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Review of Nuclear Power Plant Offsite Power Source Reliability and Related Recommended Changes to the NRC Rules and Regulations

R. E. Battle
F. H. Clark
T. W. Reddoch

Prepared for the
U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation
Under Interagency Agreement DOE 40-544-75

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OAK RIDGE NATIONAL LABORATORY
Oak Ridge, Tennessee 37830
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HIGHLIGHTS

Offsite power failures at the Millstone 2, Turkey Point 3 and 4, and Indian Point 3 and 4 nuclear power plants caused the U.S. Nuclear Regulatory Commission (NRC) to question the reliability of the offsite power. The NRC requested Oak Ridge National Laboratory (ORNL) to examine several aspects of the offsite power system and to make recommendations to improve the NRC licensing procedure. The specific tasks that were undertaken for this project are the following: (1) evaluate the Florida Power and Light (FPL) and the Consolidated Edison (ConEd) system-wide blackouts of 1977, (2) survey the complete losses of offsite power at nuclear power plants, (3) evaluate a method to improve the security of the offsite power, (4) determine the maximum decay rate of the grid frequency, (5) evaluate a long-term dynamics computer code, and (6) generate and evaluate a method to identify critical system parameters.

The recommendations in this report that suggest modifying the NRC rules and regulations are contained in Sects. 2 and 3. Section 2 contains 13 recommendations, of which some suggest changes to GDC-17 in the Code of Federal Regulations, the Standard Review Plan, and Regulatory Guide 1.93; others do not specify an NRC document. The subjects covered include the single-failure criterion for the grid, grid emergency plans, maintenance procedures, operational procedures, design procedures, and power grid restoration plans. Appendix A contains a survey of the complete losses of offsite power at nuclear power plants, and Appendices B and C contain reviews and evaluations of the FPL and ConEd blackouts of 1977. Section 3 addresses the grid security concept, and it contains recommendations that NRC require utilities to implement grid security procedures. Section 4 is a study of the maximum frequency decay rate. It shows that an upper bound of the rate is greater than the acceptable value calculated by the nuclear plant vendors, but the study also supports the NRC decision to relegate the frequency decay problem to a low priority. Section 5 contains an evaluation of an Electric Power Research Institute (EPRI) computer program that simulates system response over a period of minutes (long-term dynamics), and Sect. 6 contains a description of a method to evaluate power grid stability using sensitivity analysis. These computational techniques may be useful for utility studies, but they are not yet ready to be used by NRC for licensing.

The recommendations contained in this report were derived primarily from studying the reports of the FPL and ConEd blackouts of 1977, surveying the losses of offsite power, and discussing operating and design features with utility engineers. The information we have gathered from these sources has led us to believe that the recommendations contained in Sects. 2 and 3, if implemented, will contribute to a more reliable offsite power source for nuclear power plants.

CONTENTS

1. INTRODUCTION

There are two electric power sources, the offsite power system and the onsite power system, that can deliver power to the safety equipment in a nuclear power plant. The offsite power system, which consists of the power grid, the main generator, and the equipment that connects them to the nuclear plant distribution busses, is defined in the industry standards[1] and NRC regulatory guides[2] as the preferred power system. The onsite power system, which consists of diesel generators, batteries, and associated equipment, is a backup power source to the preferred, offsite power system.

In a published document,[3] the NRC stated its concern about the reliability of the offsite power system as the preferred emergency source and about the possible damage to a pressurized water reactor (PWR) that could result from a rapid decay of power grid frequency. ORNL contracted with NRC to provide technical assistance to establish criteria that can be used to evaluate the offsite power system for the licensing of a nuclear power plant. The results of many of the studies for this contract are recommendations to assess and control the power grid during operation. This is because most of the NRC regulations pertaining to the offsite power system are related to the design of the power grid, and we believe that additional emphasis on monitoring the power grid operation will improve the reliability of the nuclear plant offsite power supply.

REFERENCES

1. IEEE Standard 308-1978, "IEEE Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations," IEEE, New York (1978).

2. Regulatory Guide 1.6, "Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems," USNRC (March 10, 1971).

3. NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976, Memorandum from Director, NRR, to NRR Staff," USNRC (November 1976).

2. RECOMMENDATIONS FOR NUCLEAR PLANT OFFSITE POWER SYSTEMS

2.1 Introduction

A significant part of these activities for the NRC has been a survey of all nuclear power plant losses of offsite power that were reported to the NRC as Licensee Event Reports and a study of system-wide power outages (also called system "blackouts"). Because system blackouts can last for several hours, may affect the offsite power at several nuclear plants, and will disrupt community services, the study of blackouts was focused intensively on two system blackouts: (1) the ConEd grid on July 13, 1977, which caused a loss of offsite power to the Indian Point nuclear plant; and (2) the FPL grid on May 16, 1977, which caused a loss of offsite power to the St. Lucie and Turkey Point nuclear plants.

These topics have been reported as letter reports to the NRC (included as Appendices A, B, and C to this document).

Our recommendations derive from these studies. Two include fundamental changes that warrant modification of GDC-17. Others would be better dealt with through technical specifications, regulatory guides, and the Standard Review Plan.

2.2 Recommendations Related to GDC-17

The requirements of GDC-17 on the time and manner of availability of the second offsite circuit should be made more specific. The present language has led to an interpretation or implementation in the Standard Review Plan, Sect. 8.2, para. II .2.d, where the procedures described are inadequate and below current standards of practice. Telephone conversations between the control room and switchyard during the July 13, 1977, ConEd power outage (which were taped and are in the record) demonstrate vividly how inadequate such procedures can be in an emergency.[1] Therefore, our first recommendation is as follows:

Recommendation 1. *In GDC-17, immediately after the sentence which begins "One of these circuits shall be designed...", the following, or similar, language should be incorporated: The second, or reserve, offsite power circuit may be of delayed access if the circuit can be actuated by switching in the reactor control room.*

GDC-17 does not apply the single-failure criterion to the offsite power circuits for, we believe, three reasons:

1. There is a great reluctance to apply the single-failure rule to anything that has not been designated as safety equipment.

2. The unit generator(s) and the onsite ac electric power system are additional backups, and the single-failure rule is applied to the totality of these ac electric power sources.

3. Application of the rule necessarily would be directed at components in the electric transmission systems and might suggest a jurisdictional conflict with the Federal Energy Regulatory Commission (FERC).

Militating for inclusion of the single-failure rule in GDC-17 as it applies to offsite power sources are these considerations: First, whether or not the offsite power source is called "safety equipment," it is recognized as an important part of the system's safety defense. Second, the Standard Review Plan, Sect. 8.2, para. III.2.f, explicitly details procedures that are equivalent to a single-failure criterion for the offsite power sources. Third, the industry standards, as set forth in the North American Power Systems Interconnection Committee (NAPSIC) publication, cited in the next paragraph, apply the single-failure rule to the transmission grid.

In the NAPSIC publication, Sect. II, entitled, "Minimum Criteria for Operating Reliability, April 1970," states the following:

1. The bulk power systems will be operated at all times so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency. Multiple outages of a credible nature will be examined and the system operated when practical to protect against instability, uncontrolled separation or cascading outages.

2. The bulk power systems will be operated to achieve the highest degree of reliability practical, and appropriate remedial action will be taken promptly to relieve any abnormal conditions which jeopardize reliable operation. Power transfers for economy purposes, and other transfers insofar as feasible, will be adjusted as required to achieve or restore reliable bulk power system operation.

3. Operating Reserve

   The reliable operation of interconnected bulk power systems requires that adequate capacity be available at all times to maintain the frequency at 60.0 Hz, supply requirements for load-frequency regulation, replace capacity lost due to forced outages of generating or transmission equipment, and provide for errors in load forecasts.

In view of these criteria, we believe that two (or more) circuits providing offsite power in a transmission grid are reasonable proof against a single failure. Moreover, this is sufficiently fundamental that it appears reasonable to put a basis for it in GDC-17. This and the next item are covered in the same suggested language (which is offered below).

A number of suggestions which we are making in this note deal with matters related to the operation of the transmission grid and the postures assumed by the utility when certain conditions prevail on the grid. Such matters are ordinarily the province of FERC. On the other hand, it is clearly within the province of NRC to forbid the connection of a nuclear power reactor safety system to a substandard electric power source. We suggest that a basis be laid for dealing with this problem and also with the single-failure rule as follows:

Recommendation 2. *In order to establish the nature of NRC's interest in electric power transmission systems we suggest that in an appropriate place in GDC-17 a statement be made that the offsite power supply must be of adequate amount, quality, and reliability.*

2.3 Recommendations Not Referring to Specific Documents

Recommendations 3 through 10 do not suggest wording changes to any specific NRC documents, but it is our judgment that inclusion of these recommendations in the NRC rules and regulations will help assure the reliability of the offsite power source.

Our studies of blackouts have disclosed that several have occurred as a result of failure of a single component in the generator-transmission system. The following events occurred in the FPL system.

a. On April 3, 1973, a reactor trip occurred, causing an area blackout with loss of offsite power to the Turkey Point reactors (Appendix A).

b. On April 4, 1973, substantially the same thing occurred (Appendix A).

c. On June 23, 1973, a crane contacted a transmission line, causing an area blackout (but not causing loss of offsite power to nuclear plants).[2]

d. On March 1, 1974, Turkey Point 4 (and 1 min later Turkey Point 3) tripped, causing an area blackout (but not causing loss of offsite power to nuclear plants).[3]

e. On April 25, 1974, an incorrect setting of the startup transformer lockout relay caused Turkey Point 3 and 4 to trip, leading to an area blackout and loss of offsite power to the nuclear plants (Appendix A).

f. On June 28, 1974, a slowly clearing ground fault led to tripping of Turkey Point 3 and 4, causing an area blackout (but no loss of offsite power to nuclear plants).[4]

g. On May 16, 1977, Turkey Point 3 tripped, and 16 min later the Ft. Myers-Ranch line relayed open, causing an area blackout with loss of power to nuclear plants. The company claims that the relaying of the line was due to causes independent of the disturbed condition of the system following the reactor trip. No such independent cause has been brought forth, and we find the claim unconvincing (Appendix A).

Of the preceding events, *a*, *b*, and *c* clearly were situations where the design and manner of operation of the transmission-generation system were such that failure of a single component immediately brought on a blackout. Events *d*, *e*, *f*, and probably *g* were situations where a single failure induced a sufficient number of failures in a short period of time to bring on a blackout.

Observation 1. *It appears that in more than one instance sufficient system security was not provided (for example, adequate spinning reserves, properly distributed geographically) by Florida Power and Light to maintain the system intact when a single large generating unit or large capacity transmission line has been lost in the Miami area. It further appears that there have been design or component deficiencies such that a single failure of a component has led to the sequential loss of more than one large element of the transmission-generation system, bringing on a blackout. Both of these kinds of deficiency appear to be failures to comply with Standard Review Plan 8.2, III.2.f, and NAPSIC, Minimum Criteria for Operating Reliability, II.1 (previously quoted).*

Recommendation 3. *Substantial portions of the system spinning reserve will be maintained as close to nuclear plants (in terms of electrical impedances) as feasible. In times of system alert or emergency, all system reserves in the neighborhood of a nuclear plant should be brought to spinning condition. The licensee should be responsible for providing adequate spinning reserves.*

Observation 2. *Paragraph 8.2, III.1.f, of the Standard Review Plan and the NAPSIC criterion cited, in fact, constitute a requirement for a generation-transmission system which can sustain a single failure without collapse, whether or not such a requirement is formally spelled out elsewhere.*

We have been unable to find a well-defined criterion of transmission system failure or of transmission system instability. The words "stability" and "instability" appear to be reserved jealously for describing conditions of synchronization and out-of-synchronization of generators. Operationally, a generator cannot long remain much out of synchronization without going off line. Calculational assessments are rarely carried to the point where a computed "trip" occurs. Moreover, the determination of instability in a calculation does not seem to be based on fixed criteria but rather on subjective feelings about the appearance of plots.

Recommendation 4. *Applicants will be required to state [in the Safety Analysis Report (SAR)] in precise terms the criterion of stability used in analysis and calculations.*

The ConEd system on the night of July 13, 1977, for approximately 35 min following the second lightning stroke (i.e., 10:08 to 10:24 AM) were both in a highly unsettled state (see Appendices B and C). They were in the "emergency" state, in the lexicon of Fink and Carlsen,[5] unable to meet the demands for real and reactive power. In that condition, they were subject to further losses of capability and system breakup with modest additonal disturbance. Such a state cannot be considered reliable for the supply of offsite electric power to a nuclear power plant.

Recommendation 5. *A transmission system in the "emergency" state will be considered to be in a failed condition in any assessment of its adequacy and reliability as a supplier of offsite electric pc Hence, any requirements imposed to assure system security will be interpreted as requirements that the system be maintained in a more secure state than the "emergency" state. The licensee (applicant) will provide an adequate description or definition of the emergency state for his own transmission system. The applicant will further have plans of corrective action for immediate implementation by the system operator on occurrence of an "emergency" state.*

Recommendation 6. *All switching operations on the offsite power lines and on the station transformer circuits performed during maintenance will follow a written checklist approved and signed by responsible engineering supervisory personnel.*

Following the lightning-induced blackout of New York City on July 13, 1977, ConEd introduced a number of new procedures to diminish the probability of a recurrence. Collectively, they are called the "storm watch." More severe storm stresses than those of July 13, 1977, have been experienced since then, and with the storm watch procedures there has been no disastrous interruption of service.

The storm watch is invoked when the weather bureau reports the approach of a storm. Briefly, it consists of (a) manning a number of facilities which might otherwise be left unmanned, (b) suspending certain kinds of maintenance work and returning the equipment under maintenance to service, (c) reassessing, by on-line calculation, the current distribution of load and generation, with the assumption of loss of a double and a single transmission circuit.

Recommendation 7. *An applicant for licensing should be required to incorporate in the SAR satisfactory plans beyond ordinary operating spinning reserves for maintaining the integrity of the electric power system during stressful circumstances.*

Restoration of offsite electric power to the Indian Point facility did not take place until about 7 h after the initiation of the July 13, 1977, blackout. Damage at a local substation was a major cause of the delay in restoration of power to Indian Point, while restoration in the metropolitan part of the system was complicated by the nature of the underground distribution facilities. In any event, prompt restoration of power to a nuclear facility is an important safety consideration, and prompt restoration of power may require more than routine efforts. Plans drawn up in advance to be used as, at least, a routine guide to restoration of power following an area-wide failure could be very helpful. Since a single set of plans might not adapt to all reasonably anticipated restoration contingencies, more than one set might be necessary.

Recommendation 8. *An applicant for licensing should be required to have plans for prompt restoration of quality power to the nuclear plant following a blackout.*

To assess the expected behavior and response of a power system under various conditions, one must obviously work not with the system itself but with a model of it. Hence, a good bit of the regulatory and the licensing processes depends on behavior of a model. Therefore the model must be reasonably faithful to those aspects of the system which contribute importantly to the questions under consideration. This does not imply that the model must be highly detailed. Our studies indicate that relatively few busses were sufficient to show whether a disturbance was apt to lead to instability of the transmission system (see Sect. 6.3). Granted that much more detailed information would often be required by the system operator and available only through a detailed model, such detail is not essential to NRC in judging the essential interactions of the transmission system with the nuclear power plant. Of considerably more importance than detail is the ability to evaluate the impact of different operating conditions. The use of a simplified model makes feasible the computation of many such cases.

Recommendation 9. *The applicant will, on request by NRC, furnish a description of the computational model used to represent the system by calculations made in connection with NRC requirements and, on request, will explain the representation in detail.*

Recommendation 10. *The applicant will provide (in the SAR) analyses of electric transmission system stability for a sufficient number and diversity of cases that all anticipated operating configurations and conditions are bounded. If during subsequent operations a configuration or condition is planned which is not clearly bounded by cases previously analyzed and found stable, additional analyses will be performed to establish the stability of the configuration prior to its implemention. If, during operations, events occur which draw the system into an unanticipated configuration or condition which has not been bounded in analyzed, stable cases; then, as soon as it is determined that this may be the case, the system operator will be expected to enter a higher state of alert, taking precautions of the sort discussed in Recommendations 5 and 7.*

2.4 Recommendations Related to Regulatory Guide 1.93

We have a number of suggestions to make with regard to Regulatory Guide 1.93.

"GDC-17 specifies design requiremen. , not operating requirements; it therefore does not stipulate operational restrictions on the loss of power sources."

The preceding quotation from RG 1.93 is of dubious validity in that it makes any design requirement irrelevant to operating configurations.

Recommendation 11. *The above quote and associated language should be removed.*

The following quotes are from RG 1.93.

"Under certain conditions, iit may be safer to continue operation at full or reduced power for a limited time than to effect an immediate shutdown or the loss of some of the required electric power sources. Such decisions should be based on an evaluation that balances the risks associated with immediate shutdown against those associated with continued operation. If, on balance, immediate shutdown is the safer course, the unit should be brought promptly to an orderly shutdown, and to a cold shutdown state as soon as possible.

"If the LCO has not been achieved, the unit should be promptly brought to an orderly shutdown after the allowed time for continued power operation has elapsed and to a cold shutdown state as soon as possible thereafter."

It appears to follow from these quotes that after the lapse of the allowed time if an LCO (Limiting Condition for Operation) has not been achieved the unit is to be shut down *whether or not that appears to be the safest course*. We do not know if this is an intended implication.

Moreover, it does not appear that on loss of ac power from partial loss to below an LCO, operators customarily make any meaningful evaluations to determine whether the safer course is shutdown. There are certainly no guidelines for this situation. Nor have we found any instance where the NRC made an inquiry to determine if such an evaluation had been made. It appears to us that the allowed time for below-LCO operations has been treated as a grace period, during which the NRC would like to see corrective action taken but does not require it. Consider, for example, the following quotes (from RG 1.93):

"The premise here is that the time allowed for continued operation could have been used to enhance the safety of the imminent shutdown. For example, the dispatcher could take such system-wide actions as increasing generation at other plants or dropping selected loads to ensure that the shutdown does not cause grid instability.

"If, on balance, continued power operation is the safer course, the period of continued operation should be used to restore the lost source and to prepare for an orderly shutdown, provided, of course, that these activities do not risk further degradation of the electric power system or in any way jeopardize plant safety."

Recommendation 12. *Certain grace times are provided in certain below-LCO conditions (with respect to availability of ac power). The operator will be expected to employ every available means to restore the LCO during the grace period. If the LCO has not been restored by the end of the grace period and if every available means has not been employed, the operator will shut down immediately and go as rapidly as possible to cold shutdown; and further, he will be found to have been in violation of specifications during the grace period.*

The following quote is from RG 1.93.

"However, the loss of an offsite source due to a cause associated with extensive consequences such as a severe ice storm or a forest fire would have implications more severe than the loss of an offsite ac supply. The risks associated with such an offsite loss would be compounded by three effects: (a) the maintainability advantage of the offsite sources would be lost, (b) the remaining offsite circuit could be susceptible to the same cause, and (c) the stability of the offsite power system might be affected. Thus, the loss of an offsite source by such a cause should be treated as equivalent to the loss of both required offsite sources."

We call attention to the last sentence of the quote. We know of no case where the loss of a single power source was treated as though both required sources had been lost. We wonder if it is really intended and, if so, within what limits.

Recommendation 13. *Clarify or omit this statement: "Thus the loss of an offsite source by such a cause should be treated as equivalent to the loss of both required offsite sources."*

REFERENCES

1. "Second Phase Report System Blackout and System Restoration, July 13-14, 1977 (Analysis of System Separation)," Consolidated Edison Board of Review, August 24, 1977.

2. "Analyses of Florida Bulk Power Supply Disturbance of June 23, 1973," Southeastern Electric Reliability Task Force, September 1973.

3. "Summary of Meeting with Florida Power and Light Company," letter from E. C. Marinos to T. A. Ippolito, Chief, Electrical, Instrumentation and Control Systems Branch, L, NRC Docket No. 50-250 and 50-251, Summary of NRC staff meeting with FPL, letter dated September 26, 1974.

4. "Report on System Disturbance June 28, 1974," report to the Federal Power Commission by Florida Power and Light Company, July 19, 1974.

5. L. H. Fink and K. Carlsen, "Operating Under Stress and Strain," *Spectrum* 15, 3 (1978).

6. D. N. Ewart, "Whys and Wherefores of Power System Blackouts," *Spectrum* 15, 4 (1978).

3. ON THE ASSESSMENT OF GRID QUALITY: THE SECURITY CONCEPT

3.1 INTRODUCTION

Safe operation of a nuclear power plant requires a highly reliable electric supply for its Class 1E safety electric system. Because of the failure of the off-site power systems at the Indian Point, St. Lucie, and Millstone nuclear plants, there is concern about the reliability of off-site power systems.

The NRC requires utilities to verify the reliability of the power grid by demonstrating that the grid *design* meets NRC requirements; most pertinent NRC standards and regulations pertain to design only. Regulatory Guide 1.93[1] specifies limiting conditions for operation of a nuclear plant when less than two power lines are available, as required by GDC-17.[2] There are no other limiting conditions for operation of the nuclear plant based on the condition of the grid, but if grid conditions should deteriorate in either frequency or voltage, local protection would trip the plant. The reliability of the power delivered to the nuclear plant may be improved by expanding the NRC regulations to include additional grid operating requirements.

A method for the NRC to regulate power grid operation is that it would require each utility operating a nuclear plant to establish security procedures. A description of security and its possible use for power system operation is the thrust of this section. There is also a brief review of power system planning considerations.

3.2 Power System Planning

The power system planner is obligated to devise a sound technical plan that is consistent with the particular utility's philosophy of design. Of paramount importance to the utility is that the devised system shall balance the cost/reliability trade-off, that is, a design of minimum cost but of sufficient quality to absorb a credible list of component failures. The cost aspects of planning are omitted from this report.

3.3 Design Methods

The system designer postulates operating scenarios and assesses the system reliability by both probabilistic and deterministic analytical methods. In deterministic analysis, several failure modes are applied to the design model, and the integrity of the system is predicted by computer studies. These studies include load flow to quantify the power flow and voltage profiles of the system, fault studies to coordinate relays and determine breaker ratings, and transient stability studies to determine possible loss of synchronism. In probabilistic analysis, the expected frequency and severity of failures are estimated, and their consequences are assessed in terms of the expected number and total duration of supply failures. These assessment techniques are applied to ensure that future expansion of generation and transmission facilities will serve the load at a prescribed level of reliability.

There are at least three measures for assessing the probability of maintaining supply, as follows:

1. The probable number of times a curtailment of supply will occur in a given period of time--the loss of load probability.
2. The probable ratio of the demand energy not supplied to the total demand energy--the loss of energy probability.
3. The probable interval between failures to meet the demand and the duration of each failure--frequency and duration.

In the planning phase of a nuclear plant, the NRC requires an evaluation of the system to show that the ac power supply would be adequate even if the largest single supply should fail.[3] Such adequacy can be proved using load flow and transient stability analyses. The results of these analyses could indicate that the power grid would be adequate for the postulated operating conditions and for a particular, simulated failure. Although these studies may be severe tests of the grid, actual operating configurations may occur that are not bound by these studies.

3.4 Power System Operation

Once facilities are constructed and accepted, they become an active part of power system operation, and the operator is responsible for deploying these facilities in real-time. In operation, the available facilities may be configured in a manner other than was planned. Therefore, it is desirable for the operator to be prepared to respond to unexpected conditions.

Historically, the actions of the operator have been left to his experience and judgment. Precise actions must be taken quickly during emergencies to prevent the loss of power to customers or plants. Following the power failure in the Northeast in 1965, a search for a technique with a more systematic and consistent set of automated features was undertaken to improve the efficiency and accuracy of an operator's decisions. The modern, centralized, digitally directed control center began to emerge in the late 1960's, with a central theme of *operational* reliability--system security.

3.5 Security

The notion of security applies to the operation of a power system; thus, it denotes the real-time integrity of a system that is subject to contingent failures. Fink and Carlsen define security as "... an instantaneous, time-varying condition that is a function of the robustness of the system relative to imminent disturbances."[4] Of particular importance is the time-varying quality of the system; that is, at times the system is vulnerable to disturbances because the effective reserve margins have been reduced to below desirable levels. Security characterizes the real-time capability of the power system to maintain the integrity of the physical plant and production equipment, but the security procedures should be compatible with the economical dispatch of power. To maintain security, preventive action is taken to reduce the vulnerability of the system to conditions such as cascading outages; system break-up; widespread power outages; violation of acceptable limits on current, voltage, or system frequency; and loss of synchronism-stability.

The concepts of security and reliability are obviously related. That is, a system with high reliability is generally well planned and thoroughly tested against most credible disturbances, it exhibits few periods of insecurity. If a major disturbance occurs during a period of insecurity, even a well-designed system may experience a major disruption. The simultaneous occurrence of an inadequate reserve margin and a system disturbance could result in a failed system. The assessment of system security provides an up-to-date measure of the integrity of the system.

There are three important aspects to the security concept: security monitoring (SM), security assessment (SA), and security enhancement (SE). The first of these, SM, is the on-line identification and display of the actual operating conditions of the power system. In fact, this is the feature that differentiates the traditional dispatch center from the modern system control center.[5] SA is the determination of the relative security of the system; SE is the collection of control actions designed to remove security violations.

3.5.1 Security monitoring

SM, the root of the modern, digitally directed dispatch center, performs two primary functions:

1. It displays real-time information for the determination of security; hence, it requires extensive, system-wide instrumentation and telemetry hardware. The parameters measured include transmission line, real and reactive power flows; bus voltages and power; circuit breaker status; protective relay operations; transformer tap settings; and miscellaneous substation status. In real time, telemetry data are checked continuously against equipment limits, both for determining security violations and for data validation. Often, poor data will indicate a security violation; thus, state estimation is used to enhance data quality to permit valid security decisions.

2. It determines the network configuration, which is particularly important where there is direct responsibility for transmission switching and safety. Precise information on the status of all elements, for example, whether a line is energized or deenergized, prevents an undesired switching operation from occurring. Thus, SM is the first step toward implementation of the security concept.

3.5.2 Security assessment

SA is used to evaluate the present and possible future states of the power grid. The concept of state used to describe the condition of the power system was proposed by Dy Liacco,[6] later modified by General Electric engineers,[7] and subsequently expanded by Fink.[4] Specifically, it is a terminology that has evolved through attempts to classify operating conditions by describing the ability of the power system to supply electric power on a continuous basis. SA is also known as "contingency analysis," since it is typically performed using a load flow program to study the results of a number of preselected single contingencies. Classification methods have been the subject of many investigations, with each seeking more effective and efficient ways of detecting system abnormalities. Although there are few quantified security procedures, qualitative measures have evolved into guidelines for establishing system states for security procedures.

System operating conditions are usually separated into three states, with substates as indicated below (see also Fig. 1):

State	Substate
Normal	Secure
	Alert
Emergency	Overload
	In extremis
Restorative	

The states are governed by two constraints: equality and inequality. Equality constraints refer to the balance between total system generation and load, including the effects of dynamics. Inequality constraints refer to allowable maximum and minimum limits, including system variables such as voltage, current, and frequency.

In the *secure, normal* state, the equality and inequality constraints are not violated. Furthermore, in this state no single contingency, alone, will cause violation of these two constraints. Sufficient reserve margin in generation and transmission of power and a balanced load-generation distribution are measures that help establish the *secure, normal* state.

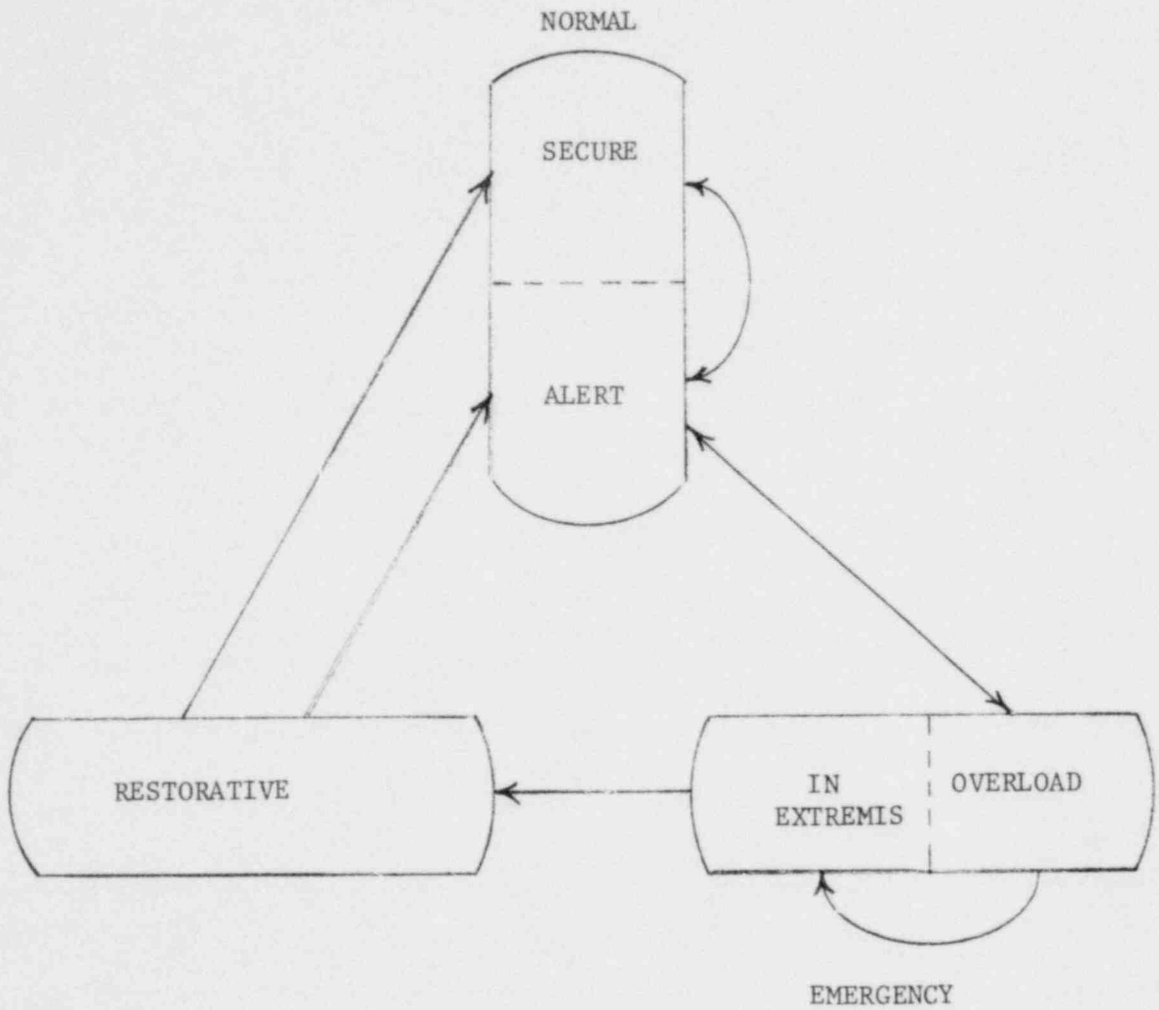

Fig. 1. Operating state diagram.

A system is in an *alert, normal* state if a single failure would cause the system to change to the *emergency* state. In the *alert, normal* state, neither the equality nor the inequality constraints are violated. However, there is at least one component that can fail and cause one or both of these constraints to be violated. The particular component that can cause the violation is usually identified by on-line load flow analysis. When a system is in the *alert, normal* state, it is likely a response to an accumulation of small disturbances. After each disturbance, the state of the system must be determined; when the state is no longer *secure, normal*, special action must begin to assure the security of the grid and return it to the *secure, normal* state.

The *emergency* state can be characterized by two levels of seriousness: (1) violation of inequality constraints, or *overload* substate, and (2) violation of equality and inequality constraints, or *in extremis* substate. It is unlikely that a condition would prevail where only the equality constraints would be violated, since the *in extremis* substate is a severe shock to the system. System instabilities are associated with the *in extremis, emergency* state, and equipment limit violation defines the *overload, emergency* state.

The *restorative* state occurs after a partial or total system collapse. Control actions are taken to restore the system to the *normal* state following transition from the *in extremis, emergency* state. The system may be forced to operate temporarily with some system elements overloaded, that is, violation of inequality constraints may be acceptable for a while to establish a more desirable operating condition. In other situations, violation of the equality constraints (load shedding) may be acceptable for a part of the system to restore normality to the remainder of the system.

3.5.3 Security enhancement

SE is any feasible and practicable procedure that seeks to eliminate a potentially dangerous operating condition in the power system. The control actions applied are of two classes: preventive and corrective. Preventive controls are used to return the system from the *alert, normal* state to the *secure, normal* state; corrective controls are used to relieve emergency situations. SE and SA are not separable, because SE is dependent on SA as the feedback path of information.

3.6 Control Techniques

The power industry has established techniques to control the power system during times of normal operation. Units are committed using economic considerations--contractual tie-line power flows are maintained and units are dispatched economically--while meeting established industry and utility reliability constraints. Many automatic control features assist in the operation of the power system during the normal system operation, but during emergency situations these normal control features may not be adequate, and a different control regime must be available to maintain system integrity.

To implement the appropriate control action during changing conditions, some utilities have incorporated system state as a decision variable and have specified what action should be taken in each state. Although there is no published industry standard that defines the system states and the appropriate control action for each state, the concept is developing within the industry and is being used in some utility control centers.

If a system does fail, modern dispatch procedures enable more rapid and effective restoration of the system. Since a utility can experience a major outage via many different paths, the need exists for more-comprehensive and -thorough techniques to orderly and safely return service to customers. Because of the uncertainty of the condition of the equipment after a system failure, precise restoration procedures are not usually available to the dispatcher prior to the failure. However, general guidelines to direct the dispatcher may be helpful to restore power quality.

3.7 State of the Art in Modern Control Centers

Methods of implementing power system security practices may vary widely throughout the industry, from sophisticated computerized control centers to control centers that rely largely on telephone systems to transmit information to the dispatcher. Control centers with computers may be elaborate, performing operational functions such as on-line load-flow contingency studies or monitoring transmission lines for overloading or performing other security functions to obtain detailed information related to the state of the system. Control centers without real-time data collection and computer analysis must operate the system with less detailed and timely information. However, even where a computerized system is not available, security procedures can be implemented to improve system operation. Response time and capability may vary between utilities, but each utility can establish security procedures based on its method of control. Appendix D is a listing compiled in 1978 of the system control centers throughout the world.

3.8 Recommendations

The following recommendations are made:

1. Since present NRC methods for certifying the integrity of a power grid do not include the operational aspects of the system, the NRC should require each utility to document the security procedures for its system. Security procedures can be established along the following guidelines:

a. Security monitoring. The utility central power dispatcher can monitor the grid parameters determined necessary for the evaluation of the system state. The critical parameters can be compared to established equipment limits to evaluate the vulnerability of the equipment.

b. Security assessment. Power grid security assessment can be accomplished by specifying the three states--*normal*, *emergency*, and *restorative*--and establishing methods to determine the state of the grid.

c. Security enhancement. Guidelines can be established to assist the central power dispatcher to return the grid to the *secure, normal* state when security assessment reveals the state is other than *secure, normal*.

2. As a part of the NRC requirement for the proof of integrity of the power grid, procedures for operating the system in configurations other than the normal state should be documented. These procedures should be an active part of the system security package.

3. The plans for and the priority of restoring power to the nuclear plant after a failure of the grid supply should be specified.

4. Procedures for ensuring the security of the power grid and the power to the nuclear plants should be available for periods when the power system is highly vulnerable to outages, for example, during electrical storms, hurricanes, tornados, and unusual operating patterns.

5. Any planned or installed automated equipment for enhancement of the security of the power system should be identified as a part of the demonstration of the quality of the power grid.

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4. SOME ASPECTS OF POWER SYSTEM FREQUENCY DECAY RATES AND PWR REACTOR COOLANT PUMPS

4.1 Statement of the Problem of Power Grid Frequency Decay

It is assumed that as a result of an underfrequency signal a PWR is tripped off line. Since an underfrequency trip signal indicates an inadequate electric supply from the primary source, the emergency system with emergency coolant pumping is called on line. During the changeover period, which is of the order of a few seconds, it is assumed that the reactor coolant pumps will continue to pump coolant to ensure that the departure from nucleate boiling ratio (DNBR) limits will not be exceeded. Reactor coolant pumps are designed, and provided with sufficiently massive flywheels, to ensure that even with power to them interrupted, their momentum will be sufficient to provide adequate cooling flow during their coast-down period as the emergency system pumps are brought up.

A concern has arisen that the power grid might not only cease supplying the reactor coolant pumps with power at such a time but under some circumstances could also withdraw the stored mechanical energy in the pump-motor system. During such an event the grid frequency would decay, and the pump motor would become a generator supplying power to the grid, and the stored energy would be withdrawn from the pump-motor system. The rate of decay is the measure of the rate at which the stored energy would be withdrawn.

ORNL has been studying some aspects of frequency decay for the NRC. Initially, ORNL reviewed reports of studies by other companies of such pump motors and the problems that frequency decay could cause. At the direction of the NRC, ORNL limited its study to assessment of what is the maximum credible expected rate of frequency decay on a power system in the United States and to recommend what further questions must be raised to resolve these problems.

A more precise statement of what is meant by maximum credible frequency decay rate is as follows:

1. The concern over frequency decay previously mentioned is limited to frequency decay at a bus which supplies electric power to a nuclear power plant and which, while supplying that power, is connected electrically to other loads approximately equal to or greater than the nuclear power plant load.

2. Specification of a "maximum credible frequency decay rate" would not be meaningful if the rate is not sustained long enough to cause a significant drop in line frequency. In place of such a rate one should consider the maximum credible drop in line frequency that might occur during any subinterval of a specified critical time interval.

Exactly what critical time and maximum frequency drop should be specified depends on the design characteristics of the reactor system, including, importantly, the frequency level at which a reactor trip signal is generated.

The approach to the frequency decay problem and its possible effect on reactor coolant pumps has been to compute the frequency decay rate that a system could sustain without exceeding DNBR limits and then to show that such a rate is incredible on the United States power grid.

Three different PWR designs were examined, and the calculations indicate they could tolerate decay rates of 2.3, 3.0, and 6.8 Hz/s, respectively. (These calculations were made by three different organizations, and at this time, we have no way of knowing whether the different results were due to substantial design differences or to substantial differences in the computational approach.) It has been ORNL's task, principally, to determine whether these frequency decay rates are greater than the maximum credible decay rate of the power grid.

By way of anticipation, we have found that computations of grid behavior in some cases indicate the possibility of higher decay rates: there is at least one recorded case of a decay rate of 10.7 Hz/s. Under these circumstances, we must conclude that the maximum credible decay rate must be at least about 10 Hz/s, which does not support this logical approach to the problem.

We must emphasize, however, that simply because this approach to the problem does not appear to provide a fruitful resolution, it does not follow that frequency decay poses a very serious safety issue.

For this to be a problem it appears that simultaneously (1) there must be a steep frequency decay (the probability that this will occur is quite low), (2) the generator must be off the grid, and (3) all the reactor coolant pumps must remain connected to the grid. The probability that these three events would occur simultaneously is very small.

Sequences of events where the reactor shutdown precedes the generator trip or frequency decay by as little as 2 or 3 s appear to contain no potential for problems of the kind considered here. Moreover, even if the event did occur, the system may be able to accept its apparently limited consequences as a design basis event. The consequences may be further limited when one takes into explicit account the momentum contained in the coolant water itself and its relatively loose coupling back to the electric supply system.

Therefore, while we do not assert that our findings concerning frequency decay rates support assumptions made in previous approaches to this problem, we are of the opinion that it is much less than an urgent issue and can be put in a satisfactory context by an alternative approach.

4.2 Approach to An Estimate of Maximum Credible Frequency Decay Rate

To determine a reasonable estimate of maximum credible frequency decay rate, we have relied principally on three resources: discussions with experienced persons, review of computations, and study of the literature of recorded events.

In addition, we attempted some calculations of simple systems. It soon became clear, however, that to put sufficient realism into a computational model to make it competitive with calculations in the published literature would require more resources than were available.

The results of our survey approach are discussed in the paragraphs to follow.

4.2.1 Discussions with experienced persons: the statistical tail and the fallibility of experience

When a question concerns the average behavior of a system or the spread of conditions about the average, there are few better sources of information than those who have a long experience operating the system. If the question implies extremely unusual system behavior, and especially with negative connotations, replies from experienced operating persons are often of the nature of "impossible," "never heard of such a thing," "never in my experience," "ridiculous," "only an amateur would think of such a thing," etc.

Further complications can arise if the phenomenon under study is seldom monitored or recorded, for then it may appear not to occur when, in fact, it does. Since some phenomena are created by or made important by recent technology, experience extending much beyond the recent past may have little relevance to them.

The possible differing impact of rare events on an experienced individual and on a national regulatory body may be illustrated by the following. For an assumption that an event could occur at a plant (1) once in 40 y (about once in a working lifetime) or (2) once in 100 y, the probabilities, respectively, are 0.025 and 0.01/plant-year. For an assumption that the same event has an equal and independent probability of occurring at any of 40 plants, the probability that the event will occur in at least one of the 40 plants during any year is for case (1), $1\text{-}0.975^{40} = 0.64$; and for case (2), $1\text{-}0.99^{40} = 0.33$.

The significance of the frequency decay rate cannot be determined by experience alone. Substantial decays at a high decay rate are rarely experienced. Further, there is very little monitoring of frequency decay on time scales of significance to this problem. For these reasons, an engineer with many years of experience may never have seen a high frequency decay rate. Therefore, by basing his considerations solely on experience, such an engineer may consider the maximum frequency decay rate not to be high enough to cause a problem for the reactor coolant pumps.

4.2.2 Published calculations of frequency decay

Catelli et al.[1] studied the topology of the Northeast Utilities system and determined two ways in which it might break into islands by loss of transmission lines. Their conclusion from this study was that initial frequency decay rates in a range from 0.5 to 1.5 Hz/s could be expected. Based on their system data on line outages and an assumption of statistical independence of events, their computation of the joint probability of simultaneous failure of the two circuits (which would precipitate the event) predicted a failure rate of once in 2000 years. (Since this calculation was based on 8 years of data, and an assumption of statistical independence, and since the northeast blackout did happen--even if conditions have been changed since then--this prediction appears optimistic.) In further studies of loss of generation under conditions where the system was considered virtually isolated from additional outside support, initial frequency decay rates of up to 6 Hz/s were computed. It is emphasized that these results apply only to the system under study.

The results of a series of related studies of frequency decay were published by the Westinghouse Electric Corp.[2-4] The authors of ref. 2 emphasized the determination of limits to generator loading and stated the following conclusions:

1. "The rate at which frequency can decay during a system disturbance is limited. The equations presented in this paper provide a means of calculating the maximum decay rate.

2. "The highest frequency decay rate occurs immediately after the overload is imposed.

3. "Increasing the attempted overload increases the amount by which the generator is actually loaded up to some maximum value. An attempted overload in excess of that value will result in a load bus voltage drop sufficient to decrease the overload and the frequency decay rate.

4. "The voltage regulator action raises the generator terminal voltage and load bus voltage after a few seconds but not enough to modify the rate of decay adversely.

5. "Any load shedding will further decrease the rate of frequency decay after a brief time delay.

6. "The load power factor has a very significant effect on the decay rate.

7. "A uniform distribution of spinning reserve on a power system is very desirable."

The same reference also says, "This paper describes a method of determining the maximum *probable* (emphasis ours) rates at which power system frequency will decay following a disturbance...." The treatment is neither exhaustive nor bounding, but it demonstrates certain limiting characteristics of generators of a standard type. Among the frequency decays computed for various cases, not necessarily realistic, were 3.65, 4.1, and 6.5 Hz/s.

Reference 3, citing what appears to be the same studies as ref. 2, states: "Frequency decay rates up to the maximum *credible* (emphasis ours) decay rate (5 Hz/sec)...." The studies reported in this reference assume a constant rate of frequency decay and compute the thermohydraulic consequences of the assumption. The result is that, for the reactor systems and the constraints considered, a DNBR of at least 1.3 would be maintained if the frequency decay rate is no greater than 6.8 Hz/s. Figure 4.5 in ref. 3 clearly demonstrates a region of not improbable operations where, according to the calculations presented, the maximum frequency decay rate would exceed 5 Hz/s.

Reference 4 carries on the analyses of the electric power grid for other cases, explicitly taking into account units with leading power factor, multimachine islands, and units connected to long, high-capacity transmission lines. One of the significant results presented is the following: "The study concludes that under some conditions, frequency decay rates greater than 5 Hz/s are possible when the unit is operating at rated turbine power...." In one case, a maximum frequency decay rate of 10.9 Hz/s was computed.

All of the foregoing calculations were, and necessarily so in view of the complexity of the problem, specific in many details. Hence, generality cannot be claimed for the results. However, it is apparent that serious and strenuous efforts were made to consider cases that were among the most severe that might be encountered. Results obtained in the more extreme cases considered conform generally with the highest frequency decay rates which we have been able to find recorded from actual operating experience.

4.2.3 Recorded events--the empirical approach

As indicated in the preceding sections, our discussions with persons expert in electric utility operations and our examination of some of the available computational studies on the subject appeared to yield a consensus that maximum credible frequency decay rates were reasonably low, quite possibly low enough to ensure no problem from this source to the reactor coolant pumps. However, some doubts remained, perhaps because some of the calculations indicated a possibility of high frequency decay rates in regions that could not be considered incredibly inaccessible to operations.

We began searching records of events that might have shown significant frequency decay rates. There is a considerable body of writing on the northeast blackout of 1965, in which the highest frequency decay rate reported for that event is about 1 Hz/s.[5] In fact, there was little frequency monitoring equipment in place at that time, which lack continued until recently. In recent years, a few oscillographic recorders were placed in service at selected locations. These are strip chart devices that display one cycle of a 60-Hz frequency over several inches of paper, thus enabling response of the recorder to rapid frequency changes which otherwise could not be resolved with a recorder of a slower response. The oscillographs do not continuously record at high speed on paper; they are tripped *on* when an electric signal indicates that a problem has occurred. The strip chart movement of these instruments is based on timing signals independent of system frequency. Thus, the frequency decays recorded by these instruments show time resolutions sufficient to permit a determination of decay rate in Hertz per second (Hz/s).

Most instruments record frequency traces on coarse time scales (Fig. 2 is one such), and many other recorders provide even poorer resolution. Such recordings permit observation of the total frequency swing, but not its rate. Whether the inertia of such recorders would permit them to show the total swing of an event restored in 5 s is doubtful.

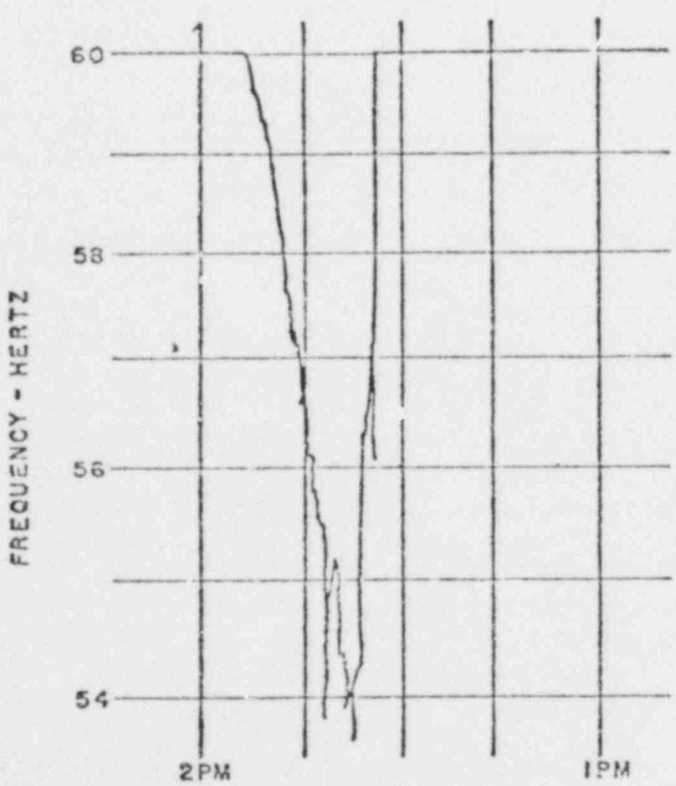

Fig. 2. Frequency of fringe portion of southern system islanding on July 5, 1957.

Recorded frequency data (on a gross resolution time scale) of a major southeastern utility were examined. These data had been recorded during critical periods of the week of January 17, 1977--a period of protracted cold during which the area had experienced its greatest load demand to that time. The frequencies were below 60 Hz, the integrated time error at one point was about 30 s, and the reserves were minimal. At approximately the same time, a large generator had failed in a neighboring utility, causing a total frequency drop of ∿0.1 Hz. Although this experience gives little information on assessment of the maximum credible frequency decay rate, it does give some indication of the stresses on grids and of their inherent strength.

The reporting activity of the Federal Power Commission (FPC) concerning power losses grew following the northeast blackout. Looking for information on frequency decay, we read all quarterly reports of electric power disturbances published by the FPC, numerous topical reports, and reports by utilities to the FPC related to system disturbances. Two documents issued by FPL[6,7] reported frequency decays in their system that exceeded 1 Hz/s. (We found no other reports of a frequency decay rate that exceeded 1 Hz/s.) Figure 3 (from ref. 6) shows a severe frequency drop which occurred on their system June 28, 1974. Figure 4 (from ref. 7) shows the decay of frequency at one bus of the FPL system during the final stages of system collapse in the outage of May 16, 1977.

In a parallel study of loss of offsite electric power at nuclear power plants, we found only one case where frequency decay during an event was noted and reported (ref. 7, already cited).

4.3 Discussion of Recorded Frequency Decays

Figures 3 and 4 bear some discussion to place them in the context of the problem we are considering. As noted, Fig. 4 is a record of the frequency collapse of a subsystem after it had become isolated and had lost all its power generation capability. The power did not drop instantly to zero, because energy was stored in inductive devices. However, as the system parasitically drained off that energy, the rotating pump motors (serving as generators) slowed down, and the line frequency decreased correspondingly. Such an outcome had been foreseen as qualitatively the worst case of frequency decay that might occur, and, in view of the scarcity of recorded information, it is fortunate that it was reported to the FPC. In Fig. 4, the frequency decay rate is 10.7 Hz/s in the interval between 14 and 15 s. This measured decay rate is the largest that we have determined throughout the investigation.

Although Fig. 3 shows a lower decay rate, it nevertheless merits some discussion. The frequency rises to just above 62 Hz, plunges to below 55 Hz, and then recovers. During this disturbance on June 28, 1974, some load was lost in southeast Florida, causing the increase in frequency. Then at >62 Hz, some large generators tripped off on overspeed, causing the plunge in frequency. During the plunge, underfrequency relays acted

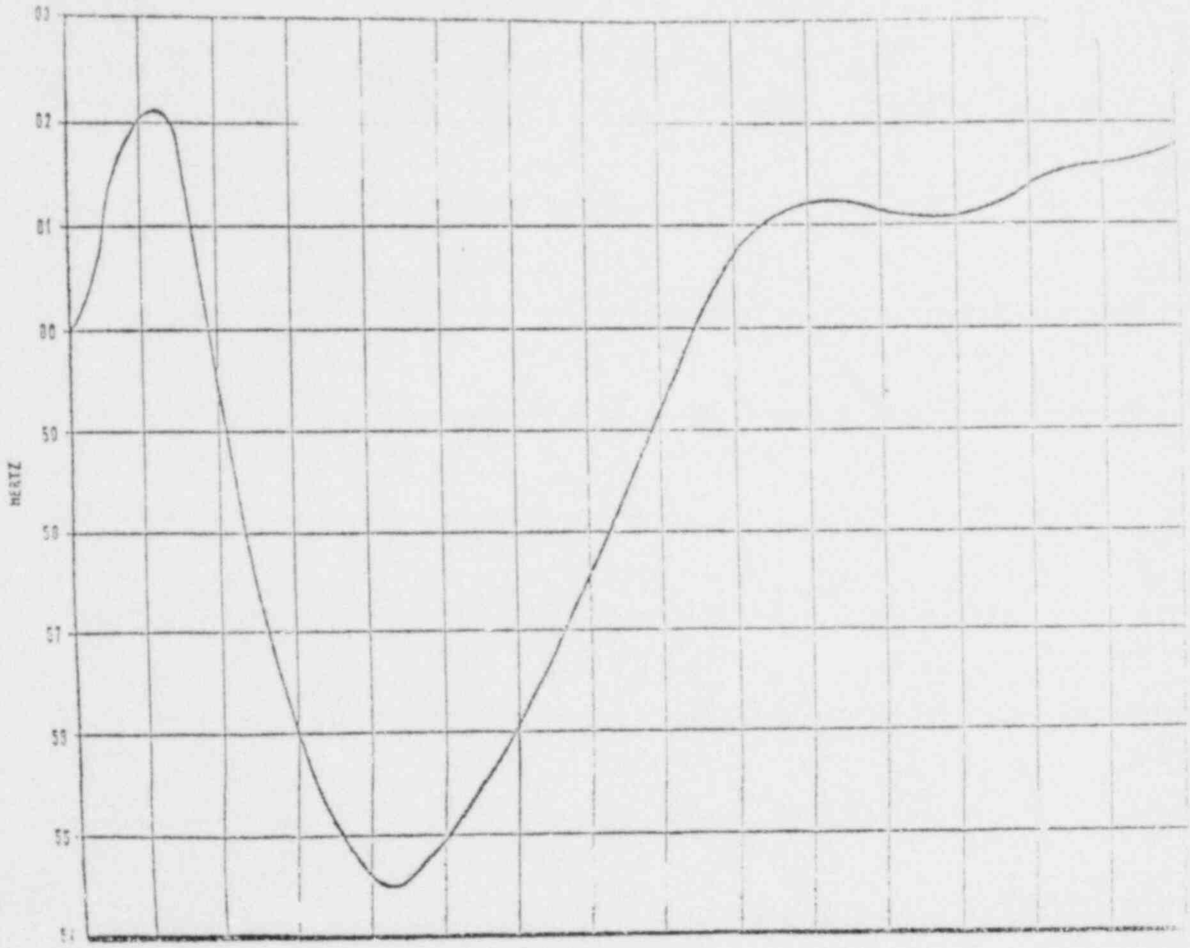

Fig. 3. Florida Power and Light Company, Dade Station frequency disturbance on June 28, 1974.

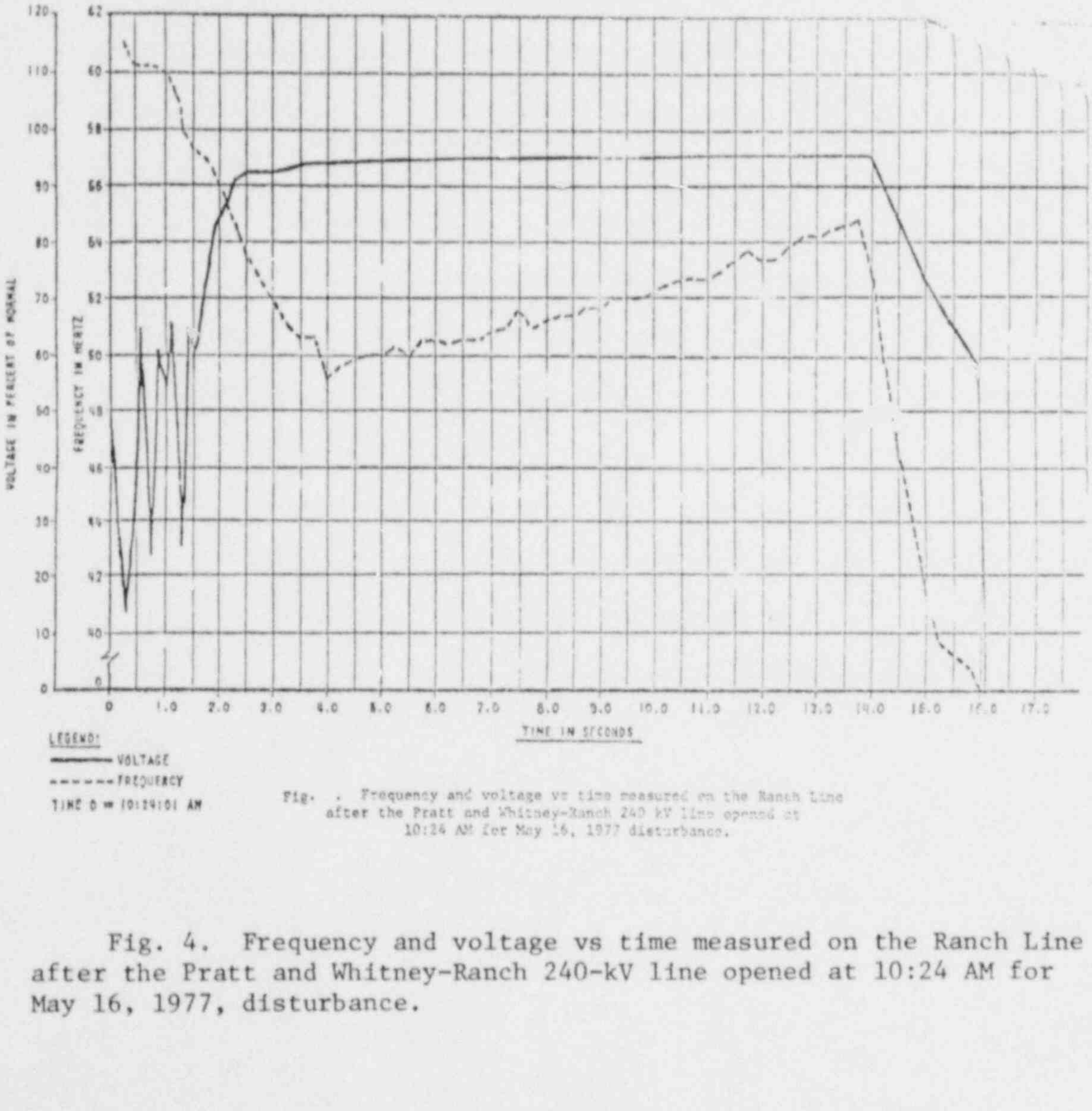

Fig. 4. Frequency and voltage vs time measured on the Ranch Line after the Pratt and Whitney-Ranch 240-kV line opened at 10:24 AM for May 16, 1977, disturbance.

automatically between 59.2 and 58.5 Hz, shedding load and leading to the recovery of the subsystem from 54.5 Hz.

Two important considerations follow from the fact that this decay began at >62 Hz. First, if a PWR plant with reactor coolant pumps had been connected to the bus on which this frequency decay was recorded--and there was not--the initial overspeed to 62 Hz would have added stored energy to the pump-motor system; therefore, in the initial part of the subsequent decay, the pump-motor system would have been returning excess energy to the grid. Second, because the decay started from >62 Hz, extra time was required to reach the load-shedding trip levels distributed from 59.2 to 58.5 Hz, thereby prolonging the duration of the decay.

From these considerations, we believe that it is quite possible that a thermohydraulic analysis of this case might show that it has a severely limited potential for damage to the reactor of the kind under consideration.

4.4 Other Approaches to the Frequency Decay Problem

From our study described in the preceding section, we believe that an assessment of the probability of occurrence of special events that must happen to create serious problems due to frequency decay might support two conclusions: (1) the probability of occurrence of such an event would lie within tolerable limits, and (2) the consequences would be bearable.

An encompassing study of frequency decay would include the following considerations as well:

1. To cause a problem, not only must the frequency decay be severe, but, simultaneously, all reactor coolant pumps must remain tied to the grid, and the nuclear plant generators apparently must be detached from the grid. What is the probability of such joint events?

2. Given the occurrence of such joint events, what DNBR would be achieved, and how much damage would result? In such an evaluation, how loosely is the momentum in the coolant water coupled to the electric grid (includes taking account of effects of pump bypasses and other similar paths.)?

3. Are frequency decays that begin from greater than 60 Hz substantially less troublesome?

Since different vendors of PWRs have determined that 2.3, 3.0, and 6.8 Hz/s are the magnitudes of frequency decay rate their systems can tolerate without exceeding DNB limits, it appears that there are substantial differences either in the systems or in the assumptions made in dealing with the problem. Thus, to develop a basis for a generic resolution of these differences, it appears that the NRC should request the vendors or the operators to provide sufficiently detailed assessments of their plants so that significant differences can be compared and understood. The following information, we believe, would be appropriate for operators of PWR power plants:

1. Assume the following: the power transmission systems, or fringes of it, have separated; the PWR plant is in a separate segment, all generation in that segment is lost, and the PWR plant generator is the last to shut down. What would be the expected rate of frequency decay as the last generator goes off line and the segment then draws stored energy from on-line inductive devices during its final collapse?

2. How many times during the past 20 years has there been a total interruption of service to customers of this system when the total load was 200 MW or more? Give the time, description, and duration of each such event.

3. Does the utility record line frequencies at any point or points? If it does; what is the largest total frequency drop that has occurred in any time period of 5 s or less? Give a fully detailed description of the event. If the recording equipment does not resolve 5 s, give a detailed description of the largest frequency drops that have occurred in resolved times. If such equipment was operating in any area in which service was interrupted as described in question 2, supply a copy of the record of the final frequency decay in each case.

4. How many reactor coolant pumps does the PWR have? What is the minimum number of pumps that would have to be disconnected from the power grid during a frequency decay rate of 11 Hz/s extending over 2 s to ensure that the system would not exceed DNBR limits during coastdown and changeover to alternative cooling? What DNBR would be reached if all pumps remained connected to the power grid. What damage to fuel, cladding, or other components would result? What breakers or other mechanisms are there for separation of the reactor coolant pumps from the electric power grid? Describe the various ways these mechanisms would be actuated during a frequency decay of the magnitude contemplated.

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5. REVIEW OF A POWER SYSTEM LONG-TERM DYNAMICS DIGITAL COMPUTER CODE

5.1 Introduction

The long-term dynamics computer code, LOTDYS,[1] was evaluated for possible use in power system planning and reliability studies of mathematical models of power transmission networks. The changes of an electric power network that occur over a period of minutes are considered as long-term dynamics, but those that occur over a period of a few seconds are short-term dynamics. The LOTDYS code was selected for evaluation because there are not any production-grade, long-term dynamics codes in use in the power industry, and there is some evidence that blackouts have resulted from components within power systems that slowly respond to system perturbations (long time-constant instabilities).[2] The use of a long-term dynamics computer code will provide additional information about the reliability of the power being supplied to nuclear power plants.

Conventional transient stability codes are used to study short-term dynamics, but the LOTDYS code is being developed to study long-term dynamics. EPRI has developed a midterm dynamics code that starts with a transient analysis and then changes and performs several minutes of long-term analysis.[3] However, we know of no code that is available today as a production version to perform long-term dynamics. LOTDYS, developed originally by General Electric for EPRI, is not completely documented, and the input data are difficult to manage without error. The sample-data program provided by EPRI with the LOTDYS program has been run on the ORNL computing facilities, but the code is not yet reliable for actual power system studies.

5.2 Program Features

LOTDYS is self-standing, in that its input does not require the output of any other program. However, by itself, it is not a sufficient tool to analyze long-term system stability; it must be used in conjunction with a computer program that analyzes short-term disturbances, the reason being that LOTDYS does not compute the angular swings caused by a disturbance, but the short-term dynamics analysis program will. LOTDYS will compute the longer time-constant system control actions which may result in overloaded equipment, relay action, load shedding, or other such occurrences. The technique of using the two programs together is described as follows.

The short-term dynamics program determines the effect of an initiating event on the system, and, if the system is stable, the LOTDYS program is started. The LOTDYS program continues to run until it predicts the occurrence of a second event, such as a generator trip. The initial conditions established at this time by LOTDYS are entered into the short-term dynamics analysis program, and the short-term stability of the system is determined. If the system is stable, LOTDYS is restarted for further long-term dynamics analysis. This procedure of using the two programs together can be continued up to 20 min of simulation time or until the system becomes unstable.

The LOTDYS code can simulate power system performance for periods up to 20 min; it can model up to 100 generators, 300 busses, and 500 lines. The power plants can be modeled as coal-fired steam plants, hydro units, BWRs, or gas turbines. (A model of a PWR is being developed by the University of Tennessee, and it will be incorporated into the code later.) The time steps in LOTDYS are typically about 1 s. At each time step, the program calculates a new load flow, depending on the results of five selected tests. In each time step, the net imbalance between load and generation is used to calculate the system acceleration (rate of change of the system frequency). The system frequency is constant throughout each time step, but the frequency can change from one time step to the next as calculated with the acceleration. Because the system frequency is constant for each time interval, the LOTDYS code cannot be used to analyze the short-term instabilities that cause the generators to accelerate at different rates and to operate at different frequencies.

5.3 Program Models

Below is a brief description of each of the models used in LOTDYS. Most of the models are quite extensive because they include the auxiliary equipment and systems which respond to slowly varying quantities and can also have a significant effect on the long-term response of the power system.

5.3.1 Transmission line model

A "pi" model is used for the transmission lines. The admittance is calculated using the system frequency, and it varies with the frequency.

5.3.2 Transformer model

The transformer model includes the effect of the transformer series reactance, off-nominal per unit turns ratio, and saturation.

5.3.3 Load model

The load on any bus can be made to vary as a function of the system frequency and the bus voltage. The particular characteristics of any load are modeled by selecting appropriate input data.

5.3.4 Generator model

This model uses steady-state equations that include the effects of saliency, saturation, and frequency changes to determine what the exciter field voltage and current should be to maintain regulated terminal voltage. If the output of the excitation system is limited by protection devices, the generator is replaced by a voltage-behind-synchronous-reactance model.

5.3.5 Excitation system model

For generators on automatic voltage control, the following can be included: overcurrent and overvoltage protection of the excitation system, minimum excitation limits as a function of the real power, loss of excitation protection of the generator, volts per Hertz regulation, and volts per Hertz protection.

The excitation model represents the response to slowly varying loading on the generator such that the field voltage is that necessary to support the unit loading during the time step of about 1 s. The field voltage is a function of system frequency for units not on automatic control.

5.3.6 Fossil steam turbine model

The boiler turbine control model calculates changes in turbine power due to changes in the frequency, automatic generation control signal, and station voltage. The type of unit can be modeled by selection of appropriate input data. The model consists of the following components: coordinated boiler-turbine control, turbine control, steam turbine, boiler controls and auxiliaries, and boiler.

Low voltage and frequency are reflected by degraded unit performance.

5.3.7 Hydro turbine model

The hydro turbine model can simulate pumped hydro units or run-of-river units.

5.3.8 Combustion turbine model

The combustion turbine model simulates a single-shaft turbine-generator. A single-shaft unit is one that drives the compressor and generator on a single shaft. Since a combustion turbine responds in fractions of a second and the time steps are about 1 s, this model is relatively simple. The effects of low voltage and frequency on the auxiliary equipment are included.

5.3.9 Boiling water reactor

This model generates the power response of a plant to changes in load demand by manipulating the recirculation flow and pressure regulator setpoints. The model used is an input-output type and does not actually model the individual components of the BWR. The effects of off-nominal frequency and voltage are included.

5.3.10 Relay model

The relay models included in LOTDYS are the following: underfrequency load shedding, underfrequency unit trip, undervoltage load trip, undervoltage unit trip, loss of excitation unit trip, and distance relays.

Since the relays respond to slowly varying positive sequence quantities, the effects of fast-acting relays cannot be studied using LOTDYS.

5.3.11 Automatic generation control

This model incorporates load frequency control and economic dispatch. It maintains the system frequency and scheduled tie-line flows by sending a power control signal to each of the controlled plants.

5.4 Program Uses

When LOTDYS becomes an operational code, it could be an excellent tool to analyze events such as the FPL blackout of May 16, 1977.[4,5] The long-term dynamics code might have predicted the VAR (volt-ampere reactive) power generation problem which occurred at St. Lucie and also the precarious condition of the Ft. Myers-Ranch line. The initiating event, the tripping of Turkey Point 3, occurred at 10:08 AM. During the succeeding 16 min interval, the voltage and frequency on the system fluctuated enough to cause the tie lines to the Florida Power Corp. and the Southern Co. to open. The St. Lucie operator reported fluctuating voltage, MVA (megavolt-ampere) output above maximum rating, and high MVAR (megavolt-ampere reactance) production. The period of the voltage oscillation was about 30 s, as observed by the St. Lucie operator, but the amplitude of the oscillation is not known. Time constants such as these can be calculated using the LOTDYS program. The blackout occurred at 10:24 AM.

Major system disruptions, such as the FPL blackout, are not caused by a single failure; instead the cause is a combination of several events. Sometimes it cannot be determined if the first disturbance contributed to the succeeding disturbances or if the events were independent. LOTDYS would help determine if the events are independent, or it could indicate that the system has moved into a vulnerable condition which could result in a system collapse following only a minor disturbance. Such an analysis could be valuable to a utility, but application of the

LOTDYS code will probably be much like that of the transient stability codes; that is, it will probably be used in planning and reliability studies and not in daily operating studies.

5.5 Recommendations

Since LOTDYS is not yet a reliable code, the NRC cannot immediately use it in the licensing process. However, EPRI is continuing to fund development of the LOTDYS code. (We understand that an updated version of the code will be available in CY1980.) If LOTDYS is developed into a usable code as EPRI plans, it may be useful in safety analysis reports (SAR), much like the short-term dynamics analysis study. If the SAR short-term dynamics analysis indicates system stability, the study can be continued using the LOTDYS code to show that the longer time constants will not cause loss of a preferred power source to the nuclear plant.

When the code becomes available, the NRC should observe the progress of the code as it is applied by the utilities, and gain expertise in understanding its application and results. Its usefulness in the licensing process will have to be reevaluated after the EPRI research is completed, but such a program, if reliable, can be valuable for system reliability studies, and an asset to NRC for the licensing process.

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6. A GRID SENSITIVITY MATRIX AND ITS POSSIBLE USES

6.1 Introduction

The effects of various transmission line failures on models of power transmission systems operating at steady state were studied, and from these results, a mathematical index was developed that informs the system operators whether failure of a particular *power line* would cause the system to become transiently unstable. This index is determined by using steady-state load flow calculations and power grid sensitivity calculations. The power utilities do not use this method of calculating an index of stability; instead, they determine the potential transient instability of their power systems with computer codes that simulate the grid response to the failure of a *grid component*. These utility codes require too much computer memory and time for practical use on line; all such "transient instability" codes we know of are run *off line*, for which the model is constructed from anticipated operating configurations. To improve the security of nuclear plant offsite power, the NRC wants the utilities to be capable of predicting the transient instability of the power grid using an *on-line* technique because an on-line model probably would portray the actual operating configuration better than a model used in an off-line computer study.

To calculate an index to predict instability does not require a dynamic computer code, only a steady-state load flow computer code and a sensitivity computer code. A sensitivity computer code was developed by the authors for use with a load flow computer code developed by the Philadelphia Electric Co. Load flow programs are used on line by many utilities, and we believe that the sensitivity program may also be used on line.

Another possible use of the sensitivity code results is that they could be used to indicate the sensitivity of bus voltage to a change of the injected reactive power at any other bus in the model. In this manner, the sensitivity results could be tools to study voltage degradation, as that experienced at the Millstone 2 nuclear plant.[1,2]

The determination of a grid sensitivity index depends on the variation of several numbers calculated by the sensitivity program. Since the percentage variation of these numbers may be different for each system studied, the index will be specific for each system, and, thus, an index reference value must be determined beforehand for each system. Therefore, before we can recommend that the grid sensitivity index be used by the NRC to license nuclear plants, this technique requires verification using an operating power grid.

6.2 Sensitivity Calculations

The sensitivity matrix studied is calculated from a Jacobian matrix which is formed from a Taylor series expansion about a given steady-state operating point by assuming that all of the second- and higher-order derivatives in the Taylor series are negligible.[3] This assumption is usually acceptable for small perturbations about the operating point for which the Taylor series is written. A matrix equation obtained from the remaining terms of the Taylor series is given in Eq. (1).

$$\begin{bmatrix} \Delta\bar{P} \\ \\ \Delta\bar{Q} \end{bmatrix} = \begin{bmatrix} \dfrac{\partial P_i}{\partial \delta_j} & \dfrac{\partial P_i}{\partial |V_j|} \\ \\ \dfrac{\partial Q_i}{\partial \delta_j} & \dfrac{\partial Q_i}{\partial |V_j|} \end{bmatrix} \begin{bmatrix} \Delta\bar{\delta} \\ \\ \Delta|\bar{V}| \end{bmatrix} \quad \begin{matrix} i = 1,n \\ j = 1,n \end{matrix} \tag{1}$$

where

$\Delta\bar{P}$ is the vector of the change in real power at all busses in the system,

$\Delta\bar{Q}$ is the vector of the change in reactive power at all busses in the system,

$\Delta\bar{\delta}$ is the vector of the change in voltage angle at all busses in the system,

$\Delta|\bar{V}|$ is the vector of the change in voltage magnitude at all busses in the system,

$\dfrac{\partial P_i}{\partial \delta_j}$ is the element of the matrix of partial derivatives of the real power at bus i with respect to the voltage angle at bus j,

$\dfrac{\partial P_i}{\partial |V_j|}$ is the element of the matrix of partial derivatives of the real power at bus i with respect to the voltage magnitude at bus j,

$\dfrac{\partial Q_i}{\partial \delta_j}$ is the element of the matrix of partial derivatives of the reactive power at bus i with respect to the voltage angle at bus j,

$\dfrac{\partial Q_i}{\partial |V_j|}$ is the element of the matrix of partial derivatives of the reactive power at bus i with respect to the voltage magnitude at bus j,

n is the number of busses in the system, excluding the swing bus.

This matrix of patrial derivatives is a Jacobian matrix. The sensitivity matrix, S, is calculated by solving Eq. (1) for $\Delta\bar{\delta}$ and $\Delta|\bar{V}|$; the result is given in Eq. (2).

$$\begin{bmatrix} \Delta\bar{\delta} \\ \\ \Delta|\bar{V}| \end{bmatrix} = S \begin{bmatrix} \Delta\bar{P} \\ \\ \Delta\bar{Q} \end{bmatrix} \tag{2}$$

The sensitivity matrix relates the change of the voltage angle and voltage magnitude at a bus to the variation of the real or the reactive power at any bus in the system.

For a power system with n busses, the Jacobian matrix will be a $2n \times 2n$ array that can be partitioned into four $n \times n$ matrices--J_1, J_2, J_3, and J_4, corresponding to the partitioned matrices in Eq. (1). Matrix S can be partitioned in a like manner into S_1, S_2, S_3, and S_4. This notation can be used to rewrite the Eqs. (1) and (2) in the forms given in Eq. (3).

$$\begin{gathered} \begin{bmatrix} \Delta\bar{P} \\ \\ \Delta\bar{Q} \end{bmatrix} = \begin{bmatrix} J_1 & J_2 \\ \\ J_3 & J_4 \end{bmatrix} \begin{bmatrix} \Delta\bar{\delta} \\ \\ \Delta|\bar{V}| \end{bmatrix} \\ \begin{bmatrix} \Delta\bar{\delta} \\ \\ \Delta|\bar{V}| \end{bmatrix} = \begin{bmatrix} S_1 & S_2 \\ \\ S_3 & S_4 \end{bmatrix} \begin{bmatrix} \Delta\bar{P} \\ \\ \Delta\bar{Q} \end{bmatrix} \end{gathered} \tag{3}$$

For most cases, there is only a small coupling between real power and voltage magnitude and also between reactive power and voltage angle.[4] Therefore, J_2 and J_3 are usually small and can be assumed to be zero without introducing a significant error in the calculation of $\Delta\bar{P}$ and $\Delta\bar{Q}$. This simplifying assumption allows J to be written as shown in Eq. (4), and S can be written as in Eq. (5):

$$J = \begin{bmatrix} J_1 & 0 \\ \\ 0 & J_4 \end{bmatrix} \tag{4}$$

$$S = \begin{bmatrix} S_1 & 0 \\ \\ 0 & S_4 \end{bmatrix} \tag{5}$$

The advantage of this assumption is that S_1 becomes the inverse of J_1, and S_4 becomes the inverse of J_4. This saves computer time when solving for the inverse of J_1 and J_4.

6.3 Study Models

Two synthetic power system models were used in this study. Test System 1 (Fig. 5) was constructed from data submitted by FPL to the Federal Power Commission (FPC), now the Federal Energy Regulatory Commission (FERC). The data were used to approximate a model of the FPL system of May 16, 1977, the day of an FPL system-wide blackout. The other model, Test System 2 (Fig. 6), was developed by EPRI.[5] Although these models were designed to include only a few busses, still they approximate an operating power system and are useful for sensitivity studies.

The types of transmission lines and the conductor spacing were specified in FPC Schedule 18. These specifications were used to calculate the transmission line impedance and line charging. Bus load information was calculated using FPC Schedule 12, which describes the seasonal, peak, real power flowing on the transmission lines. The bus loads were calculated by summing the power entering and leaving the bus nodes. Since reactive power data were not available, a nominal power factor of 0.9 was assumed for all loads. Since specific FPL generator data were not available, typical data were obtained from a reference by Anderson and Fouad.[6]

The model constructed at ORNL consisted of 32 busses and 62 transmission lines, of which seven were 138-kV lines, and the remainder were 230-kV lines. Not shown in Fig. 5 is the 500-kV line that connects Western Florida to Southern Florida because this line was not in service on May 16, 1977, the day of the blackout, that is, at the time during which the model approximates the actual system.

Since the load flow results determined by the ORNL Test System 1 were comparable to the actual real power flows to the FPL system prior to the blackout on May 16, we are confident of the validity of the model. Then, in further study with the 500-kV line out of service (the condition of May 16), the model was transiently unstable after the loss of the 230-kV transmission line between Ft. Myers and Ranch. (In Fig. 5 this is the transmission line between busses 3 and 13.) The model did not show the voltage variations that actually occurred, but, since the actual VAR loading was not known, the voltage response was not expected to be accurate.

The conclusion is that the ORNL Test System 1, consisting of 32 busses, does give an indication of the instability of an operating system under unusual loading conditions. It appears not to be necessary to use large, computer models to determine system stability; but to obtain more accurate results, a more detailed model is necessary.

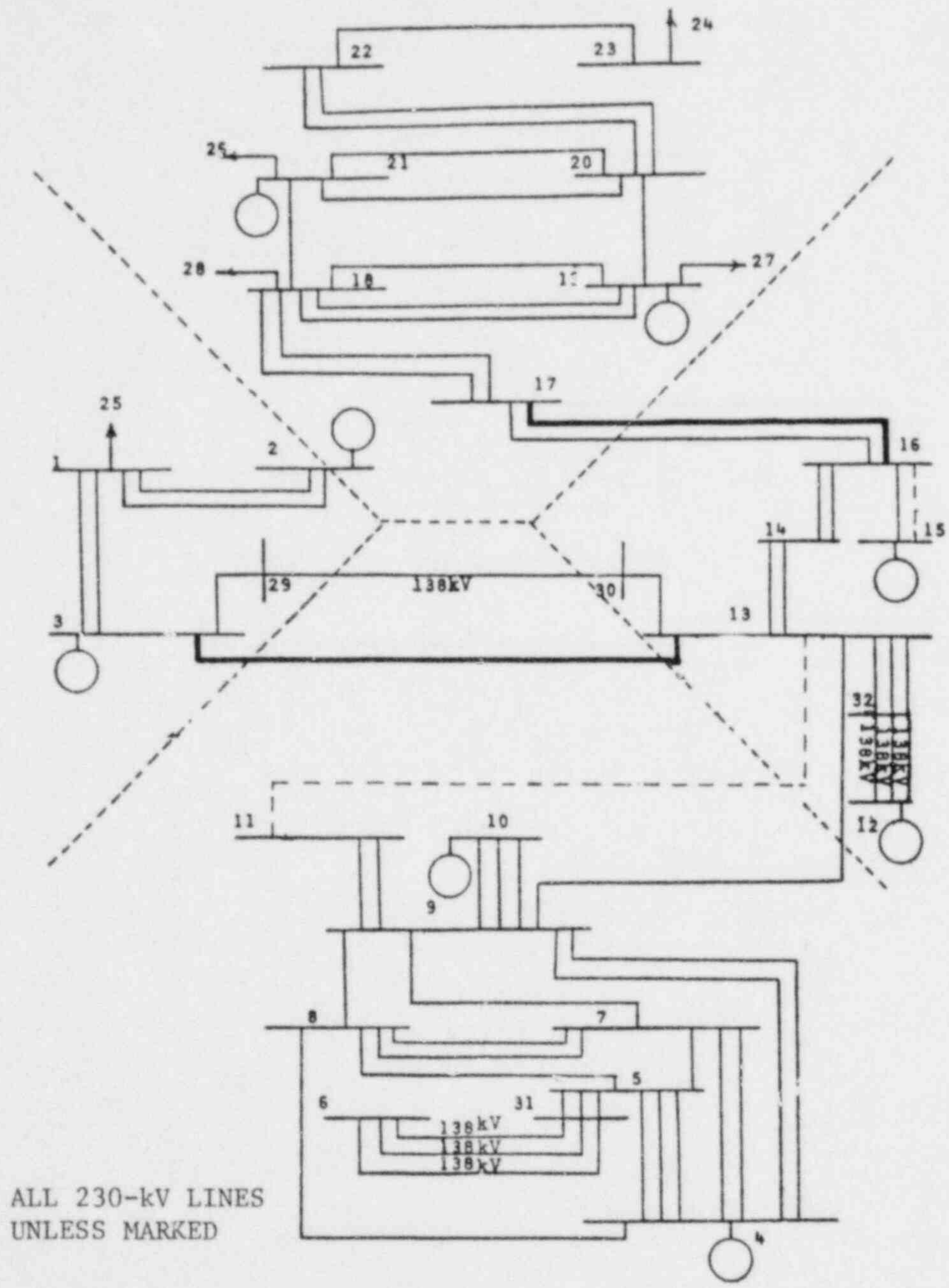

Fig. 5. Test System 1

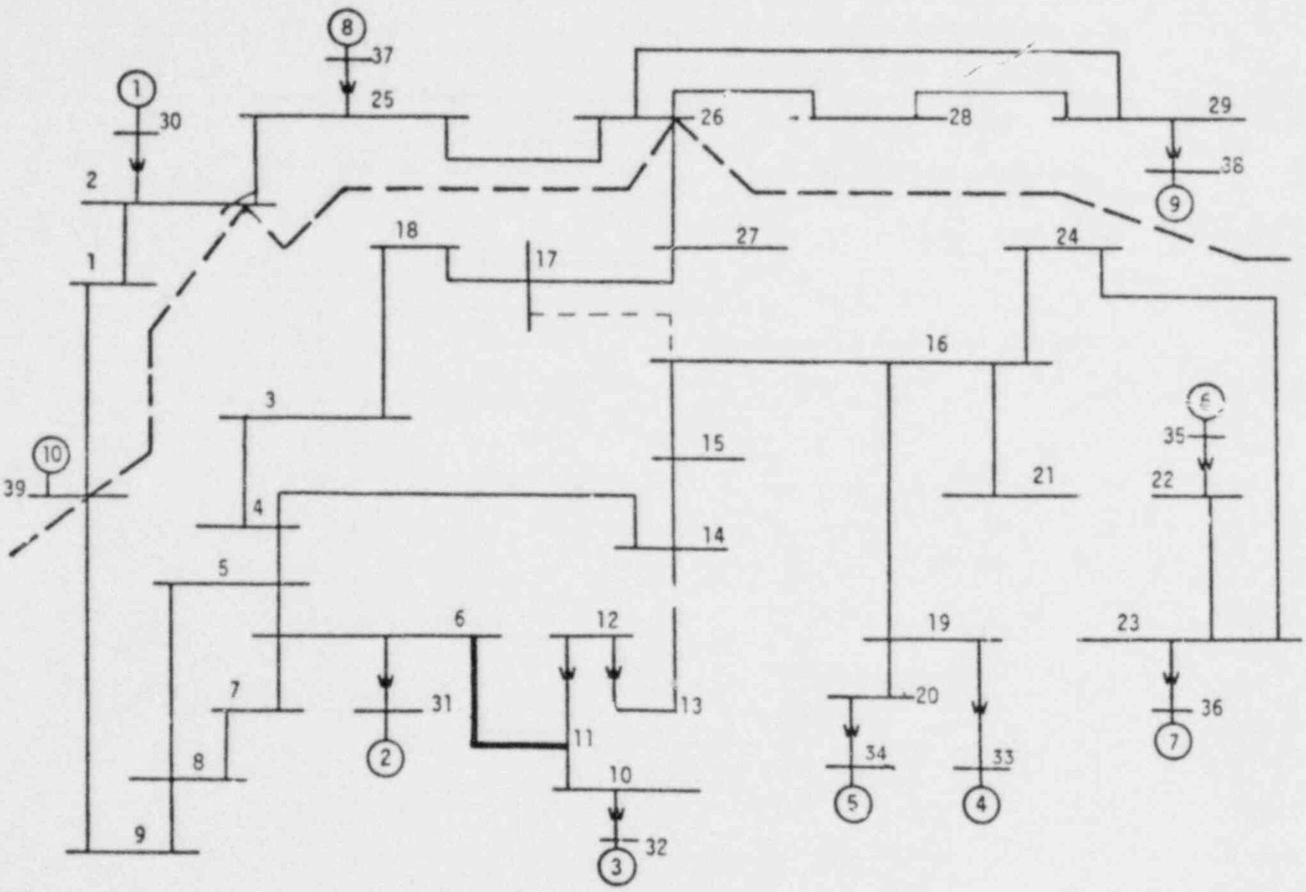

Fig. 6. Test System 2.

6.4 Calculation Procedure

The procedure for calculation of a sensitivity index is as follows:

1. Solve for the base load flow, and determine a base sensitivity matrix, S_1.
2. Simulate the removal of the transmission line under study, and solve for a new load flow; calculate a new sensitivity matrix using the new voltage magnitudes and angles output by the load flow program.
3. Subtract the two sensitivity matrices (one for the base case and one after the removal of the transmission line) to obtain a difference matrix, ΔS_1.

The value of the elements in the matrix ΔS_1 are an index of the grid transient stability after the loss of the transmission line under study.

Most of the elements in the matrix ΔS_1 will be zero or very nearly zero, but, if the system is approaching instability, some of the elements of ΔS_1 will change significantly. The amount of change of these elements is dependent on the system, but it is the variation of these matrix elements in ΔS_1 that is the index of stability.

Table 1 shows the variation of some of the sensitivity elements for stable and unstable cases for each of the two models used in this study. The variation of the sensitivity elements is the index of stability. It is difficult to find a number above which the index indicates instability and below which the index indicates stability. The table also reveals that, for the models studied, variation of a sensitivity element by more than 80% indicates instability, and variation less than 30% indicates stability. In any case, there were only a few elements that varied more than 80%. A dynamic transient stability computer code was used to verify whether the system became stable or unstable following the loss of the transmission line.

Table 1. Variation of sensitivity elements for the removal of transmission lines

TEST SYSTEM 1						TEST SYSTEM 2					
UNSTABLE			STABLE			UNSTABLE			STABLE		
Line Removed[a] FM-To	Sensitivity[b] Element	Variation of Element (%)	Line Removed[a] FM-To	Sensitivity[b] Element	Variation of Element (%)	Line Removed[a] FM-To	Sensitivity[b] Element	Variation of Element (%)	Line Removed[a] FM-To	Sensitivity[b] Element	Variation of Element (%)
3-13	$S_{1,1}$	171	15-16	$S_{18,28}$	10	6-11	$S_{10,32}$	122	16-17	$S_{16,16}$	28
3-13	$S_{1,2}$	170	15-16	$S_{18,19}$	4	6-11	$S_{11,32}$	95	16-17	$S_{16,23}$	28
3-13	$S_{1,3}$	173				6-11	$S_{12,32}$	81	16-17	$S_{10,32}$	0
16-17	$S_{18,19}$	90									
16-17	$S_{18,21}$	93									

[a] The numbers in this column refer to From and To busses in Figs. 4 and 5.

[b] The subscripts refer to the element position in the sensitivity matrix.

6.5 Voltage Degradation Studies

The sensitivity matrix, S_4, can be used to weight the importance of generators for voltage degradation studies. The concern is to determine which bus j produces the largest change in voltage at bus i. Equation (8) is the matrix equation that relates the change in reactive power to a change of voltage, and Eq. (9) relates the change of reactive power at bus j to the change of voltage at bus i. (The vertical bars signify absolute values.) The partial derivative in Eq. (9) is one of the elements of S_4. The equations are as follows:

$$\Delta|\bar{V}| = S_4 \Delta\bar{Q} \; ; \tag{8}$$

$$\Delta|V_i| = \frac{\partial V_i}{\partial Q_j} \; |\Delta Q_j| \; . \tag{9}$$

Since the change in voltage is dependent both upon the change in reactive power and the elements of S_4, the power of each generator bus must be weighted by the appropriate elements of S_4 to determine which generator failure will produce the largest voltage effect.

This matrix can be used to determine which generator in the system will have the largest effect on the voltage at a nuclear bus by using the following technique:

1. Select the matrix S_4 from the sensitivity code output.
2. If the nuclear bus of interest in the model is bus i, select the row i from the sensitivity matrix.
3. If the generator busses in the system are p, q, and r, select the sensitivity elements S_{ip}, S_{iq}, and S_{ir}.
4. Multiply S_{ip} by the reactive power generated at bus p; multiply S_{iq} by the reactive power generated at bus q; multiply S_{ir} by the reactive power generated at bus r.
5. The largest product of this multiplication will indicate which generator, p, q, or r, when tripped, will have the largest voltage effect on bus i.

The sensitivity matrix S_4 could be a basis for asking more significant questions for SARs. Currently, an applicant is required to make calculations for a simulated failure of the largest generator in the system and to determine the effects on the bus where the proposed nuclear reactor is to be located. Failure of the largest generator, however, would not necessarily produce the largest effect on the bus that is the feeder for the safety equipment in the nuclear plant. The generator to be tripped is selected by applying steps 1 through 5 in the procedure above.

6.6 Recommendations

The establishment of operational security procedures for a power system is probably beneficial to a utility to maintain power to its nuclear plants and to the majority of its customers. Although the stability analysis technique presented in this report could become a useful tool to determine grid security, it is unproved in practice. Because of this, we do not, as yet, recommend that it be included in the NRC licensing procedure. Section 3 of this report addresses the security concept and some of the procedures that we recommend.

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APPENDIX A

LETTER REPORT ON LOSS OF
OFFSITE POWER (June 20, 1978)

OAK RIDGE NATIONAL LABORATORY
OPERATED BY
UNION CARBIDE CORPORATION
NUCLEAR DIVISION

POST OFFICE BOX X
OAK RIDGE, TENNESSEE 37830

June 20, 1978

Director
Division of Operating Reactors
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555

Dear Sir:

Loss of Offsite Power at Nuclear Power Plants

Attached is subject report prepared by F. H. Clark in accordance with our responsibilities under Contract No. 40-544-75, 189 No. B0235.

Sincerely,

L. C. Oakes

pj

Attachment

cc: J. L. Anderson
R. Brodsky, DOE
F. H. Clark
R. G. Fitzpatrick, NRC
H. N. Hill
G. D. McDonald, NRC
F. R. Mynatt
T. W. Reddoch, UT
D. B. Trauger

ATTACHMENT*

Loss of Offsite Power at Nuclear Power Plants

F. H. Clark

Oak Ridge National Laboratory
Oak Ridge, Tennessee 37830

SUMMARY

This note reviews reports of loss of offsite power at nuclear power plants. An attempt is made to classify various aspects of these events as to cause: whether a failure was common mode; whether the emergency on-site power system functioned correctly; or whether the problem was in the external power grid (rather than internal to the plant). A total of 44 events are presented. Some attempt is made to devise rough empirical expectations of loss of offsite power based on this experience.

The note is divided into a main body describing the approach and the results, and a second section containing some of the details of each event.

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*Attachment to letter from L. C. Oakes to Director, DOR, dated June 20, 1978.

APPROACH AND RESULTS

Section 1. Approach

There were four principal sources for discovering the occurrence of a loss of offsite power. They were (1) the selective distribution list of the Nuclear Safety Information Center, (2) the monthly publication of License Event Reports (LERs) and similar reports by the Technical Information Service, (3) the monthly summary of LERs issued by the USNRC, and (4) direct calls from the USNRC when a loss of offsite power was reported to them. The events dealt with are those which appear to involve the complete separation of the plant from offsite electric power sources.

In most instances, the only information available to describe the event is the LER itself. That is often sketchy and incomplete.

In Section 2, we have set out a capsule description of each of the events covered in this report. They are arranged alphabetically by plant name, and, within any plant name, in time order. The first four items presented in those descriptions are objective and unequivocal: plant name, operator name, date of event, reference. Next is a brief description of what happened. Often, on account of the sketchy nature of the description, or because the descriptive report was written before events were well understood, or because we are in no position to ask for clarifying details, these descriptions may be vague, incomplete, or in some error.

Finally, there are four classification items representing our interpretations of the event. These interpretations, it should be emphasized, may have large subjective components. First is the "Location of Deficiency," which was the proximate cause of the loss of offsite power. Did it happen at the "plant" or on the "grid"? For these purposes the plant is the station service and startup transformers and everything on the plant side of them. The grid is the cable connections of the transformers to switchyard, the switchyard, and the transmission system beyond the switchyard. Even if some operational mishap occurred within the plant that led to the opening of breakers in the switchyard with resultant loss of offsite power, that would be listed as grid because the proximate cause was located there.

Second is "Failure Mode." The failures we are talking about are failures of the offsite power supply. This is provided by two or more connections to the power grid. Hence, if both (or all) are unavailable, we are concerned with what kind of failure mode brought that condition about. In fact, virtually all of these failures have been classified (by us) as "Common Mode" or "Single Protection" mode. By Common Mode we mean that some event or condition occurred which substantially increased the probability of or directly caused the failure of each of the offsite power lines. By Single Protection mode we mean that for some reason, generally maintenance, only one offsite power source was available at the time of its loss. In most cases the Common Mode is a direct failure cause.

However, there are six lightning induced losses of offsite power. In three of those cases, a single bolt of lightning caused the loss of offsite power, clearly Common Mode. In three other cases, two separate lightning strokes were required to cause a loss of offsite power. We have recorded those also as Common Mode because the lightning storm itself was a common element, significantly increasing the probability of failure. It would certainly be a tenable point of view to set aside this commonality and consider the failures as independent.

Third is "Emergency Source." If the onsite emergency ac power supply did not function in every way as required, we indicated some kind of malfunction.

Fourth is "Primary Cause." In fact, what is here called Primary Cause is seldom even roughly primary. We have interpreted primary in many cases to be what we felt was of primary concern to the USNRC. For example, every extensive power system failure involving widespread blackouts which we have examined was due to some reasonably discernible cause. However, in every one of these cases we have listed the Primary Cause of the loss of offsite power as the grid disturbance itself. Other things, like personnel or procedural error, may have more basic causes, as we shall observe below, but it is the superficial cause that is listed.

Summary of Results

We have collected references to loss of offsite power at nuclear power plants, affording the following summary information.

Number of Times Nuclear Power Plants Suffered a Complete Loss of Offsite Power

As a result of condition of power grid	28
As a result of condition at nuclear plant	15
For unclassified condition	1
Total	44

Number of Times the Onsite Emergency Power System Operated in a Substandard Fashion When Offsite Power was Unavailable	7

Causes of Losses of Offsite Power

Lightning storm	6
Ice, rain, snow, or wind storm	7
Personnel error	8
Procedural error	3
Equipment malfunction	1
Fire	1
Fault on grid	3
Grid power failure	7
Unknown	8

Failure Modes

Common	35
Single protection	7
Unknown	2

Statistics from which the above numbers were drawn tend to be incomplete for years prior to 1972 and are obviously incomplete for 1978. Therefore, for the sole purpose of computing some empirical expectation values, we have analyzed the data for just the years 1972-77 to arrive at the results below.

For Period 1972-77

Number of Nuclear Plants Experiencing a Complete Loss of Offsite Power

From condition on grid	22
From condition in plant	13
Unknown cause	1
	36

Using information from the September-October issue of *Nuclear Safety* for each of the years 1972-77, we have estimated representative numbers for nuclear plants in operation each of those years, respectively, as 28, 30, 32, 35, 42, 44 -- a total of 211 nuclear plant years. With these numbers for the period 1972-77, we are led to

Expectation Value of Losses of Offsite Power per Nuclear Plant per Year on Account of Condition on the Grid $\frac{22}{211} = 0.10$

Expectation Value of Losses of Offsite Power per Nuclear Plant per Year for all Causes $\frac{36}{211} = 0.17$

The first of these expectation values might be used in assessing system security from grid related happenings. The second expectation value might be used in assessing the number of challenges to the onsite emergency power source.

The collection and classification of many of these events affords a perspective and suggests questions which might be less obvious in the light of the individual events.

The year 1977 showed a very large number of losses of offsite power - 13. By comparison, there were 3 in 1976, 4 in 1975. There was not a correspondingly large, or even comparable, increase in the number of nuclear power plants. Was this, then, a statistical quirk? Was there a change in the reporting requirements that caused a greater number of events to be reported? Has there been a change in the relative security of the electric power grid in some parts of the country?

The number of losses of offsite power associated with faults on the grid, which apparently were not adequately cleared and restored by relaying, is significant. It might justify a review of relaying practices to determine whether any reasonable improvements are possible there.

A significant number (six) of losses of offsite power were due to lightning, and seven more were attributable to other kinds of storm and weather problems.

Some of the Primary Causes of events may bear further study to determine whether there is a more serious underlying cause. Examples of this are (1) Connecticut Yankee, three losses of offsite power attributed to switching procedures; (2) Palisades, four losses of offsite power attributed to deenergizing of "R" bus (for unknown reasons); (3) Turkey Point and St. Lucie (both Florida Power and Light), three, possibly four, widespread power outages with loss of offsite power occurrences, as a result of failure of a single system component (single contingency).

Also worthy of note is the high incidence of Common Mode failures of the offsite power supply. That is, redundancy seems to add very little extra reliability, relatively speaking. The number of times failures have occurred when there was only a single source available, Single Protection, is sufficiently great (13) to suggest that more alertness during maintenance periods may be justified.

Section 2. Description of Events

Plant: Big Rock Point
Operator: Consumers Power
Event: January 25, 1972
Reference: Docket 50155; Date March 3, 1972

On January 24, 1972, there was a heavy rain and snow storm. The following day there were high winds that caused ice-laden transmission lines to sway, moving relative to each other. Numerous faults occurred. The Gaylord (substation) 388 OCB operated twelve times in response to these faults, but on the thirteenth, its trip coil burned out and it failed to operate. Other breakers, operating in consequence of this failure, caused opening of the line which was the primary source of offsite power. Transfer to the alternative source of offsite power was unsuccessful on account of a faulty relay.

The onsite diesel generators came on properly. Offsite power was restored in 49 min.

Location of Deficiency: Grid
Failure Mode: Common
Emergency Source: Functioned
Primary Cause: Ice and rain storm

Plant: Brunswick
Operator: Carolina P&L
Event: March 26, 1975
Reference: Docket 50324; Date April 9, 1975

With one line out for maintenance, a ground fault caused the other line to relay. Power was restored in 4 min.

Location of Deficiency: Grid
Failure Mode: Single protection
Emergency Source: Functioned
Primary Cause: Grid fault

Plant: Calvert Cliffs
Operator: Baltimore Gas and Electric
Event: December 20, 1973
Reference: Docket 50317; Date April 22, 1974

With one transformer out for maintenance, rain led to a ground fault which tripped one offsite power line and to another ground fault which took out the remaining service transformer. All offsite power was lost.

Location of Deficiency: Plant
Failure Mode: Single protection
Emergency Source: Functioned
Primary Cause: Rain

Plant: Connecticut Yankee (Haddam Neck)
Operator: Connecticut Yankee
Event: April 27, 1968
Reference: Docket 50213; Date January 16, 1969

One of two offsite power supply lines was out of service for maintenance. While it was being brought back into service, the switching procedure followed caused the trip of both station transformers. All offsite power was lost. All three emergency diesels were brought on. After 4 min, all three diesels behaved erratically and tripped. The plant was entirely without ac power for a short time until the diesels were returned to operation. The offsite power was unavailable for a total of 25 min.

Location of Deficiency: Plant
Failure Mode: Single protection
Emergency Source: Malfunctioned
Primary Cause: Incorrect procedure

Plant: Connecticut Yankee
Operator: Connecticut Yankee
Event: July 15, 1969
Reference: Docket 50213; Date July 24, 1969

A transformer tripped while 115-kV lines were being switched, causing a loss of offsite power. There was some problem in phasing diesels, but they came on.

Location of Deficiency: Plant
Failure Mode: Common
Emergency Source: Partial malfunction
Primary Cause: Switching procedure

Plant: Connecticut Yankee (Haddam Neck)
Operator: Connecticut Yankee
Event: January 19, 1974
Reference: Docket 50213; Date February 1, 1974

A fault caused both offsite supply lines to relay.

Location of Deficiency: Grid
Failure Mode: Common
Emergency Source: Functioned
Primary Cause: Grid fault

Plant: Connecticut Yankee
Operator: Connecticut Yankee
Event: June 26, 1976
Reference: Docket 50213; Date July 9, 1976

With the reactor shut down for refueling, one offsite power supply line was taken down for testing. When an attempt was made to switch this line back into service, the other offsite power line tripped, causing a complete loss of offsite power. The diesel generators came on as required. With some variation in procedures, the same thing was attempted twice more; and twice more all offsite power was lost and the diesel generators came on. The offsite power outages were for 30, 10, and 10 s, respectively. Subsequently, the circuitry was revised and the condition corrected.

Location of Deficiency: Plant
Failure Mode: Single protection
Emergency Source: Functioned
Primary Cause: Procedure

Plant: Cook
Operator: Indiana and Michigan Power
Event: February 1, 1975
Reference: Docket 50315; Date March 10, 1975

An improperly spliced cable caused the loss of a transformer and offsite power.

Location of Deficiency: Plant
Failure Mode: Common
Emergency Source: Functioned
Primary Cause: Poor splice

Plant: Cook
Operator: Indiana and Michigan Power
Event: September 1, 1977
Reference: Docket 50315; Date September 1, 1977

On September 1, 1977, during a thunderstorm, a lightning strike at 6:57 PM caused a loss of the "normal reserve" source of power. A second lightning strike at 7:06 PM caused a loss of the "normal" source of power, and the emergency onsite diesel generators came on. Offsite power was restored at 8:55 PM.

Location of Deficiency: Grid
Failure Mode: Common (1 storm, 2 lightning strikes)
Emergency Source: Functioned
Primary Cause: Lightning storm

Plant: Cooper
Operator: Nebraska Public Power
Event: February 21, 1976
Reference: Docket 50298; Date March 5, 1976

During a blizzard, a line fault occurred on a 345-kV line. Other 345-kV lines opened as a result of false relaying associated with the fault. All offsite power was lost. The generator tripped on loss of load, and the reactor scrammed. Emergency systems functioned properly.

No indication is given of the duration of the outage.

Location of Deficiency: Grid
Failure Mode: Common
Emergency Source: Functioned
Primary Cause: Probably blizzard

Plant: Farley
Operator: Alabama Power
Event: September 16, 1977
Reference: Docket 50348; Date September 29, 1977

Lightning caused a loss of offsite power.

Location of Deficiency: Grid
Failure Mode: Common
Emergency Source: Functioned
Primary Cause: Lightning

Plant: Ft. Calhoun
Operator: Omaha Public Power
Event: March 13, 1975
Reference: Docket 50285; Date March 17, 1975

A fault caused a transformer to trip off, and all offsite power was lost. One diesel did not automatically close on the bus. An operator closed it on manually.

Location of Deficiency: Plant
Failure Mode: Common
Emergency Source: Partially failed
Primary Cause: Unknown

Plant: Ginna
Operator: Rochester Gas and Electric
Event: October 21, 1973
Reference: Docket 50244; Date October 31, 1973

Relaying on a ground fault caused a loss of one offsite power supply line, and immediately thereafter two others relayed. The fourth (and last) line was out for maintenance. All offsite power was lost.

Location Deficiency: Grid
Failure Mode: Common
Emergency Source: Functioned
Primary Cause: Grid instability

Plant: Hatch
Operator: Georgia Power
Event: September 28, 1977
Reference: Docket 50321; Date October 26, 1977

An arc occurred on a transformer during testing, causing a loss of offsite power.

Location of Deficiency: Plant
Failure Mode: Common
Emergency Source: Functioned
Primary Cause: Unknown

Plant: Humboldt Bay
Operator: Pacific G&E
Event: July 17, 1970
Reference: Docket 50133: Date March 4, 1971

A fault on the grid caused a loss of offsite power for 18 min. As a result of other complications, the system remained shut down for 20.8 d.

Location of Deficiency: Grid
Failure Mode: Common
Emergency Source: Functioned
Primary Cause: Fault in grid

Plant: Humboldt Bay
Operator: Pacific G&E
Event: November 27, 1970
Reference: Docket 50133; Date November 28, 1970

A storm caused a loss of one 115-kV line for 28 h. The other line went down for 14 min--the cause not specified. The onsite power sources functioned properly.

Location of Deficiency: Grid
Failure Mode: Unknown
Emergency Source: Functioned
Primary Cause: Unknown

Plant: Indian Point
Operator: Con Edison
Event: July 20, 1972
Reference: Dockets 50003 and 50247; Date August 18, 1972

At 2:20 PM, a drop of load occurred, lasting 3-4 s. At 3:10 PM, the reactor scrammed on undervoltage. At 3:15 PM, all offsite power was lost. Power was restored at 4:10 PM. This grid disturbance has not been explained.

Location of Deficiency: Grid
Failure Mode: Common
Emergency Source: Functioned
Primary Cause: Grid instability

Plant: Indian Point
Operator: Con Edison
Event: May 6, 1977
Reference: Docket 50286; Date May 29, 1977

Lightning caused a loss of the feeder line to the station service transformer. The diesels came on and assumed a 480-V bus load. The brief loss of power caused a turbine runback to 750 MW.

Location of Deficiency: Grid
Failure Mode: Common
Emergency Source: Functioned
Primary Cause: Lightning

Plant: Indian Point
Operator: Con Edison
Date: July 13, 1977
Reference: First Phase Report, System Blackout and System Restoration July 13-14, 1977, Con Edison, July 26, 1977

Lightning strikes at 8:37 PM and at 8:55 PM on July 13, 1977, caused a loss of four transmission lines and subsequent collapse of the ConEd power grid. The offsite power was lost to Indian Point at about 9:37 PM on July 13 and was restored at about 3:45 AM on July 14. The emergency diesel generator functioned as required.

Location of Deficiency: Grid
Failure Mode: Common (2 lightning strikes, 1 storm)
Emergency Source: Functioned
Primary Cause: Lightning storm

Plant: La Crosse
Operator: Dairyland Power
Event: January 20, 1971
Reference: Docket 1155-100; Date February 10, 1971

Maintenance workers in a substation caused a trip of the 116-kV and 69-kV busses.

Location of Deficiency: Grid
Failure Mode: Common
Emergency Source: Functioned
Primary Cause: Personnel error

Plant: La Crosse
Operator: Dairyland Power
Event: September 17, 1974
Reference: Docket 50409; Date September 18, 1974

A trip of a circuit breaker caused a loss of offsite power. The diesel had operated 10 min previously, was overheated, and would not operate. The offsite power was restored in 2 min.

Location of Deficiency: Unknown
Failure Mode: Common
Emergency Source: Failed
Primary Cause: Unknown

Plant: La Crosse
Operator: Dairyland Power
Event: April 28, 1975
Reference: Docket 50409; Date May 8, 1975

During a maintenance period, vital busses (480 V) were inadvertently isolated from their offsite power source. The emergency source picked up as required. During this operation, a vital switch in the emergency system was partially burned and damaged.

Location of Deficiency: Plant
Failure Mode: Common
Emergency Source: Sustained damage
Primary Cause: Switching error (personnel)

Plant: Millstone
Operator: Northeast Nuclear
Event: August 10, 1976
Reference: Docket 50336; Date September 3, 1976

Salt spray from a hurricane encrusted the switchyard equipment and caused a loss of all offsite power. The power was restored in 21 h.

Location of Deficiency: Grid
Failure Mode: Common
Emergency Source: Functioned
Primary Cause: Storm (hurricane)

Plant: Nine Mile Point
Operator: Niagara Mohawk
Event: November 17, 1973
Reference: Docket 50220; Date November 21, 1973

An employee inadvertently opened a breaker to an offsite supply line when the other offsite supply line was down for maintenance.

Location of Deficiency: Plant
Failure Mode: Single protection
Emergency Source: Functioned
Primary Cause: Personnel error

Plant: Oyster Creek
Operator: Jersey Power and Light
Event: September 8, 1973
Reference: Docket 50219; Date September 8, 1973

A transformer tripped on a switching signal, causing a loss of offsite power. The trip had been set incorrectly since July 30, 1973.

Location of Deficiency: Plant
Failure Mode: Common
Secondary Source: Functioned
Primary Cause: Personnel error

Plant: Palisades
Operator: Consumers Power
Date: September 2, 1971
Reference: Docket 50255; Dates September 9, 1971, and September 29, 1971

A breaker on the "R" bus failed to operate properly during a fault induced by lightning. This led to operation of other breakers (as designed) and a loss of all offsite power. One diesel did not automatically close in on the 2400-V ID bus as required. It was found that this diesel was incorrectly wired, although the wiring diagram was correct. The wiring was corrected.

Location of Deficiency: Grid
Failure Mode: Common
Emergency Source: Malfunctioned
Primary Cause: Lightning

Plant: Palisades
Operator: Consumers Power
Event: October 17, 1974
Reference: Docket 50255; Date November 17, 1974

During testing, a transformer relayed, causing a loss of offsite power. The power was restored in 30 min.

Location of Deficiency: Plant
Failure Mode: Common
Emergency Source: Functioned
Primary Cause: Unknown

Plant: Palisades
Operator: Consumers Power
Event: September 24, 1977
Reference: Docket 50255; Date October 18, 1977

During an electric storm, the "R" bus became deenergized, causing a complete loss of offsite power. The power was restored after 4.75 h. The plant functioned "as designed" during the event.

The exact cause of the loss of electrical power is not known. The "Tech Specs" will be changed to make this type of event a nonviolation.

Location of Deficiency: Grid
Failure Mode: Common
Emergency Source: Functioned
Primary Cause: Possibly lightning storm

Plant: Palisades
Operator: Consumers Power
Event: November 25, 1977
Reference: Docket 50255; Date December 16, 1977

The "R" bus was deenergized, leading to opening of 345-kV breakers and a loss of all offsite power. The emergency diesels functioned as required. The offsite power was restored in 23 h.

Location of Deficiency: Grid
Failure Mode: Common
Emergency Source: Functioned
Primary Cause: Unknown

Plant: Palisades
Operator: Consumers Power
Event: December 11, 1977
Reference: Docket 50255; Date December 21, 1977

The "R" bus became deenergized, causing the offsite power line breakers to trip and the plant to lose offsite power.

Location of Deficiency: Grid
Failure Mode: Common
Emergency Source: Functioned
Primary Cause: Unknown

Plant: Pilgrim
Operator: Boston Edison
Event: April 15, 1974
Reference: Docket 50293; Date May 13, 1974

A lightning strike caused a loss of all offsite power.

Location of Deficiency: Grid
Failure Mode: Common
Emergency Source: Functioned
Primary Cause: Lightning

Plant: Pilgrim
Operator: Boston Edison
Event: May 26, 1974
Reference: Docket 50293; Date June 18, 1974

The busses were "inadvertently deenergized." The power was restored in 2 h.

Location of Deficiency: Plant
Failure Mode: Common
Emergency Source: Functioned
Primary Cause: Personnel error

Plant: Pilgrim
Operator: Boston Edison
Event: May 1, 1977
Reference: Docket 50293; Date June 10, 1977

A forest fire caused a transmission line fault, loss of load, reactor scram, and loss of offsite power.

Location of Deficiency: Grid
Failure Mode: Common
Emergency Source: Functioned
Primary Cause: Forest fire

Plant: Pilgrim
Operator: Boston Edison
Event: May 10, 1977
Reference: Docket 50293; Date June 9, 1977

A snow storm caused a transmission line to relay, resulting in a loss of load, a generator shut down, and a loss of offsite power. The onsite diesels functioned properly. Offsite power was restored in about 9 h 40 min.

Location of Deficiency: Grid
Failure Mode: Common
Emergency Source: Functioned
Primary Cause: Snow storm

Plant: Pilgrim
Operator: Boston Edison
Event: February 6, 1978
Reference: Docket 50293; Date February 22, 1978

Snow-coated insulators caused flashovers, circuit breaker action, and a loss of all transmission lines. The power was out from 9:29 to 10:26 AM.

Location of Deficiency: Grid
Failure Mode: Common
Emergency Source: Functioned
Primary Cause: Snow

Plant: Point Beach
Operator: Wisconsin Electric
Event: October 13, 1973
Reference: Docket 50266; Date March 1, 1974

While one unit transformer was out for maintenance, a lightning mast fell on another transformer, causing a complete loss of offsite power.

Location of Deficiency: Plant
Failure Mode: Single protection
Emergency Source: Functioned
Primary Cause: Mechanical failure

Plant: Quad Cities 2
Operator: Commonwealth Edison
Event: November 6, 1977
Reference: Docket 50265; Date November 7, 1977

A transformer faulted, causing a loss of normal offsite power to Unit 2 and also causing the reactor to trip. During the transient, Unit 1 also tripped for as yet unknown reasons.

Location of Deficiency: Plant
Failure Mode: Unknown
Emergency Source: Functioned
Primary Cause: Unknown

Plant: St. Lucie 1
Operator: Florida Power and Light
Event: May 16, 1977
Reference: Dockets 50250 and 50251; Date July 20, 1977

A spurious reactor trip at Turkey Point led to a power grid disturbance. This caused the voltage at the St. Lucie bus to be so degraded that it transferred to onsite power. Subsequently during recovery operation, a transformer pressure relay failure caused a second system disturbance, which caused a complete loss of offsite power.

Location of Deficiency: Grid
Failure Mode: Common
Emergency Source: Functioned
Primary Cause: Grid failure

Plant: St. Lucie 1
Operator: Florida Power and Light
Event: May 14, 1978
Reference: Power System Disturbance, May 14, 1978, FPL; Date May 25, 1978

Incorrect switching at a substation, along with relays which had been miswired, led to the isolation of the Midway station and a complete loss of offsite power to St. Lucie. The power was restored after 8 min.

Location of Deficiency: Grid
Failure Mode: Common
Emergency Source: Functioned
Primary Cause: Personnel error

Plant: San Onofre
Operator: So. Cal. Edison
Event: June 7, 1973
Reference: Docket 50206; Date July 1973

One transformer was out for maintenance. The control relays had been grounded for a test and were left in that condition. When a motor was turned on, the grounded relays caused a loss of the other transformer. The diesels came on. Diesel 1 failed after 50 min and caused diesel 2 to trip. Diesel 2 was out for 1 min. During that period, there was no ac power.

Location of Deficiency: Plant
Failure Mode: Single protection
Emergency Source: Failed
Primary Cause: Personnel error

Plant: Turkey Point 3
Operator: Florida Power and Light
Event: April 3, 1973
Reference: Dockets 50250 and 50251; Date September 26, 1974

A spurious trip of the Turkey Point 3 reactor led to a loss of electric power to much of southern Florida and a loss of offsite power at Turkey Point.

Location of Deficiency: Grid
Failure Mode: Common
Emergency Source: Functioned
Primary Cause: Grid failure

Plant: Turkey Point 3
Operator: Florida Power and Light
Event: April 4, 1973
Reference: Dockets 50250 and 50251; Date September 26, 1974

Events substantially identical to the preceding report occurred again.

Location of Deficiency: Grid
Failure Mode: Common
Emergency Source: Functioned
Primary Cause: Grid failure

Plant: Turkey Point 3 and 4
Operator: Florida Power and Light
Event: April 25, 1974
Reference: Dockets 50250 and 50251; Date September 26, 1974

Personnel performing maintenance on a startup transformer lockout relay reset the system incorrectly, energizing units 3 and 4 generator breakers. Both units tripped. A power system disturbance resulted, causing isolation of peninsular Florida and a loss of offsite power to Turkey Point 3 and 4.

Location of Deficiency: Grid
Failure Mode: Common
Emergency Source: Functioned
Primary Cause: Gri instability caused by personnel error

Plant: Turkey Point 3 and 4
Operator: Florida Power and Light
Event: May 16, 1977
Reference: Dockets 50250 and 50251; Date July 20, 1977

While Turkey Point 4 and a major transmission line were out of service, a spurious signal caused the trip of Turkey Point 3. This, with events in the next 16 min, led to a system disturbance which caused a loss of power to southeast Florida and a complete loss of offsite power to Turkey Point. The power was restored in about 90 min. Almost immediately, during recovery operations, a transformer pressure relay failed, causing a second system disturbance with a complete loss of offsite power.

Location of Deficiency: Grid
Failure Mode: Common
Emergency Source: Functioned
Primary Cause: Grid failure

APPENDIX B

LETTER REPORT ON TRANSMISSION

SYSTEM DISTURBANCE AT FLORIDA POWER
AND LIGHT May 16, 1977, AND AT CONSOLIDATED
EDISON July 13, 1977 (April 11, 1978)

OAK RIDGE NATIONAL LABORATORY
OPERATED BY
UNION CARBIDE CORPORATION
NUCLEAR DIVISION

POST OFFICE BOX X
OAK RIDGE, TENNESSEE 37830

April 11, 1978

Director
Division of Operating Reactors
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555

Dear Sir:

Transmission System Disturbances: Florida Power and Light, May 16, 1977; Con Edison, July 13, 1977

Pursuant to our responsibilities under Contract No. 40-544-75, we have reviewed reports of events related to power system disturbances in the Miami area on May 16, 1977, and in the New York City area on July 13-14, 1977. A report of our conclusions is enclosed.

Sincerely,

L. C. Oakes

pj

Enclosure

cc: R. Brodsky, DOE
F. H. Clark
S. J. Ditto
H. N. Hill
G. D. McDonald, NRC
F. R. Mynatt
D. B. Trauger

TRANSMISSION SYSTEM DISTURBANCES: FLORIDA POWER AND LIGHT, MAY 16, 1977; CON EDISON, JULY 13, 1977

F. H. Clark
Oak Ridge National Laboratory
Oak Ridge, Tennessee 37830

We have made a limited review of power system disturbances which occurred in the Florida Power and Light (FPL) system May 16, 1977, and the Con Edison (ConEd) system July 13, 1977. The review is limited in that our primary objective is to determine whether conditions and practices prevailing at the time of the disturbance were consistent with the safe operation of nuclear reactors. We feel it is useful to report on these two events together on account of some mutual insights they provide.

In reviewing the system blackouts it is not our intention to reproduce the detail already reported by ConEd, FPL, NRC, FPC, and others, but simply to highlight that part of it (with references) that appears essential to our review responsibility.

ConEd System Disturbance, July 13, 1977

At the time of the disturbance which occurred in the ConEd system on July 13, 1977, there was a lightning storm in Westchester County. The ConEd system load was about 5800 MW, of which about 3200 MW were generated in New York City and the remainder at ConEd and other system facilities outside the city. One major in-city generator was out of service (600 MW Astoria 6, owned by PASNY), and one major tie line was out of service (345 kV line joining the ConEd Farragut substation in Brooklyn with the Public Service Electric and Gas, Hudson substation in New Jersey).[1]

At 8:37 PM a lightning stroke on a transmission tower carrying two 345-kV feeder lines (W97 and W98) caused these lines to relay open between Millwood West and Buchanan South substations. An incorrectly designed relay circuit then caused the 345-kV feeder Y88 to open between Buchanan South and Ladentown. None of these lines was brought back into service by relay reclosure. The loss of lines W97 and W98 caused the isolation of Indian Point 3, which shut down as required. A second lightning strike at about 8:56 PM on a tower carrying two 345-kV feeders, W99 between Millwood West and Sprain Brook, and W93 between Buchanan North and Sprain Brook, caused both of these lines to relay open. The relays on W99 reclosed at both ends, but W93 remained open at one end (on account of a relay setting). These last two trips, along with a damaged relay at the Millwood West substation, caused feeder W81 to trip almost immediately. At 9:19 PM, the 345-kV line W92 from Leeds substation to Pleasant Valley substation tripped on account of a fault. It is believed this fault was caused by operating the line overloaded for 23 min. This cut the last 345-kV tie to the north and west. Seconds later, the transformer at

Pleasant Valley between the 138-kV and the 345-kV systems tripped, further burdening the remaining transmission. (By this time, transmission facilities for about 2800 MW had been lost and had largely been compensated by drawing on other ties, bringing additional generation on, and decreasing the load by reducing the voltage.) At 9:22 PM, the Long Island Lighting Co. opened its tie to ConEd to protect its system. The phase angle regulator at the Goethals substation failed at 9:29 PM. This left the 138-kV feeders 11 and 16 at Pleasant Valley as the only remaining ties to the outside. These two lines tripped on the overload. The available generation within the system was insufficient for the demand, and automatic load shedding controls were actuated as the frequency dropped. The actual load shedding did not suitably match the real and reactive loads, and the voltages increased excessively. The residual generation system was unable to settle into a stable configuration, and the system blacked out at 9:36 PM.[2,3]

During the period from 8:37 PM, when the first lightning strike occurred, until the system shut down, the record of activity in the Control Center reveals a number of things. The system was not sufficiently well telemetered to afford the Control Center a correct and timely picture of its condition -- whether lines were in or out, energized or not. There was not an accurate record of available generation. Load shedding was not undertaken at about 8:55 PM when suggested by the New York Power Pool; at 9:11 PM, the voltage was reduced 5%, at 9:17, 8%; at 9:22 an attempt was made, unsuccessfully, to shed load manually.[3] Although a great effort was made to supply the power deficiency from other transmission ties and local generation, the effort was ultimately unavailing.

Shortly after 10:00 PM on July 13, an attempt was made at rapid restoration of service. Within a short time it was apparent that the attempt had failed, and a plan was devised to sectionalize the system and proceed with restoration, part by part. Implementation of the plan was begun at about 11:00 PM on July 13 and was substantially complete 24 h later.

Specifically Nuclear Considerations -- ConEd

Some of the events that occurred during this disturbance that had specific implications for nuclear systems were as follows.

The loss of both transmission lines connecting Indian Point 3 to the system required Indian Point 3 to shut down. The shutdown was accomplished without error.

At the time of the Indian Point 3 shutdown, there were two 480-V emergency and four 6.9-kV nonemergency busses which had been supplied from the IP-3 generator. The automatic transfer circuit sensed the available offsite power and determined that it was not of sufficient quality to merit transfer. The emergency diesels were, therefore, brought in automatically and functioned as required. Two other 480-V emergency busses which had been continuously on the offsite power supply remained attached during this period, indicating a difference in the transfer sensing circuits of these two busses and the others. When the system blacked out, these busses transferred properly to emergency diesel generators. (Subsequently, a design error was found in the transfer circuit and corrected.)[4]

The restoration of power under the sectionalized system plan was initiated at about 11:00 PM on July 13. Offsite power was restored to Indian Point at 3:43 AM on July 14. A badly damaged transformer at the Buchanan substation prevented earlier restoration to Indian Point.

Principal Conclusions -- ConEd

1. The ConEd system is much more heavily dependent on bulk transmission than most systems. Much of the generation equipment which supplies the system is distant from its customer service area. This is in part, at least, a demographic necessity on account of the very high concentration of population and activities in New York City and its environs. It is in part due to decisions of various regulatory bodies. The underground transmission system, also made necessary by high population densities, provides special problems of stability in dynamic situations on account of its very high capacitance and also presents severe problems of power restoration on account of the need for electrically powered pumps to provide pressurization. These characteristics of the system make it especially vulnerable to conditions of the sort faced on July 13, 1977.

2. It is apparent that the system was able to replace the capacity lost in the first lightning stroke and was in no serious trouble as a result of it. After the second stroke, the system entered an unsettled condition, from which it did not recover. It seems fair to conclude that the dicta of GDC 17 were met; it required the loss of at least two major facilities to bring the system down.

3. Reclosing of relays is a recognized defense against the crippling effects of lightning. With one exception, the major lines lost during the period prior to system blackout were not brought back into service by relay action for a number of reasons. Some of the relays did not function properly; some functioned as set, but the setting precluded the kind of action needed.

4. ConEd, at the time the lightning strokes began, was required (by NYPP) to have a 10-min response reserve of 292 MW. In fact, it had a reserve of 397 MW (105 MW more than required).

5. The ConEd reports on equipment availability at the Control Center showed 738 MW of 10-min availability generation. Even though the amount actually available, 397 MW, was 105 MW more than the required amount (292 MW), the fact that the reported availability was overstated by 341 MW seriously misled the system operator.

6. Important conditions in the transmission system (e.g., open lines) were not clearly indicated at the Control Center.

7. There did not appear to be an orderly procedure for dealing with emergency conditions at the Control Center.

8. The automatic load shedding equipment, activated by underfrequency, was not programmed to bring the system into a stable configuration.

9. The nuclear safety equipment functioned as required when the offsite power was lost, and Indian Point went into shutdown properly. A circuit flaw which did not properly sense and transfer from degraded voltage prior to loss of offsite power was discovered and corrected.

10. A substantial number of corrective measures have been undertaken by ConEd at its own behest and at the direction of regulatory bodies.

The FPL System
Disturbance of May 16, 1977

Although there have been two reports from FPL on the May 16, 1977, disturbance, and further questions and answers, there still remains some substantial uncertainty as to the events which caused this disturbance.

There were two major facilities unavailable on May 16. Turkey Point 4 (681 MW nuclear) had gone down for refueling on May 9. On the evening of May 15, the 500-kV, Orange River-Andytown transmission line was taken out of service for maintenance and recalibration. There were other smaller equipment items out for service--as might normally be expected. Prior to the beginning of the disturbance, the FPL load was 4660 MW and the generation was 4710 MW (real); in the South (Miami area), the load was 2560 MW and the generation was 1668 MW (real). The spinning reserve was 400 MW. Allegedly, there was a reserve of 1571 MW in fast start, but, in view of the failure to bring gas turbines on line, this number is questionable.[5]

At 10:08 AM, chattering relay contacts led to a false relay operation and a turbine and reactor trip at Turkey Point 3. This took 684 MW (TP3 output) off line. During the next few minutes, a number of lines relayed, including those that connect peninsular Florida to the mainland, the system frequency dropped, and the Port Everglades Unit 2 tripped. By 10:14 AM, system frequency was back to 60 Hz and ties had been restored to the mainland.

The system, however, remained highly unsettled. Voltage in the Miami area was reported to be 95% of normal. Lauderdale gas turbines could not be automatically synchronized to the line at 10:20 AM because the voltage at that time was 11.5 kV, or 87% of normal. From about 10:18 to 10:20, charts show violent swings of VARs at Big Bend 1 and 2.

The preliminary report[6] gives the following chronology of events at St. Lucie. (It cautions that the times given are uncertain, but subsequent and final reports have not presented a corrected table. Worthy of special note is the entry of 10:23. The Ft. Myers-Ranch separation occurred at 10:24.)

Initial Condition:

"790 MW Gross
210 MVARs
238 kV

"10:08 Load spiked up to 868, down to 738, then returned to about 790 MW. Voltage swing 245 to 212, leveled at 229 kV.

"10:10 Voltage decay to 220 kV. Machine reactive increase to 570 MVARs. Phase amps 27.2, 27.5, 27.5 mas. rating 26.0. Reactive increased to 700 MVAR.

"10:17 Voltage reduced to 219 kV to reduce reactive from 740 to 600.

"10:20 Reduced reactive from 600 to 550 MVARs.

"10:23 Load increased to 850 MW, then dropped to zero.

"10:24 Tripped reactor manually, which then tripped the turbine which gave gen. trip and lockout. Voltage stabilized at 237 kV."

The Alarm/Operations Log[7] records the following swings in St. Lucie voltage:

10:16:14	219 kV
10:19:59	normal
10:20:14	219 kV
10:20:30	normal
10:20:44	219 kV
10:20:59	normal
10:21:13	219 kV
10:21:29	normal
10:21:44	219 kV
10:22:14	normal
10:23:29	219 kV
10:23:44	normal

During this period, the system operator was attempting to hold the St. Lucie voltage at 219 kV to reduce VAR generation. It is possible, therefore, that the above log record is a relatively small amplitude oscillation. In any event, more information concerning it is necessary.

The final report has the following to say about conditions at St. Lucie.

Page 2: "Approximately four seconds after 10:24 a.m. St. Lucie Unit 1 was tripped manually following a load rejection due to high frequency. Prior to this time the St. Lucie operator had reported low system voltage, and excessive reactive and armature current on the unit."

Pages 3-4: "The St. Lucie operator reported low system voltage, excessive reactive on the unit and excessive armature current. The unit was operating in excess of its rated capacity of 1000 MVA. Relief was needed or the unit would have to be removed from service. System voltage had dropped to 230 kV from a normal of 238 kV. Reactive loading was 700 MVARS. Armature current was 27,000 amps on a maximum rating of 26,000."

Page 5: "The St. Lucie Unit 1 load spiked from 790 MW to 850 MW just prior to the transmission line separation south of the St. Lucie Plant. The frequency then went high when the transmission lines opened to the south. Governor action decreased the load rapidly. Approximately four seconds later, St. Lucie Unit 1 reactor was tripped manually following load rejection to about 100 MW."

The above description, especially that from the final report, is imprecise as to time sequence and vague in description. We assume from content that "load rejection" means shutting down the turbine, although confirmation of this interpretation is desirable. We would like to see time traces of the load during the last minute of operation. The preliminary and final reports may be in some disagreement on the question of which came first, the load rejection or the trip of the Ft. Myers-Ranch line, although this, too, is vague. There seems to be agreement in the two reports that the spike in the St. Lucie load up to 850 MW occurred immediately before the opening of the Ft. Myers-Ranch line. No explanation is offered for the spike.

At 10:24 AM, the Ft. Myers-Ranch line relayed open. The system deteriorated rapidly, leading to a blackout in much of southeast Florida. Both the final and the preliminary reports say that this line was carrying 420 MW (its normal maximum rating) during the period 10:08-10:24 AM.

At 11:00 AM, the Orange River-Andytown, 500-kV line was energized. By 12:03 PM, the system service had been largely restored, but a fault pressure relay on a key transformer operated improperly and caused a second collapse of the system. Between 2:00 and 3:00 PM, the system was substantially restored.

Both Turkey Point 3 and 4 and St. Lucie 1 were without offsite power for an extended time (not specified in the reports). Emergency on-site electrical generators functioned as required. Turkey Point 3 was brought on line at 9:18 PM, and St. Lucie 1 at 9:58 PM.

Specifically Nuclear Considerations, FPL

As noted before, the nuclear plants at Turkey Point and at St. Lucie switched satisfactorily to emergency on-site power when offsite power was lost. The account of conditions at St. Lucie between 10:08 and 10:24 AM is still too vague and confused to determine whether conditions there were consonant with good operating practice for a nuclear reactor.

Questions Concerning FPL Blackout

The following questions have occupied much of our study of the FPL blackout.

1. Did the relaying of the Ft. Myers-Ranch line occur substantially as a consequence of system conditions brought about by the Turkey Point 3 trip or did it occur as a result of some independent, coincident event? What were the conditions on that line?

2. What were the voltage, frequency, and generation as a function of time (during this event) at the nuclear power plant busses, St. Lucie especially?

3. Was there adequate prior assessment of the impact of removing Turkey Point 4 and the 500-kV Orange River-Andytown line simultaneously?

4. Have the corrective measures that were promised in the wake of past system disturbances been adequately implemented?

5. Does the transmission system design conform with the requirements of GDC 17 with respect to single contingencies?

6. Do normal operating practices appear to conform with requirements?

7. Are emergency operating practices satisfactory?

Our findings regarding the above questions follow:

1. The first question, concerning whether or not the relaying of the Ft. Myers-Ranch line was independent of the Turkey Point 3 trip,

has received a great deal of attention, probably more than justified. FPL contends that the relaying must have been caused by some additional undetected independent event, probably environmental. We believe that a fair summary of the reasons they advanced for this position is as follows. The line was not substantially overloaded; the system appeared stable; the relaying was brought on by a line-to-ground fault; no evidence had been found on the right of way to suggest that the fault was due to line sag into an object; with the assumed power flow and temperatures, the line sag should be less than 16 ft; the line had a record of 22 relayings in the period from January 1, 1976, to May 16, 1977.

On examining these arguments, we have found the following. We asked for records of the power or current in the line, and we were told that they were not available. To estimate power in the line, we were given five graphs[7] with a time resolution of no better than minutes and crude ink traces of power. It was necessary to read a difference from each of these graphs and sum them. Our estimates of the uncertainties in reading these graphic differences are 40, 60, 45, 65, and 5 MW. One can easily arrive at an estimate of line loading that is 60 MW higher than the FPL estimate. Further, the 420-MW estimate of FPL is real power only, reactive power omitted. Also, any disturbance occupying only a few seconds would not show up in the time resolution of these graphs. The only really firm data we have on the line loading is that the threshold alarm, which is triggered when the power exceeds 418 MW, was activated at 10:10, and the power did not drop below 418 MW thereafter. We think it reasonable to conclude that the power loading of the line was substantially above 420 MVA during the entire period of 10:10-10:24.

The statement that the system appeared stable after 10:14 appears to be based on the following: frequency restored to 60 Hz, lines which had relayed open after 10:08 had reclosed; no more lines relayed (until 10:24); the appearance of the 60-Hz current and the voltage traces in the oscillograms (prior to fault) is uniform. In Figs. 7-9, we have produced the three oscillograms provided us, and these figures do, indeed, reveal a uniform character. Figure 10 is an oscillogram from the ConEd Leeds substation, showing the fault which opened W92 at 9:19 PM on July 13, 1977. Figure 10 has that same reassuring character and appearance, but no one has suggested that the ConEd system was stable at 9:19 PM on July 13, 1977. Although the frequency had recovered and the lines had reclosed by 10:14, there remained the low voltages, the wild swings of reactive power at about 10:20, the inability to synchronize gas turbines, and the events reported at St. Lucie. It would be pointless to digress into a precise definition of "stable." It seems clear that at 10:24 the system was in an unsettled and vulnerable condition. In fact, based on the objective criteria set forth in the recent article in *Spectrum* by Fink and Carlsen, the system was in the emergency state - $(E, \bar{I})$.[8]

Figures 7 and 9 show unmistakably a sudden simultaneous increase in the B- and, with lesser amplitude, the A-phase currents at Ringling (which is a good many miles from Ft. Myers). This is evidently due to a fault -- whether a B-phase-to-ground fault as claimed or some other kind we cannot tell without inspecting transformer couplings, etc., between the oscillogram location and the fault (not yet received). Even a line-to-ground fault does not appear to us to be a compelling argument for an independent cause. This line had apparently been running overloaded for 14 min. We quote from ref. 3, p. 12:

> Feeder 92 from Niagara Mohawk's Leeds Substation to Con Edison's Pleasant Valley Substation, which supplied feeder 80, tripped due to a fault. This fault was not a result of lightning stroke and is believed to have beeen caused by operating feeder 92 above its short time emergency rating for about 23 minutes.

That is, in strikingly similar circumstances, ConEd attributes the occurrence of the line-to-ground fault to line overload, not to an independent, undetected event.

The argument that no evidence of sag into an obstacle was found along the right of way is tempered by other considerations. This is not the only way a fault can occur. No evidence was found of anything at all. The location of the fault has not been found. The right of way is almost 160 km (100 miles) long, most of it through swampland. The right-of-way inspection, we understand, was undertaken partly on foot, partly by helicopter.

The argument that 22 relayings between January 1, 1976, and May 16, 1977, suggest a high probability of line relaying bears examination. The probability is certainly much higher than it should be. A short calculation, assuming all these were independent events, shows that the probability per minute of relaying is about 3×10^{-5}; so for any arbitrary 16-min period (such as 10:08-10:24) the a priori probability of independent relaying would be about 1/2000, which is not a high probability for a coincidence.

All things considered, it is certainly possible that an independent event occurred at 10:24 to trigger the relaying, but we do not think that is suggested by the weight of the evidence.

2. We do not have sufficient information about what occurred at the nuclear sites, St. Lucie in particular. Perhaps we have not asked the questions well. We have a voltage trace at Midway and a frequency trace at Malabar for the time 10:24:01-10:24:17. We have no good data to elucidate the reported voltage drops, excess currents, excess reactive power, and, especially, the real power spike reported at St. Lucie. Without a clearer definition of these events and their time, one can hardly assess the implications of these events to the St. Lucie plant.

3. In reply to our questions about what calculations were made prior to removing Turkey Point 4 and the 500-kV, Orange River-Andytown line from service, it was reported that a Florida Coordinating Group (FCG) calculation had been made of a similar configuration, and it had suggested no stability problems. From the sketchy description provided of the FCG computation, we are of the opinion that it does not adequately bound the conditions of May 16, 1977. The response, in part, says[7]

> The latest FCG study, "Off-Peak Transient Stability Study for 1977," considered the loss of Turkey Point Unit 4 with a fragmented system. This fragmented transmission system simulated the simultaneous removal of three major circuits: the 500 kV Andytown - Orange River circuit (FPL), the Midway - Indiantown 230 kV circuit (FPL), and the Central Florida - Clermont East 230 kV circuit (FPC). System recovery was normal and no load shedding or relay action was observed. There was no reason to believe that the system could not be operated satisfactorily under the May 16, 1977 conditions. In any such tests several key points are examined. These include: did any generator pull out of synchronism, did transmission lines relay, and was any customer load shed?
>
> Indeed, from the events of May 16, 1977, we know that at 10:[illegible] a.m. following the sudden loss of Turkey Point Unit 3, no generator pulled out of synchronism, no transmission lines relayed, and no customer load was shed.

We are puzzled by the latter part of the above quote since, following the TP-3 trip, a Port Everglades generator tripped and transmission lines linking peninsular Florida to the north opened (to be reclosed at 10:14).[5]

There appears to have been no assessment made of the implications of the simultaneous removal of Turkey Point 4 and the Orange River-Andytown line.

4. We have reviewed various documents prepared following past disturbances on the FPL system. Most of the corrective measures undertaken have apparently been substantially implemented. Some exceptions noted are as follows. The 800-MW exchange capability with Southern Co. was not realized by 1976 as projected. This has been attributed to changing load requirements. Nor has an agreement yet been made with Southern Co. for the 500-kV link.[9] A continuous recording, high-speed oscillograph was promised for Turkey Point nuclear units,[10] but we have seen no output from it for the May 16 event. We do not know how effectively it has been emplaced.

5. GDC 17 requires that a system be so designed that under peak stress conditions it will operate reliably unless at least two major components fail. It is our opinion that the FPL system, including all components in operation May 16, 1977, plus Turkey Point 4, plus the 500-kV Orange River-Andytown line, would have been able to withstand the events of May 16 and, therefore, at that level of stress met the design requirements of GDC 17.

6. The following is a quote from Regulatory Guide 1.93

> GDC-17 specifies design requirements, not operating requirements; it therefore does not stipulate operational restrictions on the loss of power sources. Nevertheless, operational restrictions based on the intent of GDC-17 on the loss of power sources have

been included in the Technical Specifications of recently licensed nuclear power plants. Such restrictions are based on the following assumptions:

• The LCO of nuclear power plants is met when all the electric power sources required by GDC-17 are available.

• Under certain conditions, it may be safer to continue operation at full or reduced power for a limited time than to effect an immediate shutdown on the loss of some of the required electric power sources. Such decisions should be based on an evaluation that balances the risks associated with immediate shutdown against those associated with continued operation.

Two major facilities, Turkey Point 4 and the Orange River-Andytown line, were taken out of service. The Ft. Myers-Ranch line, which had a record of unreliability -- 22 relayings since January 1, 1976 -- was in a vital position. The tie lines to Georgia, also of increased importance, had a poor record of reliability. The Florida Public Service Commission reports[11] that these ties relayed 22 times on reactor trips in the period from February 20, 1974, to April 3, 1977, and further states that

> Peninsular Florida will in most instances momentarily separate itself from the United States transmission grid whenever the Florida to Georgia transfer capability is less than the megawatt loading on a generating unit that is tripped off line.

In spite of these circumstances FPL made no evaluation of the effect of taking out these facilities and apparently instituted no special operational precautions. Moreover, it appears that in doing this the system may have come to a condition of less than single-contingency reliability. With all these things considered, we believe that FPL was not in conformance with the Regulatory Guide 1.93 guideline of an "evaluation that balances the risks. ..."

7. Following the trip of Turkey Point 3, gas turbines at Ft. Myers were ordered on line, but the order was not received the first time it was issued. Of twenty available gas turbines at Lauderdale, three were ordered up; these three did not synchronize to the line on account of low line voltage; the system operator was apparently unaware that the low voltage would inhibit synchronization; there is no indication of any attempts at premeditated load shedding during the period 10:08-10:24. The Ft. Myers-Ranch, 240-kV line was apparently loaded above normal rating. From interrogation of FPL, we learned that there were no short-term emergency ratings or other operating guidelines,[7] that apparently there were no instructions to inhibit operating personnel from loading the line to any level for any length of time. The St. Lucie generator was operating at a point exceeding its rated armature current, exceeding its rated VAR loading and exceeding its rated MVA capacity. We do not know if there were any short-term emergency guidelines affecting these quantities.

By and large, we believe the actions and procedures during emergency periods should be improved.

General Recommendations

1. Our most important recommendation, we believe, is that, under certain well-defined and predefined conditions, a power system shall be declared to be in some class of alert, and that for each such class there be well-defined procedures to mandate or to guide the actions of the operating personnel.

ConEd, for example, has, since its July 1977 blackout, instituted a storm watch which causes a number of precautions to be undertaken on certain weather reports. Under the storm watch, ConEd survived a severe storm and multiple lightning strikes in September 1977 without significant interruption of service.

The ConEd storm watch is expensive, and we would not recommend that it be adopted at minimal levels of alert. There should be a group of procedures appropriate to the threat at each level.

There are several reasons for having alerts and alert procedures:

1. Operating personnel may face a psychological problem in recognizing or admitting that preconditions to a possible emergency exist. But if a system of criteria and alarms insists that a possible emergency does exist, the problem is dealt with.
2. Since people do not necessarily function well under emergency stress, it should be helpful to have instructions and checklists to apply in appropriate situations. This can be especially true when the indicated remedy is something traditionally repugnant, such as load shedding.
3. If the situation should reach the final stages close to islanding, it is essential that all possible early corrective measures be completed.
4. All indications are that power system design is adequate to deal with anticipated stress, but that unconstrained methods of operation can sometimes bring systems to distress.

Some of the causes which might place a system in an alert condition of some class are the following: planned outage of significant components, extended severe weather spells which strain the capacity over an extended area, impending storms, fires, floods, sudden loss of components, or sudden misbehavior of state variables for no known reason. Evidently, some of the these situations could be dealt with in a fairly leisurely way with policies affecting actions in a number of departments. Others would require frantic activity, generally within the Control Center.

To minimize the possibility of missing a serious real threat, it is necessary to react to many appearances of potential threats, i.e., false alarms. Hence, the low-level alert response should incur a low cost or no cost and should involve no inconvenience to the customers. Few customers would object to loss of service for 20 min in half of New York City to avoid the July 13 blackout. But there would be many objections to such an interruption every 2 weeks brought on by false alarms.

Some of the practical actions that might have been taken in the FPL, May 16 situation -- though we are not necessarily sure they were possible -- are as follows. A prior assessment of possible impacts of the Turkey Point 4 and Orange River-Andytown shutdown might have caused the service work on the line to have been scheduled prior to May 9; it might have led to a maintenance arrangement with the crew in radio contact who possibly could have reenergized the line in a few minutes; or it might have caused the Lauderdale gas turbines to be on line during the few days the line was down. Or, with the situation actually existing, an automatic command to shed load in the Miami area at 10:20 when the voltages were so poor might have retrieved the situation. At least this kind of precautionary or emergency activity could be made quite practicable.

The listing and the definition of the alert states and the prescription of required remedies during any alert condition are best left to the utility itself, which should know the most about it, but subject to guidelines and to final approval by the regulatory body.

We believe that the adoption of alert and emergency procedures such as these would lie well within the present capability of the industry, would be a very low-cost remedy, and would be the most effective means possible of avoiding severe system disturbances.

2. This is really a subpart of the first recommendation, but it is worth separate statement. The Florida Public Service Commission recommends[11]

> Second contingency operation - FP&L should take every step possible to immediately establish spinning reserve in Southeast Florida to cover the next contingency upon occurrence of the first contingency. Such an operating practice may necessitate starting gas turbines whenever a large base load generating unit trips off-line, which will cause some increase in costs.

That is, when generation is lost, try to make it up immediately within the same area. Very likely, all operators try to do that anyway, but the thrust of the recommendation is "Try harder! Call up more gas turbines and diesels sooner!"

3. If a Control Center is to function effectively in an emergency, it is apparent that it must have current information on the state of all major transmission and generation components. This implies more and better telemetering.

4. Daily reports related to equipment availability, disabling of major relays, etc., should be available and current in the Control Center.

5. If, prior to a planned outage of any major component, there does not exist a stability evaluation of a configuration of bounding magnitude, such an evaluation should be required.

GDC 17, Regulatory Guide 1.93, and similar regulations apply to the state or operation of an actual physical system. Determination of whether there is compliance with such regulations is often left to the results of a mathematical calculation which purports to describe the regulated property of the system. The computations now generally available and in use in the industry do not address system instability problems of the kind experience in the ConEd and FPL events. The only widely used computations are "load flow" (steady state) and "transient stability" (2 to 10 s following a disturbance). Development work is now in progress on calculations that, hopefully, would be good for operating periods of 20 to 30 min, but they are not yet reduced to reliable practice. This means that when the stability of a configuration is computed, the most that is determined is whether the configuration would remain stable during the first 10 s following a disturbance. Hence, if transient stability calculations are to be used to determine the state of alertness appropriate to a system configuration (recommendation 1), we recommend that double contingencies be computed and that a computed instability within 10 s on double contingency be interpreted as a probable indication of a long-term instability on single contingency.

6. For load shedding to be a consistently reliable line of defense in extreme circumstances, it is probably necessary to be able to make reasonably accurate adjustments in the load within well-selected geographic limits and also to adjust the system reactance as needed. To do this would require sophisticated telemetering of data and on-line computer control. We believe the industry may be ready to study systems of this sort.

7. When severe power system disturbances occur, it is not uncommon for the affected utility to meet with or report to the appropriate regulatory body and to set forth corrective measures to be undertaken. When this occurs, it appears to us that there is an implied obligation to the public for the regulatory body to follow up and ensure that these measures are taken or that there is a good reason not to; and an equally implied obligation on the part of the utility to report promptly any delays in or departures from these undertakings.

Most of the matters which we have discussed lie within the jurisdictional areas of several government bodies, and in some, the jurisdiction of another agency seems clearer than that of the NRCs. We believe, however, that recommendations (1) and (5) are of immediate importance and availability and that they are within the purview of NRC. We believe they should be generically applied to all nuclear power plant operators but with greater immediacy to those with a history of power system disturbances.

References

1. *First Phase Report - System Blackout and Restoration, July 13-14, 1977*, Con Edison Board of Review, July 26, 1977.

2. *Third Phase Report - System Blackout and Restoration, July 13-14, 1977*, Con Edison Board of Review, December 28, 1977.

3. *Second Phase Report - System Blackout and Restoration, July 13-14, 1977*, Con Edison Board of Review, August 24, 1977.

4. *Preliminary Staff Report on the New York City Power Outage of July 13-14, 1977*, September 12, 1977 (NRC staff).

5. *Report on System Disturbance, May 16, 1977*, Florida Power and Light, June 29, 1977.

6. *Preliminary Report on System Disturbance, May 16, 1977*, Florida Power and Light, May 20, 1977.

7. Responses to questions, letter from Robert Uhrig, FPL, to George Lear, NRC, dated December 14, 1977, Docket 50250, 50251, 50335.

8. L. H. Fink and K. Carlsen, "Operating Under Stress and Strain," *Spectrum*, 48 (March 1978).

9. Stone and Webster, report to Florida Public Service Commission, 1973.

10. *Report on System Disturbance, June 28, 1974*, Florida Power and Light, July 19, 1974.

11. Florida Public Service Commission, Engineering Department, *Final Report on Florida Power and Light, May 16 Blackout*, February 1, 1978.

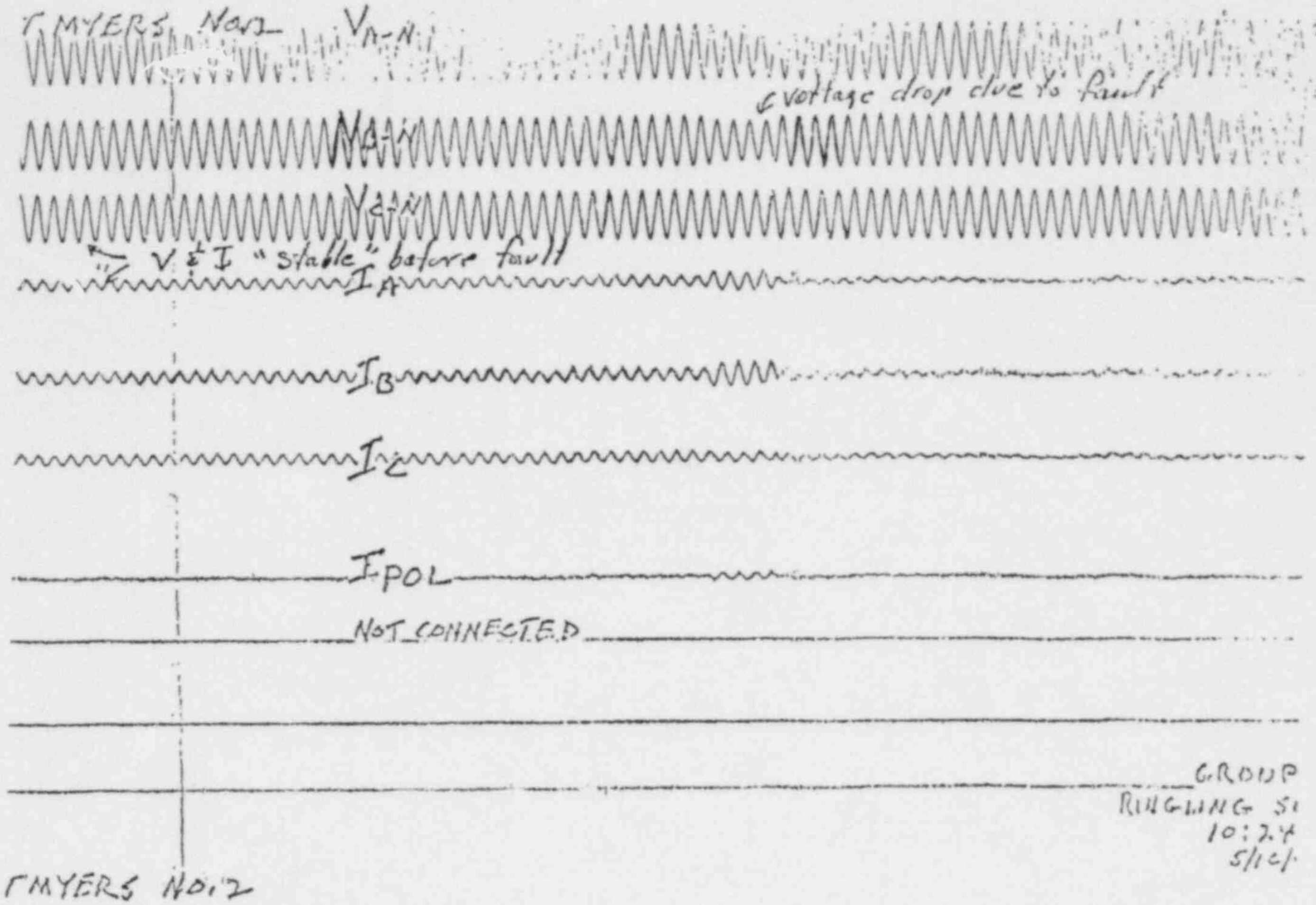

Fig. 7. Ringling substation oscillogram at 10:24 AM on May 16, 1977.

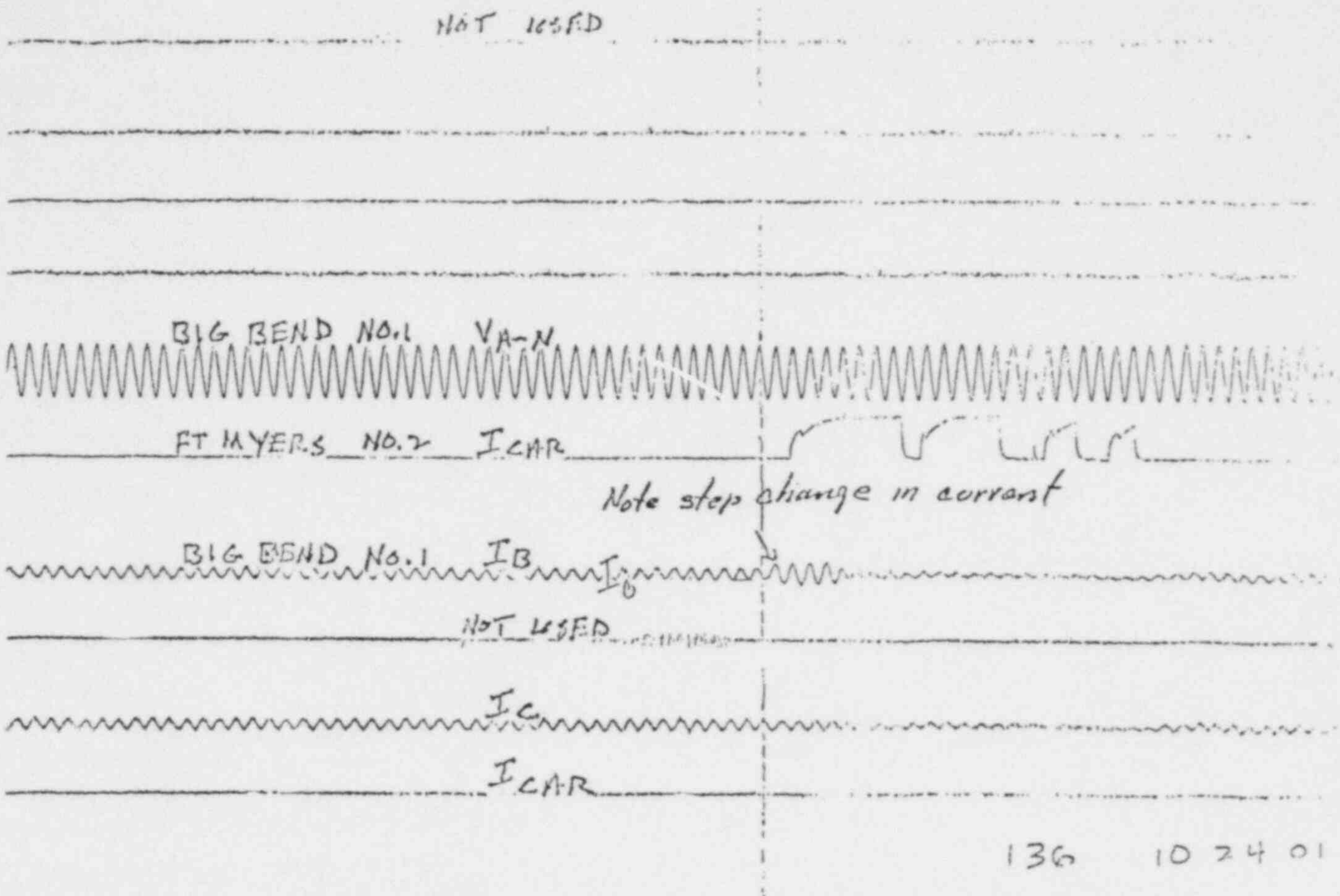

Fig. 8. Ringling substation oscillogram at 10:24 AM on May 16, 1977.

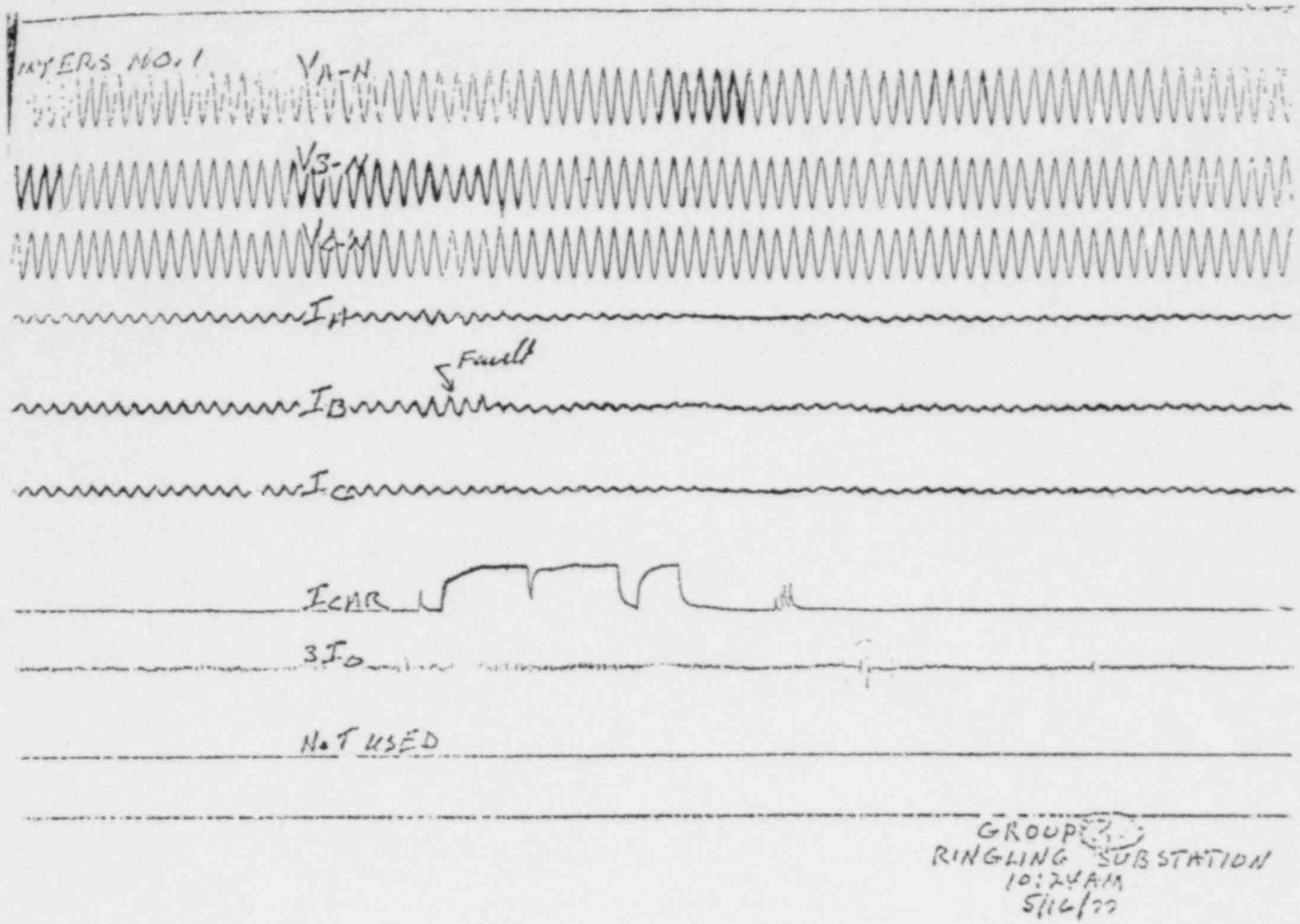

Fig. 9. Ringling substation oscillogram at 10:24 AM on May 16, 1977.

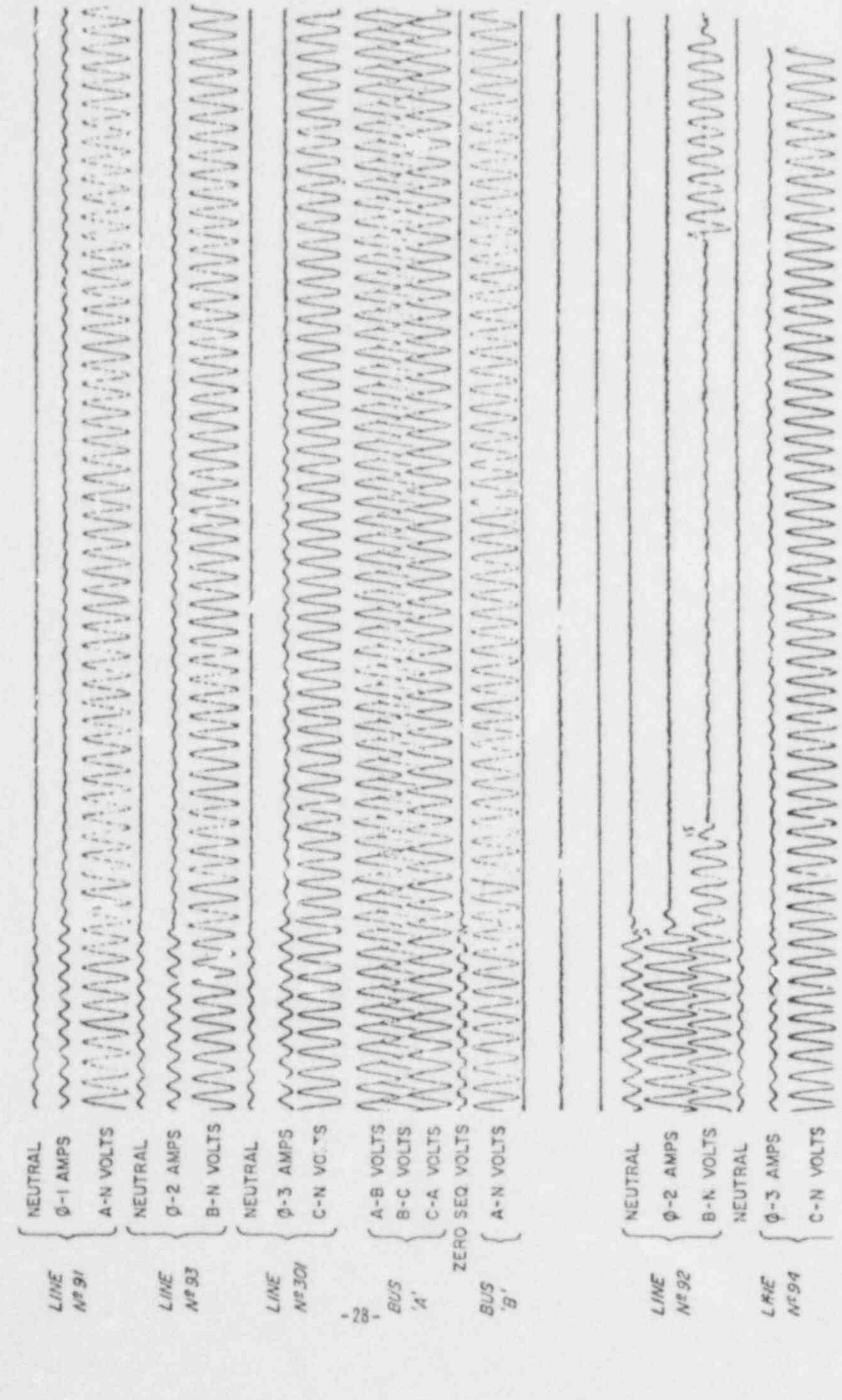

Fig. 10. Leeds substation oscillograph record fault on feeder 92 21:19 hours.

APPENDIX C

SUPPLEMENTARY LETTER REPORT

ON TRANSMISSION SYSTE   DISTURBANCE
AT FLORIDA POWER AND LIG. . May 16, 1977

(May 11, 1978)

OAK RIDGE NATIONAL LABORATORY
OPERATED BY
UNION CARBIDE CORPORATION
NUCLEAR DIVISION

POST OFFICE BOX X
OAK RIDGE, TENNESSEE 37830

May 11, 1978

Director
Division of Operating Reactors
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555

Dear Sir:

Supplement to Transmission System Disturbances:
Florida Power and Light, May 16, 1977; Con Edison, July 13, 1977

Attached is a supplementary report on power system disturbances, specifically the Florida Power and Light system disturbance of May 16, 1977, prepared under Contract No. 40-544-75, 189 No. B0235.

Sincerely,

L. C. Oakes

pj

Attachment

cc: R. Brodsky, DOE
F. H. Clark
S. J. Ditto
H. N. Hill
G. D. McDonald, NRC
F. R. Mynatt
D. B. Trauger

Attachment*

SUPPLEMENT TO
TRANSMISSION SYSTEM DISTURBANCES:
FLORIDA POWER AND LIGHT, MAY 16, 1977;
CON EDISON, JULY 13, 1977
(SUBMITTED APRIL 11, 1978)

F. H. Clark
Oak Ridge National Laboratory
Oak Ridge, Tennessee 37830

This supplement has been made necessary by two circumstances: (1) there were too many uncertainties at the time the April 11 report was written concerning conditions at St. Lucie on May 16, 1977, and (2) additional information concerning the May 16, 1977, event has been received -- written responses to questions by Florida Power and Light dated April 4, 1978,[1] oral responses to questions put to Florida Power and Light at a meeting at St. Lucie Nuclear Plant April 24, 1978, affidavit of Ernest L. Bivans, Vice-President, FPL.[2]

This supplement deals with the conditions at St. Lucie, May 16, 1977, comments on the additional information supplied, and offers some clarification of the April 11 report.

The conditions reported at St. Lucie which had caused us confusion were the following:

1. LER[3] dated June 16, 1977, reported loss of off-site power but did not indicate that on-site diesels came on.

2. Both preliminary[4] and final[5] reports of the system disturbance appeared to suggest that a load spike at St. Lucie of unspecified magnitude and duration may have immediately preceded the relaying operations that led to final system collapse (at 10:24).

3. The final report[5] attributed to governor action the unloading of the turbine (at St. Lucie) at a rate which appeared to be considerably greater than the rates at which governors can operate.

4. Various electrical parameters at St. Lucie exceeded ratings[4,5] (and were so reported). Further elucidation of these matters appeared necessary.

5. The system was manually scrammed by the operator.[6] Further review of this appeared worthwhile.

---

*Attachment to letter from L. C. Oakes to Director, DOR, dated May 11, 1978.

We report the following findings concerning St. Lucie on May 16, 1977:

1. Emergency on-site diesels came on twice as required at St. Lucie on May 16, 1977 (ref. 2, p. 11). The first time from 10:38 AM until about 11:00 AM, a period during which voltage was available at the bus but was degraded. The off-site power was lost at 12:03 PM for 17 min as a result of the loss of the Andytown transformer and consequent system disturbance. The on-site diesels came on as required (although it was not so reported in ref. 3). We conclude that the on-site emergency electrical systems functioned properly.

2. The power spikes alluded to in refs. 4 and 5, occurring at approximately 10:08 AM and around 10:23 or 10:24 AM, were, according to the operator who observed them, sharp and of short duration, less than a second. Evidently a pulse of such short duration would not have its origin in either the external load demand or the reactor heat supply, both of which are coupled into the electrical generators by substantially longer time constants. Moreover, questioning of operating personnel made it clear that there was no independent means of determining the time of these pulses to the precision that would be necessary to fix their time order with respect to events occurring almost simultaneously in other parts of the grid. It appears that the most reasonable explanation by far for these pulses is that they are associated with voltage pulses brought on by sudden disturbances, like line relaying, in other parts of the grid. We conclude that these pulses are of no particular significance to the safe operation of the reactor.

3. Operating personnel at St. Lucie explained that the turbine runback attributed to governor action[4,5] was, in fact, due to the operation of the fast intercept valve which responds to an excessive power generation signal and closes in about 0.5 s. This explanation cleared up the question and is consistent with ref. 6, p. 10.2.1.

4. The description of St. Lucie electrical system parameters on May 16, 1977, as contained in refs. 4 and 5 was confirmed by the operating personnel as substantially correct, subject to the modifications already noted. It was further reported by them that during the period after a component-related parameter exceeds its normal range and prior to the action of automatic protective mechanisms, operating personnel bear the responsibility for decisions to protect the equipment. In fact, during the period 10:08-10:16 AM, MVA and phase currents exceeded normal limits; and the operating personnel intervened at about 10:16 AM to reduce voltage, bringing these parameters back within normal rating. Parameters had not at this point come to the place where automatic action would be taken, and the action of the operating personnel had brought the parameters back to acceptable ranges. We accept this explanation as satisfactory.

5. At 10:24 AM, immediately following the turbine runback (caused by the automatically actuated intercept valve closure -- see 3 above), the reactor operator manually scrammed the reactor. We think it appropriate to determine whether there should have been an automatic scram signal. The intercept valve action without scram signal is consistent with descriptions in ref. 6, Sects. 10.2.1 and 15.2.1-5. A scram signal, if needed, would be generated as a reactor coolant pressure scram signal.

6. Ref 7, Sect. 15.2.7 shows that within 9.5 s following the valve action the coolant pressure scram signal would be generated and the reactor would shut down properly. We conclude that the system for scramming the reactor was appropriate and that the operator intervention, while prudent under these extraordinary circumstances, was not strictly necessary.

Our overall assessment of conditions at St. Lucie on May 16, 1977, is that, given the circumstances of the severe system disturbance, the plant systems (including the safety systems) and the plant operating personnel performed well.

Comment on April 4, 1978, FPL Response[1] to Request for Additional Information

Oscillograms and associated circuit diagrams were submitted to an expert to determine what conclusions can be drawn from them concerning the nature of the (10:24 AM) fault on the Ft. Myers-Ranch line. There is no question that a fault of some sort occurred on the Ft. Myers-Ranch line at 10:24. Examination of the circuit and oscillogram records may confirm that it was a B-phase-to-ground fault, as suggested by FPL, or the examination might suggest it was some other kind of fault. This, however, is a relatively minor question. The only remaining question of substantial interest concerning the fault is whether it was probably due substantially to the unsettled condition of the grid or to some unrelated, independent, undetected event. These records will shed no further light on that question.

A second item in ref. 1 requiring comment is the reference to the computer study made by the Florida Coordinating Group (FCG). At issue here is whether the existence of this study was a sufficient basis for FPL to assume that with Turkey Point 4 and the Orange River-Andytown line simultaneously out of service the system would have sufficient operational security. That must depend on (1) whether the FCG study can be said to have produced credible results, and (2) whether the case studied appears to have bounded the conditions present on May 16, 1977.

The following are some excerpts of the description of the FCG study taken from ref. 1:

1. The study was made on a load flow and a transient stability code (modified Philadelphia Electric version).

2. The physical case studies included:

   a. The following significant units (among others) were part of the system: Andytown-Orange River, 500-kV line; Crystal River 3; St. Lucie 1; Port Manatee 1.

   b. Assumed not in service were the Andytown-Orange River, 500-kV line; Midway, Indiantown 230-kV line; Central Florida, Clermont East 230-kV line.

   c. The load level chosen was 55% of the 1977 estimate of the summer peak load of each utility. For FPL this was 4634 MW, or almost identically its load at 10:08 AM, May 16, 1977.

   d. Georgia-Florida tie lines were carrying 3 MW out of Florida (virtually zero).

   (There were many other quantities required to define the case, of course. The most important of these still unknown to us is the amount of power flowing on each of the major transmission lines into southern Florida and into Central Florida.)

3. The transient was triggered by assuming that Turkey Point Unit 4 had tripped.

4. Some of the results and conclusions reported are as follows:

   a. A voltage minimum of 0.898 p.u. at St. Lucie is reported, and as low as 0.922 p.u. at other stations.

   b. The import of power from the Georgia tie lines reached 515 MW.

   c. There would be no separation of Peninsular Florida from the north following a loss of this unit.

   d. No transmission line relay operations would occur following a loss of this unit.

The following excerpt relevant to this discussion is taken from Ref. 8.

> (b) Florida to Southern (Georgia) Transmission Line Transfer Capability -- The benefits of increased transmission line transfer capability between Florida and Georgia is a function of the number, forced-outage-rate and size of generating units and of load growth. The benefits decrease as the number of generating units increases; the benefits increase with both increasing unit sizes and forced-outage-rates. Peninsular Florida will in most instances momentarily separate itself from the United States transmission grid whenever the Florida to Georgia transfer capability is less than the

megawatt loading on a generating unit that is tripped off line. Appendix G shows the times that peninsular Florida has electrically isolated itself upon the loss of a large FP&L nuclear unit. (Ed. note: 22 times from February 20, 1974, to April 3, 1977.) In 1959, the largest generating unit in Florida was 165 MW. Today there are nine* generating units in Florida with a net summer rating over 400 MW, the largest being Florida Power Corporation's 816-MW Crystal River No. 3. In 1959, there were one 230-kV, three 115-kV, and one 96-kV transmission lines connecting peninsular Florida with Southern (Georgia). The steady state transfer was 100 to 150 MW, slightly less than the largest generating unit. Today there are nine transmission line interconnections with the Southern Company. In 1981, the steady state transfer capability is planned to increase with the addition of a 230-kV transmission line between peninsula Florida and Southern (Georgia) in the following manner:

PLANNED PENINSULA FLORIDA --
SOUTHERN (GEORGIA) TRANSFER CAPABILITY

Year	From	To	Normal MW
1977	Southern	Florida	300
	Florida	Southern	200
1981	Southern	Florida	1100
	Florida	Southern	800

SOURCE: Southeast Electric Reliability Council, "Coordinated Bulk Power Supply Programs -- 1977-1997."

A 500-kV transmission line will generally increase the above transfer capabilities an additional 1,500 MW. Although the normal tie capability between Florida and Southern is less than the capability of the largest generating unit in Florida, Crystal River No. 3, stability studies indicate that Crystal River No. 3 can be tripped off line without loss of load due to underfrequency relaying. Furthermore, the studies indicate that peninsular Florida will remain

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*Manatee 1 -- 775 MW
Manatee 2 -- 775 MW
St. Lucie 1 -- 802 MW
Turkey Point 3 -- 666 MW
Turkey Point 4 -- 666 MW
Anclote 1 -- 509 MW
Crystal River 2 -- 498 MW
Crystal River 3 -- 816 MW
Northside 3 -- 518 MW

stable and connected to Southern. It should be noted that if electric reliability is to be enhanced by increasing the Florida to Southern (Georgia) transmission line transfer capability, power cannot be imported into Florida on a steady state basis. Actually, to enhance reliability, steady state power should be exported, not imported."

We note the following:

1. The distribution of voltages computed and reported in ref. 1 is generally consistent with the kinds of voltages explicitly reported in refs. 4 and 5, although none is as low as the 87% of normal implied by the failure of the Lauderdale gas turbine to synchronize.

2. Reference 8 indicates that the Georgia tie line will contribute significantly to protection against Florida generation loss only if power is being exported to Georgia during normal operations (thereby permitting a substantial power swing from normal export to maximum import). Hence, a conservative analysis of this tie line would place it initially in the "*import* from Georgia" condition. Initially, the system at a condition of "3 MW export to Georgia" provided no substantial test of the firmness of the Georgia-Florida interconnection.

3. Reference 8 seems to suggest, without clearly stating it, that the Georgia-Florida interconnections will open when the power transfer on them exceeds 400 MW. Reference 1 indicates that, in the study, the power on the Georgia-Florida tie lines reached 515 MW, but no line relayed and the connections between Georgia and Florida remained intact.

4. The conclusions in this study that no lines would relay and that the Georgia-Florida connection would remain intact, along with a similar conclusion in another study alluded to in ref. 8, should be compared with the comment in ref. 8 that "Peninsula Florida will in most instances momentarily separate...when the Florida to Georgia transfer capability is less than the megawatt loading on a generating unit that is tripped off line...." They should be compared with the reality of 22 such separations from February 20, 1974, to April 3, 1977. They should be compared with the further reality that on May 16, 1977, following the 10:08 Turkey Point 3 trip and prior to the 10:24 Ft. Myers-Ranch line relaying, such a separation occurred and lasted for several minutes.

We have been provided only a limited amount of information describing the FCG study and its results. Based on that limited information we cannot conclude that the study made a conservative or a valid appraisal of the system behavior.

The disturbance of May 16, 1977, was much more a problem of south Florida or of south and central Florida than it was of peninsular Florida, although, of course, there was substantial coupling. Let us examine the FCG study from the viewpoint of bounding the conditions in south Florida. The FPL system load in the study was virtually identical in total to the FPL system load at 10:08 AM on May 16, 1977. We do not know how the load was distributed in the study, but let us assume the distribution was comparable. Tripping of Turkey Point 4 in the study can be assumed to be equivalent to tripping of Turkey Point 3 in the event. The outage of the Andytown-Orange River, 500-kV line is an identity in both the study and the event. The outage of the Central Florida-Clermont East 230-kV line in the study has no counterpart in the event, but it is removed so far from south Florida that it probably has little relevance to conditions there. There remains the outage of Turkey Point 4 in the event and of the Midway-Indiantown 230-kV line in the study. Unavailability of Turkey Point 4 caused a loss of generation of about 684 MW within the south Florida area, thereby causing a burden on the transmission lines to bring that much additional power in. The Midway-Indiantown line does not run into south Florida. It is a segment of one of the transmission paths through central Florida. As such, its outage in some degree compromises transmission capability into south Florida. Its capacity is 840 MW,[9] somewhat more than the Turkey Point 4 generating capacity; it is outside of south Florida; and there is a roughly parallel transmission line Midway-Ranch of comparable capacity, 774 MW.[9]

In view of the above and in view of the apparent failure of the study to indicate that a Port Everglades generator would trip and Lauderdale voltages would become dangerously low (as happened following the Turkey Point 3 trip and prior to the opening of the Ft. Myers-Ranch line), we cannot conclude that the FCG study bounded conditions existent in south Florida at 10:08 AM on May 16, 1977.

Other portions of ref. 1 appear to require no comment.

Explanatory Comment

Our report of April 11, 1978, on "Transmission System Disturbances,"[10] in the final paragraph used the words "immediate" and "immediacy." Within the content of the meaning we intended to convey, we would consider action initiated anytime in 1978 as "immediate."

References

1. Letter from Robert E. Uhrig, FPL, to A. Schwencer, USNRC, dated April 4, 1978, re: Request for additional information, Dockets 50250, 50251, 50335.

2. Affidavit before Atomic Safety and Licensing Board, made by Ernest L. Bivans, Vice-President, Florida Power and Light, March 31, 1978, Docket 50389.

3. LER, June 16, 1977, Docket 50335, Loss of off-site power, St. Lucie.

4. Preliminary Report on System Disturbance, May 16, 1977, Florida Power and Light, May 20, 1977.

5. Report on System Disturbance, May 16, 1977, Florida Power and Light, June 29, 1977.

   Enclosure to letter from Robert Uhrig, FPL, to Victor Stello, USNRC, July 20, 1977.

6. Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, LWR Edition, NUREG 75/087, USNRC, (September 1975).

7. St. Lucie No. 1 Final Safety Analysis Report, Docket 50335.

8. Florida Public Service Commission Engineering Department, "Final Report on Southeast Florida's Susceptibility to Blackouts, February 1, 1978." In re: Docket No. 770489-EU (CI). Investigation of the system reliability of Florida Power and Light Company.

9. 1975 Power System Statement from Florida Power and Light to Federal Power Commission.

10. F. H. Clark, Transmission System Disturbances: Florida Power and Light, May 16, 1977; Con Edison, July 13, 1977. Submitted to NRC, April 11, 1978.

APPENDIX D

SUPPLEMENTARY LETTER REPORT

POWER SYSTEM CONTROL CENTERS AROUND THE WORLD - PRACTICES AND TRENDS, JUNE 1978[1]

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[1]Reprinted with permission, from *IEEE SPECTRUM* 15 (6), 46-48 (1978).

I. Power-system control centers around the world—practices and trends

In Service	Company	Computer System and On-Line Func' ns*
June 1969	Michigan Electric Power, Ann Arbor	1 GEPAC 4020 + 1 GEPAC 4060 + 2 GEPAC 4010 + data links to two member companies (AGC, EDC, SM, SA)
June 1970	New England Power Exch., West Springfield, Mass.	1 SIGMA 2 + 1 SIGMA 2 + data links to four satellite computers (AGC, EDC, SM)
July 1970	Pennsylvania-Jersey-Maryland (PJM) Interconnection, Norristown, Pa.	Dual IBM 370/158 + two IBM System 7 + data links to nine pool member locations (AGC, EDC, SM, SA)
Dec. 1970	Central Electricity Generating Board, London, England	Dual ARGUS 500 + data links to seven regional centers (SM, SA, OLF, OSC)
Oct. 1971	Kyushu Electric Power, Fukuoka, Japan	1 TOSBAC 7000/20 + 1 TOSBAC 3000 (AGC†, EDC, AVC, SM, **SA, SBC, SE, OLF**)
Nov. 1971	Houston Lighting & Power,	Duplex SIGMA 5 (AGC, EDC, SBC, SVC, SM, SA, OLF, PLSC)
Mar. 1972	Norwegian Water Resources & Electricity Board, Tokke	1 NORD 1 (AGC, EDC, SE, SA, EC, OLF)
June 1972	New York Power Pool, Albany	Dual IBM 370/155 + dual data links to eight member companies (AGC, EDC, SM, SA)
Oct. 1972	Tohoku Electric Power, Sendai, Japan	1 HITAC 7250 + 2 HIDIC 100 + 1 HIDIC 100 + data link to regional office with 1 HIDIC 500 + 1 HIDIC 100 (AGC†, EDC, SM, **AVC, SA, OLF**)
	Electric Power Utility, Laufenburg, Switzerland	1 IBM 1800 + 1 IBM S/7 (AGC†, SM, SE)
Dec. 1972	Cleveland (Ohio) Electric Illuminating	Dual SIGMA 5 + data links to five P2000 plant computers (AGC, EDC, SBC, SM, OLF, OPF, ASTA, EC, SA, **SE, SVC, ACR**)
Feb. 1973	Kansai Electric Power, Osaka, Japan	1 HITAC 8300 + 1 HIDIC 500 + 1 HIDIC 100 + data link to two IBM 370/158 (AGC†, EDC, SM, SA, OLF)
Mar. 1973	Commonwealth Edison, Chicago, Ill.	Dual SIGMA 5 (AGC, EDC, SM, SA, OLF)
	Tokyo (Japan) Electric Power	Dual TOSBAC 7000/20 + Dual TOSBAC 40C (AGC†, EDC, SM, **SA**)
	General Public Utilities, Reading, Pa.	Dual SIGMA 5 + data links to PJM and three member companies (AGC, EDC, SM)
July 1973	Interbrabant, Schaerbeek, Belgium	1 Westinghouse P2000 + 1 Westinghouse P2500 + 1 Westinghouse P2500 + data link to CPTE (see Apr. 1976) (SBC, SM, SE, SA, OLF, OPF)
	Electricite de France (EDF), National Control Center, Paris	1 CII 9080 + 1 CII 9040 + dta links to five regional control centers (AGC†, SM, SA, SE, OLF)
Sept. 1973	Southern Services, Birmingham, Ala.	Dual IBM 370/158 + 4 ADS 900 + 1 (spare) + video data links to four company dispatch centers and to 13 division control centers (AGC, EDC, SM, **SA, SE, OLF**)
Oct. 1973	American Electric Power, Canton, Ohio	1 IBM 1800 + 3 HP2116B + 1 (spare) + data link to 1 IBM 370/165 (AGC†, EDC, SE, **SA**)
	Philadelphia (Pa.) Electric	Triple Burroughs 6700 + data links to two plant computers and to PJM (AGC, EDC, SM, SA)
Nov. 1973	Hokuriku Electric Power, Toyama, Japan	1 OTSBAC 7000/20 + 1 TOSPAC 3000 + 1 TOSBAC 40 (AGC, EDC, AVC, SE, EC)
May 1974	Pennsylvania Power & Light, Allentown	Dual SIGMA 5 + data links to PJM and to six division offices (AGC, EDC, SBC, SM, SA, **SVC**)
Sept. 1974	Carolina Power & Light, Raleigh, N.C.	Dual SIGMA 5 + 2 GEPAC 3010 (AGC, EDC, SBC, SM, SA)
Dec. 1974	Bonneville Power Administration, Portland, Oreg.	Dual PDP-10 + 2 PDP-11 + 1 PDP-11 + daul GEPAC 4010 + dual GEPAC 3010 + 1 GEPAC 30CS + future dual SEL85 (AGC, SM, SA, SE, **AVC, OLF**)
	Iowa-Illinois Gas & Electric, Davenport, Iowa	Dual SIGMA 5 (AGC, EDC, SBC, SVC, SM, **SA, OLF**)

*On-line functions. (bold face denotes planned functions)

† implemented by analog controller

ACR	= automatic circuit restoration	EDC	= economic dispatch control	SA	= steady-state security analysis
AGC	= automatic generation control	NOX	= minimum NOx emission dispatch	SBC	= supervisory breaker control
ASTA	= automatic system trouble analysis	OLF	= on-line load flow	SE	= state estimation
AVC	= automtic voltage/var control	OPF	= optimum power flow	SM	= security monitoring
DTA	= distribution trouble analysis	OSC	= on-line short circuit	SVC	= supervisory voltage control
EC	= emergency control	PLSC	= pipeline supervising control		

In Service	Company	Computer System and On-Line Functions*
Jan. 1975	Sierra Pacific Power, Reno, Nev.	Dual SLASH/5 (AGC, EDC, SM)
Apr. 1975	City of Gainesville, Fla.	Dual W2500 (AGC, EDC, SBC, SVC, SM)
June 1975	Public Service Electric and Gas, Newark, N.J.	Dual GEPAC 4010 + 1 GE 4050 + data links to PJM (SBC, SVC, SM, SA)
Aug. 1975	Wisconsin Electric Power, Milwaukee	Quad CDC SC-1700 + daul CDC CYBER 72-13 + data link to Wisconsin-Michigan Power (AGC, EDC, SBC, SM, SA, SE, **OLF, OPF**)
	Tennessee Valley Authority, Chattanooga	1 SIGMA 5 + 3 GEPAC + data links to five area dispatch centers (AGC, EDC, SM, **SA, SE, OLF**)
Oct. 1975	Rheinisch-Westfalisches Elektrizitatswerk (REW), Brauweiler, West Germany	Dual SIEMENS 360 (AGC†, SM, SE, SA, OLF, OSC)
	Rhode Island-Eastern Massachusetts-Vermont, Westborough, Mass.	1 GEPAC 4020 + data links to NEPEX (AGC, EDC, SM)
Nov. 1975	Technische Werke der Stadt, Stuttgart, West Germany	1 Siemens 306 + data link to IBM 370 (SBC, SM, SE, SA, OLF)
Dec. 1975	Middle South Services, Pine Bluff, Ark.	Dual SIGMA 5 + data links to three member companies (AGC, EDC, SM, OLF, SA, **OPF**)
	Detroit (Mich.) Edison	Dual SIGMA 5 + data link to Michigan Power (SBC, SVC, SM, **SA, SE, OLF**)
	Ontario Hydro, Toronto Canada	Univac MP 11/42 + 3 NOVA 1200 (AGC, EDC, SM, SE, **SA, OLF**)
In 1976	National Power Administration, Warsaw, Poland	Dual CDC SC-1774 + CDC 3170 (AGC, EDC, SM, **SE, SA, AVC**)
Apr. 1976	Societe pour la Coordination de la Production et du Transport de l'Energie Electrique (CPTE), national dispatching at Linkebeek, Belgium	Dual PDP 11/45 + data links to Charleroi regional dispatching (SM, SBC, SVC)
May 1976	Potomac Electric Power, Washington, D.C.	Dual SIGMA 9 + 4 SPC 16/65 + data link to PJM + data link to IBM 360/65 + video data link to executive office (SBC, SVC, AVC, SM, DTA, **SA, OLF**)
June 1976	Eastern Iowa Light & Power Wilton	Dual PDP 11/35 (AGC, EDC, SBC, SVC, SM)
Dec. 1976	Chubu Electric Power, Nagoya, Japan	TOSBAC 7000/20 + TOSBAC 7000/25 + dual TOSBAC 40-C (AGC, EDC, AVC, SM)
Feb. 1977	Swedish State Power Board, Stockholm	Dual SIGMA 9 + 2 CDC System 17 (SM, **AGC, SA, SE, OLF**)
Apr. 1977	Board of Public Utilities, Kansas City, Kans.	Dual WP 2500 (AGC, EDC, SBC, SM, **SVC**)
May 1977	Utah Power & Light, Salt Lake City	Dual SIGMA 5 (AGC, EDC, SBC, SVC, SM, **SA, SE**)
June 1977	Nova Scotia Power, Halifax, Canada	Dual PDP 11/35 (AGC, SBC, SVC, SM)
	Kansas City (Mo.) Power & Light	Dual CDC System 17 (AGC, EDC, SBC, SM)
Nov. 1977	Corn Belt Power Co-op, Humboult, Iowa	Dual CDC System 17 (AGC, EDC, SBC, SM)
Early 1978	Louisville (Ky.) Gas & Electric	Dual HS 4400 (**AGC, EDC, SBC, SVC, SM**)
	Fuerzas Electricas de Cataluna (FECSA), Barcelona, Spain	Dual GE 4010 + dual interdata 70 (**AGC, EDC, SBC, SVC, SM, OLF**)
	Southern California Edison, Los Angeles	Quad CDC System 17 + dual CYBER 73-16 + data links to eight switching centers + video data link to headquarters office (**AGC, NOX, SM, SA, SE, OLF**)
	Iberduero, Bilbao, Spain	Dual Duplex MODCOMP IV + data links to two regional centers (**AGC, EDC, SM, SE, OLF**)

I. (Continued)

In Service	Company	Computer System and On-Line Functions*
	Jacksonville (Fla.) Electric Authority	Dual PDP 11/40 + data links to distribution center (**AGC, EDC, SBC, SVC, SM**)
Mid-1978	Hidroelectrica Espanola, Madrid, Spain	Dual MODCOMP IV (**AGC, EDC, SBC, SM**)
	Public Service of Oklahoma, Tulsa	Dual MODCOMP IV + data links to two regional offices (**AGC, EDC, SBC, SM**)
	Minnesota Power & Light, Duluth	Dual Xerox 550 (**AGC, EDC, SBC, SVC, SM, SA, OLF**)
	Romergo National Load Dispatching, Bucharest, Romania	Dual SIEMENS 330 + data links to five regional control CENTERS (**EDC, SM, SE, SA**)
	Gas-Elektrizitats-und Wasserwerke (GEW), Cologne, W. Germany	Dual SIEMENS 330 + 1 SIEMENS 330 + data links to one regional control center (**EDC, SM, SE, SA, OLF**)
	Portland (Oreg.) General Electric	Dual MODCOMP IV + video data links to six regional offices (**AGC, SBC, SM**)
	Public Service Company of New Hampshire, Manchester	Dual SEL 32/55 + data links to NEPEX (**AGC, EDC, SBC, SVC, SM, SE, SA, OLF**)
Late 1978	Servicios Electricos del Gran Buenos Aires (SEGBA), Argentina	Dual MODCOMP IV (**SM, SA, SE, OLF, OSC**)
	Virginia Electric & Power, Richmond	Dual Xerox 550 (**AGC, EDC, SM, OLF**)
	Taiwan Power, Taipei	Dual Xerox 550 (**AGC, EDC, SBC, SM, OLF**)
	Northern Indiana Public Service, Hammond	Dual SEL 32/55 (**AGC, EDC, SBC, SVC, SM**)
	Hungarian Electric Power, Budapest	Dual HIDIC-80 (**AGC, EDC, SM, OLF**)
	Florida Power & Light, Miami	Dual CYBER 173-6 + quad CDC System 17 + data links to six remote offices (**AGC, EDC, SBC, SM, SE, SA**)
	Korea Electric, Seoul	Dual LN CP400 (**AGC, EDC, SBC, SM**)
Early 1979	Delmarva Power & Light, Wilmington, Dela.	Dual CYBER 172-4 + quad CDC System 17 (**AGC, EDC, SBC, SM, SE, SA, OPF**)
	Connecticut Valley Electric Exchange System (CONVEX), Berlin, Conn.	Dual PDP11/70 + dual PDP11/34 + data links to NEPEX + data link to IBM 370/165 (**AGC, EDC, SBC, SM, SA, OLF**)
	Electricity Supply Commission of South Africa, Johannesburg	Dual Xerox 550 (**AGC, EDC, SBC, SVC, SM, SA, OLF**)
	Florida Power, St. Petersburg	Dual duplex Xerox 550 + dual LN CP400 + data links to two distribution dispatching offices (**AGC, EDC, SVC, SM, SE, SA, OLF**)
Mid-1979	New England Power Exchange (NEPEX), West Springfield, Mass.	1 IBM 370/148 + 1 IBM S/7 + data links to four satellite computers (**AGC, EDC, SM, SA, OLF**)
	State Electric Commission of Victoria, Melbourne, Australia	Dual SEL 32/55 + dual MAC-16 + data links to two area control centers (**AGC, EDC, SM**)
Late 1979	Agua y Energia Electrica, Buenos Aires, Argentina	Dual SIEMENS 340 + 1 SIEMENS 340 + data links to six regional control centers (**EDC, SM, SE, SA, OLF, OSC**)
	Dayton (Ohio) Power and Light	Dual SEL 32/75 + data links to two companies (**AGC, EDC, SBC, SM, OLF, SE, SA**)
Early 1980	Columbus & Southern Ohio Electric	Quad SLASH/7 (**AGC, EDC, SBC, SVC, SM, SE, SA, OLF**)
	Imatran Voima, Helsinki, Finland	Dual MODCOMP IV + 3 PDP 11/34 + data links to eight district centers (**AGC, EDC, SVC, SM, SE, OLF**)
	Duquesne Light, Pittsburgh, Pa.	Dual SEL 32/75 + data links to distribution control center (**AGC, EDC, NOX, SBC, SVC, SM, SE, OLF**)
Mid-1980	Israel Electric	Dual PDP 11/70 + dual PDP 11/70 + data links to two subsidiary control centers (**AGC, EDC, SBC, SVC, SM, SE, SA, OLF**)
	Italian Electric Power State Board (ENEL), National Control Center, Rome	Dual DEC KL-10 + dual PDP 11/70 + data links to eight area control centers (**AGC, EDC, SM, SE, SA, AVC, EC**)
	Cincinnati (Ohio) Gas & Electric	Dual PDP 11/70 + data links to four remote centers each with PDP 11/34 + data links to two companies (**AGC, EDC, SM, SBC, SM**)
Early 1981	Electricite de France (EDF), National Control Center, Paris	Dual MITRA 125 + third computer + dual Solar 16-40 + data links to seven regional control centers (**AGC, SM, SE, SA**)

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