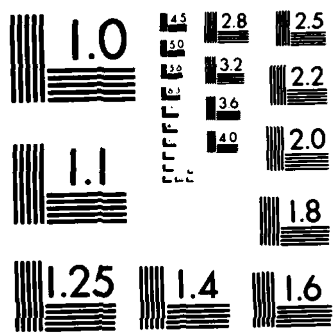
AD-A151 574 AN INTEGRATED REAL-TIME CLOSED-LOOP CONTROLLER FOR NORMAL AND EMERGENCY O..(U) AIR FORCE INST OF TECH WRIGHT-PATTERSON AFB OH P G OSSOWSKI 1984 1/1

UNCLASSIFIED AFIT/CI/NR-85-26T F/G 10/2 NL

END



MICROCOPY RESOLUTION TEST CHART
NATIONAL BUREAU OF STANDARDS 1963 A

UNCLASS

SECURITY CLASSIFICATION OF THIS PAGE (When Data Entered)

REPORT DOCUMENTATION PAGE		READ INSTRUCTIONS BEFORE COMPLETING FORM
1. REPORT NUMBER AFIT/CI/NR 85-26T	2. GOVT ACCESSION NO.	3. RECIPIENT'S CATALOG NUMBER
4. TITLE (and Subtitle) An Integrated Real-Time Closed-Loop Controller For Normal And Emergency Operation Of Electrical Power Systems		5. TYPE OF REPORT & PERIOD COVERED THESIS/DISSERTATION
		6. PERFORMING ORG. REPORT NUMBER
7. AUTHOR(s) Paul Gerard Ossowski		8. CONTRACT OR GRANT NUMBER(s)
9. PERFORMING ORGANIZATION NAME AND ADDRESS AFIT STUDENT AT: University of Washington		10. PROGRAM ELEMENT, PROJECT, TASK AREA & WORK UNIT NUMBERS
11. CONTROLLING OFFICE NAME AND ADDRESS AFIT/NR WPAFB OH 45433		12. REPORT DATE 1984
		13. NUMBER OF PAGES 69
14. MONITORING AGENCY NAME & ADDRESS (if different from Controlling Office)		15. SECURITY CLASS. (of this report) UNCLASS
		15a. DECLASSIFICATION/DOWNGRADING SCHEDULE

16. DISTRIBUTION STATEMENT (of this Report)

APPROVED FOR PUBLIC RELEASE; DISTRIBUTION UNLIMITED

17. DISTRIBUTION STATEMENT (of the abstract entered in Block 20, if different from Report)

18. SUPPLEMENTARY NOTES

APPROVED FOR PUBLIC RELEASE: IAW AFR 190-1

LYNN E. WOLAVER
Dean for Research and Professional Development
AFIT, Wright-Patterson AFB OH

19. KEY WORDS (Continue on reverse side if necessary and identify by block number)

20. ABSTRACT (Continue on reverse side if necessary and identify by block number)

ATTACHED

DD FORM 1473, 1 JAN 73 — EDITION OF 1 NOV 65 IS OBSOLETE

UNCLASS

SECURITY CLASSIFICATION OF THIS PAGE (When Data Entered)

85 03 11 052

University of Washington

Abstract

AN INTEGRATED REAL-TIME CLOSED-LOOP CONTROLLER FOR NORMAL AND EMERGENCY OPERATION OF ELECTRICAL POWER SYSTEMS

by Paul Gerard Ossowski

Chairperson of the Supervisory Committee:
Professor Atteri Kuppurajulu
Department of Electrical Engineering

The development of an IRCC (Integrated Real-time Closed-loop Controller) which performs the functions of Economic Load Dispatch (ELD), Automatic Generation Control (AGC), and overload alleviation is discussed. The objective of the IRCC is to adjust the system variables and Lagrange multipliers so as to satisfy the Kuhn-Tucker conditions of optimality, thereby steering the system to a new optimal operating state. The IRCC performs this task on a real-time basis using SCADA (Supervisory Control And Data Acquisition) measurements. The performance of the IRCC is tested under normal as well as contingency operation by simulating the long-term dynamics of a multi-area power system.

AFIT RESEARCH ASSESSMENT

The purpose of this questionnaire is to ascertain the value and/or contribution of research accomplished by students or faculty of the Air Force Institute of Technology (AU). It would be greatly appreciated if you would complete the following questionnaire and return it to:

AFIT/NR
Wright-Patterson AFB OH 45433

RESEARCH TITLE: An Integrated Real-Time Closed-Loop Controller For Normal And Emergency Operation Of Electrical Power Systems

AUTHOR: Paul Gerard Ossowski

RESEARCH ASSESSMENT QUESTIONS:

1. Did this research contribute to a current Air Force project?

( ) a. YES ( ) b. NO

2. Do you believe this research topic is significant enough that it would have been researched (or contracted) by your organization or another agency if AFIT had not?

( ) a. YES ( ) b. NO

3. The benefits of AFIT research can often be expressed by the equivalent value that your agency achieved/received by virtue of AFIT performing the research. Can you estimate what this research would have cost if it had been accomplished under contract or if it had been done in-house in terms of manpower and/or dollars?

( ) a. MAN-YEARS ________ ( ) b. $________

4. Often it is not possible to attach equivalent dollar values to research, although the results of the research may, in fact, be important. Whether or not you were able to establish an equivalent value for this research (3. above), what is your estimate of its significance?

( ) a. HIGHLY SIGNIFICANT ( ) b. SIGNIFICANT ( ) c. SLIGHTLY SIGNIFICANT ( ) d. OF NO SIGNIFICANCE

5. AFIT welcomes any further comments you may have on the above questions, or any additional details concerning the current application, future potential, or other value of this research. Please use the bottom part of this questionnaire for your statement(s).

NAME GRADE POSITION

ORGANIZATION LOCATION

STATEMENT(s):

An Integrated Real-Time Closed-Loop Controller for Normal and Emergency Operation of Electrical Power Systems

by

Paul Gerard Ossowski

A thesis submitted in partial fulfillment
of the requirements for the degree of

Master of Science
in
Electrical Engineering

University of Washington

1984

Approved by ______________________________

(Chairperson of Supervisory Committee)

Program Authorized
to Offer Degree ELECTRICAL ENGINEERING

Date NOV. 30, 1984

Master's Thesis

University of Washington

Abstract

AN INTEGRATED REAL-TIME CLOSED-LOOP CONTROLLER FOR NORMAL AND EMERGENCY OPERATION OF ELECTRICAL POWER SYSTEMS

by Paul Gerard Ossowski

Chairperson of the Supervisory Committee:
Professor Atteri Kuppurajulu
Department of Electrical Engineering

The development of an IRCC (Integrated Real-time Closed-loop Controller) which performs the functions of Economic Load Dispatch (ELD), Automatic Generation Control (AGC), and overload alleviation is discussed. The objective of the IRCC is to adjust the system variables and Lagrange multipliers so as to satisfy the Kuhn-Tucker conditions of optimality, thereby steering the system to a new optimal operating state. The IRCC performs this task on a real-time basis using SCADA (Supervisory Control And Data Acquisition) measurements. The performance of the IRCC is tested under normal as well as contingency operation by simulating the long-term dynamics of a multi-area power system.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

NOMENCLATURE

P_{Gi} - Generation at the ith bus.

P_{ei} - Electrical output of the generator at the ith bus.

P_{mi} - Mechanical input of the generator at the ith bus.

P_{Gi}^{m} - Lower limit of generation at the ith bus.

P_{Gi}^{M} - Upper limit of the generation at the ith bus.

R_i - Generation ramp rate constraint at the ith bus.

P_{Li} - Load at the ith bus.

p - Total losses in the area.

Pl_j - Flow in the jth line.

Pl_j^{M} - Maximum flow or capacity of the jth line.

C_i - Cost of generation at the ith bus.

C - Sum of the C_i's, total cost of generation.

IC_i - Incremental cost of generation at the ith bus.

X_{ei} - Measure of the main piston position or valve power.

P_{ci} - Control signal issued to the ith bus.

T_{gi} - Governor time constant at the ith bus.

T_{ti} - Turbine time constant at the ith bus.

Ω_i - The generator regulation constant at the ith bus.

σ_i - The load regulation constant at the ith bus.

H_i - The inertia constant at the ith bus.

Ω - Sum of the Ω_i's, total area generator regulation.

σ - Sum of the σ_i's, total area load regulation.

H - Sum of the H_i's, total system inertia.

R_j - Resistance of the jth line.

B_{ij} - Susceptance of the line running from bus i to bus j.

θ_i - Voltage angle at the ith bus.

θ_{ij} - Angular difference between bus i and bus j.

f - System frequency.

B - Area frequency bias parameter.

N - Total number of buses in the area.

L - Total number of lines in the area.

K - Total number of tie lines connected to the area.

Δ - Denotes a change from the nominal value.

h - The Area Control Error, ACE.

ACKNOWLEDGEMENTS

The author wishes to express sincere appreciation to Professor Atteri Kuppurajulu, a distinguished visiting professor from the Indian Institute of Technology, Madras, without whose guidance successful completion of this research would not have been possible. Special thanks also to Professors El-Sharkawi and Venkata for their valuable help and support.

INTRODUCTION

One of the main concerns of the dispatcher of power systems is to ensure that the system is secure, i.e., the load demands are met without unduly stressing the various components or allowing the network variables to stray from prescribed limits. Secure operation is to be ensured not only under normal operating conditions with a slowly changing load profile but also under sudden outage conditions or contingencies. [1,2] Since the likely contingencies that can arise in a system are unknown apriori, one of the possible means to ensure secure operation is to simulate the "next contingency set" and evolve a suitable normal operating state such that even if any of these contingencies arise, the system will remain secure. [3-6,8]

In practice, however, due to various operational limitations, secure operation may not always be possible and major violations of the operational constraints, such as overloading of system components or violations of the network variable limits, may occur. The system is said to be in an emergency state when these operational constraints are violated either due to the occurrence of a sudden contingency or subsequent events, such as tripping of circuit breakers due to loss of stability or frequency. When the system is in an emergency state the main concern is to remove the operational constraints, thereby preventing further cascade tripping. References [3-13,18] are devoted to this problem and suggest various algorithms suitable for use in a real-time computer at the dispatch center.

Unlike these approaches, this paper is devoted to the possibility of synthesizing an Integrated Real-time Closed-loop Controller (IRCC) which performs not only the conventional functions of Economic Load Dispatch (ELD) and Automatic Generation Control (AGC), but also relieves system overloads as they occur, during both normal as well as emergency conditions. Therefore, in the approach presented here, the operational constraints of main concern are the transmission line overload limits, although the generation and generation ramp rate limits are also taken into account.

RECENT RESEARCH

Recently, much research has been conducted in the area of optimal generation reallocation in the emergency state. Some of these studies have been concerned with the development of algorithms which would be suitable for real-time computer applications, while others are directed towards off-line applications. There are presently three basic approaches which have been developed to reschedule the generation so as to relieve system operational constraint violations: 1) Dynamic Security Dispatch; 2) Optimal Power Flow; and 3) Linear Programmig Formulations.

Dynamic Security Dispatch

In reference [3] Chadrashekhar and Hill discuss a direct method for dynamic security dispatch in large power systems. They propose to incorporate a stability index into the cost function for economic dispatch, thereby representing the tradeoff which exists between the requirements for economy and stability when selecting an appropriate operating state. The system is modelled by simplified load flow equations and the individual generator swing equations.

When the system is in the normal operating state, the generations are allocated economically. The generations may then be further varied in order to ensure dynamic security/stability with respect to a given set of contingencies.

This type of approach does not actually reschedule the generations while the system is in the emergency state, but does so prior to the occurrence of any contingencies in an attempt to prevent such an emergency state from ever occurring.

Although the authors state that this approach has the potential to be used as an on-line tool to optimally control the generations, many substantially complex and timely calculations must be performed and an entire set of contingencies must be examined.

Optimal Power Flow

The Optimal Power Flow (OPF) method can be used for various types of real-time system studies depending upon the choice of the objective or "cost" function. If this cost function is chosen so as to reflect the cost of generation, the OPF is known as an Economic Load Dispatch (ELD). On the other hand, if the cost function is chosen so as to minimize the generation change or the amount of required load shedding, the OPF becomes either a preventive security dispatch, if a contingency check is performed, or a corrective type of dispatch used to relieve existing emergency conditions, if no contingency check is performed. In either case, the objective function is minimized with respect to a set of constraints which always includes the equality constraint of load-generation balance (the AC load flow equations) and may include many types of inequality constraints, such as generation limits, line flow limits (or the corresponding limits on the bus angle differences across the transmission lines), voltage limits, etc. In many approaches, these inequality constraints are linearized so as to increase computational efficiency. In addition, these OPF solution techniques require the use of the Jacobian and/or the Hessian matrices, which tends to add to the complexity of the problem as well as the storage requirement.

Although the Linear Programming approaches which will be discussed later can be considered variations of the OPF technique, the term Optimal Power Flow usually applies to the methods which model the system by the non-linear AC load flow equations and not by linear approximations. These non-linearities increase the complexity and computation time, thereby precluding on-line usage at the present state of the art. [8,14-17]

Linear Programming Formulation

References [4-7,11-13] deal with linear programming (LP) techniques designed to allocate system generations so as to relieve line overloads on a real-time basis. Most of these techniques do not follow the classic LP format exactly, but take advantage of the many unique properties of power systems to develop algorithms which are simpler and faster than the standard LP formulation. In all of the algorithms presented in these references, the basic approach is identical. The equations used to model the system are linearized about a given initial operating point (determined by a state estimator or load flow). Some type of "cost" function is then minimized subject to various constraints. In general, these constraints include the limits on the generation, the generation ramping rate, and the line flows (current or power flows). This minimization is then performed using an iterative LP solution method such as the Simplex or the Dual Simplex methods.

In references [4-6], the authors propose a preventive-type security control scheme which requires an examination of a set of possible contingencies as in the dynamic security dispatch algorithms previously discussed. This check is accomplished by first rank ordering the various constraint violations which would result if any of these contingencies were to occur. The criteria used in this ordering process is based upon the severity of the violation. Each of these violations is then relieved in order, to arrive at a final generation schedule which would ensure secure operation with respect to this set of contingencies. This method is complex and time consuming since an entire set of contingencies must be examined, and each rescheduling move to relieve a particular "possible" overload requires a complete iteration.

In reference [7], Chan and Schweppe introduce a method which incorporates load shedding as well as generation reallocation in an LP formulation. The "cost" function in this approach, however, is not based upon the economics of generation. Instead, the cost function consists of one term to penalize load shedding and another to penalize deviations from the nominal or base case generation schedule. It is assumed that this nominal generation schedule has previously been determined by some form of Economic Load Dispatch (ELD). Both of these terms include a weighting factor to determine which term should receive greater emphasis during the minimization process. Normally, the load shedding term is given the greater weight since load shedding is used only as a last resort.

Additional constraints based on voltage limits and reactive power injections are included and a linear DC load flow is taken as the system model. This approach is therefore nothing more than a linearized version of the OPF approach.

A similar approach is proposed by Krogh and Javid in reference [11]. Here, a multiple time-stage approach is developed which allows for time-dependent constraints, such as generation response rates, transmission line overload duration constraints, and turbine start-up times. The authors also introduce the concept of rotating overloads from one transmission line to another to allow additional time for the generations at critical buses to change. This feature is merely introduced as a possible extension, however, and is not included in the actual problem formulation.

Krogh expands upon this approach in references [12,13]. In this revised approach, the set of generation ramp rates, not the generations themselves, are solved via an LP formulation to relieve the various operational constraint violations. By considering only the generation ramp rates, the magnitude of the generations and the actual magnitudes of the line flows do not enter into the actual problem formulation. In addition, the duration of the overloads are used to determine the relative urgency (severity) of the overload conditions when multiple overloads are present.

All these LP formulations have one thing in common, the calculations needed to determine an appropriate generation schedule are performed iteratively. Such iterative techniques tend to be better suited for off-line operation.

FORMULATION OF THE IRCC

The IRCC differs from these other approaches in that the functions of both Automatic Generation Control (AGC) and Economic Load Dispatch (ELD) are combined with the function of overload alleviation. In many of the approaches previously discussed, it was assumed that the required control signals were to be sent to the various generators via the existing AGC/ELD channels, but the AGC signal itself was never included in the overall problem formulation. [5] If additional control signals are to be added to the existing AGC or ELD signals, one must ensure that the original functions of these existing controls are preserved.

In addition, many of the approaches discussed above required an examination of a set of contingencies in order to ensure secure operation. This type of preventive control is very expensive. In an attempt to reduce this expense, it has been suggested that preventive control be utilized only in those cases where a possible contingency would result in an "uncontrollable" state, and that corrective control measures be allowed to handle any contingencies which may result in "controllable" violations of the operational constraints. [4] When this type of selective preventive control is applied, the system is said to be in a marginally secure state. [18]

The term "controllable" refers to a state in which the violations or overloads present may be controlled solely by rescheduling the available generations. The IRCC is one such corrective type of controller since it does not attempt to prevent possible violations over an entire set of contingencies, but merely attempts to correct for any such violations if and when they occur.

The following section briefly describes the objectives the IRCC is designed to meet.

Objectives of the IRCC

The IRCC must perform the conventional functions of Automatic Generation Control (AGC) and Economic Load Dispatch (ELD) under normal operating conditions. In addition, the IRCC should ensure that the equipment overload, generation, and ramp limits are not violated under both a slowly changing load profile and contingency operation. The interactive type of Optimal Power Flow (OPF) algorithms [3,7-9] based on momentary system conditions do not meet this requirement unless a series of studies are conducted for anticipated load changes.

The IRCC is an on-line feedback controller which should have a reasonable response time of perhaps two to ten seconds and must integrate all of the above functions so that discontinuities in control due to conflicting requirements are kept to a minimum. If the IRCC can perform its functions fast enough not only under normal operation with a slowly changing load profile but also when major contingencies occur in a system, then it can effectively be used as an emergency controller and obviates the necessity of a more restrictive secure economic dispatch based on "anticipated" contingencies.

Functions of the IRCC

The following sections briefly describe each of the IRCC's three basic functions.

Automatic Generation Control (AGC). [19,20] AGC systems have been developed in order to allow individual power companies or control areas to interconnect, thereby increasing the overall system security. The function of the AGC is to ensure that each interconnected control area contributes to the overall maintenance of the system frequency at the nominal 60 Hz and allows the interconnected areas to buy or sell constant amounts of power back and forth. The AGC system must, however, allow for emergency transfers of power between the areas following large disturbances if, in fact, the overall system security is to be enhanced. On the other hand, the individual control areas must not be expected to aid the neighboring areas in meeting their loads during normal variations in the load profile.

The AGC systems accomplish this task by sensing the system imbalances via an error term known as the Area Control Error (ACE). This error reflects situations when the individual generators in an area are either not meeting their load demands or are exceeding them, and can be used to determine a control signal which will change the generations in the area so as to restore the generation-load balance.

This error term consists of two parts: 1) an error component reflecting any deviation from the scheduled power flows on the tie lines which connect the area to its neighbors, and 2) an error component reflecting any deviation in the overall system frequency. This second term must be multiplied by a proportionality constant to convert the frequency deviation from Hz to per unit MW. This proportionality is known as the frequency bias parameter, B. The ACE is then:

$$ACE = -(B\Delta f + \underset{k=1}{\overset{K}{SUM}}\{\Delta Pl_k\})$$

The signals sent to the generators in the area are taken as some fraction of the integral of this ACE. The integral control employed here, ensures that the ACE will be forced to zero and remain there, barring any additional disturbances. The fraction of this integral which is given to the individual generators of the area is known as the participation factor and is normally calculated so as to maintain some sense of economic operation as the generations change to eliminate the ACE.

The negative sign associated with the ACE ensures that the proper controls are sent out to correct for this error. For example, if the area is absorbing more than its scheduled share of power from its neighbors, the above ACE will be positive and the signal sent to the generators of the area will cause their generations to increase, thereby forcing the area to meet its own demand.

A more detailed discussion of the AGC function can be found in any textbook on power systems analysis. [19,20]

Economic Load Dispatch (ELD). [19,20] One of the main concerns of any business is to produce its products or provide its customers with a service in the most economical way possible in order to return the biggest profit without increasing the cost seen by the customers. This general rule can be applied to the business of supplying electrical power. In order to produce the "product" economically, the generation in a particular area must be scheduled so as to minimize the overall cost.

When the transmission losses of a system are neglected, the most economic allocation of an area's generations occurs when the "incremental generation costs" of the individual generators are equal. This can be proven by minimizing an objective function consisting of the sum of the costs associated with each generator subject to the equality constraint of load-generation balance with losses neglected. This proof along with a more detailed discussion can be found in any textbook on power systems analysis. [19,20]

When the costs associated with each generator are approximated by a quadratic function of the generated power, the "incremental generation costs", or the derivatives of the cost with respect to the generated power, are linear functions of the generations. If the total cost of generation can be approximated by:

$$C_i = a_i P_{Gi}^2 + b_i P_{Gi} + c_i$$

Then the incremental cost, IC_i, is:

$$IC_i = dC_i/dP_{Gi} = 2a_i P_{Gi} + b_i$$

The assumption of a lossless system will not always be valid especially when the power is transmitted over large distances or a relatively low load density area is served. In these cases, one must reformulate the problem with transmission losses considered. This formulation involves nonlinear constraints and increases the complexity of the problem. In the final construction of the IRCC used to test its feasibility and performance, the linearity of the constraints is maintained and the losses are neglected.

Overload Alleviation. In order to properly relieve the system of transmission line overloads, the power injections must be either increased or decreased at the appropriate buses. Here the direction of change is most critical since an opposite direction of control would only worsen the situation. The actual value of the control that is sent to the appropriate buses is of secondary importance; this will merely affect the amount of time it takes for the overload to be alleviated and not the eventual outcome.

The determination of the "appropriate" buses at which the controls should be applied is accomplished by examining the bus-line distribution factors. These factors reflect the sensitivity of the line flows with respect to the bus power injections and can therefore be used to determine both which buses are the "appropriate" ones and whether the controls should be positive or negative. The derivation of these factors can be found in Appendix A.

If the "appropriate" bus is a generator bus, the bus power injections can be varied in one of two ways; either by changing the power generated at that bus or by changing the load connected to that bus. Load buses possess only the latter option. Since it is impractical, in most situations, to increase the load at any bus, the load can only be decreased. This reduction in load is referred to as load shedding and is considered only as a last resort--after all, the primary objective of the power company is to provide continuous power to as many of its customers as possible.

This leaves variation of the bus generations as the only desirable means by which the system overloads may be relieved when they occur. Load shedding is considered a viable alternative only in those special cases when mere rescheduling of the area generations is insufficient to relieve the overloads, and then only after all other alternatives have been exhausted.

In order to determine the relative urgency of the various overloads when multiple overloads are present, the actual overload values of the transmission lines should be normalized by their maximum flows to obtain the relative extent of overload. These relative values, J_j, can then be used, along with the line flow-generation sensitivities, determined from the bus-line distribution factors, to calculate the necessary controls to relieve the overloads. The controls necessary to eliminate each of the system overloads may then be summed at each bus, resulting in a final control which will attempt to correct for all overloads simultaneously. Any conflicting controls due to multiple overloads will merely result in a smaller control signals at those particular buses in the proper direction to correct for the violation with the greatest relative extent of overload. Although such a system will result in a longer time for complete correction, it will not affect the desired steady-state outcome.

The IRCC should not only keep track of the actual overload values but their integrals as well, since both the extent and duration of overload are main factors that will influence the decision of whether or not load shedding is necessary. When load shedding is required, the integral of the relative extent of overload, referred to as the lambda value, continues to increase regardless of the controls sent out to the various generators, indicating that generation rescheduling alone is inadequate to completely correct the problem.

A very simplified automatic load shedding algorithm is used to test the performance of the IRCC. This algorithm requires that the load be grouped into discrete "blocks", as in any load shedding routine. The very nature of the loads and the way in which the loads are connected to the system necessitates such a requirement. In addition, this algorithm assumes that these discrete loads are prioritized at each bus; the highest priority is given to the load which should, if possible, remain connected at all times (i.e., a hospital or residential load center which serves someone who uses a dialysis machine or life support system).

The criteria used to determine when load must be shed in order to relieve an overload on the jth line is whether or not the λ_j variable exceeds some specified threshold value. The IRCC then checks for the most sensitive bus at which a reduction in its load would alleviate the overload by the greatest extent. The "block" of load which is presently given the lowest priority at that bus is then shed. No other load is shed until the IRCC can reevaluate the status of the overload when the SCADA measurements are processed after the next SCADA cycle.

Although it is possible to calculate the exact amount of load needed to completely correct the problem, it may be possible to find some other means of aiding in the correction of the problem before the next SCADA cycle, thereby eliminating the need for any further load shedding. For example, a generator which was previously off-line may be quickly started up and brought on-line. This process therefore, tends to shed a minimum amount of load in order to restore the system to a normal operating state.

There are, however, additional considerations. Perhaps the load should be prioritized for the entire area, not just at each bus. Then some sort of optimization process would be necessary to determine which loads should be shed at which buses to reduce the overload. This optimal load would not necessarily be shed at the most sensitive bus if, for example, a smaller "block" of load at another bus would adequately relieve the overload in a reasonable amount of time.

The necessity and feasibility of automatic load shedding must also be considered. Perhaps the IRCC should merely present the various load shedding options to the operator when it is determined that rescheduling of generation is inadequate, thus leaving the final decision in the hands of the personnel at the control center.

In addition, there are other alternatives available which are not considered by the IRCC, such as emergency start-up of generators, line switching, and overload rotation.

Regardless of the type of load shedding algorithm used, the two principles which should guide the decision of which loads are to be shed are: 1) load shedding must be used only as a last resort and 2) when it is determined that load shedding is required only the very minimum amount of load should be shed to correct the problem.

In the following section the feedback control problem to realize the above objectives is formulated and the mathematical structure of the IRCC is derived.

Mathematical Formulation of the IRCC

If $Ci(P_{Gi})$ is the cost of the generation, P_{Gi}, of the ith unit in the area, then the objective is:

$$\text{Min } C = \sum_{i=1}^{N} \{Ci(P_{Gi})\} \tag{1}$$

The constraints are:

1. Area Generation/Load Balance:

$$h = \sum_{i=1}^{N}\{P_{Gi}\} - \sum_{i=1}^{N}\{P_{Li}\} - p - \sum_{k=1}^{K}\{Pl_k\} = 0.0 \tag{2}$$

2. Generation Limit Constraints:

$$P_{Gi}^{m} \leq P_{Gi} \leq P_{Gi}^{M} \tag{3}$$

3. Generation Rate Constraints:

$$|\dot{P}_{Gi}| \leq R_i \quad i = 1,2,\ldots,N \tag{4}$$

4. Line Flow Constraints:

$$|Pl_j| \leqslant Pl_j^M \quad j = 1,2,\ldots,L \tag{5}$$

The modified objective function which includes the equality constraint (2) and the inequality constraints (3), (4), and (5) can be written as:

$$F = C - \gamma h + \underset{i=1}{\overset{N}{\text{SUM}}}\{\mu_i(P_{Gi} - P_{Gi}^{Lim})\} + \underset{j=1}{\overset{L}{\text{SUM}}}\{\lambda_j J_j\} \tag{6}$$

where: Lim = min or Max

J_j = relative extent of overload present on line j, found by applying the following equation:

$$J_j = \frac{|Pl_j| - Pl_j^M}{Pl_j^M}$$

γ, μ_i, and λ_j are Lagrange multipliers.

The Kuhn-Tucker conditions for the optimum can then be stated as:

At the optimum point, dF/dx = 0.0

where: x is a vector of the following variables:

$$x = (P_{Gi}, \gamma, \mu_i, \lambda_j) \quad \begin{array}{l} i=1,2,\ldots,N \\ j=1,2,\ldots,L \end{array} \tag{7}$$

$$\begin{array}{ll} \lambda_j > 0.0 & \text{if } J_j = 0.0 \\ \lambda_j = 0.0 & \text{if } J_j < 0.0 \end{array} \tag{8}$$

$$\begin{array}{ll} \mu_i < 0\ 0 & \text{if } P_{Gi} = P_{Gi}^m \\ \mu_i = 0.0 & \text{if } P_{Gi}^m < P_{Gi} < P_{Gi}^M \\ \mu_i > 0.0 & \text{if } P_{Gi} = P_{Gi}^M \end{array} \tag{9}$$

To ensure the above conditions, a feedback controller can be synthesized as:

$$-\dot{P}_{ci} = -\dot{P}_{Gi} = dF/dP_{Gi}$$

$$= K_i dC/dP_{Gi} - \gamma(1 - dp/dP_{Gi} - \sum_{k=1}^{K}\{dPl_k/dP_{Gi}\})$$

$$+ \sum_{j=1}^{L}\{\lambda_j(dJ_j/dP_{Gi})\} + \mu_i \qquad (10)$$

$$\text{with} \quad |P_{Gi}| \leq R_i$$

$$\dot{\gamma} = K_a(dF/d\gamma) = K_a h$$

$$\dot{\lambda}_j = K_j(dF/d\lambda_j) = K_j J_j$$

$$\dot{\mu}_i = dF/d\mu_i = (P_{Gi} - P_{Gi}^{Lim}) \qquad (11)$$

where: K_i, K_a, and K_j are attenuation factors chosen so as to prevent unnecessary oscillations in the control signal.

$$K_i = 1/(2a_i)$$

$$K_a = 0.5[(f^o\sigma^2)/(8H)][1 + \Omega^2\sigma^2]$$

$$K_j = 6.0$$

The equality constraint (2) for the deviations from the scheduled value of generation P_{Gi}^b, load P_{Li}^b, and tie line flows Pl_k^b can be written as:

$$h = \sum_{i=1}^{N}\{(P_{Gi}^b - \Omega_i \Delta f)\} - \sum_{i=1}^{N}\{(P_{Li}^b + \sigma_i \Delta f)\} - p -$$

$$(\sum_{k=1}^{K}\{Pl_k^b\} + \sum_{k=1}^{K}\{\Delta Pl_k\}) \qquad (12)$$

where: Δf = the deviation from the nominal frequency

ΔPl_k = the deviation from the scheduled value of the tie line flows.

Equation (12) reduces to :

$$h = -(B\Delta f + \mathrm{SUM}_{k=1}^{K}\{\Delta Pl_k\}) \qquad (13)$$

where: $B = \mathrm{SUM}_{i=1}^{N}\{(\beta_i + \sigma_i)\} = \beta + \sigma$

From equation (13), it can be seen that h is the Area Control Error (ACE) used to calculate the AGC control signal which is denoted here as γ.

The structure of the controller is essentially dictated by equation (10) with the Lagrange multiplier values γ, μ_i, and λ_j being governed by the differential equations (11) and the constraints (8) and (9).

The differential equations (11) can be rewritten in the integral form as:

$$\gamma = \int(K_a h)dt = -K_a\int(B\Delta f + \mathrm{SUM}_{k=1}^{K}\{\Delta Pl_k\})dt$$

$$\lambda_j = \int(K_j J_j)dt = K_j\int((Pl_j - Pl_j^M)/Pl_j^M)dt$$

$$\mu_i = \int(P_{Gi} - P_{Gi}^L)dt \qquad (14)$$

The main computational burden would appear to lie in the evaluation of the partial derivatives dp/dP_{Gi} and dJ_j/dP_{Gi}. However, if a DC model is assumed, dp/dP_{Gi} becomes a simple function of the generation values and

dJ_j/dP_{Gi} becomes a function of the bus-line distribution factors which are constants and can be easily evaluated from the X-matrix using the one-step process outlined in Appendix A. If the X-matrix is precomputed and stored, then the determination of the distribution factors for overloaded lines under outage conditions is also a one-step process. If greater accuracy is desired, the partial derivatives can be evaluated from the factored form of the Jacobian matrix of the system. The Jacobian matrix would need to be updated only for major changes in the load-generation profile and for outage conditions.

In the actual IRCC structure used in the testing of its performance and feasibility, the partial derivative, dp/dP_{Gi}, was neglected for simplicity. This term can, however, be incorporated in the overall formulation in a fairly straight forward manner.

In addition, the AGC control signal, γ, is usually multiplied by a constant K_a which is somewhat arbitrarily chosen as a certain percentage of some critical value. The partial derivative, dPl_k/dP_{Gi}, in equation (10), however, is a constant (the bus-line distribution factor corresponding to the ith bus and kth line, a_{ki}) and merely scales the value of γ. Therefore, these partial derivatives have the same effect as varying the arbitrarily chosen scaling factor K_a, and may be neglected in the actual control structure.

Furthermore, if the generation limits are observed by some type of hard delimiter, the term μ_i can also be ignored and the actual control signal becomes a simple summation of three separate terms: the original AGC control signal, an economic allocation signal, and an overload alleviation signal.

The λ_j variables in equation (11) are integrals of the overload values and can be used to initiate load shedding or line tripping as in the simplified automatic load shedding algorithm previously discussed.

The computations involved to arrive at a control signal are very few and can well be completed in a SCADA cycle. The measurements required are summated tie line flows, area frequency, bus power injections, and power flows in critical lines. The effect of any involuntary switchings and changes in the network topology can be considered by carrying out a few simple additional computations using the precomputed X-matrix for the normal case as shown in Appendix A.

During the testing of the IRCC's performance, it is assumed that the controller uses the measurements of bus power injections, frequency, and summated tie line flows after every SCADA cycle, computes the required control signals, applies these signals to the simulated system, and waits for the next SCADA cycle. This process is performed continuously for both normal as well as emergency conditions.

One of the main advantages of the IRCC is the fact that it can be used continuously and will eliminate any "incidental" overloads which may occur as the load profile of the system slowly increases to a peak value during normal operation. The line flows on these "incidentally" overloaded lines will gradually increase, but as soon as an overload is detected, no matter how small, the IRCC will initiate appropriate controls so as to eliminate it. This will prevent any overloads caused by fluctuations in the normal load profile from causing further cascaded problems.

Details of the simulation of the power system and contingencies used in the testing of the performance of the IRCC are explained in the next section.

SIMULATION

Simulation of the Operation of the Power System

To study the performance of the IRCC, the long term dynamics of the system are simulated by using the power system model described in references [19,21,22]. The system dynamic equations for this system model are given below.

The change in the system frequency is calculated from the following differential equation:

$$d\Delta f/dt = (f^{o}/2H)\left(\sum_{i=1}^{N}\{\Delta P_{mi}\} - \sum_{i=1}^{N}\{\Delta P_{Li} - \sigma_i \Delta f\} - \Delta p\right) \quad (15)$$

The governor dynamics for the ith bus are:

$$d\Delta X_{ei}/dt = (-\Delta X_{ei} - \sigma_i \Delta f + \Delta P_{ci})/T_{gi} \quad (16)$$

where: ΔP_{ci} = the control signal applied at the ith bus, found by the equations given above in the mathematical formulation of the controller.

The turbine dynamics for the ith bus are:

$$d\Delta P_{mi}/dt = (-\Delta P_{mi} + \Delta X_{ei})/T_{ti} \quad (17)$$

Using this approach, the system frequency and the governor dynamics of each bus are represented by a set of differential equations. Neglecting the interbus swings in an area, changes in the electrical power output of the ith unit can be calculated from:

$$\Delta P_{ei} = \Delta P_{mi} + \left(H_i/\sum_{i=1}^{N}\{H_i\}\right)\left(\sum_{i=1}^{N}\{\Delta P_{Li}\} + \Delta p - \sum_{i=1}^{N}\{\Delta P_{mi}\}\right) \quad (18)$$

These values can be used to calculate the actual electrical power outputs which can, in turn, be used to find the corresponding deviations of the real power flows in the transmission lines by performing an AC load flow. The general AC load flow equation is given below:

$$S_i = P_i + jQ_i = V_i\left(\sum_{j=1}^{N}\{y_{ij}V_j\}\right)^* \qquad (19)$$

where: S_i = the complex power at the ith bus.

P_i = the real power at the ith bus.

Q_i = the reactive power at the ith bus.

V_i = the voltage at the ith bus.

y_{ij} = the ith row, jth column entry of the bus admittance matrix, Y.

$*$ = the complex conjugate.

A detailed derivation and explanation of these equations can be found in any textbook on power systems analysis such as references [19,20].

Contingency Simulation

Three basic contingencies were simulated: 1) sudden load changes which account for sudden switchings of loads in or out of the system; 2) partial or total generation outages at particular buses; and 3) transmission line outages. These contingencies were simulated by imposing certain initial conditions on the variables in the system dynamic equations and adjusting the appropriate system parameters.

Sudden Load Changes. This contingency was the easiest to simulate. The given value of the load which is switched into or out of the system (in p.u.) is added to the appropriate load deviation term in the system dynamic equations so that the initial value of load deviation is set equal to the amount of load switched.

Partial or Total Generator Outage. When a generator outage is simulated at a particular bus, the nominal generation at that bus is merely decreased by the amount of "lost" generation; thereby decreasing the net power injection at the bus.

The capacity of the remaining generation at the bus is adjusted by the appropriate amount to reflect the loss. This is accomplished by deleting a fraction of the original capacity equal to the amount of generation lost divided by the original bus generation. In the case of total generation loss, the remaining capacity is set equal to zero and the generator bus becomes a load bus.

The bus inertia constant, H, is also changed to reflect the loss. For a partial generation loss, the inertia constant is decreased by the same fraction as above. In the the case of a total loss of generation, however, the inertia constant is set to an arbitrarily small value, presently taken as 0.01 sec, to represent the inertia of the load demand at the bus.

Transmission Line Outage. A line outage from bus i to bus j is simulated by merely setting its series and shunt admittance parameters to zero and deleting these values from the bus admittance matrix, Y. Then when a new AC load flow is performed during the simulation, the line flow from bus i to bus j is found to be zero as though a line were not connected between these two buses.

PERFORMANCE OF THE IRCC

Five Bus Test System

The performance of the IRCC was initially studied on a test system consisting of 2 separate control areas with a total of 5 buses and 5 lines. The system diagram along with the nominal bus generations, loads, line flows, and maximum line flows (in parentheses) is shown in Figure 1. The system parameters for the lines and the generator/load dynamics are listed in Appendix B.

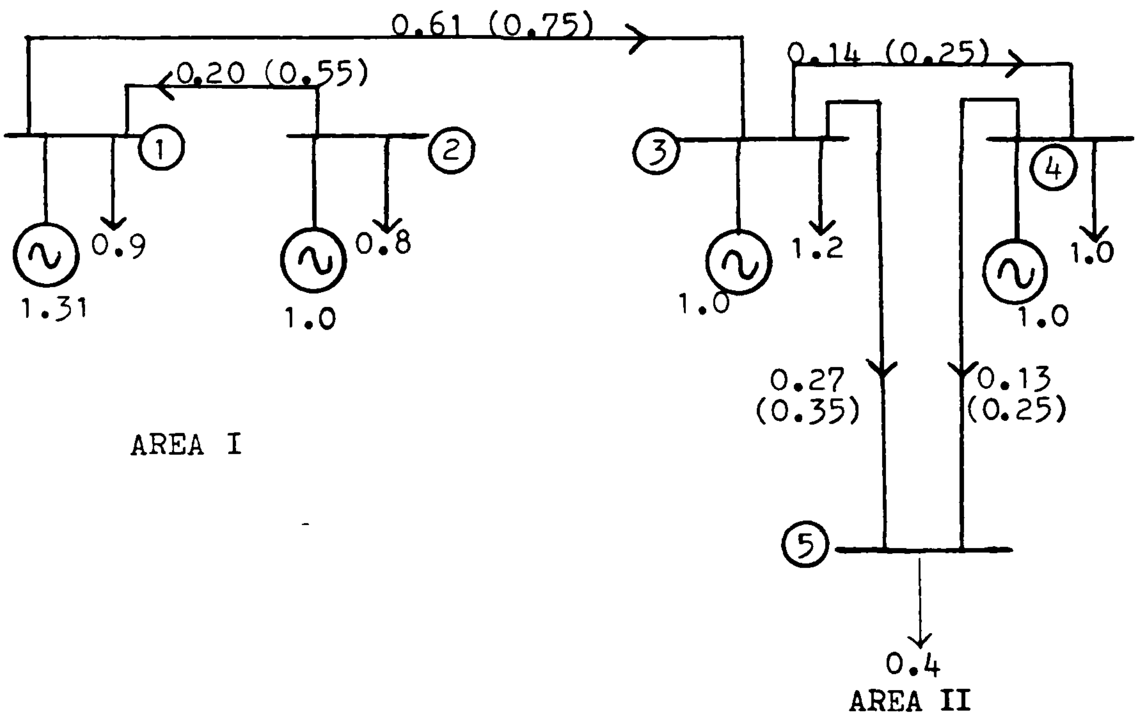


Figure 1: Two Area, Five Bus System Diagram.

Four test cases were chosen to illustrate the function of the IRCC under various operating conditions for this five bus system. During the simulation of these test cases, the AGC and ELD portions of the signal are given every two seconds beginning at times of two seconds and four seconds respectively; whereas the overload alleviation portion of the signal is given every four seconds beginning at a time of four seconds. The four second interval was chosen since the SCADA cycle was assumed to be four seconds and this portion of the signal is dependent on measurements obtained once during each SCADA cycle.

Case I: No System Disturbance. In the first test case the IRCC was investigated under normal operating conditions with no disturbance to the system, thereby illustrating the controller's economic allocation function.

Initially, the generations in the two areas are not optimally allocated. After the controls are initiated, the IRCC reschedules the generations so that the incremental costs for each generator in each of the two areas are equal, indicating an optimal state when the system losses are neglected. The initial and final incremental costs are listed in the following table.

Bus	Area	Initial Incremental Cost	Final (60 sec) Incremental Cost
1	1	$1161.33/p.u.-hr	$1106.55/p.u.-hr
2	1	$1040.00/p.u.-hr	$1106.55/p.u.-hr
3	2	$1040.00/p.u.-hr	$1048.08/p.u.-hr
4	2	$1060.00/p.u.-hr	$1048.08/p.u.-hr

Table 1: Incremental Generation Costs--Five Bus System.

In the final state, the incremental generation costs of the generations of each area are all equal, indicating that each area is meeting its own load demands in the most economic way.

Case II: Outage of Line 3-4. (Figs. 2,3) When line 3-4 trips, a severe overload is created on line 3-5 resulting in an emergency condition which requires corrective action by the IRCC .

When line 3-4 is tripped the power which was initially flowing from bus #3 to bus #5 via bus #4 (due to the system configuration) must now flow directly to bus #5 (refer to Figure 1). The new line flow in line 3-5 should now be equal to the nominal flow in line 3-5 plus the nominal flow in line 3-4 (plus any additional losses present in line 3-5 due to the increased flow). The IRCC must try to readjust the generations so that some of the load required at bus #5 is supplied by the generators at bus #4.

Figure 2 plots the line flow of the overloaded line 3-5. The step-like appearance of the plot results from the fact that the IRCC receives the line flow measurements at discrete time intervals. Before any type of corrective control takes effect ($t < $ four seconds) the line is overloaded by 0.06 p.u. If the IRCC is not used, this overload would have persisted until the dispatcher took notice of the overload and carried out appropriate remedial action. The IRCC, however, alleviates this overload condition before the next SCADA cycle ($t =$ eight seconds). Also note that although the controller initially overcorrects for this overload condition slightly, the final steady state line flow is set to its limiting value, consistent with the most economic operation possible under the given conditions.

Since the line remains at its limiting value, the integral of the relative extent of overload, λ_j, reaches and maintains a constant value as shown in Figure 3. This lambda value is very important for two basic reasons. First, it is one of the Lagrange multipliers used in the formulation of the IRCC and must therefore satisfy the Kuhn-Tucker conditions of optimality listed above in Chapter II. Second, this value is monitored and used to initiate load shedding when required.

Note that the Kuhn-Tucker conditions are indeed satisfied, since $\lambda_j > 0.0$ when the relative extent of overload disappears (i.e., when $J_j = 0.0$).

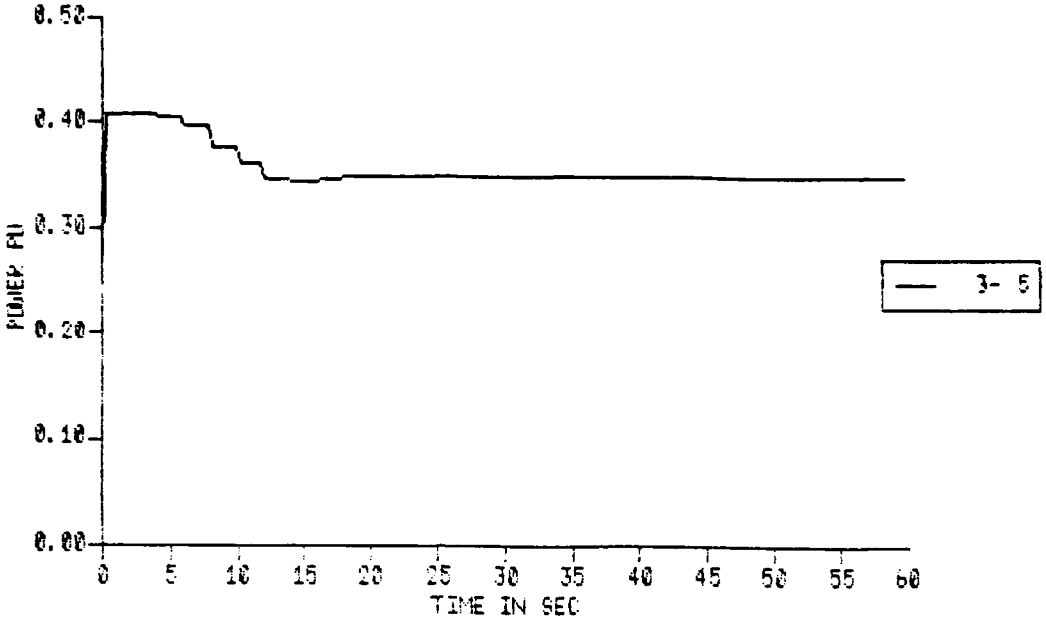


Figure 2: Power Flow Through Line 3-5, Line 3-4 Out.

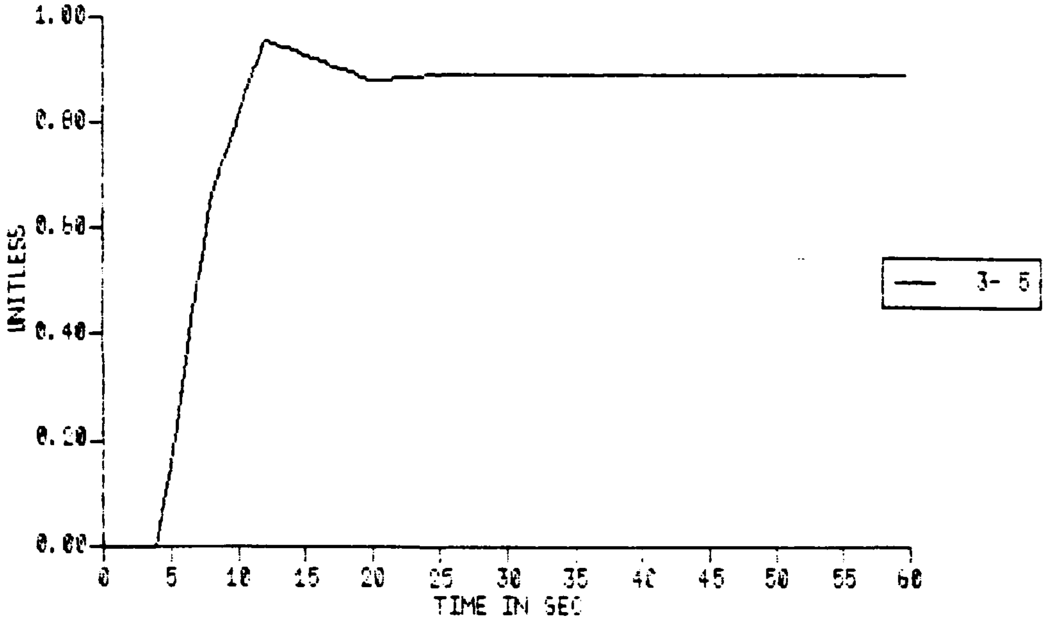


Figure 3: Lambda Value of Line 3-5, Line 3-4 Out.

Case III: Outage of Line 4-5. (Figs. 4-8) In this test case line 4-5 trips resulting in a very serious overload on line 3-5 which cannot be controlled by generation rescheduling alone; load shedding must be initiated if the overload is to be relieved. In fact, in this case the overload cannot be relieved at all by rescheduling the generation since no generator exists on the load-side (bus #5, refer to Figure 1) of the overloaded line 3-5. Upon examination of the system itself it can be seen that load must be shed at bus #5 in order to relieve this overload. This is exactly what the IRCC "suggests" when the load shedding option is in effect.

This test case was run twice, once without the load shedding option and once with this option in effect. Figure 4 plots the line flow in the overloaded line 3-5 without load shedding when the line connecting the load bus #5 to the second generator bus #4 is lost. As shown in this plot, this overload will persist indefinitely until one of two things happens; either the line 4-5 is restored or load is shed at bus #5.

Figure 5 plots the lambda value of the overloaded line 3-5. Note that since the overloaded condition cannot be relieved at all, this value continues increasing at a constant rate.

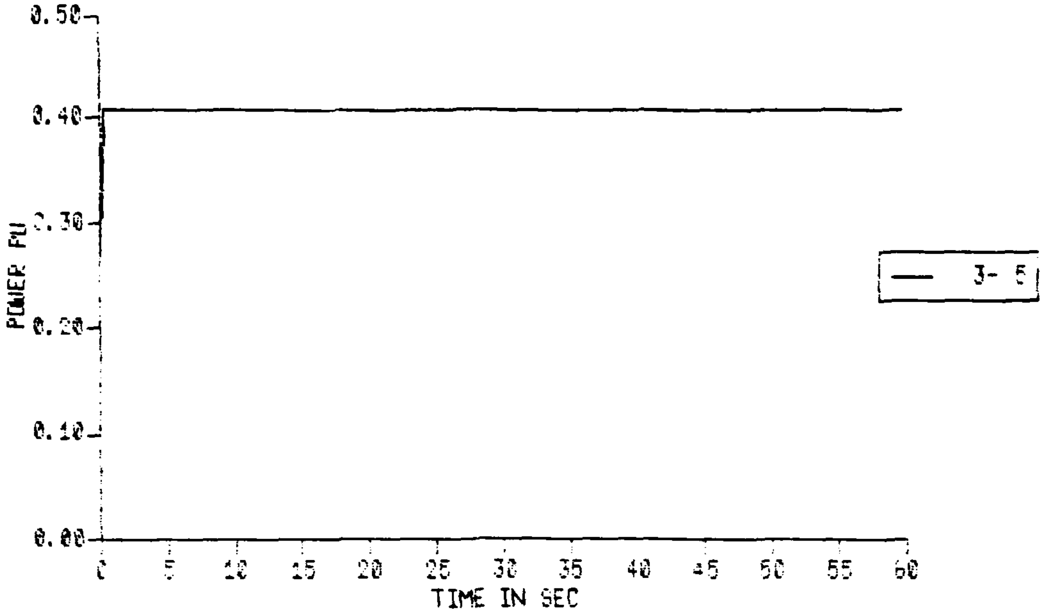


Figure 4: Power Flow Through Line 3-5, Line 4-5 Out. No Load Shedding Performed.

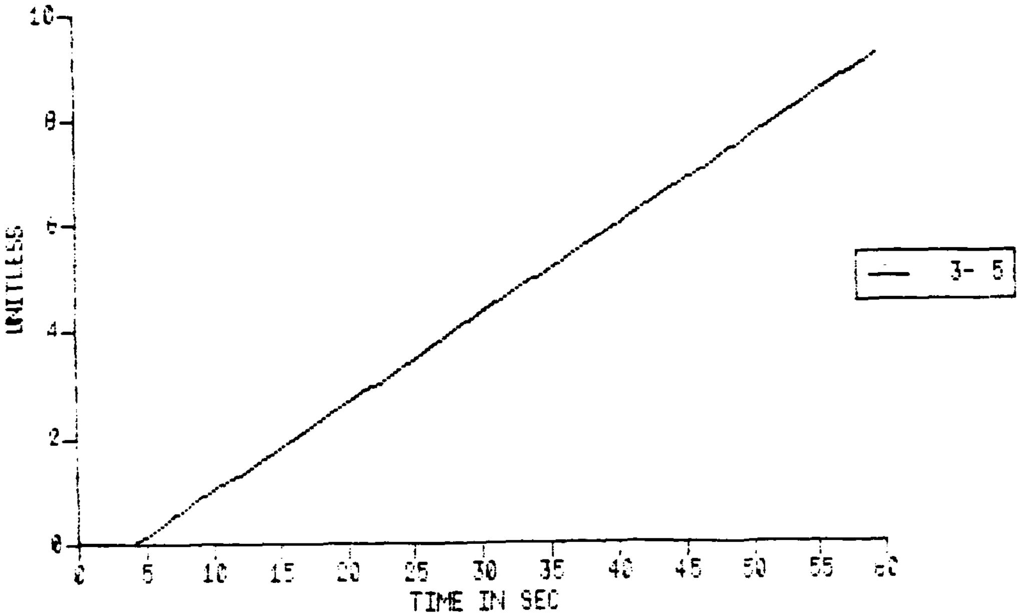


Figure 5: Lambda Value of Line 3-5, Line 4-5 Out. No Load Shedding Performed.

When the load shedding option is in effect, the IRCC suggests that 0.1 p.u. of load be shed at bus #5. This is the "block" of load with the lowest priority available at bus #5. Figure 6 plots the corresponding line flow in the overloaded line 3-5. Note that although the line was initially overloaded at the same value of 0.06 p.u. as before, the new final steady-state flow is set to 0.30 p.u. which is less than the line's limiting value of 0.35 p.u. The reason the line is not set to the limiting value itself, as in test case II when line 3-4 tripped, is that the amount of load shed was more than enough to relieve the overload. This seems to imply that the minimum amount of load was not shed, but we must remember that load can only be shed in discrete amounts. Therefore, even when the minimum discrete amount of load is shed starting with the lowest priority load as in this case, the overloaded condition may be overcorrected.

Figure 7 shows the new plot of the lambda value for line 3-5 with the load shedding option in effect. Note that the lambda totally disappears in the final steady-state. This is consistent with the Kuhn-Tucker conditions of optimality; $\lambda_j = 0.0$ when the final steady-state line flow is less than its limiting value (i.e., when $J_j < 0.0$).

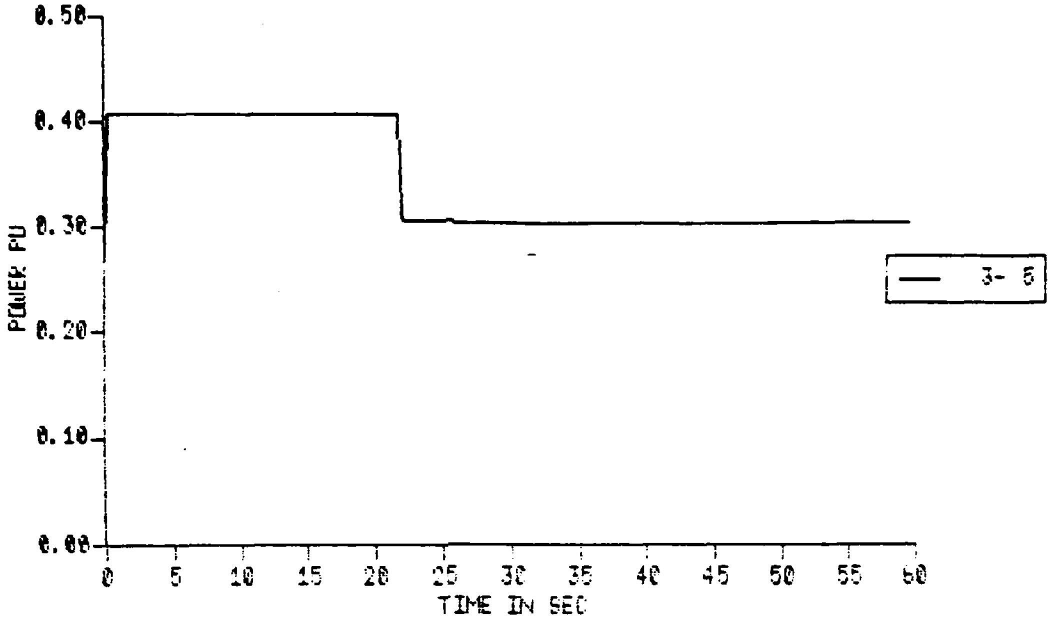


Figure 6: Power Flow Through Line 3-5, Line 4-5 Out, Load Shedding Performed.

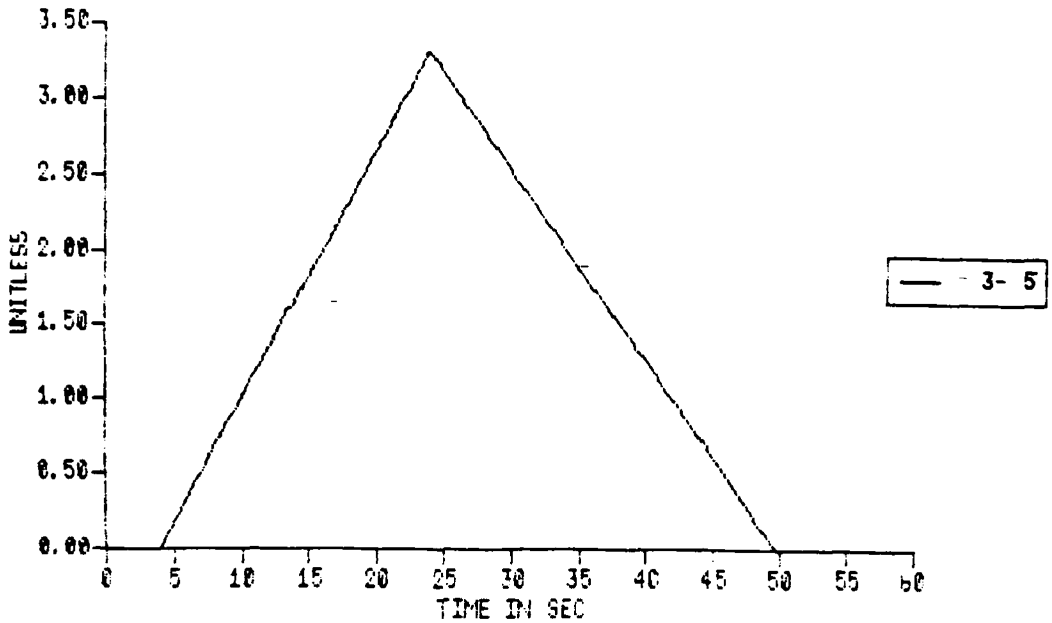


Figure 7: Lambda Value of Line 3-5, Line 4-5 Out, Load Shedding Performed.

Figure 8 plots the deviations in the total generation, the total demand, and the net power flow on the tie lines in Area II. The proper AGC action is clearly illustrated. In the final steady-state, the generation of Area II decreases by 0.1 p.u. so as to not exceed the new load demand which has been decreased by this same amount due to the load shedding performed by the IRCC.

Immediately after the load is shed, Area II produces an excess of generation which is reflected in a positive change in the tie line flow to Area I. In the final steady-state, however, the tie line flow returns to its scheduled value, illustrated in the plot as zero change from the initial or nominal value (i.e., $SUM\Delta Pl_k = 0.0$).

As the generation/load balance is restored , the system frequency also returns to its nominal value (i.e., $\Delta f = 0.0$). Therefore, the control signals which have been added to the existing AGC signal do not alter its original function.

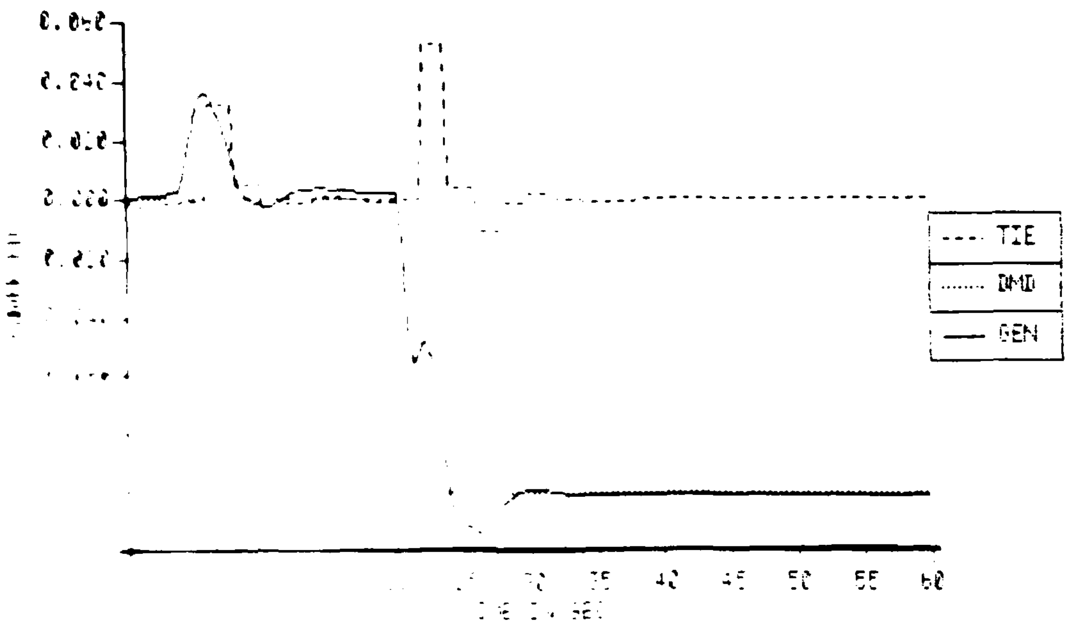


Figure 8: Deviations of Area II Generation, Demand and Tie Line Flow With Line 4-5 Out.

Case IV: Simultaneous Outages. (Figs. 9,10) In this test case, line 3-4 is tripped and a load of 0.2 p.u. is switched in at bus #1. These simultaneous contingencies result in the eventual overloading of two separate lines: line 3-5 and line 1-2. The line from bus #3 to bus #5 is immediately overloaded by 0.05 p.u. since the load at bus #5 must be met. The line from bus #1 to bus #2 is overloaded (in the opposite direction) by 0.01 p.u., but only after the economic allocation portion of the signal has been allowed to reschedule the Area I generation to meet the increased load demand. The IRCC, however, has no trouble in alleviating both overloads simultaneously.

The actual line flows are plotted in Figure 9 and the corresponding lambda values are shown in Figure 10. Note that both of the line flows are set to their respective limiting values, consistent with the most economic operation possible given the new system configuration and load. Also note that the lambda values of both overloaded lines reach and maintain constant values which confirms the Kuhn-Tucker conditions of optimality.

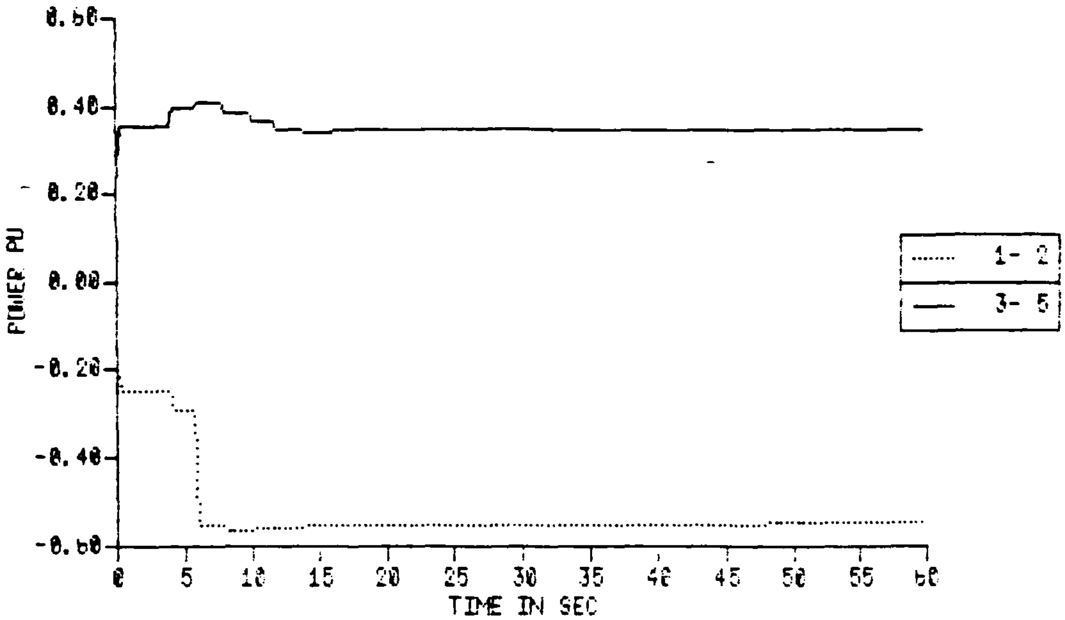


Figure 9: Power Flow Through Lines 1-2 And 3-5, Simultaneous Outages.

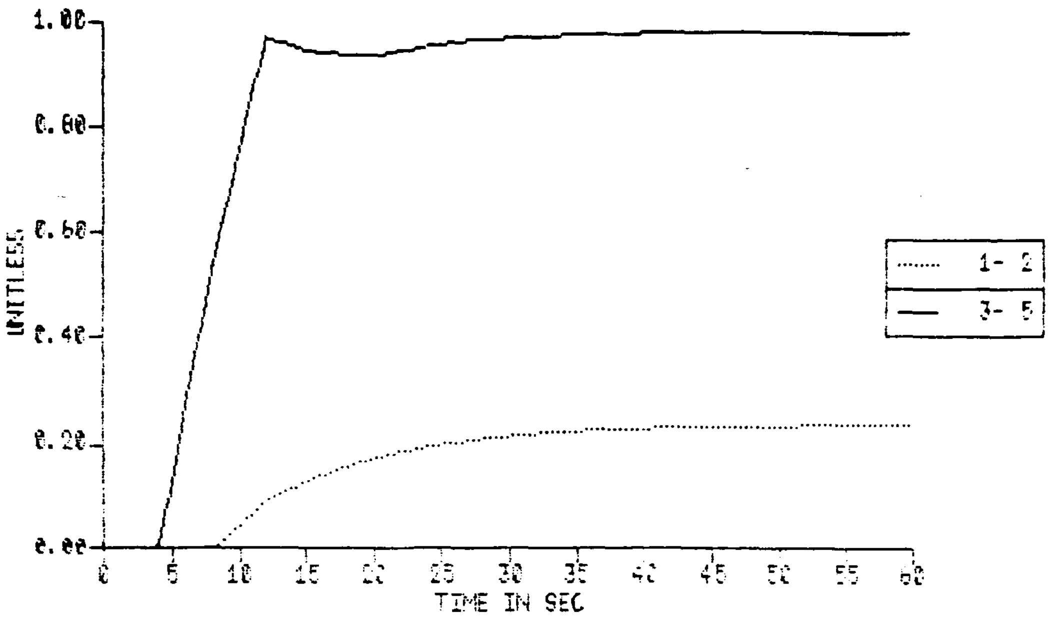


Figure 10: Lambda Values of Lines 1-2 And 3-5, Simultaneous Outages.

Fourteen Bus Test System

The performance of the IRCC was studied on another test system consisting of 11 buses and 14 lines. This system forms part of a pool and is connected to three neighboring areas by means of six tie lines. Each of these three areas is represented by a generator-load equivalent. The system diagram along with the nominal bus generations, loads, line flows, and maximum line flows (in parentheses) is shown in Figure 11 on the following page. The system parameters for the lines and the generator/load dynamics are listed in Appendix C.

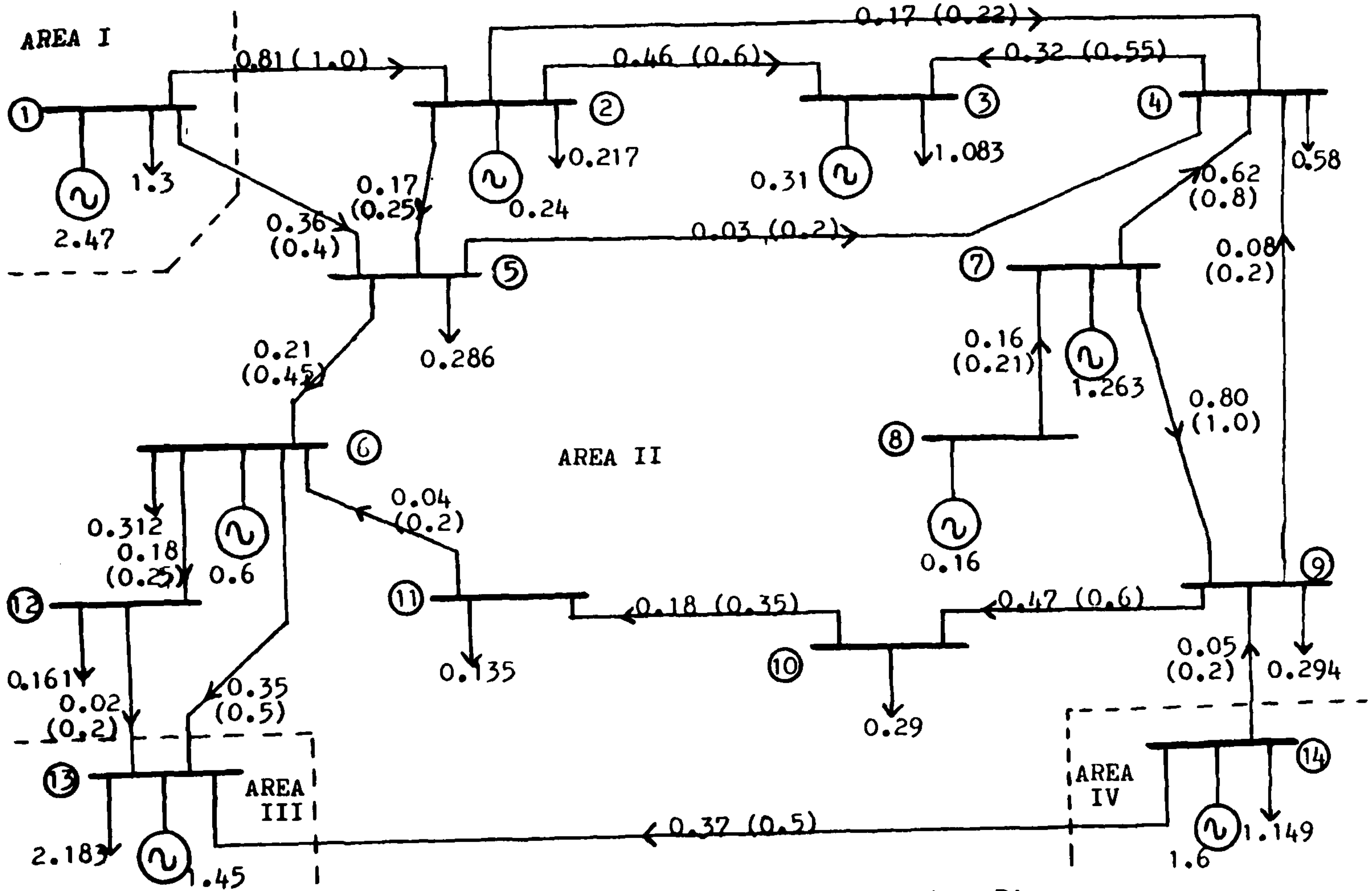


Figure 11: Four Area, Fourteen Bus System Diagram.

Four similar test cases were chosen to illustrate the function of the IRCC on the larger 14 bus system. The time intervals at which the various portions of the signal are given are the same as in the test cases previously performed on the five bus system.

Case V: No System Disturbance. In the first test case the IRCC was again investigated under normal operating conditions with no disturbance to the system, thereby illustrating how the IRCC performs the function of economic generation allocation. Initially, the generation in Area II is not optimally allocated. After the controls are initiated, however, the IRCC reschedules the generation so that the incremental costs of each of the generators in Area II are the same, indicating an optimal state for a lossless system. The initial and final incremental costs are listed in Table 2 below:

Bus	Area	Initial Incremental Cost	Final (60 sec) Incremental Cost
1	1	$1020.84/p.u.-hr	$1020.84/p.u.-hr
2	2	$970.56/p.u.-hr	$966.16/p.u.-hr
3	2	$962.00/p.u.-hr	$966.16/p.u.-hr
6	2	$970.00/p.u.-hr	$966.16/p.u.-hr
7	2	$964.19/p.u.-hr	$966.16/p.u.-hr
8	2	$967.20/p.u.-hr	$966.16/p.u.-hr
13	3	$1000.80/p.u.-hr	$1000.79/p.u.-hr
14	4	$980.00/p.u.-hr	$980.06/p.u.-hr

Table 2: Incremental Generation Costs--14 Bus System.

In the final state, the generations and hence the incremental costs of the neighboring Areas I, III, and IV are not appreciably altered. This is exactly what one would expect.

Case VI: Generator Outage. (Figs. 12,13) In this test case 0.5 p.u. generation is lost at bus #7. This contingency results in a slight transient overload on line 2-4.

Figure 12 plots the line flow of the overloaded line 2-4. Although it is difficult to determine from the plot alone, this overload is merely a transient overload and is not present in the final state. When such a transient condition occurs, the lambda value reaches a peak and then decreases to zero (Fig.13), illustrating that all of the control signals previously sent to the generators to alleviate the overload are later counterbalanced by equal and opposite signals once the line flow drops below its maximum limiting value. Although the overload would have been eliminated without any outside intervention, the presence of the IRCC permitted the overload to be alleviated in a much shorter time.

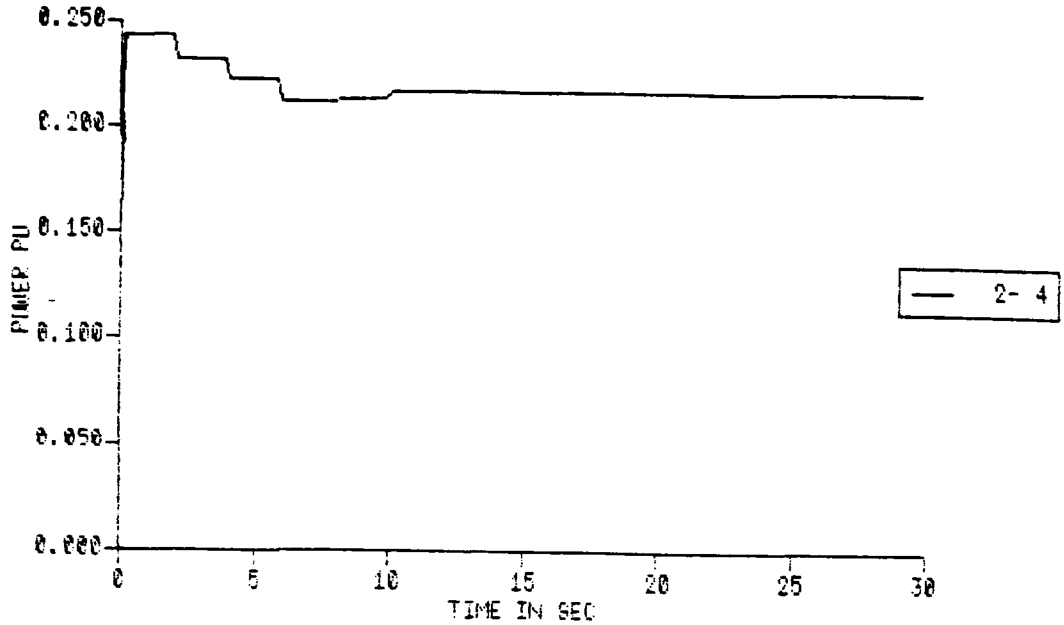


Figure 12: Power Flow Through Line 2-4, Generator Outage at Bus #7.

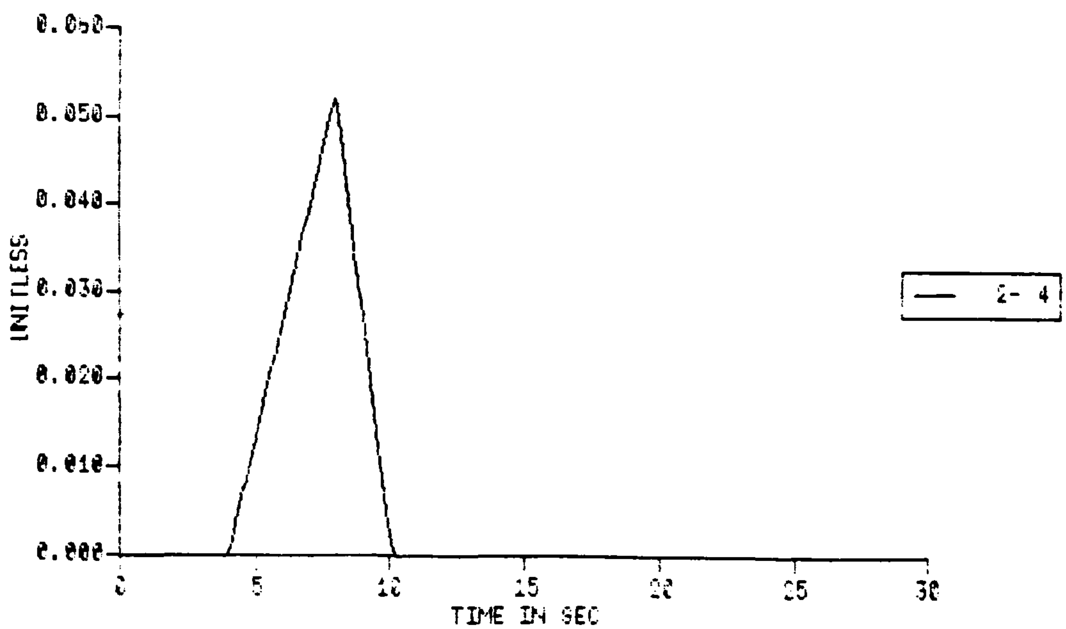


Figure 13: Lambda Value of Line 2-4, Generator Outage at Bus #7.

Case VII: Simultaneous Outages. (Figs. 14,15) In this test case, line 3-4 is tripped and 0.1 p.u. of generation at bus #3 is lost. This possible double contingency leads to a very serious overload on line 2-3. So serious in fact, that given the present generator capacities, the overload cannot be alleviated by merely rescheduling the generation. In order to completely remedy this condition, load must be shed. This test case was run twice, once without the load shedding option and once with it in effect, to once again illustrate the ability of the IRCC to handle such "uncontrollable" situations. The lambda values for the overloaded line for both cases are shown in Figures 14 and 15.

When no load shedding is available, the lambda value continues to increase and will do so indefinitely until some type of additional remedial action is initiated (Fig. 14). Note, however, that the rate of this increase is lessened considerably more than if the IRCC had not been used at all. This indicates that even though the overload cannot be totally alleviated, the extent of overload is significantly reduced giving the dispatcher more time to decide which loads, if any, should be shed or if some other type of corrective action would be more appropriate.

When the load shedding option is in effect, the IRCC determines that generation rescheduling is inadequate to completely alleviate the problem at approximately 16 sec

(Fig. 15). At this time the IRCC sheds 0.03 p.u. of load at the bus #3, the bus at which the line 2-3 is most sensitive to increases in the net power injection. Unlike the previous case, the load shed performed here does not overcorrect for the overload as reflected in the plot of the lambda value; the value is constant in the final steady-state.

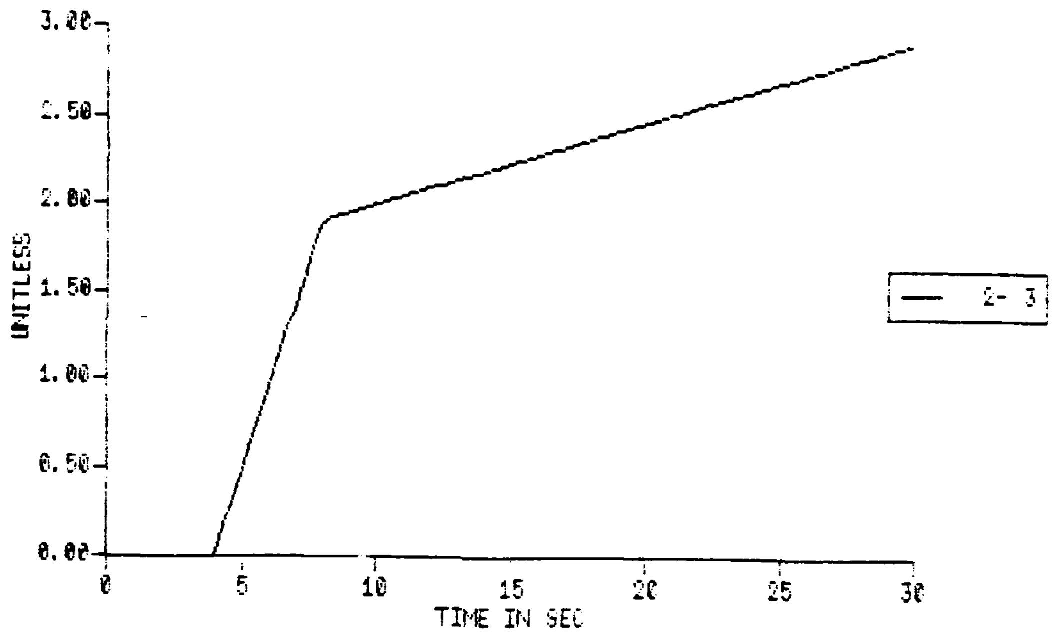


Figure 14: Lambda Value of Line 2-3, No Load Shedding Performed.

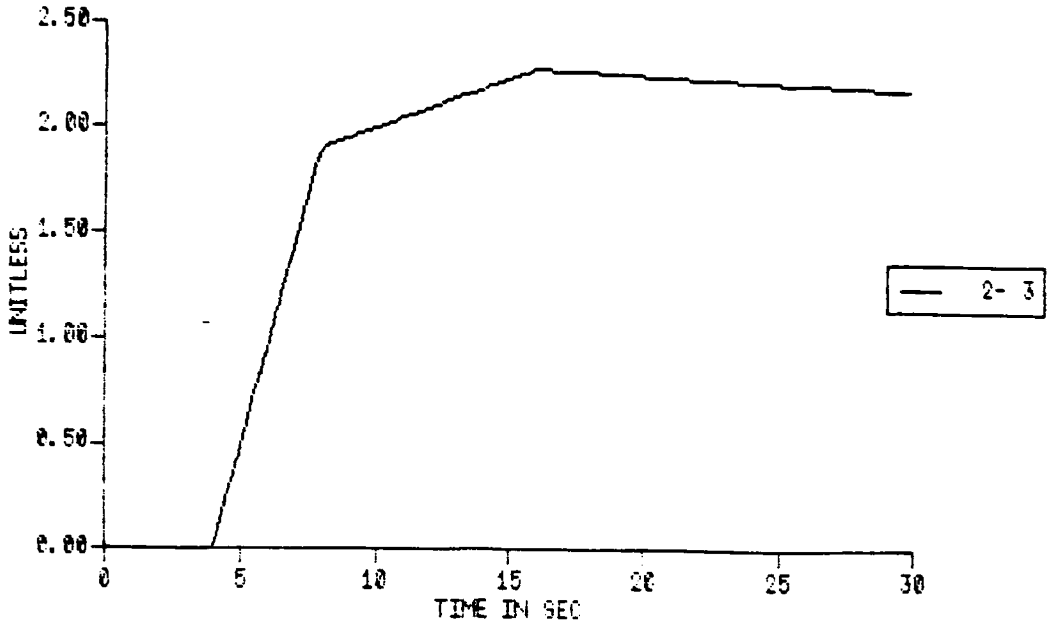


Figure 15: Lambda Value of Line 2-3, Load Shedding Performed.

Case VIII: Tie Line Limiting. In the preceding test cases the three basic functions of the IRCC: AGC, ELD, and overload alleviation, were illustrated. There is, however, an additional function which may be performed. The IRCC can be used to limit the exchange between any two control areas while maintaining the conventional AGC function of area generation-load balance in the individual areas. This would allow the dispatcher to place even more stringent restrictions upon the area exchange than conventional AGC.

Suppose, for example, that Area II wished to limit the power flow to Area III through tie line 6-13 to only 0.3 p.u. In order to accomplish this, one would merely set a "psuedo" maximum line flow of 0.3 p.u. for tie line 6-13 and allow the IRCC to correct for the resulting "overload." Such action would also reduce the power flow through the tie line 12-13 because of its location relative to the "overloaded" line. Since the AGC would ensure that the net tie line flow for Area II would remain constant, the power flow from Area II to Area IV must increase (or decrease since the actual flow is from Area IV to Area II). When such a case was simulated the following line flows were obtained:

From	To	Initial Flow	Final Flow
6	13	0.352 p.u.	0.300 p.u.
12	13	0.018 p.u.	0.003 p.u.
9	14	-0.046 p.u.	0.021 p.u.

Table 3: Tie Line Flows.

As a result of this shifting of tie line flows the exchange between Area II and Area IV will be altered. This alteration must be eliminated by the AGC controls within these two areas.

Proceeding one step further, the total exchange between Area II and Area III can be limited by setting appropriate "psuedo" line flow limits for both of the tie lines connecting the two areas.

COMPARISON OF THE IRCC AND OTHER APPROACHES

There are a few very significant differences between the IRCC and the various other approaches outlined in this paper. These differences are explained in the following sections which compare the IRCC with the other types of approaches discussed earlier.

IRCC -vs- Dynamic Security Dispatch

The Dynamic Security Dispatch algorithms have two basic drawbacks: 1) increased computational time is required in order to examine an entire set of contingencies; 2) added expense may be incurred as the system state is steered away from the optimal state in an attempt to prevent "possible" violations which may not even occur; and 3) some contingencies resulting in violations may not be prevented if these contingencies are somehow absent from the contingency set.

First of all, a preventive security dispatch, be it dynamic or steady-state, requires an examination of a set of contingencies. This examination takes time, and for a reasonably large and complete contingency set, the amount of time necessary to perform the required calculations all but eliminates the possibility of developing an adequate dynamic security package for use on a real-time computer.

The dynamic security approach requires that each of the violations which "may" result from these "possible" contingencies be prevented by rescheduling the generation prior to the contingency's occurrence. If this contingency does not occur, the system has been needlessly steered away from its optimal operating state. This results in added expense. It is also possible, although improbable, that these algorithms will perceive a "possible" violation resulting from a particular contingency that will not even occur if the contingency actually develops. This is referred to as a "false alarm" and will result in additional expense. These false alarms are possible since the effects of these possible contingencies are merely predicted through the use of simplifying approximations. A complete analysis void of these simplifying assumptions would require an extreme amount of computational time and render the approach useless as an on-line tool.

In an attempt to reduce the total computational time required, dynamic security packages which are now being theorized use a smaller set of contingencies selected on the basis of the probability of their occurrence and the importance of their possible effects. Such a selected set of contingencies is, by nature, far from complete; it is always possible (though not probable if an adequate contingency selection algorithm is used) for a contingency which has not been included in this set to occur. If no other type of on-line emergency control is functioning and such a contingency does in fact occur which results in violations in one or more of the operational constraints, the violation will persist until the operator takes notice and manually initiates some corrective control measures. This undesirable situation is referred to as a "miss" and its occurrence must somehow be minimized.

The IRCC is free of the above limitations. It is a corrective type of controller designed to correct for the violations of the operational constraints if and when they occur. A corrective type of controller has two main advantages over a preventive type of controller designed to ensure the system security with respect to a given set of contingencies. First, the corrective type of control requires far less computational time and is therefore better suited to a real-time environment.

Second, the corrective type of controller is less expensive than the preventive type of security dispatch algorithms in that the system state is not unnecessarily steered away from the optimal operating state by preventing "possible" violations, but does so only when these violations actually materialize.

With the IRCC present, the preventive security control algorithms are necessary for only those contingencies which may result in "uncontrollable" operational constraint violations. Any remaining contingencies which may occur and result in "controllable" violations, and even undetected "uncontrollable" violations, can be handled by the IRCC quite easily.

IRCC -vs- Optimal Power Flow

The optimal power flow approach is basically used as a study tool for the existing system conditions or for short-term predicted conditions. The optimal generation schedules are precalculated on an offline basis at definite intervals of time on the basis of these conditions. This requires, among other things: 1) the steady state load flow model for the system, and 2) the projected load schedules at some future time interval.

The inaccuracies of modelling and the forecast errors can at times result in unacceptable schedules. In addition, the real-time computer may be burdened with an enormous amount of calculations because of the AC load flow constraints used to model the system.

In the closed-loop IRCC approach presented here, these inaccuracies are absent since the measurements are taken from the actual system itself at very close time intervals. The nature of the formulation results in computations which are far less taxing on the computer and can be performed well within a SCADA cycle.

The linearized DC model used in the computation of the partial derivatives, dJ_j/dP_{Gi}, for the IRCC does not affect the accuracy of the final optimal state of the system. This approximation can only affect the time it takes for the system variables to reach their new steady-state values.

In addition, the IRCC in its present form does not require the use of either the Jacobian or the Hessian matrices as do the OPF approaches. This results in a less complex formulation with minimal storage requirements.

The IRCC would not replace the OPF algorithms now used, but would merely supplement them. The IRCC could be used as a continuously operating controller for use under both normal and emergency operation; whereas the OPF algorithms would retain their present use as study tools to warn of possible emergencies in the near future by simulating existing or predicted system conditions.

IRRC -vs- LP Approach to Generation Reallocation

Many of the LP formulations previously discussed are nothing more than linearized versions of the preventive security dispatch algorithms, if an examination of a given set of contingencies is performed. This type of formulation possesses the same drawbacks of increased expense and computational burden as the dynamic security approaches.

On the other hand, those LP formulations which are intended to be used for corrective action, are actually linearized versions of the OPF algorithms. These LP approaches do not possess the same difficulties, however, since the linearization results is decreased computational time. But by their very nature, the algorithms require a complete LP (usually Simplex or Dual Simplex) solution for each overload condition which includes many individual iterations. These iterations require a significant amount of time and taxes the on-line computer more so than the proposed IRCC approach which imposes little computational burden and is only limited in time by the SCADA cycle which provides the necessary measurements of the system parameters.

Furthermore, these LP formulations model the system conditions by either a steady-state AC or a steady-state DC load flow. This modelling technique may contain inaccuracies which result in unacceptable generation schedules since the modelled conditions may not correspond to the actual system conditions present once a contingency has occurred. The IRCC, however, is void of these inaccuracies since no such modelling is required. The actual system measurements are used to determine the present system state. In other words, the IRCC is a closed-loop feedback controller designed specifically for on-line usage; whereas these LP formulations are not.

The IRCC, then, is a major departure from the conventional closed-loop controller in that, by itself, it is a nonlinear dynamic system with Lagrange multipliers among its time dependent variables. Synthesizing such a controller is possible only on a digital system and exploits the full potentialities of a real-time computing system.

CONCLUSIONS

A new closed-loop control system, an IRCC (Integrated Real-time Closed-loop Controller), is proposed to perform the major functions of Economic Load Dispatch (ELD), Automatic Generation Control (AGC), and overload limiting and alleviation. The synthesis is based upon a logic which is set up to dynamically steer the system variables and Lagrange multipliers so as to satisfy the Kuhn-Tucker conditions of optimality.

The performance of the IRCC has been tested under various conditions by simulating the long-term dynamics of a multi-area power system. The results indicate that the controller achieves all three of its objectives and that the transition to the new operating state is smooth.

Deficiencies of the IRCC

The IRCC held up well under testing, but it is not without its deficiencies.

For example, as was previously mentioned, the IRCC does not at present possess a completely adequate load shedding algorithm. For this reason, the IRCC, in its present form, cannot really be relied upon to offer the dispatcher a satisfactory load shedding plan in each and every situation in which load shedding is required.

Furthermore, it should be noted that overloads may be relieved by rescheduling the generation as well as by adjusting the taps of the phase shifting transformers before resorting to more extreme measures such as load shedding. The IRCC, however, does not consider these phase shifting transformers in its present form, although it may be easily modified to do so.

In addition, the IRCC will not be able to correct for an overload on a line which has a significant reactive power flow component. In fact, given the way in which the IRCC presently checks for overload violations, the IRCC may not even be able to detect these overloads. The IRCC presently checks for overloads by examining the real power flow on the lines; if the overloads consisting of a large reactive power component were to be detected, the IRCC should check for the overloads by examining either the current flow, or the total complex power flow on the lines. This is only a detection problem and does not affect the IRCC basic structure.

Even if these types of "reactive" overloads are detected, real power rescheduling alone may not totally eliminate the problem. In order for the IRCC to correct all types of overloads, reactive power control must be incorporated into its structure.

Another shortcoming of the present IRCC is the omission of the voltage limit constraints. This again would require some type of reactive power control which is not included in the present formulation. The IRCC, however, can be easily extended to include reactive as well as active power control.

The deficiencies listed above can therefore be eliminated with the addition of: 1) a more robust optimal load shedding algorithm, and 2) some type of reactive power control.

Advantages of the IRCC

The advantages gained by the IRCC easily outweigh its deficiencies. The IRCC, for example, is much less expensive and less time consuming than the Dynamic Security approaches and many of the Linear Programming (LP) approaches, since the system state is not unnecessarily steered from the optimal operating state and no check is made against a set list of possible contingencies. Instead the IRCC is to be used as a continuously functioning controller for both normal and emergency operation; the violations which result from the occurrence of a contingency are corrected for if and when they actually occur, not before.

Unlike the techniques based on the OPF approaches, the IRCC does not require that the system be modelled by the load flow constraints. This results in better accuracy, earlier corrective action, and less computational burden. In fact, the speed of response of the IRCC is limited only by the SCADA scan period.

Simply stated, the IRCC is less complex, faster, and more appropriate than these other approaches for use as an on-line emergency controller.

In addition, the IRCC can be used to offer a plan to "optimally" shed load in cases where the overload cannot be alleviated by generation rescheduling alone.

Where the system conditions warrant, it is also possible to incorporate a more generalized AGC function, which satisfies not only the area generation-load balance, but also accounts for constraints on the tie line exchanges with individual neighboring areas. This allows the individual areas to impose more stringent restrictions upon the exchanges with other areas than the original AGC system.

Additional Work Required

The design of the IRCC, however, is not complete. Additional work must be accomplished in order to incorporate reactive power control to ensure that the voltage limits are maintained and that reactive power overloads are alleviated quickly and efficiently.

The load shedding logic also needs to be reexamined so as to provide the dispatcher a plan for truly optimal load shedding when required.

LIST OF REFERENCES

[1] T. E. DyLiacco. "The Adaptive Reliability Control System," IEEE Transactions on Power Apparatus and Systems. May 1967, pp. 517-531.

[2] L. K. Fink and K. Carlson. "Operating Under Stress and Strain," IEEE Spectrum. Vol.15, March 1978, pp. 48-53.

[3] K. S. Chandrashekhar and D. J. Hill. "Dynamic Security Dispatch: Basic Formulation," IEEE Transactions on Power Apparatus and Systems. Vol. PAS-102, July 1983, pp. 2145-2154.

[4] B. Stott and E. Hobson. "Power System Security Control Calculation Using Linear Programming, Part I," IEEE Transactions on Power Apparatus and Systems. Vol. PAS-97, Sep/Oct 1978, pp. 1713,1720.

[5] B. Stott and E. Hobson. "Power System Security Control Calculation Using Linear Programming, Part II," IEEE Transactions on Power Apparatus and Systems. Vol. PAS-97, Sep/Oct 1978, pp. 1721,1731.

[6] B. Stott and J. L. Marinho. "Linear Programming for Power System Network Security Applications," IEEE Transactions on Power Apparatus and Systems. Vol. PAS-98, May/June 1979, pp. 837-848.

[7] S. M. Chan and F. C. Schweppe. "A Generation Reallocation and Load Shedding Algorithm," IEEE Transactions on Power Apparatus and Systems. Vol. PAS-98, Jan/Feb 1983, pp. 26-34.

[8] S. N. Talukdar and F. F. Wu. "Computer Aided Dispatch for Electric Power Systems," Proceedings IEEE. Vol. 69, No. 10, October 1981, pp. 1212-1231.

[9] J. Zaborszky, K. W. Whang and K. V. Prasad. "Stabilizing Control in Emergencies. Part I - Equilibrium Point and State Determination. Part II - Control by Local Feedback," IEEE Transactions on Power Apparatus and Systems. Vol. PAS-100, May 1981, pp. 2374-2389.

[10] J. N. Wrubel and P. Van Olinda. "Expanding an Energy Control Center to Include a Bulk Systems Security Package," Proceedings PICA Conference. 1981.

[11] B. H. Krogh, S. H. Javid, and J. H. Chow. "Multi-Stage Rescheduling of Generation, Load Shedding and Short-Term Transmission Capacity for Emergency State Control," IEEE Transactions on Power Apparatus and Systems. Vol. PAS-102, May 1983, pp. 1466-1472.

[12] B. H. Krogh. "Allocation of Generation Ramping to Reduce Transmission Line Overloads," IEEE Transactions on Power Apparatus and Systems. Vol. PAS-102, July 1983, pp. 2110-2115.

[13] J. H. Chow, R. P. Schulz, and B. H. Krogh. "Simulation Testing of Rate Allocation Control to Relieve Transmission Overloads During Emergencies," IEEE Transactions on Power Apparatus and Systems. Vol. PAS-103, October 1984, pp. 2855-2863.

[14] J. Carpentier and G. Cotto. "Modern Concepts for Security Control in Electric Power Systems," CIRGE-IFAC Symposium. No: 102-01, Florence 1983.

[15] A. Kuppurajulu and K. Raman Nayar. "Optimal Load Flow, a Reformulation of the Load Flow Problem," ETZ-A(Germany). Oct. 72, Vol. 93.

[16] O. Alsac and B. Stott. "Optimal Load Flow with Steady-State Security," IEEE Transactions on Power Apparatus and Systems. Vol. PAS-93, May/June 1974, pp. 745-751.

[17] D. I. Sun, B. Ashley, B. Brewer, A. Hughes, and W. F. Tinney. "Optimal Power Flow by Newton Approach," IEEE Transactions on Power Apparatus and Systems. Vol. PAS-103, October 1984, pp. 2864-2880.

[18] N. Narasimhamurthi. "On-Line Real Power Scheduling in Marginally Secure Power Systems," IEEE Transactions on Power Apparatus and Systems. Vol. PAS-103, April 1984, pp. 869-873.

[19] O. I. Elgerd. Electric Energy Systems Theory: An Introduction. Second Edition, New York: McGraw-Hill, 1982.

[20] W. D. Stevenson, Jr. Elements of Power System Analysis. Fourth Edition, New York: McGraw-Hill, 1982.

[21] K. Sato, Z. Yamazaki, T. Haba, N. Fukushima, K. Masegi, and H. Hayashi. "Dynamic Simulation of a Power System Network for Dispatcher Training," IEEE Transactions on Power Apparatus and Systems. Vol. PAS-101, October 1982, pp. 3742-3750.

[22] O. R. Davidson, D. N. Ewart, and L. K. Kirchmayer. "Long-term Dynamic Response of Power Systems: An Analysis of Major Disturbances," IEEE Transactions on Power Apparatus and Systems. Vol. PAS-94, May/June 1975, pp. 819-826.

[23] A. Kuppurajulu. "An Emergency Control Algorithm for Real-Time Applications," To be presented at: The IEEE/PES 1985 Winter Meeting. New York, New York, Feb. 3-8, 1985.

APPENDIX A: A-MATRIX CALCULATIONS

1. Bus-Line Distribution Factors [23]

If the line flow P_{ij} between the buses i and j is written as a function of the angular difference θ_{ij}:

$$P_{ij} = B_{ij}\theta_{ij} \qquad (A.1)$$

where: B_{ij} = the susceptance of the line

then,

$$P = K\theta \qquad (A.2)$$

where: P = N-1:1 vector of bus power injections.

θ = N-1:1 vector of bus angles.

K = N-1:N-1 matrix whose elements are:

$$K_{ii} = \underset{\substack{j=1 \\ j\neq i}}{\overset{N}{\mathrm{SUM}}}\{\ B_{ij}\ \} \quad \text{and} \quad K_{ij} = -B_{ij} \qquad (A.3)$$

From (1) the line flow vector for L lines can be written as:

$$Pl = AP \qquad (A.4)$$

where: Pl = L:1 vector of line flows.

A = the L:N-1 bus-line distribution factor matrix calculated from:

$$A = MX \qquad (A.5)$$

where: M = N-1:N-1 bus incidence matrix.

$$X = K^{-1} \qquad (A.6)$$

The elements of the A-matrix are computed only as they are needed, thereby avoiding explicit storage of the entire matrix.

If the kth column of the A-matrix, A_k, corresponds to the kth line connected between buses i and j, then

$$A_k = [0 \ldots \underset{i}{B_{ij}} \ldots \underset{j}{-B_{ij}} \ldots 0]X$$

$$\text{(i.e.)} \quad A_k = B_{ij}(X_i - X_j) \tag{A.7}$$

where: X_i = the ith column of the X-matrix.

If $X_i - X_j = Z_k$, then

$$A_k = B_{ij}Z_k \tag{A.8}$$

The Z_k-vector can be evaluated by solving for:

$$\theta = Z_k \text{ from (2) with}$$

$$P = [0 \ldots \underset{i}{1} \ldots \underset{j}{-1} \ldots 0]$$

To solve equation (2), sparsity programming techniques are used by storing the K-matrix in the sparse form.

2. A-Matrix With a Branch Outage [23]

If an outage of branch γ (line or transformer) connecting nodes p and q has occurred, then the new vector A_k' under the outage condition can be evaluated from:

$$A_k' = A_k - B_{ij}(Z_{\gamma i} - Z_{\gamma j})Z_\gamma/\Delta \tag{A.9}$$

where: $Z_{\gamma i}$ = ith element of Z_{γ}.

$\Delta = Z_{\gamma p} - Z_{\gamma q} - \mathcal{Z}_{pq}$.

$\mathcal{Z}_{pq}$ = impedance of the line connecting nodes p and q.

The information from the last two sections was taken from reference [23].

3. Evaluation of dJi/dPGi and dp/dPGi

It is seen from the above relationships that $dJ_j/dP_{Gi} = a_{ji}$, where a_{ji} is the jth row, ith column entry of the A-matrix.

If the total losses in the system are approximated by:

$$p = \mathrm{SUM}_{j=1}^{L}\{R_j Pl_j^2\} \qquad (A.10)$$

where: R_j = resistance of line j.

then,

$$dp/dP_{Gi} = 2(\mathrm{SUM}_{j=1}^{L}\{R_j Pl_j (dPl_j/dP_{Gi})\})$$

$$= 2(\mathrm{SUM}_{j=1}^{L}\{R_j (Pl_j)(a_{ji})\}) \qquad (A.11)$$

APPENDIX B: FIVE BUS TEST SYSTEM DATA.

The following tables contain the system parameters used in the testing of the IRCC on the five bus test system. All values are in p.u.

Line #	From Bus	To Bus	R_j	X_j	Ysh_j	Pl_j^M
1	1	2	0.0194	0.0592	0.0	0.55
2	3	4	0.0540	0.2240	0.0	0.25
3	3	5	0.0469	0.1980	0.0	0.35
4	4	5	0.0581	0.1763	0.0	0.25
5	1	3	0.0	0.2091	0.0	0.75

Table B.1: Line Data for the Five Bus System.

Bus #	P_{Li} (MW)	P_{Gi} (MW)	P_{Gi}^M (MW)	P_{Gi}^m (MW)	H_i (sec)	σ_i (MW/Hz)	V_i (V)
1	0.9	1.31	1.4	0.4	5.0	0.00833	1.0
2	0.8	1.0	1.5	0.3	5.0	0.00833	1.01
3	1.2	1.0	1.5	0.7	5.0	0.00833	1.01
4	1.0	1.0	1.5	0.5	5.0	0.00833	1.01
5	0.4	0.0	---	----	0.05	0.00833	----

Table B.2: Bus Data for the Five Bus System.

Bus #	T_{gi} (MW)	T_{ti} (MW)	n_i (Hz/MW)	a_i	b_i
1	0.08	0.3	2.4	100.0	900.0
2	0.08	0.3	2.4	120.0	800.0
3	0.08	0.3	2.4	120.0	800.0
4	0.08	0.3	2.4	180.0	700.0

Table B.3: Generator Parameters for the Five Bus System.

APPENDIX C: FOURTEEN BUS TEST SYSTEM DATA.

The following tables contain the system parameters used in the testing of the IRCC on the 14 bus test system. All values are in p.u.

Line #	From Bus	To Bus	R_j	X_j	Ysh_j	Pl_j^M
1	2	3	0.0469	0.1980	0.0418	0.60
2	2	4	0.0581	0.1763	0.0374	0.22
3	2	5	0.0569	0.1739	0.0368	0.25
4	3	4	0.0670	0.1710	0.0350	0.55
5	4	5	0.0133	0.0421	0.0090	0.20
6	4	7	0.0	0.2091	0.0439	0.80
7	4	9	0.0	0.5562	0.1224	0.20
8	5	6	0.0	0.2590	0.0544	0.45
9	6	11	0.095	0.1990	0.0406	0.20
10	6	12	0.1229	0.2558	0.0537	0.25
11	7	8	0.0	0.1761	0.0370	0.21
12	7	9	0.0	0.1100	0.0231	1.00
13	9	10	0.032	0.0845	0.0178	0.60
14	10	11	0.082	0.1920	0.0403	0.35
15	1	2	0.0194	0.0592	0.0124	1.00
16	1	5	0.0540	0.2240	0.0470	0.40
17	6	13	0.0661	0.1303	0.0270	0.50
18	12	13	0.0	0.2000	0.0420	0.20
19	9	14	0.1271	0.2704	0.0569	0.20
20	13	14	0.1709	0.3480	0.0731	0.50

Table C.1: Line Data for the 14 Bus System.

Bus #	P_{Li} (MW)	P_{Gi} (MW)	P_{Gi}^{M} (MW)	P_{Gi}^{m} (MW)	H_i (sec)	σ_i (MW/Hz)	V_i (V)
1	1.31	2.47	2.853	0.0	10.0	0.00833	1.0
2	0.217	0.24	0.38	0.0	2.0	0.00181	1.01
3	1.083	0.31	0.7	0.0	2.2	0.00833	1.01
4	0.58	0.0	----	----	0.03	0.00483	----
5	0.286	0.0	----	----	0.005	0.00238	----
6	0.312	0.6	1.0	0.0	3.0	0.00260	1.02
7	0.0	1.263	1.6	0.0	5.0	-----	1.02
8	0.0	0.16	0.2	0.0	1.0	-----	1.02
9	0.294	0.0	----	----	0.04	0.00245	----
10	0.29	0.0	----	----	0.01	0.00256	----
11	0.135	0.0	----	----	0.005	0.00119	----
12	0.161	0.0	----	----	0.01	0.00151	----
13	2.183	1.45	1.8	0.0	7.0	0.01666	1.02
14	1.149	1.60	2.05	0.0	3.0	0.00833	1.02

Table C.2: Bus Data for the 14 Bus System.

Bus #	T_{gi} (MW)	T_{ti} (MW)	R_i (Hz/MW)	a_i	b_i
1	0.08	0.3	1.2	65.0	700.0
2	0.08	0.3	10.0	147.0	900.0
3	0.08	0.3	7.74	100.0	900.0
6	0.08	0.3	4.0	100.0	850.0
7	0.08	0.3	2.14	65.0	800.0
8	0.08	0.3	16.88	210.0	900.0
13	0.08	0.3	1.66	52.0	850.0
14	0.08	0.3	1.5	50.0	820.0

Table C.3: Generator Parameters for the 14 Bus System.

END

FILMED

4-85

DTIC