proposes to add the following measures to its previously approved program as follows:

Attic Insulation R15 to R30 Upgrade

This portion of the program encourages customers having less than R16 existing insulation to increase the attic insulation to R30 by paying a portion of the installed cost. The incentive will be $75 per residence up to 1500 sq. ft.; an additional incentive of 7¢ per square foot is paid for larger homes.

Spray-In Wall Insulation

This portion of the program encourages customers to add insulation to the block wall area by paying a portion of the installed cost. The proposed incentive will be 20¢ per square foot for the installation of wall insulation adjacent to conditioned space with a maximum incentive of $300 per residence.

Central Electric Air Conditioning with Existing Non-Electric Heat

This portion of the program encourages customers with existing non-electric heat, to install high efficiency electric air conditioners. PEF will provide an incentive of $50 per unit with a SEER rating of 14 or higher.

Supply and Return Plenum Duct Seal

This measure encourages the sealing of the supply and return portion of the plenum to the air handler. This incentive applies only for new heating/cooling systems with a qualifying SEER rating of 14 or higher. The proposed incentive for plenum sealing is $50 per system.

Proper Sizing of High Efficiency Air Conditioners

This portion of the program encourages the customer to have the air conditioning unit properly sized using an approved sizing software. This incentive applies only for heating/cooling systems when installing a new air handler and condensing unit. The proposed incentive for the proper sizing of high efficiency heating/cooling systems is $75 per system.

HVAC Commissioning

This portion of the program encourages the evaluation and optimization of heating/cooling systems using approved software. To qualify for the $50 incentive per system the customer must complete the specified recommendations.

Reflective Roof Manufactured Homes

This measure will provide incentives to install an approved Energy Star Roofing Product. The residence must have whole house electric cooling to be eligible for an incentive of $40 per residence.

Reflective Roof Single Family Homes

This measure provides an incentive to install light colored roofs on the residence. The residence must have whole house electric cooling to be eligible for this measure. The incentive will be 15¢ per square foot over conditioned space with a maximum incentive of $150.

Window Film and Window Screen

This portion of the program encourages customers to install qualifying film or screening on their windows facing east, west, and south. The residence must have whole house electric cooling to be eligible for this measure. The proposed maximum incentive is half the cost up to $100.

Replacement Windows

This measure encourages the installation of new high performance windows when replacing existing windows. The customer must have whole house electric cooling and heating to be eligible for this measure. Windows of the residence qualify for the incentive of $1.00 per square foot of the window area with a maximum incentive of $250 per residence.

Projected Program Participation

Cumulative participation estimates for the program are shown in the table below.

Residential Home Energy Improvement Table for 2006 DSM Modification Filing				
Year	Total Number of Customers (1)	Total Number of Eligible Customers (2)	Annual Number of Measures	Cumulative Penetration Level (%)
2007	1,452,431	101,670	14,759	15%
2008	1,481,473	205,373	29,908	15%
2009	1,509,934	311,069	45,057	14%
2010	1,538,271	418,748	60,206	14%
2011	1,566,662	528,414	75,355	14%
2012	1,595,236	640,080	90,504	14%
2013	1,623,967	753,758	105,653	14%
2014	1,652,629	869,442	120,802	14%

1. *Total Number of Customers is the forecast of all residential customers, from the August 2006 Forecast.*
2. *Total number of Eligible Customers is based on an approximatly 7% eligiblity. (assume 7%)*

Projected Savings

Total program savings were developed by first estimating the total savings for each individual measure based on each measure's (1) per customer savings and, (2) annual projected participation. The total projected program savings were then computed as the sum of the individual measure savings, and are shown in the following tables.

Home Energy Improvement - At the Meter						
Year	Per Customer KWH Reduction	Per Customer Winter KW Reduction	Per Customer Summer KW Reduction	Total Annual KWH Reduction	Total Annual Winter KW Reduction	Total Annual Summer KW Reduction
2007	684	1.377	0.44	10,098,870	20,321	6,543
2008	688	1.365	0.44	20,571,385	40,810	13,299
2009	689	1.361	0.45	31,043,900	61,300	20,056
2010	690	1.359	0.45	41,516,415	81,790	26,812
2011	690	1.357	0.45	51,988,930	102,280	33,569
2012	690	1.357	0.45	62,461,445	122,769	40,325
2013	690	1.356	0.45	72,933,960	143,259	47,082
2014	690	1.356	0.45	83,406,475	163,749	53,838

Home Energy Improvement - At the Generator						
Year	Per Customer KWH Reduction	Per Customer Winter KW Reduction	Per Customer Summer KW Reduction	Total Annual KWH Reduction	Total Annual Winter KW Reduction	Total Annual Summer KW Reduction
2007	729	1.467	0.472	10,761,154	21,653	6,972
2008	733	1.454	0.474	21,920,456	43,487	14,172
2009	734	1.450	0.474	33,079,759	65,320	21,371
2010	735	1.448	0.475	44,239,061	87,154	28,571
2011	735	1.446	0.475	55,398,364	108,987	35,770
2012	735	1.445	0.475	66,557,667	130,820	42,970
2013	736	1.445	0.475	77,716,969	152,654	50,169
2014	736	1.444	0.475	88,876,272	174,487	57,369

Cost Effectiveness Analysis

Home Energy Improvement				
Cost-Effectiveness Test	NPV Benefits $(000)	NPV Costs $(000)	NPV Net Benefits $(000)	B/C Ratio
Rate Impact Measure	193,895	115,644	78,251	1.68
Participant	112,362	36,584	75,778	3.07
Total Resource Cost	193,895	39,867	154,029	4.86

PROGRAM: Home Energy Improvement Program RIM

	BENEFITS					COSTS							
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	TOTAL FUEL & O&M SAVINGS	AVOIDED T&D CAP. COSTS	AVOIDED GEN. CAP. COSTS	REVENUE GAINS	TOTAL BENEFITS	TOTAL FUEL & O&M INCREASE	INCREASED T&D CAP. COSTS	INCREASED GEN. CAP. COSTS	UTILITY PROGRAM COSTS	INCENTIVE PAYMENTS	REVENUE LOSSES	TOTAL COSTS	NET BENEFITS
YEAR	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
2006	5	1	0	0	5	0	0	0	3	10	5	18	-12
2007	2,195	503	0	0	2,697	0	0	0	985	5,290	1,996	8,271	-5,574
2008	3,840	721	1,616	0	6,177	0	0	0	422	2,234	2,910	5,566	611
2009	5,015	954	2,297	0	8,267	0	0	0	447	2,421	3,830	6,697	1,569
2010	5,559	1,208	3,001	0	9,768	0	0	0	482	2,654	5,060	8,196	1,572
2011	5,229	1,478	5,206	0	11,913	0	0	0	509	2,811	6,488	9,808	2,105
2012	8,367	1,771	4,952	0	15,090	0	0	0	553	3,061	7,990	11,604	3,486
2013	9,757	2,067	6,621	0	18,445	0	0	0	557	3,087	9,361	13,004	5,441
2014	11,823	2,354	8,952	0	23,129	0	0	0	537	2,992	10,651	14,179	8,950
2015	12,603	2,354	11,417	0	26,374	0	0	0	0	0	11,086	11,086	15,287
2016	12,177	2,354	10,152	0	24,683	0	0	0	0	0	11,745	11,745	12,939
2017	11,761	2,354	8,497	0	22,611	0	0	0	0	0	11,417	11,417	11,194
2018	11,793	2,354	9,657	0	23,804	0	0	0	0	0	11,531	11,531	12,273
2019	11,720	2,354	8,891	0	22,966	0	0	0	0	0	11,421	11,421	11,545
2020	12,053	2,354	11,725	0	26,132	0	0	0	0	0	11,238	11,238	14,894
2021	12,028	2,354	10,918	0	25,300	0	0	0	0	0	11,358	11,358	13,942
2022	11,779	2,354	9,773	0	23,906	0	0	0	0	0	11,481	11,481	12,425
2023	11,840	2,354	9,219	0	23,414	0	0	0	0	0	11,608	11,608	11,806
2024	11,950	2,354	8,637	0	22,941	0	0	0	0	0	11,738	11,738	11,203
2025	12,326	2,354	8,810	0	23,490	0	0	0	0	0	11,871	11,871	11,619
2026	12,515	2,354	8,852	0	23,722	0	0	0	0	0	12,007	12,007	11,714
2027	12,817	2,354	9,150	0	24,320	0	0	0	0	0	12,148	12,148	12,172
2028	13,004	2,354	9,559	0	24,917	0	0	0	0	0	12,292	12,292	12,625
2029	13,347	2,354	9,571	0	25,271	0	0	0	0	0	12,441	12,441	12,830
2030	13,605	2,354	9,978	0	25,938	0	0	0	0	0	12,593	12,593	13,344
2031	13,913	2,354	10,027	0	26,294	0	0	0	0	0	12,750	12,750	13,544
2032	14,189	2,354	10,569	0	27,112	0	0	0	0	0	12,911	12,911	14,201
2033	14,523	2,354	10,622	0	27,499	0	0	0	0	0	13,076	13,076	14,423
2034	14,791	2,354	11,247	0	28,392	0	0	0	0	0	13,246	13,246	15,146
2035	15,228	2,354	11,170	0	28,751	0	0	0	0	0	13,421	13,421	15,330
NOMINAL	321,747	60,493	241,088	0	623,328	0	0	0	4,493	24,558	301,671	330,722	292,606
NPV	100,635	19,844	73,416	0	193,895	0	0	0	3,283	17,891	94,471	115,644	78,251

Utility Discount Rate = 8.1

Benefit Cost Ratio = 1.677

PROGRAM: **Home Energy Improvement Program Participant**

	BENEFITS				COSTS			
	(1) SAVINGS IN PARTICIPANT'S BILL	(2) INCENTIVE PAYMENTS	(3) OTHER PARTICIPANT'S BENEFITS	(4) **TOTAL BENEFITS**	(5) PARTICIPANT'S COST	(6) PARTICIPANT'S BILL INCREASE	(7) **TOTAL COSTS**	(8) **NET BENEFITS TO PARTICIPANTS**
YEAR	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
2006	5	10	0	15	48	0	48	-33
2007	1,996	5,290	0	7,286	9,975	0	9,975	-2,689
2008	2,910	2,234	0	5,144	4,879	0	4,879	265
2009	3,830	2,421	0	6,250	5,422	0	5,422	828
2010	5,060	2,654	0	7,714	5,763	0	5,763	1,952
2011	6,488	2,811	0	9,299	5,903	0	5,903	3,396
2012	7,990	3,061	0	11,051	6,125	0	6,125	4,926
2013	9,361	3,087	0	12,447	6,152	0	6,152	6,296
2014	10,651	2,992	0	13,643	5,999	0	5,999	7,643
2015	11,086	0	0	11,086	0	0	0	11,086
2016	11,745	0	0	11,745	0	0	0	11,745
2017	11,417	0	0	11,417	0	0	0	11,417
2018	11,531	0	0	11,531	0	0	0	11,531
2019	11,421	0	0	11,421	0	0	0	11,421
2020	11,238	0	0	11,238	0	0	0	11,238
2021	11,358	0	0	11,358	0	0	0	11,358
2022	11,481	0	0	11,481	0	0	0	11,481
2023	11,608	0	0	11,608	0	0	0	11,608
2024	11,738	0	0	11,738	0	0	0	11,738
2025	11,871	0	0	11,871	0	0	0	11,871
2026	12,007	0	0	12,007	0	0	0	12,007
2027	12,148	0	0	12,148	0	0	0	12,148
2028	12,292	0	0	12,292	0	0	0	12,292
2029	12,441	0	0	12,441	0	0	0	12,441
2030	12,593	0	0	12,593	0	0	0	12,593
2031	12,750	0	0	12,750	0	0	0	12,750
2032	12,911	0	0	12,911	0	0	0	12,911
2033	13,076	0	0	13,076	0	0	0	13,076
2034	13,246	0	0	13,246	0	0	0	13,246
2035	13,421	0	0	13,421	0	0	0	13,421
NOMINAL	301,671	24,558	0	326,229	50,265	0	50,265	275,964
NPV	94,471	17,891	0	112,362	36,584	0	36,584	75,778

Utility Discount Rate = 8.1

Benefit Cost Ratio = 3.071

PROGRAM: Home Energy Improvement Program TRC

	BENEFITS					COSTS						
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	TOTAL FUEL & O&M SAVINGS	AVOIDED T&D CAP. COSTS	AVOIDED GEN. CAP. COSTS	OTHER PARTICIPANT BENEFITS	TOTAL BENEFITS	PARTICIPANT'S COST	TOTAL FUEL & O&M INCREASE	INCREASED T&D CAP. COSTS	INCREASED GEN. CAP. COSTS	UTILITY PROGRAM COSTS	TOTAL COSTS	NET BENEFITS
YEAR	\$(000)	\$(000)	\$(000)	\$(000)	\$(000)	\$(000)	\$(000)	\$(000)	\$(000)	\$(000)	\$(000)	\$(000)
2006	5	1	0	0	5	48	0	0	0	3	51	-45
2007	2,195	503	0	0	2,697	9,975	0	0	0	985	10,960	-8,263
2008	3,840	721	1,616	0	6,177	4,879	0	0	0	422	5,301	876
2009	5,015	954	2,297	0	8,267	5,422	0	0	0	447	5,869	2,398
2010	5,559	1,208	3,001	0	9,768	5,763	0	0	0	482	6,244	3,524
2011	5,229	1,478	5,206	0	11,913	5,903	0	0	0	509	6,412	5,501
2012	8,367	1,771	4,952	0	15,090	6,125	0	0	0	553	6,678	8,412
2013	9,757	2,067	6,621	0	18,445	6,152	0	0	0	557	6,709	11,737
2014	11,823	2,354	8,952	0	23,129	5,999	0	0	0	537	6,536	16,593
2015	12,603	2,354	11,417	0	26,374	0	0	0	0	0	0	26,374
2016	12,177	2,354	10,152	0	24,683	0	0	0	0	0	0	24,683
2017	11,761	2,354	8,497	0	22,611	0	0	0	0	0	0	22,611
2018	11,793	2,354	9,657	0	23,804	0	0	0	0	0	0	23,804
2019	11,720	2,354	8,891	0	22,966	0	0	0	0	0	0	22,966
2020	12,053	2,354	11,725	0	26,132	0	0	0	0	0	0	26,132
2021	12,028	2,354	10,918	0	25,300	0	0	0	0	0	0	25,300
2022	11,779	2,354	9,773	0	23,906	0	0	0	0	0	0	23,906
2023	11,840	2,354	9,219	0	23,414	0	0	0	0	0	0	23,414
2024	11,950	2,354	8,637	0	22,941	0	0	0	0	0	0	22,941
2025	12,326	2,354	8,810	0	23,490	0	0	0	0	0	0	23,490
2026	12,515	2,354	8,852	0	23,722	0	0	0	0	0	0	23,722
2027	12,817	2,354	9,150	0	24,320	0	0	0	0	0	0	24,320
2028	13,004	2,354	9,559	0	24,917	0	0	0	0	0	0	24,917
2029	13,347	2,354	9,571	0	25,271	0	0	0	0	0	0	25,271
2030	13,605	2,354	9,978	0	25,938	0	0	0	0	0	0	25,938
2031	13,913	2,354	10,027	0	26,294	0	0	0	0	0	0	26,294
2032	14,189	2,354	10,569	0	27,112	0	0	0	0	0	0	27,112
2033	14,523	2,354	10,622	0	27,499	0	0	0	0	0	0	27,499
2034	14,791	2,354	11,247	0	28,392	0	0	0	0	0	0	28,392
2035	15,228	2,354	11,170	0	28,751	0	0	0	0	0	0	28,751
NOMINAL	321,747	60,493	241,088	0	623,328	50,265	0	0	0	4,493	54,758	568,570
NPV	100,635	19,844	73,416	0	193,895	36,584	0	0	0	3,283	39,867	154,029

Utility Discount Rate = 8.1

Benefit Cost Ratio = 4.864

RESIDENTIAL NEW CONSTRUCTION

Program Start Date: 1995
Program modified 2000, 2004, 2006
Proposed modification for 2007

Program Description

The New Construction program is an "umbrella" program for the New Construction, single family, multi-family, and manufactured home building segments. The New Construction program promotes energy efficient construction in order to provide customers with more efficient dwellings combined with improved environmental comfort. This program has three levels of participation with various options within each level. The builder is offered a choice of energy efficiency measures that more closely meet the home's design criteria. Program details such as builder qualification criteria, home certification requirements, and incentive levels for high efficient equipment promoted by this program will be presented in the Program Participation Standards. The incentives are paid to the builder.

PEF proposes to add the following measures to its previously approved program as follows:

HVAC Commissioning

This measure uses approved software to evaluate and insure proper refrigerant charge and air flow per manufacture specifications. The proposed incentive is $50 per unit.

Window Film and Window Screen

This portion of the program involves the installation of qualifying shading coefficient film or screen on the windows facing east, west, and south. The proposed incentive is $100 for installing window film or window screen. Only one incentive would apply per home.

Reflective Roof Single Family

This portion of the program provides an incentive for the installation of reflective roof material on the home. The proposed incentive is $100 per home.

Attic Spray-On Foam Insulation

This portion of the program provides an incentive for adding foam insulation above the ceiling area by paying a portion of the installed cost. The proposed incentive will be $100 per home.

Wall Insulation

This portion of the program provides an incentive to add insulation to the block wall area adjacent to conditioned space beyond code requirements by paying a portion of the installed cost. The proposed incentive is $200 per home.

Conditioned Space Air Handler

This portion of the program will provide a $50 incentive for locating the air handler in conditioned space. The proposed incentive would apply upon conversion of the design plan to accommodate the location of the air handler to conditioned space.

Energy Recovery Ventilation

This program measure promotes the installation of high efficiency energy recovery ventilation (ERV) units in the conditioned air stream for homes with whole house electric heat pump systems. The proposed incentive will be $150 per home.

Projected Program Participation

Cumulative participation estimates for the program are shown in the table below.

Residential New Construction Table for 2006 DSM Modification Filing

Year	Total Number of Customers (1)	Total Number of Eligible Customers (2)	Annual Number of Measures/ Participants (3)	Cumulative Penetration Level (%)
2007	1,452,431	28,982	20,978	72%
2008	1,481,473	58,024	42,216	73%
2009	1,509,934	86,485	63,504	73%
2010	1,538,271	114,822	84,792	74%
2011	1,566,662	143,213	106,080	74%
2012	1,595,236	171,787	127,368	74%
2013	1,623,967	200,518	148,656	74%
2014	1,652,629	229,180	169,944	74%

1. *Total Number of Customers is the forecast of all residential customers, from the August 2006 Forecast.*
2. *Total number of eligible new homes constructed in PEF's territory.*
3. *Annual Number of Measure Participants is the projected number of cumulative measure applications from all measures promoted by this program. Because customer can install multiple measures, the actual number of participants will be less.*

Projected Savings

Total program savings were developed by first estimating the total savings for each individual measure based on each measure's (1) per customer savings and, (2) annual projected participation. The total projected program savings were then computed as the sum of the individual measure savings, and are shown in the following tables.

Residential New Construction - At the Meter						
Year	Per Customer KWH Reduction	Per Customer Winter KW Reduction	Per Customer Summer KW Reduction	Total Annual KWH Reduction	Total Annual Winter KW Reduction	Total Annual Summer KW Reduction
2007	298	0.728	0.35	6,248,862	15,276	7,391
2008	301	0.727	0.35	12,713,044	30,706	14,940
2009	302	0.727	0.35	19,200,176	46,180	22,482
2010	303	0.727	0.35	25,687,308	61,653	30,025
2011	303	0.727	0.35	32,174,440	77,127	37,567
2012	304	0.727	0.35	38,661,572	92,600	45,110
2013	304	0.727	0.35	45,148,704	108,073	52,652
2014	304	0.727	0.35	51,635,836	123,547	60,195

Residential New Construction - At the Generator						
Year	Per Customer KWH Reduction	Per Customer Winter KW Reduction	Per Customer Summer KW Reduction	Total Annual KWH Reduction	Total Annual Winter KW Reduction	Total Annual Summer KW Reduction
2007	317	0.776	0.375	6,658,662	16,277	7,876
2008	321	0.775	0.377	13,546,765	32,720	15,919
2009	322	0.775	0.377	20,459,324	49,208	23,956
2010	323	0.775	0.377	27,371,882	65,696	31,994
2011	323	0.775	0.377	34,284,440	82,184	40,031
2012	323	0.775	0.377	41,196,998	98,673	48,068
2013	324	0.775	0.377	48,109,556	115,161	56,105
2014	324	0.775	0.377	55,022,115	131,649	64,142

Cost Effectiveness Analysis

Residential New Construction				
Cost-Effectiveness Test	NPV Benefits $(000)	NPV Costs $(000)	NPV Net Benefits $(000)	B/C Ratio
Rate Impact Measure	140,833	61,998	78,835	2.27
Participant	54,742	22,062	32,680	2.48
Total Resource Cost	140,833	29,318	111,515	4.80

PROGRAM: **Residential New Construction Program RIM**

	BENEFITS					COSTS							
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
YEAR	TOTAL FUEL & O&M SAVINGS $(000)	AVOIDED T&D CAP. COSTS $(000)	AVOIDED GEN. CAP. COSTS $(000)	REVENUE GAINS $(000)	TOTAL BENEFITS $(000)	TOTAL FUEL & O&M INCREASE $(000)	INCREASED T&D CAP. COSTS $(000)	INCREASED GEN. CAP. COSTS $(000)	UTILITY PROGRAM COSTS $(000)	INCENTIVE PAYMENTS $(000)	REVENUE LOSSES $(000)	TOTAL COSTS $(000)	NET BENEFITS $(000)
2006	0	0	0	0	0	0	0	0	0	0	0	0	0
2007	855	246	0	0	1,100	0	0	0	1,231	293	664	2,188	-1,088
2008	2,226	496	1,176	0	3,898	0	0	0	1,278	330	1,376	2,984	914
2009	3,222	745	1,821	0	5,787	0	0	0	1,274	313	2,047	3,634	2,153
2010	3,830	994	2,563	0	7,386	0	0	0	1,274	313	2,832	4,419	2,967
2011	3,392	1,242	4,569	0	9,204	0	0	0	1,274	313	3,698	5,285	3,919
2012	5,800	1,491	4,199	0	11,491	0	0	0	1,274	313	4,548	6,135	5,356
2013	6,769	1,740	5,402	0	13,912	0	0	0	1,274	313	5,316	6,903	7,009
2014	7,976	1,989	6,657	0	16,622	0	0	0	1,274	313	6,063	7,650	8,972
2015	8,331	1,989	7,921	0	18,241	0	0	0	0	0	6,311	6,311	11,930
2016	8,210	1,989	7,419	0	17,618	0	0	0	0	0	6,686	6,686	10,933
2017	8,012	1,989	6,550	0	16,551	0	0	0	0	0	6,499	6,499	10,052
2018	8,046	1,989	7,237	0	17,272	0	0	0	0	0	6,564	6,564	10,708
2019	8,012	1,989	6,827	0	16,828	0	0	0	0	0	6,501	6,501	10,327
2020	8,129	1,989	8,336	0	18,454	0	0	0	0	0	6,397	6,397	12,057
2021	8,157	1,989	7,981	0	18,126	0	0	0	0	0	6,466	6,466	11,660
2022	8,077	1,989	7,433	0	17,499	0	0	0	0	0	6,536	6,536	10,963
2023	8,129	1,989	7,181	0	17,299	0	0	0	0	0	6,608	6,608	10,691
2024	8,223	1,989	6,942	0	17,154	0	0	0	0	0	6,682	6,682	10,472
2025	8,458	1,989	7,095	0	17,542	0	0	0	0	0	6,758	6,758	10,784
2026	8,578	1,989	7,165	0	17,733	0	0	0	0	0	6,836	6,836	10,897
2027	8,766	1,989	7,370	0	18,125	0	0	0	0	0	6,916	6,916	11,210
2028	8,900	1,989	7,694	0	18,584	0	0	0	0	0	6,998	6,998	11,586
2029	9,122	1,989	7,781	0	18,892	0	0	0	0	0	7,083	7,083	11,809
2030	9,279	1,989	8,032	0	19,300	0	0	0	0	0	7,169	7,169	12,130
2031	9,494	1,989	8,163	0	19,646	0	0	0	0	0	7,259	7,259	12,387
2032	9,661	1,989	8,509	0	20,159	0	0	0	0	0	7,350	7,350	12,810
2033	9,893	1,989	8,652	0	20,534	0	0	0	0	0	7,444	7,444	13,090
2034	10,058	1,989	9,057	0	21,103	0	0	0	0	0	7,541	7,541	13,563
2035	10,326	1,989	9,047	0	21,362	0	0	0	0	0	7,640	7,640	13,722
NOMINAL	217,927	50,715	188,780	0	457,422	0	0	0	10,151	2,501	170,786	183,439	273,983
NPV	67,383	16,424	57,026	0	140,833	0	0	0	7,256	1,788	52,954	61,998	78,835

Utility Discount Rate = 8.1

Benefit Cost Ratio = 2.272

PROGRAM: **Residential New Construction Program Participant**

YEAR	BENEFITS (1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT'S BENEFITS $(000)	(4) TOTAL BENEFITS $(000)	COSTS (5) PARTICIPANT'S COST $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) TOTAL COSTS $(000)	(8) NET BENEFITS TO PARTICIPANTS $(000)
2006	0	0	0	0	0	0	0	0
2007	664	293	0	957	3,741	0	3,741	-2,784
2008	1,376	330	0	1,706	3,898	0	3,898	-2,192
2009	2,047	313	0	2,360	3,871	0	3,871	-1,510
2010	2,832	313	0	3,146	3,871	0	3,871	-725
2011	3,698	313	0	4,011	3,871	0	3,871	141
2012	4,548	313	0	4,861	3,871	0	3,871	991
2013	5,316	313	0	5,629	3,871	0	3,871	1,759
2014	6,063	313	0	6,376	3,871	0	3,871	2,506
2015	6,311	0	0	6,311	0	0	0	6,311
2016	6,686	0	0	6,686	0	0	0	6,686
2017	6,499	0	0	6,499	0	0	0	6,499
2018	6,564	0	0	6,564	0	0	0	6,564
2019	6,501	0	0	6,501	0	0	0	6,501
2020	6,397	0	0	6,397	0	0	0	6,397
2021	6,466	0	0	6,466	0	0	0	6,466
2022	6,536	0	0	6,536	0	0	0	6,536
2023	6,608	0	0	6,608	0	0	0	6,608
2024	6,682	0	0	6,682	0	0	0	6,682
2025	6,758	0	0	6,758	0	0	0	6,758
2026	6,836	0	0	6,836	0	0	0	6,836
2027	6,916	0	0	6,916	0	0	0	6,916
2028	6,998	0	0	6,998	0	0	0	6,998
2029	7,083	0	0	7,083	0	0	0	7,083
2030	7,169	0	0	7,169	0	0	0	7,169
2031	7,259	0	0	7,259	0	0	0	7,259
2032	7,350	0	0	7,350	0	0	0	7,350
2033	7,444	0	0	7,444	0	0	0	7,444
2034	7,541	0	0	7,541	0	0	0	7,541
2035	7,640	0	0	7,640	0	0	0	7,640
NOMINAL	170,786	2,501	0	173,288	30,862	0	30,862	142,425
NPV	52,954	1,788	0	54,742	22,062	0	22,062	32,680

Utility Discount Rate = 8.1

Benefit Cost Ratio = 2.481

PROGRAM: **Residential New Construction Program TRC**

	BENEFITS					COSTS						
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
YEAR	TOTAL FUEL & O&M SAVINGS $(000)	AVOIDED T&D CAP. COSTS $(000)	AVOIDED GEN. CAP. COSTS $(000)	OTHER PARTICIPANT BENEFITS $(000)	**TOTAL BENEFITS** $(000)	PARTICIPANT'S COST $(000)	TOTAL FUEL & O&M INCREASE $(000)	INCREASED T&D CAP. COSTS $(000)	INCREASED GEN. CAP. COSTS $(000)	UTILITY PROGRAM COSTS $(000)	**TOTAL COSTS** $(000)	**NET BENEFITS** $(000)
2006	0	0	0	0	0	0	0	0	0	0	0	0
2007	855	246	0	0	1,100	3,741	0	0	0	1,231	4,972	-3,872
2008	2,226	496	1,176	0	3,898	3,898	0	0	0	1,278	5,176	-1,279
2009	3,222	745	1,821	0	5,787	3,871	0	0	0	1,274	5,144	643
2010	3,830	994	2,563	0	7,386	3,871	0	0	0	1,274	5,144	2,242
2011	3,392	1,242	4,569	0	9,204	3,871	0	0	0	1,274	5,144	4,060
2012	5,800	1,491	4,199	0	11,491	3,871	0	0	0	1,274	5,144	6,347
2013	6,769	1,740	5,402	0	13,912	3,871	0	0	0	1,274	5,144	8,767
2014	7,976	1,989	6,657	0	16,622	3,871	0	0	0	1,274	5,144	11,478
2015	8,331	1,989	7,921	0	18,241	0	0	0	0	0	0	18,241
2016	8,210	1,989	7,419	0	17,618	0	0	0	0	0	0	17,618
2017	8,012	1,989	6,550	0	16,551	0	0	0	0	0	0	16,551
2018	8,046	1,989	7,237	0	17,272	0	0	0	0	0	0	17,272
2019	8,012	1,989	6,827	0	16,828	0	0	0	0	0	0	16,828
2020	8,129	1,989	8,336	0	18,454	0	0	0	0	0	0	18,454
2021	8,157	1,989	7,981	0	18,126	0	0	0	0	0	0	18,126
2022	8,077	1,989	7,433	0	17,499	0	0	0	0	0	0	17,499
2023	8,129	1,989	7,181	0	17,299	0	0	0	0	0	0	17,299
2024	8,223	1,989	6,942	0	17,154	0	0	0	0	0	0	17,154
2025	8,458	1,989	7,095	0	17,542	0	0	0	0	0	0	17,542
2026	8,578	1,989	7,165	0	17,733	0	0	0	0	0	0	17,733
2027	8,766	1,989	7,370	0	18,125	0	0	0	0	0	0	18,125
2028	8,900	1,989	7,694	0	18,584	0	0	0	0	0	0	18,584
2029	9,122	1,989	7,781	0	18,892	0	0	0	0	0	0	18,892
2030	9,279	1,989	8,032	0	19,300	0	0	0	0	0	0	19,300
2031	9,494	1,989	8,163	0	19,646	0	0	0	0	0	0	19,646
2032	9,661	1,989	8,509	0	20,159	0	0	0	0	0	0	20,159
2033	9,893	1,989	8,652	0	20,534	0	0	0	0	0	0	20,534
2034	10,058	1,989	9,057	0	21,103	0	0	0	0	0	0	21,103
2035	10,326	1,989	9,047	0	21,362	0	0	0	0	0	0	21,362
NOMINAL	217,927	50,715	188,780	0	457,422	30,862	0	0	0	10,151	41,013	416,408
NPV	67,383	16,424	57,026	0	140,833	22,062	0	0	0	7,256	29,318	111,515

Utility Discount Rate = 8.1

Benefit Cost Ratio = 4.804

Neighborhood Energy Saver

Program Start Date: 2007

Program Description

The Neighborhood Energy Saver Program (NES) was designed by Progress Energy Florida (PEF) to assist low-income families with escalating energy costs. The goal of the NES program is to implement a comprehensive package of electric conservation measures at no cost to the customer. In addition to the installation of the conservation measures, an important component of this program is educating families on energy efficiency techniques and the promotion of behavioral changes to help customers control their energy usage. Additionally, the NES program uses a unique canvassing technique that employs a door-to-door implementation strategy with a coinciding informational and educational communications campaign. The comprehensive package of electric conservation measures will consist of the following items:

Compact Fluorescent Bulb

This measure will provide the resident with five (5) compact fluorescent bulbs to replace incandescent bulbs with the identical lumens output.

Water Heater Wrap and Insulation for Water Pipes

This portion of the program will furnish and install a hot water heater wrap and pipe insulation as identified by the Neighborhood Energy Saver Program Home Energy Evaluation form.

Water Heater Temperature Check and Adjustment

The portion of the program will provide a temperature check of the hot water heater and inform the customer of the possibility for turn-down adjustment.

Low Flow Faucet Aerator

This measure will allow for the installation of a maximum of three (3) aerators per household.

Low Flow Showerhead

This measure will allow for the installation of a maximum of two (2) low flow showerheads per household.

Water Closet Leak Detection Tablets

This portion of the program will educate the customer on the process of leak detection.

Refrigerator Coil Brush

This portion of the program will provide the customer with a coil brush.

Refrigerator Thermometer

This measure will provide for the installation of one (1) thermometer in the food compartment and one (1) thermometer in the freezer of the refrigerator.

Wall Plate Thermometer

This portion of the program will provide the installation of one (1) wall plate thermometer per home.

HVAC Winterization Kit

This measure will provide for the installation of a winterization HVAC kit for wall/window AC units if seasonably applicable. The resident will receive or have installed a maximum of three (3) kits. The customer will be educated on the proper use and value of the weatherization kit as a method of stopping air infiltration in the home.

HVAC Filters

This portion of the program will allow each customer to receive a one year supply (12) of filters.

Change Filter Calendar

This portion of the program will provide each homeowner a Progress Energy magnetic calendar to help remind them to clean or change filter monthly.

Weatherization Measures

This portion of the program will provide weather stripping, door sweeps, caulk, foam sealant, clear patch tape which will be used to reduce or stop air infiltration around doors, windows, attic doors, and where pipes enter the home. Air infiltration reduction is key to saving energy and customer comfort.

Projected Program Participation

Neighborhood Energy Saver				
Year	Total Number of Customers (1)	Total Number of Eligible Customers (2)	Annual Number of Measures	Cumulative Penetration Level %
2007	1,452,431	2,000	1,500	75%
2008	1,481,473	4,000	3,000	75%
2009	1,509,934	6,000	4,500	75%
2010	1,538,271	8,000	6,000	75%
2011	1,566,662	10,000	7,500	75%
2012	1,595,236	12,000	9,000	75%
2013	1,623,967	14,000	10,500	75%
2014	1,652,629	16,000	12,000	75%

1. *Total Number of Customers is the forecast of all residential customers, from the August 2006 Forecast.*
2. *Total number of Eligible Customers is based on 2000 expected participants per year and derived from an estimate of preliminary data from the 2000 U.S. Census.*

Projected Savings

Total program savings were developed by first estimating the total savings for each individual measure based on each measure's (1) per customer savings and, (2) annual projected participation. The total projected program savings were then computed as the sum of the individual measure savings, and are shown in the following tables.

Neighborhood Energy Saver - At the Meter						
Year	Per Customer KWH Reduction	Per Customer Winter KW Reduction	Per Customer Summer KW Reduction	Total Annual KWH Reduction	Total Annual Winter KW Reduction	Total Annual Summer KW Reduction
2007	2596	0.59	0.92	3,893,627	892	1,385
2008	2596	0.59	0.92	7,787,254	1,784	2,770
2009	2596	0.59	0.92	11,680,881	2,676	4,155
2010	2596	0.59	0.92	15,574,507	3,568	5,540
2011	2596	0.59	0.92	19,468,134	4,460	6,925
2012	2596	0.59	0.92	23,361,761	5,352	8,310
2013	2596	0.59	0.92	27,255,388	6,244	9,696
2014	2596	0.59	0.92	31,148,279	7,135	11,080

Neighborhood Energy Saver - At the Generator						
Year	Per Customer KWH Reduction	Per Customer Winter KW Reduction	Per Customer Summer KW Reduction	Total Annual KWH Reduction	Total Annual Winter KW Reduction	Total Annual Summer KW Reduction
2007	2766	0.634	0.984	4,148,971	950	1,476
2008	2766	0.634	0.984	8,297,942	1,901	2,952
2009	2766	0.634	0.984	12,446,913	2,851	4,428
2010	2766	0.634	0.984	16,595,884	3,802	5,904
2011	2766	0.634	0.984	20,744,854	4,752	7,380
2012	2766	0.634	0.984	24,893,825	5,703	8,855
2013	2766	0.634	0.984	29,042,796	6,653	10,331
2014	2766	0.634	0.984	33,190,983	7,603	11,807

Cost Effectiveness Analysis

Neighborhood Energy Saver				
Cost-Effectiveness Test	NPV Benefits $(000)	NPV Costs $(000)	NPV Net Benefits $(000)	B/C Ratio
Rate Impact Measure	26,266	23,106	3,160	1.14
Participant	21,878	0	21,878	N/A
Total Resource Cost	26,266	1,228	25,039	21.40

PROGRAM: **Neighborhood Energy Saver RIM**

	BENEFITS						COSTS							
	(1)	(2)	(3)	(4)	(5)		(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
YEAR	TOTAL FUEL & O&M SAVINGS $(000)	AVOIDED T&D CAP. COSTS $(000)	AVOIDED GEN. CAP. COSTS $(000)	REVENUE GAINS $(000)	TOTAL BENEFITS $(000)		TOTAL FUEL & O&M INCREASE $(000)	INCREASED T&D CAP. COSTS $(000)	INCREASED GEN. CAP. COSTS $(000)	UTILITY PROGRAM COSTS $(000)	INCENTIVE PAYMENTS $(000)	REVENUE LOSSES $(000)	TOTAL COSTS $(000)	NET BENEFITS $(000)
2006	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2007	218	28	0	0	246	0	0	0	0	184	91	239	514	-268
2008	488	56	141	0	685	0	0	0	0	184	91	482	757	-72
2009	722	83	223	0	1,028	0	0	0	0	184	91	713	987	41
2010	826	111	304	0	1,241	0	0	0	0	184	91	983	1,257	-17
2011	889	139	555	0	1,584	0	0	0	0	184	91	1,281	1,556	28
2012	1,280	167	485	0	1,931	0	0	0	0	184	91	1,574	1,848	83
2013	1,415	194	599	0	2,208	0	0	0	0	184	91	1,838	2,112	96
2014	1,635	223	704	0	2,562	0	0	0	0	184	91	2,094	2,369	193
2015	1,785	250	843	0	2,879	0	0	0	0	184	91	2,453	2,727	152
2016	2,043	278	940	0	3,261	0	0	0	0	184	91	2,887	3,161	100
2017	2,134	278	930	0	3,343	0	0	0	0	0	0	2,806	2,806	537
2018	2,023	278	968	0	3,269	0	0	0	0	0	0	2,834	2,834	435
2019	2,084	278	973	0	3,335	0	0	0	0	0	0	2,807	2,807	528
2020	1,921	278	1,036	0	3,235	0	0	0	0	0	0	2,762	2,762	472
2021	2,008	278	1,052	0	3,338	0	0	0	0	0	0	2,792	2,792	546
2022	2,064	278	1,059	0	3,402	0	0	0	0	0	0	2,822	2,822	580
2023	2,141	278	1,067	0	3,486	0	0	0	0	0	0	2,853	2,853	633
2024	2,208	278	1,073	0	3,559	0	0	0	0	0	0	2,885	2,885	675
2025	2,287	278	1,100	0	3,665	0	0	0	0	0	0	2,918	2,918	747
2026	2,339	278	1,123	0	3,741	0	0	0	0	0	0	2,951	2,951	790
2027	2,396	278	1,151	0	3,825	0	0	0	0	0	0	2,986	2,986	839
2028	2,424	278	1,193	0	3,895	0	0	0	0	0	0	3,021	3,021	874
2029	2,511	278	1,219	0	4,008	0	0	0	0	0	0	3,058	3,058	951
2030	2,551	278	1,250	0	4,079	0	0	0	0	0	0	3,095	3,095	984
2031	2,633	278	1,277	0	4,189	0	0	0	0	0	0	3,134	3,134	1,055
2032	2,660	278	1,320	0	4,258	0	0	0	0	0	0	3,173	3,173	1,085
2033	2,751	278	1,349	0	4,378	0	0	0	0	0	0	3,214	3,214	1,164
2034	2,795	278	1,404	0	4,477	0	0	0	0	0	0	3,256	3,256	1,222
2035	2,904	278	1,424	0	4,606	0	0	0	0	0	0	3,298	3,298	1,307
NOMINAL	56,135	6,813	26,762	0	89,710		0	0	0	1,838	907	71,205	73,950	15,760
NPV	16,566	2,120	7,581	0	26,266		0	0	0	1,228	606	21,272	23,106	3,160

Utility Discount Rate = 8.1

Benefit Cost Ratio = 1.137

PROGRAM: **Neighborhood Energy Saver Participant**

	BENEFITS					COSTS			
	(1)	(2)	(3)	(4)		(5)	(6)	(7)	(8)
YEAR	SAVINGS IN PARTICIPANT'S BILL $(000)	INCENTIVE PAYMENTS $(000)	OTHER PARTICIPANT'S BENEFITS $(000)	TOTAL BENEFITS $(000)		PARTICIPANT'S COST $(000)	PARTICIPANT'S BILL INCREASE $(000)	TOTAL COSTS $(000)	NET BENEFITS TO PARTICIPANTS $(000)
2006	0	0	0	0	0	0	0	0	0
2007	239	91	0	330	0	0	0	0	330
2008	482	91	0	573	0	0	0	0	573
2009	713	91	0	803	0	0	0	0	803
2010	983	91	0	1,074	0	0	0	0	1,074
2011	1,281	91	0	1,372	0	0	0	0	1,372
2012	1,574	91	0	1,664	0	0	0	0	1,664
2013	1,838	91	0	1,928	0	0	0	0	1,928
2014	2,094	91	0	2,185	0	0	0	0	2,185
2015	2,453	91	0	2,543	0	0	0	0	2,543
2016	2,887	91	0	2,977	0	0	0	0	2,977
2017	2,806	0	0	2,806	0	0	0	0	2,806
2018	2,834	0	0	2,834	0	0	0	0	2,834
2019	2,807	0	0	2,807	0	0	0	0	2,807
2020	2,762	0	0	2,762	0	0	0	0	2,762
2021	2,792	0	0	2,792	0	0	0	0	2,792
2022	2,822	0	0	2,822	0	0	0	0	2,822
2023	2,853	0	0	2,853	0	0	0	0	2,853
2024	2,885	0	0	2,885	0	0	0	0	2,885
2025	2,918	0	0	2,918	0	0	0	0	2,918
2026	2,951	0	0	2,951	0	0	0	0	2,951
2027	2,986	0	0	2,986	0	0	0	0	2,986
2028	3,021	0	0	3,021	0	0	0	0	3,021
2029	3,058	0	0	3,058	0	0	0	0	3,058
2030	3,095	0	0	3,095	0	0	0	0	3,095
2031	3,134	0	0	3,134	0	0	0	0	3,134
2032	3,173	0	0	3,173	0	0	0	0	3,173
2033	3,214	0	0	3,214	0	0	0	0	3,214
2034	3,256	0	0	3,256	0	0	0	0	3,256
2035	3,298	0	0	3,298	0	0	0	0	3,298
NOMINAL	71,205	907	0	72,113		0	0	0	72,113
NPV	21,272	606	0	21,878		0	0	0	21,878

Utility Discount Rate = 8.1
Benefit Cost Ratio = 9999

PROGRAM: **Neighborhood Energy Saver TRC**

	BENEFITS						COSTS						
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) TOTAL BENEFITS $(000)		(6) PARTICIPANT'S COST $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) TOTAL COSTS $(000)	(12) NET BENEFITS $(000)
2006	0	0	0	0	0	0	0	0	0	0	0	0	0
2007	218	28	0	0	246	0	0	0	0	0	184	184	62
2008	488	56	141	0	685	0	0	0	0	0	184	184	501
2009	722	83	223	0	1,028	0	0	0	0	0	184	184	844
2010	826	111	304	0	1,241	0	0	0	0	0	184	184	1,057
2011	889	139	555	0	1,584	0	0	0	0	0	184	184	1,400
2012	1,280	167	485	0	1,931	0	0	0	0	0	184	184	1,747
2013	1,415	194	599	0	2,208	0	0	0	0	0	184	184	2,024
2014	1,635	223	704	0	2,562	0	0	0	0	0	184	184	2,378
2015	1,785	250	843	0	2,879	0	0	0	0	0	184	184	2,695
2016	2,043	278	940	0	3,261	0	0	0	0	0	184	184	3,077
2017	2,134	278	930	0	3,343	0	0	0	0	0	0	0	3,343
2018	2,023	278	968	0	3,269	0	0	0	0	0	0	0	3,269
2019	2,084	278	973	0	3,335	0	0	0	0	0	0	0	3,335
2020	1,921	278	1,036	0	3,235	0	0	0	0	0	0	0	3,235
2021	2,008	278	1,052	0	3,338	0	0	0	0	0	0	0	3,338
2022	2,064	278	1,059	0	3,402	0	0	0	0	0	0	0	3,402
2023	2,141	278	1,067	0	3,486	0	0	0	0	0	0	0	3,486
2024	2,208	278	1,073	0	3,559	0	0	0	0	0	0	0	3,559
2025	2,287	278	1,100	0	3,665	0	0	0	0	0	0	0	3,665
2026	2,339	278	1,123	0	3,741	0	0	0	0	0	0	0	3,741
2027	2,396	278	1,151	0	3,825	0	0	0	0	0	0	0	3,825
2028	2,424	278	1,193	0	3,895	0	0	0	0	0	0	0	3,895
2029	2,511	278	1,219	0	4,008	0	0	0	0	0	0	0	4,008
2030	2,551	278	1,250	0	4,079	0	0	0	0	0	0	0	4,079
2031	2,633	278	1,277	0	4,189	0	0	0	0	0	0	0	4,189
2032	2,660	278	1,320	0	4,258	0	0	0	0	0	0	0	4,258
2033	2,751	278	1,349	0	4,378	0	0	0	0	0	0	0	4,378
2034	2,795	278	1,404	0	4,477	0	0	0	0	0	0	0	4,477
2035	2,904	278	1,424	0	4,606	0	0	0	0	0	0	0	4,606
NOMINAL	56,135	6,813	26,762	0	89,710		0	0	0	0	1,838	1,838	87,872
NPV	16,566	2,120	7,581	0	26,266		0	0	0	0	1,228	1,228	25,039

Utility Discount Rate = 8.1

Benefit Cost Ratio = 21.397

RENEWABLE ENERGY PROGRAM

Program Start Date: Proposed start date of 2007

Program Description

The Renewable Energy program is a new program designed to provide an incentive for renewable energy technology used in conjunction with energy management. This voluntary customer program allows PEF to reduce peak demand and defer generation construction. Renewable energy technology supplements a portion of consumer demand, while peak demand is reduced by interrupting service to selected electrical equipment with radio controlled switches installed on the customer's premises. These controlled interruptions are at PEF's option, during specified time periods, and coincident with hours of peak demand.

PEF has determined this program is cost-effective under the RIM test. This program allows the promotion of select "green" or renewable energy alternatives when they are bundled with the Energy Management program.

Specific eligibility requirements for the initial measures promoted in this program will be presented in the "Program Participation Standards."

PEF proposes the following measures for initial implementation of this program:

Solar Water Heater with Energy Management

This measure encourages residential customers to install a solar thermal water heating system. The customer must have whole house electric cooling, electric water heating, and electric heating to be eligible for this program. Pool heaters and photovoltaic systems would not qualify. In order to qualify for this incentive, the heating, air conditioning, and water heating systems must be on the Energy Management program. The proposed incentive is $450 per residence plus an associated Energy Management program credit, as stipulated in rate schedule attached as Appendix C.

Solar Photovoltaics with Energy Management

This measure promotes environmental stewardship and renewable energy education through the installation of solar energy systems at schools within Progress Energy Florida's service territory. Customers participating in the Winter-Only Energy Management or Year Round Energy Management Plan can elect to donate their monthly credit toward the Solar Photovoltaics with Energy Management Fund. The fund will accumulate associated participant credits for a period of 2 years, at which time the customer may elect to renew for an additional 2 years.

All proceeds collected from participating customers, and their associated monthly credits, will be used to promote photovoltaics and renewable energy educational opportunities.

Projected Program Participation

Cumulative participation estimates for the program are shown in the table below.

Renewable Energy Table for 2006 DSM Modification Filing				
Year	Total Number of Customers (1)	Total Number of Eligible Customers (2)	Annual Number of Measure Participants	Cumulative Penetration Level (%)
2007	1,452,431	347,000	1,066	0.31%
2008	1,481,473	357,000	1,503	0.42%
2009	1,509,934	382,000	2,035	0.53%
2010	1,538,271	407,000	2,617	0.64%
2011	1,566,662	427,000	3,214	0.75%
2012	1,595,236	437,000	3,771	0.86%
2013	1,623,967	447,000	4,348	0.97%
2014	1,652,629	457,000	4,945	1.08%

1. *Total Number of Customers is the forecast of all residential customers, from the August 2006 Forecast.*
2. *Total number of Eligible Customers is based on Current and projected residential energy management participation.*

Projected Savings

Total program savings were developed by estimating the total savings for the Solar Water Heater with Energy Management measure based on the measure's (1) per customer savings and, (2) annual projected participation. (3) kW and kWh contribution are per solar water with energy management only. Total Program savings are shown in the following tables.

Renewable Energy - At the Meter						
Year	Per Customer KWH Reduction	Per Customer Winter KW Reduction	Per Customer Summer KW Reduction	Total Annual KWH Reduction	Total Annual Winter KW Reduction	Total Annual Summer KW Reduction
2007	911	0.040	0.27	22,775	1	7
2008	911	0.040	0.27	68,325	3	20
2009	911	0.040	0.27	113,875	5	34
2010	911	0.040	0.27	159,425	7	47
2011	911	0.040	0.27	204,975	9	61
2012	911	0.040	0.27	250,525	11	74
2013	911	0.040	0.27	296,075	13	88
2014	911	0.040	0.27	341,625	15	101

Renewable Energy - At the Generator						
Year	Per Customer KWH Reduction	Per Customer Winter KW Reduction	Per Customer Summer KW Reduction	Total Annual KWH Reduction	Total Annual Winter KW Reduction	Total Annual Summer KW Reduction
2007	971	0.043	0.288	24,269	1	7
2008	971	0.043	0.288	72,806	3	22
2009	971	0.043	0.288	121,343	5	36
2010	971	0.043	0.288	169,880	7	50
2011	971	0.043	0.288	218,417	10	65
2012	971	0.043	0.288	266,954	12	79
2013	971	0.043	0.288	315,492	14	94
2014	971	0.043	0.288	364,029	16	108

Cost Effectiveness Analysis

Renewable Energy				
Cost-Effectiveness Test	NPV Benefits $(000)	NPV Costs $(000)	NPV Net Benefits $(000)	B/C Ratio
Rate Impact Measure	1,116	737	379	1.51
Participant	483	474	9	1.02
Total Resource Cost	1,116	728	388	1.53

PROGRAM: Residential Year-Round LM with Solar WH RIM

	BENEFITS					COSTS							
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
YEAR	TOTAL FUEL & O&M SAVINGS $(000)	AVOIDED T&D CAP. COSTS $(000)	AVOIDED GEN. CAP. COSTS $(000)	REVENUE GAINS $(000)	TOTAL BENEFITS $(000)	TOTAL FUEL & O&M INCREASE $(000)	INCREASED T&D CAP. COSTS $(000)	INCREASED GEN. CAP. COSTS $(000)	UTILITY PROGRAM COSTS $(000)	INCENTIVE PAYMENTS $(000)	REVENUE LOSSES $(000)	TOTAL COSTS $(000)	NET BENEFITS $(000)
2006	0	0	0	0	0	0	0	0	0	0	0	0	0
2007	2	0	0	0	2	0	0	0	8	12	2	22	-20
2008	8	0	7	0	16	0	0	0	18	24	7	49	-33
2009	16	1	13	0	30	0	0	0	21	25	11	57	-27
2010	21	1	19	0	40	0	0	0	24	25	16	66	-26
2011	15	1	32	0	48	0	0	0	27	26	22	75	-27
2012	32	1	31	0	64	0	0	0	30	27	27	84	-20
2013	37	2	39	0	78	0	0	0	33	28	32	93	-15
2014	59	2	78	0	138	0	0	0	36	29	37	102	37
2015	60	2	82	0	144	0	0	0	23	6	38	67	77
2016	58	2	83	0	143	0	0	0	23	6	41	69	74
2017	58	2	83	0	143	0	0	0	23	6	40	68	75
2018	59	2	88	0	149	0	0	0	23	6	40	68	80
2019	58	2	89	0	149	0	0	0	23	6	39	68	81
2020	58	2	96	0	156	0	0	0	23	6	39	67	89
2021	59	2	97	0	158	0	0	0	23	6	39	68	91
2022	60	2	98	0	160	0	0	0	23	6	40	68	92
2023	58	2	100	0	159	0	0	0	23	6	40	69	91
2024	60	2	101	0	162	0	0	0	23	6	41	69	93
2025	59	2	103	0	164	0	0	0	23	6	41	70	94
2026	60	2	106	0	168	0	0	0	23	6	42	70	98
2027	61	2	109	0	172	0	0	0	23	6	42	71	102
2028	62	2	112	0	176	0	0	0	23	6	43	71	105
2029	62	2	115	0	179	0	0	0	23	6	43	72	107
2030	62	2	118	0	182	0	0	0	23	6	44	72	110
2031	63	2	122	0	186	0	0	0	23	6	44	73	113
2032	63	2	125	0	189	0	0	0	23	6	45	73	116
2033	65	2	128	0	195	0	0	0	23	6	45	74	122
2034	67	2	132	0	200	0	0	0	23	6	46	74	126
2035	67	2	136	0	204	0	0	0	23	6	47	75	129
NOMINAL	1,463	47	2,444	0	3,955	0	0	0	672	320	1,031	2,023	1,932
NPV	438	15	663	0	1,116	0	0	0	254	167	316	737	379

Utility Discount Rate = 8.1

Benefit Cost Ratio = 1.514

PROGRAM: Residential Year-Round LM with Solar WH Participants

	BENEFITS				COSTS			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
YEAR	SAVINGS IN PARTICIPANT'S BILL $(000)	INCENTIVE PAYMENTS $(000)	OTHER PARTICIPANT'S BENEFITS $(000)	TOTAL BENEFITS $(000)	PARTICIPANT'S COST $(000)	PARTICIPANT'S BILL INCREASE $(000)	TOTAL COSTS $(000)	NET BENEFITS TO PARTICIPANTS $(000)
2006	0	0	0	0	0	0	0	0
2007	2	12	0	14	45	0	45	-31
2008	7	24	0	30	90	0	90	-60
2009	11	25	0	36	90	0	90	-54
2010	16	25	0	41	90	0	90	-49
2011	22	26	0	48	90	0	90	-42
2012	27	27	0	54	90	0	90	-36
2013	32	28	0	60	90	0	90	-30
2014	37	29	0	65	90	0	90	-25
2015	38	6	0	44	0	0	0	44
2016	41	6	0	47	0	0	0	47
2017	40	6	0	46	0	0	0	46
2018	40	6	0	46	0	0	0	46
2019	39	6	0	45	0	0	0	45
2020	39	6	0	45	0	0	0	45
2021	39	6	0	45	0	0	0	45
2022	40	6	0	46	0	0	0	46
2023	40	6	0	46	0	0	0	46
2024	41	6	0	47	0	0	0	47
2025	41	6	0	47	0	0	0	47
2026	42	6	0	48	0	0	0	48
2027	42	6	0	48	0	0	0	48
2028	43	6	0	49	0	0	0	49
2029	43	6	0	49	0	0	0	49
2030	44	6	0	50	0	0	0	50
2031	44	6	0	50	0	0	0	50
2032	45	6	0	51	0	0	0	51
2033	45	6	0	51	0	0	0	51
2034	46	6	0	52	0	0	0	52
2035	47	6	0	53	0	0	0	53
NOMINAL	1,031	320	0	1,351	675	0	675	676
NPV	316	167	0	483	474	0	474	9

Utility Discount Rate = 8.1

Benefit Cost Ratio = 1.019

PROGRAM: **Residential Year-Round LM with Solar WH TRC**

	BENEFITS					COSTS						
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) TOTAL BENEFITS $(000)	(6) PARTICIPANT'S COST $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) TOTAL COSTS $(000)	(12) NET BENEFITS $(000)
2006	0	0	0	0	0	0	0	0	0	0	0	0
2007	2	0	0	0	2	45	0	0	0	8	53	-51
2008	8	0	7	0	16	90	0	0	0	18	108	-92
2009	16	1	13	0	30	90	0	0	0	21	111	-82
2010	21	1	19	0	40	90	0	0	0	24	114	-74
2011	15	1	32	0	48	90	0	0	0	27	117	-69
2012	32	1	31	0	64	90	0	0	0	30	120	-56
2013	37	2	39	0	78	90	0	0	0	33	123	-45
2014	59	2	78	0	138	90	0	0	0	36	126	12
2015	60	2	82	0	144	0	0	0	0	23	23	121
2016	58	2	83	0	143	0	0	0	0	23	23	120
2017	58	2	83	0	143	0	0	0	0	23	23	121
2018	59	2	88	0	149	0	0	0	0	23	23	126
2019	58	2	89	0	149	0	0	0	0	23	23	127
2020	58	2	96	0	156	0	0	0	0	23	23	134
2021	59	2	97	0	158	0	0	0	0	23	23	136
2022	60	2	98	0	160	0	0	0	0	23	23	137
2023	58	2	100	0	159	0	0	0	0	23	23	137
2024	60	2	101	0	162	0	0	0	0	23	23	140
2025	59	2	103	0	164	0	0	0	0	23	23	141
2026	60	2	106	0	168	0	0	0	0	23	23	145
2027	61	2	109	0	172	0	0	0	0	23	23	150
2028	62	2	112	0	176	0	0	0	0	23	23	154
2029	62	2	115	0	179	0	0	0	0	23	23	156
2030	62	2	118	0	182	0	0	0	0	23	23	159
2031	63	2	122	0	186	0	0	0	0	23	23	164
2032	63	2	125	0	189	0	0	0	0	23	23	167
2033	65	2	128	0	195	0	0	0	0	23	23	173
2034	67	2	132	0	200	0	0	0	0	23	23	178
2035	67	2	136	0	204	0	0	0	0	23	23	181
NOMINAL	1,463	47	2,444	0	3,955	675	0	0	0	672	1,347	2,608
NPV	438	15	663	0	1,116	474	0	0	0	254	728	388

Utility Discount Rate = 8.1
Benefit Cost Ratio = 1.533

RESIDENTIAL YEAR ROUND ENERGY MANAGEMENT

Program Start Date: 1993
Program closed 2001
Proposed modification for 2007

Program Description

Residential Year Round Energy Management is a voluntary customer program that allows PEF to reduce peak demand and defer generation construction. Peak demand is reduced by interrupting service to selected electrical equipment with radio controlled switches installed on the customers' premises. These controlled interruptions are at PEF's option during specified time periods and coincident with hours of peak demand.

PEF has recently determined that it is currently cost-effective to add new participants to the Residential Year Round Energy Management program. As a result, PEF is proposing to reopen the year round program. This program has been closed since April 2001 and any new participants have been winter only participants. The winter-only program remains cost effective.

Re-opening the Year Round Energy Management would increase the summer and winter load control capabilities. In addition, to increase the program's winter effectiveness, a 100% strip control would be added to any new participants and existing participants requesting a change having heat pump equipment.

Projected Program Participation

Cumulative program participation estimates beginning in the year 2007 are shown in the following table, and reflect re-opening the year round program, maintaining a winter only option, 100% strip control, and increasing the net new participants.

Residential Year Round Load Management				
Year	Total Number of Customers (1)	Total Number of Eligible Customers (2)	Annual Number of Participants (3)	Cumulative Penetration Level % (4)
2007	1,446,239	1,234,991	5,000	0.40%
2008	1,472,551	1,257,459	10,000	0.80%
2009	1,498,885	1,279,947	20,000	1.56%
2010	1,524,944	1,302,199	30,000	2.30%
2011	1,550,477	1,324,003	40,000	3.02%
2012	1,575,780	1,345,610	50,000	3.72%
2013	1,600,906	1,367,066	60,000	4.39%
2014	1,625,899	1,388,408	70,000	5.04%

1. *The total number of customers in residential rate class*
2. *The total number of eligible customers in residential rate class*
3. *Net New participants of winter only or year round LM Schedule*
4. *Column 3 cumulative does not reflect participation prior to 2007*

Projected Savings

The total program savings shown in the following tables reflect the demand and energy savings associated with reopening the year round program and maintaining the current winter only program.

Year-Round Load Management - At the Meter						
Year	Per Customer KWH Reduction	Per Customer Winter KW Reduction	Per Customer Summer KW Reduction	Total Annual KWH Reduction	Total Annual Winter KW Reduction	Total Annual Summer KW Reduction
2007	15	1.877	0.47	75,076	9,385	2,346
2008	15	1.877	0.94	150,153	18,769	7,038
2009	15	1.877	0.94	300,306	37,538	16,423
2010	15	1.877	0.94	450,459	56,307	25,808
2011	15	1.877	0.94	600,612	75,076	35,192
2012	15	1.877	0.94	750,765	93,846	44,577
2013	15	1.877	0.94	900,918	112,615	53,961
2014	15	1.877	0.94	1,051,071	131,384	63,346

Year-Round Load Management - At the Generator						
Year	Per Customer KWH Reduction	Per Customer Winter KW Reduction	Per Customer Summer KW Reduction	Total Annual KWH Reduction	Total Annual Winter KW Reduction	Total Annual Summer KW Reduction
2007	16	2.000	0.500	80,000	10,000	2,500
2008	16	2.000	1.000	160,000	20,000	7,500
2009	16	2.000	1.000	320,000	40,000	17,500
2010	16	2.000	1.000	480,000	60,000	27,500
2011	16	2.000	1.000	640,000	80,000	37,500
2012	16	2.000	1.000	800,000	100,000	47,500
2013	16	2.000	1.000	960,000	120,000	57,500
2014	16	2.000	1.000	1,120,000	140,000	67,500

Cost Effectiveness Analysis

Year Round Energy Management				
Cost-Effectiveness Test	NPV Benefits $(000)	NPV Costs $(000)	NPV Net Benefits $(000)	B/C Ratio
Rate Impact Measure	147,032	53,946	93,086	2.73
Participant	35,102	0	35,102	N/A
Total Resource Cost	147,032	18,844	128,188	7.80

PROGRAM: **Residential LM - Year-Round RIM**

	BENEFITS					COSTS						
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
YEAR	TOTAL FUEL & O&M SAVINGS $(000)	AVOIDED T&D CAP. COSTS $(000)	AVOIDED GEN. CAP. COSTS $(000)	REVENUE GAINS $(000)	TOTAL BENEFITS $(000)	TOTAL FUEL & O&M INCREASE $(000)	INCREASED T&D CAP. COSTS $(000)	INCREASED GEN. CAP. COSTS $(000)	UTILITY PROGRAM COSTS $(000)	INCENTIVE PAYMENTS $(000)	REVENUE LOSSES $(000)	TOTAL COSTS $(000)
2006	0	0	0	0	0	0	0	0	0	0	0	0
2007	7	0	0	0	7	0	0	0	1,425	315	2	1,742
2008	424	0	909	0	1,333	0	0	0	1,475	630	3	2,108
2009	875	0	1,917	0	2,792	0	0	0	2,950	1,260	3	4,213
2010	1,599	0	2,973	0	4,573	0	0	0	3,050	1,890	5	4,945
2011	422	0	5,321	0	5,743	0	0	0	3,150	2,520	6	5,676
2012	2,453	0	5,235	0	7,688	0	0	0	3,250	3,150	8	6,408
2013	3,242	0	6,661	0	9,903	0	0	0	3,350	3,780	7	7,137
2014	5,859	0	12,545	0	18,403	0	0	0	3,450	4,410	16	7,876
2015	6,145	0	13,257	0	19,402	0	0	0	700	4,410	6	5,116
2016	5,886	0	13,296	0	19,182	0	0	0	700	4,410	12	5,122
2017	5,612	0	13,421	0	19,033	0	0	0	700	4,410	24	5,134
2018	5,933	0	14,200	0	20,133	0	0	0	700	4,410	12	5,122
2019	5,698	0	14,345	0	20,043	0	0	0	700	4,410	17	5,127
2020	6,218	0	15,468	0	21,686	0	0	0	700	4,410	5	5,115
2021	6,052	0	15,651	0	21,703	0	0	0	700	4,410	8	5,118
2022	5,882	0	15,846	0	21,728	0	0	0	700	4,410	13	5,123
2023	5,711	0	16,055	0	21,766	0	0	0	700	4,410	19	5,129
2024	5,704	0	16,280	0	21,984	0	0	0	700	4,410	30	5,140
2025	5,765	0	16,682	0	22,446	0	0	0	700	4,410	30	5,140
2026	5,682	0	17,141	0	22,823	0	0	0	700	4,410	36	5,146
2027	5,787	0	17,612	0	23,399	0	0	0	700	4,410	34	5,144
2028	5,744	0	18,096	0	23,840	0	0	0	700	4,410	30	5,140
2029	5,669	0	18,594	0	24,263	0	0	0	700	4,410	38	5,148
2030	5,711	0	19,105	0	24,816	0	0	0	700	4,410	35	5,145
2031	5,662	0	19,631	0	25,293	0	0	0	700	4,410	41	5,151
2032	5,730	0	20,171	0	25,901	0	0	0	700	4,410	35	5,145
2033	5,673	0	20,725	0	26,398	0	0	0	700	4,410	41	5,151
2034	5,750	0	21,295	0	27,045	0	0	0	700	4,410	33	5,143
2035	5,634	0	21,881	0	27,515	0	0	0	700	4,410	45	5,155
NOMINAL	136,525	0	394,312	0	530,837	0	0	0	36,800	110,565	592	147,957
NPV	40,186	0	106,844	0	147,032	0	0	0	18,844	34,959	143	53,946

Utility Discount Rate = 8.1

Benefit Cost Ratio = 2.726

PROGRAM: **Residential LM - Year-Round Participant**

	BENEFITS				COSTS			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
YEAR	SAVINGS IN PARTICIPANT'S BILL $(000)	INCENTIVE PAYMENTS $(000)	OTHER PARTICIPANT'S BENEFITS $(000)	TOTAL BENEFITS $(000)	PARTICIPANT'S COST $(000)	PARTICIPANT'S BILL INCREASE $(000)	TOTAL COSTS $(000)	NET BENEFITS TO PARTICIPANTS $(000)
2006	0	0	0	0	0	0	0	0
2007	2	315	0	317	0	0	0	317
2008	3	630	0	633	0	0	0	633
2009	3	1,260	0	1,263	0	0	0	1,263
2010	5	1,890	0	1,895	0	0	0	1,895
2011	6	2,520	0	2,526	0	0	0	2,526
2012	8	3,150	0	3,158	0	0	0	3,158
2013	7	3,780	0	3,787	0	0	0	3,787
2014	16	4,410	0	4,426	0	0	0	4,426
2015	6	4,410	0	4,416	0	0	0	4,416
2016	12	4,410	0	4,422	0	0	0	4,422
2017	24	4,410	0	4,434	0	0	0	4,434
2018	12	4,410	0	4,422	0	0	0	4,422
2019	17	4,410	0	4,427	0	0	0	4,427
2020	5	4,410	0	4,415	0	0	0	4,415
2021	8	4,410	0	4,418	0	0	0	4,418
2022	13	4,410	0	4,423	0	0	0	4,423
2023	19	4,410	0	4,429	0	0	0	4,429
2024	30	4,410	0	4,440	0	0	0	4,440
2025	30	4,410	0	4,440	0	0	0	4,440
2026	36	4,410	0	4,446	0	0	0	4,446
2027	34	4,410	0	4,444	0	0	0	4,444
2028	30	4,410	0	4,440	0	0	0	4,440
2029	38	4,410	0	4,448	0	0	0	4,448
2030	35	4,410	0	4,445	0	0	0	4,445
2031	41	4,410	0	4,451	0	0	0	4,451
2032	35	4,410	0	4,445	0	0	0	4,445
2033	41	4,410	0	4,451	0	0	0	4,451
2034	33	4,410	0	4,443	0	0	0	4,443
2035	45	4,410	0	4,455	0	0	0	4,455
NOMINAL	592	110,565	0	111,157	0	0	0	111,157
NPV	143	34,959	0	35,102	0	0	0	35,102

Utility Discount Rate = 8.1
Benefit Cost Ratio = 9999

PROGRAM: **Residential LM - Year-Round TRC**

	BENEFITS					COSTS						
	(1) TOTAL FUEL & O&M SAVINGS	(2) AVOIDED T&D CAP. COSTS	(3) AVOIDED GEN. CAP. COSTS	(4) OTHER PARTICIPANT BENEFITS	(5) TOTAL BENEFITS	(6) PARTICIPANT'S COST	(7) TOTAL FUEL & O&M INCREASE	(8) INCREASED T&D CAP. COSTS	(9) INCREASED GEN. CAP. COSTS	(10) UTILITY PROGRAM COSTS	(11) TOTAL COSTS	(12) NET BENEFITS
YEAR	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
2006	0	0	0	0	0	0	0	0	0	0	0	0
2007	7	0	0	0	7	0	0	0	0	1,425	1,425	-1,418
2008	424	0	909	0	1,333	0	0	0	0	1,475	1,475	-142
2009	875	0	1,917	0	2,792	0	0	0	0	2,950	2,950	-158
2010	1,599	0	2,973	0	4,573	0	0	0	0	3,050	3,050	1,523
2011	422	0	5,321	0	5,743	0	0	0	0	3,150	3,150	2,593
2012	2,453	0	5,235	0	7,688	0	0	0	0	3,250	3,250	4,438
2013	3,242	0	6,661	0	9,903	0	0	0	0	3,350	3,350	6,553
2014	5,859	0	12,545	0	18,403	0	0	0	0	3,450	3,450	14,953
2015	6,145	0	13,257	0	19,402	0	0	0	0	700	700	18,702
2016	5,886	0	13,296	0	19,182	0	0	0	0	700	700	18,482
2017	5,612	0	13,421	0	19,033	0	0	0	0	700	700	18,333
2018	5,933	0	14,200	0	20,133	0	0	0	0	700	700	19,433
2019	5,698	0	14,345	0	20,043	0	0	0	0	700	700	19,343
2020	6,218	0	15,468	0	21,686	0	0	0	0	700	700	20,986
2021	6,052	0	15,651	0	21,703	0	0	0	0	700	700	21,003
2022	5,882	0	15,846	0	21,728	0	0	0	0	700	700	21,028
2023	5,711	0	16,055	0	21,766	0	0	0	0	700	700	21,066
2024	5,704	0	16,280	0	21,984	0	0	0	0	700	700	21,284
2025	5,765	0	16,682	0	22,446	0	0	0	0	700	700	21,746
2026	5,682	0	17,141	0	22,823	0	0	0	0	700	700	22,123
2027	5,787	0	17,612	0	23,399	0	0	0	0	700	700	22,699
2028	5,744	0	18,096	0	23,840	0	0	0	0	700	700	23,140
2029	5,669	0	18,594	0	24,263	0	0	0	0	700	700	23,563
2030	5,711	0	19,105	0	24,816	0	0	0	0	700	700	24,116
2031	5,662	0	19,631	0	25,293	0	0	0	0	700	700	24,593
2032	5,730	0	20,171	0	25,901	0	0	0	0	700	700	25,201
2033	5,673	0	20,725	0	26,398	0	0	0	0	700	700	25,698
2034	5,750	0	21,295	0	27,045	0	0	0	0	700	700	26,345
2035	5,634	0	21,881	0	27,515	0	0	0	0	700	700	26,815
NOMINAL	136,525	0	394,312	0	530,837	0	0	0	0	36,800	36,800	494,037
NPV	40,188	0	106,844	0	147,032	0	0	0	0	18,844	18,844	128,188

Utility Discount Rate = 8.1
Benefit Cost Ratio = 7.803

COMMERCIAL CONSERVATION PROGRAMS

Progress Energy Florida's DSM Plan includes three (3) commercial programs which the company seeks to modify:

A. Standby Generation – Demand control program based upon the indirect control of the customer equipment

B. Better Business – Program for existing commercial, industrial, and government customers

C. Commercial New Construction – This program fosters the design and construction of energy efficient buildings

Each program is described in detail in the following sections.

STANDBY GENERATION PROGRAM

Program Start Date: 1993
Program modified 1995
Proposed modification for 2007

Program Description

The Standby Generation program is a demand control program that will reduce PEF's demand based upon the indirect control of customer equipment. The program is a voluntary program available to all commercial and industrial customers who have on-site generation capability and are willing to reduce their PEF demand when PEF deems it necessary. The program is offered through the General Service Load Management-2 (GSLM-2) rate schedule.

PEF may have direct control of the customer equipment or will rely upon the customer to initiate the generation upon being notified by PEF and continue running it until PEF notifies the customer that the generation is no longer needed. PEF does not restrict other use of the equipment by the customer.

Standby Generation program participants will receive a monthly credit on their energy bill according to the demonstrated ability of the customer to reduce demand at PEF's request. In addition, it is proposed to add an additional credit based on the kWh the customer provides. The credits will be based upon the load served by the customer's generator, which would have been served by PEF if the Standby Generation program were not in operation. By compensating the customer for the use of their on-site generation, PEF can impact the commercial and industrial market while minimizing rate impacts. The proposed incentive will be $2.30 per kWh per month plus and additional compensation of $0.05 per kWh to support customer O & M associated with run time requested by the company.

Projected Program Participants

Stand By Generation				
Year	Total Number of Customers (1)	Total Number of Eligible Customers (2)	Annual Number of Participants	Cumulative Penetration Level %
2007	191,778	603	20	3%
2008	196,120	543	40	7%
2009	200,385	532	60	11%
2010	204,629	521	80	15%
2011	208,882	510	100	20%
2012	213,159	499	120	24%
2013	217,454	488	140	29%
2014	221,739	477	160	34%

1. *Total Number of Customers is the August 2006 forecast of all commercial and industrial customers.*
2. *The total number of eligible customers in commercial rate class*

Projected Savings

Standby Generation - At the Meter						
Year	Per Customer KWH Reduction	Per Customer Winter KW Reduction	Per Customer Summer KW Reduction	Total Annual KWH Reduction	Total Annual Winter KW Reduction	Total Annual Summer KW Reduction
2007	3,771	471	471	75,422	9,428	9,428
2008	3,771	471	471	150,844	18,855	18,855
2009	3,771	471	471	226,266	28,283	28,283
2010	3,771	471	471	301,688	37,711	37,711
2011	3,771	471	471	377,109	47,139	47,139
2012	3,771	471	471	452,531	56,566	56,566
2013	3,771	471	471	527,953	65,994	65,994
2014	3,771	471	471	603,375	75,422	75,422

Standby Generation - At the Generator						
Year	Per Customer KWH Reduction	Per Customer Winter KW Reduction	Per Customer Summer KW Reduction	Total Annual KWH Reduction	Total Annual Winter KW Reduction	Total Annual Summer KW Reduction
2007	4,000	500	500	80,000	10,000	10,000
2008	4,000	500	500	160,000	20,000	20,000
2009	4,000	500	500	240,000	30,000	30,000
2010	4,000	500	500	320,000	40,000	40,000
2011	4,000	500	500	400,000	50,000	50,000
2012	4,000	500	500	480,000	60,000	60,000
2013	4,000	500	500	560,000	70,000	70,000
2014	4,000	500	500	640,000	80,000	80,000

Cost Effectiveness Analysis

Standby Generation				
Cost-Effectiveness Test	NPV Benefits $(000)	NPV Costs $(000)	NPV Net Benefits $(000)	B/C Ratio
Rate Impact Measure	99,480	20,266	79,214	4.91
Participant	18,632	0	18,632	N/A
Total Resource Cost	99,480	1,634	97,846	60.88

PROGRAM: **Standby Generation RIM**

	BENEFITS					COSTS							
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
YEAR	TOTAL FUEL & O&M SAVINGS $(000)	AVOIDED T&D CAP. COSTS $(000)	AVOIDED GEN. CAP. COSTS $(000)	REVENUE GAINS $(000)	TOTAL BENEFITS $(000)	TOTAL FUEL & O&M INCREASE $(000)	INCREASED T&D CAP. COSTS $(000)	INCREASED GEN. CAP. COSTS $(000)	UTILITY PROGRAM COSTS $(000)	INCENTIVE PAYMENTS $(000)	REVENUE LOSSES $(000)	TOTAL COSTS $(000)	NET BENEFITS $(000)
2006	0	0	0	0	0	0	0	0	0	0	0	0	0
2007	12	0	0	0	12	0	0	0	180	281	2	463	-451
2008	812	0	1,748	0	2,560	0	0	0	190	562	2	754	1,806
2009	1,257	0	2,765	0	4,022	0	0	0	200	843	1	1,044	2,978
2010	2,049	0	3,812	0	5,861	0	0	0	210	1,124	2	1,336	4,525
2011	496	0	6,395	0	6,891	0	0	0	220	1,405	2	1,627	5,264
2012	2,826	0	6,040	0	8,866	0	0	0	230	1,686	3	1,919	6,947
2013	3,633	0	7,472	0	11,105	0	0	0	240	1,967	2	2,209	8,896
2014	3,402	0	7,239	0	10,641	0	0	0	250	2,248	4	2,502	8,139
2015	3,560	0	7,650	0	11,210	0	0	0	80	2,248	1	2,329	8,881
2016	3,417	0	7,672	0	11,089	0	0	0	80	2,248	3	2,331	8,758
2017	3,271	0	7,745	0	11,015	0	0	0	80	2,248	7	2,335	8,680
2018	3,445	0	8,194	0	11,639	0	0	0	80	2,248	4	2,332	9,308
2019	3,320	0	8,278	0	11,598	0	0	0	80	2,248	6	2,334	9,263
2020	3,603	0	8,926	0	12,529	0	0	0	80	2,248	1	2,329	10,200
2021	3,513	0	9,031	0	12,544	0	0	0	80	2,248	2	2,330	10,214
2022	3,422	0	9,144	0	12,566	0	0	0	80	2,248	5	2,333	10,233
2023	3,333	0	9,265	0	12,598	0	0	0	80	2,248	8	2,336	10,261
2024	3,439	0	9,395	0	12,834	0	0	0	80	2,248	15	2,343	10,491
2025	3,516	0	9,626	0	13,142	0	0	0	80	2,248	15	2,343	10,799
2026	3,475	0	9,891	0	13,366	0	0	0	80	2,248	19	2,347	11,019
2027	3,574	0	10,163	0	13,737	0	0	0	80	2,248	18	2,346	11,391
2028	3,500	0	10,442	0	13,942	0	0	0	80	2,248	16	2,344	11,599
2029	3,486	0	10,730	0	14,216	0	0	0	80	2,248	21	2,349	11,867
2030	3,502	0	11,025	0	14,526	0	0	0	80	2,248	18	2,346	12,180
2031	3,504	0	11,328	0	14,831	0	0	0	80	2,248	23	2,351	12,481
2032	3,523	0	11,639	0	15,162	0	0	0	80	2,248	19	2,347	12,815
2033	3,518	0	11,959	0	15,477	0	0	0	80	2,248	23	2,351	13,126
2034	3,536	0	12,288	0	15,824	0	0	0	80	2,248	18	2,346	13,479
2035	3,518	0	12,626	0	16,144	0	0	0	80	2,248	25	2,353	13,790
NOMINAL	87,457	0	242,489	0	329,946	0	0	0	3,400	57,324	284	61,008	268,938
NPV	27,682	0	71,798	0	99,480	0	0	0	1,634	18,569	62	20,266	79,214

Utility Discount Rate = 8.1
Benefit Cost Ratio = 4.909

PROGRAM: **Standby Generation Participant**

YEAR	BENEFITS (1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT'S BENEFITS $(000)	(4) TOTAL BENEFITS $(000)	COSTS (5) PARTICIPANT'S COST $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) TOTAL COSTS $(000)	(8) NET BENEFITS TO PARTICIPANTS $(000)
2006	0	0	0	0	0	0	0	0
2007	2	281	0	283	0	0	0	283
2008	2	562	0	564	0	0	0	564
2009	1	843	0	844	0	0	0	844
2010	2	1,124	0	1,126	0	0	0	1,126
2011	2	1,405	0	1,407	0	0	0	1,407
2012	3	1,686	0	1,689	0	0	0	1,689
2013	2	1,967	0	1,969	0	0	0	1,969
2014	4	2,248	0	2,252	0	0	0	2,252
2015	1	2,248	0	2,249	0	0	0	2,249
2016	3	2,248	0	2,251	0	0	0	2,251
2017	7	2,248	0	2,255	0	0	0	2,255
2018	4	2,248	0	2,252	0	0	0	2,252
2019	6	2,248	0	2,254	0	0	0	2,254
2020	1	2,248	0	2,249	0	0	0	2,249
2021	2	2,248	0	2,250	0	0	0	2,250
2022	5	2,248	0	2,253	0	0	0	2,253
2023	8	2,248	0	2,256	0	0	0	2,256
2024	15	2,248	0	2,263	0	0	0	2,263
2025	15	2,248	0	2,263	0	0	0	2,263
2026	19	2,248	0	2,267	0	0	0	2,267
2027	18	2,248	0	2,266	0	0	0	2,266
2028	16	2,248	0	2,264	0	0	0	2,264
2029	21	2,248	0	2,269	0	0	0	2,269
2030	18	2,248	0	2,266	0	0	0	2,266
2031	23	2,248	0	2,271	0	0	0	2,271
2032	19	2,248	0	2,267	0	0	0	2,267
2033	23	2,248	0	2,271	0	0	0	2,271
2034	18	2,248	0	2,266	0	0	0	2,266
2035	25	2,248	0	2,273	0	0	0	2,273
NOMINAL	284	57,324	0	57,608	0	0	0	57,608
NPV	62	18,569	0	18,632	0	0	0	18,632

Utility Discount Rate = 8.1
Benefit Cost Ratio = 9999

PROGRAM: **Standby Generation TRC**

	BENEFITS					COSTS						
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
YEAR	TOTAL FUEL & O&M SAVINGS $(000)	AVOIDED T&D CAP. COSTS $(000)	AVOIDED GEN. CAP. COSTS $(000)	OTHER PARTICIPANT BENEFITS $(000)	TOTAL BENEFITS $(000)	PARTICIPANT'S COST $(000)	TOTAL FUEL & O&M INCREASE $(000)	INCREASED T&D CAP. COSTS $(000)	INCREASED GEN. CAP. COSTS $(000)	UTILITY PROGRAM COSTS $(000)	TOTAL COSTS $(000)	NET BENEFITS $(000)
2006	0	0	0	0	0	0	0	0	0	0	0	0
2007	12	0	0	0	12	0	0	0	0	180	180	-169
2008	812	0	1,748	0	2,560	0	0	0	0	190	190	2,370
2009	1,257	0	2,765	0	4,022	0	0	0	0	200	200	3,822
2010	2,049	0	3,812	0	5,861	0	0	0	0	210	210	5,651
2011	496	0	6,395	0	6,891	0	0	0	0	220	220	6,671
2012	2,826	0	6,040	0	8,866	0	0	0	0	230	230	8,636
2013	3,633	0	7,472	0	11,105	0	0	0	0	240	240	10,865
2014	3,402	0	7,239	0	10,641	0	0	0	0	250	250	10,391
2015	3,560	0	7,650	0	11,210	0	0	0	0	80	80	11,130
2016	3,417	0	7,672	0	11,089	0	0	0	0	80	80	11,009
2017	3,271	0	7,745	0	11,015	0	0	0	0	80	80	10,935
2018	3,445	0	8,194	0	11,639	0	0	0	0	80	80	11,559
2019	3,320	0	8,278	0	11,598	0	0	0	0	80	80	11,518
2020	3,603	0	8,926	0	12,529	0	0	0	0	80	80	12,449
2021	3,513	0	9,031	0	12,544	0	0	0	0	80	80	12,464
2022	3,422	0	9,144	0	12,566	0	0	0	0	80	80	12,486
2023	3,333	0	9,265	0	12,598	0	0	0	0	80	80	12,518
2024	3,439	0	9,395	0	12,834	0	0	0	0	80	80	12,754
2025	3,516	0	9,626	0	13,142	0	0	0	0	80	80	13,062
2026	3,475	0	9,891	0	13,366	0	0	0	0	80	80	13,286
2027	3,574	0	10,163	0	13,737	0	0	0	0	80	80	13,657
2028	3,500	0	10,442	0	13,942	0	0	0	0	80	80	13,862
2029	3,486	0	10,730	0	14,216	0	0	0	0	80	80	14,136
2030	3,502	0	11,025	0	14,526	0	0	0	0	80	80	14,446
2031	3,504	0	11,328	0	14,831	0	0	0	0	80	80	14,751
2032	3,523	0	11,639	0	15,162	0	0	0	0	80	80	15,082
2033	3,518	0	11,959	0	15,477	0	0	0	0	80	80	15,397
2034	3,536	0	12,288	0	15,824	0	0	0	0	80	80	15,744
2035	3,518	0	12,626	0	16,144	0	0	0	0	80	80	16,064
NOMINAL	87,457	0	242,489	0	329,946	0	0	0	0	3,400	3,400	326,546
NPV	27,682	0	71,798	0	99,480	0	0	0	0	1,634	1,634	97,846

Utility Discount Rate = 8.1

Benefit Cost Ratio = 60.879

Better Business Program

Program Start Date: 1995
Program modified 2000, 2005
Proposed modification for 2007

Program Description

All business customers are eligible for this program. The Better Business program is the umbrella efficiency program for existing commercial, industrial, and government customers who want to retrofit with high efficiency improvements. Better Business builds on the Business Energy Check by using the audit to provide customers with information and education on energy issues and incentives on efficiency measures that are cost-effective to PEF and its customers. Participating in Business Energy Check is a prerequisite for receiving most of the incentives. Better Business promotes a number of high efficiency measures:

- heating, ventilation, air conditioning
- energy recovery ventilation
- ceiling insulation upgrade
- duct leakage test and repair
- cool roof

PEF proposes to make some changes to several existing measures and add the following measures to its previously approved program as follows:

Roof Insulation Upgrade

This measure encourages customers who have electric space heat to add insulation to the roof area by paying for a portion of the installed cost. The facility must have an existing roof insulation level less than R12 to participate and upgrade to a minimum value of R19 to receive the incentive. The incentive amount will be 7¢ per square foot of conditioned space with a maximum of $5,000 per building.

Thermal Energy Storage w/ Time-of-Use Rate

This measure will provide an incentive to encourage existing business customers to utilize thermal energy storage (TES) systems to reduce the size and cost of replacement chillers and lower energy costs. To generate maximum cost savings, customers should enter into the Time-of-Use Rate. The proposed incentive for the new measure will be up to $300 per kW of reduced cooling load at peak times.

Green Roof

This measure is designed to encourage business customers to increase the thermal efficiency of their buildings by utilizing Green Roof designs and resulting in reduced peak kW. The proposed incentive will be 25¢ per square foot over conditioned space for the installation of an approved Green Roof.

Efficient Compressed Air System

This measure will provide an incentive to encourage business customers to utilize a proactive approach to increase the efficiency of compressed air systems. Proposed incentives will be calculated based on $50 per kW reduction.

Occupancy Sensors

This measure will provide an incentive to encourage business customers to install occupancy sensors in any areas where indoor lights would be used on peak. The proposed incentive will be $50 per kW of lighting load controlled with approved controls.

Roof Top Unit Recommission

This measure will provide an incentive to encourage existing business customers to perform recommissioning to Rooftop Air Conditioning units (RTU). Recommissioning will consist of performing maintenance to assure the unit is operating at optimal efficiency. The proposed incentive for the new measure will be $15 per ton of RTU.

HVAC Steam Cleaning

This measure will provide an incentive to encourage existing business customers who utilize Packaged Terminal Air Conditioning (PTAC) and Packaged Terminal Heat Pump (PTHP) units to have the coils steam cleaned. This steam cleaning process will improve the efficiency of the HVAC equipment. The proposed incentive is $15 per unit on a one-time basis.

Efficient Indoor Lighting

This measure is intended to promote energy efficiency through the retrofit of older inefficient lamp and ballast technology in indoor lighting fixtures with more energy efficient technologies. The proposed incentives will be $50 per kW reduced.

Demand Control Ventilation

This measure will provide incentives for the installation of Demand Control Ventilation (DCV) using CO_2 sensors. DCV saves energy by automatically adjusting building ventilation rates in real time based on occupancy. This measure provides incentives of $50 per ton with properly designed and installed DCV control programming.

Efficient Motors

This measure promotes the installation of high efficiency polyphase motors through a simple incentive structure based on the motor size and a specified $/hp. The maximum incentive amount will be from $1.75 to $2.75 per hp. The specific incentive amount will be a function of the motor size and efficiency.

Window Film

Progress Energy Florida will provide customers with an incentive to install window film on new windows having east, west, and south exposures. The maximum incentive will be 75¢ per square-foot of window film installed. An exception to this limitation will be made for facilities with multiple guest rooms, such as hotels, motels, hospitals, and assisted-care living facilities, which may receive incentives up to a maximum of $55 per room.

Projected Program Participation

Better Business				
Year	Total Number of Customers (1)	Total Number of Eligible Customers	Annual Number of Participants (2)	Cumulative Penetration Level (%)
2007	191,778	171,258	957	1%
2008	196,120	175,335	1,914	1%
2009	200,385	178,114	2,892	1%
2010	204,629	181,027	3,869	2%
2011	208,882	183,832	4,847	2%
2012	213,159	186,547	5,825	3%
2013	217,454	189,202	6,782	3%
2014	221,739	191,835	7,739	3%

1. *Total Number of Customers is the August 2006 forecast of all commercial and industrial customers.*
2. *This total is larger than the number of actual customers anticipated installing eligible measures and earning an incentive since many customers install multiple measures at one account.*

Projected Savings

Total program savings were developed by first estimating the total savings for each individual measure based on each measure's (1) per customer savings and, (2) annual projected participation. The total projected program savings were then computed as the sum of the individual measure savings, and are shown in the following tables.

Better Business – At The Meter						
Year	Per Customer KWH Reduction	Per Customer Winter KW Reduction	Per Customer Summer KW Reduction	Total Annual KWH Reduction	Total Annual Winter KW Reduction	Total Annual Summer KW Reduction
2007	12,834	4.2	6.8	12,281,969	4,035	6,551
2008	12,834	4.2	6.8	24,563,938	8,071	13,101
2009	12,781	4.2	6.9	36,959,507	12,106	19,841
2010	12,755	4.2	6.9	49,355,076	16,142	26,580
2011	12,740	4.2	6.9	61,750,645	20,177	33,319
2012	12,729	4.2	6.9	74,146,214	24,212	40,058
2013	12,744	4.2	6.9	86,428,183	28,248	46,609
2014	12,755	4.2	6.9	98,710,152	32,283	53,159

Better Business – At The Generator						
Year	Per Customer KWH Reduction	Per Customer Winter KW Reduction	Per Customer Summer KW Reduction	Total Annual KWH Reduction	Total Annual Winter KW Reduction	Total Annual Summer KW Reduction
2007	13,719	4.5	7.3	13,129,425	4,314	7,003
2008	13,719	4.5	7.3	26,258,850	8,628	14,005
2009	13,663	4.5	7.3	39,509,713	12,942	21,209
2010	13,635	4.5	7.3	52,760,576	17,255	28,414
2011	13,619	4.4	7.3	66,011,440	21,569	35,618
2012	13,608	4.4	7.4	79,262,303	25,883	42,822
2013	13,623	4.5	7.3	92,391,728	30,197	49,825
2014	13,635	4.5	7.3	105,521,152	34,511	56,827

Cost Effectiveness Analysis

PEF has analyzed this program for cost-effectiveness using the Commission-approved tests described in Rule 25-17.008, Florida Administrative Code. The economic results of the program are as follows:

Better Business				
Cost-Effectiveness Test	NPV Benefits $(000)	NPV Costs $(000)	NPV Net Benefits $(000)	B/C Ratio
Rate Impact Measure	113,209	76,838	36,371	1.47
Participant	75,965	33,172	42,794	2.29
Total Resource Cost	113,209	34,044	79,165	3.33

PROGRAM: **Better Business Program RIM**

	BENEFITS					COSTS							
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) REVENUE GAINS $(000)	(5) TOTAL BENEFITS $(000)	(6) TOTAL FUEL & O&M INCREASE $(000)	(7) INCREASED T&D CAP. COSTS $(000)	(8) INCREASED GEN. CAP. COSTS $(000)	(9) UTILITY PROGRAM COSTS $(000)	(10) INCENTIVE PAYMENTS $(000)	(11) REVENUE LOSSES $(000)	(12) TOTAL COSTS $(000)	(13) NET BENEFITS $(000)
2006													
2007	1,206	137			1,343				151	1,154	930	2,235	-892
2008	2,711	274	828		3,812				151	1,154	1,859	3,164	648
2009	3,886	411	1,190		5,487				154	1,164	2,775	4,093	1,394
2010	4,425	548	1,747		6,721				154	1,164	3,757	5,075	1,646
2011	4,623	686	3,210		8,518				154	1,164	4,947	6,265	2,254
2012	6,751	823	2,626		10,200				154	1,164	6,088	7,406	2,794
2013	7,266	960	2,934		11,160				151	1,154	7,083	8,389	2,771
2014	8,106	1,097	2,823		12,025				151	1,154	8,052	9,357	2,668
2015	7,522	1,097	2,292		10,910						8,415	8,415	2,495
2016	8,019	1,097	2,729		11,845						8,644	8,644	3,201
2017	8,679	1,097	3,353		13,129						8,389	8,389	4,740
2018	8,120	1,097	3,173		12,389						8,492	8,492	3,897
2019	8,551	1,097	3,520		13,167						8,281	8,281	4,885
2020	7,600	1,097	2,940		11,636						8,120	8,120	3,517
2021	8,076	1,097	3,281		12,454						8,230	8,230	4,224
2022	8,477	1,097	3,686		13,259						8,344	8,344	4,915
2023	8,929	1,097	4,017		14,043						8,462	8,462	5,581
2024	9,285	1,097	4,257		14,639						8,583	8,583	6,056
2025	9,678	1,097	4,429		15,203						8,706	8,706	6,497
2026	9,900	1,097	4,572		15,569						8,834	8,834	6,735
2027	10,169	1,097	4,669		15,934						8,965	8,965	6,969
2028	10,251	1,097	4,801		16,149						9,100	9,100	7,049
2029	10,639	1,097	4,973		16,708						9,237	9,237	7,471
2030	10,817	1,097	5,080		16,994						9,380	9,380	7,613
2031	11,152	1,097	5,254		17,503						9,526	9,526	7,977
2032	11,323	1,097	5,367		17,786						9,675	9,675	8,111
2033	11,675	1,097	5,545		18,317						9,830	9,830	8,487
2034	11,808	1,097	5,654		18,558						9,988	9,988	8,570
2035	12,316	1,097	5,848		19,260						10,151	10,151	9,109
NOMINAL	241,956	27,966	104,797		374,718				1,220	9,273	222,846	233,338	141,380
NPV	73,919	9,059	30,231		113,209				873	6,635	69,330	76,838	36,371

Utility Discount Rate = 8.1

Benefit Cost Ratio = 1.473

PROGRAM: **Better Business Program Participant**

	BENEFITS				COSTS			
YEAR	(1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT'S BENEFITS $(000)	(4) TOTAL BENEFITS $(000)	(5) PARTICIPANT'S COST $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) TOTAL COSTS $(000)	(8) NET BENEFITS TO PARTICIPANTS $(000)
2006								
2007	930	1,154		2,084	5,789		5,789	-3,705
2008	1,859	1,154		3,013	5,789		5,789	-2,776
2009	2,775	1,164		3,939	5,799		5,799	-1,860
2010	3,757	1,164		4,921	5,799		5,799	-879
2011	4,947	1,164		6,111	5,799		5,799	311
2012	6,088	1,164		7,252	5,799		5,799	1,453
2013	7,083	1,154		8,238	5,789		5,789	2,449
2014	8,052	1,154		9,206	5,789		5,789	3,417
2015	8,415			8,415				8,415
2016	8,644			8,644				8,644
2017	8,389			8,389				8,389
2018	8,492			8,492				8,492
2019	8,281			8,281				8,281
2020	8,120			8,120				8,120
2021	8,230			8,230				8,230
2022	8,344			8,344				8,344
2023	8,462			8,462				8,462
2024	8,583			8,583				8,583
2025	8,706			8,706				8,706
2026	8,834			8,834				8,834
2027	8,965			8,965				8,965
2028	9,100			9,100				9,100
2029	9,237			9,237				9,237
2030	9,380			9,380				9,380
2031	9,526			9,526				9,526
2032	9,675			9,675				9,675
2033	9,830			9,830				9,830
2034	9,988			9,988				9,988
2035	10,151			10,151				10,151
NOMINAL	222,846	9,273		232,119	46,355		46,355	185,764
NPV	69,330	6,635		75,965	33,172		33,172	42,794

Utility Discount Rate = 8.1

Benefit Cost Ratio = 2.290

PROGRAM: Better Business Program TRC

	BENEFITS					COSTS						
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	TOTAL FUEL & O&M SAVINGS	AVOIDED T&D CAP. COSTS	AVOIDED GEN. CAP. COSTS	OTHER PARTICIPANT BENEFITS	TOTAL BENEFITS	PARTICIPANT'S COST	TOTAL FUEL & O&M INCREASE	INCREASED T&D CAP. COSTS	INCREASED GEN. CAP. COSTS	UTILITY PROGRAM COSTS	TOTAL COSTS	NET BENEFITS
YEAR	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
2006												
2007	1,206	137			1,343	5,789				151	5,940	-4,597
2008	2,711	274	828		3,812	5,789				151	5,940	-2,128
2009	3,886	411	1,190		5,487	5,799				154	5,953	-466
2010	4,425	548	1,747		6,721	5,799				154	5,953	767
2011	4,623	686	3,210		8,518	5,799				154	5,953	2,565
2012	6,751	823	2,626		10,200	5,799				154	5,953	4,247
2013	7,266	960	2,934		11,160	5,789				151	5,940	5,220
2014	8,106	1,097	2,823		12,025	5,789				151	5,940	6,085
2015	7,522	1,097	2,292		10,910							10,910
2016	8,019	1,097	2,729		11,845							11,845
2017	8,679	1,097	3,353		13,129							13,129
2018	8,120	1,097	3,173		12,389							12,389
2019	8,551	1,097	3,520		13,167							13,167
2020	7,600	1,097	2,940		11,636							11,636
2021	8,076	1,097	3,281		12,454							12,454
2022	8,477	1,097	3,686		13,259							13,259
2023	8,929	1,097	4,017		14,043							14,043
2024	9,285	1,097	4,257		14,639							14,639
2025	9,678	1,097	4,429		15,203							15,203
2026	9,900	1,097	4,572		15,569							15,569
2027	10,169	1,097	4,669		15,934							15,934
2028	10,251	1,097	4,801		16,149							16,149
2029	10,639	1,097	4,973		16,708							16,708
2030	10,817	1,097	5,080		16,994							16,994
2031	11,152	1,097	5,254		17,503							17,503
2032	11,323	1,097	5,367		17,786							17,786
2033	11,675	1,097	5,545		18,317							18,317
2034	11,808	1,097	5,654		18,558							18,558
2035	12,316	1,097	5,848		19,260							19,260
NOMINAL	241,956	27,966	104,797		374,718	46,355				1,220	47,574	327,144
NPV	73,919	9,059	30,231		113,209	33,172				873	34,044	79,165

Utility Discount Rate = 8.1

Benefit Cost Ratio = 3.325

COMMERCIAL/INDUSTRIAL NEW CONSTRUCTION PROGRAM

Program Start Date: 1993
Program modified 2000, 2005
Proposed modification for 2007

Program Description

All business customers are eligible for this program. The primary goal of the PEF Commercial/Industrial (C/I) New Construction program is to foster the design and construction of energy efficient buildings. The new construction program will: 1) provide education and information to the design community on all aspects of energy efficient building design; 2) require that the building design, at a minimum surpasses the state energy code; 3) provide financial incentives for specific energy efficient equipment; and 4) provide energy design awards to building design teams. The program will simultaneously target building developers/owners and the building design community and will work one-on-one with them throughout a new construction project. PEF will also focus on developing relationships with the key decision-makers of commercial and industrial new construction projects early in the design process. This program promotes a number of high efficiency measures:

- heating, ventilation, air conditioning
- energy recovery ventilation
- cool roof

PEF proposes to make some changes to several existing measures and add the following measures to its previously approved program as follows:

Roof Insulation

This measure encourages customers whose facilities will have electric space heat to increase insulation to the roof area. The facility must increase their roof insulation level above minimum code to participate and must be planning to heat by electricity in order to receive the incentive. The customer must upgrade their roof insulation to R-19 or higher. The incentive amount will be 7¢ per square foot of conditioned space with a maximum of $5,000 per building.

Thermal Energy Storage w/ Time-of-Use Rate

This measure will provide an incentive to encourage new business customer facilities to utilize thermal energy storage (TES) systems to reduce the initial size and cost of chillers and lower energy costs. To generate maximum cost savings, customers, should enter into the Time-of-Use Rate. The proposed incentive for the new measure will be up to $300 per kW of reduced cooling load at peak times.

Green Roof

This measure is designed to encourage business customers building new facilities to increase the thermal efficiency of their buildings by utilizing Green Roof designs and resulting in reduced kW. The proposed incentive will be 25¢ per square foot over conditioned space for the installation of an approved Green Roof.

Efficient Compressed Air System

This measure will provide an incentive to encourage business customers to design a system that optimizes the energy efficiency of compressed air systems. Proposed incentives will be calculated based on $50.00 per kW reduction.

Occupancy Sensors

This measure will provide an incentive to encourage business customers to install occupancy sensors in any areas where indoor lights would be used on peak. The proposed incentive will be $50 per kW of lighting load controlled with approved controls.

Efficient Indoor Lighting

This measure is intended to promote energy efficiency through the specification of energy efficient indoor lighting technology through a range of options. The proposed incentives will be $50 per kW reduced.

Demand Control Ventilation

This measure will provide incentives for the installation of Demand Control Ventilation (DCV) using CO_2 sensors. DCV saves energy by automatically adjusting building ventilation rates in real time based on occupancy. This program provides incentives of $50 per ton with properly designed and installed DCV control programming.

Efficient Motors

This measure promotes the installation of high efficiency polyphase motors through a simple incentive structure based on the motor size and a specified $/hp. The maximum incentive amount will be from $1.75 to $2.75 per hp. The specific incentive amount will be a function of the motor size and efficiency.

Window Film

Progress Energy Florida will provide customers with an incentive to install window film on new windows having east, west, and south exposures. The maximum incentive will be 75¢ per square-foot of window film installed. An exception to this limitation will be made for facilities with multiple guest rooms, such as hotels, motels, hospitals, and assisted-care living facilities, which may receive incentives up to a maximum of $55 per room.

Projected Program Participation

Commercial New Construction				
Year	Total Number of Customers (1)	Total Number of Eligible Customers	Annual Number of Measures/ Participants (2)	Cumulative Penetration Level (%)
2007	191,778	7,671	424	4%
2008	196,120	7,845	849	8%
2009	200,385	8,015	1,273	12%
2010	204,629	8,185	1,697	16%
2011	208,882	8,355	2,121	19%
2012	213,159	8,526	2,546	23%
2013	217,454	8,698	2,970	27%
2014	221,739	8,870	3,394	30%

1. Total Number of Customers is the August 2006 forecast of all commercial and industrial customers.

2. This total is larger than the number of actual customers anticipated installing eligible measures and earning an incentive since many customers install multiple measures at one account.

Projected Savings

Total program savings were developed by first estimating the total savings for each individual measure based on each measure's (1) per customer savings and, (2) annual projected participation. The total projected program savings were then computed as the sum of the individual measure savings, and are shown in the following tables.

Commercial New Construction – At The Meter						
Year	Per Customer KWH Reduction	Per Customer Winter KW Reduction	Per Customer Summer KW Reduction	Total Annual KWH Reduction	Total Annual Winter KW Reduction	Total Annual Summer KW Reduction
2007	14,014	5.0	7.8	5,945,289	2,136	3,301
2008	14,014	5.0	7.8	11,890,578	4,273	6,602
2009	14,014	5.0	7.8	17,835,867	6,409	9,904
2010	14,014	5.0	7.8	23,781,156	8,546	13,205
2011	14,014	5.0	7.8	29,726,445	10,682	16,506
2012	14,014	5.0	7.8	35,671,734	12,818	19,807
2013	14,014	5.0	7.8	41,617,023	14,955	23,109
2014	14,014	5.0	7.8	47,562,312	17,091	26,410

Commercial New Construction – At The Generator						
Year	Per Customer KWH Reduction	Per Customer Winter KW Reduction	Per Customer Summer KW Reduction	Total Annual KWH Reduction	Total Annual Winter KW Reduction	Total Annual Summer KW Reduction
2007	14,981	5.4	8.3	6,355,514	2,284	3,529
2008	14,981	5.4	8.3	12,711,028	4,568	7,058
2009	14,981	5.4	8.3	19,066,542	6,851	10,587
2010	14,981	5.4	8.3	25,422,056	9,135	14,116
2011	14,981	5.4	8.3	31,777,570	11,419	17,645
2012	14,981	5.4	8.3	38,133,084	13,703	21,174
2013	14,981	5.4	8.3	44,488,598	15,987	24,703
2014	14,981	5.4	8.3	50,844,112	18,270	28,232

Per measure impacts for 2007-2014, assuming no overlap.
Per measure impacts vary from year to year because of the changing mix of measures assumed to be installed in any given year.

Cost Effectiveness Analysis

PEF has analyzed this program for cost-effectiveness using the Commission-approved tests described in Rule 25-17.008, Florida Administrative Code. The economic results of the program are as follows:

Commercial New Construction				
Cost-Effectiveness Test	NPV Benefits $(000)	NPV Costs $(000)	NPV Net Benefits $(000)	B/C Ratio
Rate Impact Measure	53,743	37,659	16,084	1.43
Participant	37,212	20,357	16,855	1.83
Total Resource Cost	53,743	20,803	32,939	2.58

PROGRAM: **Commercial New Construction Program RIM**

	BENEFITS					COSTS							
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
YEAR	TOTAL FUEL & O&M SAVINGS $(000)	AVOIDED T&D CAP. COSTS $(000)	AVOIDED GEN. CAP. COSTS $(000)	REVENUE GAINS $(000)	TOTAL BENEFITS $(000)	TOTAL FUEL & O&M INCREASE $(000)	INCREASED T&D CAP. COSTS $(000)	INCREASED GEN. CAP. COSTS $(000)	UTILITY PROGRAM COSTS $(000)	INCENTIVE PAYMENTS $(000)	REVENUE LOSSES $(000)	TOTAL COSTS $(000)	NET BENEFITS $(000)
2006													
2007	582	64			645				78	677	448	1,204	-559
2008	1,305	128	394		1,827				78	677	896	1,652	175
2009	1,861	191	560		2,612				78	677	1,335	2,091	521
2010	2,126	255	830		3,210				78	677	1,806	2,562	648
2011	2,221	319	1,526		4,065				78	677	2,377	3,132	933
2012	3,239	383	1,239		4,860				78	677	2,925	3,680	1,180
2013	3,474	446	1,371		5,291				78	677	3,404	4,160	1,131
2014	3,868	510	1,288		5,666				78	677	3,871	4,627	1,039
2015	3,576	510	1,015		5,102						4,046	4,046	1,056
2016	3,824	510	1,233		5,566						4,156	4,156	1,410
2017	4,159	510	1,564		6,233						4,033	4,033	2,199
2018	3,882	510	1,462		5,854						4,083	4,083	1,771
2019	4,096	510	1,646		6,252						3,982	3,982	2,270
2020	3,625	510	1,323		5,458						3,904	3,904	1,554
2021	3,858	510	1,495		5,863						3,957	3,957	1,906
2022	4,063	510	1,715		6,288						4,012	4,012	2,276
2023	4,288	510	1,891		6,690						4,069	4,069	2,621
2024	4,463	510	2,009		6,981						4,127	4,127	2,855
2025	4,648	510	2,087		7,244						4,186	4,186	3,059
2026	4,754	510	2,151		7,414						4,247	4,247	3,167
2027	4,886	510	2,204		7,599						4,310	4,310	3,289
2028	4,926	510	2,260		7,696						4,375	4,375	3,321
2029	5,114	510	2,349		7,973						4,441	4,441	3,532
2030	5,196	510	2,397		8,105						4,510	4,510	3,596
2031	5,357	510	2,473		8,340						4,580	4,580	3,760
2032	5,441	510	2,529		8,480						4,652	4,652	3,828
2033	5,610	510	2,612		8,732						4,726	4,726	4,006
2034	5,676	510	2,664		8,850						4,802	4,802	4,047
2035	5,921	510	2,765		9,196						4,880	4,880	4,315
NOMINAL	116,035	13,006	49,051		178,092				624	5,419	107,142	113,185	64,906
NPV	35,419	4,213	14,111		53,743				447	3,878	33,334	37,659	16,084

Utility Discount Rate = 8.1
Benefit Cost Ratio = 1.427

PROGRAM: Commercial New Construction Program Participants

YEAR	BENEFITS (1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT'S BENEFITS $(000)	(4) TOTAL BENEFITS $(000)	COSTS (5) PARTICIPANT'S COST $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) TOTAL COSTS $(000)	(8) NET BENEFITS TO PARTICIPANTS $(000)
2006								
2007	448	677		1,126	3,556		3,556	-2,430
2008	896	677		1,574	3,556		3,556	-1,982
2009	1,335	677		2,013	3,556		3,556	-1,543
2010	1,806	677		2,484	3,556		3,556	-1,072
2011	2,377	677		3,054	3,556		3,556	-501
2012	2,925	677		3,602	3,556		3,556	46
2013	3,404	677		4,082	3,556		3,556	526
2014	3,871	677		4,548	3,556		3,556	993
2015	4,046			4,046				4,046
2016	4,156			4,156				4,156
2017	4,033			4,033				4,033
2018	4,083			4,083				4,083
2019	3,982			3,982				3,982
2020	3,904			3,904				3,904
2021	3,957			3,957				3,957
2022	4,012			4,012				4,012
2023	4,069			4,069				4,069
2024	4,127			4,127				4,127
2025	4,186			4,186				4,186
2026	4,247			4,247				4,247
2027	4,310			4,310				4,310
2028	4,375			4,375				4,375
2029	4,441			4,441				4,441
2030	4,510			4,510				4,510
2031	4,580			4,580				4,580
2032	4,652			4,652				4,652
2033	4,726			4,726				4,726
2034	4,802			4,802				4,802
2035	4,880			4,880				4,880
NOMINAL	107,142	5,419		112,561	28,447		28,447	84,114
NPV	33,334	3,878		37,212	20,357		20,357	16,855

Utility Discount Rate = 8.1
Benefit Cost Ratio = 1.828

PROGRAM: **Commercial New Construction Program TRC**

	BENEFITS					COSTS						
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
YEAR	TOTAL FUEL & O&M SAVINGS $(000)	AVOIDED T&D CAP. COSTS $(000)	AVOIDED GEN. CAP. COSTS $(000)	OTHER PARTICIPANT BENEFITS $(000)	TOTAL BENEFITS $(000)	PARTICIPANT'S COST $(000)	TOTAL FUEL & O&M INCREASE $(000)	INCREASED T&D CAP. COSTS $(000)	INCREASED GEN. CAP. COSTS $(000)	UTILITY PROGRAM COSTS $(000)	TOTAL COSTS $(000)	NET BENEFITS $(000)
2006												
2007	582	64			645	3,556				78	3,634	-2,989
2008	1,305	128	394		1,827	3,556				78	3,634	-1,807
2009	1,861	191	560		2,612	3,556				78	3,634	-1,022
2010	2,126	255	830		3,210	3,556				78	3,634	-424
2011	2,221	319	1,526		4,065	3,556				78	3,634	432
2012	3,239	383	1,239		4,860	3,556				78	3,634	1,226
2013	3,474	446	1,371		5,291	3,556				78	3,634	1,657
2014	3,868	510	1,288		5,666	3,556				78	3,634	2,032
2015	3,576	510	1,015		5,102							5,102
2016	3,824	510	1,233		5,566							5,566
2017	4,159	510	1,564		6,233							6,233
2018	3,882	510	1,462		5,854							5,854
2019	4,096	510	1,646		6,252							6,252
2020	3,625	510	1,323		5,458							5,458
2021	3,858	510	1,495		5,863							5,863
2022	4,063	510	1,715		6,288							6,288
2023	4,288	510	1,891		6,690							6,690
2024	4,463	510	2,009		6,981							6,981
2025	4,648	510	2,087		7,244							7,244
2026	4,754	510	2,151		7,414							7,414
2027	4,886	510	2,204		7,599							7,599
2028	4,926	510	2,260		7,696							7,696
2029	5,114	510	2,349		7,973							7,973
2030	5,198	510	2,397		8,105							8,105
2031	5,357	510	2,473		8,340							8,340
2032	5,441	510	2,529		8,480							8,480
2033	5,610	510	2,612		8,732							8,732
2034	5,676	510	2,664		8,850							8,850
2035	5,921	510	2,765		9,196							9,196
NOMINAL	116,035	13,006	49,051		178,092	28,447				624	29,071	149,021
NPV	35,419	4,213	14,111		53,743	20,357				447	20,803	32,939

Utility Discount Rate = 8.1
Benefit Cost Ratio = 2.583

Appendix C

TARIFF REVISIONS
(CLEAN COPY)

RATE SCHEDULE RSL-1
RESIDENTIAL LOAD MANAGEMENT

Availability:

Available only within the range of the Company's Load Management System.
Available to customers whose premises have active load management devices installed prior to [date TBD].
Available to customers whose premises have load management devices installed after [date TBD] that have and are willing to submit to load control of, at a minimum, central electric cooling and heating systems.

Applicable:

To customers eligible for Residential Service under Rate Schedule RS-1 or RSS-1 having a minimum average monthly usage of 600 kWh (based on the most recent 12 months, or, where not available, a projection for 12 months), and utilizing any of the following electrical equipment:

1. Water Heater
2. Central Electric Heating System
3. Central Electric Cooling System
4. Swimming Pool Pump

Character of Service:

Continuous service, alternating current, 60 cycle, single-phase, at the Company's standard distribution secondary voltage available. Three-phase service, if available, will be supplied only under the conditions set forth in the Company's booklet "Requirements for Electric Service and Meter Installations."

Limitation of Service:

Service to the electrical equipment specified above may be interrupted at the option of the Company by means of load management devices installed on the customer's premises.

For new service requests after [date TBD] customers with a central electric heating system that is a heat pump will be installed on Interruption Schedule S. All other new service requests will be installed on Interruption Schedule B. Interruption Schedule C shall be at the option of the customer.

For new service requests after April 1, 1995, and before [date TBD], customers who select the swimming pool pump schedule must also select at least one other schedule.

An installation of an alternative thermal storage heating system under Special Provision No. 7 of this rate schedule is not available after April 1, 1995.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month: –

Customer Charge: $ 8.03

Energy and Demand Charges:

Non-Fuel Energy Charges:

First 1,000 kWh	3.315¢ per kWh
All additional kWh	4.315¢ per kWh

Plus the Cost Recovery Factors listed in Rate Schedule BA-1, *Billing Adjustments*, except the Fuel Cost Recovery Factor: See Sheet No. 6.105 and 6.106

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Load Management Monthly Credit Amounts:[1,2]

Interruptible Equipment	Interruption Schedule				
	A	B	C	D	S
Water Heater	-	-	$3.50	-	-
Central Heating System[3]	$2.00	$8.00	-	-	$8.00
Central Heating System w/Thermal Storage[3]	-	-	-	$8.00	-
Central Cooling System[4]	$1.00	$5.00	-	-	$5.00
Swimming Pool Pump	-	-	$2.50	-	-

(Continued on Page No. 2)

RATE SCHEDULE RSL-1
RESIDENTIAL LOAD MANAGEMENT
(Continued from Page No. 1)

Any customer with a heat pump not taking service under Schedule S who requests a change under this tariff will be required to take service under Schedule S.
Premises taking service under this tariff and controlled by load management devices will remain on the existing schedule until such time as the current customer affirmatively requests a change.
See also Special Provisions 10 and 11 below for further customer optional adjustments to the above credits.

Notes: (1) Load Management credits shall not exceed 40% of the Non-Fuel Energy Charge associated with kWh consumption in excess of 600 kWh per month.

(2) Premises that have load management devices installed prior to [date TBD] may remain on the existing schedule until such time as the customer requests a change under this tariff. When a change is requested, customers may take service only under Schedule B or Schedule S if the customer has a heat pump. Customers may also opt for Schedule C if taking service under another Schedule. Customers whose premises have load management devices installed after [date TBD] will be subject to the Limitations of Service above.

(3) For the billing months of November through March only.

(4) For the billing months of April through October only.

Interruption Schedules:

Schedule A — Equipment interruptions will not exceed an accumulated total of 10 minutes during any 30 minute interval within the Company's designated Peak Periods.

Schedule B — Equipment interruptions will not exceed an accumulated total of 16.5 minutes during any 30 minute interval within the Company's designated Peak Periods.

Schedule C — Equipment may be interrupted continuously, not to exceed 300 minutes, and during the Company's designated Peak Periods. Where a thermal storage system has been installed hereunder, additional interruptions to the water heater will be made during periods of charging thermal the storage system.

Schedule D — The regular heating system may be interrupted continuously and alternative heating provided by means of a thermal storage system installed hereunder.

Schedule S — Equipment interruptions will not exceed an accumulated total of 16.5 minutes during any 30 minute interval within the Company's designated Peak Periods. Heat pump back-up strip may be interrupted continuously, not to exceed 300 minutes, during the Company's designated Peak. When the heat pump back-up strip is being interrupted, the heat pump will not be interrupted.

Peak Periods:

The Peak Periods expressed in terms of prevailing clock time shall be, but are not limited to these as follows:

(1) For the calendar months of November through March, All Days: 6:00 a.m. to 11:00 a.m., and 6:00 p.m. to 10:00 p.m.

(2) For the calendar months of April through October, All Days: 1:00 p.m. to 10:00 p.m.

Terms and Conditions:

All terms and conditions of Rate Schedule RS-1, Residential Service, (i.e. Fuel Charges and other Billing Adjustments, Minimum Monthly Bill, Terms of Payment, Term of Service and Average Billing Plan), shall apply to service under this rate schedule.

(Continued on Page No. 3)

RATE SCHEDULE RSL-1
RESIDENTIAL LOAD MANAGEMENT
(Continued from Page No. 2)

Special Provisions:

1. The Company shall be allowed reasonable access to the customer's premises to install, maintain, inspect, test and remove load management devices on the electrical equipment specified above.

2. Prior to the installation of load management devices, the Company may inspect the customer's electrical equipment to ensure good repair and working condition, but the Company shall not be responsible for the repair or maintenance of the electrical equipment.

3. The Company shall not be required to install load management devices on electrical equipment which would not be economically justified for reasons, such as, excessive installation costs, insufficient load, oversized equipment or abnormal utilization of equipment, including but not limited to, vacation or other limited occupancy residences or qualifying common use facilities.

4. Multiple units of any electrical equipment specified above must all be installed with load management devices to qualify for the credit attributable to that equipment type at that premise.

5. The limitation on interruptible schedules shall not apply during critical capacity conditions on the Company's system; nor shall limitations apply at times the Company requires additional generating resources to maintain firm power sales commitments or supply emergency interchange service to another utility for its firm load obligations only. The Company may also exercise equipment interruptions at any time for purposes of testing and performance evaluation of its Load Management System.

6. If the Company determines that the load management devices have been tampered with, the Company may discontinue service under this rate schedule and bill for all prior load management credits received by the customer, unless an earlier tampering date can be established, plus applicable investigative charges.

7. An alternative thermal storage heating system is available to customers who (a) have resistance strip heating solely as their central electric heating system, (b) have adequate space and provide access for installation and maintenance of a thermal storage system, (c) have an electric water heater circuit which can be utilized for charging a thermal storage system and (d) have normal residential water heating and central heating requirements. The Company shall not be required to provide a thermal storage system where the Company deems the installation to be economically unjustified.

   For qualifying customers, the Company will install, maintain and operate a thermal storage system consisting of a thermal storage (water) tank, a pump, and a heat exchanging coil. The storage tank will be charged at the option and under the control of the Company. When this option is exercised, heating from this system will be available in place of the customer's regular heating system. During periods that the storage tank is being charged, electric service to the customer's regular water heater will be interrupted. An initial incentive payment of $50.00 shall be made to a participating customer.

8. Billing under this Rate Schedule will commence with the first complete billing period following installation of the load management devices. A customer may change interruption schedules or the selection of eleictrical equipment installed with load management devices or transfer to another rate schedule by notifying the Company forty-five days in advance. However, in the event of any revision to the interruption schedules which may affect customer, the Customer shall be allowed ninety days from the effective date of the revision to change schedules or equipment or transfer to another rate schedule.

9. If the Company determines that the effect of equipment interruptions has been offset by the customer's use of supplementary or alternative electrical equipment, or if access cannot be obtained by the Company to inspect, maintain, or remove load management devices, service under this rate schedule may be discontinued and the customer billed for all prior load management credits received over a period not in excess of six months.

10. For customers at premises taking service under Interruption Schedule B or S, and C for electric water heating, for which the premise at any time received the solar thermal water heating incentive, the monthly credit amount will be 25% of the above credit values for Interruption Schedules B, S and C, except for the pool pump. The pool pump credit amount will be at 100%.

11. A customer may elect to have all their credits contributed to the Progress Energy "Photovoltaics for Schools" green program. No partial contributions will be allowed. This program installs photovoltaic panels on schools as funds become available.

RATE SCHEDULE RSL-2
RESIDENTIAL LOAD MANAGEMENT – WINTER ONLY

Availability:

Available only within the range of the Company's Load Management System.

Applicable:

To customers eligible for Residential Service under Rate Schedule RS-1 or RSS-1 having a minimum average monthly usage of 600 kWh for the months of November through March (based on the most recent billings, where not available, a projection for those months) and utilizing both electric water heater and central electric heating systems.

Character of Service:

Continuous service, alternating current, 60 cycle, single-phase, at the Company's standard distribution secondary voltage available. Three-phase service, if available, will be supplied only under the conditions set forth in the Company's booklet "Requirements for Electric Service and Meter Installations."

Limitation of Service:

Service to the electrical equipment specified above may be interrupted at the option of the Company by means of load management devices installed on the customer's premises.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:	$ 8.03
Energy and Demand Charges:	
Non-Fuel Energy Charges:	
First 1,000 kWh	3.315¢ per kWh
All additional kWh	4.315¢ per kWh
Plus the Cost Recovery Factors listed in Rate Schedule BA-1, *Billing Adjustments*, except the Fuel Cost Recovery Factor:	See Sheet No. 6.105 and 6.106

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Load Management Credit Amount:[1]

Interruptible Equipment	Monthly Credit[2]
Water Heater and Central Heating System	$11.50

Notes: (1) Load management credit shall not exceed 40% of the Non-Fuel Energy Charge associated with kWh consumption in excess of 600 kWh/month.

(2) For billing months of November through March only.

Appliance Interruption Schedule:

Heating — Equipment interruptions will not exceed an accumulated total of 16.5 minutes during any 30 minute interval within the Company's designated Peak Periods. Heat pump back-up strip may be interrupted continuously, not to exceed 300 minutes, during the Company's designated Peak. When the heat pump back-up strip is being interrupted, the heat pump will not be interrupted.

Water Heater — Equipment may be interrupted continuously, not to exceed 300 minutes, and during the Company's designated Peak Periods.

(Continued on Page No. 2)

RATE SCHEDULE RSL-2
RESIDENTIAL LOAD MANAGEMENT – WINTER ONLY
(Continued from Page No. 1)

Peak Periods:

The Peak Periods expressed in terms of prevailing clock time shall be, but are not limited to these as follows:

(1) For the calendar months of November through March - All Days: 6:00 a.m. to 11:00 a.m., and
6:00 p.m. to 10:00 p.m.

Terms and Conditions:

All terms and conditions of Rate Schedule RS-1, Residential Service (i.e. Fuel Charges and other Billing Adjustments, Minimum Monthly Bill, Terms of Payment, Term of Service and Budget Billing Plan), shall apply to service under this rate schedule.

Special Provisions:

1. The Company shall be allowed reasonable access to the customer's premises to install, maintain, inspect, test and remove load management devices on the electrical equipment specified above.

2. Prior to the installation of load management devices, the Company may inspect the customer's electrical equipment to ensure good repair and working condition, but the Company shall not be responsible for the repair or maintenance of the electrical equipment.

3. The Company shall not be required to install load management devices on electrical equipment which would not be economically justified for reasons, such as, excessive installation costs, insufficient load, oversized equipment, or abnormal utilization of equipment, including but not limited to, vacation or other limited occupancy residences or qualifying common use facilities.

4. Multiple units of any electrical equipment specified above must all be installed with load management devices to qualify for the credit attributable to that equipment at that premise.

5. The limitation on interruptible schedules shall not apply during critical capacity conditions on the Company's system; nor shall limitations apply at times the Company requires additional generating resources to maintain firm power sales commitments or supply emergency interchange service to another utility for its firm load obligations only. The Company may also exercise equipment interruptions at any time for purposes of testing and performance evaluation of its Load Management System.

6. If the Company determines that the load management devices have been tampered with, the Company may discontinue service under this rate schedule and bill for all prior load management credits received by the customer, unless an earlier tampering date can be established, plus applicable investigative charges.

7. Billing under this Rate Schedule will commence with the first complete billing period following installation of the load management devices. A customer may transfer to another rate schedule by notifying the Company forty-five (45) days in advance. If a customer tranfers to another rate schedule they are not eligible for service under this rate schedule for 12 months from the date of transfer.

8. If the Company determines that the effect of equipment interruptions has been offset by the customer's use of supplementary or alternative electrical equipment, or if access cannot be obtained by the Company to inspect, maintain, or remove load management devices, service under this rate schedule may be discontinued and the customer billed for all prior load management credits received over a period not in excess of six (6) months.

9. A customer may elect to have all their credits contributed to the Progress Energy "Photovoltaics for Schools" green program. No partial contributions will be allowed. This program installs photovoltaic panels on schools as funds become available.

RATE SCHEDULE GSLM-1
GENERAL SERVICE - LOAD MANAGEMENT

Availability:

Available only within the range of the Company's Load Management System.

Applicable:

To customers who are eligible for service under Rate Schedules GS-1, GST-1, GSD-1, or GSDT-1, excluding those customers served under the General Service transition rates, and who elect service under this rate schedule and have electric space cooling equipment suitable for interruptible operation. Also applicable to those customers who have any of the following electrical equipment installed on permanent residential structures and utilized for domestic (household) purposes: (1) water heater(s), (2) central electric heating system(s), (3) central electric cooling system(s), and/or (4) swimming pool pump(s).

Limitation of Service:

Service to specified electrical equipment may be interrupted at the option of the Company by means of load management devices installed on the customer's premises.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

The rates and all other terms and conditions of Company Rate Schedules GS-1, GST-1, GSD-1 or GSDT-1 (whichever shall otherwise be applicable) shall be applicable to service under this rate schedule, subject to the following:

LOAD MANAGEMENT MONTHLY CREDIT AMOUNT

Interruptible Equipment	Interruption Schedule	Credit Based on Installed Capacity[1]	Applicable Billing Months
Electric Space Cooling[3]	A	$ 0.26 Per kW	April thru October
Electric Space Cooling[3]	B	$ 0.56 Per kW	April thru October
Domestically Utilized Equipment[2,3]	[Availability, Schedules and Credits of the otherwise applicable Rate Schedule RSL-1or RSL-2 shall apply]		

Notes:

(1) Credit shall not exceed 50% of the Non-Fuel Energy and Demand Charges; nor, for otherwise applicable Rate Schedule GSDT-1, shall the credit exceed the On-Peak and Base Demand Charges.

(2) Equipment includes water heaters, central heating systems, central cooling systems and swimming pool pumps when such equipment is installed on permanent residential structures and utilized for domestic purposes.

(3) Restricted to existing customers as of July 20, 2000.

Interruption Schedules:

Schedule A Interruptions will not exceed an accumulated total of 10 minutes during any 30-minute interval within the designated Peak Periods.

Schedule B Interruptions will not exceed an accumulated total of 16.5 minutes during any 30-minute interval within the designated Peak Periods.

(Continued on Page No. 2)

RATE SCHEDULE GSLM-1
GENERAL SERVICE – LOAD MANAGEMENT
(Continued from Page No. 1)

Peak Periods:

The designated Peak Periods expressed in terms of prevailing clock time shall be as follows:

(1) For the calendar months of November through March,
All Days: 6:00 a.m. to 11:00 a.m., and 6:00 p.m. to 10:00 p.m.

(2) For the calendar months of April through October,
All Days: 1:00 p.m. to 10:00 p.m.

Special Provisions:

1. The Company shall be allowed reasonable access to the customer's premises to install, maintain, inspect, test and remove load management devices on the electrical equipment specified above.

2. Prior to the installation of load management devices, the Company may inspect the customer's electrical equipment to ensure good repair and working condition, but the Company shall not be responsible for the repair or maintenance of the electrical equipment. The Company may, at its option, require a commercial energy audit as a prerequisite to receiving service under this rate. The audit may be used to establish or confirm equipment capacity, operating hours, or to determine the ability of the Company to control electric demand.

3. The Company shall not be required to install load management devices on electrical equipment, which would not be economically justified, for reasons such as excessive installation costs, oversized equipment or abnormal utilization of equipment, including operating hours which are not considered within the designated Peak Periods.

4. If the Company determines that equipment operating schedules and/or business hours have reduced the ability of the Company to control electric demand during the above designated peak periods, then service under this rate will be discontinued.

5. Where multiple units (including standby or multi-stage) of space conditioning equipment are used to heat or cool a building, all of these units must be equipped with load management devices and normally must be controlled on the same interruption cycle.

6. Billing under this rate schedule will commence with the first complete billing period following installation of the load management devices. During the first year of service, a customer may transfer to another rate schedule by notifying the Company forty-five (45) days in advance. After the first year of service, the customer may transfer to another rate schedule by notifying the Company twelve (12) months in advance. However, in the event of any revision to the interruption schedules which may affect customer, the customer shall be allowed ninety (90) days from the effective date of the revision to change schedules or equipment or transfer to another rate schedule.

7. The limitations on Interruptible Schedules shall not apply during cirtical capacity conditions on the Company's system; nor shall limitations apply at times the Company requires additional generating resources to maintain firm power sales comittments or supply emergency interchange service to another utility for its firm load obligations only. The Company may also exercise equipment interruptions at any time for purposes of testing and performance evaluation of its Load Management System.

8. If the Company determines that the load management devices have been tampered with or disconnected without notice, the Company may discontinue service under this rate schedule and bill for prior load mangement credits received by the customer, plus applicable investigative charges.

9. If the Company determines that the effect of equipment interruptions have been offset by the customer's use of supplementary or alternative electrical equipment, service under this rate schedule may be discontinued and the customer billed for all prior load management credits received over a period not in excess of six (6) months.

10. For purposes of determining eligible credits related to domestically utilized equipment, the customer shall provide the Company actual occupancy rates of permanent residential structures containing each type of equipment for the previous winter (November through March) and summer (April through October) periods. Credits for the current billing period shall apply to the number of items of each installed type of equipment multiplied by the corresponding previous seasonal period's occupancy rate.

RATE SCHEDULE GSLM-2
GENERAL SERVICE LOAD MANAGEMENT – STANDBY GENERATION

Availability:

Available only within the range of the Company's radio switch communications capability.

Applicable:

To customers who are eligible for service under Rate Schedules GS-1, GST-1, GSD-1, or GSDT-1 who have standby generation that will allow facility demand reduction at the request of the Company. The customer's Standby Generation Capacity calculation must be at lease 50 kW in order to remain eligible for the rate. Customers cannot be on this rate schedule and also the General Service Load Management (GSLM-1) rate schedule. Customers cannot use the standby generation for peak shaving.

Limitation of Service:

Operation of the customer's equipment will occur at the Company's request. Power to the facility from the Company will normally remain as back up power for the standby generation. The Customer will be given fifteen (15) minutes to initiate the demand reduction before the capacity calculation (see Definitions) is impacted.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

The rates and all other terms and conditions of Company Rate Schedules GS-1, GST-1, GSD-1 or GSDT-1 (whichever shall otherwise be applicable) shall be applicable to service under this rate schedule, subject to the following:

GSLM-2 MONTHLY CREDIT AMOUNT
STANDBY GENERATION

Credit	Cumulative Fiscal Year Hours
\$2.30 x *C* + \$0.05[1] x kWh monthly	$0 \leq CRH \leq 200$
\$2.76 x *C* + \$0.05[1] x kWh monthly	$200 < CRH$

Immediately upon going on the rate, the customer's Capacity (***C***) is set to a value equivalent to the load the customer's standby generator carries during testing observed by the Customer and a Company representative. The ***C*** will remain at that value until the equipment is requested to run by the Company. The ***C*** for that month and subsequent months will be a calculated value based upon the following formula:

$$C = \frac{\text{kWh annual}}{[\text{CAH} - (\text{\# of Requests} \times \frac{1}{4}\text{ hour})]}$$

Definitions:

kWh annual = Actual measured kWh generated by the standby generator during the previous twelve (12) months during Company control periods (rolling total).

CAH = Cumulative hours requested by the Company for the standby generation to operate for the previous twelve (12) months (rolling total).

CRH = Cumulative standby generator running hours during request periods of the Company for the current fiscal year (the fiscal year begins on the month the customer goes on the GSLM-2 rate).

\# of Requests = The cumulative number of times the Company has requested the standby generation to be operated for the previous twelve (12) months (rolling total).

kWh monthly = Actual measured kWh generated by the standby generator for the current month during Company control periods.

[1] This \$ per kWh rate represents an incentive credit to support Customer O&M associated with run time requested by the Company. PEF will periodically review this incentive rate and request changes as deemed appropriate.

(Continued on Page No. 2)

RATE SCHEDULE GSLM-2
GENERAL SERVICE LOAD MANAGEMENT – STANDBY GENERATION
(Continued from Page No. 1)

Schedules:

Requests by the Company for the customer to reduce facility demand by operation of the standby generation can occur at any time during the day. The GSLM-2 will not be operated more than twice each day with the total operation not exceeding twelve (12) hours. Under extreme emergency conditions, the Company may request the Customer to voluntarily operate their standby generation for longer than twelve (12) hours a day.

Special Provisions:

1. The Company shall be allowed reasonable access to the customer's premises to install, maintain, inspect, test and remove the equipment associated with this rate.
2. Prior to the installation of the equipment, the Company may inspect the customer's electrical equipment (including standby generator) to ensure good repair and working condition, but the Company shall not be responsible for the repair or maintenance of the electrical equipment (including standby generator). The Company may, at its option, require a commercial energy audit as a prerequisite to receiving service under this rate. The audit may be used to establish or confirm equipment capacity, operating hours, or to determine the ability of the Company to control electric demand.
3. If the Company determines that the equipment installed as part of this rate by the Company has been tampered with, the Company may discontinue service under this rate and bill the customer for prior credits received under this rate for that fiscal year.

No changes have been made to this tariff sheet

Appendix C

TARIFF REVISIONS
(LEGISLATIVE FORMAT)

RATE SCHEDULE RSL-1
RESIDENTIAL LOAD MANAGEMENT

Availability:

Available only within the range of the Company's Load Management System. ~~As of July 20, 2000, a~~Available ~~only~~ to customers whose premises have active load management devices installed prior to [date TBD]. ~~As of April 1, 2001, available only to customers taking service hereunder on this date.~~ Available to customers whose premises have load management devices installed after [date TBD] that have and are willing to submit to load control of, at a minimum, central electric cooling and heating systems.

Applicable:

To customers eligible for Residential Service under Rate Schedule RS-1 or RSS-1 having a minimum average monthly usage of 600 kWh (based on the most recent 12 months, or, where not available, a projection for 12 months), and utilizing any of the following electrical equipment:

1. Water Heater
2. Central Electric Heating System
3. Central Electric Cooling System
4. Swimming Pool Pump

Character of Service:

Continuous service, alternating current, 60 cycle, single-phase, at the Company's standard distribution secondary voltage available. Three-phase service, if available, will be supplied only under the conditions set forth in the Company's booklet "Requirements for Electric Service and Meter Installations."

Limitation of Service:

Service to the electrical equipment specified above may be interrupted at the option of the Company by means of load management devices installed on the customer's premises.

For new service requests after [date TBD] customers with a central electric heating system that is a heat pump will be installed on Interruption Schedule S. All other new service requests will be installed on Interruption Schedule B. Interruption Schedule C shall be at the option of the customer.

For new service requests after April 1, 1995, and before [date TBD], customers who select the swimming pool pump schedule must also select at least one other schedule.

An installation of an alternative thermal storage heating system under Special Provision No. 7 of this rate schedule is not available after April 1, 1995.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:	$ 8.03
Energy and Demand Charges:	
Non-Fuel Energy Charges:	
First 1,000 kWh	3.315¢ per kWh
All additional kWh	4.315¢ per kWh
Plus the Cost Recovery Factors listed in Rate Schedule BA-1, *Billing Adjustments*, except the Fuel Cost Recovery Factor:	See Sheet No. 6.105 and 6.106

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Load Management Monthly Credit Amounts:[1,2]

~~(a) Load Management Program (monthly credits)~~

Interruptible Equipment	Interruption Schedule A	B	C	D	S
Water Heater	-	-	$3.50	-	-
Central Heating System[3]	$2.00	$8.00	-	-	$8.00
Central Heating System w/Thermal Storage[3]	-	-	-	$8.00	-
Central Cooling System[4]	$1.00	$5.00	-	-	$5.00
Swimming Pool Pump	-	-	$2.50	-	-

(Continued on Page No. 2)

RATE SCHEDULE RSL-1
RESIDENTIAL LOAD MANAGEMENT
(Continued from Page No. 1)

Any customer with a heat pump not taking service under Schedule S who requests a change under this tariff will be required to take service under Schedule S.
Premises taking service under this tariff and controlled by load management devices will remain on the existing schedule until such time as the current customer affirmatively requests a change.
See also Special Provisions 10 and 11 below for further customer optional adjustments to the above credits.
~~(b) Advanced Load Management Program (per day interrupted credits)~~

~~Interruptible Equipment~~

~~Central Cooling System[4] = $4.50 x (% - 1)~~
~~50~~
~~Central Heating System[3] = $3.00 x (% - 1)~~
~~50~~
~~60 ≤ % ≤ 100~~
~~% = Customer selected maximum interruption %~~

Notes: (1) Load Management credits shall not exceed 40% of the Non-Fuel Energy Charge associated with kWh consumption in excess of 600 kWh/ per month.

(2) Premises that have load management devices installed prior to [date TBD] may remain on the existing schedule until such time as the customer requests a change under this tariff. When a change is requested, customers may take service only under Schedule B or Schedule S if the customer has a heat pump. Customers may also opt for Schedule C if taking service under another Schedule.~~For central heating and cooling systems, selection of Interruption Schedule A, Schedule B or Advanced Load Management is at the option of the customer.~~ Customers whose premises have load management devices installed after [date TBD] will be subject to the Limitations of Service above.

(3) For the billing months of November through March only.

(4) For the billing months of April through October only.

Interruption Schedules:

Schedule A — Equipment interruptions will not exceed an accumulated total of 10 minutes during any 30 minute interval within the Company's designated Peak Periods.

Schedule B — Equipment interruptions will not exceed an accumulated total of 16.5 minutes during any 30 minute interval within the Company's designated Peak Periods.

Schedule C — Equipment may be interrupted continuously, not to exceed 300 minutes, and during the Company's designated Peak Periods. Where a thermal storage system has been installed hereunder, additional interruptions to the water heater will be made during periods of charging thermal the storage system.

Schedule D — The regular heating system may be interrupted continuously and alternative heating provided by means of a thermal storage system installed hereunder.

Schedule S — Equipment interruptions will not exceed an accumulated total of 16.5 minutes during any 30 minute interval within the Company's designated Peak Periods. Heat pump back-up strip may be interrupted continuously, not to exceed 300 minutes, during the Company's designated Peak. When the heat pump back-up strip is being interrupted, the heat pump will not be interrupted.

~~Advanced — Under the Advanced Load Management Program, customers may select from among Company determined interruption schedules for central heating systems and/or central cooling systems ranging from 18 minutes during any 30 minute interval to 30 minutes during any 30 minute interval.~~

~~Customers participating in the Advanced Load Management Program must also be Interruption Schedule B participants. Under the Advanced Load Management Program, customers will receive an Advanced Load Management credit for each day (midnight to midnight) in which this program is implemented. This credit will be in addition to the customer's monthly load management credits.~~

Peak Periods:

The Peak Periods expressed in terms of prevailing clock time shall be, but are not limited to these as follows:

(1) For the calendar months of November through March, All Days: 6:00 a.m. to 11:00 a.m., and 6:00 p.m. to 10:00 p.m.

(2) For the calendar months of April through October, All Days: 1:00 p.m. to 10:00 p.m.

Terms and Conditions:

All terms and conditions of Rate Schedule RS-1, Residential Service, (i.e. Fuel Charges and other Billing Adjustments, Minimum Monthly Bill, Terms of Payment, Term of Service and Average Billing Plan), shall apply to service under this rate schedule.

(Continued on Page No. 3)

RATE SCHEDULE RSL-1
RESIDENTIAL LOAD MANAGEMENT
(Continued from Page No. 2)

Special Provisions:

1. The Company shall be allowed reasonable access to the customer's premises to install, maintain, inspect, test and remove load management devices on the electrical equipment specified above.

2. Prior to the installation of load management devices, the Company may inspect the customer's electrical equipment to ensure good repair and working condition, but the Company shall not be responsible for the repair or maintenance of the electrical equipment.

3. The Company shall not be required to install load management devices on electrical equipment which would not be economically justified for reasons, such as, excessive installation costs, insufficient load, oversized ~~heating or cooling~~ equipment or abnormal utilization of equipment, including but not limited to, vacation or other limited occupancy residences or qualifying common use facilities.

4. Multiple units of any electrical equipment specified above must all be installed with load management devices to qualify for the credit attributable to that equipment type at that premise.

5. The limitation on interruptible schedules shall not apply during critical capacity conditions on the Company's system; nor shall limitations apply at times the Company requires additional generating resources to maintain firm power sales commitments or supply emergency interchange service to another utility for its firm load obligations only. The Company may also exercise equipment interruptions at any time for purposes of testing and performance evaluation of its Load Management System.

6. If the Company determines that the load management devices have been tampered with, the Company may discontinue service under this rate schedule and bill for all prior load management credits received by the customer, unless an earlier tampering date can be established, plus applicable investigative charges.

7. An alternative thermal storage heating system is available to customers who (a) have resistance strip heating solely as their central electric heating system, (b) have adequate space and provide access for installation and maintenance of a thermal storage system, (c) have an electric water heater circuit which can be utilized for charging a thermal storage system and (d) have normal residential water heating and central heating requirements. The Company shall not be required to provide a thermal storage system where the Company deems the installation to be economically unjustified.

   For qualifying customers, the Company will install, maintain and operate a thermal storage system consisting of a thermal storage (water) tank, a pump, and a heat exchanging coil. The storage tank will be charged at the option and under the control of the Company. When this option is exercised, heating from this system will be available in place of the customer's regular heating system. During periods that the storage tank is being charged, electric service to the customer's regular water heater will be interrupted. An initial incentive payment of $50.00 shall be made to a participating customer.

8. Billing under this Rate Schedule will commence with the first complete billing period following installation of the load management devices. A customer may change interruption schedules or the selection of eleictrical equipment installed with load management devices or transfer to another rate schedule by notifying the Company forty-five days in advance. However, in the event of any revision to the interruption schedules which may affect customer, the Customer shall be allowed ninety days from the effective date of the revision to change schedules or equipment or transfer to another rate schedule.

9. If the Company determines that the effect of equipment interruptions has been offset by the customer's use of supplementary or alternative electrical equipment, or if access cannot be obtained by the Company to inspect, maintain, or remove load management devices, service under this rate schedule may be discontinued and the customer billed for all prior load management credits received over a period not in excess of six months.

10. For customers at premises taking service under Interruption Schedule B or S, and C for electric water heating, for which the premise at any time received the solar thermal water heating incentive, the monthly credit amount will be 25% of the above credit values for Interruption Schedules B, S and C, except for the pool pump. The pool pump credit amount will be at 100%.

11. A customer may elect to have all their credits contributed to the Progress Energy "Photovoltaics for Schools" green program. No partial contributions will be allowed. This program installs photovoltaic panels on schools as funds become available.

RATE SCHEDULE RSL-2
RESIDENTIAL LOAD MANAGEMENT – WINTER ONLY

Availability:

Available only within the range of the Company's Load Management System.

Applicable:

To customers eligible for Residential Service under Rate Schedule RS-1 or RSS-1 having a minimum average monthly usage of 600 kWh for the months of November through March (based on the most recent billings, where not available, a projection for those months) and utilizing both electric water heater and central electric heating systems.

Character of Service:

Continuous service, alternating current, 60 cycle, single-phase, at the Company's standard distribution secondary voltage available. Three-phase service, if available, will be supplied only under the conditions set forth in the Company's booklet "Requirements for Electric Service and Meter Installations."

Limitation of Service:

Service to the electrical equipment specified above may be interrupted at the option of the Company by means of load management devices installed on the customer's premises.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:	$ 8.03
Energy and Demand Charges:	
Non-Fuel Energy Charges:	
First 1,000 kWh	3.315¢ per kWh
All additional kWh	4.315¢ per kWh
Plus the Cost Recovery Factors listed in Rate Schedule BA-1, *Billing Adjustments,* except the Fuel Cost Recovery Factor:	See Sheet No. 6.105 and 6.106

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Load Management Credit Amount:[1]

Interruptible Equipment	Monthly Credit[2]
Water Heater and Central Heating System	$11.50

Notes: (1) Load management credit shall not exceed 40% of the Non-Fuel Energy Charge associated with kWh consumption in excess of 600 kWh/month.

(2) For billing months of November through March only.

Appliance Interruption Schedule:

Heating — Equipment interruptions will not exceed an accumulated total of 16.5 minutes during any 30 minute interval within the Company's designated Peak Periods. Heat pump back-up strip may be interrupted continuously, not to exceed 300 minutes, during the Company's designated Peak. When the heat pump back-up strip is being interrupted, the heat pump will not be interrupted.

Water Heater — Equipment may be interrupted continuously, not to exceed 300 minutes, and during the Company's designated Peak Periods.

(Continued on Page No. 2)

RATE SCHEDULE RSL-2
RESIDENTIAL LOAD MANAGEMENT – WINTER ONLY
(Continued from Page No. 1)

Peak Periods:

The Peak Periods expressed in terms of prevailing clock time shall be, but are not limited to these as follows:

(1) For the calendar months of November through March - All Days: 6:00 a.m. to 11:00 a.m., and 6:00 p.m. to 10:00 p.m.

Terms and Conditions:

All terms and conditions of Rate Schedule RS-1, Residential Service (i.e. Fuel Charges and other Billing Adjustments, Minimum Monthly Bill, Terms of Payment, Term of Service and Budget Billing Plan), shall apply to service under this rate schedule.

Special Provisions:

1. The Company shall be allowed reasonable access to the customer's premises to install, maintain, inspect, test and remove load management devices on the electrical equipment specified above.
2. Prior to the installation of load management devices, the Company may inspect the customer's electrical equipment to ensure good repair and working condition, but the Company shall not be responsible for the repair or maintenance of the electrical equipment.
3. The Company shall not be required to install load management devices on electrical equipment which would not be economically justified for reasons, such as, excessive installation costs, insufficient load, oversized ~~heating or cooling~~ equipment, or abnormal utilization of equipment, including but not limited to, vacation or other limited occupancy residences or qualifying common use facilities.
4. Multiple units of any electrical equipment specified above must all be installed with load management devices to qualify for the credit attributable to that equipment at that premise.
5. The limitation on interruptible schedules shall not apply during critical capacity conditions on the Company's system; nor shall limitations apply at times the Company requires additional generating resources to maintain firm power sales commitments or supply emergency interchange service to another utility for its firm load obligations only. The Company may also exercise equipment interruptions at any time for purposes of testing and performance evaluation of its Load Management System.
6. If the Company determines that the load management devices have been tampered with, the Company may discontinue service under this rate schedule and bill for all prior load management credits received by the customer, unless an earlier tampering date can be established, plus applicable investigative charges.
7. Billing under this Rate Schedule will commence with the first complete billing period following installation of the load management devices. A customer may transfer to another rate schedule by notifying the Company forty-five (45) days in advance. If a customer tranfers to another rate schedule they are not eligible for service under this rate schedule for 12 months from the date of transfer.
8. If the Company determines that the effect of equipment interruptions has been offset by the customer's use of supplementary or alternative electrical equipment, or if access cannot be obtained by the Company to inspect, maintain, or remove load management devices, service under this rate schedule may be discontinued and the customer billed for all prior load management credits received over a period not in excess of six (6) months.
9. A customer may elect to have all their credits contributed to the Progress Energy "Photovoltaics for Schools" green program. No partial contributions will be allowed. This program installs photovoltaic panels on schools as funds become available.

RATE SCHEDULE GSLM-1
GENERAL SERVICE - LOAD MANAGEMENT

Availability:

Available only within the range of the Company's Load Management System.

Applicable:

To customers who are eligible for service under Rate Schedules GS-1, GST-1, GSD-1, or GSDT-1, excluding those customers served under the General Service transition rates, and who elect service under this rate schedule and have electric space cooling equipment suitable for interruptible operation. Also applicable to those customers who have any of the following electrical equipment installed on permanent residential structures and utilized for domestic (household) purposes: (1) water heater(s), (2) central electric heating system(s), (3) central electric cooling system(s), and/or (4) swimming pool pump(s).

Limitation of Service:

Service to specified electrical equipment may be interrupted at the option of the Company by means of load management devices installed on the customer's premises.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

The rates and all other terms and conditions of Company Rate Schedules GS-1, GST-1, GSD-1 or GSDT-1 (whichever shall otherwise be applicable) shall be applicable to service under this rate schedule, subject to the following:

LOAD MANAGEMENT MONTHLY CREDIT AMOUNT

Interruptible Equipment	Interruption Schedule	Credit Based on Installed Capacity[1]	Applicable Billing Months
Electric Space Cooling[3]	A	$ 0.26 Per kW	April thru October
Electric Space Cooling[3]	B	$ 0.56 Per kW	April thru October
Domestically Utilized Equipment[2,3]	[Availability, Schedules and Credits of the otherwise applicable Rate Schedule RSL-1or RSL-2 shall apply]		

Notes:

(1) Credit shall not exceed 50% of the Non-Fuel Energy and Demand Charges; nor, for otherwise applicable Rate Schedule GSDT-1, shall the credit exceed the On-Peak and Base Demand Charges.

(2) Equipment includes water heaters, central heating systems, central cooling systems and swimming pool pumps when such equipment is installed on permanent residential structures and utilized for domestic purposes.

(3) Restricted to existing customers as of July 20, 2000.

Interruption Schedules:

Schedule A Interruptions will not exceed an accumulated total of 10 minutes during any 30-minute interval within the designated Peak Periods.

Schedule B Interruptions will not exceed an accumulated total of 16.5 minutes during any 30-minute interval within the designated Peak Periods.

(Continued on Page No. 2)

RATE SCHEDULE GSLM-1
GENERAL SERVICE – LOAD MANAGEMENT
(Continued from Page No. 1)

Peak Periods:

The designated Peak Periods expressed in terms of prevailing clock time shall be as follows:

(1) For the calendar months of November through March,
All Days: 6:00 a.m. to 11:00 a.m., and 6:00 p.m. to 10:00 p.m.

(2) For the calendar months of April through October,
All Days: 1:00 p.m. to 10:00 p.m.

Special Provisions:

1. The Company shall be allowed reasonable access to the customer's premises to install, maintain, inspect, test and remove load management devices on the electrical equipment specified above.

2. Prior to the installation of load management devices, the Company may inspect the customer's electrical equipment to ensure good repair and working condition, but the Company shall not be responsible for the repair or maintenance of the electrical equipment. The Company may, at its option, require a commercial energy audit as a prerequisite to receiving service under this rate. The audit may be used to establish or confirm equipment capacity, operating hours, or to determine the ability of the Company to control electric demand.

3. The Company shall not be required to install load management devices on electrical equipment, which would not be economically justified, for reasons such as excessive installation costs, oversized ~~heating or cooling~~ equipment or abnormal utilization of equipment, including operating hours which are not considered within the designated Peak Periods.

4. If the Company determines that equipment operating schedules and/or business hours have reduced the ability of the Company to control electric demand during the above designated peak periods, then service under this rate will be discontinued.

5. Where multiple units (including standby or multi-stage) of space conditioning equipment are used to heat or cool a building, all of these units must be equipped with load management devices and normally must be controlled on the same interruption cycle.

6. Billing under this rate schedule will commence with the first complete billing period following installation of the load management devices. During the first year of service, a customer may transfer to another rate schedule by notifying the Company forty-five (45) days in advance. After the first year of service, the customer may transfer to another rate schedule by notifying the Company twelve (12) months in advance. However, in the event of any revision to the interruption schedules which may affect customer, the customer shall be allowed ninety (90) days from the effective date of the revision to change schedules or equipment or transfer to another rate schedule.

7. The limitations on Interruptible Schedules shall not apply during cirtical capacity conditions on the Company's system; nor shall limitations apply at times the Company requires additional generating resources to maintain firm power sales comittments or supply emergency interchange service to another utility for its firm load obligations only. The Company may also exercise equipment interruptions at any time for purposes of testing and performance evaluation of its Load Management System.

8. If the Company determines that the load management devices have been tampered with or disconnected without notice, the Company may discontinue service under this rate schedule and bill for prior load mangement credits received by the customer, plus applicable investigative charges.

9. If the Company determines that the effect of equipment interruptions have been offset by the customer's use of supplementary or alternative electrical equipment, service under this rate schedule may be discontinued and the customer billed for all prior load management credits received over a period not in excess of six (6) months.

10. For purposes of determining eligible credits related to domestically utilized equipment, the customer shall provide the Company actual occupancy rates of permanent residential structures containing each type of equipment for the previous winter (November through March) and summer (April through October) periods. Credits for the current billing period shall apply to the number of items of each installed type of equipment multiplied by the corresponding previous seasonal period's occupancy rate.

RATE SCHEDULE GSLM-2
GENERAL SERVICE LOAD MANAGEMENT – STANDBY GENERATION

Availability:

Available only within the range of the Company's radio switch communications capability.

Applicable:

To customers who are eligible for service under Rate Schedules GS-1, GST-1, GSD-1, or GSDT-1 who have standby generation that will allow facility demand reduction at the request of the Company. The customer's Standby Generation Capacity calculation must be at lease 50 kW in order to remain eligible for the rate. Customers cannot be on this rate schedule and also the General Service Load Management (GSLM-1) rate schedule. Customers cannot use the standby generation for peak shaving.

Limitation of Service:

Operation of the customer's equipment will occur at the Company's request. Power to the facility from the Company will normally remain as back up power for the standby generation. The Customer will be given fifteen (15) minutes to initiate the demand reduction before the capacity calculation (see Definitions) is impacted.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

The rates and all other terms and conditions of Company Rate Schedules GS-1, GST-1, GSD-1 or GSDT-1 (whichever shall otherwise be applicable) shall be applicable to service under this rate schedule, subject to the following:

GSLM-2 MONTHLY CREDIT AMOUNT
STANDBY GENERATION

Credit	Cumulative Fiscal Year Hours
\$2.30~~10~~ x C + \$0.05[1] x kWh monthly	0 ≤ CRH ≤ 200
\$2.76 x C + \$0.05[1] x kWh monthly	200 < CRH

Immediately upon going on the rate, the customer's Capacity (**C**) is set to a value equivalent to the load the customer's standby generator carries during testing observed by the Customer and a Company representative. The **C** will remain at that value until the equipment is requested to run by the Company. The **C** for that month and subsequent months will be a calculated value based upon the following formula:

$$C = \frac{\text{kWh annual}\cancel{\text{(actual)}}}{[\text{CAH} - (\text{\# of Requests} \times \tfrac{1}{4}\text{ hour})]}$$

Definitions:

kWh annual = Actual ~~M~~measured kWh generated by the standby generator during the previous twelve (12) months during Company control periods (rolling total).

CAH = Cumulative hours requested by the Company for the standby generation to operate for the previous twelve (12) months (rolling total).

CRH = Cumulative standby generator running hours during request periods of the Company for the current fiscal year (the fiscal year begins on the month the customer goes on the GSLM-2 rate).

\# of Requests = The cumulative number of times the Company has requested the standby generation to be operated for the previous twelve (12) months (rolling total).

kWh monthly = Actual measured kWh generated by the standby generator for the current month during Company control periods.

[1] This \$ per kWh rate represents an incentive credit to support Customer O&M associated with run time requested by the Company. PEF will periodically review this incentive rate and request changes as deemed appropriate.

(Continued on Page No. 2)

RATE SCHEDULE GSLM-2
GENERAL SERVICE LOAD MANAGEMENT – STANDBY GENERATION
(Continued from Page No. 1)

Schedules:

Requests by the Company for the customer to reduce facility demand by operation of the standby generation can occur at any time during the day. The GSLM-2 will not be operated more than twice each day with the total operation not exceeding twelve (12) hours. Under extreme emergency conditions, the Company may request the Customer to voluntarily operate their standby generation for longer than twelve (12) hours a day.

Special Provisions:

1. The Company shall be allowed reasonable access to the customer's premises to install, maintain, inspect, test and remove the equipment associated with this rate.
2. Prior to the installation of the equipment, the Company may inspect the customer's electrical equipment (including standby generator) to ensure good repair and working condition, but the Company shall not be responsible for the repair or maintenance of the electrical equipment (including standby generator). The Company may, at its option, require a commercial energy audit as a prerequisite to receiving service under this rate. The audit may be used to establish or confirm equipment capacity, operating hours, or to determine the ability of the Company to control electric demand.
3. If the Company determines that the equipment installed as part of this rate by the Company has been tampered with, the Company may discontinue service under this rate and bill the customer for prior credits received under this rate for that fiscal year.

No changes have been made to this tariff sheet

Ms. Blanca S. Bayo
Division of the Commission Clerk
And Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

RE: Docket 060647

Dear Ms. Bayo:

Enclosed for filing in the subject docket on behalf of Progress Energy Florida, Inc. are an original and xxxx copies of revision to certain exhibits to the Petition for Approval of Demand Side Management Programs filed on September 27, 2006. Amended program details are provided for the following items:

Renewable Energy Program beginning on page 26. The projected savings estimates contain typographical and pasting errors and do not reflect the correct "Per Customer Winter KW Reduction" or "Total Annual Winter KW reduction. The correct savings at the meter and generator tables are provided below. Additionally, a footnote (3) was added to the "Projected Program Participation" table to clarify that the estimated annual number of measure participants represents the estimated participants for the solar thermal and photovoltaic portions of this program. That modification has also been included below.

Renewable Energy Table for 2006 DSM Modification Filing

Year	Total Number of Customers (1)	Total Number of Eligible Customers (2)	Annual Number of Measure Participants (3)	Cumulative Penetration Level (%)
2007	1,452,431	347,000	1,066	0.31%
2008	1,481,473	357,000	1,503	0.42%
2009	1,509,934	382,000	2,035	0.53%
2010	1,538,271	407,000	2,617	0.64%
2011	1,566,662	427,000	3,214	0.75%
2012	1,595,236	437,000	3,771	0.86%
2013	1,623,967	447,000	4,348	0.97%
2014	1,652,629	457,000	4,945	1.08%

1. *Total Number of Customers is the forecast of all residential customers, from the August 2006 Forecast.*
2. *Total number of Eligible Customers is based on Current and projected residential energy management participation.*
3. *Annual number of measure participants reflects the expected participattion in the Solar Thermal and PV portions of the program.*

Renewable Energy - At the Meter						
Year	Per Customer KWH Reduction	Per Customer Winter KW Reduction	Per Customer Summer KW Reduction	Total Annual KWH Reduction	Total Annual Winter KW Reduction	Total Annual Summer KW Reduction
2007	929	2.14	1.20	23,229	54	30
2008	929	2.14	1.20	69,687	161	90
2009	929	2.14	1.20	116,145	268	150
2010	929	2.14	1.20	162,603	375	210
2011	929	2.14	1.20	209,061	482	270
2012	929	2.14	1.20	255,519	589	330
2013	929	2.14	1.20	301,977	696	390
2014	929	2.14	1.20	348,435	803	450

Renewable Energy - At the Generator						
Year	Per Customer KWH Reduction	Per Customer Winter KW Reduction	Per Customer Summer KW Reduction	Total Annual KWH Reduction	Total Annual Winter KW Reduction	Total Annual Summer KW Reduction
2007	990	2.28	1.279	24,752	57	32
2008	990	2.28	1.279	74,257	171	96
2009	990	2.28	1.279	123,762	285	160
2010	990	2.28	1.279	173,267	399	224
2011	990	2.28	1.279	222,771	513	288
2012	990	2.28	1.279	272,276	627	352
2013	990	2.28	1.279	321,781	741	416
2014	990	2.28	1.279	371,285	855	480

Residential Year Round Energy Management beginning on page 32. The Projected Program Participation table "Residential Year Round Load Management" on page 33 does not reflect the correct Annual Number of Participants. Also, the savings estimates shown on page 34 in the tables, "At the Meter" and "At the Generator" were incorrectly pasted and do not accurately reflect the savings impact. The corrected tables are provided below.

Residential Year Round Load Management				
Year	Total Number of Customers (1)	Total Number of Eligible Customers (2)	Annual Number of Participants (3)	Cumulative Penetration Level % (4)
2007	1,446,239	1,234,991	7,200	0.58%
2008	1,472,551	1,257,459	14,500	1.15%
2009	1,498,885	1,279,947	22,200	1.73%
2010	1,524,944	1,302,199	29,900	2.30%
2011	1,550,477	1,324,003	37,600	2.84%
2012	1,575,780	1,345,610	45,300	3.37%
2013	1,600,906	1,367,066	53,100	3.88%
2014	1,625,899	1,388,408	61,400	4.42%

1. *The total number of customers in residential rate class*
2. *The total number of eligible customers in residential rate class*
3. *Net New participants of previously submitted winter only and year round LM Schedule*
4. *Column 3 cumulative does not reflect participation prior to 2007*

Year-Round Load Management - At the Meter						
Year	Per Customer KWH Reduction	Per Customer Winter KW Reduction	Per Customer Summer KW Reduction	Total Annual KWH Reduction	Total Annual Winter KW Reduction	Total Annual Summer KW Reduction
2007	18	2.14	1.20	130,752	15,408	8,640
2008	18	2.14	1.20	263,320	31,030	17,400
2009	18	2.14	1.20	403,152	47,508	26,640
2010	18	2.14	1.20	542,984	63,986	35,880
2011	18	2.14	1.20	682,816	80,464	45,120
2012	18	2.14	1.20	822,648	96,942	54,360
2013	18	2.14	1.20	964,296	113,634	63,720
2014	18	2.14	1.20	1,115,024	131,396	73,680

Year-Round Load Management - At the Generator						
Year	Per Customer KWH Reduction	Per Customer Winter KW Reduction	Per Customer Summer KW Reduction	Total Annual KWH Reduction	Total Annual Winter KW Reduction	Total Annual Summer KW Reduction
2007	19	2.28	1.28	139,327	16,418	9,207
2008	19	2.28	1.28	280,589	33,065	18,541
2009	19	2.28	1.28	429,591	50,624	28,387
2010	19	2.28	1.28	578,593	68,182	38,233
2011	19	2.28	1.28	727,595	85,741	48,079
2012	19	2.28	1.28	876,597	103,299	57,925
2013	19	2.28	1.28	1,027,535	121,086	67,899
2014	19	2.28	1.28	1,188,147	140,013	78,512

Additional Amendments

Some additional minor changes to clarify language in the Home Energy Improvement and Neighborhood Energy Saver Program are noted below:

Home Energy Improvement Program: Beginning on page 6 of the document the following change noted in red below is provided:

Attic Insulation R15 to R30 Upgrade

This portion of the program encourages customers having greater than R 11 and less than R16 existing insulation to increase the attic insulation to R30 by paying a portion of the installed cost. The incentive will be $75 per residence up to 1500 sq. ft.; an additional incentive of 7¢ per square foot is paid for larger homes.

Neighborhood Energy Saver Program: On pages 2 and 19 of the document, the following references will be struck from the document:

This program includes the following measures:

- Compact fluorescent bulb
- Water heater wrap and insulation for water pipes
- Water heater temperature check and adjustment
- Low flow faucet aerators
- Low flow showerhead

- ~~Water closet leak detection tablets~~
- Refrigerator coil brush
- Refrigerator thermometer
- Wall plate thermometer
- HVAC winterization kit
- HVAC filters
- Change filter calendar
- Weatherization Measures

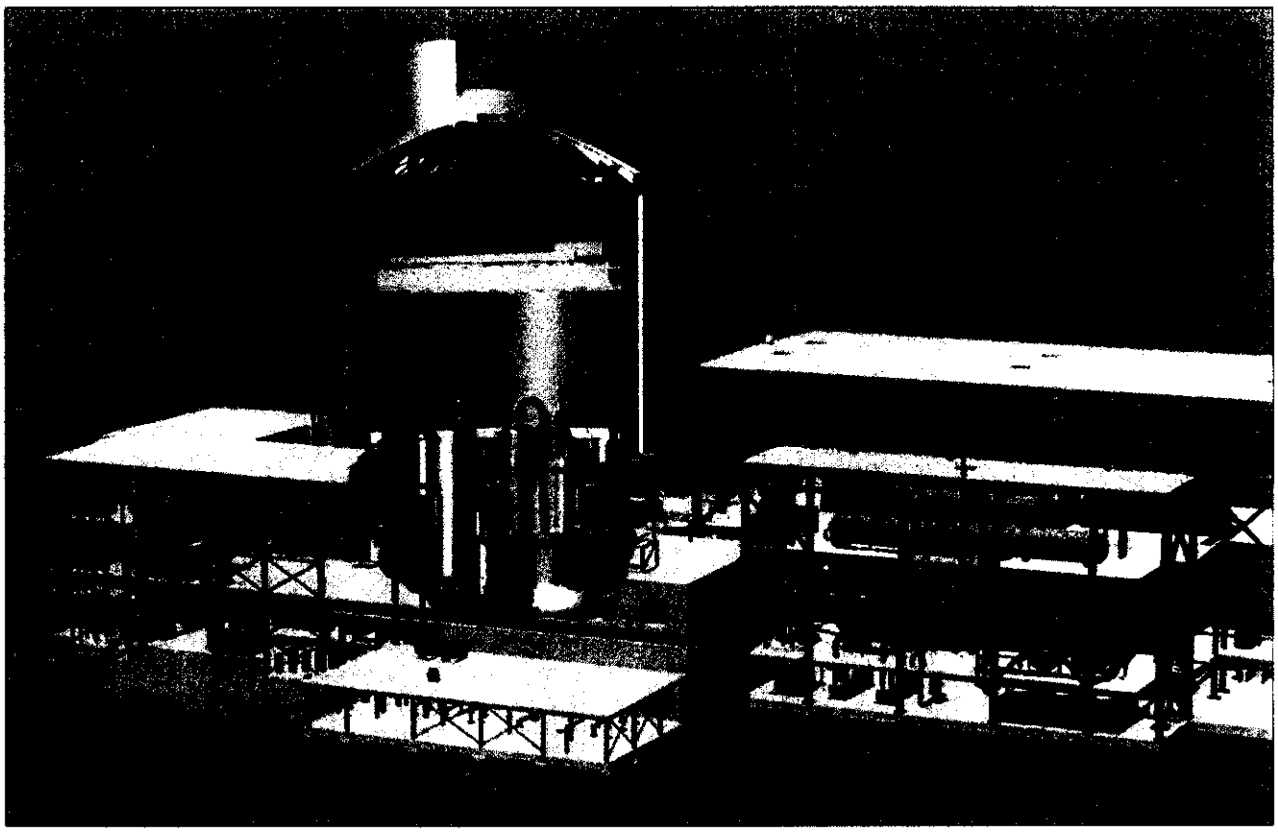
Water Closet Leak Detection Tablets

~~This portion of the program will educate the customer on the process of leak detection.~~

If you have any questions about the amendments, please do not hesitate to call me.

Sincerely,

John A. Masiello
Manager, DSM & Alternative Energy Strategies



BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Generic investigation into the aggregate electric utility reserve margins planned for Peninsular Florida.	DOCKET NO. 981890-EU ORDER NO. PSC-99-2507-S-EU ISSUED: December 22, 1999

The following Commissioners participated in the disposition of this matter:

JOE GARCIA, Chairman
J. TERRY DEASON
SUSAN F. CLARK
E. LEON JACOBS, JR.

APPEARANCES:

JAMES D. BEASLEY and LEE WILLIS, Ausley & McMullen, Post Office Box 391, Tallahassee, Florida 32302, appearing on behalf of Tampa Electric Company.

JOSEPH A. McGLOTHLIN, McWhirter, Reeves, McGlothlin, Davidson, Dekker, Kaufman, Arnold & Steen, 117 South Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of Reliant Energy Power Generation.

VICKI GORDON KAUFMAN and JOHN MCWHIRTER, McWhirter, Reeves, McGlothlin, Davidson, Dekker, Kaufman, Arnold & Steen, 117 South Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of the Florida Industrial Power Users Group.

GARY L. SASSO, Carlton, Fields, Ward, Emmanuel, Smith & Cutler, P.A., Post Office Box 2861, St. Petersburg, Florida 33731, appearing on behalf of Florida Power Corporation.

MATTHEW M. CHILDS, Steel, Hector & Davis, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301, appearing on behalf of Florida Power & Light Company.

DEBRA SWIM, Legal Environmental Assistance Foundation, 1115 North Gadsden Street Tallahassee, Florida 32301, appearing on behalf of Legal Environmental Assistance Foundation (LEAF).

ROY YOUNG, Young, van Assenderp and Varnadoe, P. A., P. O. Box 1833, Tallahassee, Florida 32302-1833, appearing on behalf of the City of Lakeland and Kissimmee Utility Authority.

PAUL SEXTON, Thornton Williams & Associates, 215 South Monroe Street, Suite 600-A, Tallahassee, Florida 32301, appearing on behalf of the Florida Reliability Coordinating Council, Inc.

JON C. MOYLE, JR. Moyle, Flanigan, Katz, Kolins, Raymond & Sheehan, 210 South Monroe Street, Tallahassee, Florida 32301, appearing on behalf of PG&E Generating Company.

ROBERT SCHEFFEL WRIGHT, Landers & Parsons, 310 West College Avenue, Tallahassee, Florida 32302, appearing on behalf of Duke Energy New Smyrna Beach Power Company, Ltd., L.L.P.

FREDERICK M. BRYANT, General Counsel, Florida Municipal Power Agency, 2010 Delta Boulevard, Tallahassee, Florida 32315, appearing on behalf of Florida Municipal Power Agency.

THOMAS J. MAIDA, III, Foley & Lardner, Post Office Box 508, Tallahassee, Florida 32302, appearing on behalf of Seminole Electric Cooperative.

KENNETH A. HOFFMAN, Rutledge, Ecenia, Underwood, Purnell and Hoffman, P. O. Box 511, 215 South Monroe Street, Suite 420, Tallahassee, Florida 32302-0551, appearing on behalf of the City of Tallahassee.

MICHAEL B. WEDNER, Office of General Counsel, 117 West Duval Street, Suite 480, Jacksonville, Florida 32202, appearing on behalf of Jacksonville Electric Authority.

ROBERT V. ELIAS, GRACE JAYE and COCHRAN KEATING, FPSC Division of Legal Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Florida Public Service Commission Staff.

ORDER APPROVING STIPULATION

BY THE COMMISSION:

During our reviews of the Ten Year Site Plans filed in 1997 and 1998, we expressed concerns about the adequacy of the reserve margins planned for Peninsular Florida. At the December 15, 1998, Internal Affairs meeting, we directed staff to open this docket to consider the reserve margins planned for Peninsular Florida electric utilities.

By Order No. PSC-99-1274-PCO-EI, nineteen issues were identified for consideration in this proceeding. The investor-owned utilities, the cooperative utilities, several municipal utilities, the various intervenors, and Commission staff filed testimony concerning these issues. The hearing was scheduled for November 2nd and 3rd, 1999.

At the outset of the hearing, Florida Power & Light Company (FPL), Florida Power Corporation (FPC), and Tampa Electric Company (TECO), presented a proposal designed to settle the case; addressing what they believe are the Commission's major concerns. By the proposal, these three utilities stipulated to voluntarily adopting a twenty percent reserve margin planning criterion. Each of these three utilities would achieve the twenty percent level by the summer of 2004. Further, pursuant to the proposal, no decisions would be made concerning the specifically enumerated issues, and the docket would be closed. FPL, FPC, and TECO would be the only utilities adopting the twenty percent criteria.

Other parties argued in support of and against the proposal. The Florida Industrial Power Users Group (FIPUG) requested additional time to present a counter-proposal. The hearing was continued until November 30, 1999, and the parties were directed to attempt to reach a negotiated settlement. FIPUG offered a counter-proposal on November 17, 1999. No settlement was reached.

At the continued hearing, we considered both proposals. After discussion, FPL, FPC, and TECO agreed to further modifications to their proposal. A document incorporating these agreed-upon changes was filed on December 15, 1999. A copy of this document (hereinafter the "Stipulation") is included in this Order as Attachment A and is incorporated herein by reference. FPL, FPC, and TECO have each agreed to achieve a planned twenty percent reserve margin by the summer of 2004. In response to concerns expressed by some of the other parties, each utility has agreed to make a good faith effort to notify the Commission if it opts to modify the twenty percent criterion. The three utilities signing the Stipulation further acknowledge in paragraph 9 at page 4 that

> the Commission shall retain the ability and discretion to consider all facts and circumstances applicable to a given utility and/or peninsular Florida. Further, with respect to the evaluation of the adequacy of reserves in peninsular Florida, the Commission may employ any methodology and consider any facts and circumstances it deems appropriate, subject to applicable legal requirements.

We approve the Stipulation agreed to by Florida Power & Light Company, Florida Power Corporation, and Tampa Electric Company. It addresses the basic concern about the adequacy of planned reserve margins for Peninsular Florida. Collectively, these three utilities plan for approximately 80 percent of the Peninsular Florida load. Thus, a twenty percent planning criterion adopted by these three utilities is a significant increase over the fifteen percent criterion currently employed.

Further, we will convene a workshop to receive and consider information regarding how distributed resources, both demand and supply-side, may be used to meet Florida's energy service reliability needs. In addition, we will convene a workshop for the consideration of the appropriate relationship between the non-firm load of an individual utility and the total reserves required to maintain the utility's appropriate reserve margin.

Based on the foregoing, it is therefore

ORDERED by the Florida Public Service Commission that the Stipulation agreed to by Florida Power & Light Company, Florida Power Corporation, and Tampa Electric Company, which is included in this Order as Attachment A and is incorporated by reference herein, is approved. It is further

ORDERED that this docket shall be closed.

By ORDER of the Florida Public Service Commission this 22nd day of December, 1999.

/s/ Blanca S. Bayó

BLANCA S. BAYÓ, Director
Division of Records and Reporting

This is a facsimile copy. A signed copy of the order may be obtained by calling 1-850-413-6770.

(S E A L)

RVE

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Director, Division of Records and Reporting, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Director, Division of Records and reporting and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Generic investigation into the aggregate electric utility reserve margins planned for Peninsular Florida
______________________/

Docket No. 981890-EU

STIPULATION

WHEREAS, the Florida Public Service Commission initiated this proceeding regarding reserve margins of Peninsular Florida utilities in December 1998; and

WHEREAS, subsequent to that date Staff and parties identified certain issues to be addressed and procedures to be followed; and

WHEREAS, Florida Power & Light Company (FPL), Florida Power Corporation (FPC), and Tampa Electric Company (TECO) (collectively, the IOUs) have asserted, and continue to assert, that the scope of the proceeding has been expanded beyond the intent of the Commission, and that the procedural posture of this proceeding is such that the Commission cannot lawfully take formal action that would affect their substantial interests at this time; and

WHEREAS, in Orders No. PSC-99-1274-PCO-EU and No. PSC-99-1716-PCO-EU the Commission overruled the IOUs' procedural objections, clarified the scope of the docket, identified specific issues to be addressed, and confirmed its intent to conduct a formal evidentiary proceeding in this docket and take the actions it deems appropriate; and

WHEREAS, Reliant Energy Power Generation, Inc (Reliant Energy), Florida Industrial Power Users Group (FIPUG), PG&E Generating Company (PG&E), the Legal Environmental Assistance Foundation, Inc. (LEAF), and Duke Energy North America, LLC, and Duke Energy New Smyrna Beach Power Company, Ltd., LLP (Duke Energy), (hereinafter referred to as Intervenors), filed Petitions to Intervene in which they alleged the actions contemplated by the Commission in this docket would affect their substantial interests; and

WHEREAS, the Commission granted Intervenors' petitions to intervene, and Intervenors have participated as full parties to the proceeding; and

WHEREAS, on October 29, 1999, FPC, acting on behalf of the IOUs, submitted to the Commission Staff a proposal for the resolution of the issues in this proceeding; and

WHEREAS, upon receipt of the proposal the Commission continued the hearing scheduled for November 2, 1999 and convened on that date a conference of all parties for the purpose of discussing the proposal of the IOUs; and

WHEREAS, upon consideration of the IOUs' proposal, without waiving their respective litigation positions and for the purposes of compromise and settlement, the undersigned, representing all of the parties to this proceeding that have been identified by the Commission or allowed by Commission to intervene, have decided to prepare this Stipulation, and present it to the Commission for the purpose of concluding this docket.

NOW, THEREFORE, the parties stipulate and agree as follows:

1. The IOUs will each voluntarily adopt a minimum reserve margin planning criterion of twenty percent (20%).

2. The twenty percent (20%) reserve margin planning criterion will be a minimum; no maximum or cap will be represented or implied by this criterion.

3. No utility other than the three IOUs identified hereinabove is agreeing to adopt a twenty percent (20%) reserve margin planning criterion by virtue of this Stipulation.

4. The IOUs will calculate the minimum twenty percent (20%) reserve margin by employing their current methodology; i.e., Reserve Margin (%) = [(Total Firm Capacity – Peak Firm Demand)/Peak Firm Demand] x 100, where Total Firm Capacity will be based on generating capacity owned by the IOUs or capacity for which there is a firm commitment to these IOUs and

where Peak Firm Demand means total demand reduced by demand side resources.

5. The IOUs will undertake to implement the twenty percent reserve margin criterion over a transition period of four years, meaning that they will plan to achieve a twenty percent (20%) reserve margin by the Summer of 2004.

6. The IOUs agree to adopt the twenty percent (20%) reserve margin planning criterion with the good faith intention of maintaining that planning criterion for the indefinite future, but each IOU must reserve the prerogative individually to modify its planning criteria to adapt to relevant circumstances. By the same token, it is understood that the Commission remains free to initiate an investigation or to take other appropriate action to review and to respond to any changes that the IOUs may make in the future regarding their planning criteria.

7. Should any IOU exercise its prerogative to change its twenty percent (20%) minimum reserve margin planning criterion discussed herein, such IOU will make a good faith effort to provide notice of the change to the Commission.

8. Neither the adoption by the IOUs of the minimum twenty percent (20%) planning criterion nor the approval of this Stipulation by the Commission shall be deemed to create any presumption that capacity additions must be through any particular mix of generation and/or demand-side resources. Nor shall said adoption or approval be deemed to create any presumption with respect to any proposals for adding generating capacity or create a presumption that a generating capacity addition proposed by any entity is not needed. All current and future proceedings under the Electrical Power Plant Siting Act, including those for the consideration of merchant plants, and all statutes, rules, regulations, and policies bearing on the Commission's determination of need for new generation (including the need determination criteria in § 403.519, Florida Statutes); the IOUs' obligation to solicit proposals for generating capacity; and the

obligations of the IOUs to otherwise prudently avail themselves of reasonably available conservation alternatives and cost-effective resource options; and the obligations of the IOUs to best serve their retail customers through their respective resource planning processes, are unaffected by this Stipulation and the approval thereof.

9. The parties acknowledge that for all regulatory purposes, the Commission shall retain the ability and discretion to consider all facts and circumstances applicable to a given utility and/or peninsular Florida. Further, with respect to the evaluation of the adequacy of reserves in peninsular Florida, the Commission may employ any methodology and may consider any facts and circumstances it deems appropriate, subject to applicable legal requirements.

10. The Commission is encouraged to take the following actions in conjunction with the approval of this Stipulation:

A. Convene a workshop, with the participation and the assistance of the Regulatory Assistance Project, to receive and consider information regarding how distributed resources, both demand and supply-side, may be used to meet Florida's energy service reliability needs, to be followed by any additional proceedings and/or actions relative to this matter that the Commission deems appropriate.

B. Convene a workshop for the consideration of the appropriate relationship between the non-firm load of an individual utility and the total reserves required to maintain the utility's appropriate minimum reserve margin, to be followed by any additional proceedings and/or actions relative to this matter that the Commission deems appropriate.

11. The parties enter into this Stipulation for the purpose of effecting a compromise and of achieving closure of this docket. By its participation in this Stipulation, no party expresses its endorsement of any individual provision included by any other party.

12. By entering this Stipulation, no party waives any position it has taken with respect to any aspect of this proceeding or any of the issues identified in this proceeding or any other proceeding. Further, no party waives the right and opportunity to petition the Commission to institute any action designed to provide any relief deemed appropriate or desirable by that party at any time.

13. The parties to this Stipulation agree that, by approving this Stipulation, the Commission does not waive its right and ability, pursuant to governing law, to initiate any proceeding or take any action for which it has requisite jurisdiction and authority.

14. In the event the Commission declines to approve this Stipulation in its entirety, it shall become null and void.

AGREED this 14th day of December 1999.

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Progress Energy Florida
Ten-Year Site Plan

April 2007
(revised 04/02/07)

2007-2016

Submitted to:
Florida Public Service Commission

Progress Energy

TABLE OF CONTENTS

LIST OF REQUIRED SCHEDULES

LIST OF
TABLES AND FIGURES

CODE IDENTIFICATION SHEET

Generating Unit Type

ST - Steam Turbine - Non-Nuclear
NP - Steam Power - Nuclear
GT - Gas Turbine
CT - Combustion Turbine
CC - Combined cycle
SPP - Small Power Producer
COG - Cogeneration Facility

Fuel Type

NUC - Nuclear (Uranium)
NG - Natural Gas
RFO - No. 6 Residual Fuel Oil
DFO - No. 2 Distillate Fuel Oil
BIT - Bituminous Coal
MSW - Municipal Solid Waste
WH - Waste Heat
BIO - Biomass

Fuel Transportation

WA - Water
TK - Truck
RR - Railroad
PL - Pipeline
UN - Unknown

Future Generating Unit Status

A - Generating unit capability increased
FC - Existing generator planned for conversion to another fuel or energy source
P - Planned for installation but not authorized; not under construction
RP - Proposed for repowering or life extension
RT - Existing generator scheduled for retirement
T - Regulatory approval received but not under construction
U - Under construction, less than or equal to 50% complete
V - Under construction, more than 50% complete

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INTRODUCTION

Section 186.801 of the Florida Statutes requires electric generating utilities to submit a Ten-Year Site Plan (TYSP) to the Florida Public Service Commission (FPSC). The TYSP includes historical and projected data pertaining to the utility's load and resource needs as well as a review of those needs. It is compiled in accordance with FPSC Rules 25-22.070 through 22.072, Florida Administrative Code.

Progress Energy Florida's (PEF's) TYSP is based on projections of long-term planning requirements that are dynamic in nature and subject to change. These planning documents should be used for general guidance concerning PEF's planning assumptions and projections, and should not be taken as an assurance that particular events discussed in the TYSP will materialize or that particular plans will be implemented. Information and projections pertinent to periods further out in time are inherently subject to greater uncertainty.

The TYSP document contains four chapters as described below:

CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

CHAPTER 2

FORECAST OF ELECTRICAL POWER DEMAND AND ENERGY CONSUMPTION

CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

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CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

Progress Energy

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CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

EXISTING FACILITIES OVERVIEW

OWNERSHIP

PEF is a wholly owned subsidiary of Progress Energy, Inc. (Progress Energy). Congress enacted legislation in 2005 repealing the Public Utilities Holding Company Act of 1935 (PUCHA) effective February 8, 2006. Subsequent to that date, Progress Energy is no longer subject to regulation by the Securities and Exchange Commission as a public utility holding company. Progress Energy is the parent company of PEF and certain other subsidiaries.

AREA OF SERVICE

PEF provided electric service during 2006 to an average of 1.6 million customers in Florida. Its service area covers approximately 20,000 square miles and includes the densely populated areas around Orlando, as well as the cities of St. Petersburg and Clearwater. PEF is interconnected with 22 municipal and 9 rural electric cooperative systems. PEF is subject to the rules and regulations of the Federal Energy Regulatory Commission (FERC) and the FPSC. PEF's Service Area is shown in Figure 1.1.

TRANSMISSION/DISTRIBUTION

The Company is part of a nationwide interconnected power network that enables power to be exchanged between utilities. The PEF transmission system includes approximately 5,000 circuit miles of transmission lines. The distribution system includes approximately 18,000 circuit miles of overhead distribution conductors and approximately 13,000 miles of underground cable. A map of the Electric System can be found in Figure 1.2.

ENERGY MANAGEMENT and ENERGY EFFICIENCY

PEF customers participating in the company's residential Energy Management program help to manage future growth and costs. Approximately 389,000 customers participated in the Energy Management program at the end of 2006, contributing about 755,000 kW of winter peak-shaving capacity for use during high load periods.

PEF's DSM Plan currently consists of seven residential programs, eight commercial and industrial programs, and one research and development program. This includes the 39 additional DSM measures and 2 new residential programs approved by the FPSC on January 5, 2007. (Docket 060647: Consummating Order PSC-07-0017-CO-EG making Order PSC-0601018-TRG-EG effective and final). Megawatt contributions to the TYSP have increased as a result of these changes to conservation, standby, and residential load management programs.

TOTAL CAPACITY RESOURCE

As of December 31, 2006, PEF had total summer capacity resources of approximately 10,752 MW consisting of installed capacity of 8,844 MW (excluding Crystal River 3 joint ownership) and 1,908 MW of firm purchased power. Additional information on PEF's existing generating resources is shown on Schedule 1 and Table 3.1.

FIGURE 1.1

PROGRESS ENERGY FLORIDA

Service Area Map

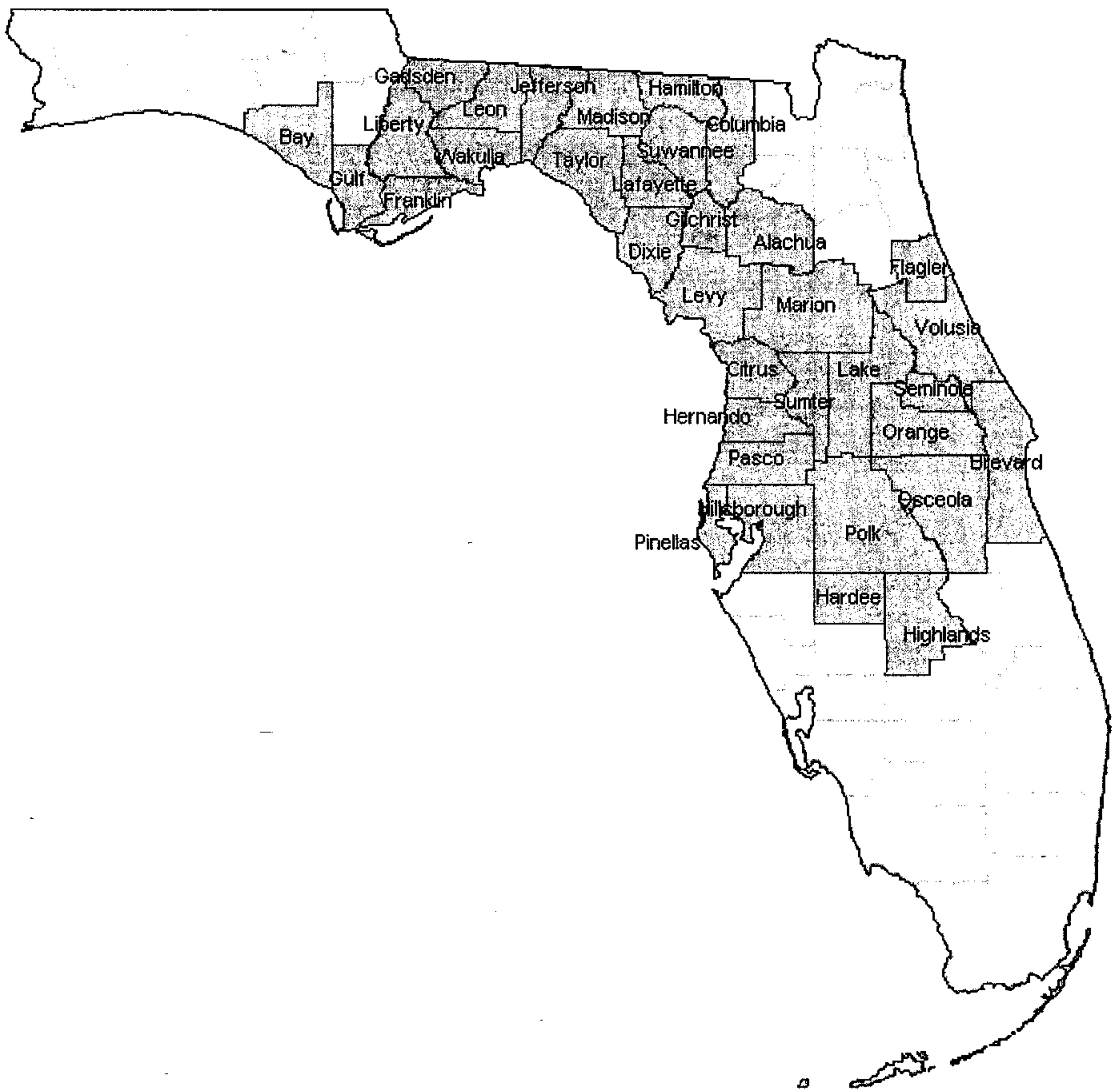
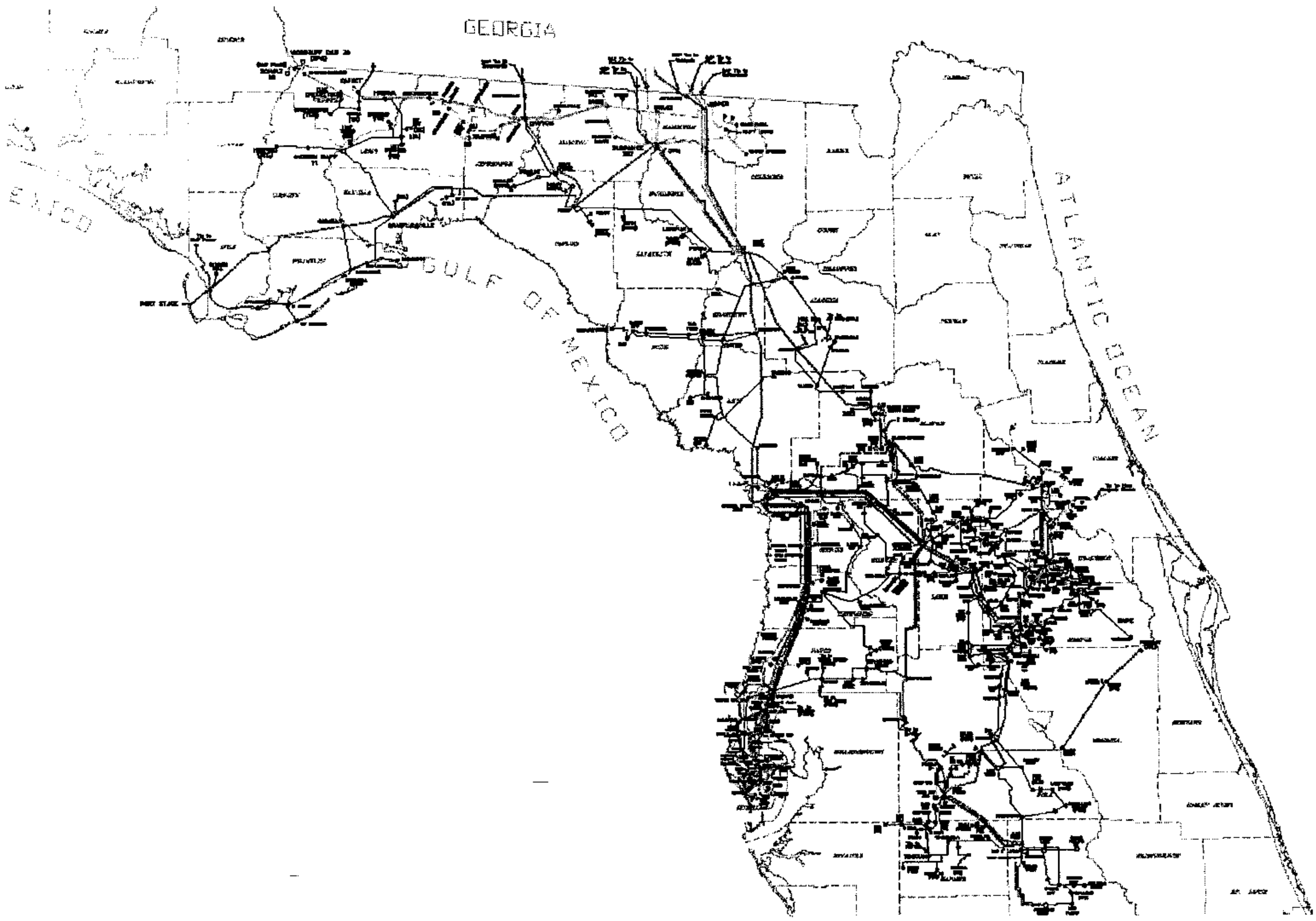


FIGURE 1.2

PROGRESS ENERGY FLORIDA

Electric System Map



PROGRESS ENERGY FLORIDA

SCHEDULE 1
EXISTING GENERATING FACILITIES

AS OF DECEMBER 31, 2006

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
									COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY	
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		ALT. FUEL	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	DAYS USE	MO./YEAR	MO./YEAR	KW	MW	MW
STEAM													
ANCLOTE	1	PASCO	ST	RFO	NG	PL	PL		10/74		556,200	498	522
ANCLOTE	2	PASCO	ST	RFO	NG	PL	PL		10/78		556,200	507	526
BARTOW	1	PINELLAS	ST	RFO		WA			09/58		127,500	121	125
BARTOW	2	PINELLAS	ST	RFO		WA			08/61		127,500	119	124
BARTOW	3	PINELLAS	ST	RFO	NG	WA	PL		07/63		239,360	204	215
CRYSTAL RIVER	1	CITRUS	ST	BIT		RR	WA		10/66		440,550	379	386
CRYSTAL RIVER	2	CITRUS	ST	BIT		RR	WA		11/69		523,800	491	496
CRYSTAL RIVER	3 *	CITRUS	ST	NUC		TK			03/77		890,460	769	788
CRYSTAL RIVER	4	CITRUS	ST	BIT		WA	RR		12/82		739,260	722	734
CRYSTAL RIVER	5	CITRUS	ST	BIT		WA	RR		10/84		739,260	721	734
SUWANNEE RIVER	1	SUWANNEE	ST	RFO	NG	TK/RR	PL		11/53		34,500	30	33
SUWANNEE RIVER	2	SUWANNEE	ST	RFO	NG	TK/RR	PL		11/54		37,500	31	31
SUWANNEE RIVER	3	SUWANNEE	ST	RFO	NG	TK/RR	PL		10/56		75,000	80	82
												4,672	4,796
COMBINED-CYCLE													
HINES ENERGY COMPLEX	1	POLK	CC	NG	DFO	PL	TK	2***	04/99		546,500	463	528
HINES ENERGY COMPLEX	2	POLK	CC	NG	DFO	PL	TK		12/03		548,250	490	562
HINES ENERGY COMPLEX	3	POLK	CC	NG	DFO	PL	TK		11/05		561,000	503	570
TIGER BAY	1	POLK	CC	NG		PL			08/97		278,100	203	225
												1,659	1,885
COMBUSTION TURBINE													
AVON PARK	P1	HIGHLANDS	GT	NG	DFO	PL	TK	3***	12/68		33,790	25	34
AVON PARK	P2	HIGHLANDS	GT	DFO		TK			12/68		33,790	25	36
BARTOW	P1, P3	PINELLAS	GT	DFO		WA			05/72, 06/72		111,400	86	112
BARTOW	P2	PINELLAS	GT	NG	DFO	PL	WA	8	06/72		55,700	44	56
BARTOW	P4	PINELLAS	GT	NG	DFO	PL	WA	8	06/72		55,700	46	58
BAYBORO	P1-P4	PINELLAS	GT	DFO		WA			04/73		226,800	177	232
DEBARY	P1-P6	VOLUSIA	GT	DFO		TK			12/75-04/76		401,220	311	393
DEBARY	P7-P9	VOLUSIA	GT	NG	DFO	PL	TK	8	10/92		345,000	249	287
DEBARY	P10	VOLUSIA	GT	DFO		TK			10/92		115,000	83	99
HIGGINS	P1-P2	PINELLAS	GT	NG	DFO	PL	TK		03/69, 04/69		67,580	53	68
HIGGINS	P3-P4	PINELLAS	GT	NG	DFO	PL	TK	1	12/70, 01/71		85,850	57	65
INTERCESSION CITY	P1-P6	OSCEOLA	GT	DFO		PL,TK			05/74		340,200	282	369
INTERCESSION CITY	P7-P10	OSCEOLA	GT	NG	DFO	PL	PL,TK	5	10/93		460,000	332	376
INTERCESSION CITY	P11 **	OSCEOLA	GT	DFO		PL,TK			01/97		165,000	143	161
INTERCESSION CITY	P12-P14	OSCEOLA	GT	NG	DFO	PL	PL,TK	5	12/00		345,000	235	278
RIO PINAR	P1	ORANGE	GT	DFO		TK			11/70		19,290	13	16
SUWANNEE RIVER	P1, P3	SUWANNEE	GT	NG	DFO	PL	TK	9****	10/80, 11/80		122,400	106	133
SUWANNEE RIVER	P2	SUWANNEE	GT	DFO		TK			10/80		61,200	51	66
TURNER	P1-P2	VOLUSIA	GT	DFO		TK			10/70		38,580	22	32
TURNER	P3	VOLUSIA	GT	DFO		TK			08/74		71,200	64	85
TURNER	P4	VOLUSIA	GT	DFO		TK			08/74		71,200	64	84
UNIV. OF FLA.	P1	ALACHUA	GT	NG		PL			01/94		43,000	45	47
												2,513	3,087
											TOTAL RESOURCES (MW)	8,844	9,768

* REPRESENTS APPROXIMATELY 91.8% PEF OWNERSHIP OF UNIT

** SUMMER CAPABILITY (JUNE THROUGH SEPTEMBER) OWNED BY GEORGIA POWER COMPANY

*** FOR ENTIRE PLANT

**** P1 REQUIRES A 3-4 DAY OUTAGE IN ORDER TO SWITCH BETWEEN NG & DFO

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CHAPTER 2

FORECAST OF ELECTRIC POWER DEMAND AND ENERGY CONSUMPTION

Progress Energy

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CHAPTER 2

FORECAST OF ELECTRIC POWER DEMAND

AND

ENERGY CONSUMPTION

OVERVIEW

The following Schedules 2, 3 and 4 represent PEF's history and forecast of customers, energy sales (GWh), and peak demand (MW). High and low scenarios are also presented for sensitivity purposes.

The base case was developed using assumptions to predict a forecast with a 50/50 probability, or most likely scenario. The high and low scenarios, which have a 90/10 probability of occurrence or an 80 percent probability of an outcome falling between the high and low cases, employed a Monte Carlo simulation procedure that studied 1,000 possible outcomes of retail demand and energy.

PEF's customer growth is expected to average 1.8 percent between 2007 and 2016, less than the ten-year historical average of 2.4 percent. The ten-year historical growth rate falls to 2.1 percent when accounting for the creation of PEF's Seasonal Service Rate tariff, which artificially inflates customer growth figures. Slower population growth - based on the latest projection from the University of Florida's Bureau of Economic and Business Research – and economic conditions less favorable for the housing/construction industry (including, for example, higher interest rates, property insurance and property taxes) result in a lower base case customer projection when compared to the higher historical growth rate. This translates into lower projected energy and demand growth rates from historic rate levels.

Net energy for load (NEL), which had grown at an average of 3.2 percent between 1997 and 2006, is expected to increase by 2.6 percent per year from 2007-2016 in the base case, 2.7 percent in the high case and 2.2 percent in the low case. A lower contribution from the wholesale jurisdiction, which grew an average of 10.2 percent between 1997 and 2006, results in lower expected system growth going forward than the historic rate. Retail NEL, which grew at a

2.8 percent average rate historically, is expected to grow 2.5 percent over the next ten years. Wholesale NEL is expected to average 2.9 percent between 2007 and 2016.

Summer net firm demand is expected to grow an average of 2.1 percent per year during the next ten years. This compares to the 3.6 percent growth rate experienced throughout the last ten years. Again, lower contribution from the wholesale jurisdiction is expected going forward and a higher load management capability for the projected period. High and low summer growth rates for net firm demand are 2.3 percent and 1.8 percent per year, respectively. Winter net firm demand is projected to grow at 2.5 percent per year after having increased by 2.9 percent per year from 1997 to 2006. High and low winter net firm demand growth rates are 2.7 percent and 2.2 percent, respectively.

Summer net firm retail demand is expected to grow an average of 2.1 percent per year during the next ten years; this compares to the 3.6 percent average annual growth rate experienced throughout the last ten years. The historical growth percentage is driven by a period of declining load management capability while the projection period has a return to higher capability. High and low summer growth rates for net firm retail demand are 2.4 percent and 1.8 percent per year, respectively. Winter net firm retail demand is projected to grow at approximately 1.9 percent per year after having grown by 3.1 percent from 1997 to 2006. Again, higher load control capability is incorporated in the projection period. High and low winter net firm retail demand growth rates are 2.2 percent and 1.6 percent, respectively.

ENERGY CONSUMPTION AND DEMAND FORECAST SCHEDULES

SCHEDULE	DESCRIPTION
2.1, 2.2 and 2.3	History and Forecast of Energy Consumption and Number of Customers by Customer Class
3.1.1, 3.1.2 and 3.1.3	History and Forecast of Base, High and Low Summer Peak Demand (MW)
3.2.1, 3.2.2 and 3.2.3	History and Forecast of Base, High, and Low Winter Peak Demand (MW)
3.3.1, 3.3.2 and 3.3.3	History and Forecast of Base, High and Low Annual Net Energy for Load (GWh)
4	Previous Year Actual and Two-Year Forecast of Peak Demand and Net Energy for Load by Month

PROGRESS ENERGY FLORIDA

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					COMMERCIAL		
YEAR	PEF POPULATION	MEMBERS PER HOUSEHOLD	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER
1997	2,878,315	2.480	15,080	1,160,611	12,993	9,257	132,504	69,862
1998	2,941,589	2.487	16,526	1,182,786	13,972	9,999	136,345	73,336
1999	3,028,821	2.496	16,245	1,213,470	13,387	10,327	140,897	73,295
2000	3,026,469	2.452	17,116	1,234,286	13,867	10,813	143,475	75,365
2001	3,122,946	2.450	17,604	1,274,672	13,811	11,061	146,983	75,254
2002	3,191,315	2.452	18,754	1,301,515	14,409	11,420	150,577	75,842
2003	3,267,185	2.453	19,429	1,331,914	14,587	11,553	154,294	74,877
2004	3,348,917	2.454	19,347	1,364,677	14,177	11,734	158,780	73,901
2005	3,429,664	2.455	19,894	1,397,012	14,240	11,945	161,001	74,192
2006	3,512,066	2.453	20,021	1,431,743	13,984	11,975	162,774	73,568
2007	3,565,718	2.455	20,891	1,452,431	14,383	12,340	167,150	73,826
2008	3,629,609	2.450	21,457	1,481,473	14,484	12,674	170,889	74,165
2009	3,694,808	2.447	22,026	1,509,934	14,587	13,009	174,552	74,528
2010	3,762,611	2.446	22,605	1,538,271	14,695	13,361	178,195	74,980
2011	3,828,922	2.444	23,192	1,566,662	14,803	13,708	181,846	75,382
2012	3,895,566	2.442	23,792	1,595,236	14,914	14,056	185,520	75,765
2013	3,959,232	2.438	24,404	1,623,967	15,027	14,417	189,213	76,195
2014	4,025,804	2.436	25,027	1,652,629	15,144	14,796	192,896	76,705
2015	4,091,505	2.434	25,693	1,680,980	15,285	15,202	196,539	77,349
2016	4,155,712	2.432	26,363	1,708,763	15,428	15,622	200,111	78,067

PROGRESS ENERGY FLORIDA

SCHEDULE 2.2
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	INDUSTRIAL						
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
1997	4,188	2,830	1,479,859	0	27	2,299	30,851
1998	4,375	2,707	1,616,180	0	27	2,459	33,386
1999	4,334	2,629	1,648,536	0	27	2,509	33,442
2000	4,249	2,535	1,676,134	0	28	2,626	34,832
2001	3,872	2,551	1,517,836	0	28	2,698	35,263
2002	3,835	2,535	1,512,821	0	28	2,822	36,859
2003	4,001	2,643	1,513,810	0	29	2,946	37,958
2004	4,069	2,733	1,488,840	0	28	3,016	38,194
2005	4,140	2,703	1,531,632	0	27	3,171	39,177
2006	4,160	2,697	1,542,455	0	27	3,249	39,432
2007	4,155	2,701	1,538,319	0	28	3,353	40,767
2008	4,393	2,701	1,626,435	0	28	3,457	42,009
2009	4,423	2,701	1,637,542	0	28	3,570	43,056
2010	4,451	2,701	1,647,908	0	28	3,682	44,127
2011	4,518	2,701	1,672,714	0	28	3,798	45,244
2012	4,544	2,701	1,682,340	0	28	3,916	46,336
2013	4,571	2,701	1,692,336	0	28	4,038	47,458
2014	4,599	2,701	1,702,703	0	28	4,164	48,614
2015	4,587	2,701	1,698,260	0	28	4,293	49,803
2016	4,587	2,701	1,698,260	0	28	4,427	51,027

PROGRESS ENERGY FLORIDA

SCHEDULE 2.3
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS

(1)	(2)	(3)	(4)	(5)	(6)
YEAR	SALES FOR RESALE GWh	UTILITY USE & LOSSES GWh	NET ENERGY FOR LOAD GWh	OTHER CUSTOMERS (AVERAGE NO.)	TOTAL NO. OF CUSTOMERS
1997	1,758	1,996	34,605	18,562	1,314,507
1998	2,340	2,037	37,763	19,013	1,340,851
1999	3,267	2,451	39,160	19,601	1,376,597
2000	3,732	2,678	41,242	20,003	1,400,299
2001	3,839	1,831	40,933	20,752	1,444,958
2002	3,173	2,535	42,567	21,156	1,475,783
2003	3,359	2,594	43,911	21,665	1,510,516
2004	4,301	2,773	45,268	22,437	1,548,627
2005	5,195	2,506	46,878	22,701	1,583,417
2006	4,220	2,389	46,041	23,182	1,620,396
2007	4,524	2,905	48,194	23,687	1,645,969
2008	4,501	2,958	49,468	24,280	1,679,343
2009	4,527	3,026	50,609	24,877	1,712,064
2010	5,238	3,151	52,516	25,474	1,744,641
2011	5,363	3,169	53,776	26,071	1,777,280
2012	5,437	3,244	55,017	26,669	1,810,126
2013	5,542	3,321	56,321	27,266	1,843,147
2014	5,673	3,445	57,732	27,864	1,876,090
2015	5,795	3,476	59,074	28,460	1,908,680
2016	5,873	3,560	60,460	29,058	1,940,633

PROGRESS ENERGY FLORIDA

SCHEDULE 3.1.1
HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)
BASE CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1997	7,786	874	6,912	288	555	78	41	124	170	6,531
1998	8,367	943	7,424	291	438	97	42	134	182	7,183
1999	9,039	1,326	7,713	292	505	113	45	145	183	7,756
2000	8,902	1,319	7,583	277	455	127	48	146	75	7,774
2001	8,832	1,117	7,715	283	414	139	48	147	75	7,726
2002	9,412	1,203	8,209	305	390	153	43	150	75	8,296
2003	8,877	887	7,990	300	393	172	44	154	75	7,738
2004	9,578	1,071	8,507	531	355	188	39	155	110	8,200
2005	10,345	1,118	9,227	448	343	206	38	158	110	9,041
2006	10,186	1,257	8,929	329	319	226	37	161	110	9,003
2007	10,658	1,321	9,337	449	319	243	43	168	110	9,327
2008	10,927	1,337	9,590	473	332	259	52	177	110	9,525
2009	11,010	1,192	9,818	474	351	275	61	185	110	9,553
2010	11,318	1,269	10,049	479	372	292	70	194	110	9,801
2011	11,569	1,287	10,282	484	393	308	80	203	110	9,992
2012	11,807	1,296	10,511	485	414	325	89	211	110	10,173
2013	12,062	1,320	10,742	486	427	342	98	220	110	10,379
2014	12,437	1,469	10,968	483	438	360	107	229	110	10,711
2015	12,671	1,483	11,188	478	441	367	110	232	110	10,932
2016	12,906	1,499	11,407	477	441	367	110	232	110	11,169

Historical Values (1997 - 2006):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) =Customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2007 - 2016):

Cols. (2) - (4) = forecasted peak without load control, conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

PROGRESS ENERGY FLORIDA

SCHEDULE 3.1.2
HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)
HIGH LOAD FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1997	7,786	874	6,912	288	555	78	41	124	170	6,531
1998	8,367	943	7,424	291	438	97	42	134	182	7,183
1999	9,039	1,326	7,713	292	505	113	45	145	183	7,756
2000	8,902	1,319	7,583	277	455	127	48	146	75	7,774
2001	8,832	1,117	7,715	283	414	139	48	147	75	7,726
2002	9,412	1,203	8,209	305	390	153	43	150	75	8,296
2003	8,877	887	7,990	300	393	172	44	154	75	7,738
2004	9,578	1,071	8,507	531	355	188	39	155	110	8,200
2005	10,345	1,118	9,227	448	343	206	38	158	110	9,041
2006	10,186	1,257	8,929	329	319	226	37	161	110	9,003
2007	10,801	1,321	9,480	449	319	243	43	168	110	9,470
2008	11,086	1,337	9,748	473	332	259	52	177	110	9,683
2009	11,185	1,192	9,993	474	351	275	61	185	110	9,728
2010	11,513	1,269	10,244	479	372	292	70	194	110	9,996
2011	11,814	1,287	10,527	484	393	308	80	203	110	10,237
2012	12,067	1,296	10,771	485	414	325	89	211	110	10,433
2013	12,369	1,320	11,049	486	427	342	98	220	110	10,686
2014	12,773	1,469	11,304	483	438	360	107	229	110	11,047
2015	13,065	1,483	11,582	478	441	367	110	232	110	11,327
2016	13,338	1,499	11,839	477	441	367	110	232	110	11,601

Historical Values (1997 - 2006):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) =Customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2007 - 2016):

Cols. (2) - (4) = forecasted peak without load control, conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

PROGRESS ENERGY FLORIDA

SCHEDULE 3.1.3
HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)
LOW LOAD FORECAST

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) NET FIRM DEMAND
1997	7,786	874	6,912	288	555	78	41	124	170	6,531
1998	8,367	943	7,424	291	438	97	42	134	182	7,183
1999	9,039	1,326	7,713	292	505	113	45	145	183	7,756
2000	8,902	1,319	7,583	277	455	127	48	146	75	7,774
2001	8,832	1,117	7,715	283	414	139	48	147	75	7,726
2002	9,412	1,203	8,209	305	390	153	43	150	75	8,296
2003	8,877	887	7,990	300	393	172	44	154	75	7,738
2004	9,578	1,071	8,507	531	355	188	39	155	110	8,200
2005	10,345	1,118	9,227	448	343	206	38	158	110	9,041
2006	10,186	1,257	8,929	329	319	226	37	161	110	9,003
2007	10,524	1,321	9,203	449	319	243	43	168	110	9,193
2008	10,776	1,337	9,438	473	332	259	52	177	110	9,373
2009	10,849	1,192	9,657	474	351	275	61	185	110	9,392
2010	11,122	1,269	9,853	479	372	292	70	194	110	9,605
2011	11,350	1,287	10,063	484	393	308	80	203	110	9,773
2012	11,548	1,296	10,252	485	414	325	89	211	110	9,914
2013	11,778	1,320	10,458	486	427	342	98	220	110	10,095
2014	12,106	1,469	10,637	483	438	360	107	229	110	10,380
2015	12,305	1,483	10,822	478	441	367	110	232	110	10,567
2016	12,513	1,499	11,014	477	441	367	110	232	110	10,776

Historical Values (1997 - 2006):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) =Customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2007 - 2016):

Cols. (2) - (4) = forecasted peak without load control, conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

PROGRESS ENERGY FLORIDA

SCHEDULE 3.2.1
HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
BASE CASE

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) NET FIRM DEMAND
1996/97	8,486	1,235	7,251	290	917	133	16	98	190	6,842
1997/98	7,752	941	6,811	318	663	164	17	106	168	6,317
1998/99	10,473	1,741	8,732	305	874	196	18	110	187	8,783
1999/00	10,033	1,728	8,305	225	849	229	20	112	182	8,416
2000/01	11,443	1,984	9,459	255	826	254	23	113	187	9,785
2001/02	10,669	1,624	9,045	285	819	278	24	114	188	8,960
2002/03	11,548	1,538	10,010	271	793	313	27	117	198	9,828
2003/04	9,317	1,167	8,150	498	786	343	26	117	261	7,287
2004/05	10,824	1,600	9,224	575	777	371	26	117	282	8,676
2005/06	10,736	1,467	9,269	298	769	413	26	118	281	8,830
2006/07	11,728	1,711	10,017	366	760	454	27	120	296	9,705
2007/08	12,132	1,789	10,343	452	777	495	37	126	302	9,943
2008/09	12,302	1,727	10,575	453	793	538	47	133	305	10,034
2009/10	12,817	2,012	10,805	454	811	580	57	139	309	10,468
2010/11	13,126	2,082	11,044	464	829	623	67	146	313	10,685
2011/12	13,516	2,241	11,275	465	846	666	76	152	316	10,994
2012/13	13,885	2,377	11,508	466	864	710	86	158	320	11,280
2013/14	14,197	2,456	11,741	467	882	754	96	165	324	11,509
2014/15	14,513	2,548	11,965	461	899	798	105	171	327	11,751
2015/16	14,827	2,639	12,187	456	899	798	105	171	332	12,064
2016/17	15,139	2,729	12,410	457	899	798	105	171	336	12,372

Historical Values (1997 - 2006):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2007 - 2016):

Cols. (2) - (4) forecasted peak without load control and conservation.

Cols. (5) - (9) = Represent cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

PROGRESS ENERGY FLORIDA

SCHEDULE 3.2.2
HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
HIGH LOAD FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1996/97	8,486	1,235	7,251	290	917	133	16	98	190	6,842
1997/98	7,752	941	6,811	318	663	164	17	106	168	6,317
1998/99	10,473	1,741	8,732	305	874	196	18	110	187	8,783
1999/00	10,033	1,728	8,305	225	849	229	20	112	182	8,416
2000/01	11,443	1,984	9,459	255	826	254	23	113	187	9,785
2001/02	10,669	1,624	9,045	285	819	278	24	114	188	8,960
2002/03	11,548	1,538	10,010	271	793	313	27	117	198	9,828
2003/04	9,317	1,167	8,150	498	786	343	26	117	261	7,287
2004/05	10,824	1,600	9,224	575	777	371	26	117	282	8,676
2005/06	10,736	1,467	9,269	298	769	413	26	118	281	8,830
2006/07	11,880	1,711	10,169	366	760	454	27	120	296	9,857
2007/08	12,300	1,789	10,510	452	777	495	37	126	302	10,111
2008/09	12,487	1,727	10,761	453	793	538	47	133	305	10,219
2009/10	13,022	2,012	11,010	454	811	580	57	139	309	10,672
2010/11	13,383	2,082	11,302	464	829	623	67	146	313	10,943
2011/12	13,788	2,241	11,548	465	846	666	76	152	316	11,266
2012/13	14,207	2,377	11,831	466	864	710	86	158	320	11,603
2013/14	14,548	2,456	12,092	467	882	754	96	165	324	11,860
2014/15	14,923	2,548	12,376	461	899	798	105	171	327	12,161
2015/16	15,275	2,639	12,636	456	899	798	105	171	332	12,513
2016/17	15,643	2,729	12,915	457	899	798	105	171	336	12,876

Historical Values (1997 - 2006):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2007 - 2016):

Cols. (2) - (4) forecasted peak without load control and conservation.

Cols. (5) - (9) = Represent cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

PROGRESS ENERGY FLORIDA

SCHEDULE 3.2.3
HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
LOW LOAD FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1996/97	8,486	1,235	7,251	290	917	133	16	98	190	6,842
1997/98	7,752	941	6,811	318	663	164	17	106	168	6,317
1998/99	10,473	1,741	8,732	305	874	196	18	110	187	8,783
1999/00	10,033	1,728	8,305	225	849	229	20	112	182	8,416
2000/01	11,443	1,984	9,459	255	826	254	23	113	187	9,785
2001/02	10,669	1,624	9,045	285	819	278	24	114	188	8,960
2002/03	11,548	1,538	10,010	271	793	313	27	117	198	9,828
2003/04	9,317	1,167	8,150	498	786	343	26	117	261	7,287
2004/05	10,824	1,600	9,224	575	777	371	26	117	282	8,676
2005/06	10,736	1,467	9,269	298	769	413	26	118	281	8,830
2006/07	11,586	1,711	9,875	366	760	454	27	120	296	9,563
2007/08	11,971	1,789	10,181	452	777	495	37	126	302	9,782
2008/09	12,132	1,727	10,406	453	793	538	47	133	305	9,864
2009/10	12,609	2,012	10,597	454	811	580	57	139	309	10,259
2010/11	12,894	2,082	10,813	464	829	623	67	146	313	10,454
2011/12	13,244	2,241	11,004	465	846	666	76	152	316	10,722
2012/13	13,588	2,377	11,212	466	864	710	86	158	320	10,984
2013/14	13,853	2,456	11,397	467	882	754	96	165	324	11,165
2014/15	14,134	2,548	11,587	461	899	798	105	171	327	11,372
2015/16	14,418	2,639	11,779	456	899	798	105	171	332	11,656
2016/17	14,687	2,729	11,959	457	899	798	105	171	336	11,920

Historical Values (1997 - 2006):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2007 - 2016):

Cols. (2) - (4) forecasted peak without load control and conservation.

Cols. (5) - (9) = Represent cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

PROGRESS ENERGY FLORIDA

SCHEDULE 3.3.1
HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWh)
BASE CASE

(1) YEAR	(2) TOTAL	(3) RESIDENTIAL CONSERVATION	(4) COMM. / IND. CONSERVATION	(OTH) OTHER ENERGY REDUCTIONS*	(5) RETAIL	(6) WHOLESALE	(7) UTILITY USE & LOSSES	(8) NET ENERGY FOR LOAD	(9) LOAD FACTOR (%) **
1997	35,752	268	317	562	30,850	1,758	1,997	34,605	49.0
1998	38,949	289	333	564	33,387	2,340	2,036	37,763	53.9
1999	40,375	312	339	564	33,441	3,267	2,452	39,160	50.0
2000	42,486	334	345	565	34,832	3,732	2,678	41,242	50.5
2001	42,200	354	349	564	35,263	3,839	1,831	40,933	47.5
2002	43,860	377	352	564	36,859	3,173	2,535	42,567	50.0
2003	45,232	400	357	564	37,957	3,359	2,595	43,911	47.7
2004	46,835	427	360	780	38,193	4,301	2,774	45,268	56.5
2005	48,479	460	363	779	39,177	5,195	2,506	46,878	52.3
2006	47,680	495	365	779	39,432	4,220	2,389	46,041	52.1
2007	49,878	522	383	779	40,766	4,524	2,904	48,194	56.7
2008	51,201	552	401	780	42,009	4,501	2,958	49,468	56.6
2009	52,389	582	419	779	43,055	4,527	3,027	50,609	57.6
2010	54,344	612	437	779	44,127	5,238	3,151	52,516	57.3
2011	55,652	642	455	779	45,243	5,363	3,170	53,776	57.5
2012	56,942	672	473	780	46,337	5,437	3,243	55,017	57.0
2013	58,293	702	491	779	47,457	5,542	3,322	56,321	57.0
2014	59,752	732	509	779	48,614	5,673	3,445	57,732	57.3
2015	61,094	732	509	779	49,802	5,795	3,477	59,074	57.4
2016	62,481	732	509	780	51,027	5,873	3,560	60,460	57.2

* Column (OTH) includes Conservation Energy For Lighting and Public Authority Customers, Customer-Owned Self-service Cogeneration and Load Control Programs.

** Load Factors for historical years are calculated using the actual winter peak demand except the 1998 and 2004 historical load factors which are based on the actual summer peak demand.
Load Factors for future years are calculated using the net firm winter peak demand (Schedule 3.2.1)

PROGRESS ENERGY FLORIDA

SCHEDULE 3.3.2
HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWh)
HIGH LOAD FORECAST

(1) YEAR	(2) TOTAL	(3) RESIDENTIAL CONSERVATION	(4) COMM. / IND. CONSERVATION	(OTH) OTHER ENERGY REDUCTIONS*	(5) RETAIL	(6) WHOLESALE	(7) UTILITY USE & LOSSES	(8) NET ENERGY FOR LOAD	(9) LOAD FACTOR (%) **
1997	35,752	268	317	562	30,850	1,758	1,997	34,605	49.0
1998	38,949	289	333	564	33,387	2,340	2,036	37,763	53.9
1999	40,375	312	339	564	33,441	3,267	2,452	39,160	50.0
2000	42,486	334	345	565	34,832	3,732	2,678	41,242	50.5
2001	42,200	354	349	564	35,263	3,839	1,831	40,933	47.5
2002	43,860	377	352	564	36,859	3,173	2,535	42,567	50.0
2003	45,232	400	357	564	37,957	3,359	2,595	43,911	47.7
2004	46,835	427	360	780	38,193	4,301	2,774	45,268	56.5
2005	48,479	460	363	779	39,177	5,195	2,506	46,878	52.3
2006	47,680	495	365	779	39,432	4,220	2,389	46,041	52.1
2007	51,005	522	383	779	41,429	4,524	3,368	49,321	57.1
2008	51,987	552	401	780	42,744	4,501	3,009	50,254	56.6
2009	53,260	582	419	779	43,869	4,527	3,084	51,480	57.5
2010	55,320	612	437	779	45,032	5,238	3,222	53,492	57.2
2011	56,877	642	455	779	46,389	5,363	3,249	55,001	57.4
2012	58,250	672	473	780	47,555	5,437	3,333	56,325	56.9
2013	59,848	702	491	779	48,911	5,542	3,423	57,876	56.9
2014	61,459	732	509	779	50,203	5,673	3,563	59,439	57.2
2015	63,097	732	509	779	51,675	5,795	3,607	61,077	57.3
2016	64,684	732	509	780	53,083	5,873	3,707	62,663	57.2

* Column (OTH) includes Conservation Energy For Lighting and Public Authority Customers, Customer-Owned Self-service Cogeneration and Load Control Programs.

** Load Factors for historical years are calculated using the actual winter peak demand except the 1998 and 2004 historical load factors which are based on the actual summer peak demand.
Load Factors for future years are calculated using the net firm winter peak demand (Schedule 3.2.2)

PROGRESS ENERGY FLORIDA

SCHEDULE 3.3.3
HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWh)
LOW LOAD FORECAST

(1) YEAR	(2) TOTAL	(3) RESIDENTIAL CONSERVATION	(4) COMM. / IND. CONSERVATION	(OTH) OTHER ENERGY REDUCTIONS*	(5) RETAIL	(6) WHOLESALE	(7) UTILITY USE & LOSSES	(8) NET ENERGY FOR LOAD	(9) LOAD FACTOR (%) **
1997	35,752	268	317	562	30,850	1,758	1,997	34,605	49.0
1998	38,949	289	333	564	33,387	2,340	2,036	37,763	53.9
1999	40,375	312	339	564	33,441	3,267	2,452	39,160	50.0
2000	42,486	334	345	565	34,832	3,732	2,678	41,242	50.5
2001	42,200	354	349	564	35,263	3,839	1,831	40,933	47.5
2002	43,860	377	352	564	36,859	3,173	2,535	42,567	50.0
2003	45,232	400	357	564	37,957	3,359	2,595	43,911	47.7
2004	46,835	427	360	780	38,193	4,301	2,774	45,268	56.5
2005	48,479	460	363	779	39,177	5,195	2,506	46,878	52.3
2006	47,680	495	365	779	39,432	4,220	2,389	46,041	52.1
2007	49,569	522	383	779	40,147	4,524	3,214	47,885	57.2
2008	50,448	552	401	780	41,304	4,501	2,910	48,715	56.7
2009	51,583	582	419	779	42,306	4,527	2,970	49,803	57.6
2010	53,358	612	437	779	43,207	5,238	3,085	51,530	57.3
2011	54,549	642	455	779	44,216	5,363	3,094	52,673	57.5
2012	55,637	672	473	780	45,117	5,437	3,158	53,712	57.0
2013	56,860	702	491	779	46,123	5,542	3,223	54,888	57.0
2014	58,077	732	509	779	47,049	5,673	3,335	56,057	57.3
2015	59,234	732	509	779	48,062	5,795	3,357	57,214	57.4
2016	60,468	732	509	780	49,147	5,873	3,427	58,447	57.2

* Column (OTH) includes Conservation Energy For Lighting and Public Authority Customers, Customer-Owned Self-service Cogeneration and Load Control Programs.

** Load Factors for historical years are calculated using the actual winter peak demand except the 1998 and 2004 historical load factors which are based on the actual summer peak demand.
Load Factors for future years are calculated using the net firm winter peak demand (Schedule 3.2.3)

PROGRESS ENERGY FLORIDA

SCHEDULE 4

PREVIOUS YEAR ACTUAL AND TWO-YEAR FORECAST OF PEAK DEMAND AND NET ENERGY FOR LOAD BY MONTH

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL 2006		FORECAST 2007		FORECAST 2008	
MONTH	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh
JANUARY	7,870	3,390	9,705	3,772	9,943	3,914
FEBRUARY	10,095	3,191	7,862	3,257	8,014	3,383
MARCH	6,441	3,286	6,692	3,509	6,863	3,631
APRIL	7,837	3,582	7,387	3,498	7,540	3,576
MAY	8,382	4,020	8,482	4,271	8,672	4,361
JUNE	9,349	4,401	8,905	4,478	9,071	4,574
JULY	9,462	4,699	9,156	4,867	9,337	4,985
AUGUST	9,689	4,920	9,327	4,919	9,525	5,047
SEPTEMBER	8,794	4,270	8,553	4,434	8,729	4,537
OCTOBER	8,286	3,763	7,975	3,982	8,202	4,076
NOVEMBER	6,415	3,192	6,463	3,426	6,569	3,502
DECEMBER	6,792	3,327	7,529	3,781	7,717	3,882
TOTAL		46,041		48,194		49,468

NOTE: "Actual" = "Total" - "Interruptible" - "Res. LM" - "C/I LM" - "Voltage Reduction & Standby Generation"

FUEL REQUIREMENTS AND ENERGY SOURCES

PEF's two-year actual and ten-year projected nuclear, coal, oil, and gas requirements (by fuel units) are shown on Schedule 5. PEF's two-year actual and ten-year projected energy sources, in GWh and percent, are shown by fuel type on Schedules 6.1 and 6.2, respectively. PEF's fuel requirements and energy sources reflect a diverse fuel supply system that is not dependent on any one-fuel source. Natural gas consumption is projected to increase as plants and purchases with tolling agreements are added to meet future load growth. However, the planned nuclear addition in 2016 decreases future natural gas consumption as is shown in the projections.

PROGRESS ENERGY FLORIDA

SCHEDULE 5

FUEL REQUIREMENTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	FUEL REQUIREMENTS		UNITS	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
(1)	NUCLEAR		TRILLION BTU	60	66	61	69	52	69	64	81	75	81	75	135
(2)	COAL		1,000 TON	6,249	5,977	6,179	6,059	6,240	6,389	6,977	6,959	6,728	6,874	6,951	6,792
(3)	RESIDUAL	TOTAL	1,000 BBL	10,324	7,353	9,646	8,490	6,338	5,030	5,522	5,384	5,152	5,307	5,190	4,780
(4)		STEAM	1,000 BBL	10,324	7,353	9,646	8,490	6,338	5,030	5,522	5,384	5,152	5,307	5,190	4,780
(5)		CC	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	DISTILLATE	TOTAL	1,000 BBL	1,098	713	987	784	901	986	1,196	1,192	1,284	1,220	1,335	1,056
(9)		STEAM	1,000 BBL	97	90	41	38	46	54	53	44	54	42	47	45
(10)		CC	1,000 BBL	3	2	0	0	0	0	0	0	0	0	0	0
(11)		CT	1,000 BBL	998	621	946	746	855	932	1,144	1,148	1,230	1,177	1,288	1,010
(12)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	NATURAL GAS	TOTAL	1,000 MCF	68,447	76,448	83,645	100,282	129,303	140,233	150,996	149,977	168,758	180,835	193,010	175,170
(14)		STEAM	1,000 MCF	732	1,731	0	0	0	0	0	0	0	0	0	0
(15)		CC	1,000 MCF	52,590	61,487	65,316	84,124	112,747	125,315	133,815	132,786	151,618	164,412	175,697	159,507
(16)		CT	1,000 MCF	15,125	13,230	18,328	16,159	16,556	14,918	17,180	17,191	17,140	16,423	17,312	15,663
	OTHER (SPECIFY)														
(17)	OTHER, DISTILLATE	ANNUAL	1,000 BBL	N/A	N/A	47	11	13	5	13	19	15	0	0	0
(18)	OTHER, NATURAL GAS	ANNUAL	1,000 MCF	N/A	N/A	0	0	0	0	0	0	0	0	0	0
(18.1)	OTHER, NATURAL GAS	ANNUAL	1,000 MCF	N/A	N/A	8,512	4,954	4,720	4,327	6,867	6,743	6,524	5,956	6,720	3,861

PROGRESS ENERGY FLORIDA

SCHEDULE 6.1

ENERGY SOURCES (GWh)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
(1)	ANNUAL FIRM INTERCHANGE 1/		GWh	2,220	2,091	2,200	1,854	1,881	1,750	734	689	672	592	669	349
(2)	NUCLEAR		GWh	5,829	6,382	5,951	6,671	5,099	6,992	6,473	8,114	7,575	8,183	7,576	13,385
(3)	COAL		GWh	15,834	14,968	15,260	14,781	15,187	14,782	16,149	16,108	15,568	15,900	16,083	15,680
(4)	RESIDUAL	TOTAL	GWh	6,618	4,656	5,968	5,217	3,894	3,092	3,418	3,329	3,181	3,278	3,207	2,926
(5)		STEAM	GWh	6,618	4,656	5,968	5,217	3,894	3,092	3,418	3,329	3,181	3,278	3,207	2,926
(6)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	DISTILLATE	TOTAL	GWh	414	258	364	277	321	356	449	451	495	464	511	394
(10)		STEAM	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	0	1	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWh	414	257	364	277	321	356	449	451	495	464	511	394
(13)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	NATURAL GAS	TOTAL	GWh	8,236	9,657	10,408	12,714	16,828	18,507	19,966	19,780	22,442	24,111	25,777	23,266
(15)		STEAM	GWh	74	161	0	0	0	0	0	0	0	0	0	0
(16)		CC	GWh	7,025	8,517	9,002	11,480	15,510	17,328	18,601	18,416	21,070	22,809	24,400	22,014
(17)		CT	GWh	1,137	979	1,406	1,234	1,318	1,179	1,365	1,363	1,372	1,303	1,377	1,252
(18)	OTHER 2/														
	QF PURCHASES		GWh	4,211	4,394	3,357	3,247	2,552	2,460	2,463	2,468	2,283	1,473	1,473	1,476
	RENEWABLES		GWh	--	--	1,145	1,231	1,301	2,064	2,062	2,065	2,033	1,700	1,658	1,657
	IMPORT FROM OUT OF STATE		GWh	3,599	3,683	3,542	3,476	3,546	2,512	2,061	2,014	2,072	2,031	2,121	1,328
	EXPORT TO OUT OF STATE		GWh	-83	-48	0	0	0	0	0	0	0	0	0	0
(19)	NET ENERGY FOR LOAD		GWh	46,878	46,041	48,194	49,468	50,609	52,516	53,776	55,017	56,321	57,732	59,074	60,460

1/ NET ENERGY PURCHASED (+) OR SOLD (-) WITHIN THE FRCC REGION.

2/ NET ENERGY PURCHASED (+) OR SOLD (-).

PROGRESS ENERGY FLORIDA

SCHEDULE 6.2

ENERGY SOURCES (PERCENT)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
(1)	ANNUAL FIRM INTERCHANGE 1/		%	4.7%	4.5%	4.6%	3.7%	3.7%	3.3%	1.4%	1.3%	1.2%	1.0%	1.1%	0.6%
(2)	NUCLEAR		%	12.4%	13.9%	12.3%	13.5%	10.1%	13.3%	12.0%	14.7%	13.4%	14.2%	12.8%	22.1%
(3)	COAL		%	33.8%	32.5%	31.7%	29.9%	30.0%	28.1%	30.0%	29.3%	27.6%	27.5%	27.2%	25.9%
(4)	RESIDUAL	TOTAL	%	14.1%	10.1%	12.4%	10.5%	7.7%	5.9%	6.4%	6.1%	5.6%	5.7%	5.4%	4.8%
(5)		STEAM	%	14.1%	10.1%	12.4%	10.5%	7.7%	5.9%	6.4%	6.1%	5.6%	5.7%	5.4%	4.8%
(6)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(7)		CT	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(8)		DIESEL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(9)	DISTILLATE	TOTAL	%	0.9%	0.6%	0.8%	0.6%	0.6%	0.7%	0.8%	0.8%	0.9%	0.8%	0.9%	0.7%
(10)		STEAM	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(11)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(12)		CT	%	0.9%	0.6%	0.8%	0.6%	0.6%	0.7%	0.8%	0.8%	0.9%	0.8%	0.9%	0.7%
(13)		DIESEL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(14)	NATURAL GAS	TOTAL	%	17.6%	21.0%	21.6%	25.7%	33.3%	35.2%	37.1%	36.0%	39.8%	41.8%	43.6%	38.5%
(15)		STEAM	%	0.2%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(16)		CC	%	15.0%	18.5%	18.7%	23.2%	30.6%	33.0%	34.6%	33.5%	37.4%	39.5%	41.3%	36.4%
(17)		CT	%	2.4%	2.1%	2.9%	2.5%	2.6%	2.2%	2.5%	2.5%	2.4%	2.3%	2.3%	2.1%
(18)	OTHER 2/														
	QF PURCHASES		%	9.0%	9.5%	7.0%	6.6%	5.0%	4.7%	4.6%	4.5%	4.1%	2.6%	2.5%	2.4%
	IMPORT FROM OUT OF STATE		%	7.7%	8.0%	7.3%	7.0%	7.0%	4.8%	3.8%	3.7%	3.7%	3.5%	3.6%	2.2%
	EXPORT TO OUT OF STATE		%	-0.2%	-0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(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%	100.0%

1/ NET ENERGY PURCHASED (+) OR SOLD (-) WITHIN THE FRCC REGION.

2/ NET ENERGY PURCHASED (+) OR SOLD (-).

FORECASTING METHODS AND PROCEDURES

INTRODUCTION

Accurate forecasts of long-range electric energy consumption, customer growth, and peak demand are essential elements in electric utility planning. Accurate projections of a utility's future load growth require a forecasting methodology with the ability to account for a variety of factors influencing electric energy usage over the planning horizon. PEF's forecasting framework utilizes a set of econometric models to achieve this end. This section will describe the underlying methodology of the customer, energy, and peak demand forecasts including the principal assumptions incorporated within each. Also included is a description of how Demand-Side Management (DSM) impacts the forecast, the development of high and low forecast scenarios and a review of DSM programs.

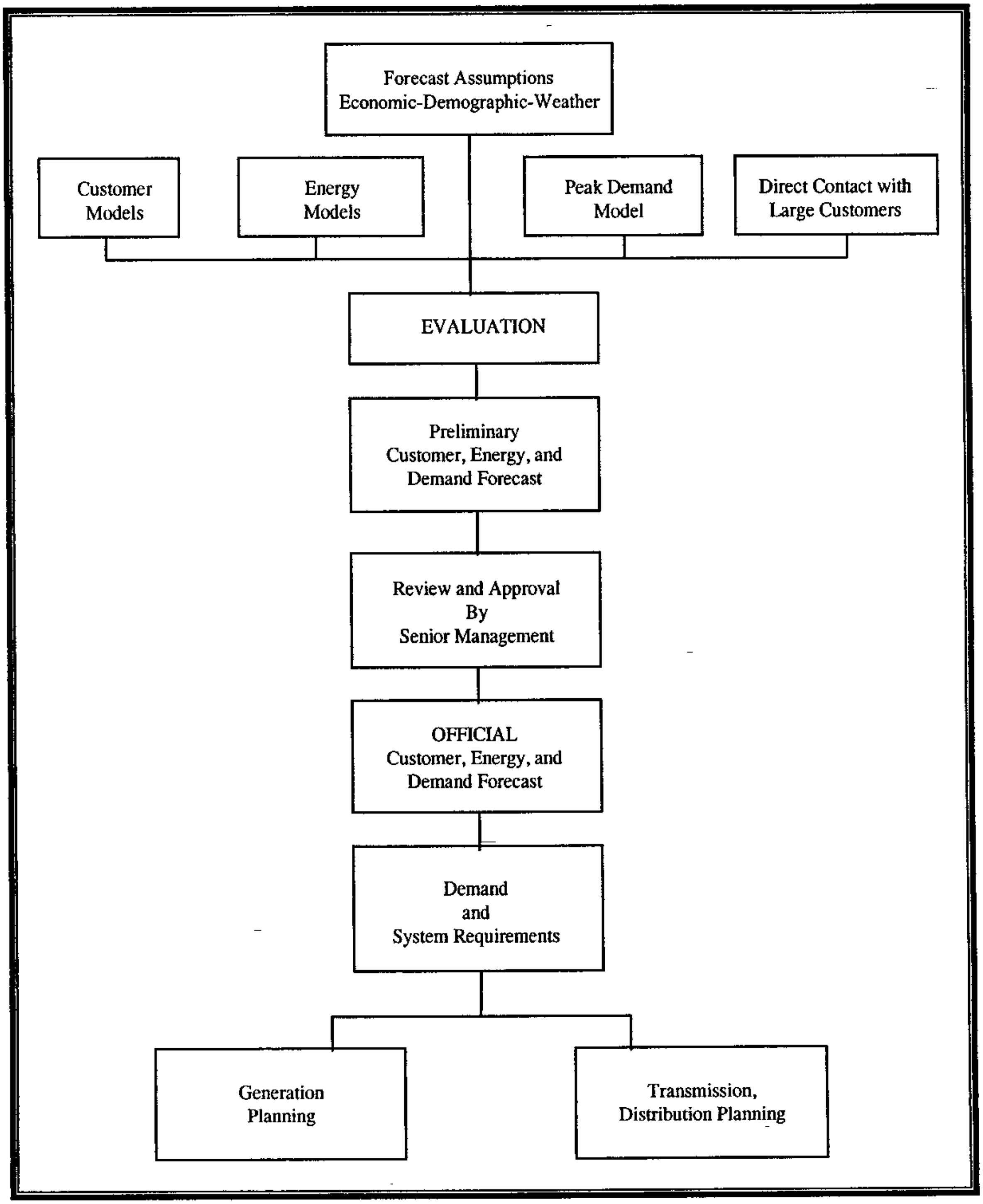
Figure 2.1, entitled "Customer, Energy and Demand Forecast", gives a general description of PEF's forecasting process. Highlighted in the diagram is a disaggregated modeling approach that blends the impacts of average class usage as well as customer growth based on a specific set of assumptions for each class. Also accounted for is some direct contact with large customers. These inputs provide the tools needed to frame the most likely scenario of the company's future demand.

FORECAST ASSUMPTIONS

The first step in any forecasting effort is the development of assumptions upon which the forecast is based. The Corporate Planning Department develops these assumptions based on discussions with a number of departments within PEF, as well as through the research efforts of a number of external sources. These assumptions specify major factors that influence the level of customers, energy sales, or peak demand over the forecast horizon. The following set of assumptions forms the basis for the forecast presented in this document.

FIGURE 2.1

Customer, Energy, and Demand Forecast



GENERAL ASSUMPTIONS

1. Normal weather conditions for energy sales are assumed over the forecast horizon using a sales-weighted thirty-year average of conditions at seven weather stations across Florida (St. Petersburg, Tampa, Orlando, Winter Haven, Gainesville, Daytona, and Tallahassee). For kilowatt-hour sales projections, normal weather is based on a historical thirty-year average of service area weighted billing month degree-days. Seasonal peak demand projections are based on a thirty-year historical average of system-weighted temperatures at time of seasonal peak at the Tampa, Orlando, and Tallahassee weather stations; the other weather stations are not used in developing the historic average because they lack the data needed for peak-weather normalization.

2. The population projections produced by the Bureau of Economic and Business Research (BEBR) at the University of Florida as published in "Florida Population Studies Bulletin No. 144 (February 2006) provide the basis for development of the customer forecast. State and national economic assumptions produced by Economy.Com in their national and Florida forecasts (March 2006) are also incorporated.

3. Within the PEF service area the phosphate mining industry is the dominant sector in the industrial sales class. Four major customers accounted for 30% of the industrial class MWh sales in 2006. These energy intensive customers mine and process phosphate-based fertilizer products for the global marketplace. Both supply and demand conditions for their products are dictated by global conditions that include, but are not limited to, foreign competition, national/international agricultural industry conditions, exchange-rate fluctuations, and international trade pacts. Load and energy consumption at the PEF-served mining or chemical processing sites depend heavily on plant operations, which are heavily influenced by the state of these global conditions as well as local conditions. After years of excess mining capacity and weak product pricing power, the industry has consolidated down to fewer players in time to take advantage of better market conditions. Also, a weaker U.S currency value on the foreign exchange is expected to help the industry in two ways. First, American farm commodities will be more competitive overseas and lead to higher crop production at home. This will result in greater demand for fertilizer products. Second, a weak U.S. dollar results in U.S. fertilizer

producers becoming more price competitive relative to foreign producers. Going forward, energy consumption is expected to increase in the near term, as a new mine operation is expected to open. A significant risk to this projection lies in the volatile price of energy (natural gas), which is a major cost of fertilizer production. Operations at several sites in the U.S. have already scaled back or shutdown in 2005-2006 due to profitability concerns caused by high energy prices. The energy projection for this industry assumes no major reductions or shutdowns of operations in the service territory.

4. PEF supplies load and energy service to wholesale customers on a "full", "partial", and "supplemental" requirement basis. Full requirements (FR) customers' demand and energy is assumed to grow at a rate that approximates their historical trend. Contracts for this service include the cities of Bartow, Chattahoochee, Mt. Dora, Quincy, Williston, and Winter Park. Partial requirements (PR) customer load is assumed to reflect the current contractual obligations reflected by the nature of the stratified load they have contracted for, plus their ability to receive dispatched energy from power marketers any time it is more economical for them to do so. Contracts for PR service included in this forecast are with the Florida Municipal Power Agency (FMPA), New Smyrna Beach, Tallahassee, Homestead, Reedy Creek Utilities, TECO Energy (Market Mitigation Sale) and Seminole Electric Cooperative, Inc. (SECI). PEF's contractual arrangement with SECI includes a "supplemental" service contract (1983 contract) for service over and above stated levels they commit to supply themselves. This contract is projected to become a "winter only" seasonal purchase in 2014 when the term of this contract expires in December 2013. A firm PR contract with SECI includes 450 MW of stratified intermediate service (October 1995 contract) which is projected to continue through the forecast horizon. In addition, a FR contract to serve SECI load, will commence in 2010, and last through the forecast horizon. Finally, an agreement to provide interruptible service at a SECI metering site has also been included in this projection.

5. This forecast assumes that PEF will successfully renew all future franchise agreements.

6. This forecast incorporates demand and energy reductions from PEF's dispatchable and non-dispatchable DSM programs required to meet the approved goals set by the FPSC.

7. Expected energy and demand reductions from self-service cogeneration are also included in this forecast. PEF will supply the supplemental load of self-service cogeneration customers. While PEF offers "standby" service to all cogeneration customers, the forecast does not assume an unplanned need for standby power.

8. This forecast assumes that the regulatory environment and the obligation to serve our retail customers will continue throughout the forecast horizon. Regarding wholesale customers, the company does not plan for generation resources unless a long-term contract is in place. Current FR customers are assumed to renew their contracts with PEF except those who have given notice to terminate. Current PR contracts are projected to terminate as terms reach their expiration date. Deviation from these assumptions can occur based on information provided by the Regulated Commercial Operations Department.

SHORT-TERM ECONOMIC ASSUMPTIONS

The economic outlook for this forecast was developed in 2006 as energy prices were hitting record highs around the world. The consensus was that the U.S. economy, which was growing at a reasonable rate, would not slip into recession due to the higher cost of energy. Instead, a "soft patch" in economic activity apparent at the time of this forecast development as high gasoline prices had been reducing consumer confidence levels. Short term interest rates, controlled mostly by Federal Reserve Board (FED) policy decisions, peaked in mid-2006 and have remained stable after 17 increases based upon signs coming from a weakening construction industry and lower inflation. Economists are not in complete agreement about where monetary policy may go from here. A slight majority suspect that the FED has ended its "tightening" policy of gradually raising interest rates as opposed to those who believe that new inflationary fears will require more rate increases.

Consensus opinion believes that the economic stimulus supplied by the three federal tax cuts and the refinancing boom have successfully kept the U.S. economy out of recession after the September 11, 2001 terrorist attacks. Now, with rates back up to more normal levels, and talk of rescinding some of the tax cuts, stimulus from these two economic tools is not expected going forward. One item believed to become a positive factor for future economic momentum is the weaker U.S. currency. Up to this point several major U.S. trading partners, mainly China, have their currencies pegged to the U.S. Dollar. This has kept the typical advantages of a weaker currency from helping U.S. manufacturers. Going forward, it is expected that economic and political pressures will force the Chinese to de-link their currency and allow it to appreciate in value. This likely will make American-produced products more competitive with imported Chinese goods, as well as other goods produced around the globe.

The housing sector, which had a record run in the first half of the decade, has peaked and has now slowed. While the fall-off in housing starts has only taken the industry down to normal levels seen before the run-up, no one feels confident predicting when the bottom will be reached. Home sales have dipped significantly and the number of unsold and even vacant homes has hit record levels leading to significant price reductions in some areas of the country. On top of all this, the number of foreclosures and mortgages in default has risen of late. More homeowners, struggling to meet higher payments from adjustable-rate loans, are walking away from homes as they become "upside-down" in the mortgage (when the market price falls below the outstanding loan amount.) All of this does not bode well for Florida, which played a major part in the recent housing boom. In order to grow out of this, migration into the State will need to absorb this overhang in available housing at a time when out-of-state homeowners may have a difficult time selling their property.

The Florida economy has faired much better than the nation, especially in terms of job growth. The tourism industry, which has bounced back from the terrorism fears of 2001, will now have to juggle the impact of high oil prices on the travel industry. Also, the increases in property insurance and property taxes in Florida have caused anxiety. Florida's reputation as a low cost-of-living state has been impacted.

Besides growth in State population, growth in energy consumption can also be directly tied to the levels of economic activity as measured by total personal income and employment. Florida has experienced excellent employment growth since the last recession – better than most other states.
However, due to the run-up in energy prices, the need for greater national energy independence and the wider review of the potential effects of climate change upon the environment, energy consumption of all types and at all consumer levels are coming under greater scrutiny. In addition, federal and state tax incentives to conserve energy are becoming more widespread and energy-saving

capital improvements are becoming more economically viable. Even players with significant economic influence – like Wal-Mart stores – are pressing their suppliers to become more energy efficient. Just as occurred after each of the Arab oil embargoes, all of these factors may drive the country to improve energy use per unit of Gross Domestic Product (GDP), which could reduce the growth in energy demand. The level of energy prices will obviously play a major role in the outcome.

LONG-TERM ECONOMIC ASSUMPTIONS

The long-term economic outlook assumes that changes in economic and demographic conditions will follow a trended behavior pattern. The main focus involves identifying these trends. No attempt is made to predict business cycle fluctuations during this period.

Population Growth Trends

This forecast assumes Florida will experience slower in-migration and population growth over parts of the long term, as reflected in the BEBR projections. Florida's climate and low cost of living have historically attracted a major share of the retirement population from the eastern half of the United States. This will continue to occur, but at less than historic rates for several reasons. First, Americans entering retirement age during the late 1990s and early twenty-first century were born during the Great Depression era of the 1930s. This decade experienced a low birth rate due to the economic conditions at that time. Now that this generation is retiring, there exists a smaller pool of retirees capable of migrating to Florida. As we enter into the second decade of the new century and the baby-boom generation enters retirement age, the reverse effect can be expected.

Second, the enormous growth in population and corresponding development of the 1980s, 1990s and early 2000s made portions of Florida less desirable and less affordable for retirement living. This diminished the quality of retiree life, and along with increasing competition from neighboring states, is expected to cause a slight decline in Florida's share of these prospective new residents over the long term.

Another reason for a population growth slowdown appears to be the fear and expense of Hurricanes. The summers of 2004 and 2005 may force some in-migrants to rethink their retirement location as the inconvenience caused by recent destruction and ever-increasing cost of property insurance makes Florida a less desirable place to live.

Economic Growth Trends

Florida has been recently experiencing a 1980s-style population explosion and service sector job creation. The State has benefited greatly from generational lows in interest rates, which along with investors' unfriendly attitude toward the equity markets, set the stage for a tremendous explosion in home construction. The national level of homebuilding in 2005, which rose to more than 31% higher than in 2000, set an all time record. This growth produced strong gains in both the construction industry and service-producing sectors of the Florida economy.

We now see that this pace of growth has not been sustained, and the economic environment that produced this construction boom has returned to normal. Interest rates have risen to more "long term" norms. Investment in equity markets over housing has occurred as well. More importantly, affordability rates have dropped as housing prices in many parts of Florida have out-paced many areas of the country. This could have a major impact on retiree decisions to move into the area. Making matters worse is the availability and affordability of homeowners insurance, which has become a concern of increasing importance since the Hurricane seasons of 2004 and 2005.

Florida's rapid population growth of late has created a period of strong job creation, especially in the service sector industries. While the service-oriented economy expanded to support an increasing population level, there were also a number of corporations migrating to Florida capitalizing on the low cost, low tax business environment. This being the case, increased job opportunities in Florida created greater in-migration among the nation's working age population. Florida's ability to attract businesses from other states because of its "comparative advantage" is expected to continue throughout the forecast period but at a less significant level. Florida's successful effort to attract a large biotech firm, Scripps Research, has the potential to draw a whole new growth industry to the State, the same way Disney and NASA once did.

The forecast assumes negative growth in real electricity price. That is, the change in the nominal price of electricity per kWh over time is expected to be less than the overall rate of inflation. This also implies that future fuel price escalation will track at or below the general rate of inflation throughout the forecast horizon.

Real personal incomes are assumed to increase throughout the forecast period thereby boosting the average customer's ability to purchase electricity. As incomes grow faster than the price of electricity, consumers, on average, will remain inclined to purchase additional electric appliances and increase their utilization of existing end-uses.

FORECAST METHODOLOGY

The PEF forecast of customers, energy sales, and peak demand is developed using customer class-specific econometric models. These models are expressly designed to capture class-specific variation over time. By modeling customer growth and average energy usage individually, subtle changes in existing customer usage are better captured as well as growth from new customers. Peak demand models are projected on a disaggregated basis as well. This allows for appropriate handling of individual assumptions in the areas of wholesale contracts, load management, and interruptible service.

ENERGY AND CUSTOMER FORECAST

In the retail jurisdiction, customer class models have been specified showing a historical relationship to weather and economic/demographic indicators using monthly data for sales models and annual data for customer models. Sales are regressed against "driver" variables that best explain monthly fluctuations over the historical sample period. Forecasts of these input variables are either derived internally or come from a review of the latest projections made by several independent forecasting concerns. The external sources of data include Moody's Economy.Com and the University of Florida's Bureau of Economic and Business Research. Internal company forecasts are used for projections of electricity price, weather conditions, and the length of the billing month. Normal weather, which is assumed throughout the forecast horizon, is based on the 30-year average of heating and cooling degree-days by month as measured at several weather stations throughout Florida for energy projections and temperatures around the hour of peak for the firm retail demand forecast. Projections of PEF's demand-side management (conservation programs) are also incorporated as reductions to the forecast. Specific sectors are modeled as follows:

Residential Sector

Residential kWh usage per customer is modeled as a function of real Florida personal income, cooling degree-days, heating degree-days, the real price of electricity to the residential class and the average number of billing days in each sales month. This equation captures significant variation in residential usage caused by economic cycles, weather fluctuations, electric price movements, and sales month duration. Projections of kWh usage per customer combined with the customer forecast provide the forecast of total residential energy sales. The residential customer forecast is developed by correlating annual customer growth with PEF service area population growth and mortgage rates. County level population projections for the 29 counties, in which PEF serves residential customers, are provided by the BEBR.

Commercial Sector

Commercial MWh energy sales are forecast based on commercial (non-agricultural, non-manufacturing and non-governmental) employment, the real price of electricity to the commercial class, the average number of billing days in each sales month and heating and cooling degree-days. The measure of cooling degree-days utilized here differs slightly from that used in the residential sector reflecting different temperature bases where heating and cooling load become observable. Commercial customers are projected as a function of the number of residential customers served.

Industrial Sector

Energy sales to this sector are separated into two sub-sectors. A significant portion of industrial energy use is consumed by the phosphate mining industry. Because this one industry comprises nearly a 30% share of the total industrial class, it is separated and modeled apart from the rest of the class. The term "non-phosphate industrial" is used to refer to those customers who comprise the remaining portion of total industrial class sales. Both groups are impacted significantly by changes in economic activity. However, adequately explaining sales levels requires separate explanatory variables. Non-phosphate industrial energy sales are modeled using Florida manufacturing employment and a Florida industrial production index developed by Economy.Com, the real price of electricity to the industrial class, and the average number of sales month billing days.

The industrial phosphate mining industry is modeled using customer-specific information with respect to expected market conditions. Since this sub-sector is comprised of only four customers, the forecast is dependent upon information received from direct customer contact. PEF industrial customer representatives provide specific phosphate customer information regarding customer production schedules, inventory levels, area mine-out and start-up predictions, and changes in self-service generation or energy supply situations over the forecast horizon.

Street Lighting

Electricity sales to the street and highway lighting class are projected to increase due to growth in the service area population base. Because this class comprised less than 0.01% of PEF's 2006 electric sales and just 0.1% of total customers, a simple time trend was used to project energy consumption and customer growth in this class.

Public Authorities

Energy sales to public authorities (SPA), comprised mostly of government operated services, is also projected to grow with the size of the service area. The level of government services, and thus energy use per customer, can be tied to the population base, as well as to the state of the economy. Factors affecting population growth will affect the need for additional governmental services (i.e., schools, city services, etc.) thereby increasing SPA energy usage per customer. Government employment has been determined to be the best indicator of the level of government services provided. This variable, along with heating and cooling degree-days (class specific), the real price of electricity and the average number of sales month billing days, results in a significant level of explained variation over the historical sample period. Intercept shift variables are also included in this model to account for the large change in school-related energy use in the billing months of January, July, and August. SPA customers are projected linearly as a function of a time-trend.

Sales for Resale Sector

The Sales for Resale sector encompasses all firm sales to other electric power entities. This includes sales to other utilities (municipal or investor-owned) as well as power agencies (Rural Electric Authority or Municipal).

SECI is a wholesale, or sales for resale, customer of PEF on both a supplemental contract basis and contract demand basis. Under the supplemental contract, PEF provides service for those energy requirements above the level of generation capacity served by either SECI's own facilities or its firm purchase obligations. Monthly supplemental energy is developed using an average historical load shape of total SECI load in the PEF control area, subtracting out the level of SECI "committed" capacity from each hour. Beyond supplemental service, PEF has an agreement with SECI to serve stratified intermediate and peaking energy. This agreement involves serving 450 MW of stratified intermediate demand that is assumed to remain a requirement on the PEF system throughout the forecast horizon. A "winter-only" seasonal peaking strata contract for 600 MW will replace the supplemental contract in 2014. An agreement to provide non-firm service is currently in effect between PEF and SECI amounting to an estimated 15 MW. Another contract, signed in 2004 to supply full requirements service for 150 MW, will begin in 2010.

The municipal sales for resale class includes a number of customers, divergent not only in scope of service, (i.e., full or partial requirement), but also in composition of ultimate consumers. Each customer is modeled separately in order to accurately reflect its individual profile. Several of the customers in this class are municipalities whose full energy requirements are met by PEF. The full requirement customers are modeled individually using local weather station data and population growth trends. Since the ultimate consumers of electricity in this sector are, to a large degree, residential and commercial customers, it is assumed that their use patterns will follow those of the PEF retail-based residential and commercial customer classes. PEF serves partial requirement service (PR) to municipalities such as New Smyrna Beach (NSB), Homestead, and Tallahassee, and other power providers like FMPA. In each case, these customers contract with PEF for a specific level and type of demand needed to provide their particular electrical system with an appropriate level of reliability. The terms of the FMPA contract is subject to change each year via a letter of "declared" MW nomination. More specifically, this means that the level and type of demand and energy under contract can increase or decrease for each year a value is nominated. The energy forecast for each contract is derived using its historical load factors where enough history exists, or typical load factors for a given type of contracted stratified load. The energy projections for FMPA also include a "losses service contract" for energy PEF supplies to FMPA for transmission losses incurred when "wheeling" power to their ultimate customers in PEF's transmission area. This projection is based on the projected requirements of the aggregated needs of the cities of Ocala, Leesburg, Bushnell, Havana, and Newberry.

PEAK DEMAND FORECAST

The forecast of peak demand also employs a disaggregated econometric methodology. For seasonal (winter and summer) peak demands, as well as each month of the year, PEF's coincident system peak is dissected into five major components. These components consist of potential firm retail load, conservation and load management program capability, wholesale demand, company use demand and interruptible demand.

Potential firm retail load refers to projections of PEF retail hourly seasonal net peak demand (excluding the non-firm interruptible/curtailable/standby services) before the cumulative effects of any conservation activity or the activation of PEF's Load Management program. The historical values of this series are constructed to show the size of PEF's firm retail net peak demand assuming no utility-induced conservation or load control had taken place. The value of constructing such a "clean" series enables the forecaster to observe and correlate the underlying trend in retail peak demand to total system customer levels and coincident weather conditions at the time of the peak without the impacts of year-to-year variation in conservation activity or load control reductions. Seasonal peaks are projected using historical seasonal peak data regardless of which month the peak occurred. The projections become the potential retail demand projection for the month of January (winter) and August (summer) since this is typically when the seasonal peaks occur. The non-seasonal peak months are projected the same as the seasonal peaks, but the analysis is limited to the specific month being projected.

Energy conservation and direct load control estimates are consistent with PEF's DSM goals that have been approved by the FPSC. These estimates are incorporated into the MW forecast. Projections of dispatchable and cumulative non-dispatchable DSM are subtracted from the projection of potential firm retail demand resulting in a projected series of retail demand figures one would expect to occur.

Sales for Resale demand projections represent load supplied by PEF to other electric utilities such as SECI, FMPA, and other electric distribution companies. The SECI supplemental demand projection is based on a trend of their historical demand within the PEF control area. The level of MW to be served by PEF is dependent upon the amount of generation resources SECI supplies itself or contracts from others. An assumption has been made that beyond the last year of committed capacity declaration (five years out), SECI will shift their level of self-serve resources to meet their base and intermediate load needs. For FMPA and NSB demand projections, historical ratios of coincident-to-contract levels of demand are applied to future MW contract levels. Demand requirements continue at the MW level indicated by the final year in their respective contract declaration letter. The full requirements municipal demand forecast is estimated for individual cities using linear econometric equations modeling both weather and economic impacts specific to each locale. The seasonal (winter and summer) projections become the January and August peak values, respectively. The non-seasonal peak months are calculated using monthly allocation factors derived from applying the historical relationship between each winter month (November to March) relative to the winter peak, and each summer month (April to October) in relation to the summer peak demand.

PEF "company use" at the time of system peak is estimated using load research metering studies and is assumed to remain stable over the forecast horizon. The interruptible and curtailable service (IS and CS) load component is developed from historic trends, as well as the incorporation of specific information obtained from PEF's large industrial accounts by field representatives.

Each of the peak demand components described above is a positive value except for the DSM program MW impacts and IS and CS load. These impacts represent a reduction in peak demand

and are assigned a negative value. Total system firm peak demand is then calculated as the arithmetic sum of the five components.

HIGH AND LOW FORECAST SCENARIOS

The high and low bandwidth scenarios around the base MWh energy sales forecast are developed using a Monte Carlo simulation applied to a multivariate regression model that closely replicates the base retail MWh energy forecast in aggregate. This model accounts for variation in Gross Domestic Product, retail customers and electricity price. The base forecasts for these variables were developed based on input from Economy.Com and internal company price projections. Variation around the base forecast predictor variables used in the Monte Carlo simulation was based on an 80 percent confidence interval calculated around variation in each variable's historic growth rate. While the total number of degree-days (weather) was also incorporated into the model specification, the high and low scenarios do not attempt to capture extreme weather conditions. Normal weather conditions were assumed in all three scenarios.

The Monte Carlo simulation was produced through the estimation of 1,000 scenarios for each year of the forecast horizon. These simulations allowed for random normal variation in the growth trajectories of the economic input variables (while accounting for cross-correlation amongst these variables), as well as simultaneous variation in the equation (model error) and coefficient estimates. These scenarios were then sorted and rank ordered from one to a thousand, while the simulated scenario with no variation was adjusted to equal the base forecast.

The low retail scenario was chosen from among the ranked scenarios resulting in a bandwidth forecast reflecting an approximate probability of occurrence of 0.10. The high retail scenario similarly represents a bandwidth forecast with an approximate probability of occurrence also at 0.10. In both scenarios, the high and low peak demand bandwidth forecasts, are projected from the energy forecasts using the load factor implicit in the base forecast scenario.

CONSERVATION

PEF's DSM performance is shown in the following tables, which compare the conservation savings actually achieved through PEF's DSM programs for the reporting years of 2005 and 2006 with the Commission-approved conservations goals.

On August 9, 2004, the FPSC issued a PAA Order approving new conservation goals for PEF that span the ten-year period from 2005 through 2014, as well as a new DSM Plan for PEF that was specifically designed to meet the new conservation goals. (Docket 040031-EG, Order No. PSC-04-0769-PAA-EG). On January 5, 2007, the FPSC issued a PAA Order approving 39 additional DSM measures and 2 residential programs, which will serve to increase the demand and energy savings available through PEF's DSM Plan. (Docket 060647: Consummating Order PSC-07-0017-CO-EG making Order PSC-06-1018-TRF-EG effective and final.)

Residential Conservation Savings Goals and Achievements

	Summer MW		Winter MW		Annual GWh Energy	
Year	Goal	Achieved	Goal	Achieved	Goal	Achieved
2005	13	18	43	48	21	29
2006	21	37	75	99	35	58

Commercial Conservation Savings Goals and Achievements

	Summer MW		Winter MW		Annual GWh Energy	
Year	Goal	Achieved	Goal	Achieved	Goal	Achieved
2005	4	8	3	6	3	3
2006	7	16	7	12	6	9

The forecasts contained in this Ten-Year Site Plan document are based on these 2007 program additions and modifications to PEF's DSM Plan and, therefore, appropriately reflect the most current projection of DSM savings over the next ten years. PEF's DSM Plan consists of seven residential programs, eight commercial and industrial programs, and one research and development program. On January 5, 2007, the FPSC issued a PAA Order approving 39 additional DSM measures and 2 residential programs. (Docket 060647: Consummating Order PSC-07-0017-CO-EG making Order PSC-06-1018-TRF-EG effective and final). Megawatt contributions to the TYSP, reflected in this report, have increased as a result of these changes to conservation, standby and residential load management programs. The programs are subject to periodic monitoring and evaluation for the purpose of ensuring that all DSM resources are acquired in a cost-effective manner and that the program savings are durable. Following is a brief description of these programs.

RESIDENTIAL PROGRAMS

Home Energy Check Program

This energy audit program provides customers with an analysis of their current energy use and recommendations on how they can save on their electricity bills through low-cost or no-cost energy-saving practices and measures. The Home Energy Check program offers PEF customers the following types of audits: Type 1: Free Walk-Through Audit (Home Energy Check); Type 2: Customer-completed Mail In Audit (Do It Yourself Home Energy Check); Type 3: Online Home Energy Check (Internet Option)-a customer-completed audit; Type 4: Phone Assisted Audit –A customer assisted survey of structure and appliance use; Type 5: Computer Assisted Audit; Type 6: Home Energy Rating Audit (Class I, II, III). Additionally, a student audit was piloted in 2006. The Home Energy Check Program serves as the foundation of the Home Energy Improvement Program in that the audit is a prerequisite for participation in the energy saving measures offered in the Home Energy Improvement Program.

Home Energy Improvement Program

This is the umbrella program to increase energy efficiency for existing residential homes. It combines efficiency improvements to the thermal envelope with upgraded electric appliances. The program provides incentives for attic insulation upgrades, duct testing and repair, and high efficiency electric heat pumps. The additional measures within this program include spray-in wall insulation, central AC 14 SEER non-electric heat, supply and return plenum duct seal, proper sizing of hi-efficiency HVAC, HVAC commissioning, reflective roof coating for manufactured homes, reflective roof for single-family homes, window film or screen, and replacement windows.

Residential New Construction Program

This program promotes energy efficient new home construction in order to provide customers with more efficient dwellings combined with improved environmental comfort. The program provides education and information to the design and building community on energy efficient equipment and construction. It also facilitates the design and construction of energy efficient homes by working directly with the builders to comply with program requirements. The program provides incentives to the builder for high efficiency electric heat pumps and high performance windows. The highest level of the program incorporates the Environmental Protection Agency's Energy Star Homes Program and qualifies participants for cooperative advertising. New measures within the Residential New Construction Program include HVAC commissioning, window film or screen, reflective roof for single-family homes, attic spray-on foam insulation, conditioned space air handler and energy recovery ventilation.

Low Income Weatherization Assistance Program

This umbrella program seeks to improve energy efficiency for low-income customers in existing residential dwellings. It combines efficiency improvements to the thermal envelope with upgraded electric appliances. The program provides incentives for attic insulation upgrades, duct testing and repair, reduced air infiltration, water heater wrap, HVAC maintenance, high efficiency heat pumps, heat recovery units, and dedicated heat pump water heaters.

Neighborhood Energy Saver Program

The newly approved Neighborhood Energy Saver (NES) Program consists of 12 measures including compact fluorescent bulb replacement, water heater wrap and insulation for water pipes, water heater temperature check and adjustment, low-flow faucet aerator, low-flow showerhead / refrigerator coil brush, HVAC filters and weatherization measures (weather stripping / door sweeps / etc.). In addition to the installation of new conservation measures, an important component of this program is educating families on energy efficiency techniques and the promotion of behavioral changes to help customers control their energy usage.

Residential Energy Management Program

This is a voluntary customer program that allows PEF to reduce peak demand and thus defer generation construction. Peak demand is reduced by interrupting service to selected electrical equipment with radio controlled switches installed on the customer's premises. These interruptions are at PEF's option, during specified time periods, and coincident with hours of peak demand. Participating customers receive a monthly credit on their electricity bills prorated above 600 kWh/month.

Renewable Energy Saver Program (2007)

The Renewable Energy Saver Program is designed to reduce system peak demand and increase renewable energy generation on the PEF grid. The program seeks to meet the following overall goals:

1. Obtain energy and demand reductions that are significant and measurable.
2. Enhance customers/contractors awareness of the capabilities of renewable energy technologies.
3. Educate customers/contractors about additional opportunities to generate / use renewable energy.
4. Develop and offer renewable energy measures to the marketplace.
5. Minimize "lost opportunities" in the renewable energy market.
6. Increase participation in the PEF Load Management program.

The Renewable Energy Saver Program consists of two measures:

- Solar Water Heater with Energy Management – This measure encourages residential customers to install a solar thermal water heating system. The customer must have whole house electric cooling, electric water heating, and electric heating to be eligible for this program. Pool heaters and photovoltaic systems would not qualify. In order to qualify for this incentive, the heating, air conditioning, and water heating systems must be on the Energy Management Program and the solar thermal system must provide a minimum of 50% of the water-heating load.

- Solar Photovoltaics with Energy Management – This measure promotes environmental stewardship and renewable energy education through the installation of solar energy systems at schools within Progress Energy Florida's service territory. Customers participating in the Winter-Only Energy Management or Year-Round Energy Management plan can elect to donate their monthly credit toward the Solar Photovoltaics with Energy Management Fund. The fund will accumulate associated participant credits for a period of two years, at which time the customer may elect to renew for an additional two years. All proceeds collected from participating customers, and their associated monthly credits, will be used to promote photovoltaics and renewable energy education opportunities.

COMMERCIAL/INDUSTRIAL (C/I) PROGRAMS

Business Energy Check Program

This energy audit program provides commercial and industrial customers with an assessment of the current energy usage at their facilities, recommendations on how they can improve the environmental conditions of their facilities while saving on their electricity bills, and information on low-cost energy efficiency measures. The Business Energy Check consists of the following types of audits: A free walk-through audit, and a paid walk-through audit. Small business customers also have the option to complete a Business Energy Check online at Progress Energy's website. In most cases, this program is a prerequisite for participation in the other C/I programs.

Better Business Program

This is the umbrella efficiency program for existing commercial and industrial customers. The program provides customers with information, education, and advice on energy-related issues and incentives on efficiency measures that are cost-effective to PEF and its customers. The Better Business Program promotes energy efficient heating, ventilation, air conditioning (HVAC), and some building retrofit measures (in particular, ceiling insulation upgrade, duct leakage test and repair, energy-recovery ventilation and Energy Star cool roof coating products.) Newly approved measures within this program include demand-control ventilation, efficient compressed air systems, efficient motors, efficient indoor lighting, green roof, occupancy sensors, packaged AC steam cleaning, roof insulation, roof-top unit recommissioning, thermal energy storage and window film or screen.

Commercial/Industrial New Construction Program

The primary goal of this program is to foster the design and construction of energy efficient buildings. The new construction program: 1) provides education and information to the design community on all aspects of energy efficient building design; 2) requires that the building design, at a minimum, surpass the state energy code; 3) provides financial incentives for specific energy efficient equipment; and 4) provides energy design awards to building design teams. Incentives will be provided for high efficiency HVAC equipment, energy recovery ventilation and Energy Star cool roof coating products. Additional options, beginning in 2007, include demand-control ventilation, efficient compressed air systems, efficient motors, efficient indoor lighting, green roof, occupancy sensors, roof insulation, thermal Energy Storage and window film or screen.

Innovation Incentive Program

This program promotes a reduction in demand and energy by subsidizing energy conservation projects for customers in PEF's service territory. The intent of the program is to encourage legitimate energy efficiency measures that reduce kW demand and/or kWh energy, but are not addressed by other programs. Energy efficiency opportunities are identified by PEF representatives during a Business Energy Check audit. If a candidate project meets program specifications, it will be eligible for an incentive payment, subject to PEF approval.

Commercial Energy Management Program (Rate Schedule GSLM-1)

This direct load control program reduces PEF's demand during peak or emergency conditions. As described in PEF's DSM Plan, this program is currently closed to new participants. It is applicable to existing program participants who have electric space cooling equipment suitable for interruptible operation and are eligible for service under the Rate Schedule GS-1, GST-1, GSD-1, or GSDT-1. The program is also applicable to existing participants who have any of the following electrical equipment installed on permanent residential structures and utilized for domestic (household) purposes: 1) water heater(s), 2) central electric heating systems(s), 3) central electric cooling system(s), and/or 4) swimming pool pump(s). Customers receive a monthly credit on their bills depending on the type of equipment in the program and the interruption schedule.

Standby Generation Program

This demand control program reduces PEF's demand based upon the indirect control of customer generation equipment. This is a voluntary program available to all commercial, industrial, and agricultural customers who have on-site generation capability and are willing to reduce their PEF demand when PEF deems it necessary. The customers participating in the Standby Generation program receive a monthly credit on their electricity bills according to the demonstrated ability of the customer to reduce demand at PEF's request.

Interruptible Service Program

This direct load control program reduces PEF's demand at times of capacity shortage during peak or emergency conditions. The program is available to qualified non-residential customers with an average billing demand of 500 kW or more, who are willing to have their power interrupted. PEF will have remote control of the circuit breaker or disconnect switch supplying the customer's equipment. In return for this ability to interrupt load, customers participating in the Interruptible Service program receive a monthly interruptible demand credit applied to their electric bills.

Curtailable Service

This direct load control program reduces PEF's demand at times of peak or emergency conditions. The program is available to qualified non-residential customers with an average billing demand of 500 kW or more, who are willing to curtail 25 percent of their average monthly billing demand. Customers participating in the Curtailable Service program receive a monthly curtailable demand credit applied to their electric bills.

RESEARCH AND DEVELOPMENT PROGRAMS

Technology Development Program

The primary purpose of this program is to establish a system to "Aggressively pursue research, development and demonstration projects jointly with others as well as individual projects" (Rule 25-17.001, {5}(f), Florida Administration Code). PEF will undertake certain development, educational and demonstration projects that have promise to become cost-effective demand reduction and energy efficiency programs. This would include projects like Broadband-Over-the

Power-Line-In-Premise load management capabilities, which the Company is currently evaluating and testing. The objective of this project is to develop the next generation of load management with goals of increasing customer awareness to efficiently use energy, while advancing demand response capabilities. Additional projects include the evaluation of off-peak generation storage for on-peak demand consumption. In most cases, each demand reduction and energy efficiency project that is proposed and investigated under this program requires field-testing with customers.

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CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

Progress Energy

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CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

RESOURCE PLANNING FORECAST

OVERVIEW OF CURRENT FORECAST

Supply-Side Resources

PEF has a summer total capacity resource of 10,752 MW, as shown in Table 3.1. This capacity resource includes nuclear (769 MW), fossil steam (3,903MW), combined cycle plants (1,659 MW), combustion turbine (2,513 MW, 143 MW of which is owned by Georgia Power for the months June through September), utility purchased power (484 MW), independent power purchases (611 MW), and non-utility purchased power (813 MW). Table 3.2 shows PEF's contracts for firm capacity provided by Qualifying Facilities (QF's).

Demand-Side Programs

Total DSM resources are shown in Schedules 3.1.1 and 3.2.1 of Chapter 2. These programs include Non-Dispatchable DSM, Interruptible Load, and Dispatchable Load Control resources. PEF's 2007 Ten-Year Site Plan Demand-Side Management projections are consistent with the DSM Goals established by the Commission in Docket No. 040031-EG.

Capacity and Demand Forecast

PEF's forecasts of capacity and demand for the projected summer and winter peaks are shown in Schedules 7.1 and 7.2, respectively. PEF's forecasts of capacity and demand are based on serving expected growth in retail requirements in its regulated service area and meeting commitments to wholesale power customers who have entered into supply contracts with PEF. In its planning process, PEF balances its supply plan for the needs of retail and wholesale customers and endeavors to ensure that cost-effective resources are available to meet the needs across the customer base. Over the years, as wholesale markets have grown more competitive, PEF has remained active in the competitive solicitations while planning in a manner that maintains an appropriate balance of commitments and resources within the overall regulated supply framework.

Base Expansion Plan

PEF's planned supply resource additions and changes are shown in Schedule 8 and are referred to as PEF's Base Expansion Plan. This Plan includes a net gain in summer capacity of 3,575 MWs through the summer of 2016. As identified in Schedule 8, PEF's next planned unit is the Hines 4 Unit, a 461 MW (summer) power block with a December 2007 in-service date. PEF's self-build option for Hines Unit 4 was determined to be the most cost-effective alternative, followed by the Bartow Repowering Project to be completed by June 2009.

PEF's Base Expansion Plan projects the need for additional units with proposed in-service dates from 2007 through 2016. These units, together with the OUC purchase (December 2006 – February 2007), the Central Power & Lime purchase (December 2005 - December 2010), the Reliant/Osceola purchase (January 2007 - February 2009), the TEA purchase (from January 2007 - February 2007, and June 2007 - September 2007), purchases currently under negotiation for the summers of 2007 and 2008, the Shady Hills Purchase (April 2007 - April 2024), and the Southern Company Purchase (June 2010 - December 2017) help the PEF system meet the growing energy requirements of its customer base. Additionally, some undesignated seasonal purchases for 2007 and 2008 are projected as well to meet requirements. Some of the identified unit additions may be impacted by PEF's ability to extend or replace existing purchase power contracts, as well as contracts with cogenerators and QF's. Status reports and specifications for new generation facilities are included in Schedule 9. Shown in Schedule 10 are the new transmission lines associated with Hines #4 and the Bartow Repowering Project.

Current planning studies identify gas-fired units as the most economic alternatives for system expansion in the near term. New nuclear technologies appear to offer more favorable long-term economics, and provide favorable environmental characteristics, measured against possible emission limits imposed by the recently issued Clean Air Interstate Rule (CAIR). PEF is currently evaluating the nuclear option with the intent of pursuing preliminary licensing activities for the addition of new nuclear capacity in 2016. In the years prior to the addition of new nuclear capacity, PEF also is investigating the possibility of coal gasification as a fuel source for one of the combined cycle facilities listed in the resource plan.

TABLE 3.1

PROGRESS ENERGY FLORIDA

TOTAL CAPACITY RESOURCES OF POWER PLANTS AND PURCHASED POWER CONTRACTS

AS OF DECEMBER 31, 2006

PLANTS	NUMBER OF UNITS	SUMMER NET DEPENDABLE CAPABILITY (MW)	
Nuclear Steam			
Crystal River	1	769	*(1)*
Total Nuclear Steam	1	769	
Fossil Steam			
Crystal River	4	2,313	
Anclote	2	1,005	
Bartow	3	444	
Suwannee River	3	141	
Total Fossil Steam	12	3,903	
Combined Cycle			
Hines Energy Complex	3	1,456	
Tiger Bay	1	203	
Total Combined cycle	4	1,659	
Combustion Turbine			
DeBary	10	643	
Intercession City	14	992	*(2)*
Bayboro	4	177	
Bartow	4	176	
Suwannee	3	157	
Turner	4	150	
Higgins	4	110	
Avon Park	2	50	
University of Florida	1	45	
Rio Pinar	1	13	
Total Combustion Turbine	47	2,513	
Total Units	**64**		
Total Net Generating Capability		**8,844**	

(1) Adjusted for sale of approximately 8.2% of total capacity
(2) Includes 143 MW owned by Georgia Power Company (Jun-Sep)

Purchased Power			
Qualifying Facility Contracts	19	813	
Investor Owned Utilities	2	484	
Independent Power Producers	2	611	
TOTAL CAPACITY RESOURCES		**10,752**	

TABLE 3.2

PROGRESS ENERGY FLORIDA

QUALIFYING FACILITY GENERATION CONTRACTS

AS OF DECEMBER 31, 2006

Facility Name	Firm Capacity (MW)
Bay County Resource Recovery	11.0
Cargill	15.0
Dade County Resource Recovery	43.0
El Dorado	114.2
Lake Cogen	110.0
Lake County Resource Recovery	12.8
LFC Jefferson	8.5
LFC Madison	8.5
Mulberry	79.2
Orange Cogen (CFR-Biogen)	74.0
Orlando Cogen	79.2
Pasco Cogen	109.0
Pasco County Resource Recovery	23.0
Pinellas County Resource Recovery 1	40.0
Pinellas County Resource Recovery 2	14.8
Ridge Generating Station	39.6
Royster	30.8
TOTAL	**812.6**

PROGRESS ENERGY FLORIDA

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)
	TOTAL	FIRM	FIRM		TOTAL	SYSTEM FIRM					
	INSTALLED	CAPACITY	CAPACITY		CAPACITY	SUMMER PEAK	RESERVE MARGIN		SCHEDULED	RESERVE MARGIN	
	CAPACITY	IMPORT	EXPORT	QF	AVAILABLE	DEMAND	BEFORE MAINTENANCE		MAINTENANCE	AFTER MAINTENANCE	
YEAR	MW	MW	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	% OF PEAK
2007	8,701	1,661 *	0	803	11,165	9,327	1,838	20%	0	1,838	20%
2008	9,175	1,503 *	0	799	11,477	9,525	1,952	20%	0	1,952	20%
2009	9,881	1,095	0	659	11,635	9,553	2,082	22%	0	2,082	22%
2010	9,891	1,253	0	775	11,919	9,801	2,118	22%	0	2,118	22%
2011	9,926	1,370	0	775	12,071	9,992	2,079	21%	0	2,079	21%
2012	10,077	1,530	0	775	12,382	10,173	2,209	22%	0	2,209	22%
2013	10,614	1,530	0	665	12,809	10,379	2,430	23%	0	2,430	23%
2014	11,151	1,530	0	478	13,159	10,711	2,448	23%	0	2,448	23%
2015	11,151	1,530	0	478	13,159	10,933	2,226	20%	0	2,226	20%
2016	12,276	1,459	0	478	14,213	11,169	3,044	27%	0	3,044	27%

* Progress Energy is pursuing summer seasonal purchases of approximately 200 MW in 2007 and 250 MW in 2008. The deals are not yet consummated as of the time of the Ten-Year Site Plan filing. Since the purchase is expected to be from peaking capacity, no energy impact has been included in the plan at this time.

PROGRESS ENERGY FLORIDA

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	FIRM	FIRM		TOTAL	SYSTEM FIRM					
	INSTALLED	CAPACITY	CAPACITY		CAPACITY	WINTER PEAK	RESERVE MARGIN		SCHEDULED	RESERVE MARGIN	
	CAPACITY	IMPORT	EXPORT	QF	AVAILABLE	DEMAND	BEFORE MAINTENANCE		MAINTENANCE	AFTER MAINTENANCE	
YEAR	MW	MW	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	% OF PEAK
2006/07	9,768	1,133	0	802	11,703	9,705	1,998	21%	0	1,998	21%
2007/08	10,286	1,295	0	788	12,369	9,944	2,425	24%	0	2,425	24%
2008/09	10,308	1,295	0	690	12,293	10,034	2,259	23%	0	2,259	23%
2009/10	11,144	1,137	0	775	13,056	10,467	2,589	25%	0	2,589	25%
2010/11	11,114	1,172	0	775	13,061	10,686	2,375	22%	0	2,375	22%
2011/12	11,254	1,442	0	775	13,471	10,994	2,477	23%	0	2,477	23%
2012/13	11,265	1,612	0	775	13,653	11,280	2,373	21%	0	2,373	21%
2013/14	11,883	1,612	0	491	13,987	11,510	2,477	22%	0	2,477	22%
2014/15	12,501	1,612	0	478	14,592	11,751	2,841	24%	0	2,841	24%
2015/16	12,501	1,541	0	478	14,521	12,064	2,457	20%	0	2,457	20%
2016/17	13,626	1,541	0	478	15,645	12,371	3,274	26%	0	3,274	26%

PROGRESS ENERGY FLORIDA

SCHEDULE 8

PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES

AS OF JANUARY 1, 2006 THROUGH DECEMBER 31, 2016

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
								CONST.	COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY			
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		START	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER		
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	MO. / YR	MO. / YR	MO. / YR	KW	MW	MW	STATUS	NOTES
HINES	1	POLK	CC						12/2007			1	1	A	(3)
HINES	4	POLK	CC	NG	DFO	PL	TK	12/2005	12/2007			461	517	V	(1)
HINES	1	POLK	CC						05/2008			2	2	A	(3)
TIGER BAY	1	POLK	CC						05/2008			10	10	A	(3)
CRYSTAL RIVER	4	CITRUS	ST						11/2008			10	10	A	(3)
CRYSTAL RIVER	5	CITRUS	ST						04/2009			(30)	(30)	D	(2)
CRYSTAL RIVER	5	CITRUS	ST						05/2009			10	10	A	(3)
BARTOW	1-3	PINELLAS	ST							06/2009		(444)	(464)	RP	(4)
BARTOW	1	PINELLAS	CC	NG	DFO	PL	WA	12/2006	06/2009			1159	1279	RP	(4)
CRYSTAL RIVER	3	CITRUS	ST						12/2009			40	40	A	(3)
CRYSTAL RIVER	4	CITRUS	ST						04/2010			(30)	(30)	D	(2)
HINES	1	POLK	CC						06/2011			35	0	A	(3)
CRYSTAL RIVER	3	CITRUS	ST						12/2011			140	140	A	(3)
CRYSTAL RIVER	1	CITRUS	ST						03/2012			11	11	A	(3)
UNCOMMITTED	1	UNKNOWN	CC	NG	DFO	PL	TK	06/2010	06/2013			537	618	P	(1)
UNCOMMITTED	2	UNKNOWN	CC	NG	DFO	PL	TK	06/2011	06/2014			537	618	P	(1)
UNCOMMITTED	3	UNKNOWN	NP	NUC	--	RR	--	01/2010	06/2016			1125	1125	P	(1)

NOTES

(1) Committed new unit.
(2) Planned derations due to FGD scrubber installations.
(3) Planned uprates.
(4) Repowering

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2006

(1)	Plant Name and Unit Number:	**HINES ENERGY COMPLEX UNIT #4**
(2)	Capacity	
	a. Summer:	461
	b. Winter:	517
(3)	Technology Type:	COMBINED CYCLE
(4)	Anticipated Construction Timing	
	a. Field construction start date:	12/2005
	b. Commercial in-service date:	12/2007 (EXPECTED)
(5)	Fuel	
	a. Primary fuel:	NATURAL GAS
	b. Alternate fuel:	DISTILLATE FUEL OIL
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION
(7)	Cooling Method:	COOLING POND
(8)	Total Site Area:	8,200 ACRES
(9)	Construction Status:	REGULATORY APPROVAL RECEIVED UNDER CONSTRUCTION
(10)	Certification Status:	SITE PERMITTED
(11)	Status with Federal Agencies:	SITE PERMITTED
(12)	Projected Unit Performance Data	
	a. Planned Outage Factor (POF):	6.0 %
	b. Forced Outage Factor (FOF):	3.0 %
	c. Equivalent Availability Factor (EAF):	91.2 %
	d. Resulting Capacity Factor (%):	49.0 %
	e. Average Net Operating Heat Rate (ANOHR):	7,866 BTU/kWh
(13)	Projected Unit Financial Data	
	a. Book Life (Years):	25
	b. Total Installed Cost (In-service year $/kW):	552.15
	c. Direct Construction Cost ($/kW):	468.30
	d. AFUDC Amount ($/kW):	83.84
	e. Escalation ($/kW):	0.00
	f. Fixed O&M ($/kW-yr):	1.29
	g. Variable O&M ($/MWh):	2.45
	h. K Factor:	NO CALCULATION

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2007

(1)	Plant Name and Unit Number:		**BARTOW REPOWERING - CC #1**
(2)	Capacity		
	a. Summer:		1,159
	b. Winter:		1,279
(3)	Technology Type:		COMBINED CYCLE
(4)	Anticipated Construction Timing		
	a. Field construction start date:		12/2006
	b. Commercial in-service date:		06/2009 (EXPECTED)
(5)	Fuel		
	a. Primary fuel:		NATURAL GAS
	b. Alternate fuel:		DISTILLATE FUEL OIL
(6)	Air Pollution Control Strategy:		DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION
(7)	Cooling Method:		COOLING WATER
(8)	Total Site Area:		1,348 ACRES
(9)	Construction Status:		UNDER CONSTRUCTION
(10)	Certification Status:		N/A
(11)	Status with Federal Agencies:		IN PROCESS
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):		6.9 %
	b. Forced Outage Factor (FOF):		4.6 %
	c. Equivalent Availability Factor (EAF):		88.8 %
	d. Resulting Capacity Factor (%):		65.3 %
	e. Average Net Operating Heat Rate (ANOHR):		7,236 BTU/kWh
(13)	Projected Unit Financial Data		
	a. Book Life (Years):		25
	b. Total Installed Cost (In-service year $/kW):		545.53 (INCREMENTAL COST)
	c. Direct Construction Cost ($/kW):		435.60
	d. AFUDC Amount ($/kW):		109.93
	e. Escalation ($/kW):		0.00
	f. Fixed O&M ($/kW-yr):		4.65
	g. Variable O&M ($/MWh):		2.57
	h. K Factor:		NO CALCULATION

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2007

(1)	Plant Name and Unit Number:	**UNCOMMITTED #1**
(2)	Capacity	
	a. Summer:	537
	b. Winter:	618
(3)	Technology Type:	COMBINED CYCLE
(4)	Anticipated Construction Timing	
	a. Field construction start date:	6/2010
	b. Commercial in-service date:	6/2013 (EXPECTED)
(5)	Fuel	
	a. Primary fuel:	NATURAL GAS
	b. Alternate fuel:	DISTILLATE FUEL OIL
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION
(7)	Cooling Method:	UNKNOWN
(8)	Total Site Area:	UNKNOWN ACRES
(9)	Construction Status:	PLANNED
(10)	Certification Status:	PLANNED
(11)	Status with Federal Agencies:	PLANNED
(12)	Projected Unit Performance Data	
	a. Planned Outage Factor (POF):	4.1 %
	b. Forced Outage Factor (FOF):	5.5 %
	c. Equivalent Availability Factor (EAF):	90.6 %
	d. Resulting Capacity Factor (%):	62.9 %
	e. Average Net Operating Heat Rate (ANOHR):	7,442 BTU/kWh
(13)	Projected Unit Financial Data	
	a. Book Life (Years):	25
	b. Total Installed Cost (In-service year $/kW):	834.79
	c. Direct Construction Cost ($/kW):	590.31
	d. AFUDC Amount ($/kW):	117.79
	e. Escalation ($/kW):	126.69
	f. Fixed O&M ($/kW-yr):	11.39
	g. Variable O&M ($/MWh):	1.94
	h. K Factor:	NO CALCULATION

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2007

(1)	Plant Name and Unit Number:	**UNCOMMITTED #2**
(2)	Capacity	
	a. Summer:	537
	b. Winter:	618
(3)	Technology Type:	COMBINED CYCLE
(4)	Anticipated Construction Timing	
	a. Field construction start date:	6/2011
	b. Commercial in-service date:	6/2014 (EXPECTED)
(5)	Fuel	
	a. Primary fuel:	NATURAL GAS
	b. Alternate fuel:	DISTILLATE FUEL OIL
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION
(7)	Cooling Method:	UNKNOWN
(8)	Total Site Area:	UNKNOWN ACRES
(9)	Construction Status:	PLANNED
(10)	Certification Status:	PLANNED
(11)	Status with Federal Agencies:	PLANNED
(12)	Projected Unit Performance Data	
	a. Planned Outage Factor (POF):	4.1 %
	b. Forced Outage Factor (FOF):	5.5 %
	c. Equivalent Availability Factor (EAF):	90.6 %
	d. Resulting Capacity Factor (%):	58.6 %
	e. Average Net Operating Heat Rate (ANOHR):	7,457 BTU/kWh
(13)	Projected Unit Financial Data	
	a. Book Life (Years):	25
	b. Total Installed Cost (In-service year $/kW):	857.75
	c. Direct Construction Cost ($/kW):	590.31
	d. AFUDC Amount ($/kW):	121.03
	e. Escalation ($/kW):	146.41
	f. Fixed O&M ($/kW-yr):	11.39
	g. Variable O&M ($/MWh):	1.94
	h. K Factor:	NO CALCULATION

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2007

(1)	Plant Name and Unit Number:	**UNCOMMITTED #3**
(2)	Capacity	
	a. Summer:	1125
	b. Winter:	1125
(3)	Technology Type:	ADVANCED LIGHT WATER NUCLEAR
(4)	Anticipated Construction Timing	
	a. Field construction start date:	1/2010
	b. Commercial in-service date:	6/2016 (EXPECTED)
(5)	Fuel	
	a. Primary fuel:	URANIUM
	b. Alternate fuel:	--
(6)	Air Pollution Control Strategy:	N/A
(7)	Cooling Method:	COOLING TOWER
(8)	Total Site Area:	UNKNOWN ACRES
(9)	Construction Status:	PLANNED
(10)	Certification Status:	PLANNED
(11)	Status with Federal Agencies:	PLANNED
(12)	Projected Unit Performance Data	
	a. Planned Outage Factor (POF):	6.1 %
	b. Forced Outage Factor (FOF):	3.8 %
	c. Equivalent Availability Factor (EAF):	90.3 %
	d. Resulting Capacity Factor (%):	89.6 %
	e. Average Net Operating Heat Rate (ANOHR):	10,400 BTU/kWh
(13)	Projected Unit Financial Data	
	a. Book Life (Years):	40
	b. Total Installed Cost (In-service year $/kW):	3616.21
	c. Direct Construction Cost ($/kW):	2175.99
	d. AFUDC Amount ($/kW):	741.67
	e. Escalation ($/kW):	698.55
	f. Fixed O&M ($/kW-yr):	84.91
	g. Variable O&M ($/MWh):	0.52
	h. K Factor:	NO CALCULATION

SOURCE: EIA Annual Energy Outlook

PROGRESS ENERGY FLORIDA

SCHEDULE 10
STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

HINES UNIT #4

(1) POINT OF ORIGIN AND TERMINATION:	West Lake Wales Substation-Hines Energy Complex
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	Existing Hines Energy Complex Site and new transmission right-of-way
(4) LINE LENGTH:	21 miles
(5) VOLTAGE:	230kV
(6) ANTICIPATED CONSTRUCTION TIMING:	12/2007
(7) ANTICIPATED CAPITAL INVESTMENT:	$46,283,089 *
(8) SUBSTATIONS:	N/A
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

* As recognized by the Florida Public Service Commission in its Order Granting Petition for Determination of Need for Hines Unit 4, the projected capital estimate may vary during construction of the Hines 4 facility.

PROGRESS ENERGY FLORIDA

SCHEDULE 10

STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

BARTOW REPOWERING

(1) POINT OF ORIGIN AND TERMINATION:	Bartow Plant - Northeast Substation
(2) NUMBER OF LINES:	3
(3) RIGHT-OF-WAY:	Existing transmission line right-of-way
(4) LINE LENGTH:	4 miles
(5) VOLTAGE:	230kV
(6) ANTICIPATED CONSTRUCTION TIMING:	06/2009
(7) ANTICIPATED CAPITAL INVESTMENT:	$72,408,125 *
(8) SUBSTATIONS:	N/A
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

* The projected capital estimate may vary during construction of the Bartow Repowering Project

PROGRESS ENERGY FLORIDA

SCHEDULE 10

STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

BARTOW REPOWERING

(1) POINT OF ORIGIN AND TERMINATION:	Northeast Substation - Thirty-Second Street Substation
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	New and existing transmission line right-of-ways
(4) LINE LENGTH:	2.4 miles
(5) VOLTAGE:	115kV
(6) ANTICIPATED CONSTRUCTION TIMING:	09/2008
(7) ANTICIPATED CAPITAL INVESTMENT:	$4,000,000 *
(8) SUBSTATIONS:	Thirty-Second Street Substation - Addition
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

* The projected capital estimate may vary during construction of the Bartow Repowering Project

PROGRESS ENERGY FLORIDA

SCHEDULE 10
STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

BARTOW REPOWERING

(1) POINT OF ORIGIN AND TERMINATION:	Northeast Substation - Fortieth Street Substation
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	New and existing transmission line right-of-ways
(4) LINE LENGTH:	8.3 miles
(5) VOLTAGE:	230kV
(6) ANTICIPATED CONSTRUCTION TIMING:	09/2008
(7) ANTICIPATED CAPITAL INVESTMENT:	$11,000,000 *
(8) SUBSTATIONS:	N/A
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

* The projected capital estimate may vary during construction of the Bartow Repowering Project

PROGRESS ENERGY FLORIDA

SCHEDULE 10
STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

BARTOW REPOWERING

(1) POINT OF ORIGIN AND TERMINATION:	Pasadena Substation - Fifty-First Street Substation
(2) NUMBER OF LINES:	2
(3) RIGHT-OF-WAY:	Existing transmission line right-or-way
(4) LINE LENGTH:	0.4 miles
(5) VOLTAGE:	230kV
(6) ANTICIPATED CONSTRUCTION TIMING:	09/2008
(7) ANTICIPATED CAPITAL INVESTMENT:	$12,000,000 *
(8) SUBSTATIONS:	Fifty-First Street Substation - Addition
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

* The projected capital estimate may vary during construction of the Bartow Repowering Project

INTEGRATED RESOURCE PLANNING OVERVIEW

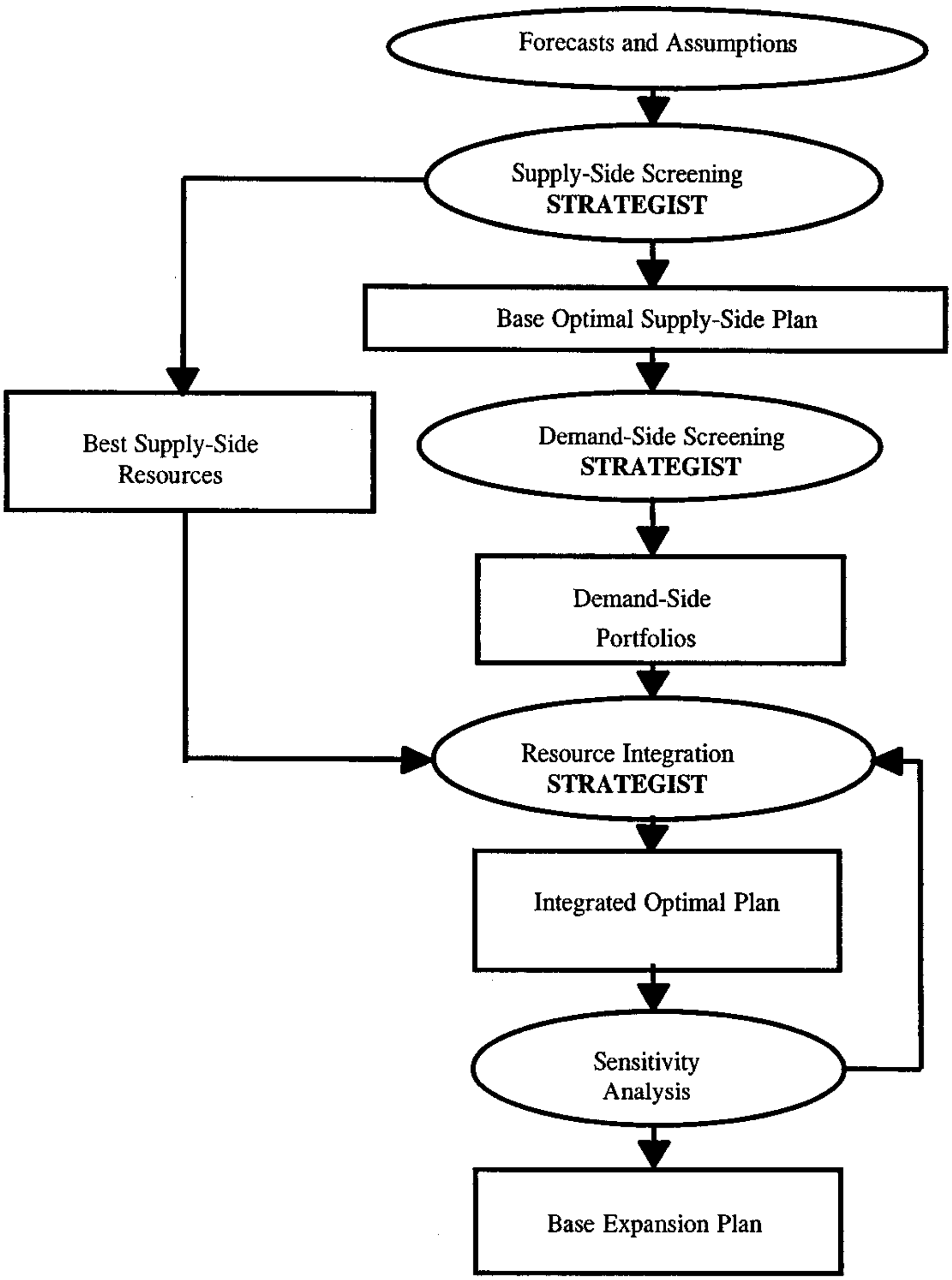
PEF employs an Integrated Resource Planning (IRP) process to determine the most cost-effective mix of supply- and demand-side alternatives that will reliably satisfy our customers' future demand and energy needs. PEF's IRP process incorporates state-of-the-art computer models used to evaluate a wide range of future generation alternatives and cost-effective conservation and dispatchable demand-side management programs on a consistent and integrated basis.

An overview of PEF's IRP Process is shown in Figure 3.1. The process begins with the development of various forecasts, including demand and energy, fuel prices, and economic assumptions. Future supply- and demand-side resource alternatives are identified and extensive cost and operating data are collected to enable these to be modeled in detail. These alternatives are optimized together to determine the most cost-effective plan for PEF to pursue over the next ten years to meet the company's reliability criteria. The resulting ten-year plan, the Integrated Optimal Plan, is then tested under different relevant sensitivity scenarios to identify variances, if any, which would warrant reconsideration of any of the base plan assumptions. If the plan is judged robust under sensitivity analysis and works within the corporate framework, it evolves as the Base Expansion Plan. This process is discussed in more detail in the following section titled "The IRP Process".

The Integrated Resource Plan provides PEF with substantial guidance in assessing and optimizing the Company's overall resource mix on both the supply side and the demand side. When a decision supporting a significant resource commitment is being developed (e.g. plant construction, power purchase, DSM program implementation), the Company will move forward with directional guidance from the IRP and delve much further into the specific levels of examination required. This more detailed assessment will typically address very specific technical requirements and cost estimates, detailed corporate financial considerations, and the most current dynamics of the business and regulatory environments.

FIGURE 3.1

IRP Process Overview



THE IRP PROCESS

Forecasts and Assumptions

The evaluation of possible supply- and demand-side alternatives, and development of the optimal plan, is an integral part of the IRP process. These steps together comprise the integration process that begins with the development of forecasts and collection of input data. Base forecasts that reflect PEF's view of the most likely future scenarios are developed, along with high and low forecasts that reflect alternative future scenarios. Computer models used in the process are brought up-to-date to reflect this data, along with the latest operating parameters and maintenance schedules for PEF's existing generating units. This establishes a consistent starting point for all further analysis.

Reliability Criteria

Utilities require a margin of generating capacity above the firm demands of their customers in order to provide reliable service. Periodic scheduled outages are required to perform maintenance and inspections of generating plant equipment and to refuel nuclear plants. At any given time during the year, some capacity may be out of service due to unanticipated equipment failures resulting in forced outages of generation units. Adequate reserve capacity must be available to accommodate these outages and to compensate for higher than projected peak demand due to forecast uncertainty and abnormal weather. In addition, some capacity must be available for operating reserves to maintain the balance between supply and demand on a moment-to-moment basis.

PEF plans its resources in a manner consistent with utility industry planning practices, and employs both deterministic and probabilistic reliability criteria in the resource planning process. A Reserve Margin criterion is used as a deterministic measure of PEF's ability to meet its forecasted seasonal peak load with firm capacity. PEF plans its resources to satisfy a 20 percent Reserve Margin criterion.

Loss of Load Probability (LOLP) is a probabilistic criterion that measures the probability that a company will be unable to meet its load throughout the year. While Reserve Margin only considers the peak load and amount of installed resources, LOLP also takes into account generating unit sizes, capacity mix, maintenance scheduling, unit availabilities, and capacity assistance available from other utilities. A standard probabilistic reliability threshold commonly used in the electric utility industry, and the criterion employed by PEF, is a maximum of one day in ten years loss of load probability.

PEF has based its resource planning on the use of dual reliability criteria since the early 1990s, a practice that has been accepted by the FPSC. PEF's resource portfolio is designed to satisfy the 20% Reserve Margin requirement and probabilistic analyses are conducted to ensure that the one day in ten years LOLP criterion is also satisfied. By using both the Reserve Margin and LOLP planning criteria, PEF's resource portfolio is designed to have sufficient capacity available to meet customer peak demand, and to provide reliable generation service under expected load conditions.

Supply-Side Screening

Potential supply-side resources are screened to determine those that are the most cost-effective. Data used for the screening analysis is compiled from various industry sources and PEF's experiences. The wide range of resource options is pre-screened to set aside those that do not warrant a detailed cost-effectiveness analysis. Typical screening criteria are costs, fuel source, technology maturity, environmental parameters, and overall resource feasibility.

Economic evaluation of generation alternatives is performed using the STRATEGIST optimization program. The optimization program evaluates revenue requirements for specific resource plans generated from multiple combinations of future resource additions that meet system reliability criteria and other system constraints. All resource plans are then ranked by system revenue requirements.

Demand-Side Screening

Like supply-side resources, data for large numbers of potential demand-side resources is also collected. These resources are pre-screened to eliminate those alternatives that are still in research and development, addressed by other regulations (building code), or not applicable to PEF's customers. STRATEGIST is updated with cost data and load impact parameters for each potential DSM measure to be evaluated.

The Base Optimal Supply-Side Plan is used to establish avoidable units for screening future demand-side resources. Each future demand-side alternative is individually tested in this plan over the ten-year planning horizon to determine the benefit or detriment that the addition of this demand-side resource provides to the overall system. STRATEGIST calculates the benefits and costs for each demand-side measure evaluated and reports the appropriate ratios for the Rate Impact Measure (RIM), the Total Resource Cost Test (TRC), and the Participant Test. Demand-side programs that pass the RIM test are then bundled together to create demand-side portfolios. These portfolios contain the appropriate DSM options and make the optimization solvable with the STRATEGIST model.

Resource Integration and the Integrated Optimal Plan

The cost-effective generation alternatives and the demand-side portfolios developed in the screening process can then be optimized together to formulate integrated optimal plans. The optimization program considers all possible future combinations of supply- and demand-side alternatives that meet the company's reliability criteria in each year of the ten-year study period and reports those that provide both flexibility and low revenue requirements (rates) for PEF's ratepayers.

Developing the Base Expansion Plan

The integrated optimized plans that provide the lowest revenue requirements are then further tested using sensitivity analysis. The economics of the plan may be evaluated under high and low forecast scenarios for load, fuel, and financial assumptions, or any other sensitivities which, in the judgment of the planner, are relevant given existing circumstances to ensure that the plan does not unduly burden the company or the ratepayers if the future unfolds in a manner significantly different from the base forecasts. From the sensitivity assessment, the ten-year plan that is identified as achieving the best balance of flexibility and cost is then reviewed within the corporate framework to determine how the plan potentially impacts or is impacted by many other factors. If the plan is judged robust under this review, it evolves as the Base Expansion Plan.

KEY CORPORATE FORECASTS

Load Forecast

The assumptions and methodology used to develop the base case load and energy forecast is described in detail in Chapter 2 of this TYSP.

Fuel Forecast

Base Fuel Case: The base case fuel price forecast was developed using short-term and long-term spot market price projections from industry-recognized sources. Coal prices are expected to be relatively stable month to month; however, oil and natural gas prices are expected to be more volatile on a day-to-day and month-to-month basis.

In the short term, the base cost for coal is based on the existing contracts and spot market coal prices and transportation arrangements between PEF and its various suppliers. For the longer term, the prices are based on spot market forecasts reflective of expected market conditions. Oil and natural gas prices are estimated based on current and expected contracts and spot purchase arrangements as well as near-term and long-term market forecasts. Oil and natural gas commodity prices are driven primarily by open market forces of supply and demand. Natural gas firm transportation cost is determined primarily by pipeline tariff rates and tends to change less frequently than commodity prices.

Financial Forecast

The key financial assumptions used in PEF's most recent planning studies were 45% debt and 55% equity capital structure, projected debt cost of 5.9%, and an equity return of 11.75%. These assumptions resulted in a weighted average cost of capital of 9.36% and an after-tax discount rate of 8.10%.

TYSP RESOURCE ADDITIONS

In this TYSP, PEF's supply-side resources include the projected combined cycle (CC) expansion of the Hines Energy Complex (HEC) with Unit 4 forecasted to be in-service by December 2007. The TYSP also includes repowering the Bartow Steam Units with F-Class combined cycle technology with a forecasted in-service date of June 2009. Two generic combined cycle units are included in the TYSP with forecasted in-service dates of June 2013 and June 2014 and a generic nuclear unit in June 2016.

The Company continues to study the economics of baseload generation alternatives including gas, coal, and nuclear. Analyses indicate that nuclear resources may provide economical baseload generation in the long-term. Therefore, this TYSP includes the addition of an advanced nuclear unit during the planning horizon with a forecasted in-service date of June 2016.

PEF will continue, however, to evaluate the nuclear schedule and reassess alternatives for this time period considering, among other things, projected load growth, fuel prices, and environmental compliance considerations. The Company will continue to examine the merits of new generation alternatives and adjust its resource plans accordingly to ensure the optimal selection of resource additions. The Company has not designated specific site(s) for future generic combined cycle or nuclear additions. However, the Company is continuing to evaluate the suitability of a site in Levy County for the potential location of a new nuclear power plant complex.

RENEWABLE ENERGY

PEF continues to make purchases from the following facilities listed by fuel type:

Municipal Solid Waste Facilities:

Lake County Resource Recovery (12.8 MW)

Metro-Dade County Resource Recovery (43 MW)

Pasco County Resource Recovery (23 MW)

Pinellas County Resource Recovery (54.8 MW)

Waste Heat from Exothermic Processes:

Mosaic Phosphate/Cargill (15 MW)

PCS Phosphate (As-Available)

Waste Wood, Tires, and Landfill Gas:

Ridge Generating Station (39.6 MW)

Photovoltaics

Various customer and PEF owned installations (400 kW connected to PEF)

In addition, PEF has entered into contracts with G2 Energy (11 MW) and Florida Biomass Group (116.6 MW). The G2 Energy facility will be powered with landfill gas and the Florida Biomass Group facility will utilize an energy crop.

PEF continues to seek out renewable suppliers that can provide reliable capacity and energy at economic rates. PEF will submit renewable standard offer contracts in compliance with the newly revised FPSC rules.

PLAN SENSITIVITIES

Load Forecast

In general, higher-than-projected load growth would shift the need for new capacity to an earlier year and lower-than-projected load growth would delay the need for new resources. PEF's TYSP includes the Hines 4 addition and Bartow repowering projects in the near term, with generic combined cycles and a nuclear addition in the longer term. The Company's resource plan provides the flexibility to shift certain resources to earlier or later in-service dates should a significant change in projected customer demand begin to materialize. PEF therefore did not conduct detailed sensitivity analyses of the plan to the base case load forecast.

Fuel Forecast

PEF's current TYSP includes new natural gas fueled resources through 2014. The plan also includes uprates to the Crystal River nuclear unit #3 in 2009 and 2011, and a new nuclear unit in 2016, the earliest projected date that a new nuclear plant can be placed in service. PEF focused its fuel forecast sensitivity on price projections for natural gas. Higher gas prices would improve the economics for non gas-fueled resources and lower gas prices would benefit gas-fueled resources. Uncertainty over future environmental regulation, particularly as it relates to mercury and carbon, favors pursuit of the nuclear option. This uncertainty also increases interest in coal gasification, which PEF is investigating as an alternative to some of the natural gas capacity in the planning horizon.

Similar to the discussion above, a higher differential between gas/oil and nuclear prices would improve the economics for coal and nuclear generation; a smaller differential in gas/oil versus nuclear prices would benefit the economics for a combined cycle plant.

Fuel price forecasts can have a significant impact on the economics of generation alternatives. Consideration of fuel forecast sensitivity for this TYSP did not suggest any significant reconsideration of the base plan. PEF will continue to monitor fuel price relationships to identify long-term structural changes and assess the potential impacts on the economics of resource selection.

Financial Forecast

PEF's current TYSP includes combined cycle additions through 2014 with a nuclear addition in 2016. Lower cost of capital and escalation rates would favor options with longer construction lead times and higher capital costs such as the nuclear addition. However, PEF does not expect these assumptions to go much lower than the current base case forecast and nuclear generation is not projected to be feasible before 2016. Conversely, higher financial assumptions would disfavor the nuclear addition. PEF will continue to assess the economics of future generation alternatives including consideration of the uncertainties in planning assumptions.

TRANSMISSION PLANNING

PEF's transmission planning assessment practices are developed to test the ability of the planned system to meet the reliability criteria as outlined in the FERC Form 715 filing. This involves the use of load flow and transient stability programs to model various contingency situations that may occur, and determining if the system response meets the reliability criteria. In general, this involves running simulations for the loss of any single line, generator, or transformer. PEF normally runs this analysis for system peak and off-peak load levels for possible contingencies, and for both summer and winter. Additional studies are performed to determine the system response to credible, but less probable criteria, to assure the system meets PEF, Florida Reliability Coordinating Council, Inc. (FRCC) and NERC criteria. These studies include the loss of multiple generators or lines, combinations of each, and some load loss is permissible under these more severe disturbances. These credible, but less probable scenarios are also evaluated at various load levels, since some of the more severe situations occur at average or minimum load conditions. In particular, critical fault clearing times are typically the shortest (most severe) at minimum load conditions, with just a few large base load units supplying the system needs.

As noted in the PEF reliability criteria, some remedial actions are allowed to reduce system loadings, in particular, sectionalizing is allowed to reduce loading on lower voltage lines for bulk system contingencies, but the risk to load on the sectionalized system must be reasonable (it would not be considered prudent to operate for long periods with a sectionalized system). In addition, the number of remedial action steps and the overall complexity of the scheme are evaluated to determine overall acceptability.

Presently, PEF uses the following reference documents to calculate Available Transfer Capability (ATC) for required transmission path postings on the Florida Open Access Same-Time Information System (OASIS):

- FRCC: FRCC ATC Calculation and Coordination Procedures, November 4, 2003, which is posted on the FRCC website: (http://frcc.com/downloads/FRCC%20ATC%20methodology-%20final-11-03.pdf)

- NERC: Transmission Transfer Capability, May 1, 1995

- NERC: Available Transfer Capability – Definitions and Determination, July 30, 1996

PEF uses the FRCC Capacity Benefit Margin (CBM) methodology to assess its CBM needs. This methodology is:

> "FRCC Transmission Providers make an assessment of the CBM needed on their respective systems by using either deterministic or probabilistic generation reliability analysis. The appropriate amount of transmission interface capability is then reserved for CBM on a per interface basis, taking into account the amount of generation available on other interconnected systems, the respective load peaking diversities of those systems, and Transmission Reliability Margin (TRM). Operating reserves may

be included if appropriate in TRM and subsequently subtracted from the CBM if needed."

PEF currently has zero CBM reserved on each of its interfaces (posted paths). PEF's CBM on each path is currently established through the transmission provider functions within PEF using deterministic and probabilistic generation reliability analysis.

Currently, PEF proposes no bulk transmission additions that must be certified under the Florida Transmission Line Siting Act (TLSA). PEF's proposed bulk transmission line additions are shown in the following table:

TABLE 3.3

PROGRESS ENERGY FLORIDA

LIST OF PROPOSED BULK TRANSMISSION LINE ADDITIONS

2007 - 2016

MVA RATING WINTER	LINE OWNERSHIP	TERMINALS		LINE LENGTH (CKT.-MILES)	COMMERCIAL IN-SERVICE DATE (MO./YEAR)	NOMINAL VOLTAGE (kV)
1141	PEF	HINES ENERGY COMPLEX	WEST LAKE WALES #1	21	12/ 2007	230
1141	PEF	LAKE BRYAN	WINDERMERE #1	10 *	3 / 2008	230
1141	PEF	LAKE BRYAN	WINDERMERE #2	10	3 / 2008	230
1141	PEF	AVALON	GIFFORD	7	7 / 2008	230
612	PEF	BARTOW	NORTHEAST Circuit 1	4	6/2009	230
612	PEF	BARTOW	NORTHEAST Circuit 2	4	6/2009	230
612	PEF	BARTOW	NORTHEAST Circuit 3	4	6/2009	230
525	PEF	NORTHEAST	32ND STREET	2.4	9/2008	115
810	PEF	NORTHEAST	40TH STREET	8.3*	9/2008	230
810	PEF	PASADENA	51ST STREET	0.4	9/2008	230
810	PEF	51ST STREET	40TH STREET	0.2	9/2008	230
837	PEF	AVON PARK	FORT MEADE	26†	6/2009	230
1141	PEF	HINES ENERGY COMPLEX	WEST LAKE WALES #2	21	5 / 2010	230
1141	PEF	INTERCESSION CITY	WEST LAKE WALES #2	30	6 / 2010	230
1141	PEF/TECO	LAKE AGNES (TECO)	GIFFORD	32	6/2011	230
1141	PEF	INTERCESSION CITY	WEST LAKE WALES #1	30 *	6/2011	230

* Rebuild existing circuit
† Convert existing 115 kV line to 230 kV

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CHAPTER 4

ENVIRONMENTAL AND LANDUSE INFORMATION

Progress Energy

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CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

PREFERRED SITES

PEF's base expansion plan has new combined cycle generation at the Hines Energy Complex (HEC) site in Polk County and the repowering of the existing Bartow Plant in Pinellas County with combined cycle technology. While these sites are suitable for new generation, PEF continues to evaluate other available options for future supply alternatives.

The next combined cycle unit at the HEC (Hines Unit 4) site is scheduled for commercial operation in December 2007. PEF is also committed to repowering the existing Bartow Steam Plant that is scheduled for commercial operation in June 2009. PEF continues to pursue siting opportunities for undesignated combined cycle units and a nuclear unit with commercial operation dates of 2013 and beyond. However, PEF's existing sites, as identified in Table 3.1 of Chapter 3, include the capability to accept additional generation. Additionally, all appropriate permitting requirements will be addressed for PEF's preferred sites as discussed in the following site descriptions. The base expansion plan does not currently designate new sites for generation additions. Therefore, detailed environmental and land use data are not included.

The ability to site new baseload generation (coal and/or nuclear) in Florida is extremely limited, however PEF has identified suitable sites for the nuclear option at this time. However, PEF does not own a site at this time, and therefore details will be provided after the acquisition is completed. Siting studies continue to identify possible sites for new coal/IGCC generation.

HINES ENERGY COMPLEX SITE

In 1990, PEF completed a statewide search for a new 3,000 MW coal capable power plant site. As a result of this work, a large tract of mined-out phosphate land in south central Polk County was selected as the primary alternative. This 8,200-acre site is located south of the City of Bartow, near the cities of Fort Meade and Homeland, south of S.R. 640 and west of U.S. 17/98 (reference Figure 4.1). It is an area that has been extensively mined and remains predominantly unreclaimed.

The Governor and cabinet approved site certification for ultimate site development and construction of the first 470 MW increment on January 25, 1994, in accordance with the rules of the Power Plant Siting Act. Due to the thorough screening during the selection process, and the disturbed nature of the site, there were no major environmental limitations. As would be the situation at any location in the state, air emissions and water consumption were issues during the licensing process.

The site's initial preparation involved moving over 10 million cubic yards of soil and draining 4 billion gallons of water. Construction of the energy complex recycled the land for a beneficial use and promoted habitat restoration.

The Hines Energy Complex is visited by several species of wildlife, including alligators, bobcats, turtles, and over 50 species of birds. The Hines site also contains a wildlife corridor, which creates a continuous connection between the Peace River and the Alafia River.

PEF arranged for the City of Bartow to provide treated effluent for cooling pond make-up. The complex's cooling pond initially covered 722 acres with an eventual expansion to 2,500 acres.

The Hines Energy Complex is designed and permitted to be a zero discharge site. This means that there will be no discharges to surface waters either from the power plant facilities or from storm water runoff. Based on this design, storm water runoff from the site can be used as cooling pond make-up, minimizing groundwater withdrawals.

The Florida Department of Environmental Protection air rules currently list all of Polk County as attainment for ambient air quality standards. The environmental impact on the site will be minimized by PEF's close coordination with regulatory agencies to ensure compliance with all applicable environmental regulations.

As future generation units are added, the remaining network of on-site clay settling ponds will be converted to cooling ponds and combustion waste storage areas, as needed, to support power plant operations. Given the disturbed nature of the property, considerable development has been required in order to make it usable for electric utility application. An industrial rail network and an adequate road system service the site.

The first combined cycle unit at this site, with a capacity of 482 MW summer, began commercial operation in April 1999. The transmission improvements associated with this first unit were the rebuilding of the 230/115 kV double circuit Barcola to Ft. Meade line by increasing the conductor sizes and converting the line to double circuit 230 kV operation.

The second combined cycle unit at this site entered commercial operation in December 2003 with a seasonal capacity rating of 516 MW summer. The transmission improvement associated with the second combined cycle unit at this site involved the addition of a 230 kV circuit from the Hines Energy Complex to Barcola.

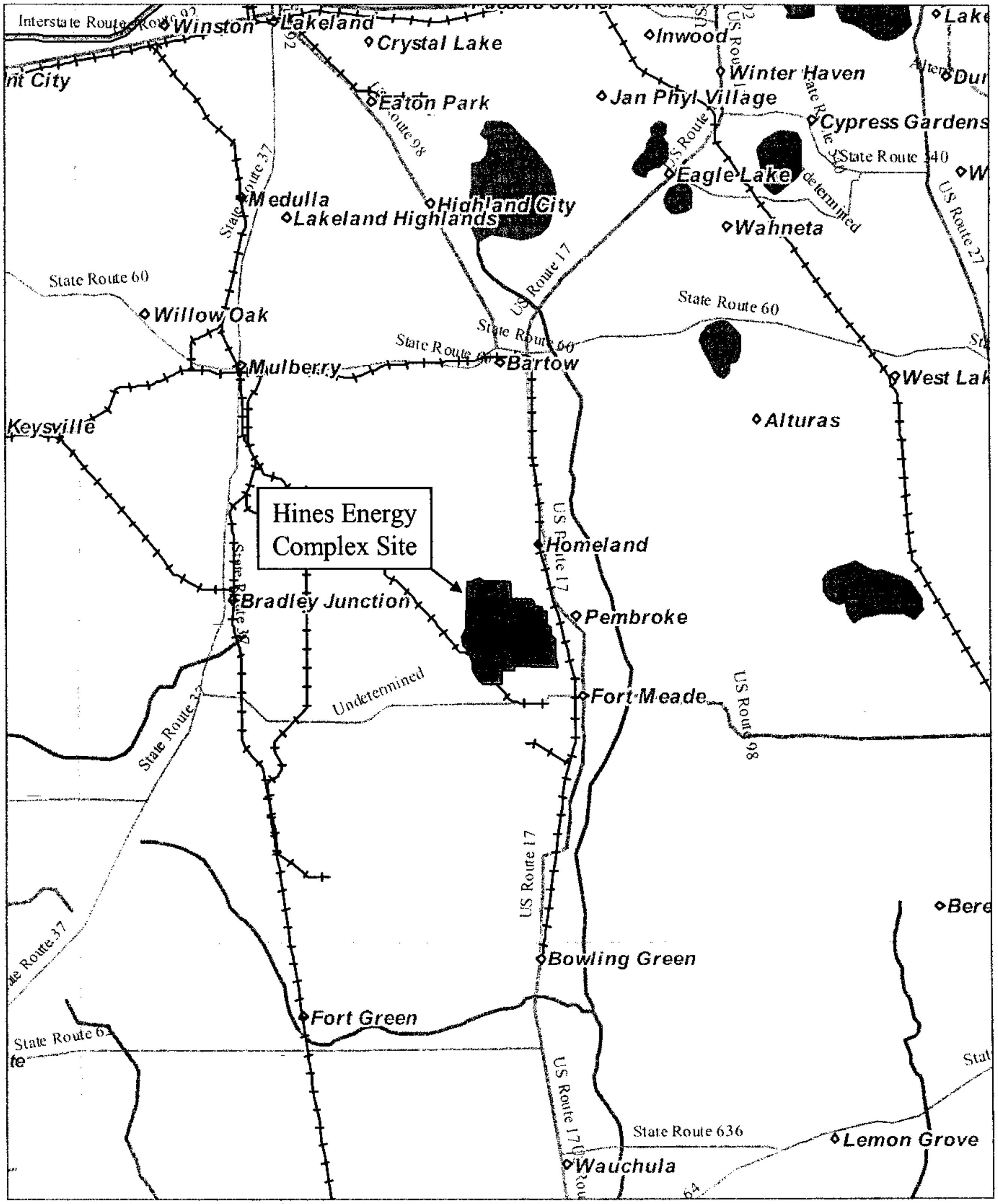
The third combined cycle unit at this site entered commercial operation in November 2005 with a seasonal capacity rating of 501 MW summer, and required no transmission upgrades.

The fourth HEC combined cycle unit is currently under construction. This unit has a commercial operation date of December 2007 with a seasonal capacity rating of 461 MW summer. The transmission improvements associated with the fourth combined cycle unit at this site involved the addition of a 230 kV circuit from the Hines Energy Complex to West Lake-Wales and associated substation expansion and breaker replacements.

The HEC is also a potential site for the combined cycle units projected for 2013 and/or 2014.

FIGURE 4.1

Hines Energy Complex Site (Polk County)



BARTOW SITE

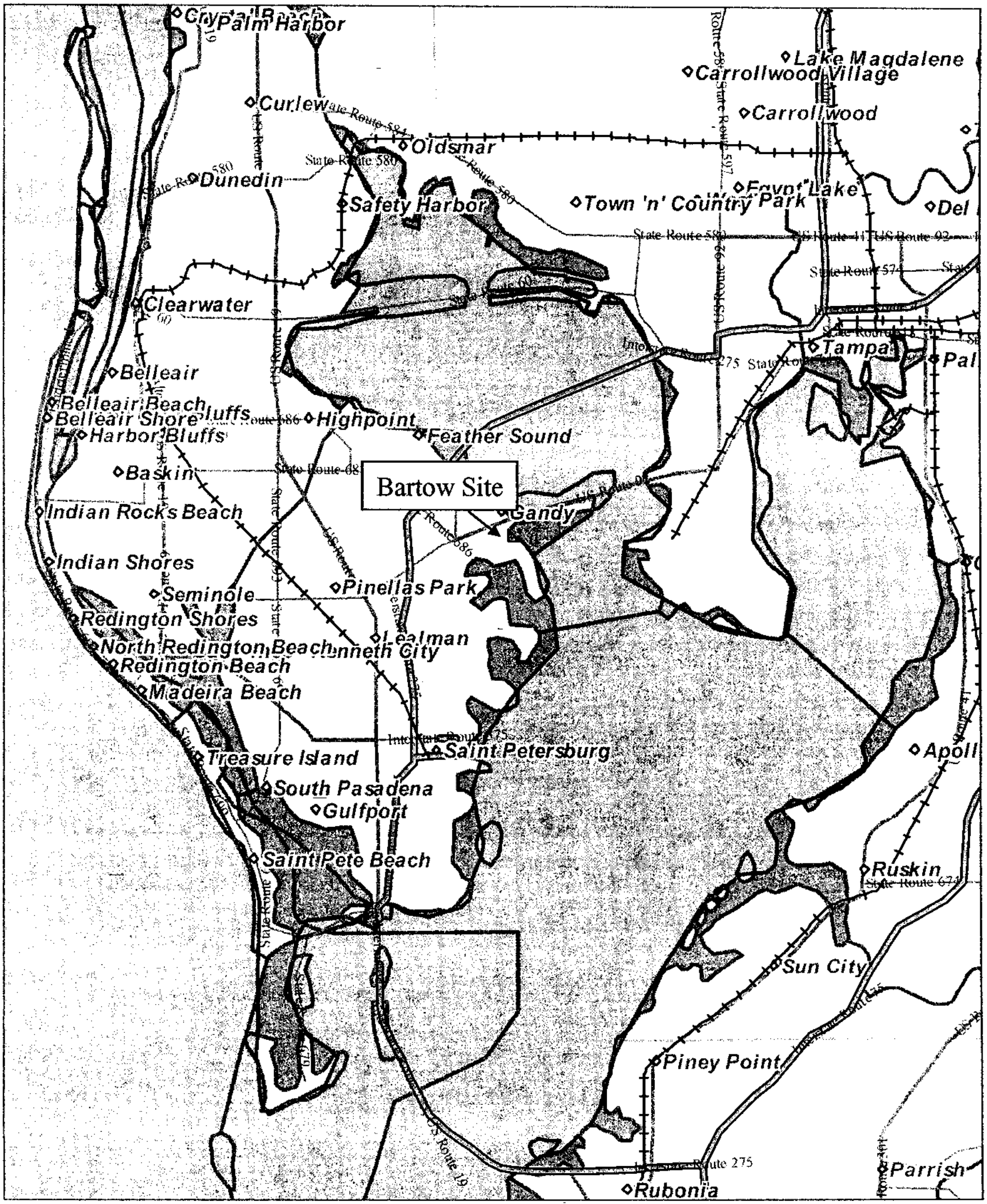
PEF has chosen to repower its existing Bartow Plant with combined cycle technology, which is scheduled for commercial operation in June 2009.

The Bartow site (Figure 4.2) consists of 1,348 acres in Pinellas County, on the west shore of Tampa Bay. The site is on Weedon Island, north of downtown St. Petersburg and adjacent to a barge fuel oil off-loading facility, a natural gas supply from the Florida Gas Transmission (FGT) pipeline, and a proposed Gulfstream natural gas pipeline.

The Florida Department of Environmental Protection air rules currently list all of Pinellas County as attainment for ambient air quality standards. The environmental impact on the site will be minimized by PEF's close coordination with regulatory agencies to ensure compliance with all applicable environmental regulations.

Transmission modifications will be required to accommodate the repowering of Bartow steam units. The Bartow site is also a potential site for the combined cycle units projected for 2013 and/or 2014.

FIGURE 4.2
Bartow Site (Pinellas County)



Appendix H.

Progress Energy Florida's Energy and Customer Forecasting Models

RESIDENTIAL CLASS SALES

RUPC = F (CON, ABDAYS, LRP2, RHDD, CDD, LRFPI2, RP6, SFeb, … SDec, SWPark, SHurr)

Where:	RUPC	=	Residential KWh use per customer adjusted for historical DSM program impacts
	CON	=	Intercept term
	ABDAYS	=	Average number of billing days in sales month
	HDD	=	Residential heating degree days – system-weighted
	CDD	=	Residential cooling degree days - system-weighted
	WTRCDD	=	Winter cooling degree days – values in Dec-Apr only
	LRFPI2	=	Log of Florida Total Personal Income – deflated by the PCE-IPD - 2 month average in millions of 1996 dollars
	RRP6	=	Real electric price to residential class – 6 mo average (cents/kWh)
	SFeb-SDec	=	Eleven monthly Intercept shift to account for unique monthly variation
	SWPark	=	Intercept shift to account for loss of Winter Park franchise
	SHURR	=	Intercept shift to account for Hurricane impacts on usage in summer 2004
	AR(1)	=	1st order autoregressive error term

RESIDENTIAL CLASS CUSTOMERS

RCUSTG = F (CON, POPG)

Where:	RCUSTG	=	Average annual change in residential billed customers
	CON	=	Intercept term
	POPG	=	Service territory population growth (Univ. of Florida Forecast)

MERCIAL CLASS SALES

CMWH = F (CON, ABDAYS, CCDD, CHDD, RCP6, LECOM2, SHURR, SWPark, SFeb,...SDEC, S911)

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nption.
hey are:

CUPC	=	Commercial MWh adjusted for historical DSM program impacts
CON	=	Intercept term
ABDAYS	=	Average number of billing days in sales month
CCDD	=	Commercial cooling degree days
CHDD	=	Commercial heating degree days
RCP6	=	Real electric price to commercial class – 6 mo average (cents/kWh)
LECOM2	=	Log Florida commercial sector employment - 2 month average = thousands
SHURR	=	Intercept shift to account for Hurricane impacts on usage in = summer 2004
SWPark	=	Intercept shift to account for loss of Winter Park franchise
SFeb-SDec	=	Eleven monthly Intercept shift to account for unique monthly variation
S911	=	Intercept shift for Sept 11 impact on class sales

ion

MERCIAL CLASS CUSTOMERS

CCUST = F (CON, RCCUST)

CCUST	=	Average annual commercial billed customers
CON	=	Intercept term
RCUST	=	Average annual residential billed customers

USTRIAL CLASS SALES

ONPHOSPHATE SUBSECTOR

IWO = F(CON, ABDAYS, ICDDS, RIP6, FLIPM, SFeb...SDec, SHURR)

erage

IWO	=	Industrial MWh sales excluding industrial phosphate sector energy sales
CON	=	Intercept term
ABDAYS	=	Average number of billing days in sales month
ICDD	=	Industrial cooling degree days
RIP6	=	Real industrial electric price – 6 mo average (cents/kWh)
FLIPM	=	Florida Industrial Production Index - Manufacturing
SFeb-SDec	=	Eleven monthly Intercept shift to account for unique monthly variation
SHURR	=	Intercept shift to account for Hurricane impacts on usage in summer 2004

ion
r 2004

Levy Nuclear Need Filing

Strategist Optimization Scenarios - 2/21/08 Update Results

	Levy Need Analysis Nuclear Plan Full Ownership Case	Levy Need Analysis Nuclear Plan 80% Joint Ownership Case	Levy Need Analysis All Gas Reference Case
2007 to 2012	**PEF Baseline Assumptions**	**PEF Baseline Assumptions**	**PEF Baseline Assumptions**
2013	CC 4x1 1,159 MW (June '13) 141 MW Suwannee Steam Retirement (June	CC 4x1 1,159 MW (June '13) 141 MW Suwannee Steam Retirement (June	CC 4x1 1,159 MW (June '13) 141 MW Suwannee Steam Retirement (June
2014			
2015			
2016	**100% Levy Unit 1 - 1,085 MW (June '16)** 196 MW Peaker Retirements (June '16)	**80% Levy Unit 1 - 1,085 MW (June '16)** 196 MW Peaker Retirements (June '16)	Generic 2x1 CC Generic Simple Cycle CT 196 MW Peaker Retirements (June '16)
2017	**100% Levy Unit 2 - 1,085 MW (June '17)**	**80% Levy Unit 2 - 868 MW (June '17)**	Generic 2x1 CC
2018			
2019			
2020			Generic 2x1 CC
2021			
2022		Generic Simple Cycle CT	
2023		Generic Simple Cycle CT (2)	Generic 2x1 CC
2024	Generic Simple Cycle CT (2)	Generic Simple Cycle CT	
2025	Generic Simple Cycle CT	Generic 2x1 CC	Generic 2x1 CC
2026	Generic Simple Cycle CT (2)		
2027	Generic Simple Cycle CT	Generic 2x1 CC	Generic 2x1 CC
2028	Generic 2x1 CC		
2029		Generic Simple Cycle CT	Generic Simple Cycle CT
2030	Generic 2x1 CC	Generic 2x1 CC	Generic Simple Cycle CT
2031			Generic 2x1 CC
2032	Generic Simple Cycle CT (2)	Generic 2x1 CC	Generic Simple Cycle CT
2033	Generic 2x1 CC	Generic Simple Cycle CT	Generic 2x1 CC
2034	Generic 2x1 CC	Generic 2x1 CC	
2035		Generic Simple Cycle CT	Generic 2x1 CC
2036	Generic 2x1 CC	Generic 2x1 CC	Generic 2x1 CC
2037	Generic 2x1 CC	Generic 2x1 CC	Generic 2x1 CC
2038			
2039			
2040			
2041			
2042			
2043	Generic 2x1 CC Generic Simple Cycle CT (2)	Generic 2x1 CC Generic Simple Cycle CT (2)	Generic 2x1 CC Generic Simple Cycle CT (2)
2044	Generic Simple Cycle CT	Generic Simple Cycle CT	Generic Simple Cycle CT
2045			
2046			Generic Simple Cycle CT (4)
2047			Generic 2x1 CC
2048			
2049			
2050			Generic 2x1 CC
2051			
2052		Generic Simple Cycle CT	
2053		Generic Simple Cycle CT (2)	Generic 2x1 CC
2054	Generic Simple Cycle CT (2)	Generic Simple Cycle CT	
2055	Generic Simple Cycle CT	Generic 2x1 CC	Generic 2x1 CC
2056	**Levy Unit 1 - 20 year Life Extension** Generic Simple Cycle CT (2)	**Levy Unit 1 - 20 year Life Extension**	
2057	**Levy Unit 2 - 20 year Life Extension** Generic Simple Cycle CT	**Levy Unit 2 - 20 year Life Extension** Generic 2x1 CC	Generic 2x1 CC
2058	Generic 2x1 CC		
2059		Generic Simple Cycle CT	Generic Simple Cycle CT
2060	Generic 2x1 CC	Generic Simple Cycle CT (3)	Generic Simple Cycle CT
2061			Generic 2x1 CC
2062	Generic Simple Cycle CT (2)	Generic 2x1 CC	Generic Simple Cycle CT
2063	Generic 2x1 CC	Generic Simple Cycle CT	Generic 2x1 CC
2064	Generic 2x1 CC	Generic 2x1 CC	
2065		Generic Simple Cycle CT	Generic Simple Cycle CT (3)
2066	Generic 2x1 CC	Generic Simple Cycle CT (3)	Generic Simple Cycle CT (3)

Levy Nuclear Need Filing

Strategist Input Assumptions - Emission Cost Estimates

	1 SO2 $/ton	2 NOX $/ton	5 Hg $/oz	EBS CO2 $/ton	EPA CO2 $/ton	MIT CO2 $/ton	Lieberman Warner CO2 $/ton
2007	520	-	-	-	-	-	-
2008	514	-	-	-	-	-	-
2009	511	4,000	-	-	-	-	-
2010	530	3,500	1,254	-	-	-	-
2011	814	3,000	1,358	-	-	35	-
2012	787	1,939	1,464	12	-	38	-
2013	743	1,856	1,572	13	-	41	-
2014	782	1,865	1,684	14	-	43	-
2015	902	1,827	1,798	15	22	46	60
2016	756	1,711	1,940	16	24	50	64
2017	616	1,591	2,088	17	26	53	68
2018	356	1,536	2,239	18	28	56	72
2019	146	1,481	2,395	20	30	60	76
2020	137	1,495	2,556	21	32	63	80
2021	135	1,498	2,614	23	34	68	86
2022	112	1,503	2,673	24	37	72	93
2023	105	1,506	2,733	26	39	77	99
2024	103	1,511	2,794	28	41	81	106
2025	99	1,515	2,857	30	44	86	112
2026	95	1,517	2,921	32	48	92	121
2027	95	1,517	2,987	34	52	98	131
2028	95	1,517	3,054	37	56	104	140
2029	95	1,517	3,123	39	59	111	149
2030	95	1,517	3,193	42	63	117	158
2031	95	1,517	3,265	45	69	125	173
2032	95	1,517	3,339	49	74	133	188
2033	95	1,517	3,414	52	79	141	203
2034	95	1,517	3,491	56	85	150	218
2035	95	1,517	3,569	60	90	159	233
2036	95	1,517	3,649	64	98	170	251
2037	95	1,517	3,732	69	106	181	269
2038	95	1,517	3,816	74	113	192	287
2039	95	1,517	3,901	79	121	203	305
2040	95	1,517	3,989	85	129	216	323
2041	95	1,517	4,079	91	139	230	349
2042	95	1,517	4,171	98	150	245	375
2043	95	1,517	4,265	105	161	261	402
2044	95	1,517	4,361	113	172	277	428
2045	95	1,517	4,459	121	183	294	454
2046	95	1,517	4,559	130	199	313	494
2047	95	1,517	4,662	139	214	333	533
2048	95	1,517	4,768	149	229	354	572
2049	95	1,517	4,877	160	244	375	611
2050	95	1,517	4,987	172	259	398	651
2051	95	1,517	5,100	184	275	420	684
2052	95	1,517	5,216	197	290	443	717
2053	95	1,517	5,335	212	305	467	751
2054	95	1,517	5,456	227	320	492	786
2055	95	1,517	5,580	243	335	517	822
2056	95	1,517	5,706	261	350	544	859
2057	95	1,517	5,836	280	366	572	895
2058	95	1,517	5,968	300	381	601	931
2059	95	1,517	6,104	322	396	631	967
2060	95	1,517	6,242	345	411	662	1,003
2061	95	1,517	6,384	370	426	694	1,038
2062	95	1,517	6,529	397	442	726	1,074
2063	95	1,517	6,677	426	457	761	1,109
2064	95	1,517	6,829	457	472	796	1,145
2065	95	1,517	6,984	490	487	832	1,181
2066	95	1,517	7,142	526	502	870	1,217

Levy Nuclear Need Filing
New Plant Modeling Information

Capital Cost Estimate for Strategist Modeling

Generic 2x1 Combined Cycle Plants	**1st Unit**	**2nd Unit**
Reference COD: 2011		
Unit Overnight Total Estimate ($2007)	560,251	458,470
Estimated Project Escalation	56,896	46,560
Escalated Construction Cost (Before AFUDC)	617,147	505,030
Adjusted Model Plant Cost Input ($2007)	575,659	471,078
Estimated Transmission Cost ($2007)	100,000	200,000
Winter Capacity Rating (MW)	620	620
Summer Capacity Rating (MW)	570	570
Estimated Overnight Cost - Winter Basis ($/kW)	904	739
Estimated Overnight Cost - Summer Basis ($/kW)	983	804
Strategist Base Year CapEx Input ($/kW Winter)	1,090	1,082

Operating Cost Estimate for Strategist Modeling

Fixed O&M ($000/yr)	3,993	527
Fixed O&M ($/kW-yr) Winter Basis	6.44	0.85
Basis - $2007, Escalating Annually at 2.25%		
Variable O&M ($/MWh)	3.81	3.81
Basis - $2007, Escalating Annually at 2.25%		
Gas Pipeline Reservation Charges ($000/yr)	31,676	31,676
Basis - $2007, Remains Constant		

Performance Estimate for Strategist Modeling

Mature Forced Outage Rate	6.36%	6.36%
Planned Outage Rate	12.77%	12.77%
Minimum Capacity (MW)	179	179
Average Heat Rate at Maximum (Btu/kWh)	6,918	6,918
Average Heat Rate at Minimum (Btu/kWh)	7,660	7,660

Levy Nuclear Need Filing
New Plant Modeling Information

Capital Cost Estimate for Strategist Modeling

Generic 4x1 Combined Cycle Plants	1st Unit
Reference COD: 2011	
Unit Overnight Total Estimate ($2007)	809,106
Estimated Project Escalation	82,205
Escalated Construction Cost (Before AFUDC)	891,311
Adjusted Model Plant Cost Input ($2007)	783,664
Estimated Transmission Cost ($2007)	200,000
Winter Capacity Rating (MW)	1,279
Summer Capacity Rating (MW)	1,159
Estimated Overnight Cost - Winter Basis ($/kW)	633
Estimated Overnight Cost - Summer Basis ($/kW)	698
Strategist Base Year CapEx Input ($/kW Winter)	769

Operating Cost Estimate for Strategist Modeling

Fixed O&M ($000/yr)	4,796
Fixed O&M ($/kW-yr) Winter Basis	3.75
Basis - $2007, Escalating Annually at 2.25%	
Variable O&M ($/MWh)	2.68
Basis - $2007, Escalating Annually at 2.25%	
Gas Pipeline Reservation Charges ($000/yr)	73,085
Basis - $2007, Remains Constant	

Performance Estimate for Strategist Modeling

Mature Forced Outage Rate	4.60%
Planned Outage Rate	7.00%
Minimum Capacity (MW)	145
Average Heat Rate at Maximum (Btu/kWh)	7,200
Average Heat Rate at Minimum (Btu/kWh)	8,300

Levy Nuclear Need Filing
New Plant Modeling Information

Capital Cost Estimate for Strategist Modeling

Generic Simple Cycle Peaking Plants	1st Unit	2nd Unit
Reference COD: 2008		
Unit Overnight Total Estimate ($2007)	93,460	84,508
Estimated Project Escalation	-	-
Escalated Construction Cost (Before AFUDC)	93,460	84,508
Adjusted Model Plant Cost Input ($2007)	93,460	84,508
Estimated Transmission Cost ($2007)	40,000	25,000
Winter Capacity Rating (MW)	201	201
Summer Capacity Rating (MW)	175	175
Estimated Overnight Cost - Winter Basis ($/kW)	465	420
Estimated Overnight Cost - Summer Basis ($/kW)	534	483
Strategist Base Year CapEx Input ($/kW Winter)	664	545

Operating Cost Estimate for Strategist Modeling

	1st Unit	2nd Unit
Fixed O&M ($000/yr)	1,463	251
Fixed O&M ($/kW-yr) Winter Basis	7.28	1.25
Basis - $2007, Escalating Annually at 2.25%		
Variable O&M ($/MWh)	10.24	10.24
Basis - $2007, Escalating Annually at 2.25%		
Gas Pipeline Reservation Charges ($000/yr)	10,700	10,700
Basis - $2007, Remains Constant		

Performance Estimate for Strategist Modeling

	1st Unit	2nd Unit
Mature Forced Outage Rate	2.95%	2.95%
Planned Outage Rate	3.97%	3.97%
Minimum Capacity (MW)	115	115
Average Heat Rate at Maximum (Btu/kWh)	10,350	10,350
Average Heat Rate at Minimum (Btu/kWh)	12,160	12,160

Levy Nuclear Need Filing

Strategist Fuel Forecasts - Mid Reference Fuel Table (1 of 2)

	FUEL 1 COAL 1.8	FUEL 2 COAL 1.2	FUEL 3 COAL 5.0	FUEL 5 COAL4.63	FUEL 4 NUCLEAR	FUEL 35 LNP U1	FUEL 36 LNP U2	FUEL 6 OIL 1.5	FUEL 7 OIL 1.1	FUEL 8 OIL 1.7
2007	2.69	2.84	2.19	2.91	0.34			9.60	9.68	0.00
2008	2.80	3.00	2.31	3.07	0.34			9.86	9.99	0.00
2009	2.89	3.11	2.36	3.15	0.34			9.86	9.99	0.00
2010		3.12	2.43	3.12	0.59				10.00	7.58
2011		3.39	2.52	2.61	0.59				9.32	7.56
2012		3.51	2.60	2.69	0.81				9.52	7.53
2013		3.61	2.67	2.77	0.81				9.67	7.47
2014		3.72	2.75	2.86	0.86				9.79	7.44
2015		3.83	2.81	2.92	0.86				9.91	7.67
2016		3.95	2.89	3.00	0.84	0.86			10.11	7.97
2017		4.06	2.97	3.09	0.84	0.86	0.87		10.30	8.33
2018		4.17	3.05	3.18	0.84	0.82	0.87		10.50	8.69
2019		4.29	3.12	3.27	0.84	0.79	0.83		10.69	9.05
2020		4.39	3.20	3.34	0.87	0.77	0.81		10.88	9.41
2021		4.50	3.27	3.42	0.87	0.77	0.79		10.96	9.56
2022		4.65	3.38	3.53	0.90	0.78	0.78		11.04	9.71
2023		4.77	3.47	3.63	0.90	0.80	0.80		11.12	9.87
2024		4.90	3.57	3.73	0.94	0.81	0.82		11.20	10.03
2025		5.04	3.66	3.83	0.94	0.83	0.83		11.28	10.19
2026		5.16	3.74	3.92	0.98	0.84	0.85		11.39	10.39
2027		5.27	3.83	4.02	1.00	0.86	0.86		11.65	10.62
2028		5.39	3.91	4.13	1.02	0.88	0.88		11.91	10.86
2029		5.51	4.00	4.25	1.04	0.90	0.90		12.18	11.11
2030		5.64	4.09	4.36	1.06	0.91	0.92		12.45	11.35
2031		5.76	4.18	4.48	1.08	0.93	0.94		12.73	11.61
2032		5.89	4.28	4.60	1.10	0.95	0.95		13.02	11.87
2033		6.02	4.37	4.73	1.13	0.97	0.97		13.31	12.14
2034		6.16	4.47	4.85	1.15	0.99	0.99		13.61	12.41
2035		6.30	4.57	4.99	1.17	1.01	1.01		13.92	12.69
2036		6.44	4.67	5.12	1.19	1.03	1.03		14.23	12.98
2037		6.59	4.78	5.26	1.22	1.05	1.05		14.55	13.27
2038		6.73	4.89	5.41	1.24	1.07	1.08		14.88	13.57
2039		6.89	5.00	5.55	1.27	1.09	1.10		15.21	13.87
2040		7.04	5.11	5.70	1.29	1.12	1.12		15.56	14.19
2041		7.20	5.22	5.86	1.32	1.14	1.14		15.91	14.50
2042		7.36	5.34	6.02	1.34	1.16	1.16		16.26	14.83
2043		7.53	5.46	6.18	1.37	1.18	1.19		16.63	15.16
2044		7.70	5.58	6.35	1.40	1.21	1.21		17.00	15.51
2045		7.87	5.71	6.52	1.43	1.23	1.24		17.39	15.85
2046		8.05	5.84	6.70	1.45	1.26	1.26		17.78	16.21
2047		8.23	5.97	6.88	1.48	1.28	1.29		18.18	16.58
2048		8.41	6.10	7.07	1.51	1.31	1.31		18.59	16.95
2049		8.60	6.24	7.26	1.54	1.33	1.34		19.01	17.33
2050		8.79	6.38	7.46	1.57	1.36	1.36		19.43	17.72
2051		8.99	6.52	7.66	1.60	1.39	1.39		19.87	18.12
2052		9.19	6.67	7.87	1.64	1.41	1.42		20.32	18.53
2053		9.40	6.82	8.09	1.67	1.44	1.45		20.78	18.94
2054		9.61	6.98	8.31	1.70	1.47	1.48		21.24	19.37
2055		9.83	7.13	8.53	1.74	1.50	1.51		21.72	19.81
2056		10.05	7.29	8.76	1.77	1.53	1.54		22.21	20.25
2057		10.28	7.46	9.00	1.81	1.56	1.57		22.71	20.71
2058		10.51	7.62	9.25	1.84	1.59	1.60		23.22	21.17
2059		10.74	7.80	9.50	1.88	1.62	1.63		23.75	21.65
2060		10.99	7.97	9.76	1.92	1.66	1.66		24.28	22.14
2061		11.23	8.15	10.02	1.95	1.69	1.70		24.83	22.63
2062		11.48	8.33	10.30	1.99	1.72	1.73		25.39	23.14
2063		11.74	8.52	10.58	2.03	1.76	1.76		25.96	23.66
2064		12.01	8.71	10.86	2.07	1.79	1.80		26.54	24.20
2065		12.28	8.91	11.16	2.11	1.83	1.84		27.14	24.74
2066		12.55	9.11	11.46	2.16	1.87	1.87		27.75	25.30

Levy Nuclear Need Filing

Strategist Fuel Forecasts - Mid Reference Fuel Table (2 of 2)

	FUEL 10 GAS FGTF	FUEL 11 GAS FGTI	FUEL 12 GAS ELB/	FUEL 14 GAS SONI	FUEL 18 GulfFirm	FUEL 19 GAS GLFI	FUEL 27 Dist 0.3	FUEL 28 Dist 0.5	FUEL 29 Dist ULS	FUEL 30 Dist .05
2007	8.13	8.13	8.13	8.13	8.13	8.13	17.38	17.10	17.81	14.30
2008	9.38	9.38	9.38	9.38	9.38	9.38	17.63	17.32	18.08	16.20
2009	9.76	9.76	9.76	9.76	9.76	9.76	17.35	17.07	17.78	16.79
2010	9.60	9.60	9.60	9.60	9.60	9.60	17.13	16.86	17.54	12.30
2011	8.09	8.09	8.09	8.09	8.09	8.09	14.00	13.86	14.22	12.13
2012	7.93	7.93	7.93	7.93	7.93	7.93	14.20	14.05	14.43	12.04
2013	7.88	7.88	7.88	7.88	7.88	7.88	14.46	14.31	14.69	11.97
2014	8.09	8.09	8.09	8.09	8.09	8.09	14.70	14.54	14.93	11.90
2015	8.36	8.36	8.36	8.36	8.36	8.36	14.92	14.77	15.16	12.13
2016	8.51	8.51	8.51	8.51	8.51	8.51	15.23	15.07	15.47	12.51
2017	8.68	8.68	8.68	8.68	8.68	8.68	15.53	15.37	15.78	13.00
2018	8.91	8.91	8.91	8.91	8.91	8.91	15.83	15.66	16.08	13.49
2019	9.19	9.19	9.19	9.19	9.19	9.19	16.13	15.96	16.39	13.99
2020	9.48	9.48	9.48	9.48	9.48	9.48	16.42	16.25	16.68	14.49
2021	9.64	9.64	9.64	9.64	9.64	9.64	16.60	16.43	16.87	14.75
2022	9.85	9.85	9.85	9.85	9.85	9.85	16.79	16.60	17.06	15.00
2023	10.07	10.07	10.07	10.07	10.07	10.07	16.97	16.78	17.24	15.27
2024	10.30	10.30	10.30	10.30	10.30	10.30	17.15	16.97	17.43	15.53
2025	10.40	10.40	10.40	10.40	10.40	10.40	17.34	17.15	17.63	15.80
2026	10.57	10.57	10.57	10.57	10.57	10.57	17.57	17.37	17.86	16.13
2027	10.81	10.81	10.81	10.81	10.81	10.81	17.96	17.76	18.26	16.49
2028	11.05	11.05	11.05	11.05	11.05	11.05	18.37	18.16	18.67	16.86
2029	11.30	11.30	11.30	11.30	11.30	11.30	18.78	18.57	19.09	17.24
2030	11.56	11.56	11.56	11.56	11.56	11.56	19.20	18.99	19.52	17.63
2031	11.82	11.82	11.82	11.82	11.82	11.82	19.63	19.42	19.96	18.03
2032	12.08	12.08	12.08	12.08	12.08	12.08	20.08	19.85	20.41	18.43
2033	12.35	12.35	12.35	12.35	12.35	12.35	20.53	20.30	20.87	18.85
2034	12.63	12.63	12.63	12.63	12.63	12.63	20.99	20.76	21.34	19.27
2035	12.92	12.92	12.92	12.92	12.92	12.92	21.46	21.22	21.82	19.70
2036	13.21	13.21	13.21	13.21	13.21	13.21	21.94	21.70	22.31	20.15
2037	13.50	13.50	13.50	13.50	13.50	13.50	22.44	22.19	22.81	20.60
2038	13.81	13.81	13.81	13.81	13.81	13.81	22.94	22.69	23.32	21.06
2039	14.12	14.12	14.12	14.12	14.12	14.12	23.46	23.20	23.85	21.54
2040	14.43	14.43	14.43	14.43	14.43	14.43	23.99	23.72	24.39	22.02
2041	14.76	14.76	14.76	14.76	14.76	14.76	24.53	24.26	24.93	22.52
2042	15.09	15.09	15.09	15.09	15.09	15.09	25.08	24.80	25.50	23.03
2043	15.43	15.43	15.43	15.43	15.43	15.43	25.64	25.36	26.07	23.54
2044	15.78	15.78	15.78	15.78	15.78	15.78	26.22	25.93	26.66	24.07
2045	16.13	16.13	16.13	16.13	16.13	16.13	26.81	26.51	27.26	24.61
2046	16.50	16.50	16.50	16.50	16.50	16.50	27.41	27.11	27.87	25.17
2047	16.87	16.87	16.87	16.87	16.87	16.87	28.03	27.72	28.50	25.73
2048	17.25	17.25	17.25	17.25	17.25	17.25	28.66	28.34	29.14	26.31
2049	17.63	17.63	17.63	17.63	17.63	17.63	29.30	28.98	29.79	26.91
2050	18.03	18.03	18.03	18.03	18.03	18.03	29.96	29.63	30.46	27.51
2051	18.44	18.44	18.44	18.44	18.44	18.44	30.64	30.30	31.15	28.13
2052	18.85	18.85	18.85	18.85	18.85	18.85	31.33	30.98	31.85	28.76
2053	19.27	19.27	19.27	19.27	19.27	19.27	32.03	31.68	32.57	29.41
2054	19.71	19.71	19.71	19.71	19.71	19.71	32.75	32.39	33.30	30.07
2055	20.15	20.15	20.15	20.15	20.15	20.15	33.49	33.12	34.05	30.75
2056	20.60	20.60	20.60	20.60	20.60	20.60	34.24	33.87	34.81	31.44
2057	21.07	21.07	21.07	21.07	21.07	21.07	35.01	34.63	35.60	32.15
2058	21.54	21.54	21.54	21.54	21.54	21.54	35.80	35.41	36.40	32.87
2059	22.03	22.03	22.03	22.03	22.03	22.03	36.60	36.20	37.22	33.61
2060	22.52	22.52	22.52	22.52	22.52	22.52	37.43	37.02	38.06	34.37
2061	23.03	23.03	23.03	23.03	23.03	23.03	38.27	37.85	38.91	35.14
2062	23.55	23.55	23.55	23.55	23.55	23.55	39.13	38.70	39.79	35.93
2063	24.08	24.08	24.08	24.08	24.08	24.08	40.01	39.57	40.68	36.74
2064	24.62	24.62	24.62	24.62	24.62	24.62	40.91	40.46	41.60	37.57
2065	25.17	25.17	25.17	25.17	25.17	25.17	41.83	41.38	42.53	38.41
2066	25.74	25.74	25.74	25.74	25.74	25.74	42.77	42.31	43.49	39.28

Levy Nuclear Need Filing
Strategist Fuel Forecasts - High Fuel Table (1 of 2)

	FUEL 1 COAL 1.8	FUEL 2 COAL 1.2	FUEL 3 COAL 5.0	FUEL 5 COAL4.63	FUEL 4 NUCLEAR	FUEL 35 LNP U1	FUEL 36 LNP U2	FUEL 6 OIL 1.5	FUEL 7 OIL 1.1	FUEL 8 OIL 1.7
2007	2.89	3.05	2.35	3.13	0.34			10.71	10.81	0.00
2008	3.06	3.27	2.53	3.35	0.34			12.02	12.17	0.00
2009	3.28	3.53	2.68	3.57	0.34			12.75	12.92	0.00
2010		3.52	2.74	3.52	0.59				13.42	10.17
2011		3.98	2.95	3.06	0.59				12.15	9.86
2012		4.09	3.03	3.14	0.81				12.55	9.93
2013		4.19	3.10	3.21	0.81				12.86	9.94
2014		4.31	3.19	3.31	0.86				13.12	9.97
2015		4.42	3.24	3.36	0.86				13.38	10.36
2016		4.53	3.32	3.45	0.84	0.86			13.74	10.84
2017		4.64	3.39	3.53	0.84	0.86	0.87		14.11	11.41
2018		4.76	3.47	3.63	0.84	0.82	0.87		14.47	11.97
2019		4.87	3.55	3.71	0.84	0.79	0.83		14.83	12.55
2020		4.97	3.62	3.79	0.87	0.77	0.81		15.18	13.13
2021		5.08	3.70	3.87	0.87	0.77	0.79		15.37	13.41
2022		5.23	3.80	3.98	0.90	0.78	0.78		15.57	13.70
2023		5.36	3.90	4.08	0.90	0.80	0.80		15.76	13.98
2024		5.49	3.99	4.18	0.94	0.81	0.82		15.94	14.27
2025		5.63	4.09	4.28	0.94	0.83	0.83		16.13	14.56
2026		5.74	4.17	4.36	0.98	0.84	0.85		16.36	14.92
2027		5.85	4.25	4.47	1.00	0.86	0.86		16.55	15.09
2028		5.97	4.33	4.58	1.02	0.88	0.88		16.74	15.27
2029		6.08	4.42	4.69	1.04	0.90	0.90		16.94	15.45
2030		6.20	4.50	4.80	1.06	0.91	0.92		17.14	15.63
2031		6.32	4.59	4.92	1.08	0.93	0.94		17.34	15.81
2032		6.45	4.68	5.03	1.10	0.95	0.95		17.54	16.00
2033		6.57	4.77	5.16	1.13	0.97	0.97		17.75	16.19
2034		6.70	4.86	5.28	1.15	0.99	0.99		17.96	16.38
2035		6.83	4.96	5.41	1.17	1.01	1.01		18.17	16.57
2036		6.96	5.05	5.54	1.19	1.03	1.03		18.38	16.76
2037		7.10	5.15	5.67	1.22	1.05	1.05		18.60	16.96
2038		7.24	5.25	5.81	1.24	1.07	1.08		18.81	17.16
2039		7.38	5.36	5.95	1.27	1.09	1.10		19.04	17.36
2040		7.52	5.46	6.10	1.29	1.11	1.12		19.26	17.56
2041		7.67	5.57	6.24	1.32	1.14	1.14		19.49	17.77
2042		7.82	5.67	6.39	1.34	1.16	1.16		19.72	17.98
2043		7.97	5.79	6.55	1.37	1.18	1.19		19.95	18.19
2044		8.13	5.90	6.71	1.40	1.21	1.21		20.18	18.40
2045		8.29	6.01	6.87	1.43	1.23	1.24		20.42	18.62
2046		8.45	6.13	7.04	1.45	1.26	1.26		20.66	18.84
2047		8.61	6.25	7.21	1.48	1.28	1.29		20.90	19.06
2048		8.78	6.37	7.38	1.51	1.31	1.31		21.15	19.28
2049		8.95	6.50	7.56	1.54	1.33	1.34		21.40	19.51
2050		9.13	6.62	7.74	1.57	1.36	1.36		21.65	19.74
2051		9.30	6.75	7.93	1.60	1.39	1.39		21.91	19.97
2052		9.49	6.88	8.12	1.64	1.41	1.42		22.16	20.21
2053		9.67	7.02	8.32	1.67	1.44	1.45		22.42	20.45
2054		9.86	7.15	8.52	1.70	1.47	1.48		22.69	20.69
2055		10.05	7.29	8.72	1.74	1.50	1.51		22.96	20.93
2056		10.25	7.44	8.94	1.77	1.53	1.54		23.23	21.18
2057		10.45	7.58	9.15	1.81	1.56	1.57		23.50	21.43
2058		10.65	7.73	9.37	1.84	1.59	1.60		23.78	21.68
2059		10.86	7.88	9.60	1.88	1.62	1.63		24.06	21.93
2060		11.07	8.03	9.83	1.92	1.66	1.66		24.34	22.19
2061		11.29	8.19	10.07	1.95	1.69	1.70		24.63	22.46
2062		11.51	8.35	10.31	1.99	1.72	1.73		24.92	22.72
2063		11.73	8.51	10.56	2.03	1.76	1.76		25.22	22.99
2064		11.96	8.68	10.82	2.07	1.79	1.80		25.51	23.26
2065		12.19	8.85	11.08	2.11	1.83	1.84		25.82	23.53
2066		12.43	9.02	11.35	2.16	1.87	1.87		26.12	23.81

Levy Nuclear Need Filing
Strategist Fuel Forecasts - High Fuel Table (2 of 2)

	FUEL 10 GAS FGTF	FUEL 11 GAS FGTI	FUEL 12 GAS ELBA	FUEL 14 GAS SONI	FUEL 18 GulfFirm	FUEL 19 GAS GLFI	FUEL 27 Dist 0.3	FUEL 28 Dist 0.5	FUEL 29 Dist ULS	FUEL 30 Dist .05
2007	9.41	9.41	9.41	9.41	9.41	9.41	19.32	19.00	19.79	15.89
2008	12.78	12.78	12.78	12.78	12.78	12.78	21.79	21.41	22.35	20.02
2009	13.94	13.94	13.94	13.94	13.94	13.94	22.29	21.93	22.83	21.56
2010	13.92	13.92	13.92	13.92	13.92	13.92	22.00	21.65	22.52	15.79
2011	11.80	11.80	11.80	11.80	11.80	11.80	18.20	18.01	18.48	15.76
2012	11.74	11.74	11.74	11.74	11.74	11.74	18.66	18.47	18.96	15.82
2013	11.79	11.79	11.79	11.79	11.79	11.79	19.16	18.96	19.46	15.86
2014	12.23	12.23	12.23	12.23	12.23	12.23	19.63	19.42	19.94	15.89
2015	12.77	12.77	12.77	12.77	12.77	12.77	20.08	19.86	20.40	16.31
2016	13.12	13.12	13.12	13.12	13.12	13.12	20.63	20.41	20.96	16.95
2017	13.50	13.50	13.50	13.50	13.50	13.50	21.19	20.96	21.52	17.74
2018	13.98	13.98	13.98	13.98	13.98	13.98	21.74	21.51	22.08	18.52
2019	14.54	14.54	14.54	14.54	14.54	14.54	22.29	22.05	22.64	19.33
2020	15.12	15.12	15.12	15.12	15.12	15.12	22.82	22.58	23.18	20.14
2021	15.49	15.49	15.49	15.49	15.49	15.49	23.20	22.95	23.57	20.61
2022	15.94	15.94	15.94	15.94	15.94	15.94	23.58	23.32	23.96	21.08
2023	16.41	16.41	16.41	16.41	16.41	16.41	23.95	23.69	24.34	21.55
2024	16.89	16.89	16.89	16.89	16.89	16.89	24.33	24.06	24.73	22.03
2025	17.16	17.16	17.16	17.16	17.16	17.16	24.70	24.43	25.11	22.52
2026	17.54	17.54	17.54	17.54	17.54	17.54	25.14	24.86	25.56	23.08
2027	17.98	17.98	17.98	17.98	17.98	17.98	25.83	25.54	26.26	23.71
2028	18.44	18.44	18.44	18.44	18.44	18.44	26.54	26.24	26.98	24.36
2029	18.90	18.90	18.90	18.90	18.90	18.90	27.26	26.96	27.72	25.03
2030	19.38	19.38	19.38	19.38	19.38	19.38	28.02	27.71	28.48	25.72
2031	19.87	19.87	19.87	19.87	19.87	19.87	28.79	28.47	29.27	26.43
2032	20.37	20.37	20.37	20.37	20.37	20.37	29.58	29.26	30.07	27.16
2033	20.88	20.88	20.88	20.88	20.88	20.88	30.40	30.06	30.90	27.91
2034	21.41	21.41	21.41	21.41	21.41	21.41	31.23	30.89	31.75	28.68
2035	21.95	21.95	21.95	21.95	21.95	21.95	32.09	31.74	32.63	29.47
2036	22.51	22.51	22.51	22.51	22.51	22.51	32.98	32.61	33.53	30.28
2037	23.07	23.07	23.07	23.07	23.07	23.07	33.89	33.51	34.45	31.11
2038	23.66	23.66	23.66	23.66	23.66	23.66	34.82	34.44	35.40	31.97
2039	24.25	24.25	24.25	24.25	24.25	24.25	35.78	35.38	36.38	32.85
2040	24.86	24.86	24.86	24.86	24.86	24.86	36.77	36.36	37.38	33.76
2041	25.49	25.49	25.49	25.49	25.49	25.49	37.78	37.36	38.41	34.69
2042	26.14	26.14	26.14	26.14	26.14	26.14	38.82	38.39	39.47	35.64
2043	26.79	26.79	26.79	26.79	26.79	26.79	39.89	39.45	40.55	36.62
2044	27.47	27.47	27.47	27.47	27.47	27.47	40.99	40.53	41.67	37.63
2045	28.16	28.16	28.16	28.16	28.16	28.16	42.11	41.65	42.82	38.67
2046	28.87	28.87	28.87	28.87	28.87	28.87	43.27	42.80	44.00	39.73
2047	29.60	29.60	29.60	29.60	29.60	29.60	44.47	43.98	45.21	40.83
2048	30.35	30.35	30.35	30.35	30.35	30.35	45.69	45.19	46.45	41.95
2049	31.12	31.12	31.12	31.12	31.12	31.12	46.95	46.43	47.73	43.11
2050	31.90	31.90	31.90	31.90	31.90	31.90	48.24	47.71	49.05	44.29
2051	32.71	32.71	32.71	32.71	32.71	32.71	49.57	49.03	50.40	45.51
2052	33.53	33.53	33.53	33.53	33.53	33.53	50.94	50.38	51.79	46.77
2053	34.38	34.38	34.38	34.38	34.38	34.38	52.34	51.76	53.21	48.06
2054	35.25	35.25	35.25	35.25	35.25	35.25	53.78	53.19	54.68	49.38
2055	36.13	36.13	36.13	36.13	36.13	36.13	55.26	54.66	56.19	50.74
2056	37.05	37.05	37.05	37.05	37.05	37.05	56.78	56.16	57.74	52.14
2057	37.98	37.98	37.98	37.98	37.98	37.98	58.35	57.71	59.33	53.57
2058	38.94	38.94	38.94	38.94	38.94	38.94	59.95	59.30	60.96	55.05
2059	39.92	39.92	39.92	39.92	39.92	39.92	61.61	60.93	62.64	56.57
2060	40.93	40.93	40.93	40.93	40.93	40.93	63.30	62.61	64.36	58.13
2061	41.96	41.96	41.96	41.96	41.96	41.96	65.05	64.34	66.14	59.73
2062	43.02	43.02	43.02	43.02	43.02	43.02	66.84	66.11	67.96	61.37
2063	44.11	44.11	44.11	44.11	44.11	44.11	68.68	67.93	69.83	63.06
2064	45.22	45.22	45.22	45.22	45.22	45.22	70.57	69.80	71.76	64.80
2065	46.36	46.36	46.36	46.36	46.36	46.36	72.51	71.72	73.73	66.58
2066	47.53	47.53	47.53	47.53	47.53	47.53	74.51	73.70	75.76	68.42

Levy Nuclear Need Filing
Strategist Fuel Forecasts - Low Fuel Table (1 of 2)

	FUEL 1 COAL 1.8	FUEL 2 COAL 1.2	FUEL 3 COAL 5.0	FUEL 5 COAL4.63	FUEL 4 NUCLEAR	FUEL 35 LNP U1	FUEL 36 LNP U2	FUEL 6 OIL 1.5	FUEL 7 OIL 1.1	FUEL 8 OIL 1.7
2007	2.49	2.62	2.02	2.69	0.34			8.62	8.69	0.00
2008	2.54	2.72	2.10	2.78	0.34			8.14	8.25	0.00
2009	2.50	2.69	2.05	2.72	0.34			7.71	7.81	0.00
2010		2.52	1.96	2.52	0.59				7.60	5.76
2011		2.81	2.09	2.16	0.59				7.21	5.85
2012		2.92	2.16	2.24	0.81				7.29	5.77
2013		3.02	2.23	2.32	0.81				7.35	5.68
2014		3.14	2.32	2.41	0.86				7.39	5.61
2015		3.25	2.38	2.47	0.86				7.43	5.75
2016		3.36	2.46	2.56	0.84	0.86			7.53	5.94
2017		3.47	2.54	2.64	0.84	0.86	0.87		7.63	6.17
2018		3.58	2.62	2.73	0.84	0.82	0.87		7.73	6.39
2019		3.70	2.70	2.82	0.84	0.79	0.83		7.82	6.62
2020		3.80	2.77	2.90	0.87	0.77	0.81		7.92	6.85
2021		3.91	2.85	2.98	0.87	0.77	0.79		7.94	6.93
2022		4.06	2.95	3.09	0.90	0.78	0.78		7.97	7.01
2023		4.18	3.05	3.19	0.90	0.80	0.80		7.99	7.09
2024		4.32	3.14	3.28	0.94	0.81	0.82		8.02	7.18
2025		4.46	3.23	3.39	0.94	0.83	0.83		8.04	7.27
2026		4.57	3.32	3.47	0.98	0.84	0.85		8.10	7.38
2027		4.67	3.39	3.56	1.00	0.86	0.86		8.25	7.52
2028		4.78	3.47	3.66	1.02	0.88	0.88		8.40	7.66
2029		4.88	3.54	3.76	1.04	0.90	0.90		8.56	7.80
2030		4.99	3.62	3.86	1.06	0.91	0.92		8.71	7.95
2031		5.11	3.70	3.97	1.08	0.93	0.94		8.88	8.09
2032		5.22	3.79	4.08	1.10	0.95	0.95		9.04	8.24
2033		5.34	3.87	4.19	1.13	0.97	0.97		9.21	8.40
2034		5.46	3.96	4.30	1.15	0.99	0.99		9.38	8.55
2035		5.58	4.05	4.42	1.17	1.01	1.01		9.55	8.71
2036		5.71	4.14	4.54	1.19	1.03	1.03		9.73	8.87
2037		5.84	4.23	4.66	1.22	1.05	1.05		9.91	9.04
2038		5.97	4.33	4.79	1.24	1.07	1.08		10.10	9.21
2039		6.10	4.43	4.92	1.27	1.09	1.10		10.28	9.38
2040		6.24	4.53	5.05	1.29	1.11	1.12		10.48	9.55
2041		6.38	4.63	5.19	1.32	1.14	1.14		10.67	9.73
2042		6.52	4.73	5.33	1.34	1.16	1.16		10.87	9.91
2043		6.67	4.84	5.48	1.37	1.18	1.19		11.07	10.09
2044		6.82	4.95	5.63	1.40	1.21	1.21		11.28	10.28
2045		6.97	5.06	5.78	1.43	1.23	1.24		11.49	10.47
2046		7.13	5.17	5.94	1.45	1.26	1.26		11.70	10.67
2047		7.29	5.29	6.10	1.48	1.28	1.29		11.92	10.87
2048		7.45	5.41	6.26	1.51	1.31	1.31		12.14	11.07
2049		7.62	5.53	6.44	1.54	1.33	1.34		12.36	11.27
2050		7.79	5.65	6.61	1.57	1.36	1.36		12.59	11.48
2051		7.97	5.78	6.79	1.60	1.39	1.39		12.83	11.70
2052		8.15	5.91	6.98	1.64	1.41	1.42		13.07	11.91
2053		8.33	6.04	7.16	1.67	1.44	1.45		13.31	12.13
2054		8.52	6.18	7.36	1.70	1.47	1.48		13.56	12.36
2055		8.71	6.32	7.56	1.74	1.50	1.51		13.81	12.59
2056		8.91	6.46	7.77	1.77	1.53	1.54		14.07	12.82
2057		9.11	6.61	7.98	1.81	1.56	1.57		14.33	13.06
2058		9.31	6.76	8.19	1.84	1.59	1.60		14.59	13.30
2059		9.52	6.91	8.42	1.88	1.62	1.63		14.87	13.55
2060		9.73	7.06	8.65	1.92	1.66	1.66		15.14	13.80
2061		9.95	7.22	8.88	1.95	1.69	1.70		15.42	14.06
2062		10.18	7.38	9.12	1.99	1.72	1.73		15.71	14.32
2063		10.41	7.55	9.37	2.03	1.76	1.76		16.00	14.59
2064		10.64	7.72	9.63	2.07	1.79	1.80		16.30	14.86
2065		10.88	7.89	9.89	2.11	1.83	1.84		16.60	15.14
2066		11.12	8.07	10.16	2.16	1.87	1.87		16.91	15.42

Levy Nuclear Need Filing
Strategist Fuel Forecasts - Low Fuel Table (1 of 2)

	FUEL 10 GAS FGTF	FUEL 11 GAS FGTI	FUEL 12 GAS ELBA	FUEL 14 GAS SONI	FUEL 18 GulfFirm	FUEL 19 GAS GLFI	FUEL 27 Dist 0.3	FUEL 28 Dist 0.5	FUEL 29 Dist ULS	FUEL 30 Dist .05
2007	6.78	6.78	6.78	6.78	6.78	6.78	15.66	15.41	16.05	12.88
2008	7.01	7.01	7.01	7.01	7.01	7.01	14.39	14.14	14.77	13.23
2009	6.99	6.99	6.99	6.99	6.99	6.99	13.68	13.46	14.01	13.23
2010	6.79	6.79	6.79	6.79	6.79	6.79	13.53	13.31	13.85	9.71
2011	5.58	5.58	5.58	5.58	5.58	5.58	10.86	10.75	11.03	9.41
2012	5.39	5.39	5.39	5.39	5.39	5.39	10.91	10.79	11.08	9.24
2013	5.30	5.30	5.30	5.30	5.30	5.30	11.02	10.90	11.19	9.12
2014	5.39	5.39	5.39	5.39	5.39	5.39	11.12	11.01	11.30	9.00
2015	5.51	5.51	5.51	5.51	5.51	5.51	11.22	11.10	11.40	9.12
2016	5.56	5.56	5.56	5.56	5.56	5.56	11.37	11.25	11.55	9.34
2017	5.62	5.62	5.62	5.62	5.62	5.62	11.53	11.40	11.71	9.65
2018	5.72	5.72	5.72	5.72	5.72	5.72	11.68	11.56	11.87	9.95
2019	5.85	5.85	5.85	5.85	5.85	5.85	11.84	11.71	12.02	10.27
2020	5.99	5.99	5.99	5.99	5.99	5.99	11.99	11.86	12.18	10.58
2021	6.05	6.05	6.05	6.05	6.05	6.05	12.06	11.93	12.26	10.71
2022	6.13	6.13	6.13	6.13	6.13	6.13	12.14	12.01	12.34	10.85
2023	6.23	6.23	6.23	6.23	6.23	6.23	12.22	12.09	12.42	10.99
2024	6.33	6.33	6.33	6.33	6.33	6.33	12.31	12.17	12.51	11.14
2025	6.35	6.35	6.35	6.35	6.35	6.35	12.39	12.26	12.60	11.29
2026	6.42	6.42	6.42	6.42	6.42	6.42	12.51	12.37	12.72	11.48
2027	6.49	6.49	6.49	6.49	6.49	6.49	12.74	12.60	12.95	11.70
2028	6.57	6.57	6.57	6.57	6.57	6.57	12.98	12.83	13.19	11.91
2029	6.65	6.65	6.65	6.65	6.65	6.65	13.22	13.07	13.44	12.14
2030	6.73	6.73	6.73	6.73	6.73	6.73	13.47	13.32	13.69	12.37
2031	6.81	6.81	6.81	6.81	6.81	6.81	13.72	13.57	13.95	12.60
2032	6.89	6.89	6.89	6.89	6.89	6.89	13.98	13.83	14.21	12.84
2033	6.97	6.97	6.97	6.97	6.97	6.97	14.24	14.09	14.48	13.08
2034	7.05	7.05	7.05	7.05	7.05	7.05	14.51	14.35	14.75	13.32
2035	7.14	7.14	7.14	7.14	7.14	7.14	14.79	14.62	15.03	13.58
2036	7.22	7.22	7.22	7.22	7.22	7.22	15.06	14.90	15.32	13.83
2037	7.31	7.31	7.31	7.31	7.31	7.31	15.35	15.18	15.60	14.09
2038	7.40	7.40	7.40	7.40	7.40	7.40	15.64	15.46	15.90	14.36
2039	7.49	7.49	7.49	7.49	7.49	7.49	15.93	15.75	16.20	14.63
2040	7.58	7.58	7.58	7.58	7.58	7.58	16.23	16.05	16.50	14.90
2041	7.67	7.67	7.67	7.67	7.67	7.67	16.54	16.35	16.81	15.18
2042	7.76	7.76	7.76	7.76	7.76	7.76	16.85	16.66	17.13	15.47
2043	7.85	7.85	7.85	7.85	7.85	7.85	17.16	16.98	17.45	15.76
2044	7.94	7.94	7.94	7.94	7.94	7.94	17.49	17.29	17.78	16.06
2045	8.04	8.04	8.04	8.04	8.04	8.04	17.82	17.62	18.11	16.36
2046	8.14	8.14	8.14	8.14	8.14	8.14	18.15	17.95	18.46	16.67
2047	8.23	8.23	8.23	8.23	8.23	8.23	18.49	18.29	18.80	16.98
2048	8.33	8.33	8.33	8.33	8.33	8.33	18.84	18.63	19.16	17.30
2049	8.43	8.43	8.43	8.43	8.43	8.43	19.20	18.99	19.52	17.63
2050	8.53	8.53	8.53	8.53	8.53	8.53	19.56	19.34	19.88	17.96
2051	8.63	8.63	8.63	8.63	8.63	8.63	19.93	19.71	20.26	18.30
2052	8.74	8.74	8.74	8.74	8.74	8.74	20.30	20.08	20.64	18.64
2053	8.84	8.84	8.84	8.84	8.84	8.84	20.68	20.46	21.03	18.99
2054	8.95	8.95	8.95	8.95	8.95	8.95	21.07	20.84	21.43	19.35
2055	9.05	9.05	9.05	9.05	9.05	9.05	21.47	21.23	21.83	19.71
2056	9.16	9.16	9.16	9.16	9.16	9.16	21.87	21.63	22.24	20.08
2057	9.27	9.27	9.27	9.27	9.27	9.27	22.28	22.04	22.66	20.46
2058	9.38	9.38	9.38	9.38	9.38	9.38	22.70	22.46	23.08	20.85
2059	9.49	9.49	9.49	9.49	9.49	9.49	23.13	22.88	23.52	21.24
2060	9.61	9.61	9.61	9.61	9.61	9.61	23.57	23.31	23.96	21.64
2061	9.72	9.72	9.72	9.72	9.72	9.72	24.01	23.75	24.41	22.05
2062	9.84	9.84	9.84	9.84	9.84	9.84	24.46	24.20	24.87	22.46
2063	9.96	9.96	9.96	9.96	9.96	9.96	24.92	24.65	25.34	22.88
2064	10.08	10.08	10.08	10.08	10.08	10.08	25.39	25.11	25.82	23.32
2065	10.20	10.20	10.20	10.20	10.20	10.20	25.87	25.59	26.30	23.75
2066	10.32	10.32	10.32	10.32	10.32	10.32	26.36	26.07	26.80	24.20

Levy Nuclear Need Filing

Customer and Energy Requirements History and Forecasts

YEAR	Average Number Of Customers		Net Energy for Load (GWh)		
	History	Forecast	Forecast Low	History Base	Forecast High
1997	1,314,508			34,605	
1998	1,340,851			37,763	
1999	1,376,595			39,160	
2000	1,400,301			41,242	
2001	1,444,958			40,933	
2002	1,475,783			42,567	
2003	1,510,516			43,911	
2004	1,548,627			45,268	
2005	1,583,417			46,878	
2006	1,620,396			46,041	
2007	1,632,368			47,633	
2008		1,662,325	48,058	48,734	49,404
2009		1,694,687	49,042	49,768	50,540
2010		1,727,055	50,802	51,615	52,522
2011		1,759,469	51,945	52,913	53,914
2012		1,791,810	53,574	54,695	55,874
2013		1,824,240	54,731	56,045	57,328
2014		1,856,553	55,397	56,905	58,369
2015		1,888,544	56,441	58,166	59,897
2016		1,918,178	57,521	59,448	61,390
2017		1,947,284	58,590	60,836	63,053
2018		1,975,865	59,880	62,256	64,850
2019		2,003,928	61,141	63,725	66,625
2020		2,031,477	62,421	65,227	68,492
2021		2,058,522	63,468	66,625	70,026
2022		2,085,101	64,492	67,970	71,755
2023		2,111,260	65,666	69,319	73,359
2024		2,137,049	66,764	70,647	75,184
2025		2,162,509	67,831	71,975	76,692
2026		2,187,690	68,883	73,385	78,497
2027		2,212,646	70,093	74,821	80,190
2028		2,237,435	71,325	76,286	81,921
2029		2,262,108	72,581	77,781	83,690
2030		2,286,727	73,858	79,306	85,498
2031		2,311,320	75,160	80,862	87,347
2032		2,335,949	76,485	82,449	89,235
2033		2,360,403	77,835	84,070	91,168
2034		2,384,881	79,210	85,723	93,143
2035		2,409,615	80,610	87,410	95,163
2036		2,434,367	82,036	89,131	97,227

Levy Nuclear Need Filing
Energy Demand History and Forecasts

YEAR	Summer Peak Net Firm Demand (MW) History[1]	Summer Peak Net Firm Demand (MW) Forecast	Winter Peak Net Firm Demand (MW) History[1]	Winter Peak Net Firm Demand (MW) Forecast
1997				
1998	7,190		6,403	
1999	7,353		8,681	
2000	7,650		8,594	
2001	7,726		9,397	
2002	8,296		9,074	
2003	7,778		9,752	
2004	8,236		7,438	
2005	8,886		8,849	
2006	9,031		9,054	
2007	9,778		8,106	
2008		9,425		10,075
2009		9,451		9,880
2010		9,689		10,311
2011		9,873		10,523
2012		10,194		10,974
2013		10,392		11,250
2014		10,568		11,318
2015		10,776		11,549
2016		10,961		11,786
2017		11,150		12,011
2018		11,335		12,242
2019		11,530		12,469
2020		11,722		12,699
2021		11,904		12,925
2022		12,092		13,154
2023		12,276		13,379
2024		12,458		13,606
2025		12,646		13,833
2026		12,825		14,059
2027		13,019		14,303
2028		13,216		14,551
2029		13,417		14,803
2030		13,620		15,060
2031		13,826		15,320
2032		14,035		15,584
2033		14,247		15,853
2034		14,462		16,125
2035		14,680		16,402
2036		14,902		16,683

Notes: 1. Recorded System - All possible DLC has been removed.

Levy Nuclear Need Filing
New Nuclear Plant Modeling Information

Capital Cost Estimate for Strategist Modeling

Levy County Units 1 and 2 ($000's)	Unit 1	Unit 2	Current Total
Unit Overnight Total Cost	5,617,297	3,686,282	9,303,579
Project Escalation @ 3%	883,980	655,388	1,539,367
Escalated Construction Cost (Before AFUDC)	6,501,276	4,341,670	10,842,946
Estimated Project AFUDC	1,814,733	1,432,029	3,246,762
LNP Unit Total	**8,316,010**	**5,773,698**	**14,089,708**
Winter Capacity Rating (MW)	1,120	1,120	2,240
Summer Capacity Rating (MW)	1,092	1,092	2,184
Estimated Overnight Cost - Winter Basis ($/kW)	5,015	3,291	4,153
Estimated Overnight Cost - Summer Basis ($/kW)	5,144	3,376	4,260
Estimated In-Service Cost - Winter Basis ($/kW)	7,425	5,155	6,290
Estimated In-Service Cost - Summer Basis ($/kW)	7,615	5,287	6,451

Operating Cost Estimate for Strategist Modeling
Levy County Units 1 and 2

	Unit 1	*Unit 2*
Fixed O&M ($/kW-yr) Summer Basis *Basis - $2007, Escalating Annually at 2.25%*	**51.79**	**36.25**
Variable O&M ($/MWh) *Basis - $2007, Escalating Annually at 2.25%*	**1.82**	**1.82**
Back End Costs (mill/kWh) for Federal Spent Fuel Disposal Fees *Basis - $2007, Remains Constant*	**1.00**	**1.00**
Decommissioning and Dismantlement (D&D) Funding ($/kW-yr) Summer Basis *Basis - $2007, Remains Constant*	**16.64**	**16.64**
Annualized Capital Replacement ($/kW-yr) Summer Basis *Basis - $2007, Escalating Annually at 2.25%, Starting 10 yrs After COD*	**8.93**	**8.93**
Winter Capacity Rating (MW)	**1,120**	**1,120**
Summer Capacity Rating (MW)	**1,092**	**1,092**