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A DESCRIPTION OF THE SYSTEM PLANNING PROCESS AT
FLORIDA POWER CORPORATION

Task I Report No. FC-5237-1

January 1980

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The Franklin Institute
Franklin Research Center
Philadelphia, Pennsylvania

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U.S. Department of Energy

Solar Energy

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**A DESCRIPTION OF THE
SYSTEM PLANNING PROCESS
AT
FLORIDA POWER CORPORATION**

**TASK I REPORT
NO. FC-5237-1**

**TO
FLORIDA POWER CORPORATION**

**PREPARED BY
FRANKLIN RESEARCH CENTER
JANUARY, 1980**

Franklin Research Center
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EXECUTIVE SUMMARY

1. WHAT IS BEING DONE AND WHY?

- Study OTEC via electric utility system planning methods
- Directly examine OTEC for actual suitability for Florida Power Corporation
- Reveal information useful to development of OTEC and related to barriers or incentives to commercialization
- Start in motion the action to make OTEC a reality for Florida Power Corporation.

2. WHAT IS ELECTRIC UTILITY SYSTEM PLANNING?

- A method of decision making on new generating capacity
- A formalism, using computer models of:
 - (a) physical and electrical characteristics of power plants, transmission and distribution systems
 - (b) corporate economic/financial interests
- Projected information, including generation plant expansion plans and consequences, including economic impacts.

3. FLORIDA POWER CORPORATION BACKGROUND

- West coast and central Florida, headquarters St. Petersburg
- 4858 MWe generating capacity, mostly petroleum fueled (as of 12/31/78)
- Larger than national average growth area
- Future needs indicate both expansion and fuel substitution
- Interconnects to Florida Light & Power Company (Miami) to east, Georgia Power Company to north, Gulf Power Company to west, and Tampa Electric Company to south.
- Adjacent to Gulf of Mexico OTEC thermal resource offshore.

4. FLORIDA POWER CORPORATION SYSTEM PLANNING PROCEDURES

- Are a continual process with annual Generation Facility Expansion Plan (10-year plan based on 20-year study)
- Prepare load forecast
- Postulate alternative system expansion plans
- Determine system reliability and economic consequences for each alternative scenario, using:
 - (a) PROMOD computer program, and
 - (b) CORPORATE MODEL program

EXECUTIVE SUMMARY (Continued)

- Examine adequacy of power transmission system; LOADFLO program
- Study long-range siting and interconnections
- Analyze results and recommend plans.

5. FLORIDA POWER CORPORATION 10-YEAR PLAN (1979)

- Load growth projected: in high-growth area nationally (Florida) and high-growth area within state
- Nuclear plants and solvent refined coal were not recommended in current plan due to financial risk and other uncertainties
- Coal-fired base-load units, combustion turbine peaking units, and purchased power reviewed
- Capacity additions of 660-670 MWe indicated in '82, '84, '86, '87, '89 and 800 MWe in '90, '92, '95.

6. OTEC INTEGRATION

- Why Florida Power Corporation important to OTEC: probable first mainland U.S. utility to use OTEC; good system planning
- Why OTEC of interest to Florida Power Corporation: near available thermal resource; dependent on uncertain fuel supplies; have openings in expansion plan OTEC could fill
- Florida Power Corporation system planning will examine OTEC for commercial suitability, using present projections as baseline and reviewing changes parametrically, if needed.

7. WHAT TO EXPECT

- From Task II (next Task): basic inputs of OTEC costs and operational features, run models, examine for suitability
- From Task III: modify inputs including cost, incentives, etc., to display elements that make OTEC more attractive
- From Task IV: institutional issues, barriers, and incentives treated more extensively.

1. INTRODUCTION AND BACKGROUND

1.1 INTRODUCTION TO THE STUDY

The decision to choose a new generating plant addition is a complex process for an electric utility company. Due to the long lead times in constructing a new facility, the decision to make an addition must be made well in advance of the actual need. Thus a forecast for the need for new generating capacity is only one of the major inputs to this decision-making process.

System planning, as exercised by major electric utility companies, involves sophisticated methodology including computer-based models employing the electric characteristics of generating plants, transmission systems, and other technical features of the utility company's total system. The methodology also includes the needed elements of the corporate financial influences and economic impacts involved in the decision-making process.

Any possible type of generating facility, be it nuclear, coal fueled, or any of the newly developing technologies, must be subjected to planning methodology to furnish the processed information needed by management in its decision making. Thus, one of the means of evaluating a new technology is to have it considered by a utility company, run through the system planning, and thus scrutinized by a potential user of the new technology in a manner directly drawn from the *user's* methods of decision making on new capacity additions.

Figure 1-1 is a graphic representation of the overall planning procedure.

By having Florida Power Corporation (FPC), a company with real potential for the future use of ocean thermal energy conversion (OTEC), exercise its system planning methods to consider this possible source of future generating capacity, a number of highly useful results will be obtained:

- (1) The company will give direct and serious consideration to OTEC and begin formulating a decision in that direction. This will, in turn, increase the company's familiarity with an understanding of the new technology.
- (2) Specific, detailed information concerning the suitability of OTEC will be revealed and, conversely, problems that might tend to work against its adoption will be exposed. Thus, OTEC developers, either government or industry, can receive valuable and timely feedback to guide the commercialization of OTEC.

Figure 1-1. Electric Utility Overall Planning Procedure

- (3) Should the evaluation of OTEC prove favorable, the first steps toward commercial introduction will be taken by a potential user and the process to commercialization can be facilitated and expedited.

1.2 SCOPE OF THE PRESENT STUDY

The overall study of the application of system planning to OTEC is being carried out in four tasks. Figure 1-2 highlights these tasks. This report covers Task I which provides a description of the existing system and the planning process. Figure 1-3 outlines the areas that are reviewed within this Task I report.

1.3 WHAT IS SYSTEM PLANNING?

Figure 1-1, from Section 1.1, indicates that an electric utility company must formulate plans for expansion of its generating capacity and transmission system in a systematic manner. It shows that the decision-making process has a multitude of inputs, (far more, in fact, than shown). The methodology by which all the factors are considered and evaluated, and a plan to meet the needs for future expansion developed, is utility system planning. System planning may include computer models dealing with the physical and electrical characteristics of generating plants and transmission facilities, as well as corporate financial and economic factors and other processes amenable to modeling.

The overall electric power supply system in the United States is the world's most capital-intensive industry and becomes even more so each year. This trend places a burden on the various utility organizations to finance the expansion of their respective systems at a time when capital is both expensive and not always readily available. It also raises to new importance the role of those individuals who have the responsibility to determine the least-cost strategy as to how the system should grow: the "system planners."

Early in the century, utility systems operated as isolated islands, each containing small clusters of load, generation, and connecting power lines. During the 1920s, the interconnection of these islands by transmission lines began, and the trend toward increasing interutility tie-line capacity continues to the present. In some cases, the interconnection was coincident with the merger of relatively small utilities to form larger ones. In virtually all cases, the public's desire for the convenience of electric service resulted in the rapid growth of the electric utility industry. Growth and interconnection of neighboring systems brought improved economies of operation, which resulted in more growth. This trend of relatively steady and strong growth continued for more than 50 years (with the exception of a dip and pause during the 1930s) until 1974. The growth in system load was

- TASK 1 — Describe the current system**
- TASK 2 — Include OTEC alternative**
- TASK 3 — Parametric Analysis**
- TASK 4 — Determine needed incentives**

Figure 1-2. The Four Major Tasks of System Planning

**UTILITY
SYSTEM
PLANNING**

**WHAT IT IS
WHY BEING USED IN THIS STUDY**

**FLORIDA
POWER
CORPORATION**

**BACKGROUND INFORMATION - PRESENT STATUS
LOAD GROWTH - REQUIREMENTS
FUTURE PLANS - IN GENERAL**

**REGIONAL
SITUATION**

**STATE OF FLORIDA
SOUTHEAST REGION**

**FLORIDA POWER CORPORATION
SYSTEMS
PLANNING**

**SYSTEM PLANNING METHODOLOGY
10-YEAR PLAN**

**INTEGRATING
OTEC**

**WHY OTEC?
APPLICATION OF FLORIDA POWER CORPORATION
SYSTEM PLANNING**

**ANTICIPATED
OUTPUT OF
STUDY**

**WHAT TO EXPECT - OUTPUT OF SYSTEM PLANNING
FUTURE TASKS - INCLUDING INSTITUTIONAL ISSUES**

Figure 1-3. Areas Reviewed for Task I

accompanied by growth in the ratings of the generating units, in the voltage levels used in the bulk power transmission system, and in system reliability.

The basic role of the system planner, therefore, has two critically important constraints: reliability and financability. Expansion and growth of the electric power system must be planned so that: (1) the established standards of reliability are satisfied, (2) the total cost of supplying electric service to all customers is minimized, and (3) the expansion can be financed. Obviously, the cost of providing electric power can be reduced if the quality of the service is reduced, but this would violate both the spirit and the letter of the laws which govern how utilities may operate. It is undoubtedly true that the high level of reliability that has been achieved by the electric power supply system in the United States has been an important factor in the strength of our economy over the years.

Reliability begins with a very long view of the generation and transmission needs of a utility system. Trends in overall load growth for several years and the load pattern from one season to the next are inputs to the system planning problem. The subject of system reliability touches many technical, economic, and "institutional" issues. It concerns not only how much generating capacity a utility should have, but what kind of plants it should build. For example, history has repeatedly shown that diversity of the types of energy resources the utility should rely upon is extremely important. Those utilities which are heavily dependent on hydropower may experience power shortages in years of small rainfall and snowfall. Those which are heavily dependent on coal will have problems in the event of a protracted strike by the miners or transportation workers, or by weather conditions which cause the coal piles at the plant to become frozen solid. Those which are heavily dependent on fuel oil are affected by international events which cut off supplies of imports, and by protracted periods of severe weather which interrupt fuel deliveries for an extended period. Those which are heavily dependent on nuclear power are subject to orders from regulatory authorities to shut-down a major fraction of their generating capability because of a suspected safety problem.

One way to achieve diversity is through the interconnection of systems that rely on different energy forms and are located in different geographic areas. In this way, a system which is not affected by a particular occurrence can supply surplus power from its own reserve capacity to an affected system. This leads to the questions of how great an investment should be made in ties to other utilities, and what are the overall economies of contracted power purchases from neighboring systems?

Long-term reliability of an electric power system is also affected by uncertainties in technology, when a given technology does not have a statistically significant performance record to use in the evaluations. This aspect of the matter is of particular relevance to this study, which is focused on the application of a new technology to a utility. For example, studies may show that a particular technology--be it a type of fuel cell, a scrubber to reduce sulfur emissions from a power plant, or an OTEC plant--will probably operate with a certain reliability. If this particular technology is then used by the utility on a large scale and the reliability is in reality significantly less, then the system reliability will be affected. For this reason, the utility industry is justifiably conservative--cautious in applying new technologies. The expense of a first-time venture with a new technology, even for only one or two power plants, can be staggering. The "technology demonstration" plant for a breeder nuclear reactor is currently estimated to be of the order of \$2 billion and will only be accomplished as a cost-sharing venture between several utilities and the federal government.* A single nuclear power plant can cost about \$1.3 billion to build. Public Service Electric and Gas Company had invested \$200 million in studies and design work for the concept of floating nuclear power plants, prior to abandoning the effort. It is obvious that government support of new technologies is needed, and that joint financing by the government and a group of utilities is a valuable way to bring new technologies to a fully commercialized status.

In addition to these long-term aspects of reliability, there are also short-term aspects. The effects of strikes and weather disturbances on generating plants have already been noted. Two aspects of reliability must be recognized in transmission planning. In an essentially steady-state sense, reliability is the system's ability to meet demand, within the specified voltage limits and the ratings of transmission generating units and transmission lines. Subtly different, is reliability in a dynamic sense, which is the ability to withstand sudden outage in its first few seconds or minutes without causing additional loss of facilities--the cascading effects that may lead to widespread blackout.

State-of-the-art deterministic transmission planning addresses both steady-state outages and transient system disturbances. Selected events are mathematically simulated by computer to determine whether the resulting model transmission system performance (voltage levels, line loadings, frequency and the like) will be within

*This statement presupposes that the breeder demonstration plant will be built someday, even though the present plans are highly indefinite.

acceptable limits. The outages and transient disturbances chosen for simulation are based on experience and judgment. Sufficient transmission is then planned to maintain adequate system performance despite occurrence of the more likely outages (e.g., failure of a single line). However, some degradation of system performance may be tolerated for less likely circumstances, such as multiple line outages or the loss of an entire power plant. The goal of this approach is to reduce the chances of widespread blackout, but if it occurs, to limit its impact in terms of population affected and time to restore service.

The impact of a given outage can be further quantified by utilizing ^{probability} ^ theory in conjunction with analytical techniques. Most of the factors that affect customer service reliability are uncertain, but long-term expected values can be calculated using the above approach (See GATOR, Appendix B.3.). This doesn't mean deliberately planning to take chances in meeting electricity demand. It does mean attempting to recognize and give relative weights to different circumstances. Most obvious are the equipment failures with immediate effects; a boiler tube leak, a severed line, a faulty transformer, or the overload that may arise from demands that are higher than installed facility ratings. There are planned circumstances to be met, too, such as scheduled removal of a generator or a line from service for maintenance. Each of these circumstances can have different effects on the reliability of the system, depending on its relative importance in that system.

Computer models of the entire electric system are also used to determine the optimum utilization of each generating unit in the system as it is envisaged some years in the future, with new plants at new and existing sites, and with new transmission ties and postulated agreements with neighboring utilities for the purchase of power. These data (basically, the amount of fuel forecasted to be used each month by each plant, over a 20-year period, and the corresponding kWh produced), are then used with other data on plant capital, fuel and operation and maintenance cost, and similar data for transmission lines, the distribution system, and general office expenses, in another (or other) computer programs to analyze the economic viability of postulated system expansion plans. The plan that meets the specified standards for reliability, and that has the lowest overall costs, is the most desirable if it can be financed. This last consideration has come to be recognized as having equal importance with the others, and may require that a more expensive expansion plan be adopted than would otherwise be the case. The common example of this situation is seen in decisions to delay the completion of power plants being constructed. Even though total costs would be lower if the plant were completed more quickly, its construction is drawn out for a few more years, during which

inflation takes its toll, because the borrowing limit of the utility has been reduced, and its earnings do not justify issuing more stock to raise capital.

In summary, the objective of the system planning function is to determine how the system should expand to meet future load demands in the most economical manner, considering the constraints posed by reliability and financing. This process is shown in Figure 1-4, and the factors which are considered in this determination include:

- Forecast of future load, so the peak power demand and kWh sales in each month during the period over which the planning study is being made can be derived, considering: (a) the ability of the utility to manage load through its own actions, such as containing service to customers who have purchased "interruptable service" and shedding loads that have associated with them an energy storage element; and (b) the probable impact of future rate increases in producing "conservation."
- Future cost and availability of various energy forms.
- Remaining economic life of existing generating plants.
- Existing, proposed or probable future regulating constraints to be placed on different energy sources or technologies.
- Cost and availability of power from neighboring systems under both emergency and normal conditions, with availability determined both by that system's generating capacity and expected load growth, and by the capability of the bulk power transfer inter-ties.
- Cost (capital and operating), availability and reliability of existing power generating technologies.
- Cost (capital and operating), availability and reliability of new technologies, considering the effect on these three factors of subsidies or other incentives provided by governmental bodies or other organizations.
- Reliability of the bulk power transmission system, considering both line outages, equipment failures, and dynamic (stability) phenomena.
- Expected rate of inflation and interest costs.
- Rapidity with which rate increases will have been made effective.

Figure 1-4. The Expansion Planning Process

2. THE BACKGROUND OF THE FLORIDA POWER CORPORATION

This section describes the Florida Power Corporation, including its geographic setting, service area and load, and its present generating and transmission facilities. It also discusses a projection of the load growth, which lead to a presentation of additional generating capacity needs and a general discussion of plans to meet future demands. A later section treats the detailed 10-year plan prepared in 1979.

2.1 THE COMPANY AND ITS SERVICE AREA

FPC is the largest investor-owned electric utility in the United States having had a peak load in 1979 of 4224 megawatts. It operates in the central, northern, and western portions of the State of Florida as indicated in Figure 2-1. Its service area spans the Gulf of Mexico coast from St. Petersburg to about 40 miles west of Apalachicola. The company's headquarters are in St. Petersburg, the largest city in its service area.

The company serves a population of almost 3 million people located in 375 cities, towns, and rural communities. The total area served is 20,000 square miles representing 32 of Florida's 67 counties. The five operating divisions of the company are also shown in Figure 2-1.

The company is interconnected with two operating companies of the Southern Company: Georgia Power Company to the north and Gulf Power Company to the west. To the south and east, it is connected to Tampa Electric Company and Florida Power & Light Company, plus municipally-owned utilities and rural cooperative electricity authorities.

At the present time, each utility functions independently; however, the Florida Electric Coordinating Group (FCG) has been formed to coordinate electric utility planning and operations within the state. The trend is toward more tightly integrated systems, and by 1990 it is planned that the major utilities in the state and adjacent states will be interconnected with 500 kV lines, and will have pooled dispatch of all generating units.

2.2 LOAD CHARACTERISTICS

For the past two years, the peak demand for the year has occurred in winter, during the first several weeks of the calendar year. This reflects the high saturation of electric space heating, an alternative made attractive by the relatively mild year-round climate. Because of recent rapid escalation in the price of fuel

Figure 2-1. Florida Power Corporation Service Territory

oil and probable increases in the price of natural gas, the trend toward more electricity for space heating is likely to continue. This would produce continued winter peak-load conditions. The FPC load factor* during the winter is low (47-50 percent).

Energy requirements are higher in the summer, however, since weather-related electricity use for space heating is intermittent, producing high short-term peaks with modest average consumption. During the long, hot and humid summers electrically driven space-cooling equipment operates at a much higher energy to peak-load ratio, and hence a higher load factor (69-79 percent). Load factors during both seasons may decrease in the future for the following reasons:

- Increased installations of electric heat in the winter.
- Decreased use (fewer running hours) of space-cooling equipment during the summer, because of customer efforts to reduce consumption.

Currently, the annual load factor is slightly greater than 50 percent; significantly lower than the average of almost 60 percent during the period 1968-1973. The peak load demand (kW) has increased at a rate of 8 percent per year since 1975, and annual kWh sales have increased at an average rate of slightly less than 7 percent annually during the same period.

During the previous five-year period (1968-1973) peak load and energy sales increased at 14 percent per year, reflecting more rapid growth of the economy and electricity use.

Sales of electricity to various customer categories are as follows:

	<u>Percent</u>
Residential:	40
Commercial:	22
Industrial:	17
Other Utilities:	18
Public Authorities:	3

This mix has been constant essentially for the past five years; earlier the industrial sector had a somewhat larger share. The 10 largest industrial customers account for 65 percent of the total kWh sales of this sector. The customers are concentrated in phosphate and limerock mining, food processing, and chemical industries. There are a few large, and a greater number of small and medium-sized electronics firms in this area.

*Kilowatt-hours consumed/maximum possible kilowatt-hours of production or system peak in kilowatts x 8760 hours/year.

Although this industry is noted as being non-energy-intensive, in aggregate these firms account for about 9 percent of the total kWh sales in the industrial category.

The number of customers in each category as of the end of 1978 was:

Residential:	649,043
Commercial:	69,736
Industrial:	61,885
Other Utilities:	137
Public Authorities:	2,057

Florida residences are heavily electrified. A survey conducted in 1977 showing the following equipment saturation:

- 85 percent having electric hot water heating
- 82 percent having electric-powered space cooling
- 80 percent having electric cooking
- 52 percent having electric space heat as the primary source, plus an additional 14 percent who use electric heating as a secondary source
- 43 percent having electric clothes dryers.

2.3 SYSTEM PLANNING CONSEQUENCES OF LOAD CHARACTERISTICS

As do electric utilities in cooler climates, FPC commissions new units ahead of the peak period to achieve high system reliability. This is true even though FPC might have an economic incentive to commission new base-load generating units a few months after the peak load of the calendar year has occurred, since the low production cost, new base-load unit could displace more expensive generating units for a larger number of kilowatt-hours (during the summer) than would be the case if the new unit were not commissioned until just before the next winter.

The relatively large percentage of interruptible load (284 MW) in the industrial category is designed to provide a "margin" for the peak load, particularly during exceptional events such as coincident forced outages of more than one unit, while other large units are down on a maintenance outage.

The growth of the winter peak might be moderated through use of load management techniques applied to electric water heating and space heating equipment.

FPC is currently engaged in testing load management programs to determine their practicality. However, the current load forecast assumes that no load management programs will be implemented.

Most of the generating units presently installed are derated by up to 10 percent during the summer months, because the higher air and water temperatures

reduce power production capability. Also, during the summer months, the maximum current-carrying capability of transmission lines is lower than during the winter because of increased sag of the lines as a result of higher ambient temperatures. The reduced capability in these two areas is fortunately "in-phase" with the peak-load demand, which is not the case for the typical summer-peaking system.

2.4 PRESENT POWER SUPPLY SYSTEM

2.4.1 Generation

The Florida Power Corporation system contains a mix of generating units, including oil or natural-gas-fired combustion turbines and oil or natural-gas-fired steam turbine-generators for intermediate service and coal-fired and nuclear-fueled base-load units. Table 2-1 presents a summary of the installed generating stations and their units as of the end of 1978. Total installed capacity was:

Steam turbine units	3382 MW
Combustion units	<u>1476 MW</u>
Total:	4858 MW

2.4.2 Transmission

The FPC bulk power transmission system consists of 230 and 500 kV transmission lines with an underlying subtransmission system consisting of 69 and 115 kV transmission lines. Figure 2-2 shows the bulk power transfer system, consisting of the 500 kV and 230 kV lines, as of the end of 1978. This figure also shows the location of generating systems and connections with other utilities.

TABLE 2-1. FPC GENERATING STATIONS AND UNITS AS OF 12/31/78

Station	Unit	Winter Capacity	Fuel*	Prime Mover†
Crystal River	-1	383	C	S
	-2	350	C	S
	-3	731	U	S
Anclote	-1	506	O	S
	-2	506	O	S
Bartow	-1	114	O	S
	-2	116	O	S
	-3	215	O/G	S
	-P1	51	O	C
	-P2	51	O	C
	-P3	51	O	C
	-P4	51	O	C
Turner	-3	72	O/C	S
	-4	75	O/G	S
	-P1	17	O	C
	-P2	17	O	C
	-P3	81	O	C
	-P4	81	O	C
Intercession City	-P1	55	O	C
	-P2	55	O	C
	-P3	55	O	C
	-P4	55	O	C
	-P5	55	O	C
	-P6	55	O	C
Debary	-P1	47	O	C
	-P2	54	O	C
	-P3	54	O	C
	-P4	47	O	C
	-P5	47	O	C
	-P6	54	O	C
Higgins	-1	40	O/G	S
	-2	41	O/G	S
	-3	42	O	S
	-P1	30	O/G	C
	-P2	30	O/G	C
	-P3	35	O/G	C
	-P4	35	O/G	C
Bayboro	-P1	52	O	C
	-P2	52	O	C
	-P3	52	O	C
	-P4	52	O	C

TABLE 2-1. FPC GENERATING STATIONS AND UNITS AS OF 12/31/78 - Continued

Station	Unit	Winter Capacity	Fuel*	Prime Mover†
Suwanee River	-1	34	O/G	S
	-2	33	O/G	S
	-3	80	O/G	S
Avon Park	-2	44	O/G	S
	-P1	35	O/G	C
	-P2	35	O/G	C
Port St. Joe	-P1	17	O	C
Rio Pinar	-P1	17	O	C

* C = Coal O = Fuel Oil † C = Combustion Turbine
 G = Natural Gas U = Uranium S = Steam Turbine

Figure 2-2. Florida Power Corporation Bulk Power Transmission System

3. CURRENT REGIONAL SITUATION

Florida Power Corporation is the second largest electric utility organization in the state; its electric generating capacity represents 16 percent of the state's total. A listing of all utilities in Florida which generate power, and their generating capability, is presented in Table 3-1.

At the present time, each utility operates as an individual unit. Although the transmission ties are free-flowing power exchanges are done in accordance with existing agreements for the purchase or sale of power; i.e., for capacity purposes, under emergency conditions, or for economy interchange. As is discussed later in Section 5, virtually all of the utilities in the state are members of FCG.

The utilities in Florida are part of a larger organization, the Southeastern Electric Reliability Council (SERC). This body is one of nine regional councils whose memberships comprise essentially all of the electric utility systems in the United States and the Canadian systems in the provinces of Ontario, British Columbia, Manitoba, and New Brunswick. Together, the regional councils comprise the National Electric Reliability Council (NERC), which was formed voluntarily by the electric utility industry in 1968 and incorporated in 1975. NERC directs its efforts to augmenting the reliability and adequacy of bulk power supply of the electric utility systems in North America. The activities of NERC and SERC also are discussed in greater detail in Section 5.

The SERC region encompasses all of the states of Florida, Georgia, North and South Carolina, Tennessee, and Alabama, and approximately half of Mississippi, and Virginia. For coordination purposes, the region is subdivided into four subregions:

- Florida (all utilities in the state)
- The Southern Company (a utility holding company with operating utilities in Florida, Georgia, Alabama, and Mississippi)
- TVA (government-owned generating utility with power plants in Tennessee, Mississippi, and Alabama)
- VACAR (interconnected utilities in Virginia and North and South Carolina).

The Florida subregion is connected only to the Southern Company. At present this is by two 230 kV lines and several 115 kV lines.

TABLE 3-1. GENERATING CAPACITY IN PENINSULAR FLORIDA
(SERC FLORIDA SUBREGION)

(Summary of Existing Capacity as of January 1, 1979)

<u>Major Utility Systems</u>	<u>Net Capability - MW</u>	
	<u>Summer</u>	<u>Winter</u>
Florida Power & Light Company	10,941	11,500
Florida Power Corporation	3,647	4,040
Fort Pierce Utilities Authority	116	116
Gainesville/Alachua County		
Regional Utilities Board	257	275
City of Homestead	52	52
Jacksonville Electric Authority	1,884	1,939
Lake Worth Utilities Authority	141	154
City of Lakeland	372	384
Orlando Utilities Commission	742	760
Seminole Electric Cooperative	14	14
Southeastern Power Administration	36	36
City of Tallahassee	495	518
Tampa Electric Company	2,505	2,505
City of Vero Beach	133	133
Total for Subregion	21,335	22,426
<u>Type</u>		
Total Nuclear	2,876	2,968
Total Fossil Steam	13,928	14,143
Total Diesel	116	117
Total Combustion Turbine	3,919	4,625
Total Combined Cycle	460	537
Total Hydro	36	36
Total for Subregion	21,335	22,426

4. FLORIDA POWER CORPORATION SYSTEM PLANNING

Section 1.3 provides a basic description of an electric utility system planning method. This section describes the specific methods used by Florida Power Corporation. Two major subsections are included:

- 1) System planning methodology and procedures
- 2) A presentation of the 1979 10-Year Plan which resulted from applying FPC system planning methods.

A condensed version of FPC's system planning procedure is provided in Appendix A. FPC's 1979 10-year plan is also included as Appendix E.

4.1 THE SYSTEM PLANNING PROCESS

Planning at Florida Power Corporation is a continual process carried out by a separate System Planning Department reporting to the Director of Corporate Planning. In September of each year, a formal Generation Facility Expansion Plan is prepared and submitted to corporate management and, after review and approval, to the Board of Directors. Formal approval by the Board sets the general policy to be followed, and the specific construction budget, power purchase and sale commitments, and site acquisition. The procedure followed in preparing this formal report is shown in Figure 4-1. Each step and their associated activities are described in the following paragraphs.

Step 1. Establish Basic Assumptions: The projected health of the economy in the region, national population shifts, weather conditions on which peak loads are based, inflation rates and related factors are examined. Policy guidelines regarding outside purchases of power and construction of jointly owned facilities are established. Also, any impact of programs related to cogeneration, solar energy, load management, and other advanced methods is estimated.

Step 2. Prepare Load Forecast: At the present time, FPC procedure is to forecast the future peak loads (summer and winter) and the annual kWh sales separately for each customer classification, and sum these to obtain the total quantities. In making these forecasts, information on past trends is combined with the known and expected future activities in the region (e.g., construction of new manufacturing plants or other large users in the industrial category) and technological developments (i.e., any likely penetration of load management techniques, use of solar energy systems, extent to which customers will install more energy-efficient lighting system, etc.) The company is in the process of acquiring an econometric-based computer model and plans to utilize this in its load forecasting activities. This will be done on a trial basis in 1980.

Figure 4-1. Generation Facility Expansion Planning Procedure

Figure 4-2. Load Forecasting Model

Step 3. Postulate Alternative System Expansion Plans: Several alternative system expansion scenarios are postulated, considering such factors as the rate of load growth, the results of the prior year's plan, the status of discussions regarding joint ownership of facilities and power purchase and sale agreements, developmental status of new technologies and actual and proposed regulatory constraints on existing technologies. Some preliminary computer studies are made to learn which of these is likely to be attractive, and to adjust the capacities and in-service dates of new installations or power purchases. During this step, an estimate of the financial risks associated with the different scenarios is made. For example, present, proposed or possible regulatory constraints on the various technologies along with past operating experience, are considered. Also, the effects of delays in the commercialization of new technologies are evaluated. The purpose of this evaluation is to determine the likely financial consequences to the company of the regulatory constraints or commercialization schedule slippage.

Step 4. Determine System Reliability and Economic Consequences for Each Alternative Scenario: Detailed investigations of each of the alternative scenarios judged to be viable are then conducted. The general sequence is:

- 1) Determine system reliability (considering the transmission facilities to be 100 percent reliable) using the PROMOD computer program. The program is an extremely powerful tool which simulates the operation of the utility's generating facilities, computing the amount of production from each unit that yields minimum overall production costs or fuel costs. The program utilizes probabilistic techniques to represent forced outages, and also simulates scheduled outages. As used in the system planning process, a 20-year period is simulated, with calculations made on a monthly basis using hourly load models.

Figure 4-3 shows the input parameters and outputs from the program. The key output parameter at this stage of the planning process is the loss-of-load probability (LOLP). Florida Power Corporation has established a LOLP criterion of one day in 10 years loss of firm load. This results in an equivalent design criterion based on projected load shape and interchange capacity availability of 3.5 hours per year dependency upon tie lines. A generating facility expansion plan which deviates significantly from this criterion is unacceptable; those which come close to it are judged to be worthy of further consideration.

- 2) Determine the economic impact of the scenario on the company and its customers by using the CORPORATE MODEL computer program. This program simulates the functioning of the company, calculating all expenses and revenues month-by-month over the entire period of the study. It is, therefore, an extremely valuable evaluation tool to aid management to exercise its decision-making functions, and is the cornerstone of FPC's Management Information System.

*PURCHASED CAPACITY OR COMPANY-OWNED FACILITY.

†SEASONAL CAPABILITY; MAINTENANCE OUTAGE REQUIREMENTS; ACCEPTABLE FUELS; COMMERCIAL OPERATION, "MATURITY" AND RETIREMENT DATES; HEAT RATE AND AVAILABILITY (UP TO FIVE CAPACITY LEVELS).

Figure 4-3. PROMOD Computer Program as Used in System Planning Studies

Figure 4-5 shows the input parameters and outputs from the program, and its relationship to other subsidiary programs with which it is used. The program simulates the necessary line of credit available from banks for short-term financing. When the limit of borrowing capacity is reached, the program simulates the sale of securities of various types for long-term financing. Rate increases are simulated as needed to maintain revenues at the level sufficient to provide a satisfactory rate of return. The key output parameters are: (1) those which indicate whether a particular system expansion scenario can be financed (the frequency and magnitude of rate increases, ability to secure funds through sale of securities); and (2) the present-worth of corporate revenue requirements during the time period simulated in the study. If more than one alternative scenario with acceptable reliability is financable, then the one with the smallest revenue requirement is considered most attractive.

- 3) Determine the adequacy of the bulk power transmission system by using conventional LOADFLO and fast linearized LOADFLO programs, plus other studies made in conjunction with other utilities in the region. All major lines and load centers within FPC are represented in these computer programs, plus those of the other utilities in the region encompassing the entire state of Florida and major portions of adjoining states. The forecasted peak summer and winter loads five years in the future, plus the generating units expected to be operating at this time also are represented. The LOADFLO program solves hundreds of linked non-linear algebraic equations and calculates: (1) the power flow through each line, and (2) the voltage level of each bus. All lines in which the power flow exceeds the normal rating are listed, plus all bus voltages which are either above or below the allowable range. These results show any potential problems during normal peak-load conditions. Alternative solutions to the indicated problems are made in the computer model representation, and the program is re-run until a satisfactory set of solutions is obtained.

After these runs are made using the LOADFLO program, a simpler program which uses linearized forms of the equations, and thus gives "approximate" rather than "exact" solutions is run to perform a contingency analysis. This term applies to the sequential removal of each and every line in the transmission network under study, and calculation of power flows and bus voltages under these circumstances. The key output consists of a listing of power flows and voltages which deviate from the emergency limits. This analysis identifies additional problems in the bulk power transmission system that need further study.

- 4) Perform long-range siting and interconnection studies using the same programs. In addition to this regular and routine set of analyses, others are made to compare alternative sites for new large generating facilities. In this case, the planning horizon is generally 8-15 years in the future, and the computer model may have a more simplified representation. The principle is the same, however, and the results indicate what changes in bulk power transmission system are needed to satisfy the load. The cost of such changes related to each alternative site are then included in the economic analysis which forms a key part of the site selection process.

Figure 4-5. CORPORATE MODEL Computer Program as Used in System Planning Studies

Representatives from the various electric utilities in the state meet together on a regular basis to keep each other informed concerning both tentative and "firm" plans for changes in the bulk energy supply system (e.g., new plants, scheduled retirements, line up-gradings, new lines) and load forecasts.

This group has recently been given the name "Florida Coordination Group," and it, in turn, has representatives which meet with other utilities which comprise the South East Reliability Council. The FCG and other power systems in the SERC region utilize the same computer programs (or variants thereof) to study system interconnections in the 10-20 year planning horizon.

Step 5. Analyze Results and Recommend Plan: This final step analyses results and recommends a plan which has the lowest revenue requirements yet meets reliability criteria, financial constraints, and scheduling constraints as closely as possible.

Two aspects of reliability must be recognized in planning the expansion of a utility's bulk power transmission system. From a "quasi-steady-state" point-of-view, the reliability of the system measures its ability to meet the load demand (within the specified voltage limits and the rating of transmission lines and transformers). From a "dynamic", or transient, point-of-view, the reliability of the system reflects its ability to withstand a sudden outage without causing additional loss of lines or generating facilities within the next few seconds or minutes. The latter situation--the cascading of one failure into several--can lead to a widespread blackout over an entire region. It is the second aspect that is addressed in part by the contingency analysis cited above in part 3 of Step 4. A more complete evaluation is made by using transient stability computer programs, but this analysis is done on a two-year planning horizon, since the programs are quite expensive to run and extremely data intensive.

FPC has developed a new computer program during the past few years. It is called GATOR (Generating and Transmission Overall Reliability). This program utilizes probabilistic methods, similar to those used in PROMOD, together with historic line outage data (i.e., probability and repair time) to calculate the probability that a line will be out of service; and combines these calculations with those for load flow and generating plant outages to determine the overall system reliability. GATOR is now in trial operation.

The four computer programs used by FPC in system planning are described further in Appendix B.

4.2 THE 1979 SYSTEM EXPANSION PLAN

The following sections briefly discuss the five major elements of system expansion planning done for in 1979.

4.2.1 Basic Assumptions

In expansion planning FPC makes the following basic assumptions:

- Normal weather conditions will prevail.
- All economic indicators at present point toward a recession of some degree. According to the national economists, this will be a short-term recession. In view of this, we anticipate a reduction in kWh growth, particularly in the residential class. This decline is also due to the cost of other goods and services eroding customer discretionary income, thereby leaving less for the purchase of electric energy.
- There will be no significant loss of energy sales to solar energy until the late 1980s.
- The filed rate increases will have no effect on electricity sales during the next two years.
- All of the wholesale load within the service area along with its associated growth in demand and energy will be served except the portion of REA and Cooperative loads to be supplied by Seminole Electric Cooperative beginning June 1, 1983.
- The population projection made by the Bureau of Economic and Business Research at the University of Florida is reasonably accurate.
- If there is any impact due to load management in our system, it will not become effective until after 1980 and will not be included in the forecast until a corporate decision is made concerning large scale implementation.
- The effects of improved equipment efficiency and the increased effectiveness of thermal envelopes due to additional and improved insulation is expected to have minor impact on the forecast.
- Inflation rates in the general economy will be:

<u>Years</u>	<u>Rate</u>
1979-1983	7.2%
1984-1988	5.0%
1989-1993	2.6%
1994-1998	2.9%

Costs for construction of utility facilities will be 1.5 percent higher than these values.

- Jointly owned generating facilities and power purchases are encouraged. Transmission ties to neighboring systems will be strengthened during the decade of the 80s.
- By 1990, oil consumption will be reduced to 50 percent of the 1979 value.
- Capital costs and fuel costs for the alternative types of generating facilities are as shown in Figures 4-6 and 4-7, respectively.

Figure 4-6. Capital Cost (1978 Dollars) Engineering Design Basis

Figure 4-7. Fuel Cost Forecast 1979 Facility Plan Study

4.2.2 Load Forecast

Figures 4-8 and 4-9 show the number of annual customers and the year-to-year percentage change in this number, both during the past 10 years and during the 1979-1998 period. Figures 4-10 and 4-11 show, for the same time periods, the historic and projected electricity sales (kWh) and growth rate in energy sales. Figures 4-12 and 4-13 show similar data for the peak load demand on the system (kW).

4.2.3 System Expansion Scenarios Eliminated Because of High Risk

Even though subsequent exploratory calculations using the computer programs showed that they would have attractive costs (more attractive in fact than the system expansion plan finally recommended), these were not recommended since the anticipated financial risk to the company would be too great if either additional nuclear-fueled generating capacity or reliance on solvent refined coal (SRC) were planned.

4.2.4 System Expansion Scenarios Considered

Serious consideration was given to various combinations of installing base-load coal-fired generation, installing oil-fired "peaking" generation using combustion turbines, and purchasing capacity from adjacent utility systems.

4.2.5 Recommended System Expansion Plan

The system expansion plan that evolved from the study is one which places major reliance on purchasing power from other utilities during the 1980s, plus constructing five large coal-fired units during this time period and three more during the 1990s. The first two units are now under construction. Ownership of and output from the next two units will be shared with another utility or utilities. (Only 660 MW from each unit is needed by FPC, but 800 MW (net) is believed at this time to be the most economically unit size to build.) The final four units may be completely owned by FPC but joint ownership to some extent may be explored at a later time. Table 4-1 presents the load and capacity forecast of the recommended plan.

The results of the system reliability and cost studies showed that the recommended plan had both higher reliability and lower costs than the alternatives. The primary reason for the favorable economics is that load growth in the Southern Company System (adjacent to FPC to the north) has been quite low, and this utility currently has an excess of low-cost, coal-fired capacity. The cost of purchasing power from this system, with its relatively low inbedded costs is a much more attractive way to provide the company's short-run (80-86) capacity requirements than the only viable alternative, peaking units.

Figure 4-8. Average Peak Demand

4-14

Figure 4-9. Percent Increase Annual Customers

Figure 4-10. Annual Sales

4-16

Figure 4-11. Percent Increase kWh Sales

Figure 4-12. Annual Peak Demand

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Figure 4-13. Percent Increase Annual Peak Demand (without demand served by Seminole)

TABLE 4-1. LOAD AND CAPACITY FORECAST

(Megawatts)								
Year	Inst. Cap.	Net Contract Purch. & Sales	Cap. Avail. @Winter Peak	Capacity Added	Capacity Retired	Inst. Cap. at End	Winter Peak Load	Reserves (%)
1979	4858	65	4923	- (1)	-	4858	4450	10.6
1980	4858	336	5194	245 (2)	-	5103	4750	9.3
1981	5103	656	5759	65 (3)	-	5168	5050	14.0
1982	5168	836	6004	670 (4)	-	5838	5360	12.0
1983	5838	661	6499	- (5)	-	5838	5660	14.8
1984	5838	536	6374	670 (6)	-	6508	5760	10.7
1985	6508	431	6939	- (7)	(44)	6464	6050	14.7
1986	6464	506	6970	660 (8)	-	7124	6140	13.5
1987	7124	406	7530	660 (9)	-	7784	6280	19.9
1988	7784	406	8190	- (10)	-	7784	6610	23.9
1989	7784	406	8190	660 (11)	(130)	8314	6800	20.4
1990	8314	406	8720	950 (12)	(69)	9195	6990	24.7
1991	9195	6	9201	- (13)	(69)	9126	7270	26.6
1992	9126	6	9132	800 (14)	-	9926	7350	24.2
1993	9926	6	9932	- (15)	-	9926	7640	30.0
1994	9926	6	9932	- (16)	-	9926	7700	29.0
1995	9926	6	9932	800 (17)	-	10726	7970	24.6
1996	10726	6	10732	- (18)	-	10726	8130	32.0
1997	10726	6	10732	- (19)	-	10726	8400	27.8
1998	10726	6	10732	- (20)	-	10726	8650	24.1

- (1) 50 MW Up-grading; 195 MW Combustion Turbine Units (3)
 (2) Combustion Turbine Unit
 (3) Crystal River Unit 4 (Coal-fired)
 (4) Crystal River Unit 5 (Coal-fired)
 (5) Station "X" Unit 1 (Coal-fired)
 (6) Station "X" Unit 2 (Coal-fired)
 (7) Station "X" Unit 3 (Coal-fired)
 (8) Station "Y" Unit 1 (Coal-fired); 150 MW Combustion Turbine Units (3)
 (9) Station "Y" Unit 2 (Coal-fired)
 (10) Station "Y" Unit 3 (Coal-fired)

Figure 4-14 displays the key data from Table 4-1, plus the corresponding historic data from the period from 1968/1969 to 1978/1979. Figure 4-15 shows the scheduled and planned additions to generating facilities and power purchases during the study period. Figure 4-16 displays the Loss-Of-Load-Probability for the first ten years of the planning period for two cases: adding base-load generating facilities only, and the final plan, with both generation additions purchased capacity. Figure 4-17 shows the fuel mix that is expected year-by-year during the study period.

Figure 4-14. Winter Peak Load Demand and Capacity at Time of Peak

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Figure 4-15. Purchase Plan

Figure 4-16. L.O.L.P. Analysis

Figure 4-17. Fuel Mix

5. REGIONAL AND NATIONAL COORDINATION

The organizations with which FPC is involved in coordinating its system planning and system operating functions--FCG, SERC and NERC, and the other utilities in the region--were identified in Section 3. The purpose of this section is to describe more fully the level of coordination that presently exists, and which may exist in the future. Since the greatest amount of coordination will always exist with regard to the nearest neighboring utilities, and since the Florida subregion is defined within SERC, most emphasis is given here to the FCG.

A listing of all the electric utilities in the state of Florida is presented in Table 5-1. It may be noted that all utilities except two are members of the FCG. At the present time, the FCG has established emergency and operating reserve policies and an economy interchange system. The FCG is composed of a general staff and several major committees. The general staff coordinates the activities of the various committees and is the central point for data collection, report distribution, and liaison with various government agencies and other utility and consumer organizations.

The controlling authority of the FCG is the Executive Committee. It determines policy for all matters within the scope of the FCG articles of incorporation and bylaws. In addition, the Executive Committee directs the overall operations of the FCG standing committees and the affairs of the FCG corporation. Customarily, the presidents of four investor-owned utilities, three chief executives from the municipal utilities, and two chief executives of rural electric cooperatives serve on this board.

The committees most directly responsible for coordinating FCG activities are the Technical Advisory Group, the Operating Committee, and the System Planning Committee. The Technical Advisory Group develops long-range objectives to meet the overall goal of providing member systems with added reliability at an economical cost. The Technical Advisory Group coordinates the planning of generation and transmission expansion programs of the Florida utilities and oversees the activities of both the Operating Committee and the System Planning Committee.

TABLE 5-1. NET GENERATING CAPACITY OF UTILITIES IN FLORIDA
(1978 Summer Rating)

<u>FCG Members</u>	<u>Generation (MW)</u>
Investor-Owned Utilities	
Florida Power & Light Company	10,941
Florida Power Corporation	3,647
Florida Public Utilities Company	2
Gulf Power Company	1,515
Reedy Creek Utility Company	12
Tampa Electric Company	2,505
	<u>18,622</u>
Municipals	
City of Alachua*	1)
City of Bushnell	1)
Florida Keys Utilities**†	14
Fort Pierce Utilities Authority	116
Gainesville/Alachua County Regional Utilities Board	257)
City of Homestead	52
Jacksonville Electric Authority	1,884
City of Key West Utility Board†	130
City of Kissimmee	36)
Lake Worth Utilities Authority	141
City of Lakeland	372
City of Leesburg*	7)
City of New Smyrna Beach Utilities Commission	26)
City of Ocala	11)
Orlando Utilities Commission	742)
City of Quincy	0
City of St. Cloud	24
Sebring Utilities Commission	29)
City of Starke	10
City of Tallahassee	495)
City of Vero Beach	133
City of Wauchula*	8
	<u>4,489</u>
Cooperatives	
Central Florida Electric Cooperative	0
Choctawhatchee Electric Cooperative	0
Clay Electric Cooperative	0
Glades Electric Cooperative	0
Lee County Electric Cooperative	0
Okefenokee Rural Electric Membership Corporation	0
Peace River Electric Cooperative	0
Seminole Electric Cooperative	14)
Sumter Electric Cooperative	0
Suwannee Valley Electric Cooperative	0
Talquin Electric Cooperative	0
Tri-County Electric Cooperative	0
Withlacoochee River Electric Cooperative	0
	<u>14</u>
Southeastern Power Administration*	36
Total	<u>23,161</u>

* Not a member of FCG.

† Not interconnected with FCG members.

) Includes joint participation in generating unit.

The Operating Committee is charged with integrating FCG operations to ensure economical and reliable electric service. Its member utilities share spinning reserves; establish policies for scheduled and inadvertent interchange procedures, emergency procedures, and time-error correction; coordinate maintenance schedules; establish and administer guidelines for utilizing underfrequency relays; maintain voice and teletype communication facilities and notification procedures for both normal and emergency conditions; and evaluate system disturbances to determine causes and seek ways of preventing future occurrences. In addition, the Operating Committee oversees the operations of the FCG energy broker system.

The System Planning Committee reviews and analyzes the planning of the electric bulk power supply system in Florida. It is responsible for exchanging planning information among FCG members systems and other organizations; determining whether the planned generating facilities and bulk power transmission grid are adequate and reliable; and recommending corrective planning, design, and operations to ensure an adequate and reliable electric power supply.

A member of the Operating and System Planning committees must be interconnected with other FCG utilities and able to meet its own system peak-load demand plus reserve requirements. The nongenerating municipal utilities and the nongenerating rural electric cooperatives each have one representative on these committees. In addition, any other member of the FCG may attend meetings as an observer. Excerpts from the FCG System Planning Committee Handbook are presented in Appendix F. The FCG is currently studying the benefits that would result from centralized power dispatch of all generating units--a true "power pooling" arrangement.

Formation of the FCG was voluntary, but was encouraged and supported by both the Florida Public Service Commission and the Southeastern Electric Reliability Council (SERC). In accordance with requirements of the Florida Electric Power Siting Act, FPC (and other utilities in the state) must submit a 10-year site plan report to the Division of State Planning on an annual schedule. The last report was submitted in March, 1979. This report contains a summary of existing facilities, the current forecast of electric power demand, a forecast of facilities requirements, and a description and impact analysis for facilities and sites that are under construction or being planned.

The National Electric Reliability Council (NERC), in keeping with its charter, devotes its efforts solely to matters which have a bearing on the reliability and adequacy of bulk power supply of the electric utility industry in North America.

NERC, working with its regional councils, concentrated its early efforts on solving the problem of cascading trip-outs of the transmission network which had led to widespread power outages--a problem defined by NERC as the "reliability" problem. As this problem eased, the emphasis has shifted to the "adequacy" problems; i.e., providing sufficient generating capability to be able at all times to meet the aggregate electric peak loads of all customers and to supply all their electric energy requirements. Figure 5-1 shows the geographic boundaries on the nine regions which comprise NERC.

The Southeastern Electric Reliability Council is the largest of the nine councils in terms of power generating capability, with 112,233 MW installed at the end of 1978. At this time, SERC had the smallest percentage reserve generating capacity: 21 percent compared with the average value of 31.5 percent for all nine regions.

As was described in Section 3, the SERC region consists of four subregions: Florida, The Southern Company, TVA, and VACAR. The interconnections are as depicted below:

DEPARTMENT OF ENERGY - ENERGY INFORMATION ADMINISTRATION

Figure 5-1. Nine NERC Regions

6. INTEGRATING OTEC

6.1 WHY OTEC

As a final preliminary to Task II (where the system planning methodology is exercised on OTEC), this section discusses the underlying reasons why OTEC should be examined in the context of potential use by FPC and conversely, why FPC could reasonably consider OTEC as a candidate power generating source.

It is shown in some preliminary detail how the 1979 10-Year Plan contains "openings" which could be filled by OTEC.

Finally a discussion is presented of what are the suitable baseline inputs for Task II and some indication of what to anticipate from the output.

6.1.1 Why OTEC Developers Should Look to Florida Power Corporation

From almost any aspect, it is wise to have an electric utility company examine OTEC in detail as a means of assuring that the future potential customer for this technology will have available a generating source which is consistent with the company's needs and which can be integrated into the utility system. Of the possible approaches a utility company could take in examining a technology such as OTEC, one of the most direct and pertinent is to consider this technology just as they consider any candidate for generating capacity addition into their system; i.e., by using the company system planning methods with OTEC as one of the candidates for future capacity expansion. For a number of reasons the Florida Power Corporation is a prime candidate for application of a novel energy source such as ocean thermal energy conversion to meet future electric power generation needs. Some of these reasons are:

- Location on the Gulf of Mexico within reach of a 20°C thermal resource (surface to deepwater temperature difference)
- A heavy dependence upon one fuel source--coal--with prospects for increasing dependence in the years ahead
- A large (almost 5000 MW) and rapidly growing (7 percent per year) demand pattern
- A fully rationalized system planning procedure incorporating advanced computer-based models for technical and economic evaluation of alternatives.

The service area and the major load centers of FPC are along the Gulf coast of Florida or nearly so. The "Sun Coast" area in the vicinity of St. Petersburg has been one of the fastest growth areas in the nation and in Florida. One of the candidate sites for large commercial OTEC plants is almost due west of St. Petersburg. This is shown in Figure 6-1, and Figure 6-2 indicates the possibility of transmission, not only to the St. Petersburg area, but to the northern sector either for local use or for further transmission inland to the north.

Figure 6-3 shows the projected annual peak-load demand beyond the previous 10-year history. The rapid growth of the service area and resultant growth in peak demand is clearly seen in the last decade, a period of really remarkable growth. The projected growth pattern presents nearly a doubling of load within the next decade!

6.1.2 Why FPC Should Look to OTEC

The same reasons that FPC is attractive to OTEC developers is reflexive, as may be expected. FPC, with its projected load growth and proximity to the OTEC thermal resource, should look at this potential alternative. There are some additional specific factors that make this a potentially suitable source of generating capacity for the future.

The capacity expansion plan as developed in 1979 shows a number of significant capacity additions in the next decade and beyond. As seen in Figure 6-4, five large increments of base load generating capacity are planned for the 1980s, each of these coal fired. Beginning in 1990, more and larger additions are indicated. Present plans call for these as being coal-fired units. This would place the company in a position of being almost entirely dependent on coal as a fuel for base-load power. Figure 6-5 shows the fuel mix that would evolve over the next two decades. The company would move from its present position of being largely oil dependent to being extremely coal dependent. Therefore there is a large incentive, from the point of diversification, to having a different source of base-load power.

It is fortuitous that OTEC could be ready for commercial introduction in the time period that would coincide with the needs of the company for new capacity. Depending on the rate of development of OTEC, it is possible that as early as 1989, some capacity would be delivered by OTEC, and particularly into the 1990s, large blocks of capacity could be allocated to this source.

Figure 6-1. OTEC Plant Site

Figure 6-2. Transmission from OTEC Site to St. Petersburg and Northern Florida

Figure 6-3. Annual Peak Demand

Figure 6-4. Base Load Facility Plan

Figure 6-5. Fuel Mix

The issue of fuel dependency has another aspect: proximity or distance from the fuel source. In Appendix C, FPC is compared to other utilities. It is shown in this appendix that the price of electricity is closely related to the proximity to either coal or to hydro resources. FPC is removed from either of the resources, but is relatively close to the OTEC thermal resource in the Gulf of Mexico. Therefore the geographic factor is not only an obvious factor in the proximity to Gulf of Mexico, but also in distance from other fuel resources.

Given the suitable location of Florida Power Corporation to the available OTEC thermal resource in the Gulf of Mexico, in addition to the direct benefit this provides to its own service area, there is the possibility that OTEC power could be delivered by FPC to other utility systems to the east or north. Thus FPC has the possibility of company economic benefit (and benefit to its own rate payers) by being the principal source of OTEC-provided power.

Whether this could become true depends on many financial factors and particularly on any incentives or credits that the company may accrue from OTEC ownership. It is fortunate that FPC has the analytic apparatus, including its systems planning models, to examine this situation.

6.2 OTEC INSTALLATION SCENARIOS

Considering both the FPC system expansion plan and the characteristics of OTEC facilities, there are a number of possible scenarios that could be considered for the system planning method runs. However, it is doubtful that OTEC could be technically available prior to 1989. The alternative scenarios extend beyond this year to examine possible financial incentives or institutional issues, but for the specific purpose of the exercise of the system planning methodology, details beyond 1989 are not pertinent.

The first scenario to be studied is one 400-MW unit. The construction may be segmented and begin with one 100-MW demonstration plant followed by expansion to 400 MW. Transmission studies will be conducted to model the effects of DC transmission in Florida. The initial transmission configuration for OTEC will consist of two DC cables each capable of carrying the full output of the plant. Three scenarios will be studied: (1) two cables to the Pinellas County area, (2) one cable to Pinellas County and one south to the Sarasota - Naples area, (3) one cable to Pinellas County and one north to the Florida "Panhandle". The cost versus reliability trade-offs of cable redundancy will also be reviewed briefly.

In all cases, it must be understood that the technology may or may not be available for use at the dates assumed in the scenarios. This is dependent on the pace and success of the developers and is not under the control of Florida Power Corporation.

7. ANTICIPATED OUTPUTS FROM OVERALL STUDY

7.1 TASK II - SYSTEM PLANNING WITH BASELINE OTEC INPUTS

The next task, Task II, will exercise the system planning methodology with OTEC as a candidate power generating source. It will be assumed that the technology will be available within the planning horizon (10 years). For this study, it is projected that a first OTEC unit, of approximately 400 MWe capacity, could be available in 1989. It is possible that this unit would be part of a commercialization demonstration so that some of the costs could be shared with the developers of OTEC, or that some financial incentives or tax credits could offset the "first-of-a-kind" nature of a 1989 unit.

The Task II report will include a detailed presentation of the inputs to the planning models, and a disclosure of the costs of the plant along with the bases for these inputs. It is planned that these inputs represent the best available information on projected costs and operational characteristics of a plant available in the time frame of the studies.

Figure 7-1 represents the basic steps to be taken in Task II. Using the existing base case for future capacity expansion planning, OTEC will be considered as a candidate. From the output of the models and other aspects of the planning methodology, it will be displayed that OTEC either is or is not competitive as a function of the inputs.

7.2 TASK III - RERUNS WITH PARAMETRIC VARIATIONS

Given the base-case plans of the company and given the inputs on OTEC, particularly capital cost, it may be the case from Task II that OTEC does not appear commercially competitive. There are possible variations, in cost, in operational characteristics (such as availability factor), or particularly in financing elements including government incentives, that can be varied and influence the commercial competitiveness of this technology.

The basic procedure of Task III will be to vary these parameters and examine the concluding outputs of the system planning models. This examination can reveal the relative and absolute importance of these parameters in the competitiveness of OTEC. Thus, valuable feedback will be provided to OTEC developers and to government planners, considering incentive systems to encourage commercialism.

TASK 2 PROCEDURE

Figure 7-1. Task II Procedures

7.3 TASK IV - INSTITUTIONAL AND FINANCIAL FACTORS

The basic system planning methods of Florida Power Corporation contains considerations of institutional and financial factors, particularly in the Corporate Model. However, there are such a variety and extent of possible incentives and institutional factors that can emerge on considering OTEC that this area requires special treatment. It is anticipated that the results of Task III will reveal strong factors of influence in the area of financing mechanisms and incentives that might be applied by the government. These will be treated and expanded in detail in this Task and thus a set of recommendations can be inferred.

APPENDIX

A

FLORIDA POWER CORPORATION
SYSTEM PLANNING PROCEDURE
(CONDENSED)

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ORGANIZATION BEING SERVED

The Corporate Plan MIS serves the senior management of Florida Power Corporation in aiding decision making concerning the strategic planning of required expansion of generation, transmission and distribution facilities.

The senior management organization to be served by the MIS is:

FIGURE 1

Due to the dynamic nature of the electric energy industry, the need for assessing the affect of rapidly changing external forces on the company's plans is greatly heightened. The time span available for effective response to change is shrinking, while at the same time, lead times on new facility installations is greatly lengthening due to social and regulatory forces. This compound affect is the catalyst that brings

about the requirement for improved decision making, and thus the need for the proposed Corporate Planning MIS.

In order to determine the information needs of the senior management staff shown in Figure 1, their involvement in the form of extensive interviews would have to be enlisted.

GROSS DESIGN

The Corporate Planning Information System as outlined on Figure 2 is an integration of several existing and new programs, procedures, and individual Management Information Systems.

This proposed corporate planning MIS will unify the MIS subsystems of budgeting, scheduling, licensing, and construction of facilities required to meet the needs of the company's customers based on established corporate objectives. Among these objectives is the need to maintain financial integrity of the company while meeting the service needs of the customers reliably. These financial and service criteria must be quantified and serve as input to the MIS. The service requirements and need for financial integrity are often in conflict in the regulatory environment in which the company must function.

First and foremost in any planning activity is the development of the forecast. As shown on Figure 2 the corporate planning MIS includes a Forecasting Model. This forecasting model produces forecasts of customers, their demand and energy requirements, and the relationships of daily and seasonal usage patterns (load model) for periods of up to 20 years.

Obviously, this forecasting model requires that certain assumptions

be made concerning economic trends, population growth, industrial trends and demographic and climatological data. In addition, this model considers econometric relationships, for example, the effect increasing fuel cost has on the price elasticity of electric energy consumption. The output is stochastic in nature, and includes expected values for MW demands and MWH sales, as well as the expected variance of these forecasted values for the period of the forecast, usually 20 years. This forecasting model is presently being implemented and will be in service in 1980.

The next step in the corporate planning MIS involves the generation facility expansion planning subsystems. This subsystem has many data requirements and involves several individual MIS as components for input.

There are a very large number of factors which may influence the planning of future generation systems; so many, in fact, that the nature of the planning problem is partially obscured by the diversity and multiplicity of factors that must be considered in making planning decisions. As an aid in understanding the portion of the planning process affected and the particular influence of a planning factor, it is possible to formulate a system for classifying the factors involved in generation expansion. At the most aggregate level, the planning factors may be classified into three general categories, viz:

1. Candidate technology characteristics
2. Power system characteristics
3. Human and physical environmental characteristics

These general categories are broken down into their components, and the many factors that affect generation facility expansion planning decisions are diagrammed on Figure 3.

One of the key data requirements as shown in Figure 2 is the forecast of demand and sales (to determine energy required), as previously discussed. This forecast, and in particular the MW demand, sets the stage for additional generating capacity needs.

In order to determine how many new generating units are required, and their size and appropriate timing (schedule of in-service), the MW demand forecast and a desired level of reliability are input to the generation reliability model as shown on Figure 2. In practice, the true objectives of generation planning are not expressed in terms of maximizing customer reliability or minimizing customer costs, since these objectives are clearly antithetical. Rather, utilities have established certain values, or criteria, for various planning objectives which have been found to produce expansion plans which are more or less compatible with all other objectives. Unfortunately, the nature of utility planning criteria is often misunderstood. Planning criteria are not inviolate planning rules. For example, utilities sometimes have to sacrifice long-term economics for a lower short-term capital outlay. Planning criteria merely provide the planner with a convenient means of narrowing the set of possible expansion plans to a region of probable feasibility.

Many different types of criteria are utilized in expansion planning. Most are based on some procedure or policy that has worked well in the past, as, for example, establishing customer service reliability on the basis of the volume of customer complaints. Others, such as earnings coverage ratios, are based largely on the perceived reactions of other

groups, in this case the financial community. Another interesting criteria in this category used by at least one utility is one limiting the rate of growth of electricity rates. Still other criteria are largely the result of common sense, instinct or the personal experiences of planners. Examples would include limitations on the reliance upon a particular fuel type or a preference for standardized components.

Although planning criteria are not inviolate, they are important in expansion planning. It is safe to say that no expansion plan which fails to meet the established planning criteria will be implemented without a very good reason.

In addition this model requires that a representation of the existing system of generating units, their characteristics, and the characteristics of future units that are candidates for additions be input to the model. These characteristics include size, maintenance schedules, and outage rates (full forced outage as well as partial forced outage). The generation reliability criteria (2.5 days/year total load loss of load probability or .1 days/year firm load isolated loss of load probability) is the pivotal parameter for determining capacity requirements. All alternative generation expansion plans are designed to meet this criteria as stated above.

The optimum mix of generating capacity types, (base load, mid range, and peaking) is determined by evaluating alternative expansion scenarios in order to determine that strategy which produces minimum revenue requirements. The characteristics of base load units (coal and nuclear in the near term, solar and other developing technologies for the far term) are such that these type plants require very high capital investment,

but yield very low energy production costs. Because of these characteristics these plants must be run most of the hours of the year. Midrange units (combined cycle and cycling steam units for the near term, and fuel cells for the far term) require lower capital investment than base load plants, and yield higher energy production costs than base load. These midrange units operate generally less than 3,500 hours per year. Peaking units (combustion gas turbines and pumped storage hydro for the near term, and batteries and load management for the far term) in general are those types that are economical only when operated for short periods of time (4 to 5 hours per day during heavy load periods).

In order to determine the revenue requirements for each alternate generation expansion scenario, the production costing MIS must be employed to determine the production costs for each year of the study. These production costs are a function of the forecasted demand and energy, as well as the characteristics of the existing and planned generating units. In addition to the production costs, the cost of ownership of the required facilities including a fair return on the stockholders equity plus all other associated expenses required to operate the company must be determined. In order to determine these total revenue requirements, the corporate model MIS must be employed.

There are many uncertainties that affect the ultimate revenue requirements for any plan. Some of these are as follows:

1. Fuel Availability - The problem of fuel availability revolves around three central issues: quality, price and length of supply. Environmental standards, mining regulations and increased oil prices have all contributed

to a rather uncertain fuels market, in which suppliers and customers alike are competing for the most favorable long-term conditions.

2. Load Estimate Uncertainty - The problem of load forecasting uncertainty is becoming more significant for two reasons. First, increased uncertainty regarding conservation efforts have had an effect on forecasting loads accurately. Second, the consequences of forecasting errors have become more costly because of increased financial pressures and the need for earlier investment commitments due to longer construction lead times.
3. Licensing Delays - The cause of licensing delays are fairly well known. The complicated and overlapping procedures and requirements of the licensing process can, and often do, produce the greatest uncertainty in the entire planning process.
4. Fuels Diversification - Fuel diversity, or the desire for it, might best be regarded as a symptom rather than a cause of planning problems. This factor might also be called the 'Don't Put All Your Eggs In One Basket Syndrome'. In certain bases, fuel diversity may also provide planning flexibility in the event of licensing delays.
5. Meeting Present Or Anticipated Environmental Standards - In addition to the contribution of environmental stand-

ards to the specific problems of fuel availability, licensing delays and the disposal of plant by-products, the general problem of meeting environmental standards is an important planning consideration. An area of particular concern is the inability to anticipate future environmental standards and the attendant impact upon planning uncertainty.

6. Providing Plan Flexibility - Like fuels diversification, planning flexibility is a response to problems rather than a problem in itself. The need to have expansion plans that can be modified at some later time, preferably at minimum cost, to allow for future planning contingencies is desirable.
7. Water Availability - A major uncertainty is that of water availability. Finding adequate cooling water is a serious problem because competition for water is becoming more of a social issue than an economic issue.
8. Regulatory Uncertainty - In speaking of regulatory uncertainty, there is great uncertainty and delay in having the Public Service Commission grant rate proposals. This problem appears to be highly dependent upon the character of the Public Service Commission.
9. Reliability Standards - Because of increasing costs, financing problems and construction problems, there is a continual need to re-examine standards for reliability in light of present conditions. In

particular is the question of the cost-effectiveness of providing adequate generating capacity to meet peak loads with the level of reliability that has been accomplished in the past.

10. Plant By-Product Disposal - This problem might best be summed up by asking 'What are we going to do with all that scrubber sludge?'

These uncertainties must be addressed in the planning process, and there are numerous methods to attempt to quantify the associated risks. Among these are parametric analysis, analyzing at extremes, etc.

In order to determine revenue requirements, the corporate model must receive many input parameters. Among these are the proposed generation and transmission expansion plans, and the forecast.

The method by which the alternative generation expansion plan is developed has been described, and the next step is the development of the associated transmission and distribution expansion plan in order that input can be made to the corporate model (for the 5 year budget period, as the corporate model has logic for estimating long term T. & D. requirements).

The design of the transmission and distribution facility expansion plan also begins with input from the forecasting system. Figure 4 details a high level flow chart of the T. & D. planning subsystem of facility planning. The forecast loads for future years are input into a model of the existing system along with inputs from the as-planned (CBID Projects) system and the Generation Facilities Planning System.

In this beginning stage, several models are developed, ranging from existing systems to medium (2-3 year) and to long range (5+ years) systems. The existing system models are used to help operating departments solve immediate problems. The medium range models are used for planning facilities required to provide and maintain adequate and reliable service to a changing and growing customer pattern. The long range models are used to plan the bulk power system, explore requirements for future generation facilities, and to evaluate lifetime of proposed solutions to area problems.

Medium range models are run through the reliability program to establish existing system reliability indices, and to evaluate and prioritize problem areas. Alternate solutions are developed, analyzed with the aid of cost and feasibility information from engineering departments, and the selected solutions assembled into an as-planned system. This as-planned system is run through the reliability model and a comparison report generated detailing improvements.

Long range models follow a similar parallel path, except each alternate is evaluated with the reliability model and a single plan selected to match each generation scenario which is called the T. & D. Generation Alternate. Stability analysis is an input to this alternate before the final G. & T. & D. alternate output goes to the corporate model and the alternate generation plan where selection will be made of the future generation plan.

Considerable feedback loops have been eliminated for clarity, but which are easy to understand when one considers that medium range transmission and substation plans will have an impact on connection costs of

future generators and vice-versa.

After completion of the formulation of each alternative G. T. & D. plan, the corporate model MIS produces a conceptual annual total revenue requirement, annual construction budget, and financial requirement schedule. In light of the overall reliability assessment produced by the individual reliability models, a selection of the best plan can then be made based on economics and reliability.

The next step in the planning process is to develop the individual projects through the approval of Construction Budget Item Description (CBIDs). These CBIDs are the keys upon which the signal for detailed engineering is based. Also the CBID is used to approve the purchase of long lead time materials, and the allocation of required manpower associated with the projects. The manpower requirements are associated with both engineering and construction, and involve both Florida Power Corporation personnel and outside consultants and contractors.

These CBIDs are the basis for the ultimate schedule of project commitments, capital budgets, work orders, and financial requirements for the company as shown on Figure 2.

The MIS produces the many reports as shown on Figure 2. Among these is the land requirements schedule which describes real estate needed for generation, transmission and substation sites. The schedule of manpower requirements is also an output report, as is the material and equipment reports associated with each project. These resource requirements (men and material) can be used to determine if new personnel must be hired vs. contract personnel, and the level of material required in stores or direct purchases delivered to the project site.

From this MIS, another important report will be the corporate con-

FIGURE 2

FIGURE 3

FUNCTIONAL DIAGRAM OF FACILITIES EXPANSION PLANNING

struction budget. This budget will include a detailed two-year budget showing individual projects followed by a line item three-year budget. This will show the amount of dollars that will be ultimately included in the rate base.

As a follow up, a report of Florida Power Corporation approved work orders, will be output to be used as a check to assure that the plan is being worked, and all constraints are being followed.

A series of reports on financial requirements is also output. This includes a source of funds statement, cash requirements, certificate issues, and rate modifications (increase or decrease) required.

In summary, what this MIS will provide is the state in which we are presently operating, so that the decision maker will have precise information to adjust the corporation's plans in order to respond in a more timely manner to the changing environment in which we must operate in, in this era of the energy industry.

APPENDIX

B

DESCRIPTIONS OF FPC COMPUTER PROGRAMS UTILIZED FOR SYSTEM PLANNING AND ANALYSIS

- LOADFLO
- PROMOD
- GATOR
- CORMOD

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APPENDIX B.1

"LOADFLO" - PROGRAM FOR CALCULATING POWER FLOWS THROUGHOUT A UTILITY SYSTEM

This program, which is modified from one originally developed for the same purpose by the Philadelphia Electric Company, calculates steady-state power flows throughout the FPC electric utility system. In order to do this properly, it is necessary to include within the computer model a representation of the major electric system elements (generating plants, higher voltage transmission lines, and load centers) in the entire state of Florida and the southern portion of the state of Georgia.

APPENDIX B.2

"PROMOD" - PROGRAM TO DETERMINE SYSTEM PRODUCTION COSTS

The PROMOD III System including standard options contains the following standard features:

- Probabilistic generating unit availability models
- Multiple pumped-hydro projects
- Automatic and prescheduled maintenance scheduling
- Multiple take-or-pay fuel contract logic
- Multiple limited fuel contract logic
- Nuclear fuel cycle cost model
- Spinning reserve model
- Calendar month calculations
- Generalized load and energy forecasts models
- Generalized data handling features
- Economic dispatch modeling with transmission penalty factors
- Unit commitment modeling
- Automatic load adjustment for load management studies
- Calculation of capacity surplus and deficiencies on basis of reliability standard
- Diversity exchange contract modeling
- Readable output report file diagnostic dump
- Generalized output reports including
 - 3 complete input reports
 - 5 monthly reports
 - 5 quarterly reports
 - 5 annual reports
 - 5 study reports
 - 4 annual fuel budget reports
 - 4 study fuel budget reports
 - 20 diagnostic reports
- Report generation restart from calculation results file
- Separate fuel handling cost accounting

- Fuel inventory model
- Both storage and run-of-river hydro models
- Combustion turbine and combined cycle models
- From two to seven capacity segments per generating unit
- Three load periods per week
- Flexible modeling for contract purchases and sales
- Overhaul cost accounting
- Cyclic derations for seasonal unit ratings

The PROMOD III System differs from conventional production costing programs in its treatment of forced outages of generating units and auxiliary equipment. The PROMOD III System offers significant improvement over earlier probabilistic program costing programs. These modeling extensions include:

i) Load Model

Three load duration curves per week permit modeling of weekend maintenance and better representation of pumped hydro operation. Unit commitment now can be modeled more exactly.

ii) Load Management

Both demand and energy forecasts may be specified with the load shape being automatically adjusted using either:

- peak bias
- neutral bias
- valley bias

Annual energy and demand forecasts may be specified after the initial year or these forecasts may be escalated.

iii) Load Shapes

Hourly loads in EEI format are input and converted by the program to the appropriate load shapes. The need for auxiliary program and/or manual calculations to prepare load shapes has been eliminated.

iv) Generating Unit Model

Each generating unit may be represented by from two to seven capacity states. This permits more accurate modeling of partial forced outages and improved economic dispatching. Historical year rate case support testimony can now be performed with great precision.

- v) Reliability Model
PROMOD doubles as both a production costing and system reliability model. If only reliability results are desired, the time-consuming production costing calculations can be bypassed.
- vi) Output Reports
All output reports have been made optional. The user may select output from any of 28 reports.
- vii) Report Period
The time period for generating output reports may be controlled independently from the study period. This permits detailed diagnostic reports to be obtained for a short period of interest without generating massive volumes of output.
- viii) Optional Calculation Speed
Either fast, standard or precision calculation speeds may be specified.
- ix) Limited Fuel Model
A new model for limited fuel sources will soon be available. The allocation of limited fuel is performed on the basis of economics.
- x) Take-or-Pay Fuel Model
A new model for take-or-pay fuel sources will soon be available. The allocation of take-or-pay fuel is performed on the basis of economics. An efficient reallocation scheme has been developed to assure that all take-or-pay fuel is consumed in the event that the economic dispatching results in under utilization of the contractual amount.
- xi) Pumped Storage Model
Full probabilistic modeling is provided for multiple pumped storage projects. With three load duration curves per week the operation of a pumped storage project with a weekly refill cycle can be modeled accurately. The limitation on pumped storage utilization - economics, pumping capacity, generating capacity, storage capacity - is displayed in the period output report.

xii) Startup Priorities

Startup priorities may be automatically assigned by the program based upon unit heat rate and fuel economics or may be specified by the user. Specification of the generalized startup logic option eliminates the use of startup priority entirely. Units are then dispatched purely on the basis of economics (startup costs, incremental heat rates, fuel prices), reserve requirements, and unit minimum downtime restrictions.

xiii) Cost Escalation Factors

Escalation factors are provided for all costs. These escalation factors may be controlled at several levels:

- system wide
- fuel categories
- fuel suppliers
- individual generating units

Input data is minimized since missing values automatically default to the proper value at the next highest level.

xiv) Diagnostic Reports

Special diagnostic reports can be activated. These labeled reports will assist the user in quickly evaluating modeling and/or data discrepancies which were not detected during validation of input data.

xv) Automatic Maintenance Scheduling

Maintenance schedules which levelize the system reliability can be developed automatically thus relieving the user from the tedious effort of preparing maintenance schedules for multiple-year studies.

xvi) Maintenance Schedule Retention

The maintenance schedule generated with the automatic maintenance scheduling module may be permanently saved for future change case studies to assure that identical maintenance schedules are followed. Without this special feature a different number of maintenance outages may result for particular units over the same study period - a situation which makes change case comparative analysis needlessly difficult.

xvii) Generating Unit Derations

Derations may be specified for any unit at any time during the study even after a unit has entered automatic maintenance. Cyclic derations permit seasonal capacity adjustments to be specified easily.

xviii) Firm Energy Transaction Models

Generalized models have been provided for firm energy purchases and sales. The preferred subperiod - day, night, weekend - may be specified for each transaction.

xix) Data Override

A generalized data override capability has been provided which permits any information related to a generating unit, a firm transaction, a fuel type, or a load forecast to be overridden at any time even after it has started escalation or a unit heat rate may be changed to reflect scrubber installation without requiring that the old unit be retired and a new unit with identical characteristics except for the heat rates be commissioned.

xx) Library Files

Permanent library files for generating unit data, automatic maintenance data, load data, transactions data and fuel type data are maintained by the PROMOD System. This simplifies the management of change case studies - instead of requiring a complete data deck for each change case only the override data cards necessary to specify the change case need to be provided.

xxi) Time Varying Forced Outage Rates

As a unit matures its forced outage rates are continuously adjusted rather than being subjected to a step change at its maturity date.

xxii) Banking Model

A model has been developed to estimate the heat required during banking operation of thermal generating units.

xxiii) Reserve Model

A new reserve model has been developed which includes:

- spinning reserve requirement
- fast start reserve requirement

The reserve requirement may be specified either as a fixed MW value which can change from month to month or a fixed percentage of the largest unit and the system peak. The participation in each reserve category may be specified for each unit. Precommissioning operation can be recognized by the reserve model.

xxiv) Combustion Turbine Model

A new combustion turbine model has been developed which permits the loading of a combustion turbine strictly on an economic basis and permits combustion turbines to participate in meeting reserve requirements.

xxv) Nuclear Model

The nuclear logic has been extended to include not only fixed energy cycles but also basic fuel cycle economics. The unit costs of the nuclear fuel cycle components may be used in conjunction with a simplified criticality and depletion model to compute the nuclear fuel cycle cost in ¢/MBTU based upon projected nuclear unit operation.

xxvi) Calendar Dates

All dates used in the program are input by calendar date eliminating the need to count weeks of the year.

xxvii) Fuel Handling Costs

Fuel handling costs may be specified for each generating unit.

xxviii) Dispatch Penalty Factor

A dispatch penalty factor may be specified for each unit to penalize units at remote sites for transmission losses.

xxix) Inventory Model

An inventory model has been provided for each fuel type. Inventory fuel cost accounting permits application of fuel rate adjustment provisions.

xxx) Fuel Utilization Confidence Levels

Both the expected value and variance of each unit's fuel consumption are computed. With these quantities fuel utilization confidence levels (e.g. 95%) are calculated to determine necessary quantities of fuel to inventory in order to avoid a shortage with 95% confidence (probability). This information is invaluable in fuel budget analysis and fuel ordering.

APPENDIX B.3

"GATOR" - PROGRAM FOR THE ASSESSMENT OF BULK POWER & SUBTRANSMISSION RELIABILITY

GATOR is a sophisticated digital computer program used to calculate bulk power and subtransmission system reliability indices. The program was developed by Florida Power Corporation during 1976-7. The program has the following characteristics:

1. Performs calculations on a frequency and duration basis, rather than based on probability calculations alone.
2. Presents the results in terms of the number of customers affected, as well as the amount of load lost.
3. Takes into account both real and reactive power flows based on system impedances.
4. Includes loss of service due to inadequate system voltages.
5. Is compatible with the existing computer power flow system.
6. Is able to model large power systems in a single run (1500 buses).
7. Keeps to a minimum the amount of data which must be handled by the user.
8. Is able to identify which buses would be interrupted or experience load curtailments, and calculate the loss of load for each contingency observed.
9. Attempts to redispatch generation to alleviate overloaded lines prior to load curtailment.
10. Estimates the amount of unserved energy and the expected number of customer hours of interruption.
11. Is designed such that area studies could be performed easily without running auxiliary programs to reduce or isolate study areas.
12. Is able to accomplish the above tasks within an acceptable amount of computer time.
13. Takes into account seasonal variations in such factors as system configuration, load distribution, equipment failure rates, repair times, scheduled maintenance, power factor, etc.

The flow diagrams on the following pages show the sequence of calculations performed in GATOR. Also shown is a listing of the system reliability indices computed by the program, which comprise the final output.

The order in which remedial measures are accomplished is significant. The order selected is:

- a. Emergency redispatching to minimize line overloading
- b. Load curtailments to eliminate line overloading (interruptible loads first)
- c. Load curtailments required to restore voltages to acceptable values

This order was selected because it seems to approximate the procedure followed in actual practice.

G & T OVERALL RELIABILITY SYSTEM
EMERGENCY REDISPATCH LOGIC

G & T OVERALL RELIABILITY SYSTEM
OVERLOAD LOGIC

G & T OVERALL RELIABILITY SYSTEM
LOW VOLTAGE LOGIC

G & T OVERALL RELIABILITY SYSTEM

G & T OVERALL RELIABILITY SYSTEM
CALCULATION OF INDICES

ANNUAL
SYSTEM RELIABILITY INDICES

PROBABILITIES:

SERVICE FAILURE PROBABILITY
UNSERVICED ENERGY PROBABILITY

EXPECTED AVERAGES:

SERVICE FAILURE HOURS
SERVICE FAILURE OCCURRENCES
UNSERVICED ENERGY
UNSERVICED CUSTOMER HOURS
CUSTOMER INTERRUPTIONS

BULK POWER INTERRUPTION INDICES:

BULK POWER INTERRUPTION INDEX
BULK POWER ENERGY CURTAILMENT INDEX
BULK POWER SUPPLY AVERAGE CURTAILMENTS PER DISTURBANCE

SERVICE RELIABILITY INDICES:

SYSTEM INTERRUPTION FREQUENCY INDEX
SYSTEM INTERRUPTION DURATION INDEX
CUSTOMER INTERRUPTION DURATION INDEX
SYSTEM SERVICE AVAILABILITY
AVERAGE NO. CUSTOMERS PER INTERRUPTION

APPENDIX B.4

"CORMOD" - CORPORATE MODEL PROGRAMS

The Corporate Model consists of a number of closely-associated computer programs which contain the logical formulae and a large data base of current financial data and derived factors to forecast monthly financial results. The Model does not optimize the results; therefore, the user must predetermine the methods by which he can manipulate the Model to achieve the desired results.

This program logic is the distillation of an extensive analysis of prior years' financial results to define the relationships that exist between external events and the financial results of operations. Thus, the Model is responsive to those changes in electric rates, tax rates, wages, customer growth, inflation, etc., that have an impact on the Company. The results of these thousands of calculations are summarized into monthly, or annual, financial statements. There is no restriction on the projection period, although data has been gathered, and is available, for only 20 years.

The results of a study are summarized into monthly, or annual, financial and supporting statements. The basic statements are:

- Income Statement
- Balance Sheet
- Cash Flow
- Fuel and Energy Statistics
- Rate of Return Statistics
- Retained Earnings
- Financial Ratios
- Construction Expenditures

In addition to these statements, the user can construct his own special statements by a Statement Generator which will provide more detail by printing any of the monthly detail in the 700 accounts maintained by the Model.

APPENDIX

C

COMPARISON OF FPC WITH OTHER UTILITIES

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APPENDIX C

COMPARISON OF FPC WITH OTHER UTILITIES

It is extremely difficult to make meaningful comparisons of the characteristics or data of one utility organization with another. This is because each utility operates within a unique set of circumstances, parameters and constraints. There are inherent differences resulting from geographic size, load density, load type and characteristics (e.g., relative amount of industrial load, three-shift industry operation or one-shift, largely rural or largely urban residential load), climate, cost and availability of competing fuels for space heating, age of system, terrain, and proximity or access to coal mines or to actual or potential hydro power installations. Within the framework of recognizing that interpretations of comparative data has limited usefulness, comparisons with average, or composite, utility data are not totally without value. They can help to highlight that certain features or characteristics of a particular utility are different from corresponding values for the entire utility industry. For example, the following table shows the change in electricity sales compared to the preceding year, both historic and projected:

Year(s)	% Change	
	FPC	All Utilities*
1969-73	14.0	7.2
74	-1.9	-0.1
75	4.7	1.9
76	6.3	6.7
77	7.5	5.5
78	7.0	3.4
79	6.5	3.5
80	5.8	2.0
81	6.8	5.6
82	6.7	5.1
81-85	4.5	4.5
86-90	3.5	3.7
91-95	2.8	3.5

*Reference: "30th Electric Utility Forecast", Electrical World, September 15, 1979.

This tabulation shows that FPC has had a more vigorous growth during the past ten years than the overall utility industry, and that a stronger growth is anticipated for the next ten years.

A similar comparison can be made of forecast reserve capability at time of system peak (for FPC) and regional peak (for the industry). Although the data are not directly comparable, they do illustrate that the reserve capability anticipated by FPC is significantly less than that for the industry as a whole.

<u>Year(s)</u>	<u>Anticipated Reserve Capability (%)</u>	
	<u>FPC</u>	<u>All Utilities*</u>
1979	10.6	38.0
1980	9.3	43.0
1981-85	13.2	36.8
1986-90	20.5	25.0

A final measure of comparison is the price of electricity sold. This indicator is perhaps the one that is most subject to misinterpretation because of: (1) the inherent differences between utilities, as discussed at the beginning of this section, and (2) cost figures are affected by the timing of rate increases granted by regulatory bodies and the specific rate structures applicable to different customer classes. For the residential class of customers, the following data show that FPC's charges are about 10-15% higher than those of the utility industry as a whole, but that the difference is narrowing.

<u>Year</u>	<u>Electricity Price (¢/kWh) to All Residential Customers</u>	
	<u>FPC</u>	<u>All Utilities**</u>
1974	3.42	2.9
75	4.09	3.4
76	4.19	3.7
77	4.51	4.1 (Est.)
78	4.78	4.4 (Est.)

*Reference: "30th Electric Utility Forecast", Electrical World, September 15, 1979.

**Reference: "Typical Electric Bills - 1977", Federal Power Commission. Cost data as of January 1, 1977, for various monthly billings (Data for ~900 KWH/Mo. usage, averaged between years).

The set of price data shown in Table 3 serves to illustrate very clearly how rates vary with locality, utility, class of customer, and amount and characteristics of use. This table shows data for Florida Power Corporation, four other utilities in Florida, and one or more utilities in other states along the Eastern Seaboard. Because they are for a single point in time (1/1/77), the specific values should be interpreted as only being indicative of a situation, since individual utilities may have received rate increases shortly after this point in time. In general, rates are somewhat higher in Florida because of its high dependence of fuel oil, resulting in part from a moderately high cost of coal (compared to other regions closer to the coal fields). Florida Power & Light probably has lower rates because of their two large nuclear-fueled plants at the Turkey Point Station. The price of electricity is rather similar for FPC, Tampa Electric, Virginia Electric and Power, Baltimore Gas & Electric, Philadelphia Electric Company, and Connecticut Light and Power. The rates for the Jacksonville Electric Authority are lower because this utility is municipally owned and therefore does not pay federal, state or local taxes, and can also borrow money at a lower rate than an investor-owned utility. In the other states, the price of electricity is low where the utility is located near to coal fields or hydropower resources, and high elsewhere; particularly in the older, highly urbanized coastal cities. The extreme case is illustrated by Consolidated Edison in New York city.

The data in Table 3 serves to reinforce the view that FPC is a good candidate for an OTEC installation, not only because of its proximity to the Gulf of Mexico but because of its distance from hydro and coal resources.

Table C-1. Price of Electricity Supplied by Various Utilities*

State	Utility	Residential		Commercial		Industrial	
		500 KWH	1000 KWH	12 KW/1.5MWH	40KW/10MWH	75 KW/15 MWH	1 MW/200 MWH
Florida	Fla. Pwr. Corp.	4.60	4.27	6.40	5.13	4.87	3.81
"	Florida P&L	4.07	3.72	5.28	4.60	4.81	3.37
"	Gulf Power Co.	3.83	3.41	5.52	3.66	3.90	3.35
"	Jacksonville El. Auth	4.15	3.74	5.17	4.40	4.27	3.54
"	Tampa Elect	4.64	4.30	5.66	4.58	4.50	3.98
Georgia	Georgia Pwr. Co.	3.84	3.75	6.50	4.91	5.93	4.19
Alabama	Ala. Pwr. Company	3.77	3.49	4.89	4.13	4.23	3.48
S. Carolina	So. Car. El. & Gas	4.54	3.96	5.07	3.73	3.54	3.17
N. Carolina	Duke Power Co.	3.60	3.40	4.96	3.59	3.32	2.85
Virginia	Va. Elect. & Pwr.	4.90	4.09	5.87	4.67	4.57	4.49
Maryland	Balt. Gas & Elec. Co.	4.81	3.82	6.24	4.93	4.69	3.84
Delaware	Delaware P & L	4.74	4.47	7.27	5.32	5.35	4.15
New Jersey	Pub. Ser. El. & Gas	5.48	5.03	8.90	6.17	6.06	4.82
Pennsylvania	Phila. Elect. Co.	4.18	4.46	8.02	5.38	4.79	4.17
"	Penna. P & L	4.38	3.86	6.45	4.49	4.48	3.49
"	Duquesne Light	4.78	4.37	8.05	5.40	5.69	4.46
New York	Consol. Edison	8.03	7.49	11.95	8.20	8.97	8.97
"	Long Isl. Lighting	5.26	4.56	5.33	5.34	5.59	4.94
"	Niagara Mohawk	3.83	3.25	5.00	4.29	4.62	3.36
Connecticut	Conn. L & P	4.94	4.11	7.20	5.03	4.63	3.85
Massachusetts	Boston Edison	4.69	4.46	8.32	5.36	6.03	4.67
New Hampshire	Pub. Ser. of N.H.	4.49	4.19	7.49	4.25	4.01	3.62

* Reference: "Typical Electric Bills - 1977", Federal Power Commission. Cost data as of January 1, 1977 for various monthly bills.

APPENDIX

D

SELECTED PAGES FROM

F C G

SYSTEM PLANNING COMMITTEE

HANDBOOK

Franklin Research Center

A Division of The Franklin Institute

The Benjamin Franklin Parkway, Phila., Pa. 19103

SECTION I

PURPOSE

Pursuant to the By-Laws of the Florida Electric Power Coordinating Group, Sec. 5.4, the System Planning Committee is "...charged with the responsibility of actively coordinating the planning of the electric bulk power supply system in Florida." This includes:

1. Exchanging information with respect to planning among FCG member systems and other organizations.
2. Investigating and determining if the planned generating facilities and bulk power transmission grid in Florida are adequate and reliable.
3. Recommending to the Florida Electric Power Coordinating Group corrective actions concerning the planning, design, and operation of the systems as required to assure an adequate and reliable electric power supply in Florida, consistent with technological advances, environmental standards, and economics.

SECTION II

ORGANIZATION AND MEMBERSHIP

Any FCG member system who owns and controls the operation of generating units whose capacity, in conjunction with any purchase of short term firm capacity that may be necessary from time to time, is sufficient to serve its own load and provide an adequate operating reserve and whose electrical system is normally operated directly interconnected with other such systems may be a member of the System Planning Committee by request to the Executive Committee. In addition, the committee will consist of one (1) representative selected by the municipal and other government-owned electric systems not otherwise qualified and one (1) representative selected by the rural electric cooperative systems not otherwise qualified.

A representative may designate other bona fide, full-time employees of his system to represent him in any of the committee's task forces or assignments.

The General Manager of the FCG may attend meetings of the System Planning Committee and he may provide assistance to the committee as appropriate.

Any FCG member may attend meetings of the System Planning Committee as an observer.

SECTION III

PROCEDURES

1. MEETINGS

The committee shall hold a regular meeting bi-monthly on the third Thursday of the month beginning in January.

The location of meetings shall be alternately in the city of each member's home office or as mutually agreed.

Each committee member shall be notified and receive an agenda at least one week prior to the meeting date.

The minutes of each committee meeting shall be submitted within the week following the meeting date.

2. OFFICERS

The affairs of the System Planning Committee shall be administered by the representatives of the member systems.

Biennially, at the last regular meeting of the calendar year, the members shall elect the following officers:

Chairman
Vice-Chairman
Secretary

The nominees are to be selected by the Nominating Committee and must be members of the System Planning Committee. Terms of officers will be two calendar years.

The Nominating Committee shall consist of the Chairman of the System Planning Committee and two members appointed by him at the regular meeting preceding the last regular meeting of the year.

The Chairman shall direct the activities of the committee. He shall arrange and conduct all meetings of the committee and he shall be responsible for the preparation of the agenda thereof. He also shall represent and report on the committee's behalf to the Technical Advisory Group of FCG and other organizations as required.

The Vice-Chairman shall serve, during the Chairman's absence, as Acting Chairman until the Chairman reassumes his duties or a new Chairman is elected by the committee. Also, the Vice-Chairman shall be the coordinator of the committee's task forces and budgeting.

The Secretary shall keep, prepare, and distribute the minutes of the committee's meetings. He shall also publish in January of each year a proposed expense allocation ratio for each member utility.

In case of the absence of the Secretary from a meeting, the Chairman may appoint the person representing the Secretary or any member of the committee to serve as Acting Secretary for this meeting. Any person substituting for a representative who may be an officer of the committee shall not be entitled to the office (he will represent the member system only).

In the case of the Chairman's resignation or inability to complete his term, at the next regular meeting, a new Chairman will be nominated, as specified in this section and will be selected by the committee for the unexpired term. Following the selection, the new Chairman will assume his duties.

In case of the resignation or inability of the Vice-Chairman or Secretary to complete a term, within the following two months, a new officer will be nominated, as specified in this section and will be selected by the committee for the unexpired term. The Chairman may appoint any member of the committee to serve as Acting Officer for the interim period. If the unexpired term is less than six months, Acting Vice-Chairman or Acting Secretary may be appointed by the Chairman until the next regular meeting.

3. TASK FORCE PROJECTS AND BUDGET PREPARATION

Because of the importance of the committee's work to the state and the amount of money invested in it each year, it is important that the committee make maximum use of its resources. A well thought-out and detailed budget is a valuable tool in achieving this objective. The following is an outline of the procedure used in the preparation of the System Planning Committee's budget which is divided into three stages. Those stages are:

A. Objective Setting

The first activity in the process is that of describing what the committee considers to be the appropriate goals for the year. These goals should be set in the areas of:

- Loadflow Analysis
- Transient Analysis
- Reliability of the Generation System
- Load and Energy
- Regional Studies
- F.P.C. 383 Support
- Data Base
- Spinning Reserve Requirements
- Other Topics

Specifically, this activity is as follows:

1. Each member of the System Planning Committee will review the purposes of all existing task forces and expand and/or modify them as appropriate to encompass the activities which each member feels the task force should address.
2. Each member will also supply suggestions for any additional projects the committee should address.
3. The information compiled in Steps 1 and 2 will be forwarded to the Vice-Chairman prior to May 1 of each year. A composite of all submissions will be prepared and returned to each committee member prior to the committee meeting in May.
4. A meeting of the committee will be held during the month of May to set objectives for the coming year. These objectives should specify the desired areas to be studied, the degree of depth, and required reports.

B. Program Formation

The second step will be to describe the programs required to meet the agreed-upon objectives. These programs shall describe in detail the specific tasks necessary to accomplish the objectives and estimate the monetary and manpower resources required. This work will be performed by individuals designated by the committee.

1. An ad hoc committee of three individuals will be assigned to prepare the preliminary scope documents.
2. All completed preliminary scope documents will be forwarded by the ad hoc committee by June 15 to the Vice-Chairman for inclusion in the draft budget for the coming fiscal year.

C. Budget Formulation

Once the necessary programs are specified, an aggregate operating budget will be compiled. This budget will be presented to the Technical Advisory Group on or before September 1 after first gaining the approval of the System Planning Committee.

1. The draft budget will be mailed by the Vice-Chairman to all committee members for discussion at their July meeting. At this meeting, all scope documents will be reviewed for approval, task force member assignments, and scheduling. The purpose of this meeting will be to adopt the System Planning Committee budget. (Draft copies will be mailed out by the first week of July.)
2. Final corrections will be made and approved copies of the budget with the final scope documents will be forwarded by August 15 to the System Planning Committee.
3. The approved System Planning Committee budget will be forwarded to the Technical Advisory Group for their approval and consideration in conjunction with a critique of the previous fiscal year's budget.

D. Task Force Authorization and Review

The approval of the final scope document is not an authorization for the task force to begin work. The task force leader shall advise the Vice-Chairman at least two weeks prior to the scheduled committee meeting preceeding the beginning of the task force's work. The Vice-Chairman shall then advise the membership of the task force's intention and request them to review the task force's final scope document and be ready to either authorize or stop the task forces's work.

When it is necessary, the Chairman shall contact committee members for their approval to proceed with unexpected projects that may require completion with limited time.

The task force leader will send a written notice to the System Planning Committee members informing them of all future task force meetings.

Each active task force shall provide a written and, if required, a verbal technical/financial progress report at each regularly scheduled committee meeting. The System Planning Committee shall review, approve, and distribute all reports from either task forces or ad hoc committees. A System Planning Committee report shall be made at each regularly scheduled Technical Advisory Group meeting.

SECTION V

PLANNING CRITERIA

The members of the Florida Electric Power Coordinating Group aim to maintain a high degree of adequacy and reliability in Peninsular Florida's bulk power system. This can be accomplished largely through coordination in planning and adoption of common planning criteria by all the electric utilities in Peninsular Florida.

The planning of FCG systems shall be guided by the regional criteria which have been set forth by the Southeastern Electric Reliability Council for avoidance of cascading. The following principles shall guide the planning of generation and transmission facilities by the FCG members.

- A. The more probable contingencies can be met without loss of load.
- B. The less probable contingencies can be sustained with a possible loss of some load.
- C. Contingencies listed in SERC Guideline No. 3 are possible, but improbable, and shall be met without the occurrence of cascading.
- D. System stability shall be maintained in Peninsular Florida during and following the contingency(s) except the load area(s) in which the major disturbance(s) occurred. This does not preclude islanding and loss of load in other areas.

1. FCG PLANNING CRITERIA

The bulk electric power system in Peninsular Florida shall be planned to meet the following criteria.

- A. MORE PROBABLE CONTINGENCIES - To be sustained without loss of load (other than the load connected to the line or transformer which is lost):

1. Loss of generation

Sudden loss of any one generating unit.

2. Loss of transmission

a. Loss of any one transmission line.

b. Loss of any one transformer bank at any one generating plant or bulk transmission substation.

Following any single element outage contingency, all equipment shall be loaded within its long time rating and voltages shall be reasonably normal.

B. LESS PROBABLE CONTINGENCIES - To be sustained with possible loss of some load*:

1. Loss of generation

Sudden loss of any one generating unit while any one generating unit is out of service.

2. Loss of transmission

Loss of any two transmission lines, which are on the same double-circuit tower.

3. Loss of generation and transmission

Loss of any one transmission line while any one generating unit is out of service for scheduled routine maintenance.

The above, less probable contingencies, may cause loss of some load* and/or instability* of some localized generation, but the State bulk power system shall stay capable of readjustment after the occurrence of the disturbance so it can be operated within its emergency ratings, and at voltages that can be accepted for their duration time interval.

C. POSSIBLE BUT IMPROBABLE DISTURBANCES - To be sustained without occurrence of cascading:

1. Loss of generation

Sudden loss of entire generating capability in any one plant.

2. Loss of transmission

- a. The outage of the most critical transmission line caused by a three-phase fault during the outage of any other critical transmission line.
- b. Sudden loss of all lines on a common right of way.
- c. Sudden loss of a substation (limited to a single voltage level within the substation, plus transformation from that voltage level within the substation), including any generating capacity connected thereto.
- d. Delayed clearing of a three-phase fault at any point on the system due to failure of a breaker to open.

3. Loss of load

Sudden loss of a large load or major load center.

These contingencies may cause disruption of a portion of the system resulting in loss of some load*, instability* of some generating units, and some islanding*, but should not result in cascading.

D. SYSTEM STABILITY

1. All load areas shall remain stable during and following a normally cleared three-phase fault at any location of the transmission system.
2. Stability shall be maintained in all load areas exclusive of the load area the disturbance occurred in during and following the contingencies in Paragraphs B.1, B.2, and B.3, assuming that transmission element loss contingencies are associated with the above fault conditions of Paragraph D.1.

* "Load Relief" measures in all load areas and transmission relaying are acceptable means for maintaining stability and avoiding cascading.

SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL

GUIDELINE NUMBER 1.

UNIFORM LOAD FORECAST REPORTING

By SERC Technical Advisory Committee
Approved - Executive Board, February 1972

SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL

GUIDELINE NUMBER 1.

UNIFORM LOAD FORECAST REPORTING

The members of the Southeastern Electric Reliability Council shall use for SERC reports load forecasts based upon the 60-minute integrated net peak demand for normal weather conditions.

It should be understood this places no constraint upon members to use other forecasts for purposes other than data collected through the efforts of SERC-TAC.

SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL

GUIDELINE NUMBER 2.

FOR

UNIFORM GENERATOR RATINGS FOR REPORTING

By SERC Technical Advisory Committee
Approved - Executive Board, February 1972

SERC PROCEDURE FOR UNIFORM GENERATOR RATINGS
FOR REPORTING

The Southeastern Electric Reliability Council Agreement provides for the exchange of information with respect to planning and operating matters relating to the reliability of bulk power supply in the areas served by SERC Members. This procedure presents the criteria for uniform generator ratings for reporting by SERC Members.

SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL
PROCEDURE FOR UNIFORM GENERATOR RATINGS FOR REPORTING

I. GENERAL

Generating capability to meet the system load and provide the required amount of reserves is necessary to assure the maximum degree of service reliability. This generating capability must be accounted for in a uniform manner which assures the use of dependably attainable values for planning and operating the system.

Procedures are herein established for rating generating units in service or which will be brought into service in the future. These procedures define the framework under which the ratings are to be established while recognizing the necessity of exercising judgment in their determination. The tests required are functional and do not require special instrumentation. They are designed to demonstrate that the ratings can be obtained for the time periods required under expected operating conditions for the equipment being tested.

It is intended that the terms defined and the ratings established pursuant to this SERC Procedure shall be used in the preparation of SERC reports or other SERC information for industry organizations, news media, and governmental agencies.

II. UNIFORM RATINGS

Each SERC Member shall establish Summer and Winter Net Capability ratings for each generating unit and station on the member's system. The seasonal Net Capability is the net power output which can be obtained for a period adequate to satisfy the daily load patterns of the member under expected conditions of operation with equipment in an average state of maintenance. The Net Capability of a member's system should include generating capability which is temporarily out of service for routine maintenance or emergency repair.

The seasonal Net Capability ratings are intended to reflect such seasonal variations as ambient temperature, condensing water temperature and availability, fuels, steam heating loads, reservoir levels and scheduled reservoir discharge.

Generating capability shall be tested to demonstrate and verify that the Summer and Winter Net Capability ratings can be achieved in the respective season. It is intended that frequent changes in Net Capability ratings be avoided. The reported capability is, therefore, a figure which should not be altered until the accumulated evidence of tests and/or analyses of operating experience indicate that a long-term change has taken place. The Net Capability ratings shall be confirmed annually, and revised at other times when necessary. Confirmations and revisions will be submitted to the applicable SERC Subregion Office recognized as the data coordinating center for the subregion.

III. GENERAL GUIDES FOR ESTABLISHING CAPABILITY RATINGS

The following general guides shall be applied in establishing Summer and Winter Net Capability ratings:

- A. The Net Capability rating for the season specified shall be that available regularly to satisfy the daily load patterns of the member.
- B. The Net Capability ratings will be determined separately for each generating unit in a steam station where the input to the prime mover of the unit is independent of the others and for each combustion turbine unit. The Net Capability ratings will be determined as a group for commonheader sections of steam stations, multiple-unit hydro stations and combined-cycle units.
- C. Net Capability, as reported, will not be reduced to provide regulating margin or spinning reserve. It will reflect operation at the power factor level at which the generating equipment is normally expected to be operated over the daily peak load period. It will exclude the temporary higher output attainable immediately after a new unit goes into service or immediately after an overhaul.
- D. The Net Capability ratings of a unit or station may include capability obtained through bypassing of feed-water heaters, by utilizing other-than-normal steam conditions, or by abnormal operation of auxiliaries in steam stations; or by abnormal utilization of reservoir storage in hydro stations; or by operation of combustion turbines or diesel units above base rating, if the conditions under Section II are met and normal procedures have been established so that this capability will be made available promptly when requested by the dispatcher.
- E. The Net Capability ratings shall include any special limitations imposed on nuclear units by fuel management programs and/or by governmental bodies.
- F. The Net Capability ratings shall include any special limitations imposed on hydroelectric stations, including pumped-hydro, by reservoir storage programs and/or by governmental bodies. These ratings will be based on adverse hydro conditions.

IV. TESTING PROCEDURES TO DEMONSTRATE CAPABILITY

A. General Procedure for Testing

1. Ratings will be confirmed by tests each year to demonstrate the Summer and Winter Net Capabilities. If adequate data are available to demonstrate the capability during normal peak load period operation, no special test is required. Peaking units and cold reserve units which are not operated frequently shall be tested at such intervals as necessary to assure that the capability is available.
2. If the total capability of a station is materially affected by the interaction of its parts, a test of the entire station will be performed to demonstrate the seasonal Net Capability.
3. At time of test all equipment will be in average operating condition and all auxiliary equipment that is needed to meet the conditions of Net Capability rating will be in service. Energy consumption by auxiliary facilities common to the entire station (for example, coal-handling or lighting) will be distributed over the appropriate units in the station, and will represent the consumption normally experienced during the high-load period of the day.
4. It is intended that the test loadings should be maintained at a constant level. The reported test results will be no greater than the mwhr/hr integrated output for the test period.

B. Steam Turbo-Generator Units Tests

1. The test period for steam turbo-generator units will be for the period adequate to satisfy the daily load patterns of the member.
2. Steam conditions for the test will be those established by the member for the Net Capability rating of the unit or station. However, if the circulating water temperature at time of test is other than the circulating water temperature upon which the Net Capability rating is based, the reported test result may be corrected for this temperature variation. The steam generator will be operated in the regularly available type and quality of fuel.

IV. TESTING PROCEDURES TO DEMONSTRATE CAPABILITY (Con't.)

C. Combustion Turbine and Diesel Units Tests

The test period for combustion turbine and diesel units will be of sufficient duration to permit stabilized operating conditions to be attained.

D. Hydroelectric Units Tests

1. The test period for hydroelectric units, including pumped-hydro units, will be of sufficient duration to permit stabilized operating conditions to be attained.
2. Water conditions will be corrected to the seasonal adverse conditions.

V. REPORTING PROCEDURES

This procedure is an official SERC Procedure and all members shall submit the required data to the applicable SERC Subregion Office recognized as the data coordinating center for the subregion. This data shall be reported on the Uniform Rating Forms as included herein. The data contained in the initial report should be based on actual test data, operating data, or each member's best estimate, if such data is not available. The subsequent reporting shall include actual data as provided in this Procedure to replace estimated data.

After the initial report covering the then current December-through-November year, each member shall submit future reports to the applicable SERC Subregion Office annually on or before November 1 for the following report year, December through November. Each annual report shall cover all existing units, planned start-up of new units, and planned retirements and/or reactivation of units and shall consist of the following:

1. A listing of those units whose Net Capability ratings have not changed.
2. Completely revised report (Form No. 2A, No. 2B, or No. 2C) for units on which a rating change has occurred.
3. Completely revised report (Form No. 1) showing planned additions, planned retirements and/or reactivations, and any rating changes, with the month of commercial operation or month of retirement being footnoted.

Between annual reporting, revised reports shall be submitted as necessary for new units placed in commercial operation, units retired, and units for which tests show the rating has changed. Any change in additions, retirements, or ratings shall be submitted within 30 days of the addition, retirement, or test.

A. Uniform Rating Form No. 1

This form is used to report the Summer and Winter Net Capability ratings of each unit or group. The total Net Capability of each station and of the system is also reported as of Winter (December-March) and Summer (June-September) seasons of the report year. Each seasonal capability shall be reported for each unit to be added during the report year, but only included in the station and system totals of the Winter and/or Summer season for which the unit is expected to be in service.

V. REPORTING PROCEDURES (Con't.)

B. Uniform Rating Form No. 2

These forms are used to report test results. It is the intent that test data equal or exceed corresponding Summer and Winter Net Capability ratings to demonstrate that this level of generation can be achieved. Where simultaneous tests of several units are conducted, as in commonheader steam stations, data should be reported as a group.

Test results should be reported as follows:

- Form No. 2A - steam turbo-generator units
- Form No. 2B - hydroelectric units
- Form No. 2C - combustion turbine units,
diesel units, and combined-
cycle units

Special Note: In submitting revised reports, each form shall be submitted in such a manner that it completely replaces the sheet on which data is being revised.

5/18/78

YEAR: _____

D-21

STEAM TURBO-GENERATOR UNIT & STATION TEST REPORT

MEMBER: _____

Station _____

Unit or Group _____

Summer:

Date of Test _____

Net Mwh/Hr Generated _____

Net Capability Rating - MW _____

Winter:

Date of Test _____

Net Mwh/Hr Generated _____

Net Capability Rating - MW _____

Remarks: _____

0-22

SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL
GUIDELINE NUMBER 3
CRITERIA FOR RELIABILITY IN SYSTEM PLANNING

By SERC Technical Advisory Committee
Approved - Executive Board, October 1972

SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL

GUIDELINE NUMBER 3

CRITERIA FOR RELIABILITY IN SYSTEM PLANNING

The purpose of SERC "...is to augment further the reliability of bulk power supply in the areas served by the member systems." This can be best accomplished by promoting maximum coordination of planning, construction and utilization of generation and transmission facilities involved in interconnected operations.

To assist in achieving these objectives, the member organizations of SERC recognizes the need for common criteria to be used in the planning of their systems for adequate and reliable bulk power supply.

LOCAL AREA CRITERIA

It is recognized that the reliability of power supply in local areas is the responsibility of the individual SERC members and that each system has internal criteria relating to the more common contingencies. It is further recognized that there are severe contingencies which are credible but of a low probability of occurrence, which may result in conditions such as islanding and/or loss of load. Such conditions are considered acceptable as long as they are controlled so as to limit the adverse impact of the disturbance and so as to leave the system or systems in such condition as to permit rapid load restoration and/or reconnection.

SERC REGIONAL CRITERIA

The objective of the regional criteria is to assure that the SERC bulk power systems are planned so that cascading outages will not result from any foreseeable contingencies. These criteria are, therefore, directed only at preventing cascading.

Cascading is defined as the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in an uncontrolled, widespread collapse of system power which collapse cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.

Each of the SERC Member Systems will be planned to avoid cascading upon the occurrence of the following contingencies:

1. Loss of Generation

Sudden loss of entire generating capability in any one plant.

2. Loss of Load

Sudden loss of a large load or major load center.

3. Loss of Transmission

- a. The outage of the most critical transmission line caused by a three-phase fault during the outage of any other critical transmission line.
- b. Sudden loss of all lines on a common right-of-way.
- c. Sudden loss of a substation (limited to a single voltage level within the substation plus transformation from that voltage level), including any generating capacity connected thereto.
- d. Delayed clearing of a three-phase fault at any point on the system due to failure of a breaker to open.

SECTION VII

TERMS AND DEFINITIONS

1. ANNUAL is defined as a calendar year.
2. ANNUAL CAPACITY FACTOR is represented by the following equation:
$$\frac{\text{Net Generation for Unit}}{(\text{Maximum Generator Nameplate Capacity})(\text{No. of Hours in Year})}$$
3. ANNUAL LOAD FACTOR is represented by the following equation:
$$\frac{\text{Annual Net Energy for Load}}{(\text{Annual Net Peak Demand})(\text{No. of Hours in Year})}$$
4. DEMAND is the rate at which electric energy is delivered by a power system.
5. ECONOMETRIC MODEL is a model that correlates economic data with either energy or demand by the application of statistical methods.
6. FORECASTS:
 - SHORT-RANGE FORECAST is a forecast of 1 - 5 years.
 - MEDIUM-RANGE FORECAST is a forecast of 6 - 10 years.
 - LONG-RANGE FORECAST is a forecast of 11 or more years.
7. NET CAPABILITY OR CAPACITY is the continuous gross capacity less the power required by all auxiliaries associated with the unit (station service), or the capacity as specified by SERC Guideline Number 2 for Uniform Generator Rating for Reporting. There are usually two such capability ratings: one for summer and another for winter.
8. NET ENERGY FOR LOAD is the net system generation plus energy received from Class I and Class II systems minus energy delivered to Class I and Class II systems.
9. NET ENERGY FOR SYSTEM is the net energy for load plus energy received from Class III or Class V systems, minus energy delivered to Class III and Class V systems.

TERMS AND DEFINITIONS (Cont'd)

10. NET PEAK DEMAND is the maximum integrated demand of energy for 60-minute clock-hour intervals. Where integrated demands for 60-minute clock-hour intervals are not available, it is desired that available data be adjusted to approximate such intervals. Estimates should be for normal weather conditions.
11. NET INTERCHANGE is the demand or energy delivered into, less demand or energy out of, a generating system.
12. NET SYSTEM GENERATION is the total energy produced by the generating units of a system less energy for station service.
13. PLANT STATION SERVICE is the demand or energy necessary to operate the plant station service equipment.
14. POWER is the time rate of transferring or transforming energy.
15. SEASONAL is the two seasons - winter and summer - which are defined as follows:

WINTER: November through April
SUMMER: May through October

16. SYSTEM CLASSIFICATION is the following groupings which have been established by the Federal Power Commission for the purpose of reporting power system operations:

CLASS BASIS

- I .. Systems which generates all or part of system requirements and whose net energy for system (NES) for the year reported was greater than 100 GWH.
 - II .. Same as I, but whose NES was between 20-100 GWH.
 - III .. Same as I, but whose NES was less than 20 GWH.
 - IV .. System engaged primarily in sales for resale and/or sales to industrials; all other sales being negligible.
 - V .. System which obtains its entire energy requirements from other systems.
17. TOTAL NUMBER OF CUSTOMERS is the total average annual number of customers. This is the average of the number of the end of the month total customers for the calendar year.
 18. WEATHER MODEL is a model that correlates weather with either energy or demand, allowing separation and analysis of weather sensitive and non-weather sensitive energy or demand.