UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY & LICENSING BOARD

In the Matter of:	)	
FLORIDA POWER & LIGHT COMPANY	)	Docket No. 50-389
(St. Lucie Nuclear Power Plant, Unit No. 2)	)	

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Testimony of
Edward J. Fowlkes
September 21, 1979

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Testimony of
Edward James Fowlkes

Relating to
ASLAB Memrandum and Order of

April 5, 1979, on

Electrical Grid Stability and Emergency Power Systems

(Question B1 - Failure of Offsite Power)

My name is Edward James Fowlkes. I am a Supervisory Electrical Engineer serving as the Chief, Interconnection & Special Investigations Branch in the Federal Energy Regulatory Commission's Office of Electric Power Regulation/ Division of Interconnection and Systems Analysis. My education and professional qualifications statement is attached to this testimony and herein incorporated by reference.

SCOPE OF TESTIMONY

The purpose of this testimony is to address Question B1 as stated in the Atomic Safety and Licensing Appeal Board Memorandum and Order of April 5, 1979, a statement of which is provided in my accompanying Affidavit.

Offsite Power Supply to the St. Lucie 1,579 MW Nuclear Plant From the Midway 500/230/138 kV Substation Evaluation

Presently and in 1983, the proposed operational date for the St. Lucie No. 2, 802 MW, nuclear unit, there are three heavy duty, (952 MVA) conservatively designed 230 kV lines, respectively 11.62, 11.77 and 11.75 miles in length. A breaker-and-a-half 230 kV circuit breaker arrangement is used to terminate the lines at both ends and in no case are the lines in the same three-breaker bay. At Midway Substation, excluding the St. Lucie 230 kV lines, there will be one 500 kV line, via a 500/230 kV 1,500 MVA FOA auto transformer with two low-side circuit breakers; five 230 kV lines, and two 138 kV line, connected via two 230/138 kV 224 MVA auto transformers. Speeifically these lines are (Ratings in parenthesis):

Length	Terminations	Voltage
26.4	Midway - Martin (2,650 MVA)	500 kV
53.74	Midway - Malabar No. 1 (387 MVA)	230 kV
50.39	Midway - Malabar No. 2 (387 MVA)	230 kV
	(These two lines are on a common Right-of-Way north to Malabar substation)	
53.31	Midway - Indiantown - Pratt & Whitney - Ranch (840 MVA)	230 kV
53.26	Midway - Ranch (773 MVA)	230 kV
	(These two lines utilize a common Right-of-way south to the Ranch Substation)	
47.9	Midway - Sherman - Martin 230 kV Indiantown (420 MVA) 230 kV	
	Midway - Plumosus (178 MVA)	138 kV
7.33	Midway - Hartman (City of Fort Pierce)	138 kV

These lines will provide eight sources (over four transfer paths) of FP&L system and other Peninsula Florida system supply of offsite power to the Midway - St. Lucie substation. The 230 kV lines terminate at Midway and St. Lucie in four substation bays arranged in a breaker-and-a-half protective scheme. To disconnect one line's terminal, two circuit breakers must open. Should one of the two breakers fail to clear, at most one line (generator at St. Lucie) would be disconnected from service. If a bus side associated line breaker fails to clear, the associated bus will be cleared, however, this would not affect the continuity of any other line (generator at St. Lucie) except the faulted line initiating protective relay action. For all double contingency (n-2) possibilities at the Midway substation, at most one Midway to St. Lucie 230 kV line's operation is affected and at least six line sources remain to Midway and at least two 230 kV lines to St. Lucie. Midway substation double contingencies

considered were:

(1) 230 kV or 138 kV line fault with bus side breaker failure;
(2) 230 kV or 138 kV line fault with mid-bay (not adjacent to bus) failure;
(3) 500 kV line fault with stuck breaker;
(4) 230/138 kV bus fault with breaker failure;
(5) 500 kV bus fault with breaker failure:
(6) double 230 kV line or 500 kV plus 230 kV line fault; and,
(7) double 230/138 kV bus fault.

These outage conditions are within the scope (SERC & FCG Planning Criteria) of those normally considered to provide an adequate bulk power supply system. In normal utility system operation, all facilities operational, the double contingency would be caused by the simultaneous failure of two components, however, this condition could also evolve from the unscheduled (forced) outage of one during the scheduled (maintenance) outage of another.

Even with a triple contingency(n-3), excluding the loss of all three Midway to St.Lucie 230 kV lines, at the Midway substation, a highly unlikely event not normally considered as a design event, 3 to 4 230 kV lines (depending on which mid-bay breaker fails to clear) remain connected to the Midway substation and 2-3 230 kV lines continue operation between Midway and St Lucie.

Therefore, it may be concluded that, short of a sustained loss of all Midway to St. Lucie 230 kV lines, the loss of all Midway supply lines and thence all offsite St. Lucie plant supply is an event substantially beyond normal electric utility design criteria.

It would require the simultaneous occurrence of more than three disabling events at Midway substation or system collapse, including a disturbance event causing the islanding and loss of generation to the FP&L Midway substation to cause the complete loss of all offsite power to St. Lucie. Short of the destruction of the Midway substation, eight essentially independent transmission failure events must occur to lose Midway substation.

To quantify the approximate failure frequency of transmission supply to the Midway and St. Lucie substation, a limited scope transmission reliability assessment was made of the transmission system supplying Midway substation through to the St. Lucie 230 kV substation. To simplify calculations, the following assumptions were made:

(1) Circuit breaker, relay, bus and transformer failure events were not included. This was partially because no source of 500/230 kV transformer failure rates and repair times was available. A bus fault concurrent with a break failure must occur to affect a line.

(2) While the Midway - Malabar 230 kV lines and the Midway - Ranch and Midway - Indiantown - Ranch 230 kV lines occupy common right-of-ways, failure independence was assumed;

(3) The failure event improvement provided by the 138 kV lines (Midway - Plumosus and Midway - Hartman) was excluded;

(4) Because of the sparsity of line failure event data provided by FP&L, 230 kV line failure rate and repair characteristics in Institute of Electrical and Electronics Engineers (IEEE) publication on transmission system reliability calculations were used (Vol. PAS-87, No. 3, March 1968, "A Method for Calculating Transmission System Reliability" Stephen A. Mallard and Virginia C. Thomas - Table I). The Transmission Interruption Summary provided by FP&L only covered the few 230 kV Midway substation line (138 kV also provided) failures that occurred during the 1975-1978 period. System outages are not incorporated in the data base.

(5) The 230 kV line failure rate (outages per unit per year) used was the weighted average of forced normal weather and forced adverse weather outages. The impact of the adverse weather component (152.63 times the normal component) was incorporated based up U.S. Department Commerce/Weather Bureau/Climatological Services Division data provided in Technical Paper No. 19, "Mean Number of Thunderstorm Days in the United States", September 1952 which showed Miami, Florida with a mean annual number of thunderstorm days of 91. Therefore, the adverse weather failure rate component was given a 25% weight. The 230 kV line failure rate used was 0.1105915 outages per mile-year consisting of normal and adverse weather components respectively of 0.00285 and 0.435. The normal and adverse

weather repair times respectively were 4.43 and 15.2 hours which when weighted accordingly provided an equivalent repair time of 7.115 hours. Failure rates calculated with the FP&L 230 kV data varied between 0.0 and 6.25 per year with most about 0.5 per year (0.01 outages/mile-year for 50 mile line)

(6) The same failure rate (230 kV) was used for the Midway - Martin 500 kV line

(7) Scheduled outage and overloads due the outage of another facility effects were not included.

Following are the line failure rates (outages per year) used in the calculations. The component repair time was 7.115 hours for all lines.

	Line Terminations	Outages Per Year
1.	Midway - Malabar No. 1, 50.39 miles	5.5727
2.	Midway - Malabar No. 2, 53.74 miles	5.9432
3.	Midway - Martin 500 kV, 26.4 miles	2.9196
4.	Midway - Sherman - Martin 230 kV Indiantown, 47.9 miles	5.2973
5.	Midway - Indiantown, 24.12 miles	2.6675
6.	Indiantown - Pratt & Whitney - Ranch, 29.19 miles	3.2282
7.	Midway - Ranch, 53.26 miles	5.8901
8.	Midway - St. Lucie No. 1, 11.62 miles	1.2851
9.	Midway - St. Lucie No. 2, 11.77 miles	1.3017
10.	Midway - St. Lucie No. 3, 11.75 miles	1.2995

Lines 4. and 5. were considered as a parallel combination in series with Line 6. This result was taken as a parallel combination with Lines 1., 2., 3., and 7. to Midway substation, resulting in a combined unavailability of all lines and failure frequency (events per year) respectively of 652.2066×10^{-15} and 4.0178×10^{-9} events per year (Mean Time Between Failures (MTBF) of 248,890,300 .4 years).

Lines 8., 9.. and 10. were combined in parallel with this combination taken in series with the above to St. Lucie 230 kV substation. The resultant unavailability of all lines, failure frequency and MTBF respectively were 1.1653×10^{-9}, 4.3058×10^{-6} events per year and 232,244.79 years. These results apply only to the specified transmission line components without consideration of generation being available to supply the lines.

Attachment Nos. 2 and 3 discussion design considerations as they apply and are used in Peninsula Florida and the FP&L interconnections with other Peninsula Florida systems.

REFERENCES

1. 1978 Power System Statement (FPC Form No. 12) from Florida Power & Lignt Company

2. 1978 Power System Statement from Florida Power Corporation

3. 1978 Power System Statement from Tampa Electric Company.

4. April 1, 1979, Coordinated Bulk Power Supply Program, 1979-1998 from Sosutheastern Electric Reliability Council.

5. April 1, 1978, Bulk Power Supply Program, 1978-1997 from Southeastern Electric Reliability Council

6. August 1, 1979, 1979 Ten-Year Plan-State of Florida-Electrical Generating Facilities and Associated Transmission Lines, Florida Electric Power Coordinating Group.

7. March 1979, Report of Special Transient Stability Study for 1978 Summer Peak, to the System Planning Committee by the Special 1978 Transient Stability Task Force.

8. January 1979, Transmission Loadflow Analysis Report - 1982 & 1987 Summer Periods by Florida Electric Power Coordinating Group, System Plannng Committee, Transmission Task Force.

9. August 23, 1978, Peninsula Florida Generation Reliability Study, 1978-1987 by Florida Electric Power Coordinating Group, Inc.

10. A Method for Calculating transmission System Reliability, Stephen A. Mallard and Virginia C. Thomas. IEEE Transactions on Power Appuratus and Systems, Vol. PAS-87, No. 3 pp. 824-834, March 1968.

11. A Probability Method for Transmission and Distribution Outage Calculations, Z.G. Todd. IEEE Transactions on Power Apparatus and Systems, Vol. 83, pp. 695-701, July 1964.

12. On Procedures for Reliability Evaluations of Transmission Systems, Robert J. Ringlee and Sheila D. Goode. IEEE Transactions on Power Apparatus and Systems, Vol. PAS - 89, No. 4, pp. 527-536, April 1970

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13. Power-System Reliability Calculations, Roy Billinton, Robert J. Ringlee and Allen J. Wood. The Massachusetts Institute of Technology Press, Cambridge, Massachusetts, 1973.

14. Power System Reliability Evaluation, Roy Billinton Gordon and Beach, Science Publishers, Inc., New York 1970.

15. Transient Stability Evaluation of the Impact of the New 230 kV Tie Between FP&L and Georgia Power Company, Florida Power & Light Company, August 31, 1979

16. Review of the Performance of Various Electrical Configurations between St. Lucie Plant and the FPL Grid, Florida Power & Light Company, August 31, 1979

17. Testimony of Frederick George Flugger relating to ASLAB Memorandum and Order of April 5, 1979, on Emergency Grid Stability and Emergency Power Systems (Questions A2, B1, B2, B3, and B4 of ALAB 537) June 22, 1979.

18. Joint Testimony of Michel P. Armand, Ernest L. Bivans, and Wilfred E. Coe Relating to Questions A1 and D of ALAB 537. June 1, 1979

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Edward J. Fowlkes
Professional Qualifications Statement

My name is Edward J. Fowlkes. I am Supervisory Electrical Engineering serving as the Chief, Interconnection & Special Investigations Branch in the Federal Energy Regulatory Commission's Office of Electric Power Regulation/Division of Interconnection and Systems Analysis. The ISI Branch analyzes and evaluates: (1) transmission, interconnection and operational characteristics of electric power systems associated with FERC, or other proceedings and investigations upon request; (2) FERC licensing jurisdiction over electric transmission lines associated with hydroelectric projects; and, (3) benefits available through increased coordination and pooling of electric power systems. Prior to my Federal employment beginning in 1971 with FERC's predecessor the Federal Power Commission/Bureau of Power/Power Supply & Reliability Division, I was employed by the Central Hudson Gas & Electric Corp., in Poughkeepsie, New York.

I received a Bachelor of Science Degree in Electrical Engineering (Power Option) in 1964 from Howard University in Washington, D.C. and a Master of Enginering Degree in Electric Power Engineering in 1971 from Rensselaer Polytechnic Institute in Troy, New York. In 1968-69, I attended the General Electric Company's Power System Engineering Course in Schenectady, New York. I am a registered Professional Engineer in the State of New York and a member of the Institute of Electrical and Electronics Engineers.

Attachment No. 1

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING APPEAL BOARD

In The Matter Of:	)	
FLORIDA POWER & LIGHT COMPANY	)	Docket No. 50-389
(St. Lucie Nucler Power Plant,	)	
Unit No. 2)	)	

AFFIDAVIT OF EDWARD J. FOWLKES

I am Edward J. Fowlkes, Chief, Interconnection & Special Investigations Branch for the Federal Energy Regulatory Commission's Office of Electric Power Regulation/Division of Interconnection and Systems Analysis. My education and professional qualifications appear as an attachment to this testimony. I am participating here at the request of the U.S. Nuclear Regulatory Commission's Counsel for the NRC staff to provide assistance in their assessment of the adequacy of the Florida Power & Light Company and the Peninsula Florida transmission system for the offsite emergency power requirements of the 802 MW St. Lucie No. 2 nuclear unit.

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The purpose of this affidavit is to respond to Question B1 concerning the failure of St. Lucie nuclear plant offsite power in the Atomic Safety and Licensing Board Memorandum and Order of April 5, 1979 (ALAB-537).

QUESTION B1

As we see it, the likelihood of loss of all AC power at St. Lucie may be expressed as the product of two factors: (1) the probability that there will be an offsite power failure involving the FPL network generally or the Midway substation in particular and a resulting loss of station power — which probability seems based on historical events, to lie in the range 1.0 ant 0.1 per year; and (2) the probability that neither of the two onsite AC power systems (diesel generators) will start. The probability that any one diesel generator will fail to start on demand is taken by the staff to be one per hundred demands, i.e., 10^{-2} 25/.

If these figures are accurate, then the combined probability for the "loss of all AC power" scenario is in the range 10^{-4} to 10^{-5} per year. 26/ In this regard, the staff's Standard Review Plan for Nuclear Power Plants sets forth numerical guidelines for determining whether an event "resulting from the presence of hazardous materials or activities in the vicinity of the plant" should be considered in designing the plant (i.e., whether it is a "design basis" event). 27/ Under these guidelines, events with a realistically calculated probability value of at least 10^{-7} per year (or 10^{-6} per year a conservative calculation) must be so considered.

The "loss of all AC power" sequence is not precisely within the category of events contemplated by the Standard Review Plan. However, its ultimate result — assuming that power is not timely restored — is an unprotected loss of coolant accident, the consequences of which are likely to exceed the guidelines of 10 CFR Part 100. We do not understand why this sequence of events (i.e., loss of offsite power combined with failure of diesels to start), which appears to have a probability well above the guideline values, should not be taken into consideration in the design of the plant. 28/ The parties are to address this point, setting forth their reasons for adhering (if they do) to a contrary position.

25/ Fitzpatrick Affidavit of June 12, 1978, p. 4. Also see Regulatory Guide 1.108, Section B.

26/ This conclusion further assumes that the failure of two diesel generators to start would be statistically independent events, an assumption which leads to the lowest likelihood of combined failure, and which might be nonconservative if there exists the potential for common failure modes for the onsite systems.

27/ NUREG 75/087, Section 2.2.3, paragraph II.

28/ We have accepted the Standard Review Plan guideline values as reasonable in another case. Public Service Electric and Gas Company (Hope Creek Units 1 and 2), ALAB - 429, 6 NRC 229 234 (1977).

I, Edward J. Fowlkes, being first duly sworn, depose and say that statements of this affadavit are true to the best of my knowledge and belief, and that if asked questions thereon, my answers in response thereto would be as contained herein.

Edward J. Fowlkes
Edward J. Fowlkes

Washington, D.C.)

Subscribed and sworn to before me this 21st day of September, 1979.

Notary Public

My Commission Expires July 1, 1982

Discussion of the Bulk Electric Power Supply Planning and Design Program

All of the following contingency analysis tests are incorporated in the FP&L and Peninsula Florida systems bulk electric power suppply planning and design process. While extensive FGC studies of the 1983 Peninsula Florida system have not been performed because of the tentative nature of area utility plans, such studies, I have been informed, are planned to be completed by early 1980.

In the process of designing the bulk power supply facilities, generation and transmission, the power system is analyzed at peak as well as lower load conditions. In the case of Peninsula Florida systems such analysis is done on an individual utility basis as well as a Peninsula Florida basis (Florida Electric Power Coordinating Group). Once the level of generation needed is established, the transmission system must be analyzed to provide an adequate means for transferring the supply to the load (MW and MVAR). The transmission system design must be thoroughly coordinated with the generation expansion program and visa versa.

Establishment of an adequate transmission system must consider both normal and unusual conditions both of the available generation and of the transmission system. Compounding this analysis are the ever present possibilities that a planned generation or transmission facility will not be available as planned (institutional, environmental or other regulatory delay). The abnormal design conditions evaluated seek to account for scheduled outages (generation, transmission line or substation maintenance) and forced (unscheduled) outages of generation or transmission facilities. Such analysis is performed through use of load flow and stability computer programs.

Load flow is used to determine the distribution pattern of the electric power throught the transmission system and losses with a specified generation schedule (economic dispatch and spinning reserve allocation) and unit availability, system load level (MW) and transmission facility availability. Such analysis will determine if with specified availability of facilities, at a specific system load level, whether the transmission system components operating within their capability limits (MVA) and voltage limits. The spectrum of situations analyzed would include:

Base Case (all generation and transmission facilities available)

A. Peak Load
B. Lower Load Level

Single Contingency

A. Single line outage
B. Single generator outage

Double Contingency

A. Double line outage (generally restricted to a double-circuit transmission line outage or two single-circuit lines on a common right-of-way)

B. Double generator outage (this would account for situations where a unit was scheduled out and another unit had to be taken off line where both units may not be at the same site and where the second unit was not lost due to fault or sudden trip)

C. Single line outage and generator outage (this would account for conditions wherein a line or generator was scheduled out and a line or generator was forced out of service)

D. Other Multiple Outages (outages of more than two bulk power supply facilities may be considered depending on anticipated area or regional conditions but are not generally design criteria)

Area Transfer Capability

A. Intra system transfer capability (to determine the capability to transfer power from one utility system subarea to another. Such analysis 14. may be useful in developing restoration plans and in determining limiting facilities)

B. Inter system transfer capability (to determine the import or export capability between utility systems or regions)

The preceeding contingencies are evaluated both at peak and lower load conditions in the process of analyzing the bulk power supply system adequacy and its adherence to design criteria. In all cases, it is presumed that if a facility or facilities are outaged because of a fault condition, the system is transiently stable and the effect of interconnected utility systems are represented through appropriate model equivalents. These load

flow contingency studies are also performed as a routine part of normal system operation's periodic security analysis via on-line load flows at modern system operations control centers, for each capability period-summer and winter, on the mid range system plan 3-7 years in future and on the longer - range system 9-15 years in the future. The extensiveness of the contingency testing will depend on the study requirements and reasons precipitating the particular study. The stability of the system(s), the ability to survive major disturbances without uncontrolled losses of generator or load and without system collapse, is determined through transient stability modelling.

Transient stability programs are design to evaluate electric power system dynamics resulting from sudden losses of bulk power supply facilities and loads due to faults or other sudden contingencies. These may include:

<u>Loss of Generation</u>

A. Outage of a critical transmission line caused by a fault.

B. Outage of a critical transmission line caused by a fault during the scheduled outage of another critical line.

C. Sudden loss of all lines on a common right-of-way (this could include the unlikely loss of three or more lines occupying a common right-of-way)

D. Delayed clearing of a fault at any point on the system due to failure of a circuit breaker to open (this accounts for system dynamics that may result if the primary protective relay system dynamics that may result if the primary protective and the back-up protective relaying and associated circuit breaker(s) must operate to clear the fault)

E. Sudden loss of a substation plus transformation including any generating capacity connected thereto. The substation loss, from a practical view point would be limited to a single voltage level at a multivoltage level substation.

The evaluation of the foregoing events would be directed towards the transient analysis of the power system(s) and would model the generator, load and protective relay dynamic performance to verify that no uncontrolled system separations, loss of generation, facility overloads or system collapse occurs. Also modelled would be the performance of underfrequency relay response consonant with encountered situations. The fact that the analysis shows that underfrequency relays operate as planned is an appropriate result dictated by the extent transmission and generation supply. The analysis may also be used to develop the appropriate underfrequency relay load shedding scheme.

Florida Peninsula Design Criteria For System Planning and Operation

The Florida Power & Light Company along with the other Florida Peninsula systems design their transmission facilities to meet the Florida Electric Power Coordinating Group (FCG) criteria which parallels the SERC Regional Criteria. The FCG planning criteria is for the operating systems in Florida is set out in the FCG Planning Handbook.

SERC Regional Criteria - the objective of the criteria is to assure that cascading outages do not result from any forseeable contingencies. Therein cascading is defined as the uncontrolled successive loss of system elements as a result of a contingency at any location. Cascading results in an uncontrolled, widespread collapse of system generation and load, which collapse cannot be restrained from subsequently spreading beyond a predetermined area through appropriate engineering models, (load flow and transient stability studies).

Pursuant to the SERC Regional Criteria, electric systems are to be planned to prevent cascading should any of the following contingencies occur:

1. Loss of Generation - the sudden loss of the entire generating capacity at any one plant.

2. Loss of Load - the sudden loss of a large load or major or major load center.

3. Loss of Transmission
   - A. The outage of the most critical transmission line due to a three-phase fault concurrent with the outage of any other critical transmission line.
   - B. The sudden loss of all transmission lines on a common right-of-way.
   - C. The sudden loss of a substation (limited to a single voltage level within the substation including transformation from that voltage level), including any generation capacity connected thereto.
   - D. The delayed clearing of a three-phase fault at any system location due to the failure of a first-protective-zone circuit breaker to open to clear the fault.

FCG Planning Criteria

A. More Probable Contingencies - to be sustained without load loss other than that connected to the lost element.

1. Loss of generation - sudden loss of any one generator

2. Loss of transmission

   a. single line outage of any one transmission line.

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

B. Less Probable Contingencies - to be sustained with possible loss of some load.

1. Loss of generation - sudden loss of any on generator while any one generator is out of service.

2. Loss of transmission - loss of any two double-circuit tower transmission lines.

3. Loss of generation and transmission - loss of any one transmission line during the scheduled-outage of any one generator.

These regional criteria serve as minimums for all SERC systems and discussion with FP&L staff indicated they were at least consonant with the FCG Criteria which is followed by FP&L. Because of the limited interconnection capability between Florida Subregion electric systems and electric systems in the remainder of SERC which are interconnected with all other electric systems east of the line formed by the eastern borders of Montana, Wyoming, Colorado and New Mexico excluding Texas, presently major losses of Peninsula Florida generation (largest plant - Turkey Point (FPL), 2066 MW or largest unit - Crystal River No. 3 (FLPC), 824 MW) would result in the separate of the Florida systems from the remainder of the Eastern Interconnection. This assumes that the specified plant and units were operating at their rated capabilities and there were no scheduled transfers to Florida.

In 1983, the present scheduled operational date for the St. Lucie No 2, 802 MW nuclear unit, the largest Florida Sub-region plant and unit respectively will be the FLPC's 2,280 MW Crystal River plant and its Crystal River No. 3, 824 MW, nuclear unit. However, for transient stability study purposes, the largest Florida peninsula. plants in 1983 would be Turkey Point (2,066 MW), St. Lucie (1,579 MW), Martin (1,550 MW) Manatee (1,528 MW), and Crystal River 500 kV-Nos.3 & 4 (1,464 MW). By then, the Installed Interconnection Capability (IIC) and the Emergency Transfer Capability (ETC) between Florida and Georgia will increase as follows:

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	Florida to Southern		Southern to Florida	
	1979	1983	1979	1983
	MW	MW	MW	MW
IIC	200	900	300	1000
ETC	50	550	100	600

The interconnections between Peninsula Florida and the remainder of the Eastern Interconnection will be:

Yulee (FP&L) - Kingsland (GOPC)	230 kV
Suwanee (FPC) - Pinegrove (GOPC)	230 kV
Port St. Joe (FPC) - Callaway (GUPC)	230 kV
Suwanee Plant (FPC) - Twin Lakes (GUPC)	115 kV
Jasper (FPC) - Pinegrove (GOPC)	115 kV
Jasper (FPC) - Traver (GOPC)	115 kV

1/	Jennings (FPC) - Valdosta (GOPC)	69 kV
	Monicello (FPC) - Boston (GOPC)	69 kV
1/	City of Quincy (FPC) - Attapulgus (GOPC)	69 kV

1/ Normally Open Interconnections

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Restricting discussion to the Southern to Florida subregion capabilities, the IIC and ETC values respectively increase by 700 MW/333.33% and 500 MW/600%. These increased values result from transmission reinforcements between the Florida and Southern Subregions: (1) 1980 operation of the Yulee (FPL) - Kingsland (Georgia Power Corp. - GUPC) 10 mile 230 kV line, and (2) 1982 uprate to 230 kV and retermination to Calloway (GUPC) of the Port St. Joe (FLPC) - Wewa 37.75 mile 115 kV line and other Florida Subregion transmission reinforcements. Between December 31, 1978 and December 31, 1983, 748.56 miles of 230 kV operated transmission line will be added to the Florida Subregion either as new line additions or uprating of existing 115 kV lines. In addition, 125.4 miles of 500 kV transmission, all on the FP&L system, will be added. Of the planned Florida 230 kV line additions, 342.40 miles/45.7% additions are on the FP&L system. The FP&L 500 kV additions through 1983 plus 199 miles planned for addition during the 1984-1988 period will establish 500 kV as the FP&L primary transmission level in their North Central, Eastern, Southeast and Miami Divisions. In 1978, these Divisions constituted 76% (33,379.9 GWH) of system energy supplied and 78% (6540 MW) of the systems non coincident peak demand.

While appropriate transient stability and load flow studies for the 1983 and subsequent periods must be performed to satisfy from an engineering viewpoint compliance with planning criteria, it is reasonable to presume that with the planned Florida - Georgia transmission interface reinforcements along with those in Florida, for the loss of the Crystal River No. 3, 824 MW,

nuclear unit, the Florida systems should remain interconnected with the Eastern Interconnection. In 1983, for the loss of the Crystal River No. 3 unit, about 778.1 MW (96%) of the instantaneous electrical energy balance adjustment will come from outside the Florida system through the Florida - Georgia interface and in terms of the planned 1983 interface capability of 1000 MW (HC), the Florida systems should remain interconnected with the Eastern Interconnection as long as: (1) no major interface lines are out of service; (2) no major transmission paths from the Florida - Georgia interface south are unavailable; and (3) the scheduled Georgia to Florida transfer is less than about 400 MW. The loss of this unit might occur as a result of at least one of two events: (1) by tripping of the unit or (2) loss of both 500 kV lines from the plant (outage of one 500 kV line due to fault during the maintainance outage of the other 500 kV line), however, this would also cause the loss of the Crystal River No. 4, 640 MW, coal fired unit, planned for installation in 1982, as well resulting in a total loss of 1,464 MW. This would exceed in generation loss magnitude as would the loss of St. Lucie Nos. 1 and 2, 1,579 MW, the largest situation provided in the August 31, 1979 FP&L analysis. Therefrom, I would presume that from a transient stability viewpoint, that initiation of Peninsula Florida separation from the Eastern Interconnection would begin in less than 3.87 seconds and the automatic underfrequency relaying will operate to shed firm load.

The preceeding discussion does not indicate the design adequacy, with respect to SERC Regional Criteria for loss of generation, load or transmission. This can only be determined through transient stability studies. My discussion with both FP&L and FCG staff concluded that FCG studies for 1980-85 period had not been done but were scheduled for later this year. However, the transient stability evaluation by FP&L confirms in part that no separation would occur or firm load shedding with an import of 300 MW and the loss of 800 MW.

Spinning reserve criteria for the Peninsula Florida systems is described by the FCG Operating Committee in the FCG Operating Handbook which is used in conjunction with the North American Power Systems Interconnection Committee (NAPSIC) Operating Manual. While I have not seen the FCG Operating Handbook, the SERC Coordinated Bulk Power Supply Program of April 11, 1979 under item 7-A," Coordination of Operations", for the Florida Subregion summarizes several of the coordinated practices including the Operating Reserve Policy. Daily Operating Reserve is that amount of generating capability and/or equivalent load relief over and above fore-casted daily peak load which is available to respond to load connected and responsive immediately to load changes and capable of becoming fully loaded in response to a frequency decline of 0.5 Hz (to 59.5 Hz from nominal or scheduled frequency of 60 Hz); and, (2) Supplemental Reserve - any generating capability and/or load relief measure which can be made fully responsive to its planned for reserve capability within 30 minutes.

The Daily Operating Reserve maintained by the combined systems (Florida Subregion systems) is equal to, or greater than, the sum of the Peak Capabiltiy Ratings of the two largest units in service. Spinning Reserve is maintained at, or greater than, the Peak Capability Rating of the largest generating unit in service. The balance of the Daily Operating Reserve is Supplemental Reserve and upon the loss of a unit, Supplemental Reserve is converted to Spinning Reserve, if required, to restore the recommended level of Spinning Reserve.

Daily Operating Reserve and Spinning Reserve requirements are allocated among participants, weighted 50% in proportion to each partcipant's maximum demand for the preceeding year and 50% for the Peak Capability of his largest unit. The effect on a participant's spinning reserve allocation must be fully considered before agreeing to sell power to another participant; the protection of a new unit undergoing shakedown is the owner's responsibiltiy; based upon 5% governors, no more than 16.6% of the Continuous Capability of a unit can be assigned to any one unit; and, each participant's Daily Operating Reserve allocation should be available to other participants without restriction by transformer, line or other limitations

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In the event that Spinning Reserve and Eastern Interconnection transmission support is insufficient, the Peninsula Florida system has a Load Preservation Program encorporating automatic underfrequency relaying (UFR). Through UFR operation a minimum of 2,859 MW (16.6%), 2,829 MW (16.4%) and 4,438 MW (25.7%) of load will automatically be shed respectively by a frequency decline to 59.0 Hz, 58.7 Hz and 58.5 Hz. This represents 58.7% of the 1979 summer peak load and would leave at least 41.3% (7,124.4 MW) of load and generation operable for restoration of lost generation and/or load. In addition, each Florida Subregion system has generating units capable of operating for extended periods isolated from the system and carrying their own auxiliary power loads, which should reduce system restoration time.

Largest Peninsula Florida Generating Unit and Plant, 1978 - 1985 1/

	1978	1979 - 1981
Largest Plant	FP&L 2/ Turkey Point 2066 MW	FP&L Turkey Point 3/ 2066 MW
Largest Unit	FLPC 2/ Crystal River No. 3 797 MW	FLPC Crystal River No. 3 824 MW

	1982 - 1983	1984 - 1985
Largest Plant	FLPC Crystal River 4/ 2280 MW	FLPC Crystal River 5/ 2920 MW
Largest Unit	FLPC Crystal River No. 3 824 MW	FLPC Crystal River No. 3 824MW

1/ April 1, 1979, Southeastern Electric Reliability Council (SERC), Coordinated Bulk Power Supply Program for the 1979 - 1998 period.

2/ FP&L - Florida Power & Light Company;
FLPC - Florida Power Corporation

3/ Unit Nos. 1 & 2 (367 MW @) connected to N.E. and N.W. 230 kV busses; Unit Nos. 3 & 4 (666 MW @) connected to S. E. and S. W. 230 kV busses; bus tie breakers between both North and South bus sections.

4/ Unit Nos. 1 & 2 (383 MW, 433 MW) on 230 kV; Unit Nos. 3 & 4 (824 MW, 640 MW) on 500 kV; No kV to 230 kV connection at plant substation.

5/ Unit Nos. 1, 2 & 5 (383 MW, 640 MW) on 230 kV; Unit Nos. 3 & 4 on 500 kV; No 500 kV to 230 kV connection at plant substation.

Florida Power & Light Company
Interconnection with Other
Peninsula Florida Systems

The Florida Power & Light Company (FP&L) has a total installed generating capacity of 10,491 MW and additions through 1983 (Martin Nos. 1 & 2, 775 MW @, 1980 and 1981; Dade Solid Waste Facility, 40 MW, 1980; and, St. Lucie No. 2, 802 MW, 1983) of 2,392 MW will raise the total system capacity to 13,333 MW. The Florida Subregion generation and load (summer peak) are projected to grow by 1983 respectively from 21,800 MW and 17,261 MW to 26,782 MW and 21,528 MW. Between FP&L and other Peninsula Florida systems there are sixteen interconnections (Table I) operating at 69 kV to 230 kV. Presently, three of these inter - connections are for limited area backup protection and are normally open. Therefore, there are 7-230 kV, 2-138 kV, 1-115 kV, and 3-69 kV normally closed interconnections with Peninsula Florida generating utilities. By the spring of 1980, the Yulee to Kingsland (Georgia Power Company) 230 kV line will be operational, providing one more source of emergency supply to FP&L directly and other Peninsula Florida system.

As part of the ongoing assessment of the adequacy of the Peninsula Florida system, the January 1979 Florida Electric Power Coordinating Group (FCG)/System Planning Committee/Transmission Task Force's Transmission Load flow Analysis Report, 1982 & 1987 Summer Periods evaluated among other through the single-line-outage adequacy of the 1982 Peninsula Florida transmission system

Interconnections Between Florida
Power & Light Company and Ohter
Peninsula Florida Systems - 1979 Generation

Florida Power Corporation - 3,647 MW

1. Sanford Plant - North Longwood	230 kV
2. Brevard - Holopaw - Canoe Creek - West Lake Wales	230 kV
(from Brevard, there are two 230 kV lines via Malabar to Midway substation)	
3. Sanford Plant - Turner	230 kV
4. Normally open	
a. Columbia - Live Oak Tap - East Oak	69 kV
b. Taps off of Palatka Plant Deland 115 kV line	
(1) Barberville	115/69 kV
(2) Deland East	115 kV

Jacksonville Electric Authority - 1884 MW

1. Baldwin - Normandy	115 kV
2. Baldwin 115/230 kV - Duval - Normandy	230 kV
3. Putnam Plant - Orangedale Greenland (JEA) - Robinwood Acreas	230 kV

Tampa Electric Company - 2,505 MW

1. Ringling - Manatee Plant - Ruskin	230/69 kV
2. Ringling - Gillette - Ruskin	230 kV

Orlando Utilities Commission - 742 MW

1. Cape Canaveral Plant - Indian River	230 kV

Lake Worth Utilities Authority - 141 MW

1. Hypoluxo - Plant Sub (from Hypoluxo, there is a 138 kV line to Ranch 138/230 kV)	138 kV

City of Vero Beach - 133 MW

1. West (138 kV) - South Sub. — 69 kV

Fort Pierce Utilities Authority - 116 MW

1. Hartman (138 kV) - Sub. No. 1 — 138/69 kV
   (from Hartman, there is a 138 kV line to Midway 138/230 kV and a 138 kV line via West to Molabar 138/230 kV

City of Homestead - 52 MW

1. Lucy - McGinn Sub. — 138 kV

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and the Area-Transfer-Capability (import capability) of the major systems. That study concluded the following:

Single-Line-Outages

The Peninsula Florida 1982 system performed adequately and within design limits for all but three contingencies which produced up to 5% overloads on three facilities:

a) L/O (FP&L) Sanford-North Longwood 230 kV
(FLPC) Turner - Lake Emma 115 kV loaded to 103% of rating and low voltages experienced in FLPC's eastern division.

b) L/O (FP&L) Ringling - Laurelwood 230 kV
(FP&L) Ringling - Charlotter 230 kV loaded to 104% of rating.

c) L/O Woodmore (FLPC) - Pine Hills (ORLA) 230 kV)
(ORLA) Southwood - Turkey Lake 115 kV line loads to 105% of its emeergency rating.

It should be noted that none of these overloads exceeds 5% and therefore are not considered major overloads. Furthermore, they would only occur if peak load conditions existed coincident with the specific line outage and even so, adjustments could be made in generation schedules to alleviate the overload condition.

FP&L's Import Case

The Big Bend to Gillette 230 kV line loaded to 442 MVA, 10% of its rating when 1,100 MW was imported by FP&L. The import to FP&L was simulated such that Florida Power Corporation, Tampa Electric Company, and Jacksonville Electric Authority each exported one-third (367 MW) of the power.

The Big Bend - Gillette 230 kV line includes an intertie with the Tampa Electric Company (TEC) at the Ruskin substation, one of two TEC interconnection points with FP&L, so that the about 40 MVA overload probably could be reduced by reducing the TEC's share of the import by about 40-50 MW.

The FP&L 1,100 MW import level (11.1% of FP&L's 1982 peak load represented) would cover most combinations of two unit outages on the FP&L system except the unavailability of St. Lucie Nos. 1 & 2 (1,589 MW), Manatee Nos. 1 & 2 (1,528 MW), Turkey Point Nos. 3 & 4 (1,332 MW) Maratin Nos. 1 & 2 (1,550 MW) and some combinations of these. However, it is unlikely that a 1,100 MW import requirement would occur because of the maintenance outage of one unit plus the forced outage of another unit during peak load periods.