2001 Ten-Year Site Plan

LAKELAND ELECTRIC

2001 Ten-Year Site Plan for Electrical Generating Facilities and Associated Transmission Lines

Submitted to
Florida Public Service Commission

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Executive Summary

This report documents the 2001 Lakeland Electric (Lakeland) Ten-Year Site Plan pursuant to 186.801 Florida Statutes and 25-22.070 - 22.073 Florida Administrative Code. The Ten-Year Site Plan provides information required by this rule. The Plan is divided into nine main sections: Introduction, General Description of Utility, Forecast of Electrical Power Demand and Energy Consumption, Demand-Side Management Programs, Forecasting Methods and Procedures, Forecast of Facilities Requirements, Analysis Results and Conclusions, Environmental and Land Use Information, and Ten-Year Site Plan Schedules.

Power for the City of Lakeland is supplied by Lakeland Electric wholly and jointly owned generating units. Lakeland Electric is also a member of the Florida Municipal Power Pool (FMPP). The total installed generating capacity based on Lakeland's ownership share is 647 MW winter and 614 MW summer as of December 31, 2000. The existing supply system has a broad range of generation technology and capabilities, but is heavily dependent upon natural gas.

Lakeland Electric has projected peak demand growth and energy consumption for the planning period. A banded forecast is provided with a base case growth, high growth, and low growth scenarios. Lakeland has adopted the use of a reserve margin criteria equal to 22 percent in the winter and 20 percent in the summer. Considering the forecasted growth, existing units, retiring units, power sales contracts, and reserve margin criteria, there emerges a need for additional capacity before the winter of 2005/06.

Lakeland Electric currently employs an aggressive demand-side management (DSM) program to improve the efficiency of consumer electricity usage. The DSM program includes two residential and three commercial programs as well as additional energy savings and energy efficiency promotion programs.

As a result of its 2000 Ten-Year Site Plan, Lakeland identified a 288 MW solid fuel unit as the most cost-effective addition to its system. As a result, Lakeland initiated a request for EPC and power purchase proposals (RFP) in June, 2000. Bids were received in December, 2000 and are currently under evaluation along with other options available to Lakeland.

While the evaluation of these options is ongoing, for purposes of the 2001 Ten-Year Site Plan, a 288 MW solid fuel unit (188 MW is Lakeland's assumed share) has been assumed to be installed in June, 2005 at the McIntosh Site (McIntosh 4). Based on the 2000 TYSP, this unit is assumed to be a pressurized fluidized bed combined cycle (PFBC) consisting of three P200 modules with petroleum coke as the primary fuel. As the evaluations of Lakeland's options advance, the plan will be revised as appropriate and will form the basis of Lakeland's Need for Power filing expected in the spring of 2001. Table ES-1 presents the expansion plan for purposes of the 2001 Ten-Year Site Plan. As seen in this table, if Lakeland secured 188 MW of power in 2005, its capacity needs would be met over the ten year horizon.

In addition to cost considerations, strategic, environmental and land use considerations are being factored into the resource plans. This will ensure that the most cost-effective plan selected is environmentally and socially responsible, consistent with Lakeland Electric's commitment to the community.

Table ES-1
Ten-Year Reliability Levels Assuming a 188 MW Capacity Addition in 2005 (Winter / Base Case)

					System Peak Demand		Reserve Margin		Excess/ (Deficit) to Maintain 22% Reserve Margin	
Winter Peak Period	Net Generating Capacity (MW)	Unit[1] Additions/ (Retirements) (MW)	Net System Purchases/ (Sales) (MW)	Net System Capacity (MW)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (%)	After Interruptible and Load Management (%)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)
2000/2001	647	L6 (24 MW)								
2001/2002	891	M5 CT 268 MW M5 CT (268 MW) M5 CC 384 MW L7 (50 MW)	(100)	791	691	627	14.5	26.2	(52.0)	26.1
2002/2003	957		(100)	857	708	644	21.0	33.1	(6.8)	71.3
2003/2004	957		(100)	857	727	662	17.9	29.5	(29.9)	49.4
2004/2005	957		(100)	857	745	679	15.0	26.2	(51.9)	28.6
2005/2006	1,058	M4 188 MW M1 (87 MW)	(100)	958	764	697	25.4	37.4	25.9	107.7
2006/2007	1,058		(100)	958	781	714	22.7	34.2	5.2	86.9
2007/2008	1,058		(100)	958	800	732	19.8	30.9	(18.0)	65.0
2008/2009	1,058		(100)	958	817	749	17.3	27.9	(38.7)	44.2
2009/2010	1,058		(100)	958	836	767	14.6	24.9	(61.9)	22.3
2010/2011	1,058		0	1,058	853	784	24.0	34.9	17.3	101.5

[1] L: Larsen Unit
M: McIntosh Unit

1.0 Introduction

This report contains the 2001 Lakeland Electric Ten-Year Site Plan (TYSP) pursuant to Florida Statutes and as adopted by Order No. PSC-97-1373-FOF-EU on October 30, 1997. The Lakeland TYSP reports the status of the utility's resource plans as of December 31, 2000. The TYSP is divided into the following nine sections: Introduction, General Description of Utility, Forecast of Electrical Power Demand and Energy Consumption, Conservation and Demand-Side Management, Forecasting Methods and Procedures, Forecast of Facilities Requirements, Analysis Results and Conclusions. Environmental and Land Use Information, and Ten-Year Site Plan Schedules. The contents of each section is summarized briefly in the remainder of this Introduction.

1.1 General Description of the Utility

Section 2.0 of the TYSP discusses Lakeland's existing generation and transmission facilities. The section includes a historical overview of Lakeland's system, and a description of existing power generating and transmission facilities. This section includes tables which show the source of the utility's current 647 MW of net winter generating capacity and 614 MW of net summer generating capacity (in the year 2000).

1.2 Forecast of Electrical Power Demand and Energy Consumption

Section 3.0 of the TYSP provides a summary of Lakeland's load forecast. Lakeland is projected to remain a winter peaking system throughout the planning period. The projected annual growth rates in peak demand for the winter and summer are 2.29 and 2.20 percent, respectively, for 2001 through 2020.

Net energy for load is projected to grow at an average annual rate of 2.07 percent for 2001 through 2020, a lower growth rate than occurred over the past 10 years. Projections are also developed for high and low load growth scenarios.

1.3 Demand-Side Management Programs

Section 4.0 provides descriptions of the existing conservation and demand-side management programs. Additional details regarding Lakeland's demand-side management programs are on file with the Florida Public Service Commission (FPSC).

Lakeland's current conservation and demand management programs include the following programs for which demand and energy savings can readily be demonstrated:

- Residential Programs:
  - SMART Load Management Program.
  - Loan Program.
- Commercial Programs:
  - Commercial Lighting Program.
  - Thermal Energy Storage Program.
  - High-Pressure Sodium Outdoor Lighting Program.

Lakeland also currently conducts the following conservation and demand-side management programs which promote energy savings and efficiency:

- Residential Programs:
  - Energy Audit Program.
  - Public Awareness Program.
  - Mobile Display Unit.
  - Speakers Bureau.
  - Informational Bill Inserts.
- Commercial Programs:
  - Commercial Audit Program.

1.4 Forecasting Methods and Procedures

Section 5.0 discusses the forecasting methods used for the TYSP and outlines the assumptions applied for system planning. This section also summarizes the integrated resource plan for Lakeland and provides planning criteria for the Florida Municipal Power Pool, of which Lakeland is a member. The integrated resource plan is fully incorporated in the TYSP.

Fuel price projections are provided for coal, natural gas, oil, and petroleum coke; with brief descriptions of the methodology. Three sensitivities are provided for the fuel price forecast: a high fuel price scenario, a low fuel price scenario, and a constant differential scenario.

Assumptions for the economic parameters and evaluation criteria which are being applied in the evaluation are also included in Section 5.0.

1.5 Forecast of Facilities Requirements

Section 6.0 integrates the electrical demand and energy forecast with the conservation and demand-side management forecast to determine Lakeland's requirements for the ten-year planning horizon. Application of the reserve margin criteria indicates a need for additional capacity by the winter of 2005/06.

1.6 Analysis Results and Conclusions

Section 7.0 discusses the supply-side evaluation being undertaken by Lakeland to identify the best option for its system. It also discusses the capacity temporarily assumed for the purposes of this report and until a preferred alternative is selected.

1.7 Environmental and Land Use Information

Section 8.0 discusses the land and environmental features of Lakeland's TYSP.

1.8 Ten-Year Site Plan Schedules

Section 9.0 presents the schedules required by the Florida Public Service Commission (FPSC) for the TYSP.

2.0 General Description of Utility

2.1 City of Lakeland Historical Background

2.1.1 Founding and Expansion

The City of Lakeland was incorporated on January 1, 1885, when 27 citizens approved and signed the city charter. Shortly thereafter the original light plant was built by Lakeland Light and Power Company at the corner of Cedar Street and Massachusetts Avenue. This plant had an original capacity of 50 kW. On May 26, 1891, plant manager Harry Sloan threw the switch to light Lakeland by electricity for the first time with five arc lamps. Incandescent lights were first installed in 1903.

Public power in Lakeland was established in 1904, when foresighted citizens and municipal officials purchased the small private 50 kW electric light plant from owner Bruce Neff for $7,500. The need for an expansion led to the construction of a new power plant on the north side of Lake Mirror in 1916. The initial capacity of the Lake Mirror Power Plant is estimated to have been 500 kW. The plant has since been expanded three times. The first expansion occurred in 1922 with the addition of 2,500 kW; in 1925, 5,000 kW additional capacity was added, followed by another 5,000 kW in 1938. With the final expansion, the removal of the initial 500 kW unit was required to make room for the addition of the 5,000 kW generating unit, resulting in a total peak plant capacity of 12,500 kW.

As the community continued to grow, the need for a new power plant emerged and the Charles Larsen Memorial Power Plant was constructed on the southeast shore of Lake Parker in 1949. The initial capacity of the Larsen Plant Steam Unit No. 4 completed in 1950 was 20,000 kW. The first addition to the Larsen Plant was Steam Unit No. 5 (1956) which had a capacity of 25,000 kW. In 1959, Steam Unit No. 6 was added and increased the plant capacity by another 25,000 kW. Three gas turbines, each with a nominal rating of 11,250 kW, were installed as peaking units in 1962. In 1966, a third steam unit capacity addition was made to the Larsen Plant. This was Steam Unit No.7 having a nominal 44,000 kW capacity and an estimated cost of $9.6 million. This brought the total Larsen Plant nameplate capacity up to a nominal 147,750 kW.

In the meantime, the Lake Mirror Plant, with its old and obsolete equipment, became relatively inefficient and hence was no longer in active use. It was kept in cold standby and then retired in 1971.

As the city continued to grow during the late 1960's, the demand for power and electricity grew at a rapid rate, making evident the need for a new power plant. A site was purchased on the north side of Lake Parker and construction commenced during

1970. Initially, two diesel units with a peaking capacity of a nominal rating 2,500 kW each were placed into commercial operation in 1970.

Steam Unit No. 1, with a nominal rating of 90,000 kW, was put into commercial operation on February 24, 1971, for a total cost of $15.22 million. In June of 1976, Steam Unit No. 2 at Plant 3 was placed into commercial operation, with a nominal rated capacity of 114,707 kW and at a cost of $25.77 million. This addition increased the total capacity of the Lakeland system to approximately 360,000 kW. At this time, Plant 3 was renamed the C. D. McIntosh, Jr. Power Plant in recognition of the former Electric and Water Department director.

On January 2, 1979, construction was started on McIntosh Unit No. 3, a nominal 334 MW coal fired steam generating unit which became commercial on September 1, 1982. The unit is capable of using low sulfur oil as an alternate fuel and supplemented by prepared solid waste. The plant utilized sewage effluent for cooling tower makeup water. This unit is jointly owned with the Orlando Utilities Commission (OUC) which has a 40 percent undivided interest in the unit.

As load continued to grow, Lakeland continually studied and reviewed alternatives for accommodating the additional growth. Alternatives included both demand- and supply-side resources. A wide variety of conservation and demand-side management programs were developed and marketed to Lakeland customers to encourage increased energy efficiency and conservation in keeping with the Florida Energy Efficiency and Conservation Act of 1980 (FEECA). These programs are discussed in further detail in Section 4.0.

Although demand and energy savings arose from Lakeland's conservation and demand-side management programs, additional capacity was required in the early 1990's. Least cost planning studies resulted in the construction of Larsen Unit No. 8, a natural gas fired combined cycle unit with a nameplate generating capability of 124,000 kW. Larsen Unit No. 8 began simple cycle operation in July 1992, and combined cycle operation in November of that year.

In 1994, Lakeland made the decision to retire the first unit at Larsen Plant, Steam Unit No. 4. This unit, put in service in 1950 with a capacity of 20,000 kW, had reached the end of its economic life. In March of 1997, Lakeland placed into cold shutdown, Larsen Unit No. 6, a 25 MW oil fired unit that was also nearing the end of its economic life.

In 1998, Lakeland regained 9 MW (its 60 percent share) from the McIntosh 3 unit after performing non-routine maintenance activities to upgrade the turbine steam path. This capacity is reflected in the unit's current performance ratings. Additional data regarding Lakeland's existing units and system are summarized in Tables 2-1 and 2-2.

In 1998, Lakeland had two long-term power purchase contracts terminated by the suppliers. The first contract was a 20 MW contract with Enron through December of 2001. The second contract, for 10 MW of baseload power, was with TECO and initially scheduled through September of 2006. Both companies paid premiums to Lakeland for the early termination of these contracts. As a result, Lakeland brought Larsen Unit No. 6 out of cold shutdown to meet its reliability requirements.

In 1999, the construction of McIntosh Unit No. 5 Simple Cycle combustion turbine was completed. The unit is in the final stages of extended check out and testing, and is scheduled to be released for commercial operation in May, 2001. The unit will be converted to a combined cycle unit by the addition of a steam turbine generator. Construction of the conversion began July 24, 2000. The scheduled commercial operation date for the combined cycle unit is January of 2002.

2.1.2 Transmission

The first phase of the Lakeland 69 kV transmission system was placed in operation in 1961 with a step-down transformer at the Lake Mirror Plant to feed the 4 kV bus, nine 4 kV feeders, and a new substation in the southwest section of town with two step-down transformers feeding four 12 kV feeders.

In 1966, a 69 kV line was completed from the northwest substation to the southwest substation, completing the loop around town. At the same time, the old tie to Bartow was reinsulated for a 69 kV line and placed in operation, feeding a new step-down substation in Highland City with four 12 kV feeders. In addition, a 69 kV line was completed from Larsen Plant around the southeast section of town to the southwest substation. By 1972, 20 sections of 69 kV lines, feeding a total of nine step-down substations, with a total of 41 distribution feeders, were completed and placed in service. By the fall of 1996, all of the original 4 kV equipment and feeders had been replaced and/or upgraded to 12 kV service. By 1998, 29 sections of 69 kV lines were in service feeding 20 distribution substations.

As the Lakeland system continued to grow, the need for additional and larger transmission facilities grew as well. In 1981, Lakeland's first 230 kV facilities went into service to accommodate Lakeland's McIntosh Unit No. 3 and to tie Lakeland into the State transmission grid at the 230 kV level. A 230 kV line was built from McIntosh Plant to Lakeland's west substation. A 230/69 kV autotransformer was installed at each of those substations to tie the 69 kV and 230 kV transmission systems together. In 1988, a second 230 kV line was constructed from the McIntosh Plant to Lakeland's Eaton Park substation along with a 230/69 kV autotransformer at Eaton Park. That line was the next phase of the long-range goal to electrically circle the Lakeland service territory with 230 kV transmission to serve as the primary backbone of the system.

In 1999, Lakeland added generation at its McIntosh Power Plant that resulted in a new 230/69/12kV substation being built and energized in March of that year. The substation, Tenoroc, replaced the switching station called North McIntosh. In addition to Tenoroc, another new 230/69/12kV substation was built. The substation, Interstate, went on line June of 1999 and is connected by what was the McIntosh West 230 kV line. This station was built to address concerns about load growth in the areas adjacent to the I-4 corridor which were causing problems at both the 69kV and distribution levels in this area.

Early transmission interconnections with other systems included a 69 kV tie at Larsen Plant with Tampa Electric Company (TECO), established in the mid 1960s. A second tie with TECO was later established at Lakeland's Highland City substation. A 115 kV tie was established in the 1970s with Florida Power Corporation (FPC) and Lakeland's west substation and was subsequently upgraded and replaced with the current two 230 kV lines to FPC in 1981. At the same time, Lakeland interconnected with Orlando Utilities Commission (OUC) at Lakeland's McIntosh Power Plant. In August 1987, the 69 kV TECO tie at Larsen Power Plant was taken out of service and a new 69 kV TECO tie was put in service connecting Lakeland's Orangedale substation to TECO's Polk City substation. In mid-1994, a new 69 kV line was energized connecting Larsen Plant to the Ridge Generating Station (Ridge), an independent power producer. Lakeland has a 30-year firm power-wheeling contract with Ridge to wheel up to 40 MW of their power to FPC. In early 1996, a new substation, East, was inserted in the Larsen Plant to the Ridge 69 kV transmission line. Later in 1996, the third tie line to TECO was built from East to TECO's Gapway substation. The multiple 230 kV interconnection configuration of Lakeland is also tied into the bulk transmission grid and provides access to the 500 kV transmission network via FPC, providing for greater reliability. At the present time, Lakeland has a total of approximately 108.6 miles of the 69 kV transmission and 18.3 miles of the 230 kV transmission lines in service along with five 150 MVA 230/69 kV autotransformers.

Table 2-1
Lakeland Electric and Water Utilities Existing Generating Facilities

Plant Name	Unit No.	Location	Unit Type[3]	Fuel[4] Pri	Fuel[4] Alt	Fuel Transport[5] Pri	Fuel Transport[5] Alt	Alt Fuel Days Use[2]	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen. Max. Nameplate kW	Net Capability Summer MW	Net Capability Winter MW
Charles Larsen Memorial	2	16-17/28S/24E	GT	NG	DFO	PL	TK	NR	11/62	Unknown	11,500	10	14
	3		GT	NG	DFO	PL	TK	NR	12/62	Unknown	11,500	10	14
	5		CA	WH	---	---	---	NR	04/56	Unknown	25,000	29	31
	6		ST	NG	RFO	PL	TK	NR	12/59	10/01	25,000	24	24
	7		ST	NG	RFO	PL	TK	NR	02/66	01/02	50,000	50	50
	8		CT	NG	DFO	PL	TK	NR	07/92	Unknown	101,520	73	93
Plant Total												196	226
C.D. McIntosh, Jr.	IC1	4-5/28S/24E	IC	DFO	---	TK	---	NR	01/70	Unknown	2,500	3	3
	IC2		IC	DFO	---	TK	---	NR	01/70	Unknown	2,500	3	3
	1GT		GT	NG	DFO	PL	TK	NR	05/73	Unknown	26,640	17	20
	ST1		ST	NG	RFO	PL	TK	NR	02/71	10/05	103,000	87	87
	ST2		ST	NG	RFO	PL	TK	NR	06/76	Unknown	126,000	103	103
	ST3[1]		ST	BIT	---	RR	---	NR	09/82	Unknown	363,870	205	205
Plant Total												418	421
System Total												614	647

[1]Lakeland's 60 percent portion of joint ownership with Orlando Utilities Commission.
[2]Lakeland does not maintain records of the number of days that alternate fuel is used.

[3]Unit Type
CA Combined Cycle Steam Part
CT Combined Cycle Combustion Turbine
GT Combustion Gas Turbine
ST Steam Turbine

[4]Fuel Type
DFO Distillate Fuel Oil
RFO Residual Fuel Oil
BIT Bituminous Coal
WH Waste Heat
NG Natural Gas

[5]Fuel Transportation Method
PL Pipeline
TK Truck
RR Railroad

Table 2-2
Lakeland Electric and Water Utilities
Existing Generating Facilities
Environmental Considerations for Steam Generating Units

Plant Name	Unit	Particulate	Flue Gas Cleaning SO_x	Flue Gas Cleaning NO_x	Type
Charles Larsen Memorial	6 7 8ST	None None N/A	None None N/A	None None N/A	OTF OTF OTF
C. D. McIntosh, Jr.	1 2 3	None None EP	None LS S	None FGR LNB	OTF WCTM WCTM

FGR = Flue gas recirculation
LNB = Low NO_x burners
EP = Electrostatic precipitators
LS = Low sulfur fuel
S = Scrubbed
OTF = Once-through flow
WCTM = Water cooling tower mechanical
N/A = Not applicable to waste heat applications

Source: Lakeland Environmental Staff

2.2 General Description: Lakeland Electric

2.2.1 Existing Generating Units

This section provides additional detail on Lakeland's existing units and transmission system. Lakeland's existing generating units are located at the two existing plant sites: Charles Larsen Memorial (Larsen) and C.D. McIntosh Jr. (McIntosh). Both plant sites are located on Lake Parker in Polk County, Florida. The two plants have multiple units with different technologies and fuel types. The following paragraphs provide a summary of the existing generating units for Lakeland. Table 2-1 summarizes the characteristics of the Lakeland generating units.

The Larsen site is located on the southeast shore of Lake Parker in Lakeland. The site has six existing units following the sale of Unit No. 1 to General Electric and its physical removal from the plant in 1998. The total net winter (summer) capacity of the plant is 226 MW (196 MW). Units 2 and 3 have a net winter (summer) rating of 14 MW (10 MW). These units burn natural gas as the primary fuel with diesel backup. Historically, Unit No. 5 consisted of a boiler for steam generation and steam turbine to convert the steam to electrical power. When the boiler began to show signs of degradation beyond economical repair, a gas turbine with a heat recovery steam generator, Unit No. 8, was added to the facility. This allowed the gas turbine (Unit No. 8) to generate electricity and the waste steam from the turbine to be injected to the Unit No. 5 steam turbine for a combined cycle configuration. The Unit No. 5 steam turbine now has a net winter (summer) rating of 31 MW (29 MW) and the Unit No. 8 combustion turbine has a net winter (summer) rating of 93 MW (73 MW). Unit No. 6 is a net 24 MW steam turbine burning natural gas that was placed in cold shutdown but was returned to service in 1998 due to the termination of the ENRON and TECO power purchase agreements. Unit No. 6 was slated for retirement in March 1999, but due to the delay of commercial operation of McIntosh Unit No. 5, Unit No. 6 remains in operation and is now scheduled for retirement in October, 2001. Unit No. 7 had been derated for several years due to boiler tube problems. The unit underwent significant boiler tube replacement in 1998 to bring the total net capacity of the unit up to 50 MW and is scheduled for retirement as part of a power sales agreement in January of 2002.

The McIntosh site is located in the City of Lakeland along the northeastern shore of Lake Parker and encompasses 513 acres. Electricity generated by the McIntosh units is stepped up in voltage by generator step-up transformers to 69 kV and 230 kV for transmission via the power grid. The McIntosh site currently includes six units in commercial operation having a total net winter and summer capacity of 421 MW and 418 MW, respectively. Unit CT1 consists of a General Electric combustion turbine with a net winter (summer) output rating of 20 MW (17 MW). Unit No. 1 is a natural gas/oil fired General Electric steam turbine with a net winter and summer output of 87 MW. Unit No. 2 is a natural gas/oil fired Westinghouse steam turbine with a winter and summer output of 103 MW. Unit No. 3 is a pulverized coal (primary fuel) fired unit owned 60 percent by Lakeland and 40 percent by OUC. Lakeland's share of the unit yields net winter and summer output of 205 MW. Unit No. 3 includes a wet flue gas scrubber for SO_2 removal and uses treated sewage water for cooling water. Two small diesel units with a net output of 3 MW each are also located at the McIntosh site.

Construction of Lakeland's seventh unit at McIntosh (Unit No. 5) is complete. The unit, a Westinghouse 501G combustion turbine, is scheduled for commercial operation May, 2001. The combustion turbine unit is expected to have a net output of 268 MW (221 MW) in the winter (summer) and will burn natural gas as the primary fuel. The unit has a guaranteed full load heat rate of 9,684 Btu/kWh higher heating value (HHV). This unit will be converted to combined cycle in January 2002. The McIntosh Unit No. 5 conversion has been approved by the FPSC and will consist of adding a heat recovery steam generator (HRSG) with new stack, a steam turbine, electrical generator, cooling tower and condenser, and associated balance-of-plant equipment.

2.2.2 Capacity and Power Sales Contracts

Lakeland had two firm power sales contracts in place as of December 31, 2000. The first contract was with TEA for a 25 MW power sale from the Larsen Unit 7. The term of this transaction was from January 1, 1999 through February 28, 2001. The second power sales contract is with the Florida Municipal Power Agency (FMPA) for capacity and energy. The contract is for 50 MW from December 15, 2000 to June 14, 2001; then 100 MW from June 15, 2001 through December 15, 2010.

Lakeland also shares ownership of the C. D. McIntosh Unit 3 with OUC. The ownership breakdown is a 60 percent share for Lakeland and a 40 percent ownership share for OUC. The energy and capacity delivered to OUC from McIntosh Unit 3 is not considered a power sales contract because of the OUC ownership share.

2.2.3 Capacity and Power Purchase Contracts

Lakeland currently has no power purchase contracts.

2.2.4 Planned Unit Retirements

Lakeland plans to retire older, less efficient units as new capacity comes on line and makes it economical to do so. These new additions will also produce the benefit of increased reliability and lower emissions on a kWh basis compared to the older generating units. Such retirements are consistent with Lakeland's strategic considerations for the future. Based on these considerations, Table 2-3 shows the units which are scheduled to be retired over the upcoming years based upon the expansion plan identified and pending FPSC approval of capacity additions.

Table 2-3
Planned Unit Retirements

Unit Name	Current Age (years)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Anticipated Retirement Date
Larsen 6	41	24	24	10/2001
Larsen 7	35	50	50	01/2002
McIntosh 1	30	87	87	10/2005

Larsen 6 - removed from cold shutdown to active duty in 1998 to replace the lost capacity from the Enron and TECO contracts - is scheduled for retirement after the summer peak of 2001 and when McIntosh 5 is in commercial operation. Larsen Unit 7 is scheduled to be retired in January of 2002. McIntosh Unit 1 is scheduled for retirement in October of 2005.

2.2.5 Total System Resources

Lakeland's total net capacity for the winter (the winter peak is in January) and summer of 2001 is estimated to be 647 MW and 835 MW, respectively. The total capacity includes the capacity from McIntosh Unit 5 which is expected to be in commercial operation in May of 2001. Of the total 647 MW of winter net capacity, 405 MW, or 63 percent, is gas fired. After McIntosh Unit 5 comes into commercial operation in 2001, 595 MW of the 835 MW of summer net capacity, or 71 percent, will be gas fired.

2.2.6 Load and Electrical Characteristics

Lakeland's load and electrical characteristics have many similarities with those of other peninsular Florida utilities. The peak demand has historically occurred during the winter months. Lakeland's actual total peak demand in the winter of 1999/00 was 661 MW, but was reduced to a net demand of 610 MW after accounting for 51 MW of residential load management. This peak occurred on January 27, 2000. The actual summer peak in 2000 was 552 MW and occurred on July 20, 2000. Lakeland's historical and projected summer and winter peak demands are presented in Section 3.0.

Lakeland is a member of the Florida Municipal Power Pool (FMPP), along with Orlando Utilities Commission (OUC), Florida Municipal Power Agency's (FMPA) All-Requirements Project, and Kissimmee Utility Authority (KUA). The FMPP operates as an hourly energy pool with all FMPP capacity from its four members committed and dispatched together. Commitment and dispatch services for FMPP are provided by OUC. Each member of the FMPP retains the responsibility of adequately planning its own system to meet native load and Florida Reliability Coordinating Council (FRCC) reserve requirements.

2.2.7 Transmission and Interconnections

Lakeland's electric system is interconnected with Florida Power Corporation (FPC) and Orlando Utilities Commission (OUC) via three 230 kV transmission lines, which connect to the West substation and McIntosh substation, respectively, and with Tampa Electric Company (TECO) via three 69 kV ties. In mid-1994, a new 69 kV tie-line was energized from the Larsen Plant to the Ridge Generating Station, an independent power producer. In early 1996, a new substation, East, was inserted in the Larsen Plant to Ridge 69 kV line. Later in 1996, the third tie line to TECO was built from East to TECO's Gapway substation. These ties are sufficient to support the electric system in a peak period. The multiple 230 kV interconnection configuration of Lakeland is also tied into the state bulk transmission grid and provides access to the 500 kV transmission network via FPC. This ultimately provides for greater reliability; however, Lakeland's system has sufficient internal generation to supply its requirements in a peak period independent of its ties. Figure 2-1 shows the Lakeland service territory and transmission facilities. In addition to these facilities, a 9.4 mile, 230 kV transmission line is proposed between Eaton Park and Crew's Lake. This line is projected to come into service in mid-2001.

At the present time, there are a total of twenty one 69/12 kV substations, feeding more than 90 circuits. Included in this total are six 12 kV feeders connected directly to the generator bus at Larsen Plant. Two of the 69/12 kV substations, West and Eaton Park, have a 230/69 kV autotransformer to tie the 69 kV system to Lakeland's internal 230 kV transmission system via the Tenoroc 230 kV switchyard which also has a 230/69 kV autotransformer. A fifth 230/69 kV autotransformer is located at the Interstate substation that also ties the 69 kV and 230 kV system together.

2.3 Service Area

Lakeland's electric service area is shown on Figure 2-1 and is entirely located in Polk County. Lakeland serves approximately 246 square miles including approximately 199 square miles outside of Lakeland's city limits.

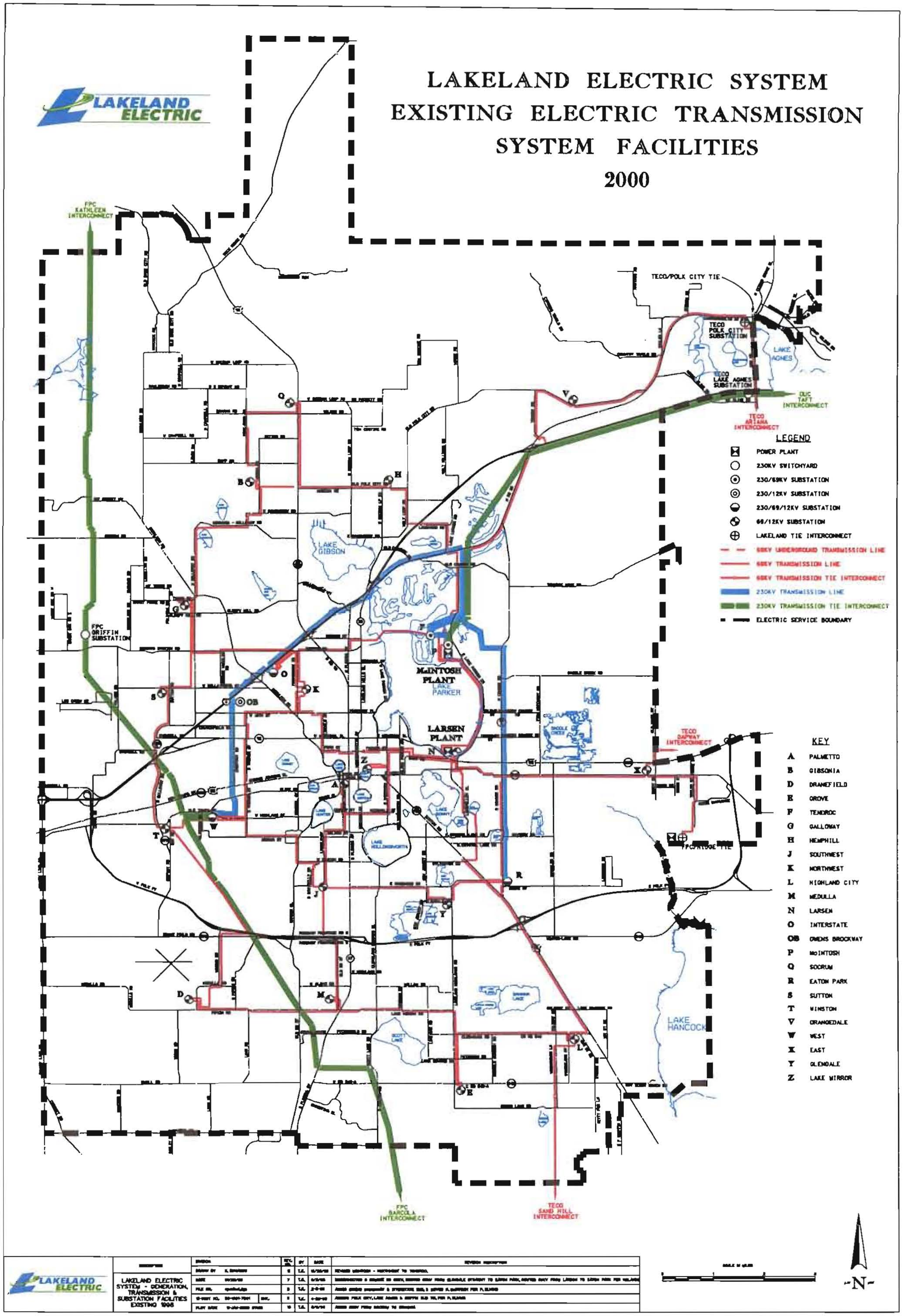

LAKELAND ELECTRIC SYSTEM
EXISTING ELECTRIC TRANSMISSION
SYSTEM FACILITIES
2000
LAKELAND ELECTRIC
FPC KATHLEEN INTERCONNECT
TECO/POLK CITY TIE
TECO POLK CITY SUBSTATION
TECO LAKE AGNES SUBSTATION
LAKE AGNES
OUC TAFT INTERCONNECT
TECO ARIANA INTERCONNECT
LAKE GIBSON
FPC GRIFFIN SUBSTATION
McINTOSH PLANT
LAKE PARKER
LARSEN PLANT
TECO DAPWAY INTERCONNECT
FPC/RIDGE TIE
LAKE HOLLINGSWORTH
SCOTT LAKE
LAKE HANCOCK
FPC BARCOLA INTERCONNECT
TECO SAND HILL INTERCONNECT
LEGEND
POWER PLANT
230KV SWITCHYARD
230/69KV SUBSTATION
230/12KV SUBSTATION
230/69/12KV SUBSTATION
69/12KV SUBSTATION
LAKELAND TIE INTERCONNECT
69KV UNDERGROUND TRANSMISSION LINE
69KV TRANSMISSION LINE
69KV TRANSMISSION TIE INTERCONNECT
230KV TRANSMISSION LINE
230KV TRANSMISSION TIE INTERCONNECT
ELECTRIC SERVICE BOUNDARY
KEY
A PALMETTO
B GIBSONIA
D DRANEFIELD
E GROVE
F TENOROC
G GALLOWAY
H HEMPHILL
J SOUTHWEST
K NORTHWEST
L HIGHLAND CITY
M MEDULLA
N LARSEN
O INTERSTATE
OB OWENS BROCKWAY
P McINTOSH
Q SOCRUM
R EATON PARK
S SUTTON
T WINSTON
V ORANGEDALE
W WEST
X EAST
Y GLENDALE
Z LAKE MIRROR
N
LAKELAND ELECTRIC
LAKELAND ELECTRIC SYSTEM - GENERATION, TRANSMISSION & SUBSTATION FACILITIES EXISTING 1998

Figure 2-1
Electric System Transmission Map

3.0 Forecast of Electrical Power Demand and Energy Consumption

Lakeland routinely develops a detailed long-term electric load and energy forecast for use in its long-term planning studies. The primary technique used is econometric although Lakeland also develops a short-term forecast for short-term budgeting and planning purposes using time-series decomposition models. Lakeland develops a detailed, long-term forecast for the following categories on a fiscal year basis, which ends on September 30.

- Service territory population
- Number of accounts
- Sales
- Net energy for load
- Summer peak demand
- Winter peak demand

The following sections discuss each of the forecast categories. The information is presented on a fiscal year basis and is aggregated per the requirements of the Florida Reliability Coordinating Council (FRCC).

3.1 Service Territory Population Forecast

The projections of service territory population utilize regression analysis techniques in which Polk County population and time were the independent variables. Lakeland's projection of Polk County population was adopted from the 1998 Annual Bureau of Economic and Business Research (BEBR). The historical service territory population was derived by using the residential accounts inside and outside the city and multiplying by the number of persons per household from the 1994 Appliance Saturation Survey.

The resulting forecast projects the service territory population to increase at a 1.37 percent average annual growth rate (AAGR) from 2001 through 2020. The historical and forecast service area population estimates are shown in Table 3-1.

3.2 Number of Accounts Forecast

Lakeland forecasts the number of accounts in the following categories:

- Residential
- Commercial:
  - General Service
  - General Service Demand

- Industrial:
  - General Service Large Demand
- Street & Highway Lighting:
  - Private Area Lighting
  - Unmetered
- Other:
  - Electric
  - Water
  - Municipal

For residential, commercial, and industrial accounts, projections are developed for inside and outside the city. The following sections describe the projections, which are presented in Table 3-1.

3.2.1 Residential Accounts

The residential account projection for inside the city was based on a combination of analyses including a regression model using the Polk County Population (PCP) as the independent variable, historical growth rates, and historical ratios of residential accounts to PCP. The residential account projection for outside the city was based on similar analyses. The projection of the total number of residential accounts was a summation of the residential inside and outside the city account projections. The projected AAGR for residential accounts is 1.32 percent for the 2001 through 2020 period. Historical and projected residential accounts are presented in Table 3-1.

3.2.2 Commercial and Industrial Accounts

The General Service (GS) account projection for both inside and outside the city was based on historical trends. The total General Service account projection is the sum of the General Service account projections for inside and outside the city. Historical trends were also analyzed to develop the inside and outside the city projections for General Service Demand (GSD) accounts. The total General Service Demand accounts is the summation of the inside and outside the city General Service Demand accounts.

The General Service Large Demand (GSLD) account projection for inside the city was based on historical relationships between GSLD accounts to PCP, residential accounts to GSLD accounts, GS accounts to GSLD accounts, and GSD accounts to GSLD accounts. The historical trend between GSLD accounts outside to residential accounts outside was used to develop the GSLD outside the city account projection. The total GSLD is the summation of the GSLD inside and outside the city accounts.

The commercial and industrial customer forecasts are presented in Table 3-1. The number of commercial and industrial customers is projected to increase at an AAGR of 1.32 and 1.35 percent, respectively, from 2001 through 2020.

Table 3-1
Forecast of Total Accounts and Sales For Lakeland

Fiscal Year	Service Territory Population	Rural and Residential			Commercial		
		GWh	Average No. of Customers	kWh/Cust	GWh	Average No. of Customers	kWh/Cust
1991	189,445	967	76,731	12,602	522	9,517	54.849
1992	198,763	987	77,863	12,676	526	9,664	54,429
1993	201.748	1,026	79,738	12,867	542	9,768	55.487
1994	206.040	1,080	81,542	13,245	574	9,967	57,590
1995	210.095	1,169	82,616	14,150	594	9,999	59,406
1996	213,347	1,201	84,089	14,282	589	9,729	60,541
1997	216,782	1,173	84,149	13,940	609	9,816	62,042
1998	218,959	1,254	86,340	14,529	634	10,127	62,644
1999	221,921	1,237	87,955	14,064	641	10,916	58,721
2000	225,558	1,274	88,813	14,345	708	11,085	63.870
Forecast							
2001	229,467	1,299	89,806	14,465	721	11,208	64,329
2002	233,047	1,331	91,127	14,606	739	11,373	64,978
2003	236,620	1,363	92,446	14,744	757	11,538	65,609
2004	240.167	1,395	93,757	14,879	774	11,702	66,143
2005	243,674	1,427	95,065	15,011	793	11,865	66,835
2006	247,221	1,460	96,384	15,148	810	12,029	67,337
2007	250,757	1,492	97,703	15,271	828	12,194	67.902
2008	254.295	1,525	99,026	15,400	847	12,359	68,533
2009	257.857	1,557	100,360	15,514	864	12,526	68.977
2010	261.441	1,589	101,700	15,624	882	12,693	69,487
2011	265.001	1,622	103,037	15,741	900	12,860	70,023
2012	268.558	1,654	104,374	15,851	919	13,027	70,514
2013	272.114	1,687	105,714	15,959	937	13,194	70,992
2014	275.671	1,720	107,057	16,063	955	13,361	71,458
2015	279.228	1,753	108,402	16,169	973	13,529	71,929
2016	282.785	1.785	109,750	16,267	991	13,694	72,383
2017	286.341	1.818	111,100	16,362	1,009	13,866	72,789
2018	289.898	1,851	112,453	16.460	1,028	14.035	73,222
2019	293.455	1,884	113,807	16,550	1,046	14,204	73.624
2020	297.012	1.917	115.132	16.647	1,064	14,369	74,057
AAGR 2001-2020	1.37%	2.07%	1.32%	0.74%	2.07%	1.32%	0.74%

Table 3-1 (Continued)
Forecast of Total Accounts and Sales For Lakeland

Fiscal Year	Industrial GWh	Industrial Average No. of Cust.	Industrial kWh/Cust	Street and Highway Lighting GWh	Other Sales to Public Authorities GWh	Total Sales to Ultimate Consumers GWh	Utility Use and Losses GWh	NEL GWh
1991	344	45	7,644,444	11	61	1,905	138	2,043
1992	356	47	7,574,468	13	65	1,947	143	2,090
1993	381	51	7,470,588	13	68	2,030	155	2,185
1994	400	51	7,843,137	14	69	2,137	146	2,283
1995	427	51	8,372,549	15	74	2,279	146	2,425
1996	436	59	7,389,831	15	78	2,319	116	2,435
1997	459	61	7,524,590	16	78	2,335	115	2,450
1998	474	62	7,645,161	17	80	2,460	132	2,592
1999	486	80	6,075,000	17	82	2,463	112	2,575
2000	532	85	6,258,824	18	11	2,543	166	2,709
Forecast								
2001	542	86	6,302,326	19	10	2,591	155	2,746
2002	556	88	6,318,182	19	10	2,655	159	2,814
2003	569	89	6,393,258	19	11	2,719	163	2,882
2004	583	90	6,477,778	20	11	2,783	167	2,950
2005	596	91	6,549,451	21	11	2,848	170	3,018
2006	610	93	6,559,140	21	11	2,912	175	3,087
2007	623	94	6,627,660	22	12	2,977	178	3,155
2008	636	95	6,694,737	22	12	3,042	182	3,224
2009	650	96	6,770,833	23	12	3,106	187	3,293
2010	664	98	6,775,510	23	13	3,171	190	3,361
2011	678	99	6,843,566	23	13	3,236	194	3,430
2012	691	100	6,911,219	24	13	3,301	198	3,499
2013	705	102	6,909,125	24	13	3,366	202	3,568
2014	718	103	6,974,172	25	13	3,431	206	3,637
2015	732	104	7,039,980	25	14	3,497	209	3,706
2016	746	105	7,102,541	26	14	3,562	213	3,775
2017	759	107	7,096,969	26	14	3,627	258	3,885
2018	773	108	7,159,203	27	14	3,693	221	3,914
2019	787	109	7,218,375	27	15	3,758	226	3,984
2020	801	111	7,212,803	28	15	3,824	229	4,053
AAGR 2001-2020	2.07%	1.35%	0.71%	2.02%	2.12%	2.07%	2.08%	2.07%

3.3 Sales Forecast

Lakeland develops energy sales forecasts for each of the account categories presented in Section 3.2.

3.3.1 Residential Sales

The total residential sales were forecast using a regression model with year, heating degree-days, and real per capital income as the independent variables. Residential sales are projected to have an AAGR of 2.07 percent from 2001 through 2020 and are presented in Table 3-1. Residential sales projections inside the city were based on a regression model using year, population, heating and cooling degree days, and real per capita income as the independent variables. Residential sales outside the city were based on the difference between total residential sales and sales inside the city.

3.3.2 Commercial and Industrial Sales

Total General Service sales are the sum of General Service sales inside and outside the city. Projections of commercial and industrial sales inside the city were based on a regression model using employment and heads of households as the independent variables. General Service sales outside the city were based on a regression model using General Service accounts outside the city and population as the independent variables.

The total General Service Demand sales are the summation of the inside and outside General Service Demand sales. General Service Demand sales projections inside the city were based on a regression model using General Service Demand accounts inside and employment as the independent variables. The General Service Demand sales outside the city were based on a regression model using population and real per capita income as the independent variables.

Total General Service Large Demand Sales projections were based on a regression model using real per capita income and population as the independent variable. General Service Large Demand sales projections inside the city were based on a regression model using heads of households and real per capita income as the independent variables. General Service Large Demand sales outside the city are the difference between the Total General Service Large Demand sales and total General Service Large Demand sales inside the city.

Commercial and industrial sales each have a projected AAGR of 2.07 percent for the 2001 through 2020 period, and are presented in Table 3-1.

3.3.3 Other Sales

Municipal sales projections were based on a regression model using year and real per capita income as the independent variables. Water sales were projected using a weighted average of the ratio of water sales to municipal sales and a trend projection. Projections were based on a historical trend using Polk County population. Electric sales projections were based on a ratio of electric sales to municipal sales.

Private Area Lighting inside sales were based on a regression model using private area light accounts and residential accounts inside as the independent variables. Private Area Lighting outside sales were based on a regression model using year as the independent variable. Unmetered sales are those derived from municipal lighting.

Street and highway lighting and other sales have projected AAGRs of 2.02 and 2.12 percent, respectively, for the 2001 through 2020 period and are presented in Table 3-1.

3.3.4 Total Sales

The total sales forecast for the City of Lakeland is a summation of the individual forecasts provided above. Summation of total sales indicates an AAGR of 2.07 percent from 2001 through 2020. This is a lower growth rate than experienced in the past. A 3.26 percent AAGR was experienced over the last 10 years of historical sales. Historical and projected total sales are presented in Table 3-1.

3.4 Net Energy for Load Forecast

Net energy for load is defined as the net electricity generation by a system's own plants, plus energy purchased from others, less the energy delivered for resale to their systems. Lakeland projects the growth rate for total percentage of system energy losses to remain relatively constant. Lakeland's projection of net energy for load includes the effect of energy conservation programs.

The forecasted net energy for load on a calendar year basis, including conservation, for the base case is summarized in Table 3-1. The projected AAGR for the base case is 2.07 percent for the 2001 through 2020 period. The projected AAGR represents a reduction from the historical AAGR of 3.19 percent for the last 10 years.

3.5 Peak Demand

Lakeland uses regression analysis to forecast electric system winter and summer season peak demands for each year. The winter season is defined as November through March and the summer season is defined as April through October. Standard deviations for the sensitivities were calculated within a 95 percent probability interval for sets of historical data related to winter and summer peaks. The results indicated a base temperature for winter to be 29.66 degrees Fahrenheit. The results indicated a base temperature for summer to be 98.7 degrees Fahrenheit.

Projections of the coincident demand for customers served on the interruptible rate were developed and applied to reduce the projection of total peak demand. Projections of the effect of Lakeland's load management program were likewise developed and applied to reduce the projection of total peak demand.

Projections of the resultant winter and summer peak demand for the base case are included in Tables 3-2 and 3-3, respectively. The projected AAGR for the winter peak demand for the base case after reductions for conservation and interruptible load for the period 2002 through 2020 is 2.29 percent. The projected AAGR for the summer peak demand for the base case after reductions for conservation and interruptible load for the period 2001 through 2020 is 2.21 percent.

Table 3-2
Winter Peak Demand – Base Case (MW)

Calendar Year	Forecast	Interruptible	Conservation	Forecast Less Conservation Only	Forecast Less Interruptible Only	Forecast Less Conservation and Interruptible
2000/2001						655
2001/2002	691	12	52	639	679	627
2002/2003	708	12	52	656	696	644
2003/2004	727	12	53	674	715	662
2004/2005	745	13	53	692	732	679
2005/2006	764	13	54	710	751	697
2006/2007	781	13	54	727	768	714
2007/2008	800	13	55	745	787	732
2008/2009	817	13	55	762	804	749
2009/2010	836	13	56	780	823	767
2010/2011	853	13	56	797	840	784
2011/2012	872	13	57	815	859	802
2012/2013	889	13	57	832	876	819
2013/2014	909	14	58	851	895	837
2014/2015	926	14	58	868	912	854
2015/2016	945	14	59	886	931	872
2016/2017	962	14	59	903	948	889
2017/2018	981	14	60	921	967	907
2018/2019	999	14	60	939	985	925
2019/2020	1,017	14	61	956	1,003	942
AAGR 2001-2020	2.17%	0.86%	0.89%	2.26%	2.19%	2.29%

Table 3-3
Summer Peak Demand – Base Case (MW)

Calendar Year	Forecast	Interruptible	Conservation	Forecast Less Conservation Only	Forecast Less Interruptible Only	Forecast Less Conservation and Interruptible
2001	584	14	21	563	570	549
2002	600	14	22	578	586	564
2003	615	14	22	593	601	579
2004	629	14	22	607	615	593
2005	644	14	22	622	630	608
2006	660	14	23	637	646	623
2007	676	15	23	653	661	638
2008	691	15	23	668	676	653
2009	706	15	23	683	691	668
2010	722	15	24	698	707	683
2011	737	15	24	713	722	698
2012	751	15	24	727	736	712
2013	766	15	24	742	751	727
2014	782	15	25	757	767	742
2015	798	16	25	773	782	757
2016	813	16	25	788	797	772
2017	829	16	26	803	813	787
2018	844	16	26	818	828	802
2019	859	16	26	833	843	817
2020	873	16	26	847	857	831
AAGR 2001-2020	2.14%	0.71%	1.13%	2.17%	2.17%	2.21%

3.6 Sensitivity Cases

Lakeland has conducted two sensitivity cases to the base case load forecast, reflecting a high load growth case and a low load growth case. These two sensitivity cases provide a band across which Lakeland can evaluate potential power supply planning alternatives and test the robustness of the base case against higher or lower load growth.

Standard deviations for the sensitivities were calculated within a 95 percent probability interval for sets of historical data related to winter and summer peaks. The results indicated a base temperature for winter to be 29.66 degrees Fahrenheit. The winter results indicated a base temperature for summer to be 98.7 degrees Fahrenheit.

3.6.1 High Load Sensitivity

The high load forecasts for demand and energy were based on a summer temperature of 104.1 degrees, and a winter temperature of 19.47 degrees, Fahrenheit. The high load forecast has an AAGR of 2.00 and 2.22 percent for winter and summer peak demand after reductions for conservation and interruptible load. Tables 3-4 and 3-5 display the winter and summer peak demand forecast and net energy for load for the planning horizon for the high load sensitivity.

3.6.2 Low Load Sensitivity

The low load forecasts for demand and energy were based on a summer temperature of 93.341 degrees, and a winter temperature of 39.847 degrees, Fahrenheit. The low load forecast has an AAGR of 2.78 and 2.17 percent for winter and summer peak demand after reductions for conservation and interruptible load. Tables 3-5 and 3-6 display the winter and summer peak demand forecasts and net energy for load for the planning horizon for the low load sensitivity.

3.6.2 High and Low Net Energy for Load

Based on Lakeland's 95 percent confidence interval, Lakeland developed a banded high and low net energy for load forecast. The high and low forecast was developed using the 2.5 percent interval on either side of the confidence interval. This is expected to catch possible variations in either direction.

Table 3-4
Winter Peak Demand – High Load (MW)

Calendar Year	Forecast	Interruptible	Conservation	Forecast Less Conservation Only	Forecast Less Interruptible Only	Forecast Less Conservation and Interruptible
2000/2001[1]						
2001/2002	798	12	52	746	786	734
2002/2003	816	12	52	764	804	752
2003/2004	834	12	53	781	822	769
2004/2005	853	13	53	800	840	787
2005/2006	871	13	54	817	858	804
2006/2007	889	13	54	835	876	822
2007/2008	907	13	55	852	894	839
2008/2009	925	13	55	870	912	857
2009/2010	943	13	56	887	930	874
2010/2011	961	13	56	905	948	892
2011/2012	979	13	57	922	966	909
2012/2013	997	13	57	940	984	927
2013/2014	1,016	14	58	958	1,002	944
2014/2015	1,034	14	58	976.	1,020	962
2015/2016	1,052	14	59	993	1,038	979
2016/2017	1,070	14	59	1,011	1,056	997
2017/2018	1,086	14	60	1,026	1,072	1,012
2018/2019	1,106	14	60	1,046	1,092	1,032
2019/2020	1,124	14	61	1,063	1,110	1,049
AAGR 2001-2020	1.92%	0.86%	0.89%	1.99%	1.94%	2.00%

1. Demand projection for the 2000/2001 winter season is not shown since it has passed.

Table 3-5
Summer Peak Demand – High Load (MW)

Calendar Year	Forecast	Interruptible	Conservation	Forecast Less Conservation Only	Forecast Less Interruptible Only	Forecast Less Conservation and Interruptible
2001	592	14	21	571	578	557
2002	608	14	22	586	594	572
2003	623	14	22	601	609	587
2004	638	14	22	616	624	602
2005	653	14	22	631	639	617
2006	670	14	23	647	656	633
2007	686	15	23	663	671	648
2008	701	15	23	678	686	663
2009	716	15	23	693	701	678
2010	732	15	24	708	717	693
2011	747	15	24	723	732	708
2012	763	15	24	739	748	724
2013	778	15	24	754	763	739
2014	794	15	25	769	779	754
2015	810	16	25	785	794	769
2016	825	16	25	800	809	784
2017	842	16	26	816	826	800
2018	857	16	26	831	841	815
2019	872	16	26	846	856	830
2020	887	16	26	861	871	845
AAGR 2001-2020	2.15%	0.71%	1.13%	2.19%	2.18%	2.22%

Table 3-6
Winter Peak Demand – Low Load (MW)

Calendar Year	Forecast	Interruptible	Conservation	Forecast Less Conservation Only	Forecast Less Interruptible Only	Forecast Less Conservation and Interruptible
2000/2001[1]						
2001/2002	558	12	52	506	546	494
2002/2003	575	12	52	523	563	511
2003/2004	594	12	53	541	582	529
2004/2005	612	13	53	559	599	546
2005/2006	631	13	54	577	618	564
2006/2007	648	13	54	594	635	581
2007/2008	667	13	55	612	654	599
2008/2009	684	13	55	629	671	616
2009/2010	703	13	56	647	690	634
2010/2011	720	13	56	664	707	651
2011/2012	739	13	57	682	726	669
2012/2013	757	13	57	700	744	687
2013/2014	776	14	58	718	762	704
2014/2015	794	14	58	736	780	722
2015/2016	812	14	59	753	798	739
2016/2017	830	14	59	771	816	757
2017/2018	848	14	60	788	834	774
2018/2019	866	14	60	806	852	792
2019/2020	884	14	61	823	870	809
AAGR 2001-2020	2.59%	0.86%	0.89%	2.74%	2.62%	2.78%

1. Demand projection for the 2000/2001 winter season is not shown since it has passed.

Table 3-7 Summer Peak Demand – Low Load (MW)						
Calendar Year	Forecast	Interruptible	Conservation	Forecast Less Conservation Only	Forecast Less Interruptible Only	Forecast Less Conservation and Interruptible
2001	568	14	21	547	554	533
2002	583	14	22	561	569	547
2003	597	14	22	575	583	561
2004	611	14	22	589	597	575
2005	625	14	22	603	611	589
2006	640	14	23	617	626	603
2007	656	15	23	633	641	618
2008	670	15	23	647	655	632
2009	684	15	23	661	669	646
2010	699	15	24	675	684	660
2011	713	15	24	689	698	674
2012	727	15	24	703	712	688
2013	741	15	24	717	726	702
2014	757	15	25	732	742	717
2015	772	16	25	747	756	731
2016	786	16	25	761	770	745
2017	801	16	26	775	785	759
2018	815	16	26	789	799	773
2019	829	16	26	803	813	787
2020	844	16	26	818	828	802
AAGR 2001-2020	2.11%	0.71%	1.13%	2.14%	2.14%	2.17%

Table 3-8
Net Energy for Load (MWh)

Calendar Year	Low	Base	High
2001	2,655,815	2,746,192	2,833,689
2002	2,671,900	2,813,947	2,949,165
2003	2,701,193	2,881,745	3,051,652
2004	2,736,808	2,949,667	3,148,197
2005	2,776,753	3,018,100	3,241,572
2006	2,819,698	3,086,847	3,332,712
2007	2,864,510	3,155,389	3,421,713
2008	2,910,884	3,223,856	3,509,126
2009	2,958,768	3,292,504	3,595,520
2010	3,007,859	3,361,237	3,680,993
2011	3,057,943	3,429,994	3,765,630
2012	3,109,002	3,498,889	3,849,684
2013	3,160,880	3,567,868	3,933,176
2014	3,213,507	3,636,933	4,016,197
2015	3,266,814	3,706,086	4,098,804
2016	3,320,743	3,775,326	4,181,050
2017	3,375,243	3,844,649	4,262,975
2018	3,430,284	3,914,063	4,344,625
2019	3,485,816	3,983,564	4,426,023
2020	3,541,634	4,052,941	4,506,967
AAGR 2001-2020	1.61%	2.07%	2.61%

4.0 Demand-Side Management Programs

Lakeland Electric is committed to reducing system demand and promoting more efficient use of electric energy to the extent to which it is cost-effective for all its consumers. Lakeland has in place several cost-effective Demand-Side Management (DSM) programs and is continuing to pursue additional cost-effective conservation and DSM programs. Presented in this section are the existing programs and the description of additional programs under evaluation. Further details can be found in Lakeland's Demand-Side Management Plan for Docket No. 930556-EG, which is on file with the Florida Public Service Commission.

This section also includes a brief description of Lakeland's advances in solar technology. Lakeland has assumed a leadership position in the deployment and commissioning of numerous solar energy devices and has established their reputation as a pro-solar electric utility.

4.1 Existing Conservation and Demand-Side Management Programs

Lakeland has several existing conservation and demand-side management programs that are currently available and address three major areas of demand-side management:

- Reduction in weather sensitive peak loads.
- Reduction of energy needs on a per customer basis.
- Movement of energy to off-peak hours when it can be generated at a lower cost.

The programs can be divided into two groups: those programs with demonstrable demand and energy savings and programs in which the impact of demand and energy savings cannot be directly measured.

4.1.1 Existing Programs with Demonstrable Demand and Energy Savings

Lakeland has several programs that demonstrate demand and energy savings for the system. The following are programs that are in place currently:

- Residential Programs:
  - SMART Load Management Program.
  - Loan Program.
- Commercial Programs:
  - Commercial Lighting Program.
  - Thermal Energy Storage Program.
  - High-Pressure Sodium Outdoor Lighting Program.

4.1.1.1 Residential Programs.

4.1.1.1.1 SMART Load Management Program. In 1981, Lakeland began the Load Management Program. The program focused on the direct load control of electric water heaters to reduce peak demand. The program was changed in 1990 to cyclically control heating, air conditioning, and ventilation systems, combined with continuous control of water heating. This change came about as newer, more cost-effective control technologies became available. This made control of HVAC systems cost-effective along with continued control of hot water heaters.

Lakeland required all new residential construction projects to have mandatory controls when the program was expanded. Lakeland has since relaxed the mandatory portion of the program for new customers due to diminished cost-effectiveness of the program. The program remains as a voluntary program which is still enjoying good response from its customers and continued demand savings. The SMART program is projected to reduce winter peak demand by 1 kW per account from each water heater control and 1.2 kW per account from control of HVAC systems.

4.1.1.1.2 Loan Program. Lakeland is the administrator for the Loan Program which provides assistance to customers to improve their home's thermal efficiency by upgrading strip heat and split type heating systems to more efficient and economical heat pumps. This program also covers additional insulation and caulking when the customer upgrades their heating system. This is accomplished through a secured utility subsidized, 8 percent low interest loan for 5 years provided through a specific local bank. This program is projected to save 844 kWh per account annually. In December of 1999 Lakeland decided to stop the current Loan Program while it evaluates how best to proceed with the program in the future.

4.1.1.2 Commercial Programs.

4.1.1.2.1 Commercial Lighting Program. The Commercial Lighting Program began in 1996 to enhance/maintain customer lighting levels while reducing the facility's associated energy needs. Commercial/Industrial account managers, in conjunction with energy consultants, perform a thorough lighting audit and provide customers with up-to-date lighting efficiency standards from the Florida Building Code and Federal Energy Policy Act of 1992. Customers are shown that through the installation of energy efficient fixtures these goals can be realized. Account managers also show how quickly a lighting investment can be paid back based on associated energy savings.

4.1.1.2.2 Thermal Energy Storage Program. The Thermal Energy Storage (TES) Program has provided Lakeland's commercial and industrial customers an effective method of transferring cooling and heating requirements to off-peak time periods. This is accomplished through TES systems that are on par in efficiency with standard systems. Lakeland is implementing two rate tariffs which are designed for load shift technologies, such as TES. This provides further economic incentive for customers to switch to TES technologies.

4.1.1.2.3 High-Pressure Sodium Outdoor Lighting Program. This program is structured to reduce lighting demands through the replacement of mercury vapor streetlights with more energy efficient high-pressure sodium (HPS) lights. The HPS lights reduce energy consumption while maintaining the same level of lighting.

Currently, all streetlights within the city limits are now high-pressure sodium bulbs. Private area lights will continue to be replaced as time allows, while all new lighting will use the HPS lights.

4.1.2 Non-Measurable Demand and Energy Savings

The programs outlined in this section cannot directly be measured in terms of demand and energy savings, but are very important in that they have been shown to influence public behavior and thereby help reduce energy requirements. Lakeland considers the following programs to be important part of its objective to cost-effectively reduce energy consumption:

- Residential Programs:
  - Energy Audit Program.
  - Public Awareness Program.
  - Mobile Display Unit.
  - Speakers Bureau.
  - Informational Bill Inserts.
- Commercial Programs:
  - Commercial Audit Program.

4.1.2.1 Residential Programs.

4.1.2.1.1 Residential Energy Audits. The Energy Audit Program promotes high energy-efficiency in the home and gives the customer an opportunity to learn about other utility conservation programs. The program provides Lakeland with a valuable customer interface and a good avenue for increased customer awareness.

4.1.2.1.2 Public Awareness Program. Lakeland believes that an informed public aware of the need to conserve electricity is the greatest conservation resource. Lakeland's public awareness programs provide customers with information to help them reduce their electric bills by being more conscientious in their energy use.

4.1.2.1.3 Mobile Display Unit. The mobile display unit is presented at a number of area activities each year, including the Engineering Expo held at the University of South

Florida, the Polk County Home Show, and numerous school engagements through the year. The display centers on themes of energy and water conservation, including electric safety.

4.1.2.1.4 Speakers Bureau. Lakeland provides speakers to local group meetings to help inform the public of new energy efficiency technologies and ways to conserve energy in the commercial and residential sectors.

4.1.2.1.5 Informational Bill Inserts. Monthly billing statements provide an excellent avenue for communicating timely energy conservation information to its customers. In this way, Lakeland conveys the message of better utilizing their electric resources on a regular basis in a low cost manner.

4.1.2.2 Commercial Programs.

4.1.2.2.1 Commercial Energy Audits. The Lakeland Commercial Audit Program includes educating customers about high efficiency lighting and thermal energy storage analysis for customers to consider in their efforts to reduce costs associated with their electric usage.

4.1.3 Demand-Side Management Technology Research

Lakeland has made a commitment to study and review promising technologies in the area of conservation and demand-side management. Some of these efforts are summarized below.

4.1.3.1 Direct Expansion Ground Source Heat Pump Study.

In cooperation with ECR Technologies of Lakeland, Lakeland Electric was given the Governor's Energy Award for work in the evaluation and analysis of direct expansion ground source heat pump (GSHP) technology. This technology will reduce weather sensitive loads and promote greater energy efficiency for Lakeland's system. A study of the demand and energy savings associated with this technology was completed in an effort to establish its cost-effectiveness for new construction, as well as retrofitting the technology to existing homes. The original units were installed nearly ten years ago and are still in service. There is little customer interest due to the cost of the units. Currently, no new sites are being developed.

4.1.3.2 Whole House Demand Controller Study.

The concept of this technology is to control multiple appliances in the customer's home. If demand on the utility were to exceed a pre-set level, no additional appliances would be allowed to turn on. There was no customer interest in this program. A large amount of information is maintained by Lakeland for this technology and will be monitored for changes in its effectiveness.

4.1.3.3 Time-of-Day Rates.

Lakeland is currently offering a time of day program and plans to continue as this makes consumers aware of the variation in costs during the day. To date, there has been limited interest by Lakeland's customers in this demand-side management program.

4.2 Solar Program Activities

Lakeland Electric views solar energy devices as distributed generators whether they interconnect to the utility grid or not. As such they can potentially fill the much-desired role that an electric utility needs to avoid future costs of building new (and/or re-working existing) distribution systems.

4.2.1 Solar Powered Street Lights.

Distributed generation produces the energy in end use form at the point of load by the customer, thereby eliminating many of the costs, wastes, pollutants, environmental degradation, and other objections to central station generation.

Solar powered streetlights offer a reliable, cost-effective solution to remote lighting needs. As shown in Figure 4-1, they are completely self-contained, with the ability to generate DC power from photovoltaic modules and batteries. During daylight hours solar energy is stored in the battery bank used to power the lights at night. By installing these self sufficient, stand-alone solar lighting products, Lakeland Electric was able to avoid the construction costs related to expansion of its distribution system into remote areas. These avoided costs are estimated to be approximately $20,000. It is Lakeland's stated desire to continue to install solar area-lighting products where similar circumstances exist.

Lakeland currently has 20 solar powered streetlights that are in service. Each of these lights replace a traditional 70 watt fixture that Lakeland typically would use in this type of application and displaces the equivalent amount of energy that the 70 watt fixture would use on an annual basis. The primary application for this type of lighting is for remote areas as stated above. Lakeland installed these 20 lights in mid-1994 in a grant program with the cooperation of the Florida Solar Energy Center (FSEC). Lakeland is continuing to collect operational and maintenance data to further assess the long-term cost-effectiveness, maintenance needs, and reliability of this type of lighting.

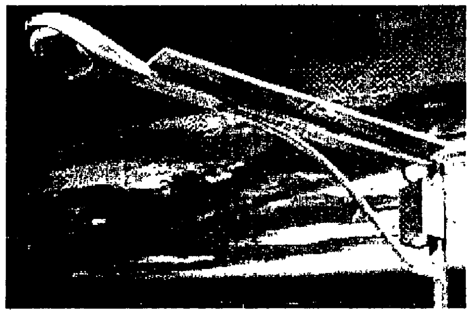


Figure 4-1
Solar Powered Streetlight

4.2.2 Solar Thermal Collectors for Water Heating.

The most effective application for solar energy is the heating of water for domestic use. Solar water heating provides energy directly to the end-user and results in a high level of end-user awareness. The sun's energy is stored directly in the heated water itself, reducing the effect of converting the energy to other forms.

Lakeland presently owns and operates 29 solar water heaters. These units are installed on the roofs of residential customers' homes, i.e. – at the point of consumption. Since this method of energy delivery bypasses the entire transmission and distribution system, there are other benefits than only avoided generation costs.

In Lakeland's program, each solar water heater remains the property of the utility, thereby allowing the customer to avoid the financial cost of the purchase. Lakeland's return on this investment is realized through the sale of the solar generated energy as a separate line item on the customer's monthly bill. This energy device is monitored by using a utility-utility Btu meter calibrated to read in kWh.

One of the purposes of this program is to demonstrate that solar thermal energy can be accurately metered and profitably sold to the everyday residential end-user of hot water. Lakeland Electric's fleet of 29 solar thermal energy generators displace approximately 3,000 kWh per year per installation on average. Lakeland plans to add an additional 30 units during the year 2001.

4.2.3 Utility-Interactive Residential Photovoltaic Systems

This project is a collaborative effort between the Florida Energy Office (FEO), FSEC, the Lakeland, and Siemens Solar Industries. The primary objectives of this program are to develop approaches and designs that integrate photovoltaic (PV) arrays into residential buildings, and to develop workable approaches to interconnection of PV systems into the utility grid. Lakeland currently has 20 PV systems installed and operating, all of which are directly interconnected to the utility grid. These systems have an average nominal power rating of approximately 2 kilowatts peak (kWp) and are displacing approximately 2000 kWh per year per installation at standard test conditions.

Lakeland will own, operate, and maintain the systems for at least 5 years. FSEC will conduct periodic site visits for testing and evaluation purposes. System performance data will be collected via telephone modem line for at least 2 years. Lakeland and FSEC will analyze the results of utility and systems simulation tests and prepare recommendations for appropriate interconnection requirements for residential PV systems. FSEC will prepare technical reports on system performance evaluation, onsite utilization, coincidence of PV generation with demand profiles, and utilization of PV generated electricity as a demand-side management option.

4.2.4 Utility-Interactive Photovoltaic Systems on Polk County Schools

Lakeland is also actively involved in a program called "Portable Power." The focus of the program is to install Photovoltaic Systems on portable classrooms in the Polk County School District. This program is a partnership including the City of Lakeland, Polk County School District, Siemens Solar Industries, Florida Solar Energy Research and Education Foundation, Florida Solar Energy Center and the Utility Photovoltaic Group. It will allow seventeen portable classrooms to be enrolled in former President Clinton's "Million Solar Roofs Initiative." With the installation of the photovoltaic systems 80 percent of the electricity requirements for these classrooms will be met.

Along with the photovoltaic systems, there will also be a specially designed curriculum on solar energy appropriate to various grade levels. An education package has been delivered to the schools for their teachers' use in the explanation of solar sciences. By addressing solar energy technologies in today's public school classrooms, Lakeland is informing the next generation of the environmental and economic need for alternate forms of energy production.

The "Portable Power" in the schools, shown in Figure 4-2, will consist of installing 2kWp photovoltaics systems on seventeen portable classrooms. In addition to the educational awareness benefits of photovoltaic programs in schools, there are several practical reasons why portable classrooms are most appropriate as the platforms for photovoltaics. They have nearly flat roofs and are installed in open spaces, so final orientation is of little consequence. Another reason is the primary electric load of the portable classroom is air conditioning, which is reduced by the shading effect of the panels on their short stand-off mounts. Most important, the total electric load on the portable classroom has high coincidence with the output from the PV system. The hot, sunny day which results in the highest cooling requirements also produces the maximum PV output.

Of extreme value to the photovoltaic industry, Lakeland Electric, in a partnership with the FSEC, provided on-site training sessions while installing the solar equipment on these school buildings. Attendees from other electric utilities were enrolled and given a hands-on opportunity to develop the technical and business skills needed to implement their own solar energy projects. The training classes covered all aspects of the solar photovoltaic experience from system design and assembly, safety and reliability, power quality, and troubleshooting to distributed generation and future requirements of deregulation.

Figure 4-2
Portable Classroom Topped by PV Panels

Lakeland will own, operate, and maintain the systems that are installed on these classrooms. Lakeland will monitor the performance and FSEC will conduct periodic testing of the equipment. Through the cooperative effort of the partnership, different ways to use photovoltaics efficiently and effectively in today's society will be evaluated.

4.2.5 Integrated Photovoltaics for Florida Residences

Lakeland's existing integrated photovoltaic program supports former President Clinton's "Million Solar Roofs Initiative". The Department of Energy granted five million dollars for solar electric businesses in addition to the existing privately funded twenty-seven million dollars, for a total of thirty-two million dollars for the program. Through the Utility Photovoltaic Group, the investment will support 1,000 PV systems in

12 states and Puerto Rico and hopes to bring photovoltaics to the main market. The 1,000 systems are part of the 500,000 commitments received for the initiative to date. The goal is to have installed solar devices on one million roofs by the year 2010. Lakeland is helping to accomplish this national goal.

This program provides research in the integration of photovoltaics in newly constructed homes. Two new homes, having identical floor plans, were built in "side-by-side" fashion. The dwellings are being measured for performance under two conditions: occupied and unoccupied. Data is being collected for end-use load and PV system interface. As a research project, the goal is to see how much energy could be saved without factoring in the cost of the efficiency features.

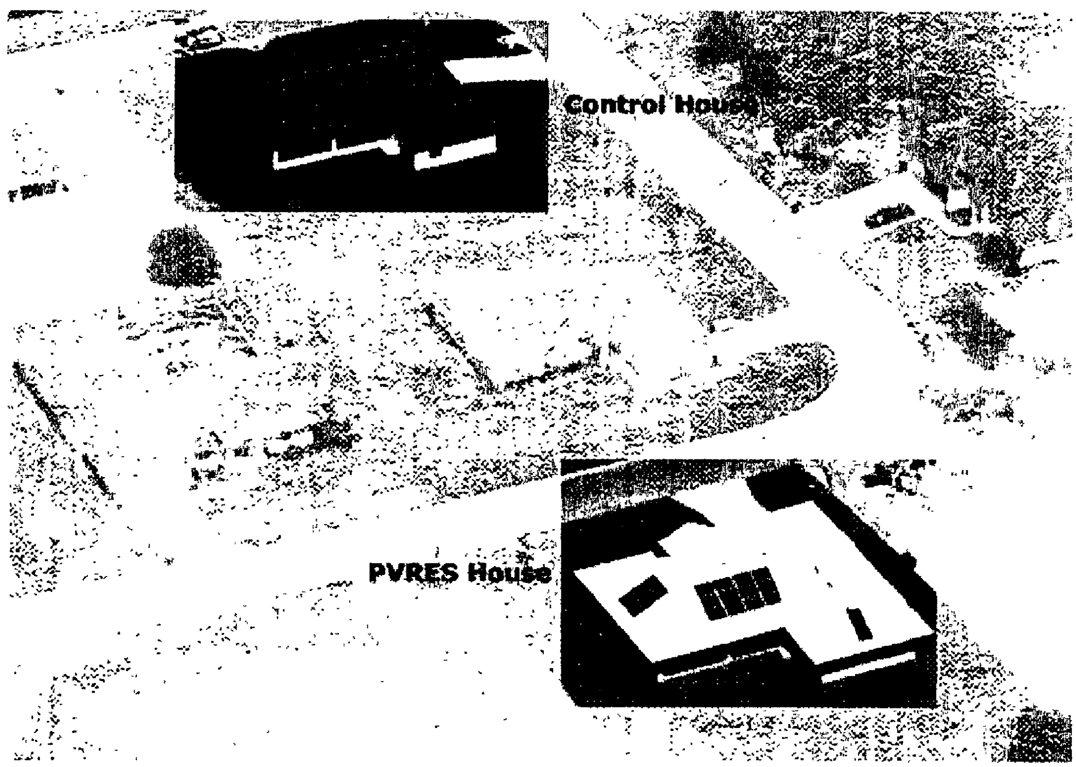


Figure 4-3
Solar House and Control House

The first solar home was unveiled May 28, 1998, in Lakeland, Florida. The home construction includes a 4 kW photovoltaic system, white tiled roof, argon filled windows, exterior wall insulation, improved interior duct system, high performance heat pump and high efficiency appliances. An identical home with strictly conventional construction features was also built as a control home. The homes are 1 block apart and oriented in the same direction as shown in Figure 4-3. For the month of July 1998, the occupied solar home air conditioning consumption was 72 percent lower than the unoccupied control house. Living conditions were simulated in the unoccupied home. With regard to total power, the solar home used 50 percent less electricity than the air conditioning consumption of the control home.

The solar home was designed to provide enough power during the utility peak that it would not place a net demand on the grid. If the solar home produces more energy than what is being consumed on the premises, the output of the photovoltaic system could be sent into the utility grid. The objective was to test the feasibility of constructing a new, single family residence that was engineered to reduce air conditioning loads to an absolute minimum so most of the cooling and other daytime electrical needs could be accomplished by the PV component.

4.3 Green Pricing Program

Because no long-term budgets have been established for the deployment of solar energy devices, many utilities are dependent on infrequent, somewhat unreliable sources of funding for their solar hardware purchases. To provide for a more regularly available budget, a number of utilities are looking into the voluntary participation of their customers. Recent market studies performed in numerous locations and among diverse population groups reveal a public willingness to pay equal or even slightly higher energy prices knowing that their payments are being directed towards renewable fuels.

The Florida Municipal Electric Association (FMEA) has assembled a workgroup called "Sunsmart". This workgroup is a committee composed of member utilities. Its purpose is to raise environmental awareness and implement "Green Pricing" programs that would call for regular periodic donations from customers who wish to invest in renewables. The Florida Solar Energy Center (FSEC) co-hosts this effort by providing meeting places and website advertising to recruit from statewide responses. A grant from the State of Florida Department of Community Affairs, Florida Energy Office has been appropriated to encourage utility involvement with Green Pricing.

Lakeland Electric is an active member of this committee and is actively pursuing the creation and implementation of a Green Pricing Program. A Green Pricing effort administered by the utility is a further demonstration that Lakeland Electric is engaged in cost-effective alternative energy sources.

5.0 Forecasting Methods and Procedures

This section describes and presents Lakeland's long-term integrated resource planning process, the economic parameter assumptions, plus the fuel price projections being used in the current evaluation process.

5.1 Integrated Resource Planning

Lakeland selects its capacity resources through an integrated resource planning process which it has used for a number of years. Lakeland's planning considers both conservation and demand-side management measures. The integrated resource planning process employed by Lakeland continuously monitors supply and demand-side alternatives and as promising alternatives emerge, they are included in the evaluation process.

5.2 Florida Municipal Power Pool

Lakeland is a member of the Florida Municipal Power Pool (FMPP) along with the Orlando Utilities Commission (OUC), Kissimmee Utility Authority, and the All-Requirements Project of the Florida Municipal Power Agency (FMPA). The four utilities operate as one control area. All FMPP capacity resources are committed and dispatched together from the OUC Operations Center. FMPP has 2,141 MW of summer capacity and 2,249 MW of winter capacity per the 2000 Load and Resource Plan published by the Florida Reliability Coordinating Council.

The FMPP does not provide for the sharing of planning reserves among its members; meaning that they must provide their own reserves. Any member of the FMPP can withdraw from FMPP with 1 year written notice. Lakeland, therefore, must ultimately plan on a stand-alone basis as reflected in this document.

5.3 Economic Parameters and Evaluation Criteria

This section presents the assumed values adopted for economic parameters and inputs used in Lakeland's planning process. The assumptions stated in this section are applied consistently throughout. Subsection 5.3.1 outlines the basic economic assumptions. Subsections 5.3.2 and 5.3.3 outline the base case, high and low, and constant differential fuel forecasts.

5.3.1 Economic Parameters

This section presents the values assumed for the economic parameters currently being used in Lakeland's least-cost planning analysis.

5.3.1.1 Inflation and Escalation Rates. The general inflation rate applied is assumed to be 3.0 percent per year. A 3.0 escalation rate is applied to capital costs and operation and maintenance (O&M) expenses. Fuel price escalation rates are discussed below in Section 5.3.2.

5.3.1.2 Bond Interest Rate. Consistent with the traditional tax exempt financing approach used by Lakeland, the self-owned supply-side alternatives assume 100 percent debt financing. Lakeland's long-term tax exempt bond interest rate is assumed to be 6.0 percent.

5.3.1.3 Present Worth Discount Rate. The present worth discount rate used in the analysis is set equal to Lakeland's assumed bond interest rate of 6.0 percent.

5.3.1.4 Interest During Construction. During construction of the plant, progress payments will be made to the EPC contractor and interest charges will accrue on loan drawdowns. The interest during construction rate is assumed to be 6.0 percent.

5.3.1.5 Fixed Charge Rates. The fixed charge rate is the sum of the project fixed charges as a percent of the project's total initial capital cost. When the fixed charge rate is applied to the initial investment, the product equals the revenue requirements needed to offset fixed costs for a given year. A separate fixed charge rate can be calculated and applied to each year of an economic analysis, but it is most common to used a levelized fixed charge rate that has the same present value as the year by year fixed charged rates. The fixed charge rate for the analysis is based upon an assumed 2.0 percent issuance fee, a 1.0 percent annual insurance cost, and a 6-month debt reserve fund earning interest at a rate equal to the bond interest rate of 6.0 percent. In the planning analysis, a 30-year bond term is assumed for solid fuel alternatives and a 25-year bond term is used for combustion turbine and combined cycles. The resultant levelized fixed charge rates are 8.47 and 9.07 percent, respectively, for the 30-year and 25-year bond terms.

5.3.2 Fuel Price Projections

This section presents the fuel price projections for coal, petroleum coke, natural gas and oil. The base case forecasts are based on Annual Energy Outlook (AEO) 2001 fuel price escalation rates published by the Energy Information Administration (EIA), which is an independent agency of the Department of Energy (DOE). The AEO 2001 energy data is a comprehensive and reliable source of domestic and international energy supply, consumption, and price information.

AEO 2001 provides an energy price forecast through the year 2020 and takes into account a number of important factors, some of which include:

- Restructuring of the U.S. electricity markets.
- Current regulations and legislation affecting the energy markets.

- Current energy issues:
  - Appliance, gasoline and diesel fuel, and renewable portfolio standards.
  - Expansion of natural gas industry.
  - Carbon emissions.
  - Competitive electricity pricing.

AEO 2001 energy information is considered objective and nonpartisan by Lakeland. It is used widely by both government and private sectors to assist in decision-making processes and in analyzing important policy issues.

AEO 2001 publishes real fuel price projections for the individual years of 1998, 1999, 2005, 2010, 2015, and 2020. From these projections, real compounded annual escalation rates (CAERs) can be calculated for 1999-2005, 2005-2010, 2010-2015, and 2015-2020 periods. Table 5-1 shows the real CAERs for the various fuel types. The base case fuel forecast applies these real CAERs and the assumed annual general inflation rate of 3.0 percent to escalate Lakeland's 2000 delivered fuel costs through the year 2020. Table 5-2 shows the resulting nominal fuel price forecast by fuel type used in the economic analyses. Additional assumptions and results of the fuel price forecasts are discussed by fuel type in the following subsections.

Table 5-1
2001 Annual Energy Outlook Real Fuel Price Projections and CAERs

AEO Forecast	1999	2005	2010	2015	2020
No. 2 Oil,* $/mmbtu	4.05	4.65	4.84	5.10	5.28
Residual Oil,* $/mmbtu	2.42	3.52	3.88	4.00	4.07
Coal,* $/mmbtu	1.21	1.13	1.05	1.01	0.98
Natural Gas,** $/mmbtu	2.08	2.49	2.69	2.83	3.13
Real CAERs	1999-2005	2005-2010	2010-2015	2015-2020	1998-2020
No. 2 Oil* Real CAERs, percent	2.33	0.80	1.05	0.70	2.23
Residual Oil* Real CAERS, percent	6.49	1.97	0.61	0.35	2.79
Coal* Real CAERs, percent	-1.13	-1.46	-0.77	-0.60	-1.17
Natural Gas** Real CAERs, percent	3.04	1.56	1.02	2.04	2.01

*Delivered price.
**Well head price.
Source: DOE Energy Information Administration website

Table 5-2
Base Case Fuel Price Forecast Summary (Nominal Delivered Price $/mmbtu)

	McIntosh 3 Coal	New Unit Coal	Existing Unit NG	New Unit NG	HS Oil	LS Oil	Diesel	McIntosh 4 Pet Coke
2001	1.63	1.95	4.12	4.40	4.42	4.82	7.03	0.78
2002	1.66	1.96	4.34	4.62	4.85	5.29	7.41	0.79
2003	1.69	1.97	4.58	4.85	5.32	5.80	7.81	0.81
2004	1.72	1.98	4.82	5.10	5.83	6.35	8.24	0.82
2005	1.75	2.02	5.08	5.36	6.39	6.97	8.68	0.84
2006	1.78	2.05	5.29	5.57	6.71	7.32	9.01	0.85
2007	2.08	2.08	5.51	5.79	7.05	7.68	9.36	0.86
2008	2.11	2.11	5.74	6.02	7.41	8.07	9.72	0.87
2009	2.14	2.14	5.98	6.26	7.78	8.48	10.09	0.89
2010	2.17	2.17	6.23	6.51	8.17	8.90	10.48	0.90
2011	2.22	2.22	6.46	6.74	8.47	9.23	10.90	0.92
2012	2.27	2.27	6.70	6.98	8.77	9.56	11.35	0.94
2013	2.32	2.32	6.95	7.22	9.09	9.91	11.81	0.96
2014	2.37	2.37	7.21	7.48	9.42	10.27	12.29	0.98
2015	2.42	2.42	7.48	7.75	9.76	10.64	12.80	1.00
2016	2.48	2.48	7.83	8.11	10.09	11.00	13.27	1.03
2017	2.54	2.54	8.20	8.48	10.43	11.37	13.76	1.05
2018	2.60	2.60	8.59	8.87	10.78	11.75	14.28	1.08
2019	2.66	2.66	9.00	9.28	11.14	12.14	14.81	1.10
2020	2.72	2.72	9.43	9.71	11.52	12.55	15.36	1.13
Average Annual Escalation Rate	2.73%	1.78%	4.45%	4.25%	5.16%	5.16%	4.19%	1.99%

5.3.2.1 Natural Gas. Natural gas, also known as methane, is a colorless, odorless fuel that burns cleaner than many other traditional fossil fuels. Natural gas can be used for heating, cooling, and production of electricity, and other industry uses.

Natural gas is found in the Earth's crust. Once the gas is brought to the surface, it is refined to remove impurities such as water, sand, and other gases. The natural gas is then transmitted through pipelines and delivered to the customer either directly from the pipeline or through a distribution company or utility. When natural gas reaches its destination through a pipeline, it is often stored prior to distribution.

5.3.2.1.1 Natural gas supply and availability. Natural gas reserves exist both in the United States and North America mainland and coastal regions. Natural gas reserves are mostly dependent on domestic production. Increasing demand for natural gas as a fuel for both home and heating power production is contributing to the volatility of its price, which in turn has provided incentives for increased production. According to the Energy Information Administration (EIA), by 2020, natural gas demand - measured as a percent of the total U.S. energy market - will increase from the 2000 level of 23 percent to almost 28 percent. This increase in demand will result from further market deregulation and competition throughout the entire energy industry.

5.3.2.1.2 Natural gas transportation. There is currently one transportation company serving Peninsular Florida, Florida Gas Transmission Company (FGT). One additional pipeline, Gulfstream, received final approval from the Federal Energy Regulatory Commission (FERC) in February of 2001.

5.3.2.1.2.1 Florida Gas Transmission Company. FGT is an open access interstate pipeline company transporting natural gas for third parties through its 5,000-mile pipeline system extending from South Texas to Miami, Florida. FGT is a subsidiary of Citrus Corporation, which in turn, is jointly owned by Enron Corporation, the largest integrated natural gas company in America, and El Paso Energy Corporation, one of the largest independent producers of natural gas in the United States.

The FGT pipeline system accesses a diversity of natural gas supply regions, including:

- Anadarko Basin (Texas, Oklahoma, and Kansas).
- Arkona Basin (Oklahoma and Arkansas).
- Texas and Louisiana Gulf Areas (Gulf of Mexico).
- Black Warrior Basin (Mississippi and Alabama).
- Louisiana – Mississippi – Alabama Salt Basin.
- Mobile Bay

FGT's total receipt point capacity is in excess of 3.0 billion cubic feet per day and includes connections with 10 interstate and 10 intrastate pipelines to facilitate transfers of natural gas into its pipeline system. FGT reports a current delivery capability to Peninsular Florida in excess of 1.4 billion cubic feet per day.

5.3.2.1.2.2 Florida Gas Transmission market area pipeline system. The FGT multiple pipeline system corridor enters the Florida Panhandle in northern Escambia County and runs easterly to a point in southwestern Clay County, where the pipeline corridor turns southerly to pass west of the Orlando area. The mainline corridor then turns to the southeast to a point in southern Brevard County, where it turns south generally paralleling Interstate Highway 95 to the Miami area. A major lateral line (the St. Petersburg Lateral) extends from a junction point in southern Orange County westerly to terminate in the Tampa, St Petersburg, Sarasota area. A major loop corridor (the West Leg Pipeline) branches from the mainline corridor in southeastern Suwannee County to run southward through western Peninsular Florida to connect to the St. Petersburg Lateral system in northeastern Hillsborough County. Each of the above major corridors includes stretches of multiple pipelines (loops) to provide flow redundancy and transport capability. Numerous lateral pipelines extend from the major corridors to serve major local distribution systems and industrial/utility customers.

5.3.2.1.2.3 Florida Gas Transmission expansion projects. FGT filed for FERC approvals of the Phase IV expansion project December 2, 1998. The filing consists of expanding services to Southwest Florida with 139 miles of underground pipelines. The $268 million Phase IV project will add more than 38,000 horsepower of compression and associated facilities and will provide approximately 197 million cubic feet per day (mmcf/d) of incremental firm transportation service on an average annual basis. FGT announced in May of 2000 that construction related to Phase IV had begun and is scheduled for service by the May 2001 target.

FGT's Phase V expansion project, filed with the FERC on December 1, 1999, will deliver natural gas to a variety of new and current FGT customers and make natural gas available to areas that have not previously had gas service. The Phase V expansion project is intended to add approximately 167 miles of new pipeline and 132,615 horsepower of compression to the existing system. The result of this expansion will be the addition of more than 425 mmcf/d of incremental mainline capacity to Florida. With an estimated cost of $466 million, the Phase V expansion plan has a target in-service date of April 1, 2002.

The Phase V expansion faced many changes that caused it to file an amended project application with FERC. The Florida Supreme Court ruling that limited the ability of non-utility merchant plants to use the Florida Electrical Power Plant Siting Act prompted the withdrawal of two major Phase V customers, Enron and Dynergy. However, FGT subsequently gained back some of the lost market by signing a long-term contract with Tampa Electric Company as a Phase V customer. FERC granted preliminary approval to the expansion in November of 2000. The Phase V expansion still requires final environmental approval.

FGT recently concluded an open season for Phase VI. FGT received what it defined as 'a positive response' to the open season. The intent of the project is to provide incremental firm transportation service to Florida. The new pipeline is proposed to extend from Savannah, Georgia to Jacksonville, Florida, with access to Southern LNG Company's liquefied natural gas. Phase VI is scheduled for an in-service date of the Spring of 2003.

FERC approved in November of 2000 FGT's request for the purchase of an undivided interest in Koch Gateway Pipeline's Mobile Bay Lateral. This purchase will give FGT the right to an additional 300,000 mmbtu/day of input capacity. The acquisition is set to become effective April 1, 2002.

5.3.2.1.2.4 Gulfstream pipeline. In September of 2000, two pipelines, Buccaneer and Gulfstream, received one of the two required environmental approvals from FERC. In November of 2000, the developers of the Buccaneer gas pipeline, Williams Energy and Duke Energy, announced their intent to purchase the Gulfstream pipeline from Coastal Corporation.

Duke Energy and Williams Energy will collaborate on the Gulfstream pipeline in lieu of the Buccaneer pipeline. Gulfstream has precedent agreements with 10 large Florida utilities and power generation facilities representing long-term commitments for the majority of its 1.1 billion cubic feet of gas per day capacity. The Gulfstream pipeline was designed primarily to serve Florida utilities and power generation facilities that plan on using high efficiency natural gas turbines to meet the incremental demand for electrical energy.

When installed, the Gulfstream pipeline will be a 744-mile pipeline originating in the Mobile Bay region and crossing the Gulf of Mexico to a landfall in Manatee County (south Tampa Bay). The pipeline is expected to supply Florida with 1.1 billion cubic feet of gas per day serving existing and prospective electric generation and industrial projects in southern Florida. Figure 5-1 shows the proposed route for the Gulfstream pipeline.

The 1.6 billion-dollar pipeline won FERC approval, subject to environmental review, on April 24, 2000. Final environmental and routing approvals by FERC were given in February of 2001. Construction for the Gulfstream pipeline is scheduled to begin June of 2001 with an estimated operation date of June of 2002. Pre-construction activities are currently underway.

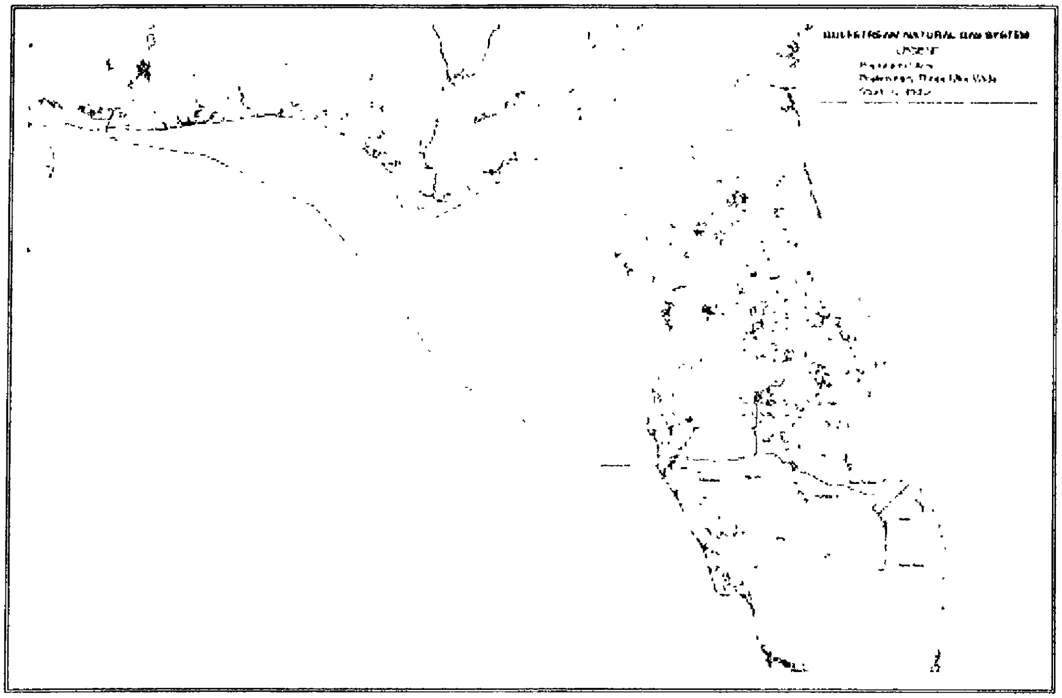


Figure 5-1
Gulfstream Natural Gas Pipeline

The first major acquisition of right-of-way occurred July 20, 2000 with a signed agreement between Coastal Corporation and the Manatee County Port Authority. The Gulfstream pipeline gained the permanent right of way easement to cross through Port Manatee. In addition to a payment to Port Manatee, Coastal Corporation will lease up to 190 acres of vacant land at Port Manatee to serve as a logistics base during Gulfstream's construction phase. Florida Power Corporation has announced Gulfstream as the natural gas transportation provider for their newly approved Hines 2 Unit. Currently, 75 percent of the pipeline capacity is under contract.

5.3.2.1.3 Natural gas price forecast. The commodity price forecast for natural gas developed by Lakeland is based on its actual average 2000 natural gas commodity cost, escalated by the AEO escalation rate and the 3.0 percent general inflation rate. For the analysis, a natural gas transportation price was also required and this is expected to differ depending on whether the supply is for an existing unit (linked to previous FGT Phases) or for new units (linked to future Phases). Table 5-2 presents the delivered natural gas price forecast both for existing units and new units.

Lakeland currently has a ten-year contract with FGT for the supply of natural gas for fifty percent of Lakeland's Phase II firm transportation natural gas entitlements. Lakeland plans to enter into long term contracts that will provide between 50 and 60 percent of its natural gas requirements and plans to enter into one to five year (spot market) contracts for the balance of its natural gas requirements.

Natural gas transportation from FGT is currently supplied under two tariffs, FTS-1 and FTS-2. Rates in FTS-1 are based on FGT's Phase II expansion and rates in FTS-2 are based on the Phase III expansion. The Phase III expansion was extensive and rates for FTS-2 transportation are significantly higher than FTS-1. Rates for the Phase IV, Phase V, and any other future expansions will be set by the Federal Energy Regulatory Commission (FERC) rate cases at the completion of the projects. Costs for future expansions are anticipated to be rolled in with Phase III costs and the resultant rates are expected to be similar to the existing Phase III rates. Current FTS-1 and FTS-2 transportation rates along with FGT's interruptible transportation rate ITS-1 are shown in Table 5-3.

For purposes of projecting delivered gas prices, transportation charges of $0.55/mmbtu were applied for existing units as this is the average cost for Lakeland to obtain natural gas transportation for those units. This average rate is realized through a current mix of FTS-1 and FTS-2 transportation, including consideration of Lakeland's ability to relinquish FTS-2 transportation and acquire other firm and interruptible gas transportation on the market. For new units being considered in the expansion plans, the FTS-2 transportation rate is being used. Transportation rates for existing and new units are considered to be fixed contracted prices and are not escalated.

5.3.2.1.3 Natural gas price forecast. The Petroleum coke is an important fuel for Lakeland. Not only does McIntosh Unit 3 use petroleum coke as a supplemental fuel, but if a solid fuel unit is selected for installation at the McIntosh site (McIntosh Unit 4) it is anticipated to use petroleum coke as its primary fuel. Petroleum coke is a by-product of the oil refining process. This by-product is a solid residue produced from the cracking of heavy residual oil to produce lighter hydrocarbons. Petroleum coke is high in fixed carbon with heating values in the range of 14,200 to 14,600 Btu/lb. Other product characteristics are low volatile content, low ash content, high sulfur content and varying degrees of hardness. The physical and chemical specifications of petroleum coke are a direct function of the oils being processed by the refinery. The amount of petroleum coke produced is increasing due to the increase in refining capacity for heavy crude oils and the declining demand for residual fuel oil. The coking process allows for a higher yield of light oil products, specifically gasoline.

Table 5-3
FGT Transportation Rates

Rates and Surcharges	Rate Schedule FTS-1 w/surcharges (cents/DTH)*	FTS-2 w/surcharges (cents/DTH)*	ITS-1
Reservation	37.53	77.85	33.84
Usage	4.34	2.63	0.00
Total	41.87	80.48	33.84
Fuel Charge	2.75%	2.75%	2.75%

* A DTH is equivalent to 1 mmbtu or 1 mmcf.

5.3.2.2.1 Petroleum coke supply and availability. While the production of petroleum coke is not the primary product of a refinery, it's production is linked to the production of high value products such as gasoline, jet fuel, diesel and other light products. The increasing demand for these high value products has led to expansions and modifications of current cokers and the addition of new cokers, thus increasing the availability of petroleum coke. The arrival of this new coker capacity began in late 2000 and be completed by early 2004. This incremental coker capacity will add approximately 20 million tons to the annual production capability of petroleum coke. Ninety-two percent of the announced petroleum coke will be produced in the Americas.

Traditionally, the majority of the petroleum coke production has been consumed by the cement, lime and steel industry. But as the availability and acceptance of petroleum coke increases, the use of petroleum coke as a fuel in the electric utility industry will significantly increase a means to remain competitive in a deregulated industry.

Approximately 65 to 70 percent of the petroleum coke produced is a fuel-grade coke, which has a sulfur content of more than four percent. The remaining petroleum coke produced is an anode-grade coke, which has a sulfur content less than four percent. The anode-grade coke is calcined and sold as a premium-grade petroleum coke used in the manufacture of aluminum anodes, furnace electrodes and liners, and shaped graphite products.

Aside from the market dynamics of supply and demand, the primary factor that drives the price of fuel-grade petroleum coke is the sulfur content. A high sulfur content, 6 percent or higher, will normally result in a lower priced product as opposed to a product with a sulfur content in the range of 4.5 to 5.5 percent. A secondary factor to be considered in the price of fuel-grade petroleum coke is the hardness of the petroleum coke. As measured by the Hardgrove Grindability Index (HGI), the harder the petroleum coke, an HGI of less than 40, then typically the lower the market price for the product. Therefore, a fuel-grade petroleum coke product with a high sulfur content and a low HGI will result in the most favorable pricing opportunities.

The availability of a high sulfur, low HGI petroleum coke product is directly tied to the specifications of the heavy crude oils being refined. During the next three to four years there will be available approximately four to six million ton annually of this particular petroleum coke product (high sulfur/low HGI). During the same time frame, another petroleum coke product with a medium range of sulfur of 5 to 5.5 percent and a HGI range of 35 to 40, with an annual production of approximately eight to ten million tons will also be available. This medium grade petroleum coke will be sourced from Venezuela. The pricing of the above products will normally be at a deeper discount than a lower sulfur, (4.5 to 5 percent) and high HGI (48 plus) petroleum coke product. Further, if the lower grade petroleum coke product can be obtained from a foreign based refinery, then the transportation cost will be approximately one-quarter to one-third of the domestic transportation cost.

As the use of fuel-grade petroleum coke has increased and gained acceptance in the electric utility industry, the sophistication of the buyers and seller has increased as well. In the past, the petroleum coke market witnessed contract terms normally a year of less, refineries were not willing to sell direct, and pricing arrangements which were not always market price sensitive. Now sellers of petroleum coke are entering into longer-term contracts, refineries are either selling or entertaining the sale of their product direct and the pricing mechanisms are allowing both the buyer and seller to stay market price sensitive in a longer term arrangement.

Based on Lakeland's research, there would be an adequate supply to support the fuel requirements of McIntosh Unit 4 which, according to preliminary modeling of McIntosh Unit 4, would be approximately 400,000 tons annually.

McIntosh Unit 3 burns approximately 58,000 tons of petroleum coke annually. The petroleum coke burned in McIntosh Unit 3 is a higher grade, lower sulfur, more expensive petroleum coke than what would be burned in McIntosh Unit 4. Therefore, the petroleum coke price forecast resembles the expected price for the low grade, high sulfur and hardness, petroleum coke for a potential petcoke unit at the McIntosh site.

5.3.2.2.2 Petroleum coke transportation. In general, petroleum coke is amenable to transport by truck, rail, barges, ocean going ships, or a combination of these modes of transportation. Currently, petroleum coke for McIntosh 3 is transported to the McIntosh site by truck. For McIntosh Unit 4, the petroleum coke would be shipped to either the port of Charleston, South Carolina or Tampa, and then railed or trucked to Lakeland. The transportation cost for delivery of the petroleum coke would comprise the largest cost component of the delivered petroleum coke price and has been included in the forecasted petroleum coke price.

5.3.2.2.3 Petroleum coke price forecast. The AEO does not include a fuel price forecast for petroleum coke. As a result, the initial petroleum coke price used in the analysis was based on the expected supply and demand conditions in the petroleum coke market in the future. The price escalation used in the forecast considered the link that exists between the price of petroleum coke and the price of coal. This link exists because of the substitutability of these two products by many units if the economics so dictated. Therefore, the base case forecast assumed that the petroleum coke price escalation would track that of coal, as resulting from the projected inflation rate and the AEO real price escalation for coal.

5.3.2.3 Coal. Coal has been used as an energy source for hundreds of years and provided the energy which fueled the Industrial Revolution of the 19^{th} Century and it was a primary fuel of the electric era in the 20^{th} Century. As of 1998, some 37 percent of the electricity generated worldwide and over half (57 percent) of the electricity generated in the United States was produced from coal.

5.3.2.3.1 Coal supply and availability. Lakeland's current coal purchase contracts are approximately 50 percent long-term and 50 percent spot purchases. Spot purchases can extend from several months to two years in length. Lakeland maintains a 30 – 35 day coal supply reserve (90,000 – 110,000 tons) at the McIntosh site.

5.3.2.3.2 Coal transportation. McIntosh Unit 3 is Lakeland's only unit burning coal. Lakeland projects McIntosh Unit 3 will burn approximately 850,000 tons of coal per year. The coal sources are located in eastern Kentucky, which affords Lakeland a single rail line haul via CSX Transportation.

5.3.2.3.3 Coal price forecast. There are two coal price forecasts in Table 5-2 representing the contracted coal price for McIntosh 3 and the projected coal price for a potential new coal unit at the McIntosh site.

Currently, Lakeland purchases coal for McIntosh 3 under a contract which expires in December of 2006. As shown in Table 5-2, after the expiration of this contract, the price assumed for McIntosh 3 coal is the same as that for a potential new unit, and is based on the AEO escalation rate and the 3.0 percent general inflation rate. The two coal price forecasts then remain equal to one another throughout the remainder of the forecast period. The initial coal price for the new coal unit is based on present market conditions.

5.3.2.4 Fuel Oil

5.3.2.4.1 Fuel oil supply and availability. The city of Lakeland currently obtains all of its fuel oil through spot market purchases and has no long-term contracts. This strategy provides the lowest cost for fuel oil consistent with usage, current price stabilization, and on-site storage. Lakeland's Fuels Section continually monitors the cost-effectiveness of spot market purchasing.

5.3.2.4.2 Fuel oil transportation. Although the City of Lakeland is not a large consumer of fuel oils, a small amount is consumed during operations for backup fuel and diesel unit operations. Fuel oil is transported to Lakeland by truck.

5.3.2.4.3 Fuel oil price forecast. The price forecast for No. 2 and No. 6 fuel oils were developed by Lakeland. Lakeland's actual 2000 fuel oil costs were escalated based on the escalation rate presented in the AEO forecast. The AEO escalation rates were applied over five year intervals and applied to Lakeland's 2000 actual fuel costs plus the 3.0 percent general inflation rate.

5.3.3 Fuel Forecast Sensitivities

While Lakeland carefully forecasts fuel prices based upon available information volatility in the market means that actual fuel prices often vary from the forecasted values. In attempt to bracket the variance of the projected fuel prices, Lakeland utilizes a high and low fuel price forecast. Lakeland also presents a case where a constant price differential is maintained over the planning horizon between natural gas/oil and coal.

5.3.3.1 High Fuel Price Forecast. The high fuel price forecast assumes that higher than expected fuel price escalation occurs over the planning horizon. Lakeland has assumed that for the high fuel price an escalation of 2.5 percent above the base case forecast is a reasonable upper limit. For natural gas, the additional escalation rate is only applied to the commodity price. The forecast is provided in Table 5-4.

5.3.3.2 Low Fuel Price Forecast. The low fuel price forecast assumes that lower than expected fuel price escalation occurs over the planning horizon. Lakeland has assumed that for the low fuel price scenario an escalation of 2.5 percent below the base case forecast is a reasonable lower limit. For natural gas, the lower escalation rate is only applied to the commodity price. The forecast is provided in Table 5-5.

5.3.3.3 Constant Differential Between Fuels. Lakeland also conducts a sensitivity analysis that assumes a constant differential between fuels over the planning horizon. This case uses the 2000 fuel cost differential between the fuels and maintains that same dollar value differential throughout the planning horizon compared to projected coal prices. Table 5-6 displays the fuel price forecast for this scenario.

Table 5-4
High Fuel Price Forecast Summary (Delivered Price $/mmbtu)

	McIntosh 3 Coal	New Unit Coal	Existing Unit NG	New Unit NG	HS Oil	LS Oil	Diesel	McIntosh 4 Pet Coke
2001	1.68	1.95	4.23	4.50	4.55	4.96	7.24	0.80
2002	1.76	1.96	4.57	4.84	5.13	5.59	7.86	0.84
2003	1.85	1.97	4.94	5.21	5.78	6.30	8.52	0.88
2004	1.94	1.98	5.34	5.62	6.52	7.10	9.25	0.92
2005	2.04	2.08	5.78	6.06	7.35	8.01	10.03	0.97
2006	2.13	2.17	6.19	6.46	7.94	8.65	10.72	1.01
2007	2.27	2.27	6.62	6.90	8.59	9.36	11.47	1.06
2008	2.38	2.38	7.09	7.37	9.28	10.12	12.26	1.11
2009	2.49	2.49	7.59	7.87	10.04	10.94	13.11	1.16
2010	2.60	2.60	8.13	8.41	10.85	11.83	14.01	1.21
2011	2.74	2.74	8.67	8.95	11.58	12.62	15.02	1.28
2012	2.88	2.88	9.25	9.53	12.36	13.47	16.10	1.35
2013	3.03	3.03	9.88	10.15	13.19	14.37	17.25	1.42
2014	3.20	3.20	10.54	10.82	14.08	15.34	18.49	1.49
2015	3.36	3.36	11.26	11.53	15.02	16.37	19.82	1.57
2016	3.55	3.55	12.13	12.41	15.99	17.42	21.17	1.66
2017	3.74	3.74	13.08	13.36	17.02	18.55	22.61	1.75
2018	3.95	3.95	14.11	14.38	18.12	19.74	24.14	1.84
2019	4.16	4.16	15.22	15.49	19.29	21.02	25.79	1.94
2020	4.39	4.39	16.42	16.69	20.53	22.37	27.54	2.05
Average Annual Escalation Rate	5.18%	4.37%	7.40%	7.14%	8.25%	8.25%	7.29%	5.08%

Table 5-5
Low Fuel Price Forecast Summary (Delivered Price $/mmbtu)

	McIntosh 3 Coal	New Unit Coal	Existing Unit NG	New Unit NG	HS Oil	LS Oil	Diesel	McIntosh 4 Pet Coke
2001	1.58	1.95	4.02	4.30	4.30	4.69	6.83	0.75
2002	1.56	1.96	4.13	4.40	4.58	4.99	6.99	0.74
2003	1.54	1.97	4.23	4.51	4.88	5.32	7.15	0.73
2004	1.52	1.98	4.35	4.62	5.20	5.67	7.31	0.73
2005	1.50	1.96	4.46	4.74	5.54	6.04	7.48	0.72
2006	1.48	1.92	4.52	4.80	5.65	6.16	7.54	0.70
2007	1.89	1.89	4.58	4.86	5.76	6.27	7.59	0.69
2008	1.86	1.86	4.64	4.92	5.87	6.40	7.65	0.68
2009	1.83	1.83	4.70	4.98	5.98	6.52	7.70	0.67
2010	1.80	1.80	4.77	5.04	6.10	6.65	7.76	0.66
2011	1.79	1.79	4.81	5.08	6.13	6.68	7.84	0.66
2012	1.77	1.77	4.85	5.13	6.16	6.72	7.92	0.65
2013	1.76	1.76	4.89	5.17	6.20	6.75	8.00	0.64
2014	1.74	1.74	4.93	5.21	6.23	6.79	8.07	0.64
2015	1.73	1.73	4.97	5.25	6.27	6.83	8.15	0.63
2016	1.71	1.71	5.06	5.34	6.28	6.85	8.21	0.63
2017	1.70	1.70	5.15	5.43	6.30	6.86	8.26	0.62
2018	1.69	1.69	5.25	5.52	6.32	6.88	8.31	0.62
2019	1.68	1.68	5.34	5.62	6.33	6.90	8.36	0.61
2020	1.67	1.67	5.44	5.71	6.35	6.92	8.41	0.61
Average Annual Escalation Rate	0.27%	-0.83%	1.60%	1.51%	2.07%	2.07%	1.10%	-1.10%

Table 5-6
Constant Differential Fuel Price Forecast Summary (Delivered Price $/mmbtu)

	McIntosh 3 Coal	New Unit Coal	Existing Unit NG	New Unit NG	HS Oil	LS Oil	Diesel	McIntosh 4 Pet Coke
2001	1.63	1.95	4.12	4.40	4.42	4.82	7.03	0.78
2002	1.66	1.96	4.15	4.43	4.45	4.85	7.06	0.81
2003	1.69	1.97	4.18	4.46	4.48	4.88	7.09	0.84
2004	1.72	1.98	4.22	4.49	4.52	4.91	7.13	0.87
2005	1.75	2.02	4.25	4.52	4.55	4.94	7.16	0.90
2006	1.78	2.05	4.27	4.55	4.57	4.97	7.18	0.93
2007	2.08	2.08	4.57	4.85	4.87	5.27	7.48	1.22
2008	2.11	2.11	4.60	4.88	4.90	5.30	7.51	1.25
2009	2 14	2.14	4.63	4.91	4.93	5.33	7.54	1.28
2010	2.17	2.17	4.66	4.94	4.96	5.36	7.57	1.32
2011	2.22	2.22	4.71	4.99	5.01	5.41	7.62	1.36
2012	2.27	2.27	4.76	5.04	5.06	5.46	7.67	1.41
2013	2.32	2.32	4.81	5.09	5.11	5.51	7.72	1.46
2014	2.37	2.37	4.86	5.14	5.16	5.56	7.77	1.51
2015	2.42	2.42	4.91	5.19	5.21	5.61	7.82	1.57
2016	2.48	2.48	4.97	5.25	5.27	5.67	7.88	1.62
2017	2.54	2.54	5.03	5.31	5.33	5.73	7.94	1.68
2018	2.60	2.60	5.09	5.37	5.39	5.79	8.00	1.74
2019	2.66	2.66	5.15	5.43	5.45	5.85	8.06	1.81
2020	2.72	2.72	5.22	5.49	5.52	5.91	8.13	1.87
Average Annual Escalation Rate	**2.73%**	**1.78%**	**1.24%**	**1.17%**	**1.17%**	**1.08%**	**0.76%**	**4.73%**

6.0 Forecast of Facilities Requirements

6.1 Need for Capacity

This section addresses the need for additional electric capacity to serve Lakeland's electric customers in the future. The need for capacity is based on Lakeland's load forecast, reserve margin requirements, power sales contracts, existing generating and unit capability and scheduled retirements of generating units.

6.1.1 Load Forecast

The load forecast described in Section 3.0 is used to determine the need for capacity. A summary of the load forecast for winter and summer peak demand for base, high, and low projections is provided in Table 6-1. The peak demands presented in Table 6-1 reflect reductions for Lakeland's conservation and demand-side management programs and interruptible loads.

6.1.2 Reserve Requirements

Prudent utility planning requires that utilities secure firm generating resources over and above the expected peak system demand to account for unanticipated demand levels and supply constraints. Several methods of estimating the appropriate level of reserve capacity are used. The most commonly used approach is the reserve margin method, which is calculated as follows:

$$\frac{\text{system net capacity - system net peak demand}}{\text{system net peak demand}}$$

This is the approach used by Lakeland. Lakeland has adopted a 22 percent minimum reserve margin requirement for the winter season and a 20 percent reserve margin for the summer season as its planning criteria.

6.1.3 Additional Capacity Requirements

By comparing the load forecast plus reserves with firm supply, the additional capacity required on a system over time can be identified. Lakeland's requirements for additional capacity are presented in Tables 6-2 through 6-5 which show the projected reliability levels for winter and summer base cases, and winter high and low load demands, respectively. Lakeland's capacity requirements are driven by the winter peak demand forecasts.

Table 6-1
Summary of System Peak Load Forecast (MW) *

	Winter Peak Demand			Summer Peak Demand		
Year	Base	High	Low	Base	High	Low
2001				549	557	533
2002	627	734	494	564	572	547
2003	644	752	511	579	587	561
2004	662	769	529	593	602	575
2005	679	787	546	608	617	589
2006	697	804	564	623	633	603
2007	714	822	581	638	648	618
2008	732	839	599	653	663	632
2009	749	857	616	668	678	646
2010	767	874	634	683	693	660
2011	784	892	651	698	708	674
2012	802	909	669	712	724	688
2013	819	927	687	727	739	702
2014	837	944	704	742	754	717
2015	854	962	722	757	769	731
2016	872	979	739	772	784	745
2017	889	997	757	787	800	759
2018	907	1,012	774	802	815	773
2019	925	1,032	792	817	830	787
2020	942	1,049	809	831	845	802

*Includes reduction for conservation reductions and interruptible load.

Table 6-2
Projected Reliability Levels - Winter / Base Case

Year	Net Generating Capacity (MW)	Net System Purchases (MW)	Net System Sales (MW)	Net System Capacity (MW)	System Peak Demand		Reserve Margin		Excess/ (Deficit) to Maintain 22% Reserve Margin	
					Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (%)	After Interruptible and Load Management (%)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)
2000/2001	647									
2001/2002	891	0	100	791	691	627	14	26	(52)	26
2002/2003	957	0	100	857	708	644	21	33	(7)	71
2003/2004	957	0	100	857	727	662	18	29	(30)	49
2004/2005	957	0	100	857	745	679	15	26	(52)	29
2005/2006	870	0	100	770	764	697	1	10	(162)	(80)
2006/2007	870	0	100	770	781	714	(1)	8	(183)	(101)
2007/2008	870	0	100	770	800	732	(4)	5	(206)	(123)
2008/2009	870	0	100	770	817	749	(6)	3	(227)	(144)
2009/2010	870	0	100	770	836	767	(8)	0	(250)	(166)
2010/2011	870	0	0	870	853	784	2	11	(171)	(86)
2011/2012	870	0	0	870	872	802	(0)	8	(194)	(108)
2012/2013	870	0	0	870	889	819	(2)	6	(215)	(129)
2013/2014	870	0	0	870	909	837	(4)	4	(239)	(151)
2014/2015	870	0	0	870	926	854	(6)	2	(260)	(172)
2015/2016	870	0	0	870	945	872	(8)	(0)	(283)	(194)
2016/2017	870	0	0	870	962	889	(10)	(2)	(304)	(215)
2017/2018	870	0	0	870	981	907	(11)	(4)	(327)	(237)
2018/2019	870	0	0	870	999	925	(13)	(6)	(349)	(259)
2019/2020	870	0	0	870	1,017	942	(14)	(8)	(371)	(279)

Table 6-3
Projected Reliability Levels - Summer / Base Case

					System Peak Demand		Reserve Margin		Excess/ (Deficit) to Maintain 20% Reserve Margin	
Year	Net Generating Capacity (MW)	Net System Purchases (MW)	Net System Sales (MW)	Net System Capacity (MW)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (%)	After Interruptible and Load Management (%)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)
2001	835	0	100	735	584	549	26	34	34	76
2002	878	0	100	778	600	564	30	38	58	101
2003	878	0	100	778	615	579	27	34	40	83
2004	878	0	100	778	629	593	24	31	23	66
2005	878	0	100	778	644	608	21	28	5	48
2006	791	0	100	691	660	623	5	11	(101)	(57)
2007	791	0	100	691	676	638	2	8	(120)	(75)
2008	791	0	100	691	691	653	0	6	(138)	(93)
2009	791	0	100	691	706	668	(2)	3	(156)	(111)
2010	791	0	100	691	722	683	(4)	1	(175)	(129)
2011	791	0	0	791	737	698	7	13	(93)	(47)
2012	791	0	0	791	751	712	5	11	(110)	(63)
2013	791	0	0	791	766	727	3	9	(128)	(81)
2014	791	0	0	791	782	742	1	7	(147)	(99)
2015	791	0	0	791	798	757	(1)	4	(167)	(117)
2016	791	0	0	791	813	772	(3)	2	(185)	(135)
2017	791	0	0	791	829	787	(5)	1	(204)	(153)
2018	791	0	0	791	844	802	(6)	(1)	(222)	(171)
2019	791	0	0	791	859	817	(8)	(3)	(240)	(189)
2020	791	0	0	791	873	831	(9)	(5)	(257)	(206)

Table 6-4
Projected Reliability Levels - Winter / High Case

Year	Net Generating Capacity (MW)	Net System Purchases (MW)	Net System Sales (MW)	Net System Capacity (MW)	System Peak Demand: Before Interruptible and Load Management (MW)	System Peak Demand: After Interruptible and Load Management (MW)	Reserve Margin: Before Interruptible and Load Management (%)	Reserve Margin: After Interruptible and Load Management (%)	Excess/ (Deficit) to Maintain 22% Reserve Margin: Before Interruptible and Load Management (MW)	Excess/ (Deficit) to Maintain 22% Reserve Margin: After Interruptible and Load Management (MW)
2000/2001	647									
2001/2002	891	0	100	791	798	734	(1)	8	(183)	(104)
2002/2003	957	0	100	857	816	752	5	14	(139)	(60)
2003/2004	957	0	100	857	834	769	3	11	(160)	(81)
2004/2005	957	0	100	857	853	787	0	9	(184)	(103)
2005/2006	870	0	100	770	871	804	(12)	(4)	(293)	(211)
2006/2007	870	0	100	770	889	822	(13)	(6)	(315)	(233)
2007/2008	870	0	100	770	907	839	(15)	(8)	(337)	(254)
2008/2009	870	0	100	770	925	857	(17)	(10)	(359)	(276)
2009/2010	870	0	100	770	943	874	(18)	(12)	(380)	(296)
2010/2011	870	0	0	870	961	892	(9)	(2)	(302)	(218)
2011/2012	870	0	0	870	979	909	(11)	(4)	(324)	(239)
2012/2013	870	0	0	870	997	927	(13)	(6)	(346)	(261)
2013/2014	870	0	0	870	1,016	944	(14)	(8)	(370)	(282)
2014/2015	870	0	0	870	1,034	962	(16)	(10)	(391)	(304)
2015/2016	870	0	0	870	1,052	979	(17)	(11)	(413)	(324)
2016/2017	870	0	0	870	1,070	997	(19)	(13)	(435)	(346)
2017/2018	870	0	0	870	1,086	1,012	(20)	(14)	(455)	(365)
2018/2019	870	0	0	870	1,106	1,032	(21)	(16)	(479)	(389)
2019/2020	870	0	0	870	1,124	1,049	(23)	(17)	(501)	(410)

Table 6-5
Projected Reliability Levels - Winter / Low Case

					System Peak Demand		Reserve Margin		Excess/ (Deficit) to Maintain 22% Reserve Margin	
Year	Net Generating Capacity (MW)	Net System Purchases (MW)	Net System Sales (MW)	Net System Capacity (MW)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (%)	After Interruptible and Load Management (%)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)
2000/2001	647									
2001/2002	891	0	100	791	558	494	42	60	110	188
2002/2003	957	0	100	857	575	511	49	68	156	234
2003/2004	957	0	100	857	594	529	44	62	132	212
2004/2005	957	0	100	857	612	546	40	57	110	191
2005/2006	870	0	100	770	631	564	22	37	0	82
2006/2007	870	0	100	770	648	581	19	33	(21)	61
2007/2008	870	0	100	770	667	599	15	29	(44)	39
2008/2009	870	0	100	770	684	616	13	25	(64)	18
2009/2010	870	0	100	770	703	634	10	21	(88)	(3)
2010/2011	870	0	0	870	720	651	21	34	(8)	76
2011/2012	870	0	0	870	739	669	18	30	(32)	54
2012/2013	870	0	0	870	757	687	15	27	(54)	32
2013/2014	870	0	0	870	776	704	12	24	(77)	11
2014/2015	870	0	0	870	794	722	10	20	(99)	(11)
2015/2016	870	0	0	870	812	739	7	18	(121)	(32)
2016/2017	870	0	0	870	830	757	5	15	(143)	(54)
2017/2018	870	0	0	870	848	774	3	12	(165)	(74)
2018/2019	870	0	0	870	866	792	0	10	(187)	(96)
2019/2020	870	0	0	870	884	809	(2)	8	(208)	(117)

The last column of Table 6-2 indicates that using the base winter forecast, 80 MW of capacity is required for the 2005/2006 winter season to maintain a 22 percent reserve margin. The capacity need accounts for the planned retirement of McIntosh 1 in October of 2005. However, even if McIntosh 1 were not retired, Lakeland would still need 7 MW of capacity for the 2005/2006 winter season.

Table 6-3 indicates that 57 MW of capacity is required for the 2006 summer season to maintain a 20 percent reserve margin. Thus, for planning purposes, Lakeland is assumed to be required to add new capacity to meet the first deficit which, absent unit additions, would occur in the winter of 2005/06.

Tables 6-4 and 6-5 show the high and low load forecasts for Lakeland. The high forecast indicates an immediate need for capacity while the low projects a delayed need for capacity until the winter of 2014/2015.

7.0 Analysis Results and Conclusions

This section discusses the status of Lakeland's determination of its optimum expansion plan as of December 31, 2000. At the time of this filing, Lakeland is continuing its evaluation of capacity options including the bids received in response to its RFP. If one or more of these options have the potential to be cost-effective, negotiations will follow the initial evaluations. Therefore, due to strategic considerations, this section describes the methodology being followed in the planning process without specifying a preferred incremental capacity resource either from the RFP or other available options.

However, given the need to show sufficient capacity over a ten year time frame, for purposes of the Ten-Year Site Plan, a 288 MW PFBC unit (188 MW Lakeland's share) is assumed to occur in 2005. This "place holder" is based on the results of the 2000 TYSP and reflects the probable size range and usage of the capacity alternative which will be chosen, but should not be viewed as a preferred alternative since the evaluation of options is ongoing.

7.1 Economic Evaluation

Lakeland's current resource planning cycle was initiated when the analysis for the 2000 TYSP indicated that a solid fuel unit with capacity of approximately 300 MW coming into operation in 2005 would be the incremental capacity addition that is part of the most cost-effective expansion plan.

Based on these results, Lakeland chose to initiate an RFP process as a means to implement the plan in a cost-effective manner, and issued the RFP on June 12, 2000. Given the extreme volatility in the natural gas market recently, and due to Lakeland's dependence on natural gas, the RFP indicated a preference for solid fuel capacity or, if not solid fuel, a guaranteed escalation of fuel costs. Capacity resources from 200 MW to 400 MW were sought, and bidders were informed of the price and non-price criteria which would be used for the evaluation of proposals.

Lakeland held a pre-bidder's conference in August, after which a number of prospective bidders asked that the due date for the proposals be extended beyond the initial due date of October 6, 2000. Lakeland agreed to extend the due date to December 1, 2000 at which time three proposals were received and deemed to be responsive. Two of the three proposals were for circulating fluidized bed (CPB) units burning petroleum coke to be built at the McIntosh site. The third proposal is for purchase power from an integrated coal gas production unit burning petroleum coke with an option for equity participation. Lakeland and FMPA have entered into a Memorandum of Understanding whereby they will jointly participate in the project or the purchase. Lakeland is continuing its evaluation of these proposals and other alternatives. The methodology by which Lakeland selected the 288 MW PFBC in the 2000 TYSP is discussed below.

7.1.1 Supply-Side Economic Analysis

The supply-side evaluations of generating unit alternatives were performed using POWROPT, an optimal generation expansion model. Black & Veatch developed POWROPT as an alternative to other optimization programs. POWROPT has been benchmarked against other optimization programs and has proven to be an effective modeling program. The program operates on an hourly chronological basis and is used to determine a set of optimal capacity expansion plans, simulate the operation of each plan, and select the most desirable plan based on cumulative present worth revenue requirements. POWROPT evaluates all combinations of generating unit alternatives and purchase power options on an annual basis while maintaining user-defined reliability criteria. The reserve criterion utilized was a minimum reserve margin of 22 percent for winter and 20 percent for summer. All capacity expansion plans were analyzed over a 20 year period from 2000 to 2019. A number of natural gas and solid fueled alternatives were available for selection in the expansion plans.

The revenue requirements evaluated include system fuel and variable O&M costs, fixed O&M costs for new unit additions (fixed O&M costs were not included for existing units because they are common to all plans), and capital costs for new unit additions (capital costs for existing units were not included since they are common to all plans).

After the optimal generation expansion plan was selected using POWROPT, Black & Veatch's POWRPRO detailed chronological production costing program was used to obtain the annual production cost for the expansion plan.

While options continue to be evaluated, purposes of the Ten Year Site Plan, Table 7-1 displays the reserve margins for the base case assuming 188 MW of additional PFBC capacity is added to the Lakeland system in 2005 (out of a 288 MW unit). As seen in Table 7-1, if this amount of capacity is added, Lakeland's minimum reserve margin will be met for the next ten years.

7.1.2 Demand-Side Economic Analysis

Concurrent with the supply-side analysis, demand side management (DSM) alternatives were evaluated to determine if any cost-effective measures could delay or mitigate the need for the capacity addition. The analysis included all the cost-effective DSM programs identified by Lakeland.

Table 7-1
Ten-Year Reliability Levels Assuming a 188 MW Capacity Addition in 2005 (Winter / Base Case)

					System Peak Demand		Reserve Margin		Excess/ (Deficit) to Maintain 22% Reserve Margin	
Winter Peak Period	Net Generating Capacity (MW)	Unit[1] Additions/ (Retirements) (MW)	Net System Purchases/ (Sales) (MW)	Net System Capacity (MW)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (%)	After Interruptible and Load Management (%)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)
2000/2001	647	L6 (24 MW)								
2001/2002	891	M5 CT 268 MW M5 CT (268 MW) M5 CC 384 MW L7 (50 MW)	(100)	791	691	627	14.5	26.2	(52.0)	26.1
2002/2003	957		(100)	857	708	644	21.0	33.1	(6.8)	71.3
2003/2004	957		(100)	857	727	662	17.9	29.5	(29.9)	49.4
2004/2005	957		(100)	857	745	679	15.0	26.2	(51.9)	28.6
2005/2006	1,058	M4 188 MW M1 (87 MW)	(100)	958	764	697	25.4	37.4	25.9	107.7
2006/2007	1,058		(100)	958	781	714	22.7	34.2	5.2	86.9
2007/2008	1,058		(100)	958	800	732	19.8	30.9	(18.0)	65.0
2008/2009	1,058		(100)	958	817	749	17.3	27.9	(38.7)	44.2
2009/2010	1,058		(100)	958	836	767	14.6	24.9	(61.9)	22.3
2010/2011	1,058		0	1,058	853	784	24.0	34.9	17.3	101.5

[1] L: Larsen Unit
M: McIntosh Unit

7.2 Sensitivity Analyses

Once the preferred option was selected in the base case, Lakeland performed several sensitivity analyses to measure the impact of important assumptions on the least cost plan. The sensitivity analyses will include the following:

- High load and energy growth.
- Low load and energy growth.
- High fuel price escalation.
- Low fuel price escalation.
- Constant differential between oil/gas and coal prices over the planning horizon.

For each sensitivity analysis, the least cost plan over the planning horizon was identified. The sensitivity analyses was performed over the 20 year planning period used in the base case economic evaluation, with a projection of annual costs and cumulative present worth costs.

7.3 Transmission

Each of the generating evaluated could be installed at the McIntosh site. Evaluation of purchase power alternatives resulting from Lakeland's potential RFP will require evaluation of transmission import capability based on the nature of the individual offer.

Lakeland will continue to make transmission system upgrades as necessary to support load growth on the system. There are no current plans for transmission upgrades with the installation of a unit at the McIntosh site.

7.4 Strategic Concerns

In selecting a power supply alternative, Lakeland must consider certain strategic factors, which reflect the utility's long-term ability to provide economical and reliable electric capacity and energy to its consumers. A number of strategic considerations favor the installation of a solid fuel unit at the McIntosh site (McIntosh Unit 4), although some of these advantages could also be captured in a power purchase having the necessary characteristics and guarantees. The benefits of placing a unit at the McIntosh site include excellent efficiency, existing site which can support the project capacity, electric industry deregulation, environmental benefits, and increased fuel diversity.

7.4.1 Efficiency

Lakeland strives to provide its customers with the lowest rates achievable while maintaining sound operating principles and environmentally clean units. The technologies being considered represent the best available solid fuel technology. With the installation of McIntosh Unit 4 or through a comparable power purchase, the capacity addition will yield high efficiency, it will strengthen Lakeland's fuel diversity and it will provide a very clean burning solution to meet Lakeland's load growth.

7.4.2 Reliability Need

Lakeland will not be able to maintain the minimum reserve margin without installing generation or purchasing power in 2005 under the base assumptions. McIntosh Unit 4 or a comparable capacity purchase offers the ability to meet Lakeland's expected load growth and reserve margin requirement of 22 percent in the winter and 20 percent in the summer. Also, with the increased fuel diversity, Lakeland customers will benefit from a more reliable power source, less subject to extreme volatility in the natural gas market.

7.4.3 Deregulation

In a deregulated environment, a solid fuel unit located in central Florida would be an economical unit due to its high efficiency, low heat rate and enhanced stability due to fuel diversity. This would ensure competitive generation for Lakeland customers and Florida residents. This will help ensure that Lakeland remains a competitive provider of electric generation for the future and reduces the risk that McIntosh 4 would become a stranded asset should retail access occur in the state.

7.4.4 Timing

With the installation of McIntosh Unit 4 or should Lakeland enter into a firm power purchase, Lakeland will benefit in many ways. The installation of McIntosh Unit 4 will counteract the scheduled retirements of older less efficient units. Customers will benefit from the replacement of older generation with cleaner more efficient generation. The financial savings from more efficient generation and fewer emissions will be passed along to the customers.

Lakeland has the opportunity to utilize its strategic advantage of low cost tax exempt municipal financing for the more capital intensive McIntosh Unit 4. The ability to use the tax exempt financing may not continue to be available as the industry deregulates.

7.4.5 Fuel Risk

If the option selected involves the construction of McIntosh Unit 4 which utilizes petroleum coke, Lakeland's natural gas dependency will decrease. The unit would also be capable of burning the coal used for McIntosh 3, thus providing Lakeland with fuel diversity should the petroleum coke supply be interrupted or should fuel economics justify a switch to coal. These advantages will also be available from purchase power fueled with petroleum coke or coal.

Currently Lakeland is dependent on natural gas. As of December 31, 2000, Lakeland is 67 percent dependent on natural gas. By December of 2005, Lakeland's generation mix will be 78 percent dependent on natural gas. The installation of McIntosh Unit 4 will significantly decrease Lakeland's dependency on natural gas in 2006 to 62 percent and create a more diverse and proportionate fuel dependency. With increased fuel diversity, Lakeland will become a more reliable source of energy generation for Lakeland's customers, FMPP, and the state of Florida.

7.4.6 Environmental Impacts

Should Lakeland chose to install a solid fuel unit at the McIntosh site, the use of the existing site minimizes environmental impacts and reduces the time and effort required for licensing. The low level of emissions with the units being considered reduces the risk associated with future environmental regulations while reducing emissions within the state through displacement and retirement of other less efficient units. Additional environmental considerations are discussed in the next section.

8.0 Environmental and Land Use Information

Lakeland's 2001 Ten-Year Site Plan includes McIntosh Unit 5 for which the simple cycle installation is complete and formal commercial operation is scheduled for May 1, 2001. The combined cycle conversion of McIntosh Unit 5 was approved by the PSC on May 10, 1999 in order No. PSC-99-0931-FOF-EM and construction began July 24, 2000. The Site Certification Application for McIntosh Unit No. 5 Steam Cycle which was filed with all the agencies for the Site Certification, contains detailed environmental and land use information.

Lakeland's Ten-Year Site Plan includes an assumed 188 MW share of McIntosh Unit 4, although as mentioned, the final capacity and unit are subject to change pending Lakeland's ongoing evaluation of options. The specific configuration of McIntosh Unit 4 will be determined as part of the Request for Proposal (RFP) process. For purposes of the Ten-Year Site Plan, McIntosh Unit 4 is assumed to a jointly owned 288 MW pressurized fluidized bed combined cycle (PFBC) with petroleum coke as the primary fuel and coal as the secondary fuel. Should another solid fuel unit ultimately be selected for installation at the McIntosh site, much of the following will also apply.

8.1 Status of Site Certification

Lakeland initiated a RFP process for the purchase of power or installation of new generation. Based on the progress of the RFP bid evaluation currently underway, Lakeland plans to file Need for Power and Site Certification Applications in the spring of 2001.

8.2 Land and Environmental Features

Control devices will be used to reduce emissions from either a new unit constructed at McIntosh or a unit constructed to provide purchase power.

Reclaimed water from treated sewage effluent is available for cooling water for a unit constructed at McIntosh. Use of reclaimed water will conserve valuable water resources. It is assumed that cooling tower blowdown will be treated for reuse as part of the design features of a unit constructed at McIntosh. Return of wastewater to the City Wastewater Treatment Facility may be possible which would reduce costs but there is limited additional capacity for this alternative. Existing fuel handling and storage facilities at McIntosh will be used, eliminating additional environmental impacts from these facilities. The location of the proposed site and the existing land use with adjacent areas is shown on Figure 8-1. The proposed site layout for a PFBC unit is also provided in Figure 8-1.

8.3 Air Emissions

The proposed commercial operating date is June of 2005. Estimated emissions for a PFBC are as follows:

- SO_2, lb/MBtu – 0.20 (requires zero stage cyclone and sorbent consumption of 40,000 lb/hr per module with 8 percent fuel sulfur).
- NO_x, lb/MBtu – 0.09
- CO, lb/MBtu – 0.022
- Particulate, lb/MBtu – 0.011

8.4 Analysis of 1990 Clean Air Act Amendments

The City of Lakeland considers the impacts to its community and Peninsular Florida a vital portion of its strategic planning. While the Florida Electrical Power Plant Siting Act carefully bifurcates the need for the power plant from the environmental impacts of the facility, the Clean Air Act requirements have a great impact on the power plant's cost and performance.

8.4.1 Authority to Construct

A new unit is required to comply with the Clean Air Act and the current Florida air quality requirements stemming from the Act. Lakeland's Authority to Construct (ATC) permit for a new unit will be obtained through the Site Certification Process. One aspect of the ATC permit will be the determination of Best Available Control Technology (BACT). Major criteria pollutants included in the BACT analysis are SO_2, NO_x, VOC, CO, and PM/PM10. Lakeland believes that the inherently low emission profile will meet BACT requirements.

8.4.2 Title V Operating Permit

Along with the ATC, the unit will be required to obtain an operating permit under Title V of the Clean Air Act. All units at the McIntosh and Larsen sites will be ultimately included in a single Title V permit. Requirements under the Title V permit for a new unit will require similar emissions control and operations to those required under the ATC and BACT determination.

8.4.3 Title IV Acid Rain Permit

In addition to the construction and operating permit requirements of the Unit, the regulations implementing the Acid Rain provisions of the Clean Air Act Amendments require that electric utility units obtain acid rain permits.

8.4.4 Compliance Strategy

A new unit will emit relatively low levels of sulfur dioxide while running on either petroleum coke or coal. An affected unit must have allowances available for emission of sulfur dioxide to comply with its future Title IV Acid Rain permit. Lakeland's ATC permit will set a limit of sulfur dioxide emissions. Lakeland's share for current operation of the McIntosh and Larsen Units result in a combined sulfur dioxide emission rate of approximately 8,680 tons per year for 1999. Lakeland currently has 12,809 allowances available annually leaving enough allowances for a new unit. Purchasing allowances will be the compliance strategy utilized if, for any reason, Lakeland's existing allowances are insufficient.

8.5 Waste Supply and Use

Cooling water supply for a new unit at McIntosh will be reclaimed sewage treatment plant effluent water using the existing reclaimed water pipeline at the site. Additional filtration facilities will be required to ensure the water quality is suitable for the cooling towers and to meet Florida requirements for reuse. Process makeup for ash systems will primarily be cooling tower blowdown. Demineralized water supply will be treated well water using a new demineralizer system.

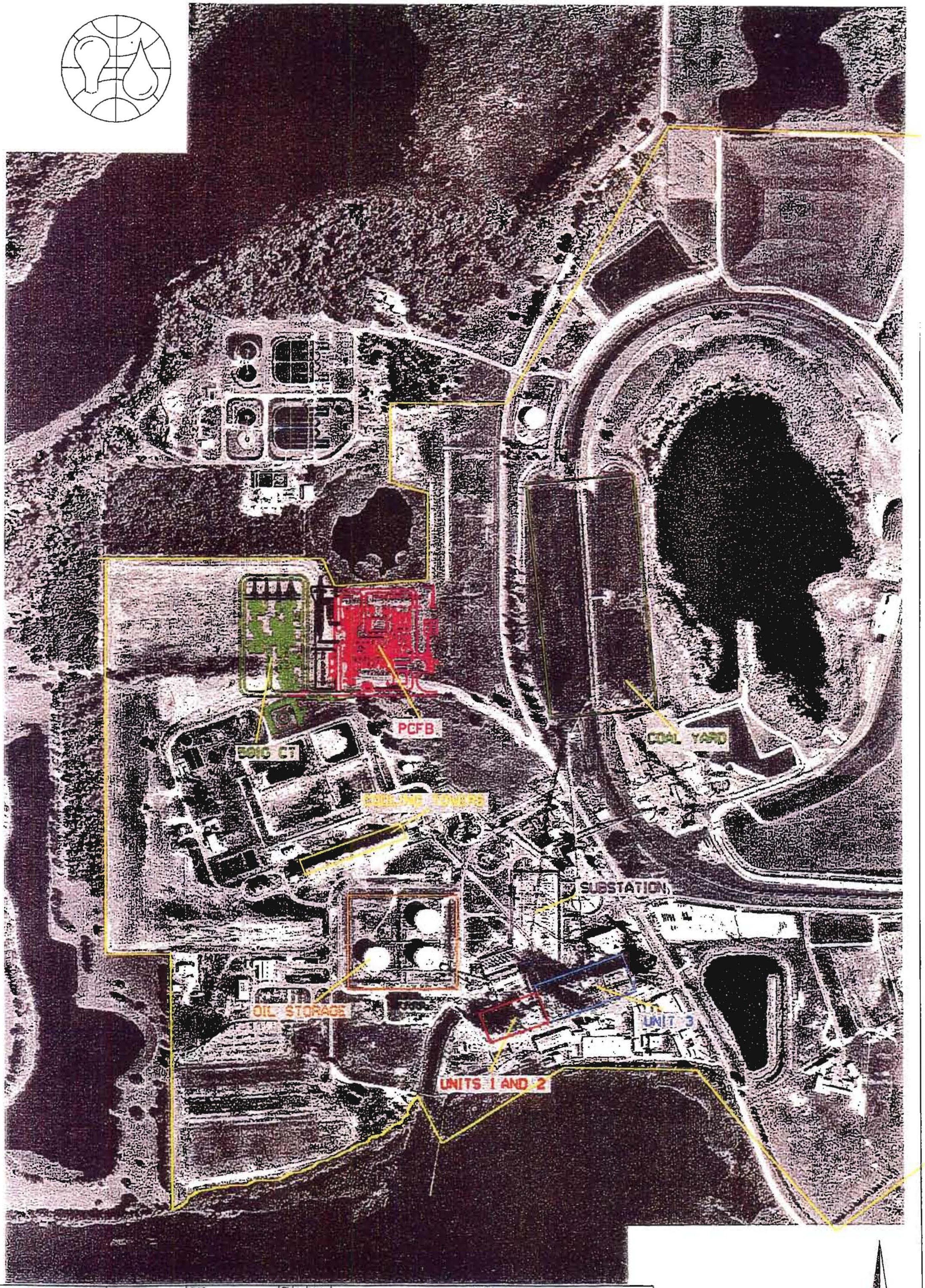
8.6 Wastewater Discharge

An existing wastewater disposal pump station and pipeline exists at McIntosh which transports wastewater back to the City's wastewater treatment plants for treatment and disposal. Because of pending discharge salinity restrictions, there may not be capacity for additional cooling tower blowdown wastewater to be disposed at the treatment facilities. Therefore, it has been assumed that cooling tower blowdown wastewater will be treated on-site at McIntosh for reuse. Cooling tower blowdown quality is suitable for direct reuse in ash conditioning systems. Excess blowdown would need to be treated by a process using reverse osmosis and evaporation technology to produce a low salinity product water and a solid waste that could be landfilled.

8.7 Fuel Delivery and Storage

A new unit at McIntosh is expected to burn 100 percent petroleum coke. The secondary fuel will be the same coal as burned in McIntosh Unit 3. The choice of the secondary fuel saves in the cost of an additional fuel storage space. Unit trains or trucks will deliver the petroleum coke. The coal is presently delivered by unit train to the site.

A separate storage pile for petroleum coke is planned adjacent to the existing coal pile for McIntosh Unit 3. Coal for secondary fuel use will be stored in the existing McIntosh Unit 3 coal pile.



CITY OF LAKELAND DEPARTMENT OF ELECTRIC & WATER UTILITIES

McINTOSH PLANT GENERAL ARRANGEMENT

9.0 Ten-Year Site Plan Schedules

The following section presents the schedules required by the Ten-Year Site Plan rules for the Florida Public Service Commission. Lakeland has attempted to provide complete information for the FPSC whenever possible.

9.1 Abbreviations and Descriptions

The following abbreviations are used throughout the Ten-Year Site Plan Schedules.

Abbreviation	Description
Unit Type	
CA	Combined Cycle Steam Part
GT	Combustion Gas Turbine
ST	Steam Turbine
CT	Combined Cycle Combustion Turbine
NG	Natural Gas
Fuel Type	
DFO	Distillate Fuel Oil
RFO	Residual Fuel Oil
BIT	Bituminous Coal
WH	Waste Heat
WH	Waste Heat
Fuel Transportation Method	
PL	Pipeline
TK	Truck
RR	Railroad
Unit Status Code	
RE	Retired
TS	Construction Complete, not yet in commercial operation
U	Under Construction
P	Planned for installation

Table 9-1
Schedule 1.0: Existing Generating Facilities as of December 31, 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Fuel		Fuel Transport						Net Capability[2]	
Plant Name	Unit No.	Location	Unit Type	Pri	Alt	Pri	Alt	Alt Fuel Days Use[3]	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen. Max. Nameplate kW	Summer MW	Winter MW
Charles Larsen Memorial	2	16-17/28S/24E	GT	NG	DFO	PL	TK	NR	11/62	Unknown	11,500	10	14
	3		GT	NG	DFO	PL	TK	NR	12/62	Unknown	11,500	10	14
	5		CA	WH	---	---	---	NR	04/56	Unknown	25,000	29	31
	6		ST	NG	RFO	PL	TK	NR	12/59	10/01	25,000	24	24
	7		ST	NG	RFO	PL	TK	NR	02/66	01/02	50,000	50	50
	8		CT	NG	DFO	PL	TK	NR	07/92	Unknown	101,520	73	93
Plant Total												196	226
C.D. McIntosh, Jr.	IC1	4-5/28S/24E	IC	DFO	---	TK	---	NR	01/70	Unknown	2,500	3	3
	IC2		IC	DFO	---	TK	---	NR	01/70	Unknown	2,500	3	3
	1GT		GT	NG	DFO	PL	TK	NR	05/73	Unknown	26,640	17	20
	ST1		ST	NG	RFO	PL	TK	NR	02/71	10/05	103,000	87	87
	ST2		ST	NG	RFO	PL	TK	NR	06/76	Unknown	126,000	103	103
	ST3[1]		ST	BIT	---	RR	---	NR	09/82	Unknown	363,870	205	205
Plant Total												418	421
System Total												614	647

[1]Lakeland's 60 percent portion of joint ownership with Orlando Utilities Commission.
[2]Net Normal.
[3]Lakeland does not maintain records of the number of days that alternate fuel is used.

Source: Lakeland Power Production Unit Rating Group

Table 9-2
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 & Residential					Commercial		
Fiscal Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption per Customer	GWh	Average No. of Customers	Average kWh Consumption per Customer
1991	189,445	2.47	967	76,731	12,602	522	9,517	54,849
1992	198,763	2.55	987	77,863	12,676	526	9,664	54,429
1993	201,748	2.53	1,026	79,738	12,867	542	9,768	55,487
1994	206,040	2.53	1,080	81,542	13,245	574	9,967	57,590
1995	210,095	2.54	1,169	82,616	14,150	594	9,999	59,406
1996	213,347	2.54	1,201	84,089	14,282	589	9,729	60,541
1997	216,782	2.58	1,173	84,149	13,940	609	9,816	62,042
1998	218,959	2.54	1,254	86,340	14,529	634	10,127	62,644
1999	221,921	2.52	1,237	87,955	14,064	641	10,916	58,721
2000	225,558	2.54	1,274	88,813	14,345	708	11,085	63,870
Forecast								
2001	229,467	2.56	1,299	89,806	14,465	721	11,208	64,329
2002	233,047	2.56	1,331	91,127	14,606	739	11,373	64,978
2003	236,620	2.56	1,363	92,446	14,744	757	11,538	65,609
2004	240,167	2.56	1,395	93,757	14,879	774	11,702	66,143
2005	243,674	2.56	1,427	95,065	15,011	793	11,865	66,835
2006	247,221	2.56	1,460	96,384	15,148	810	12,029	67,337
2007	250,757	2.57	1,492	97,703	15,271	828	12,194	67,902
2008	252,295	2.55	1,525	99,026	15,400	847	12,359	68,533
2009	257,857	2.57	1,557	100,360	15,514	864	12,526	68,977
2010	261,441	2.57	1,589	101,700	15,624	882	12,693	69,487

Table 9-3
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						
Fiscal Year	GWh	Average No. of Customers	Average kWh Consumption per Customer	Railroads and Railways	Street & Highway Lighting GWh	Other Sales to Public Authorities GWh	Total Sales to Ultimate Consumers GWh
1991	344	45	7,644,444	0	11	61	1,905
1992	356	47	7,574,468	0	13	65	1,947
1993	381	51	7,470,588	0	13	68	2,030
1994	400	51	7,843,137	0	14	69	2,137
1995	427	51	8,372,549	0	15	74	2,279
1996	436	59	7,389,831	0	15	78	2,319
1997	459	61	7,524,590	0	16	78	2,335
1998	474	62	7,645,161	0	17	80	2,460
1999	486	80	6,075,000	0	17	82	2,463
2000	532	85	6,258,824	0	18	11	2,543
Forecast							
2001	542	86	6,302,326	0	19	10	2,591
2002	556	88	6,318,182	0	19	10	2,655
2003	569	89	6,393,258	0	19	11	2,719
2004	583	90	6,477,778	0	20	11	2,783
2005	596	91	6,549,451	0	21	11	2,848
2006	610	93	6,559,140	0	21	11	2,912
2007	623	94	6,627,660	0	22	12	2,977
2008	636	95	6,694,737	0	22	12	3,042
2009	650	96	6,770,833	0	23	12	3,106
2010	664	98	6,775,510	0	23	13	3,171

Table 9-4
Schedule 2.3: History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)
Fiscal Year	Sales for Resale GWh	Utility Use & Losses GWh	Net Energy for Load GWh	Other Customers (Average No.)	Total No. of Customers
1991	0	138	2,043	0	86,293
1992	0	143	2,090	0	87,574
1993	0	155	2,185	0	89,557
1994	0	146	2,283	0	91,560
1995	0	146	2,425	0	92,666
1996	0	116	2,435	0	93,877
1997	0	115	2,450	0	94,026
1998	0	132	2,592	0	96,529
1999	0	112	2,575	0	98,951
2000	0	166	2,709	0	99,983
Forecast					
2001	0	155	2,746	0	101,100
2002	0	159	2,814	0	102,588
2003	0	163	2,882	0	104,073
2004	0	167	2,950	0	105,549
2005	0	170	3,018	0	107,021
2006	0	175	3,087	0	108,506
2007	0	178	3,155	0	109.991
2008	0	182	3,224	0	111,480
2009	0	187	3,293	0	112,982
2010	0	190	3,361	0	114,491

Table 9-5
Schedule 3.1: History and Forecast of Summer Peak Demand Base Case (MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
					Residential		Commercial/Industrial		
Year	Total	Wholesale	Retail	Interrupt.	Load Management	Conservation	Load Management	Conservation	Net Firm Demand
1991	424	0	424	0	0	0	0	0	424
1992	434	0	434	0	0	0	0	0	434
1993	477	0	477	0	0	0	0	0	477
1994	455	0	455	0	0	0	0	0	455
1995	481	0	481	0	0	0	0	0	481
1996	490	0	490	0	0	0	0	0	482
1997	509	0	509	0	0	0	0	0	509
1998	535	0	535	0	0	0	0	0	535
1999	557	0	557	0	22	0	0	0	535
2000	573	0	573	0	21	0	0	0	552
Forecast									
2001	584	0	584	14	21	0	0	0	549
2002	600	0	600	14	22	0	0	0	564
2003	615	0	615	14	22	0	0	0	579
2004	629	0	629	14	22	0	0	0	593
2005	644	0	644	14	22	0	0	0	608
2006	660	0	660	14	23	0	0	0	623
2007	676	0	676	15	23	0	0	0	638
2008	691	0	691	15	23	0	0	0	653
2009	706	0	706	15	23	0	0	0	668
2010	722	0	722	15	24	0	0	0	683

Table 9-6
Schedule 3.2: History and Forecast of Winter Peak Demand Base Case (MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
					Residential		Comm./Ind.		
Year	Total	Wholesale	Retail	Interrupt.	Load Management	Conservation	Load Management	Conservation	Net Firm Demand
1991/1992	464	0	464	0	20	0	0	0	444
1992/1993	480	0	480	0	23	0	0	0	457
1993/1994	485	0	485	0	0	0	0	0	445
1994/1995	578	0	578	0	40	0	0	0	538
1995/1996	655	0	655	0	45	0	0	0	610
1996/1997	552	0	552	0	0	0	0	0	552
1997/1998	476	0	476	0	0	0	0	0	476
1998/1999	611	0	611	0	0	0	0	0	611
1999/2000	661	0	661	0	51	0	0	0	610
2000/2001	706	0	706	0	51	0	0	0	655
Forecast									
2001/02	691	0	691	12	52	0	0	0	627
2002/03	708	0	708	12	52	0	0	0	644
2003/04	727	0	727	12	53	0	0	0	662
2004/05	745	0	745	13	53	0	0	0	679
2005/06	764	0	764	13	54	0	0	0	697
2006/07	781	0	781	13	54	0	0	0	714
2007/08	800	0	800	13	55	0	0	0	732
2008/09	817	0	817	13	55	0	0	0	749
2009/10	836	0	836	13	56	0	0	0	767
2010/11	853	0	853	13	56	0	0	0	784

Table 9-7
Schedule 3.3: History and Forecast of Annual Net Energy for Load – GWh
Base Case

(1)	(2)	(3)	(5)	(6)	(7)	(8)	(9)	(10)
Fiscal Year	Total	Residential Conservation	Comm./Ind. Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
1991	1,760	0	0	1,760	0	138	1,898	49.2
1992	1,801	0	0	1,801	0	143	1,944	50.0
1993	1,851	0	0	1,851	0	155	2,006	50.1
1994	1,972	0	0	1,972	0	146	2,118	54.3
1995	2,100	0	0	2,100	0	146	2,246	47.7
1996	2,206	0	0	2,206	0	116	2,322	43.5
1997	2,216	0	0	2,216	0	115	2,331	48.2
1998	2,300	1	0	2,299	0	132	2,431	58.3
1999	2,353	1	0	2,352	0	112	2,464	46.0
2000	2,543	0	0	2,543	0	166	2,709	50.7
Forecast								
2001	2,591	0	0	2,591	0	155	2,746	47.9
2002	2,655	0	0	2,655	0	159	2,814	51.2
2003	2,719	0	0	2,719	0	163	2,882	51.1
2004	2,783	0	0	2,783	0	167	2,950	50.9
2005	2,848	0	0	2,848	0	170	3,018	50.7
2006	2,912	0	0	2,912	0	175	3,087	50.6
2007	2,977	0	0	2,977	0	178	3,155	50.4
2008	3,042	0	0	3,042	0	182	3,224	50.3
2009	3,106	0	0	3,106	0	187	3,293	50.2
2010	3,171	0	0	3,171	0	190	3,361	50.0

Table 9-8
Schedule 4: Previous Year and Two Year Forecast of Retail Peak Demand and Net Energy for Load by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Month	Actual		2001 Forecast		2002 Forecast	
	Peak Demand[1] MW	NEL GWh	Peak Demand[1] MW	NEL GWh	Peak Demand[1] MW	NEL GWh
January	610	211,021	655	231,112	627	236,846
February	508	190,059	557	199,796	577	204,753
March	407	195,373	483	204,416	501	209,487
April	416	194,644	444	197,480	456	202,379
May	504	246,358	501	231,511	514	237,254
June	532	251,453	539	252,529	553	258,794
July	552	262,095	544	265,298	559	271,880
August	539	269,321	549	269,440	564	276,125
September	528	253,700	533	250,804	548	257,025
October	510	210,893	489	222,953	502	228,355
November	476	195,837	455	199,018	468	203,839
December	597	228,570	550	221,835	565	227,210

[1]After Load Management, Conservation and Interruptible Load exercised as needed.

Table 9-9
Schedule 5: Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				Calendar Year											
	Fuel Requirements	Type	Units	1999 – Actual	2000 - Actual	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
(1)	Nuclear		Trillion Btu	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal[1]		1000 Ton	455	580	472	454	457	462	554	637	602	640	752	757
(3)		Total	1000 BBL	181	196	0	0	0	0	0	0	0	0	0	0
(4)		Steam	1000 BBL	181	196	0	0	0	0	0	0	0	0	0	0
(5)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate[3]	Total	1000 BBL	3	4	10	1	1	1	1	2	2	2	2	3
(9)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CT	1000 BBL	3	4	10	1	1	1	1	2	2	2	2	3
(12)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	9.280	8.121	17,342	14,307	14,608	14,984	13,862	12,553	13,613	13.324	11,907	12,267
(14)		Steam	1000 MCF	3,769	3,150	3,350	1,683	1.658	1,718	1,509	892	914	872	751	793
(15)		CC	1000 MCF	5,120	3,559	5,410	12,571	12,893	13,206	12,295	11,578	12,406	12.152	10,944	11.237
(16)		CT	1000 MCF	391	1,412	8.582	53	57	60	58	83	293	300	212	237
(17)		Diesel	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(18)	Other		Trillion Btu	0	0	0	0	0	0	0	0	0	0	0	0

[1] Includes Petroleum Coke and Refuse Derived Fuel.
[2] Residual includes #4, #5 and #6 oil.
[3] Distillate includes #1, #2 oil, kerosene, jet fuel and amounts used at coal burning plants for flame stabilization and on start up.

Table 9-10
Schedule 6.1: Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				Calendar Year											
	Fuel Requirements	Type	Units	1999 – Actual	2000 - Actual	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
(1)	Firm Interchange		GWh	(18)	(28)	(466)	(581)	(577)	(577)	(579)	(567)	(564)	(561)	(597)	(595)
(2)	Nuclear		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Residual[2]	Total	GWh	100	136	0	0	0	0	0	0	0	0	0	0
(4)		Steam	GWh	99	136	0	0	0	0	0	0	0	0	0	0
(5)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	GWh	1	0	0	0	0	0	0	0	0	0	0	0
(7)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate[3]	Total	GWh	0	2	1	1	1	1	1	1	1	1	1	1
(9)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CT	GWh	0	2	1	1	1	1	1	1	1	1	1	1
(12)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	GWh	1,192	1,087	1,760	1,992	2,046	2,097	1,906	1,728	1,887	1,848	1,638	1,687
(14)		Steam	GWh	631	626	321	154	153	158	139	82	87	83	71	76
(15)		CC	GWh	534	343	595	1,834	1,889	1,935	1,763	1,641	1,775	1,739	1,547	1,591
(16)		CT	GWh	27	118	844	4	4	4	4	5	25	26	20	20
(17)	Coal[1]	Total	GWh	1,301	1,512	1,451	1,402	1,412	1,429	1,690	1,925	1,831	1,936	2,251	2,268
(18)	Net Energy for Load		GWh	2,575	2,709	2,746	2,814	2,882	2,950	3,018	3,087	3,155	3,224	3,293	3,361

[1] Includes Petroleum Coke and Refuse Derived Fuel.
[2] Residual includes #4, #5 and #6 oil.
[3] Distillate includes #1, #2 oil, kerosene, jet fuel and amounts used at coal burning plants for flame stabilization and on start up.

Table 9-11
Schedule 6.2: Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				Calendar Year											
	Energy Source	Type	Units	1999 – Actual	2000 - Actual	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
(1)	Firm Interchange[4]		%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(2)	Nuclear		%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(3)	Residual[2]	Total	%	4%	5%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(4)		Steam	%	4%	5%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(5)		CC	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(6)		CT	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(7)		Diesel	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(8)	Distillate[3]	Total	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(9)		Steam	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(10)		CC	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(11)		CT	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(12)		Diesel	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(13)	Natural Gas	Total	%	46%	40%	55%	59%	59%	60%	53%	47%	51%	49%	42%	43%
(14)		Steam	%	25%	23%	10%	5%	4%	5%	4%	2%	2%	2%	2%	2%
(15)		CC	%	21%	13%	19%	54%	55%	55%	49%	45%	48%	46%	40%	40%
(16)		CT	%	1%	4%	26%	0%	0%	0%	0%	0%	1%	1%	1%	1%
(17)	Coal[1]	Total	%	50%	55%	45%	41%	41%	41%	47%	53%	49%	51%	58%	57%
(18)	Net Energy for Load		%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

[1] Includes Petroleum Coke and Refuse Derived Fuel.
[2] Residual includes #4, #5 and #6 oil.
[3] Distillate includes #1, #2 oil, kerosene, jet fuel and amounts used at coal burning plants for flame stabilization and on start up.

Table 9-12
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)
Year	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	Projected Firm Net To Grid from NUG	Total Capacity Available	System Firm Peak Demand	Reserve Margin Before Maintenance[1]		Scheduled Maintenance	Reserve Margin After Maintenance[1]	
	MW	MW	MW	MW	MW	MW	MW	%	MW	MW	%
2001	835	0	150	0	685	549	136	25%	0	136	25%
2002	878	0	100	0	778	564	214	38%	0	214	38%
2003	878	0	100	0	778	579	199	34%	0	199	34%
2004	878	0	100	0	778	593	185	31%	0	185	31%
2005	1,066	0	100	0	966	608	358	59%	0	358	59%
2006	979	0	100	0	879	623	256	41%	0	256	41%
2007	979	0	100	0	879	638	241	38%	0	241	38%
2008	979	0	100	0	879	653	226	35%	0	226	35%
2009	979	0	100	0	879	668	211	32%	0	211	32%
2010	979	0	100	0	879	683	196	29%	0	196	29%

[1] Included exercising Load Management and Interruptible Load.

Table 9-13
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)
Year	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	Projected Firm Net To Grid from NUG	Total Capacity Available	System Firm Peak Demand	Reserve Margin Before Maintenance[1]		Scheduled Maintenance	Reserve Margin After Maintenance[1]	
	MW	MW	MW	MW	MW	MW	MW	%	MW	MW	%
2001	647	57	0	0	704	655	49	7%	0	49	7%
2002	891	0	100	0	791	627	164	26%	0	164	26%
2003	957	0	100	0	857	644	213	33%	0	213	33%
2004	957	0	100	0	857	662	195	29%	0	195	29%
2005	957	0	100	0	857	679	178	26%	0	178	26%
2006	1.058	0	100	0	958	697	261	37%	0	261	37%
2007	1,058	0	100	0	958	714	244	34%	0	244	34%
2008	1,058	0	100	0	958	732	226	31%	0	226	31%
2009	1,058	0	100	0	958	749	209	28%	0	209	28%
2010	1,058	0	100	0	958	767	191	25%	0	191	25%

[1] Included exercising Load Management and Interruptible Load

Table 9-14
Schedule 8.0: Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Plant Name	Unit No.	Location	Unit Type	Fuel		Fuel Transport		Const Start	Commercial In-Service	Expected Retirement	Gen Max Nameplate	Net Capability		Status
				Pri.	Alt.	Pri.	Alt.	Mo/Yr	Mo/Yr	Mo/Yr	kW	Sum MW	Win MW	
Charles Larsen Memorial	6	Polk County	ST	NG	RFO	PL	TK			10/01	25,000	24	24	RE
	7		ST	NG	RFO	PL	TK			01/02	50,000	50	50	RE
C.D. McIntosh Jr.	1	Polk County	ST	NG	RFO	PL	TK			10/05	103,000	87	87	RE
	5 CT		CT	NG	RFO	PL	TK	06/98	05/01	Unknown	249,000	221	268	TS
	5 CC		ST	WH				07/00	01/02	Unknown	120,000	120	120	U
	4 PFBC		ST	PC	BIT	RR	RR	01/02	06/05	Unknown	288,000	188[1]	188[1]	P

[1]Lakeland's ownership share.

Table 9-15
Schedule 9.1: Status Report and Specifications of Approved Generating Facilities

(1)	Plant Name and Unit Number:	McIntosh Unit 5
(2)	Capacity:	
(3)	Summer MW	120 MW (steam turbine only)
(4)	Winter MW	120 MW (steam turbine only)
(5)	Technology Type:	Combined Cycle
(6)	Anticipated Construction Timing:	
(7)	Field Construction Start-date:	07/01/00
(8)	Commercial In-Service date:	01/01/02
(9)	Fuel	
(10)	Primary	Waste Heat
(11)	Alternate	
(12)	Air Pollution Control Strategy:	Ultra Low NOx burners. If emissions of 9 ppm or below cannot be met with Ultra Low NOx burners, Lakeland will convert the unit and install a conventional SCR with a 7.5 ppm limit.
(13)	Cooling Method:	Mechanical Cooling Tower
(14)	Total Site Area.	9.5 acres.
(15)	Construction Status:	Combustion turbine complete. Steam turbine planned
(16)	Certification Status:	Need for Power approved. Site Certification approved.
(17)	Status with Federal Agencies:	Approved.
(18)	Projected Unit Performance Data:	
(19)	Planned Outage Factor (POF)	4.38 percent
(20)	Forced Outage Factor (FOF):	4.5 percent
(21)	Equivalent Availability Factor (EAF):	91.2 percent
(22)	Resulting Capacity Factor (%):	91.2 percent
(23)	Average Net Operating Heat Rate (ANOHR):	6,523 Btu/kWh
(24)	Projected Unit Financial Data:	
(25)	Book Life:	25 years
(26)	Total Installed Cost (In-Service year $/kW):	748.99
(27)	Direct Construction Cost ($/kW):	670.83
(28)	AFUDC Amount ($/kW):	32.03
(29)	Escalation ($/kW):	46.13
(30)	Fixed O&M ($/kW-yr):	1.133
(31)	Variable O&M ($/MWh):	1.266
(32)	K factor	1.2283

Table 9-16
Schedule 9.2: Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	McIntosh Unit 4
(2)	Capacity:	
(3)	Summer MW	288 MW (Lakeland ownership share of 188 MW)
(4)	Winter MW	288 MW (Lakeland ownership share of 188 MW)
(5)	Technology Type:	Pressurized Fluidized Bed Combine Cycle
(6)	Anticipated Construction Timing:	
(7)	Field Construction Start-date:	06/01/02
(8)	Commercial In-Service date:	06/01/05
(9)	Fuel	
(10)	Primary	Petroleum Coke
(11)	Alternate	Coal
(12)	Air Pollution Control Strategy:	SNCR, limestone, fabric filters or electrostatic precipitators for particulate matter.
(13)	Cooling Method:	Cooling Tower
(14)	Total Site Area:	PFBC Island dimensions: 510-ft.x560 ft. for Unit itself, Total site 513 acres).
(15)	Construction Status:	None.
(16)	Certification Status:	Filing planned April 2001.
(17)	Status with Federal Agencies:	No status.
(18)	Projected Unit Performance Data:	
(19)	Planned Outage Factor (POF):	7.6 percent
(20)	Forced Outage Factor (FOF):	12.0 percent
(21)	Equivalent Availability Factor (EAF):	81 percent
(22)	Resulting Capacity Factor (%):	81 percent
(23)	Average Net Operating Heat Rate (ANOHR):	9,575 Btu/kWh
(24)	Projected Unit Financial Data:	
(25)	Book Life:	30 years
(26)	Total Installed Cost (In-Service year $/kW):	1,500
(27)	Direct Construction Cost ($/kW):	1,200
(28)	AFUDC Amount ($/kW):	135
(29)	Escalation ($/kW):	165
(30)	Fixed O&M ($/kW-yr):	9.18
(31)	Variable O&M ($/MWh):	4.53 (including limestone)
(32)	K factor	1.2355

Table 9-17
Schedule 10: Status Report and Specifications of Proposed Directly Associated Transmission Lines

(1)	Point of Origin and Termination:	None planned.
(2)	Number of Lines:	None planned.
(3)	Right of Way:	None planned.
(4)	Line Length:	None planned.
(5)	Voltage:	None planned.
(6)	Anticipated Construction Time:	None planned.
(7)	Anticipated Capital Investment:	None planned.
(8)	Substations:	None planned.
(9)	Participation with Other Utilities:	None planned.