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A MICROCOMPUTER BASED SUBSTATION CONTROL SYSTEM

A DISSERTATION

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BY

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A MICROCOMPUTER BASED SUBSTATION CONTROL SYSTEM

APPROVED BY

DISSERTATION COMMITTEE

DEDICATION

For her patience and understanding during its preparation, this dissertation is dedicated to my wife, Rebecca Crawford Russell.

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The author wishes to acknowledge his indebtedness to Dr. Marion Earl Council, whose direct supervision and instruction made this investigation possible. Special recognition and thanks is given to Dr. Clovis Roland Haden, whose encouragement and assistance over the past eight years has been of inestimable value.

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GLOSSARY

Alarm. A warning of an unusual system condition.
Analog. A continually variable representation of physical quantities by means of other physical variables, such as current, voltage, resistance.
Analog Data. Data that varies continuously over a range of values.
Analog Device. A device that operates with variables represented by continuously measured quantities.
Area Tie-Line. A transmission line connecting two control areas.
Baud. A unit of signalling speed equal to the number of code elements per second.
Buffer. A device in which data is temporarily stored and/or provides signal amplification.
Bus. A conductor or group of conductors in an electrical network that serves as a common connection for two or more circuits.
Channel. A transmission path between master stations and remote stations over which communication signals can be sent.
Circuit. A power carrying connection between buses.
Circuit Breaker. A device used to interrupt current flowing in an electrical power network.
Demand. Amount of electrical energy being used during a specified period of time.
Digital Device. A device that operates on the basis of discrete numerical techniques in which the variables are represented by coded pulses or states.
Dispatcher. The title given to personnel in the electric utility industry concerned with control of operations and assignments of load to generating stations and lines.
Disturbance. An abnormal condition within the power network.
Event. A happening in an electrical system of unusual interest.
Load. The amount of electric power delivered or required at any specified point or points on a system.
Logger. A device which automatically records physical processes and events, usually chronologically.
Net Interchange. The algebraic sum of the powers and/or energies on the area tie-lines of a control area.
Off-Line. Pertaining to equipment or devices not under direct control of the central processing unit of a computer system.
On-Line. Pertaining to equipment or devices under the direct control of the central processing unit of a computer system.
Parameter. A variable that is given a constant value for a specific purpose or process.
Point. A term used to designate a sensing device that provides the source of a power system data variable.

Program. As a noun, the complete sequence of machine instructions and routines to solve a problem.

Real-Time. The performance of a computation during the actual time that the related physical process transpires in order that results of the computation can be used in guiding the physical process.

Scale. To change a quantity by a factor in order to bring its range within prescribed limits.

Scan. The action of acquiring a set of individual point measurements from a collection of remote points.

Scheduled Net Interchange. For a control area, the mutually prearranged net power and/or energy on the area tie-lines.

Set Point. The position to which a control point setting mechanism is adjusted.

Stored Program. A series of instructions in storage to direct the step by step operation of a computer.

Substation. A location where transformers, buses, circuit breakers, disconnect switches, and related equipment are located.

Telemetering. Transmission of measurements over a long distance, usually by electric means.

Tie-Line. A transmission line connecting two or more power systems or control areas.

Transducer. A sensing device for converting one form of energy into another form.

CHAPTER I

INTRODUCTION

Considerable effort has been expended in the past twenty years in applying the hardware and techniques of the rapidly expanding computer industry to the problems of the power industry. For purposes of briefly showing the development of computer use by utilities, the power system has been divided into five areas:

1. System Studies
2. Generation Control, Economic Dispatch, etc.
3. HV Substation Automation, Supervisory, Data Acquisition, etc.
4. Distribution Substation Automation, Remote Meter Reading, etc.
5. Protection Systems

The first area of application perceived by power system engineers was the use of the computational capabilities of digital computers to perform the "systems studies" which had previously been carried out on analog computer and simulator equipment. So tremendous was the success of this approach that once heavily used analog systems are obsolete. Virtually every issue of <u>Power Apparatus and Systems</u> (or any other major power publication) contains at least one article on digital simulation or computation techniques applied to power system analysis. At present, the majority of digital systems research in the power area concerns system studies. The recent trend is toward real-time studies for system control in addition to off-line analyses such as fault current and load flow calculations. The use of the computer as a tool for on-line monitoring and control was recognized early by control engineers. The vast problems of control, data acquisition, data handling, status monitoring, alarming, etc., which are found in power generation stations, made a very good case for the application of digital systems to the generation area. While original generation control and economic dispatch systems were analog, conversion to digital control is the current trend. More sophisticated control is possible taking into account new parameters, such as environmental conditions. In a recent example, boiler fuel is changed from high sulphur to low sulphur type based on an environmental evaluation by a real-time computer system. [1] Work in these areas has been intensive for the past fifteen years and is on-going with new areas of emphasis. Because of the emphasis on energy conservation, there are new problems to define and solve.

Areas 3, 4 and 5 of the above list have not been pursued to the extent of system studies and generation control. This is basically due to the requirement that the digital equipment be distributed throughout the system. However, since the advent of minicomputers on the technological scene, power systems engineers have contemplated their use in control and protection at the transmission and distribution substation level. For many years, the only digital application has been in the communications area. Coded interrogation and encoded data are very secure and efficient to transmit, receive, and handle. Most of the communication links terminate in an electromechanical relay interface to integrate them into substation operations. Only limited work has been done in the use of "smart" terminals, digital remote terminal units, computerized data acquisition systems, etc.

Limited supervisory systems have become popular with utilities. The ability to address a particular substation and receive system data or perform limited control is valuable. Because of this, many companies have installed such systems in the past few years. Most of these systems are manually initiated, rather than computer controlled and automatically updated. Needless to say, extensive work needs to be done to upgrade these systems and incorporate recent technological advances in digital systems.

The recent emphasis on fuel conservation has created an interest in distribution automation, remote meter reading, load control, etc. Remote control of the power system at the distribution and utilization level would allow the utility to accomplish control of feeder loading, multi-point sectionalizing for service restoration, network reconfiguration, and load shedding. Automatic meter reading and time-of-day metering may also be necessary in the future. The large number of meters present on any system makes digital identity coding a necessity. Sophisticated digital systems will be required to handle the mass of data collection at the residential level.

Protection systems have long been candidates for digital techniques. Until the decade of the sixties, size and cost prohibited serious consideration; however, introduction and development of relatively inexpensive minicomputers in the past fifteen years has opened up new possibilities. Numerous feasibility studies, software and hardware developments, and experimental tests have sufficiently demonstrated the theoretical capability of a digital computer to protect and monitor a typical transmission system at the substation level. These studies have shown that the job can be done by a single digital machine, yielding a system with roughly the same control characteristics as present static and electromechanical relays. It has also been confirmed, however, that many of the supposed advantages of a digital computer in this application cannot be realized due to their cost, the complicated nature of the required system, reliability problems, maintenance considerations, environmental considerations, etc.

The problem of economics versus speed slowed progress in this area and relegated most of the subsequent work to theoretical studies and algorithm development. In 1972, however, the introduction of the microprocessor (or computer-on-a-chip) by Intel Corporation provided the tool which had been lacking to make the theoretical concepts both practical and economical. It is proposed here that the microprocessor is capable of providing the necessary computational and control power to be used not only in generation control and economic dispatch, but also in substation automation, supervisory and data acquisition systems, and protection systems.

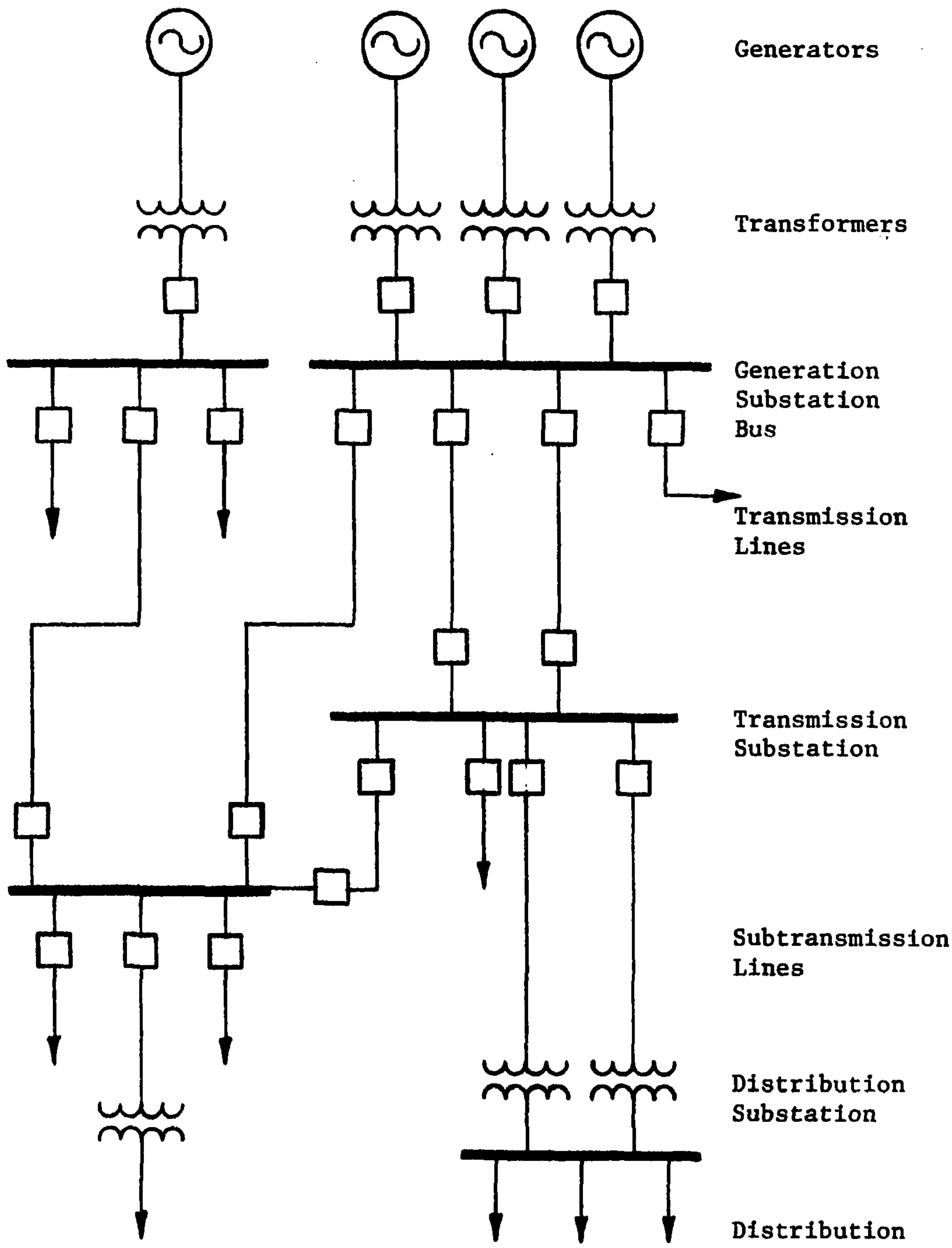
In response to the availability of a control tool such as the microcomputer, a new analysis of substation automation is warranted, taking advantage of the concept of distributed processing and control. Many of the techniques currently used to monitor and control substations are valid in light of present technology. These, of course, should be sought out and utilized where appropriate. However, improvements may be achieved by utilizing the microcomputer and distributed control concepts to replace many of the existing operating systems. Using microcomputers, a power substation automation system has been developed which will not only meet all local functional requirements, but which can be integrated into a system-wide control structure. In short, the system will interface with advanced control and data acquisition systems which use centralized computers and will make total power system automation a reality.

1.1 Definition of a Substation

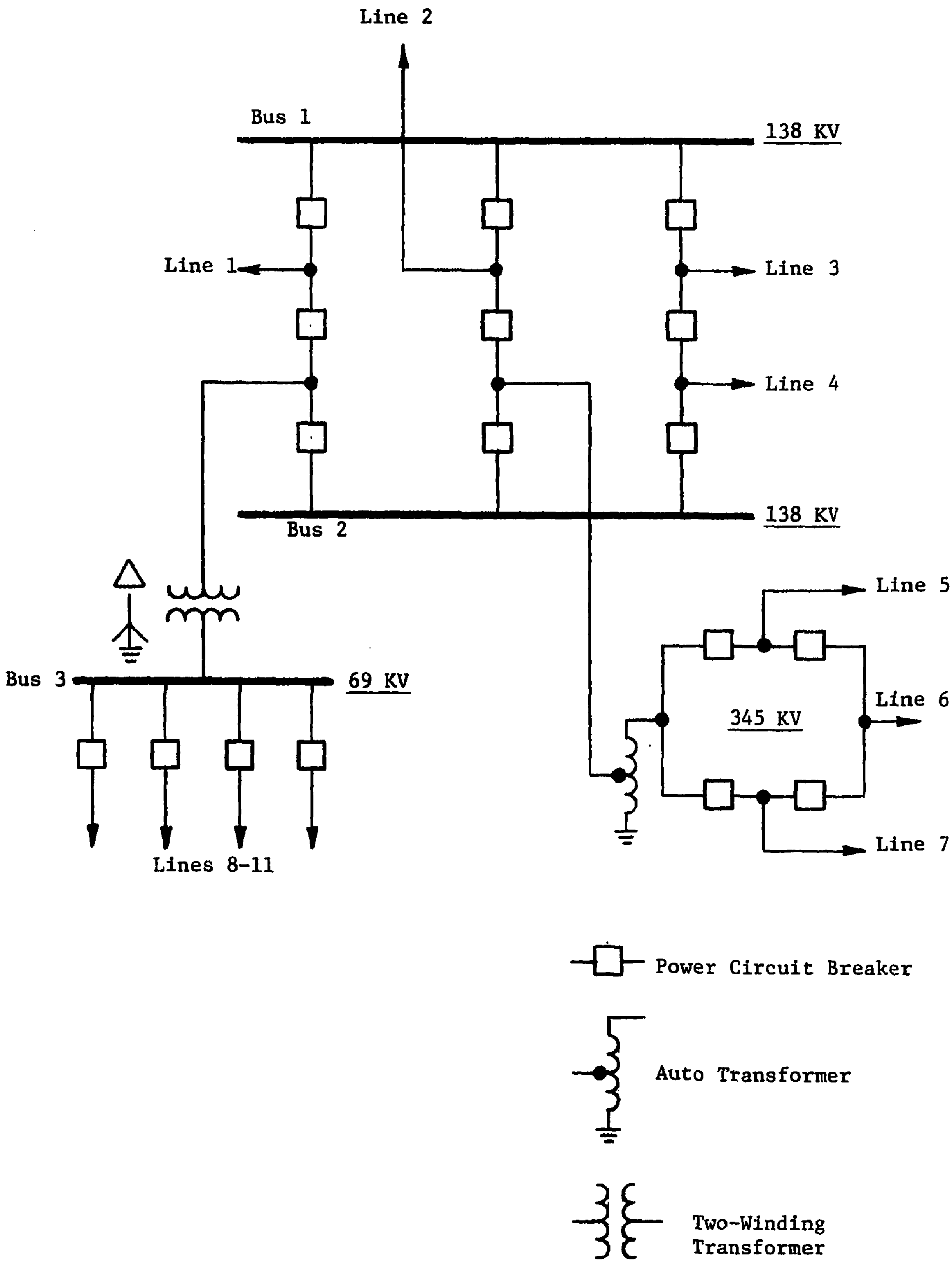
A complete understanding of the nature, performance, characteristics and operating requirements of a power system substation is mandatory if we are to attempt digital system control. The word "substation" is a very broad term. Between the points of generation and utilization of power, there exist many locations of voltage transformation, switching, line interconnections, etc. A geographical location where many of these functions are performed is known typically as a substation.

Figures 1 and 2 show simplified one-line diagrams of a typical power system and power substation. It can readily be seen that each substation exists at a node of the electrical system formed by the convergence of numerous power transmission lines of various voltage levels. Switches and breakers control these lines. Local manual control always exists and with large substations, limited control may be exercised automatically or by a central dispatch or control center.

Substations at different levels in the system have different system functions. A high-voltage substation may serve primarily to distribute bulk power from a 345-500 kV transmission line to a number of 138 kV voltage levels. With the exception of station service, no load would be served from these substations. Control at this point is concerned with line and equipment protection and network configuration modification. As substation voltage levels decrease, load service becomes more significant. Control at these lower levels, typically referred to as distribution levels, becomes as concerned with service continuity and quality as with equipment protection. Since the amount of load per substation is



TYPICAL POWER SYSTEM
FIG. 1



TYPICAL TRANSMISSION
SUBSTATION
FIG. 2

increasing, individual substations are becoming more important, making automation and data acquisition at this level of great importance.

1.2 Functional Requirements of a Substation

A practical design requires a complete and thorough understanding of the control and monitoring functions a substation might be called upon to perform. Typical substation functions may be loosely subdivided into four categories. These categories and certain representative functions for each are listed below.

1. Intra-substation and remote supervisory control
   a. Breaker open/closed with synchronization check
   b. Remote opening/closing of motor operated switches and disconnects
   c. Remote control of tap changing transformers and regulators
   d. Incremental step switching of capacitor/reactor banks
2. Alarming and Status Indications
   a. AC/DC station power service
   b. Three-phase potential on incoming lines
   c. Open/closed/lock-out status of circuit breakers
   d. Open/close status of motor operated switches
   e. Transformer winding/coil temperatures
   f. SF_6 gas/oil/air status on power circuit breakers
   g. Transformer and feeder overcurrent/overload conditions
   h. Detection of runaway tap changers
   i. Status of automatic load shedding equipment

j. Network and bus configuration

k. Substation environmental status and intruder detection

3. Data Acquisition, Logging and Sequence of Events Recording

a. Total station Megawatts, Megavars, and MVA

b. Individual transformer MVA

c. Individual feeder loading and peak determination

d. Pre/post-fault data collection

e. Fault-initiated equipment activity/time sequence log

f. Power exchange monitoring for interconnections

4. Protection

a. Primary/backup relaying for line fault clearing and isolation

b. Breaker failure protection schemes

c. Equipment and line overload protection

Since substations at various voltage levels in the system have different requirements, and since utility control practices are in no sense standardized, it is unlikely that any single substation would incorporate all of these functions. It should be expected that certain capabilities from each of these categories would be found in any substation.

Category 1 consists of control functions such as network reconfiguration and voltage profile modification. Capability exists to accomplish control on a local basis, or, in some cases, remotely through a supervisory system from a centralized location. Category 2 monitors the entire substation and compares data to predetermined limits to determine dangerous or out-of-tolerance conditions such as SF_6 gas contamination on a breaker. Trends ultimately resulting in overload or dangerous conditions can be determined prior to equipment damage allowing time for corrective action. Knowledge of the open/closed status of switches, breakers, disconnects, etc., allows a remote operator to verify the configuration of the electrical network. In Category 3, permanent copy logging of predetermined parameters such as station MVA or fault data is accomplished. Such data is typically used for off-line analysis of the system, however, improvement of the logging techniques would allow real-time use for this data for superior system security and control. Category 4 is concerned with the protection of lines and equipment. Equipment failures or overloads as well as line faults are detected and corrective action taken. Needless to say, Category 4 is of great importance and demands ultimate reliability.

1.3 Traditional Substation Control Techniques

The traditional approach to substation operation can best be classified as manual control with analog protection systems. Originally, control (including protection systems) consisted of the opening and closing of switches by a station attendant. As power and voltage levels increased and coordination and speed became considerations for the protection systems, fuses and manual switches were displaced by electromechanical protection. This has existed for many years and, with minor modifications, is still the approach taken by most utilities. With this system, protection is performed automatically. Voltage and current information is obtained from the lines through potential and current transformers. This information is presented directly to an electromechanical relay which determines out-of-tolerance or faulty conditions and initiates trip signals to the appropriate power circuit breakers. The operation of one type of electromechanical relay can best be described as a single phase induction motor. In the case of this relay, the rotor is limited to less than full rotation. As the appropriate V/I characteristics occur on the lines, the rotor (disc, cup) rotates and a set of contacts, physically attached to the rotor, make to initiate the trip signal. By altering the winding locations, magnetic structure, winding polarities, rotor characteristics, etc., the protection characteristics of the electromechanical relay can be altered to fit various protection situations. [2]

To overcome some of the limitations of electromechanical relays, several manufacturers have developed "solid state" relays to perform the protection function. [3] Using solid state components and various electronic circuits, such as comparators, integrators, filters, etc., they have successfully duplicated the protection characteristics of electromechanical relays. Many problems existed with the first solid state relay, hence acceptance has been slow. Many utilities still refuse to use these devices. New developments, superior electromagnetic shielding, transient and surge protection, and the use of integrated circuits is constantly improving these devices and hastening their acceptance by utilities.

Control and monitoring in substations was, and, in some utilities, still is performed manually by station attendants. Written records are kept of vital substation information and control consists of various manual switching operations. While some utilities still use the attended substation concept, most have come to recognize that unattended stations which are remotely controlled offer superior operating performance. Because of this, most major utilities have incorporated supervisory control and data acquisition systems (SCADA) in their substations. [4]

SCADA systems had their beginning in 1921 when Commonwealth Edison placed distribution substations under limited control using telephone lines as a communication medium. [5] Such functions as breaker open/close were performed from a central location. From this beginning, many utilities developed techniques to provide limited control over various substations throughout their systems at all voltage levels. The first major supervisory system of modern design at the distribution substation level was installed by Union Electric Company.[6] Built by Control Data Corporation, the system consists of two SC1700 central processing units which communicate with remote terminal units (RTU's) over leased telephone lines. The initial 196 remote terminal units will be expanded to 300 stations to provide supervisory control, indication, and full data acquisition. CRT's and loggers provide operator interface.

This supervisory system's operation follows a rather straightforward technique. By entering the appropriate three-number code, the supervisor may select a substation and display its one-line diagram. Station and alarm data on this substation is updated every six seconds. A change in status such as a breaker trip is indicated to the operator by change of color on the CRT. Alarms are processed by the computer and logged out as well as displayed on the CRT. Control is executed by a four-step process:

1. Device Selection

   A certain device located in the predetermined substation may be selected by a four-digit device number.

2. Operation Entry

   An operation (open, close, raise, lower, etc.) is selected by a key on the operation keyboard.

3. Verification

   The computer checks the proposed device operation and determines if it is reasonable and gives a valid or invalid indication to the operator.

4. Execute

   The operator may either cancel or execute the command. If it is executed, confirmation of operation is made and event is automatically logged.

The RTU's gather substation information and status changes. Analog information is transmitted after multiplexing and A/D conversion. Very limited intelligence exists in the RTU and no preprocessing of digital data is performed.

Information is obtained from the RTU's at the substation by a continuous scanning technique. Substations are addressed sequentially and checked for a change in status, and, where appropriate, analog data. This information is processed to determine what notification, if any, should be made to the operator, and what data should be logged. Telephone lines using a party line system with six substations per line are used for communication. Transmission rate is 600 or 1200 baud. Union Electric's SCADA system is a step toward total substation automation and is in itself a rather complete example of the state of the art of systems currently in use by utilities. However, it should be noted that since no preprocessing of data or decision making is performed at the substation level, the system has less than optimum characteristics.

Bonneville Power Administration (BPA) is advancing the state of the art by the addition of two substation computers to perform local processing of data prior to transmission to a central location. [7] The results of their efforts will be interesting; however, since no new functions will be performed by their system, total substation automation and integrated protection is still unrealized.

CHAPTER II

EVALUATION OF PREVIOUS ATTEMPTS AT SUBSTATION AUTOMATION

2.1 Problems with Classical Substation Control Techniques

In the case of the data acquisition and monitoring functions, the greatest drawback of present systems is the lack of preprocessing of data before transmission to a central location. The data is gathered and transmitted to a central computer for processing to extract the valuable information and to indicate abnormal conditions. Such a system is highly inefficient in its use of communication links. A local computer could gather all substation data, preprocess the valuable data for transmission to a central computer, and monitor the substation for abnormal conditions, calling the central computer only when such conditions exist.

The greatest problem with the protection system is centered around the fact that the protection of each line or piece of equipment is essentially independent and fixed with respect to the rest of the protection system characteristics either automatically or by operator initiation. In fact, the protection system relay settings cannot be monitored remotely, much less altered to fit changing system requirements. Adaptive relaying is quite impossible and the characteristics of the protection system represent an "unknown" piece of data to system operators. These represent only two of many insufficiencies in present substation control systems. In addition, present systems will not handle advanced adaptive control, since only elementary remote supervisory control, with no local intelligence, is available. Advanced load management based on changing system conditions is not being accomplished.

In a recent paper, the computer relaying subcommittee of the Power Systems Relaying Committee formulated the following list of functions to be performed by central control computers. [8]

Control and Protection Functions

1) Data collection and manipulation
2) Supervisory control
3) Relay target logging
4) State estimation program
5) Operating procedure recommendations
6) Automatic fault studies and relay settings
7) Power system stability monitoring
8) Corrective actions for stability problems

Dispatch Functions

1) Automatic generation control
2) Economic dispatch
3) Generation schedule
4) Optimum unit commitment
5) Interchange negotiations
6) Interchange billing
7) Volt/Var dispatch
8) Weather forecast analysis
9) Load forecast--future
10) Evaluation of proposed operations
11) Systems security

12) Load flow calculations

13) Environmental monitoring

If in the future a central computer is to perform these functions, it will require considerably more data concerning the system than it now receives. Specifically, to perform the state estimation function, the central computer must be kept informed of all circuit changes and substation operations on a real-time basis. Since no computer can digest this massive amount of raw data, only changes in the system should be presented to central computer. Hence, once again we call for local, preprocessing of substation data by a substation computer.

The substation computer working group of the Power Systems Relaying Committee has recommended the following functions be performed by a substation computer. [9]

<u>Substation Computer Functions</u>

Primary Fault Detection (Transmission Line)

Fault Classification

Breaker Tripping

Fault Location

Back-up Fault Detection

Bus Bar Protection

Transformer Protection

Electrical
Gas Pressure
Gas Analysis
Moisture content, etc.

Adaptive Relay Settings (local, remote command)

Adaptive Breaker Control

Breaker Failure (Analysis and Recovery)
Reclosing Control

Voltage and Reactive Control

Switching Control in Discrete Steps

Load Shedding and Rejection

Sectionalizing

Load Survey

Load Projection

Load Management (Voluntary and Involuntary)

Meter Reading

Oscillography

Pre- Post-Fault Data and Analysis

Substation Security

Communications Control

Encoding, Coding, Error Control

Substation Carrier

Supervisory

Data Logging

Analog Metering, Demand Metering

- MW
- MVAR
- Power Factor
- Voltage
- Voltage Angle
- Current
- Frequency
- Line Loss and MWH Calculations

Transformer Information
Breaker and Disconnect Status
Relay Status
Tap Settings
All Other Contact Status
Sequence of Events
Environment Checks
Weather Information
Control Room Temperature
Temperature of Other Elements

Computer Equipment Checks (Diagnostics)
Power Supply Monitor
Control of Operator Interface Display Console
Real Time Clock

In addition to these functions, the following might also be appropriate.

1. With increasing substation loading, attention will be given to automatic load management. Control will be at least partially exerted at the substation level by "intelligent" controllers, probably microcomputers. This will involve bulk power management and utilization level load management (voluntary and involuntary). In the case of the latter, the substation microcomputer may use distribution carrier communication systems to either control residential/commercial load or inform those loads that voluntary conservation measures are immediately required. The substation computer will invariably be interfaced to larger computers for system-wide control.
2. Should Peak Load Pricing become a reality, many utilities may adopt automatic meter reading using carrier communication systems. With such systems, considerable data management will be required at the substation level. It is conceivable that much of this will be accomplished using microcomputers interfaced to higher order computer systems.
3. The future existence of distribution communications systems and automatic meter reading opens up numerous possibilities for substation microcomputers. For example, distribution fault location could be easily achieved.

A microcomputer system could poll all remote units in rapid succession and by performing simple pattern recognition on the network using the information received, locate a fault or change in the distribution circuits very rapidly.

4. With an appropriate communication scheme, a substation microcomputer could intelligently perform such functions as remote capacitor bank switching, remote feeder switching, etc. Such Distribution Automation will become more frequent as heavy loading and circuit complexities force changes in present procedures.
5. Substation security, including intruder detection, is becoming more important as theft, vandalism, and retribution/revenge attacks on utilities become more frequent. Microcomputer based security monitoring and assessment systems should become increasingly more common.
6. Many system security and control engineers are looking at "real-time system state estimation" as an appropriate control technique for the future. Such a scheme would require numerous remote units to gather and preprocess system data and coordinate communication of that data to a central computer, or state estimator. Microcomputers seem ideally suited to this function.

It is obvious that the existing supervisory control and data acquisition systems, as well as the existing protection systems, are incapable of performing the numerous functions mentioned in the above list. A new substation automation control system which would be capable of performing all of the above functions and which could be incorporated into an overall system control structure is needed.

2.2 Evaluation of New Fault Detection Techniques

The limiting factor in a total substation automation is the ability to satisfactorily perform the protection function in a fashion compatible with system integration and reliability requirements. Therefore, an analysis of the previously proposed digital protection techniques is appropriate.

The advocates of ultra high-speed breaker action and current limiter insertion under fault conditions have caused renewed interest in the part of relay and control engineers in various fast fault detection techniques. Categorizing these techniques can be quite a problem. Three combined criteria have been chosen to help distinguish between the concepts:

1. Analog/digital
2. Active/passive
3. 60 hertz/high-frequency

The first category, analog/digital, is easily understood. Present electromechanical and static relay systems are analog in nature and many research efforts across the country are aimed at incorporating modern operational amplifier circuits in developing analog high-speed relays. In parallel with these developments, are efforts to analyze system information using digital equipment and make the required decisions in software. This work has not progressed to the applications level of analog relay hardware and techniques.

The second category, active/passive, distinguishes between systems which use available systems state information and those which actively impress additional signals on the transmission lines. Specifically, passive systems would be those which use voltage, current, and frequency information taken from the line to determine fault occurrence. They react to the change in system state and do not impress signals on the line. Active systems refer to those which, for example, inject a pulse burst on the line and take time measurements for the return to determine the distance to the fault. Such systems can be very fast but are also many times more expensive than their passive counterparts.

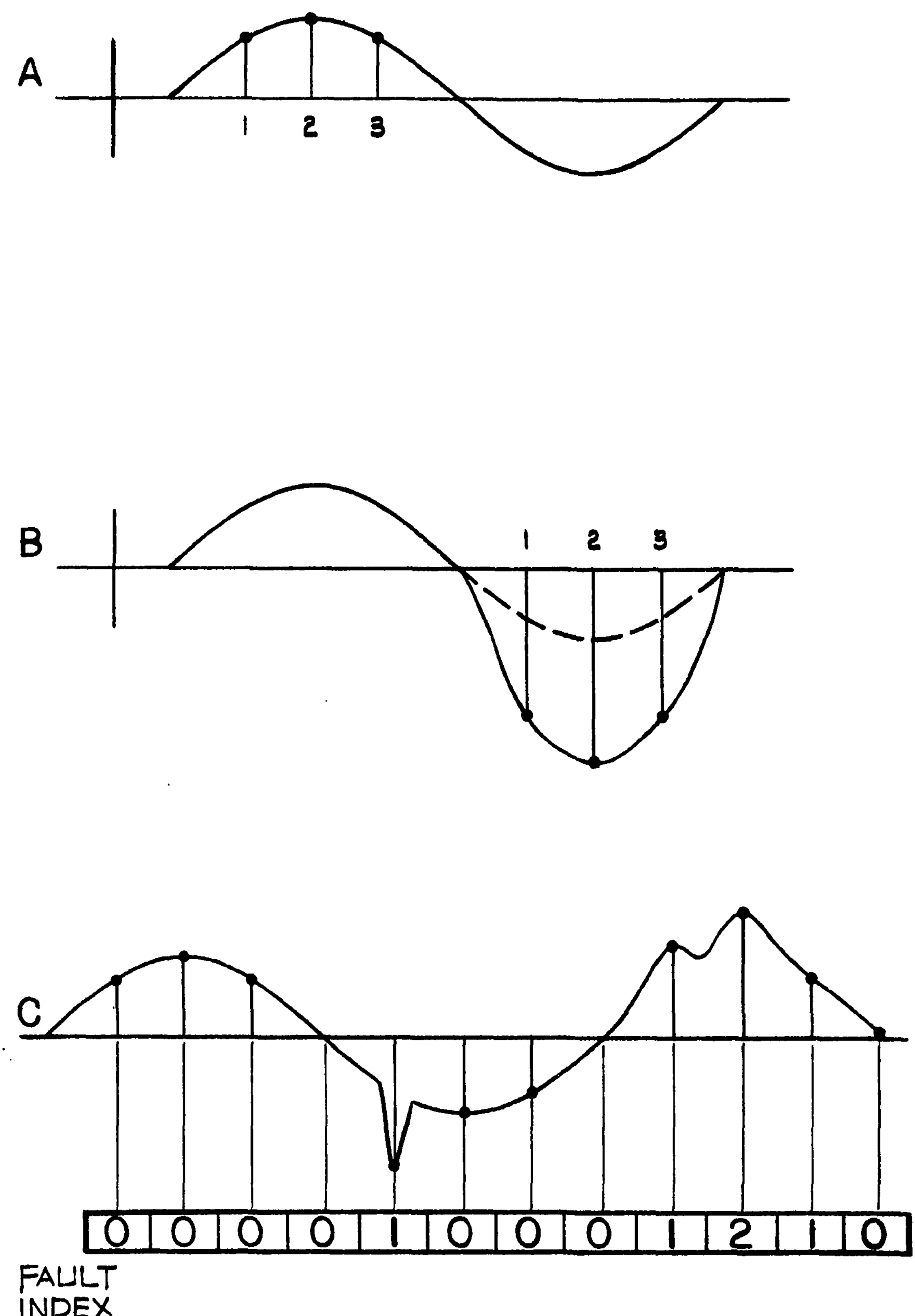
The third category, 60 hertz/high-frequency, refers to the type of data handled by the system. In the case of standard electromechanical relays, the fault determination is made from the information carried in the 60 hertz signal range, whereas in the "radar" techniques, the information is of a high-frequency nature. Certain types of relay techniques obviously fall into a specific combination of categories. Electromechanical relays are analog-passive-60 hertz, whereas recently proposed techniques are digital-active-high frequency. New techniques consisting of various combinations of these categories will be pursued at this time.

Any practical relay system must either sequentially or simultaneously detect the fault, categorize that fault, and take appropriate action. This last step might be immediate trip in the case of a very high over-current condition on a ground fault or a distance calculation for zone discrimination. Obviously before these activities are initiated, the system must determine the fault has occurred. Several techniques have been recently proposed for fault detection.

The cycle-to-cycle comparison fault detection technique has been extensively pursued by Mann and Morrison.[10] The general concept is to sample and store the voltage and current waveforms. On a continuous basis, the present cycle of information is compared to the past cycle of information and any discrepancy indicates an abnormal line condition, possibly a fault. Obviously, a one-to-one correlation between samples cannot be expected, so tolerance limits must be set establishing an allowable difference between the present and past cycles. If this tolerance level is exceeded, the sample comparison is labeled. The accumulation of a number of negative comparisons over a preset level will indicate the abnormal condition. The sensitivity of the system can be adjusted by altering this level of allowable negative comparisons. Such a system will not indicate a fault for sharp spikes or gradual fluctuations of long time constants. A sharp spike will give a single negative comparison whereas a gradual fluctuation over several cycles will not be indicated due to the allowable difference (tolerance) in sample comparisons. The system can be made self-correcting by decrementing the negative comparison indicator if a good comparison follows a negative comparison.

Figure 3A shows a healthy waveform. Samples #1, 2, and 3, when compared to the previous cycle, will yield positive comparisons and no fault is indicated. In Figure 3B, each sample will yield a negative comparison and if the fault index has been set at two, the third comparison would indicate an abnormal waveform. In Figure 3C, the fifth sample would yield a negative comparison. However, the following sample yields a good comparison and the index is decremented, cancelling the effect of sample number five.

It can easily be seen that adjustment of the comparison indices and constants adjust the sensitivity of the technique. It should also be noted that while secured sensitivity is directly proportional to

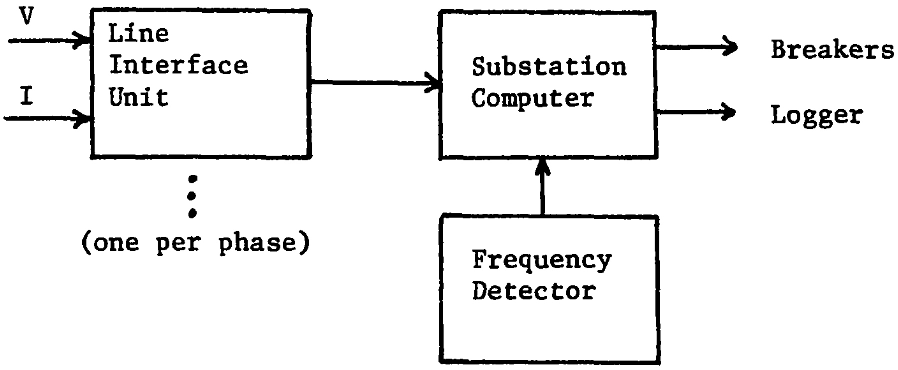


CYCLE TO CYCLE COMPARISON
TECHNIQUE FIG. 3

sampling rates, discrimination is in a sense inversely proportional. It becomes virtually impossible to distinguish between a true fault and a pseudo-fault if we constrain ourselves to high sampling rates, low comparison indices, and fast operation. The technique does give a first indication of the type of fault because the faulted phase will usually accumulate negative comparisons more rapidly than unfaulted phases. However, since no information is gained concerning distance to the fault for zone discrimination in distance relaying, additional computation can be required. This, coupled with the fact that the method uses information contained in the 60 Hz wave, makes the technique too slow for ultra-high speed relay applications. It does have promise as a simply implemented and easily modified fault indicating technique where fast relay speeds are not critical. This technique of initial fault indication has been extensively used and is still considered to be one of the best techniques for fault detection in the digital-passive-60 hertz category.

Another passive fault indication technique currently being investigated is the transient frequency analysis technique. It has long been known that faults create high frequency signals which can be used as an indication of the presence of a fault as well as the distance to the fault. [11] However, current transformers of standard design perform poorly when passing very high frequency signals. This has been a plus factor in electromechanical and static relaying because it has served to filter out transients, noise, and high frequency signals which were unnecessary and harmful to their operation and accuracy. If this technique is to be used, work should be done to develop inexpensive and practical sensors and noise-immune data links. Work in this area is under way by several manufacturers, including Hughes Research Laboratory and Westinghouse. Sensors consist typically of advanced linear couplers, air core transformers, shunt devices, etc., with considerable electronics at line potential and with data links of fiber optic material.

A specific application of the frequency detection technique has been proposed by researchers at the University of Missouri, Columbia. [12].



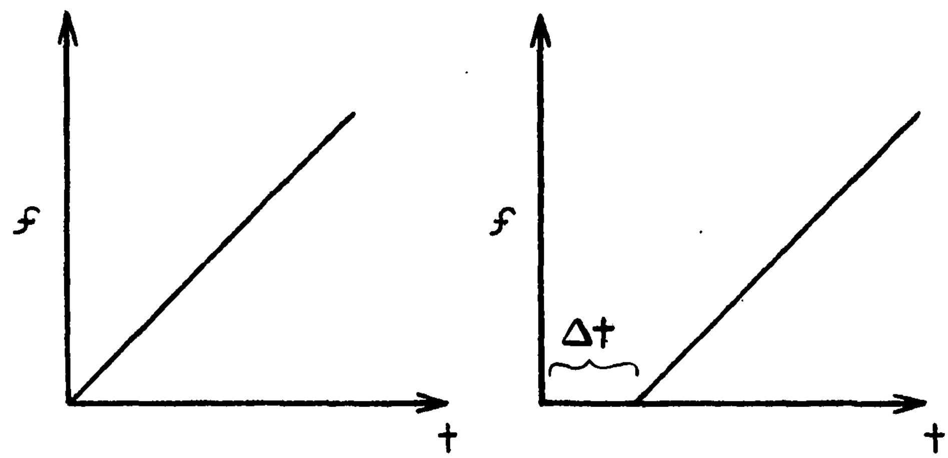
Frequency Detection Technique
Figure 4

As indicated in Figure 4, each phase of each line is outfitted with a line interface unit which detects peak values for voltage and current and phase angle and presents this information to the computer. While this information is available at all times, it is ignored unless an indication is given by the frequency detection interface unit that a high frequency transient has occurred on one of the lines. When this information is received by the computer, it reads the line information and determines the faulted line by comparing current conditions to a set of prestored normal values. Once a fault is indicated, a computer can calculate distance to the fault or perform other operations using the available system information.

The frequency analysis can also be performed using digital techniques. If a computer is used, it is obviously necessary to have fast, real-time methods of frequency spectrum analysis. In the past, such methods were far too slow and expensive to implement, but advances in computer methods for pattern recognition, fast Fourier transforms, digital filtering, etc., make a new look at the technique practical. This work depends on the previously mentioned sensor development and field tests resulting in accurate high frequency data. Work must be done to correlate this data to various system configurations, the effects of series/shunt capacitors, transformer configurations, distance to fault, frequency dependent transmission line parameters, etc. While the concept holds great promise, it can require sophisticated equipment and may prove too sensitive to change in system configuration and too expensive for general application. It may well require Walker's dedicated analog fault indicator to rapidly detect the high frequency signal and then alert the digital equipment for additional computation. [13]

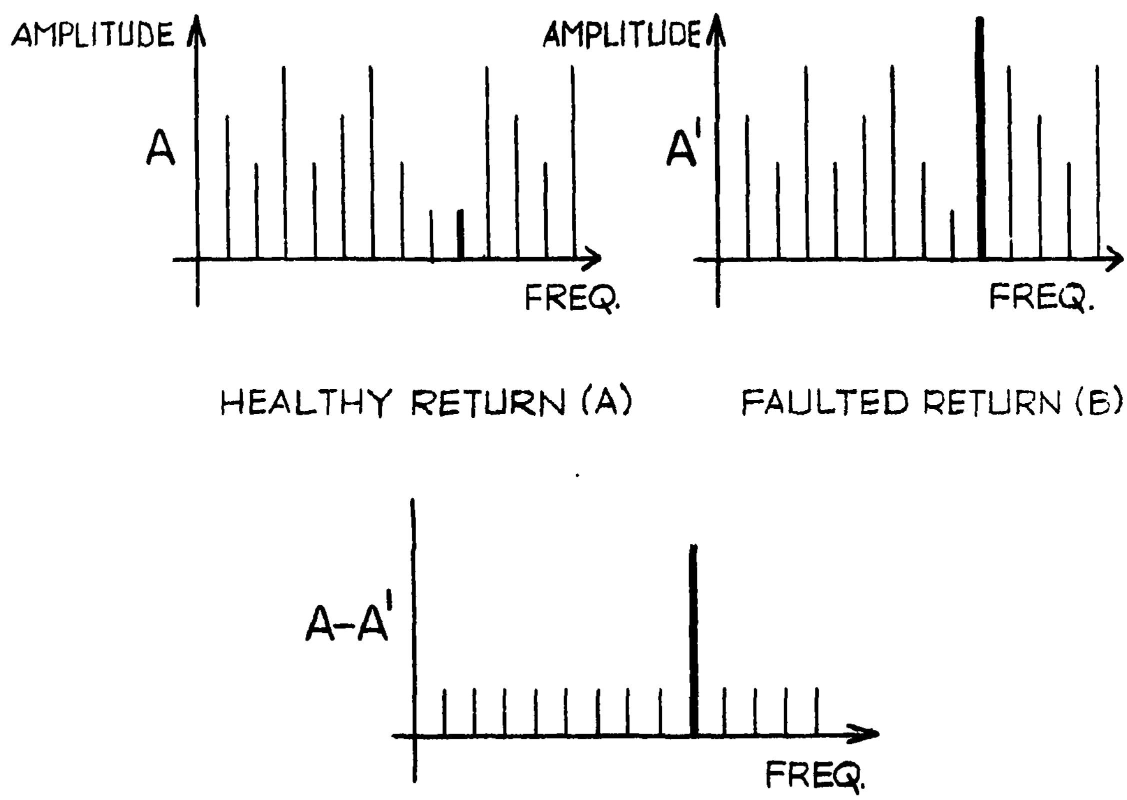
Another high-frequency technique has been labeled the "Chirp" system. While this method uses high-frequency signals, it is "active" in that it impresses its signal on the line and analyzes the return signal to obtain system information.

As shown in Figure 5, if Signal A is impressed on the transmission line, a signal similar to B is ideally returned. The time skew (Δt) is proportional to the distance from the point of signal injection to the fault condition. An obvious problem exists with multiple terminal feeders where multiple signal returns are received. Also, the nonlinear character of the transmission line causes significant deviations from the ideal case. Hughes Laboratories has proposed a modification of the technique which accounts for these two major questions. [14] Signal 5A is transmitted to the healthy line and the return signal is transformed



IMPRESSED SIGNAL (A) RETURN SIGNAL (B)

FIG. 5



FAULTED LINE CHARACTERISTIC

CHIRP SYSTEM
FIG. 6

to an amplitude plot as shown in Figure 6A and stored. Figure 6B represents the return from a faulted line. If the two returns are subtracted, the result will be a plot of a frequency characteristic which is a function of the location of, and distance to, a fault as well as the nature or type of fault. While the system will probably work, it is highly dependent on system configuration and is subject to noise problems. It should also be pointed out that transmission line parameters have frequency characteristics which are dependent on other parameters, such as temperature. A system incorporating this technique will require hand fitting to the power system and should prove very expensive to implement and later modify.

An additional fault indicating device has been developed by Hughes Research Laboratory. [13] It was originally designed as part of the controls for the current limiting device they have developed and out of necessity is very fast--on the order of 500 μs. The analog technique is simply stated, but requires some sophisticated circuitry and timing considerations. Briefly stated, the device is initiated by a very low level threshhold detector. Upon initiation, the currents from all three phases are integrated over a short period of time and comparison made to indicate the type of fault condition. This occurs in the device labeled "Fault ID Logic" in Figure 7. Once this has taken place, subsequent integrations of the line current are compared to integrations of a simulated current produced by a waveform generator. This generator simulates the waveform characteristics of a line with the type of fault indicated by the fault ID logic. If comparisons of these integrations shows a negative correlation outside some pre-set tolerances, then a fault is indicated. This system has distinct advantages. Since it

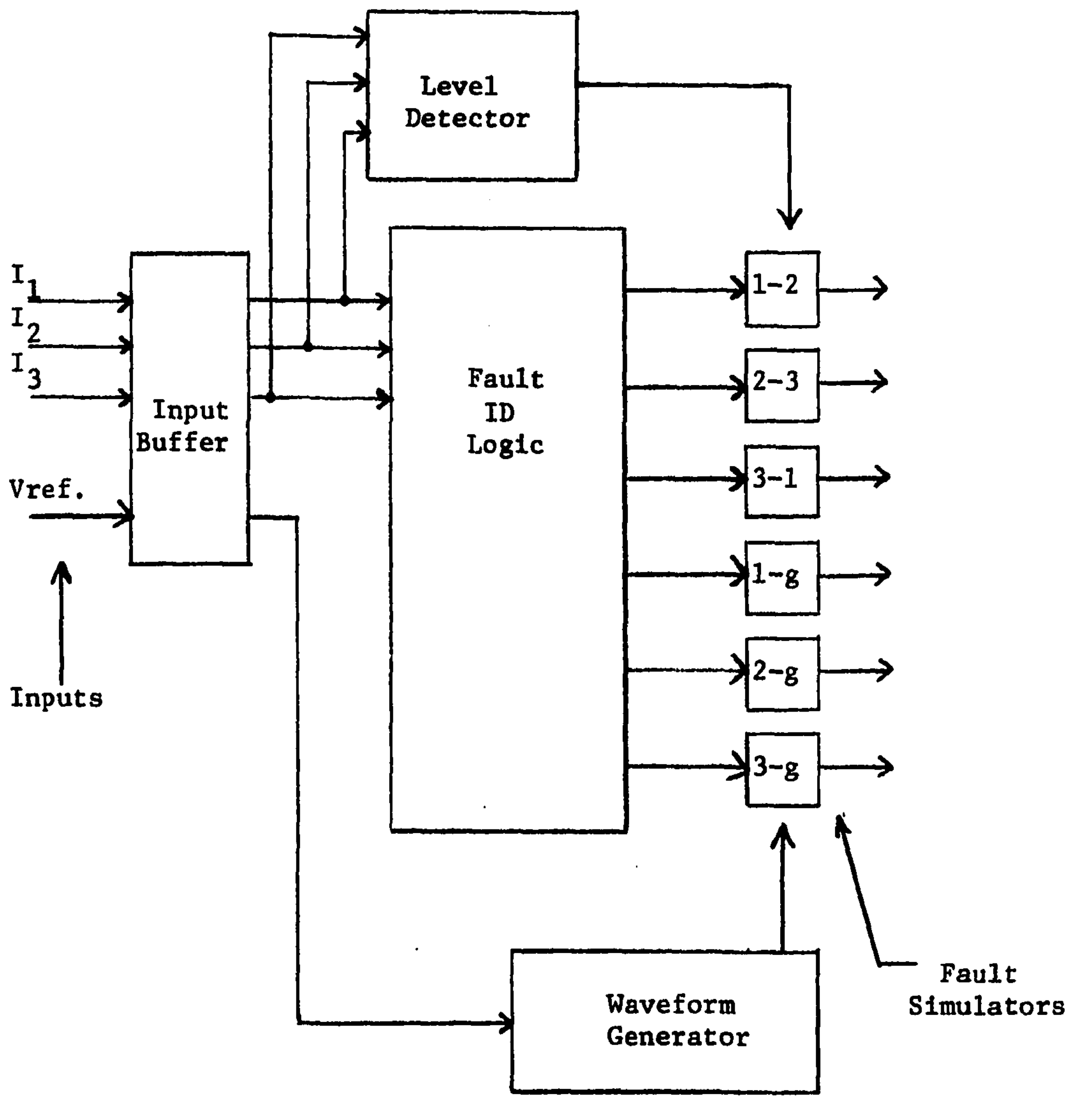
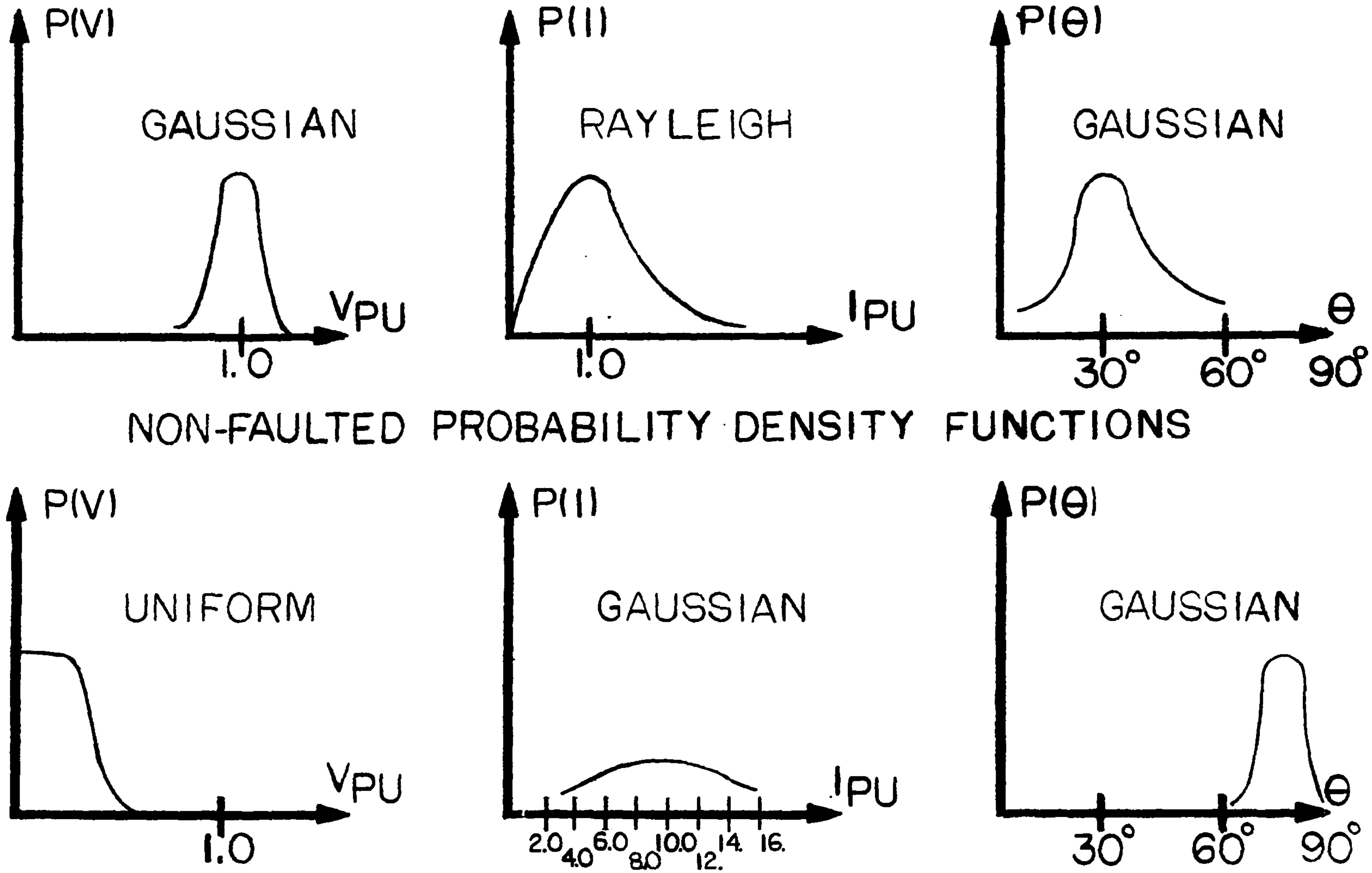

Level
Detector
I_1
I_2
I_3
Input
Buffer
Vref.
Inputs
Fault
ID
Logic
1-2
2-3
3-1
1-g
2-g
3-g
Waveform
Generator
Fault
Simulators

Figure 7

depends only on successive integrations, it can be much faster than amplitude comparison techniques. As within the integration method, it is not subject to short time constant transients on the system. Its response to events such as lightning, switching surges, etc., has not been sufficiently determined. It does require broad bandwidth sensors and data links and will be moderately expensive to implement. It holds great promise as a control for current limiting devices where discrimination between faults and pseudo-faults is not as critical as in relaying applications. The device is analog and additional work is required to apply the techniques to a digital system which can be used in remotely adaptable control schemes.

V. F. Wilreker of Westinghouse has proposed an advanced fault detection/location scheme which uses a computer generated probabilistic model of the power system. [16] It is claimed that probability density functions can be accurately generated from the system voltage, current, and phase data for both faulted and non-faulted lines (See Figure 8). If a significant difference exists in these density functions, it should be possible to create a three-dimensional space which has boundaries defining the fault no-fault areas. The advantage of this system is that detailed calculations are not required to determine a fault condition. A certain combination of voltage, current, and phase may indicate a non-faulted line. If the overall state of V, I, ϕ crosses the fault/no-fault boundary as determined by computer monitoring, then a fault is indicated on that particular line. If an entire system were monitored in such a way, fault detection and isolation could be very fast.

Significant problems exist with the concept as proposed. Wilreker suggests a single minicomputer at the substation level to monitor all



FAULTED PROBABILITY DENSITY FUNCTIONS

FIGURE 8

buses and make local decisions. This machine is coupled with a central dispatch computer over a communication link. Obviously, this system configuration leaves much to be desired in terms of reliability. It is seriously questioned whether probability density functions of state variables can be determined accurately enough to provide the reliability level for fault determination that utilities typically require. A system state estimator is also required to accurately determine time corresponding values of V, I, ϕ. Also, the combinations of voltage, current, and phase are highly dependent on the particular line being protected. This means that hand fitting of the hardware to the characteristics of each line is inevitable. Such a system would require an extensive data bank for faulted and unfaulted lines before implementation was possible. Another problem exists with fault/pseudo-fault discrimination. It has not been shown that pseudo-fault conditions do not provide V, I, ϕ state combinations which could be mistaken for fault conditions. It is hoped that such discrimination can be made but extensive field data collection will be necessary before conclusions can be drawn.

Recall the protection hardware must detect the fault, discriminate between true-faults and pseudo-faults, characterize the fault, and perform the necessary comparisons and/or calculations to locate the fault for proper breaker action and resulted fault isolation. An advantage to electromechanical relays can be seen at this point with respect to the previously mentioned computer techniques, in that they perform all three of the above functions simultaneously in one piece of hardware. While the overall system is slow, it is very efficient in that the same parameters which do fault detection perform discrimination and location. Certain of the advanced protection concepts perform more than one of these functions, yet several are limited to a piecemeal approach, applying different concepts sequentially to perform the entire protection function.

Original work was done in this area by G. D. Rockefeller, then of Westinghouse, who pursued in depth the use of a digital computer for relaying a transmission line. [17] Rockefeller correctly pointed out that the problems of computer relaying were basically speed and selectivity. While he never solved the speed problem, his work on selectivity and zone discrimination was significant. This work, coupled with that of Mann and Morrison on techniques for impedance calculation, represents the basis for digital distance protection techniques. [18]

The basic concept of distance protection requires the determination of the impedance of the faulted line from voltage and current samples. For example, in the technique of Mann and Morrison, the modulus of the impedance can be determined from

$$|Z|^2 = \frac{Vpk^2}{Ipk^2} \tag{1}$$

where

$$Vpk^2 = v^2 + \left(\frac{v'}{\omega}\right)^2 \tag{2}$$

$$Ipk^2 + i^2 + \left(\frac{i'}{\omega}\right)^2 \tag{3}$$

and the phase difference can be determined from

$$\phi_d = \arctan\left(\frac{\omega i}{i'}\right) - \arctan\left(\frac{\omega v}{v'}\right) \tag{4}$$

The values v, v', i, i' are derived from averaging samples and using the central difference expression for derivatives. Considerable success was shown using this technique. Specifically, for 1000 test faults, 99% had ± 10% modulus and ± 7° argument accuracy for the impedance.

Extensions of this work, including improved numerical analysis and sampling techniques have been numerous. [19,20,21] However, while the selectivity of these techniques is excellent, speed remains a problem. Their use in backup relaying and fault location should prove to be their primary application in the future.

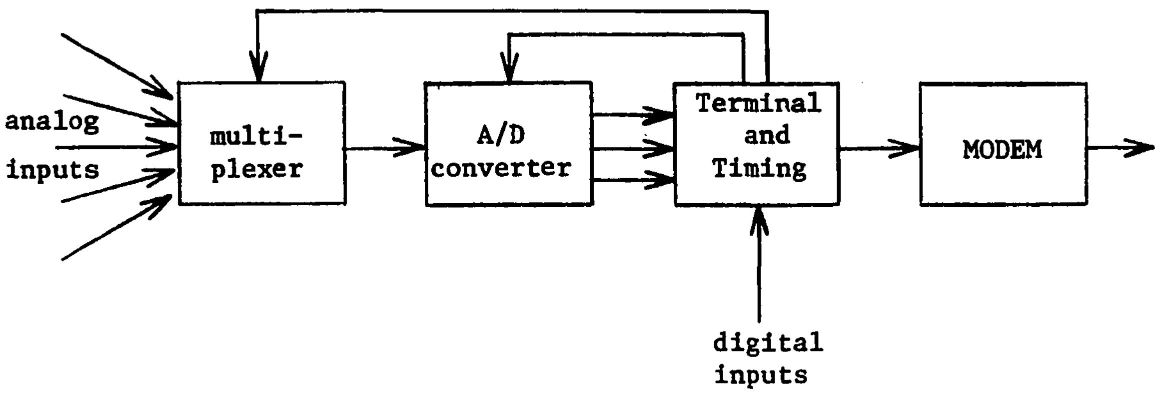
A recently developed technique by John Horton proposes to use Walsh functions to somewhat alleviate the speed problem inherent in other digital impedance techniques. [22] Walsh functions assume the values plus or minus one and therefore all calculations reduce to addition and subtraction. Since other impedance calculation algorithms require squaring, multiplying, dividing, etc., Walsh functions algorithms should result in considerable computational time reduction. In a rather detailed treatment, Horton has shown this to be the case while maintaining an equivalent accuracy in calculations. While Horton proposes this technique to do both fault detection and distance calculations, it seems best suited to the latter when one considers multiple line substations. Possible uses for the technique will be pursued in a later section.

2.3 Evaluation of Previous System Designs

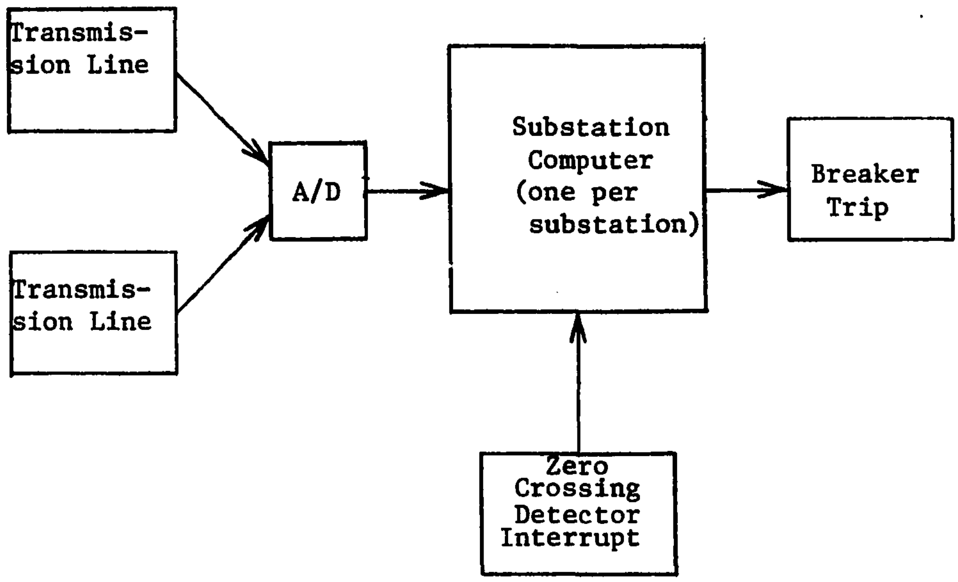
A. IBM - Substation Control System

Several substation automation system designs have resulted from attempts to automate substation control functions and perform digital protective relaying. In 1969, Patrick Mantey proposed a digital substation control system to perform event recording, digital relaying, and substation monitoring. [23] While his overall analysis of substation data acquisition requirements was acceptable, his analysis of the protection system was inadequate, and consequently his time estimates for relaying a large substation were inaccurate. In Mantey's system, substation event recording and monitoring would be performed by the standard configuration of ADC, multiplexer, parallel/serial converter, and modulation-demodulation unit (modem) seen in Figure 9. In addition, a single substation computer would be interfaced to the line by dedicated sampling hardware initiated by a zero crossing detector to provide a CPU interrupt for the relay subprogram (Figure 10). While the concept makes efficient use of CPU time and requires a minimum of equipment, it is totally unacceptable. It has been conclusively shown that the time required to detect a fault, sample faulted line data, calculate impedance and initiate breaker action (while maintaining acceptable selectivity and discrimination) is considerably longer than the 295 μsec Mantey estimated. The Westinghouse-P.G.&E. relaying project, using a Prodar 70 computer to relay the Tesla-Bellota 230 kv line, consistently showed overall fault detection and zone discrimination times of 20-23 μsec.[24] Even with more advanced computer equipment, this time could in no way be reduced to the expectations of Mantey. (It should be noted that the Prodar 70 was consistently faster than conventional relaying).

To help eliminate the burden of fault detection from the CPU, Walker proposes the use of a dedicated frequency detector (previously discussed) in conjunction with special line interface units. [25] When a fault occurs, the high frequency transients are detected by the frequency detector which notifies the computer that a fault may exist. The computer obtains information from the line interface units, processes it, verifies the existence of a fault, and initiates the appropriate action. This technique considerably reduces the CPU time required to do fault detection and discrimination. However, even if the speed of the system mentioned were acceptable, the protection hardware configuration



IBM - DATA ACQUISITION SYSTEM
FIGURE 9



IBM - COMPUTER RELAYING SYSTEM
FIGURE 10

is not. The loss of protection in a substation means multiple-millions of dollars of equipment is susceptible to destruction. Even 99.5% computer availability is not acceptable in such cases. Most utilities have therefore categorically refused the concept of single computer protection in substations. The question of reliability (computer availability) will be treated in a later section.

B. Substation Automation Approach: Hughes Laboratories

An analysis of the substation automation approach proposed by Hughes Research Laboratories shows certain unique features, but a rather standard system concept. [26] As can be seen from Figure 11, substation lines and equipment are monitored by sensors and the data is communicated to the processing equipment through data links. The structure of this system is not unique, but the equipment is. The sensors are broad bandwidth in nature, as opposed to the conventional CT, PT, etc. The signal conditioning and encoding is done at the sensor in a high-voltage environment. Distinct advantages are derived from this technique. Substation noise interference with communication links is minimized because the analog information is encoded and transmission occurs in a coded format. The information is carried over fiber optics, providing isolation between the high-voltage and low-voltage sections. Using frequency modulation or pulse-width modulation techniques gives good noise immunity. This sophistication in sensing is required by the Hughes System since the processing equipment they have devised requires broad bandwidth, high-frequency data. Once the information is processed, the resulting control decisions are communicated to the actuators for the on-line devices. A logger is provided to record operations and system data. Status and alarm sensors signal the logger and substation controller and appropriate

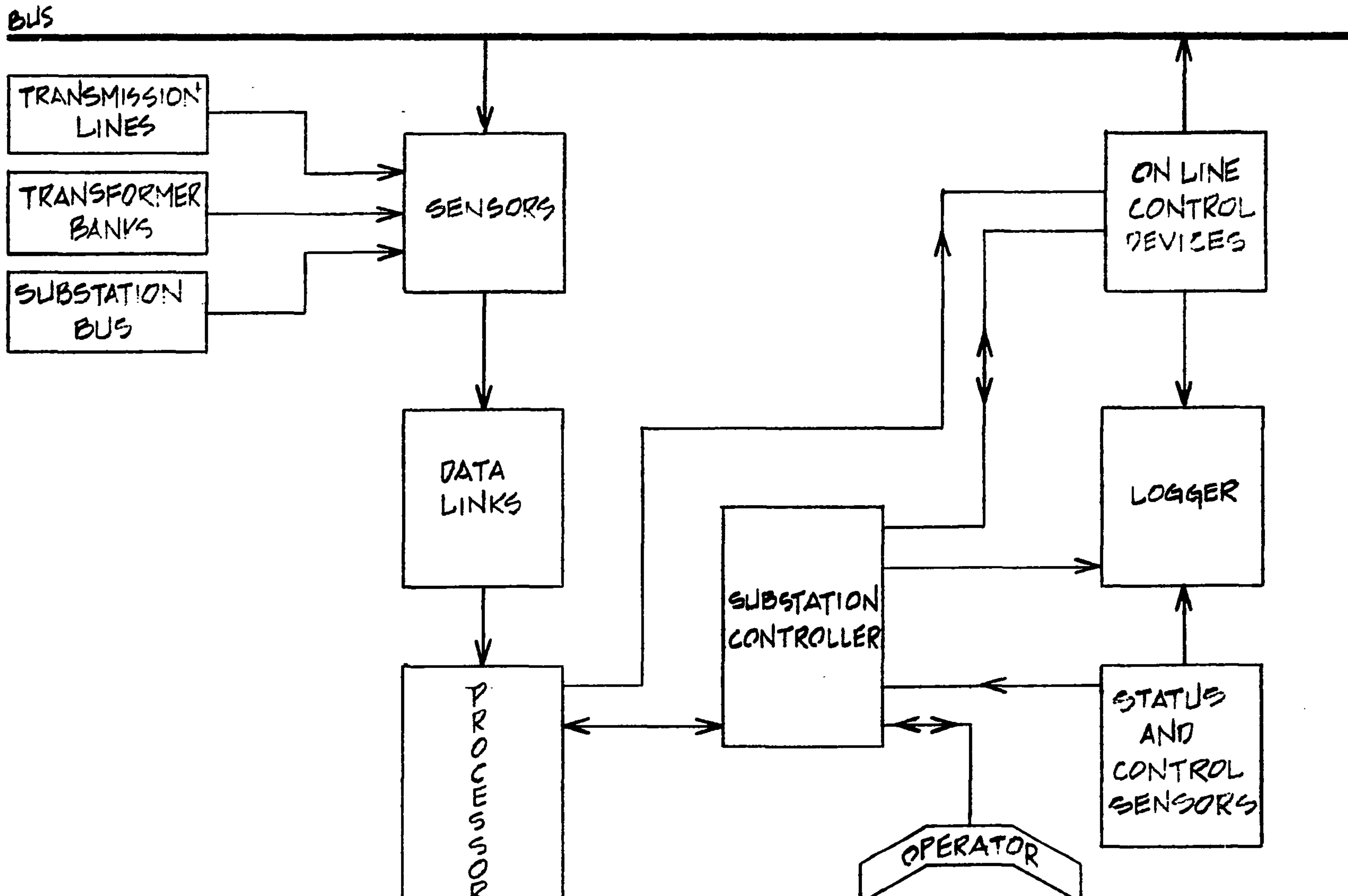


FIGURE 11 PROPOSED HUGHES APPROACH

action is taken. A terminal is provided for manual inputs to the control equipment.

The brain of the system is the processor-substation controller combination. This system must not only monitor and record voltage, current, and power data, but it must also accomplish the protective relay function and fault data recording for all lines in the substation. The memory requirements for such a machine would be excessive. The computer system is located at the substation, thus not depending on long communication links; however, the proposed system is basically a single processor concept which, from a reliability viewpoint, is not acceptable. Too much of the overall control and monitoring of the system has been dedicated to the single processor-controller combination.

2.4 Substation Automation: State of the Art

The state of the art of substation automation including system protection is, at this point, easily described. It has been shown that rather complex systems exist to provide limited remote control and monitoring of substations. The most advanced of these systems use substation computers for pre-processing of data prior to transmission to a central control computer. While this may seem a rather up-to-date approach, one can see by analyzing the functional capability of the systems currently in use that they are very limited in scope.

System protection is in practice being performed as always, using analog hardware which functions in a parallel, independent fashion with respect to the rest of the system. Attempts to implement digital relaying have failed, not because of inadequate techniques, but due to system hardware configurations resulting in unacceptable reliability. State estimation is only crudely performed and system trend analysis is quite insufficient. In short, all existing and proposed systems are somewhat lacking in system integration, consisting mainly of independent subsystems superimposed on each other in the substation. It has been shown that others have approached the problem in various ways, yielding, to this point, unsatisfactory results. The overriding problem with most of these systems is inferior reliability. Exceptional reliability is a necessary condition which must be met by all substation systems. Some have improved their reliability using very expensive techniques--an equally unacceptable solution. An extension in the state of the art is obviously called for and herein has been provided. It directly attacks the question of system integration and presents a solution which is both reliable and economically acceptable.

CHAPTER III

SUBSTATION SYSTEM ANALYSIS

3.1 System Requirements and Design Steps

An analysis of the control requirements in the power system shows several features: (1) It is necessary that information from all levels of the system be analyzed at a central data collection point to determine appropriate system control strategy. (2) To prevent a central collection point from processing excess "non-critical" data, distributed preprocessing is required at the substation level. (3) Substations perform certain critical control functions and consequently must have "stand alone" capability making their critical function independent of communication links. (4) Since substations exercise control over numerous lines and pieces of equipment, said control must be distributed in such a way as to preserve system reliability.

These requirements obviously specify a highly sophisticated hierarchical control system. However, the "weak link" character of communication systems dictates that some form of "stand alone" capability for the individual substation and its subsystems is mandatory. In order to determine an acceptable system design incorporating the above requirements, the following steps were taken:

1. Identification of the power system control/monitoring functions to be performed.
2. A determination of priority control functions at the substation level.

3. An identification of subsystems requiring "stand alone" capability.

4. An evaluation of the necessary degree of distributed computation/control between control center and substations.

5. Evaluation of the information requirements at all levels of the system and the necessary degree of information exchange between the system levels.

6. A determination of the critical nature of communication links at all levels.

7. Formulation of a hierarchical control system incorporating the requirements of steps 1-6.

The necessary and desired control and monitoring functions to be performed by the automation system have previously been identified, therefore Step 2 can now be pursued. An analysis of the substation functions shows that only a limited number could be labeled "priority" or "critical" functions on a short-term, emergency basis. For example, temporary loss of a communication link between the substation systems and a central computer would prevent carrying out some of the functions (e.g. system state estimation). On a short-term basis, most of these functions can be lost without degrading the operation of the power system or causing undue pressure on the overall system control center. However, loss of the protection system at the substation level cannot be tolerated for any time duration. In short, it is a high priority and a critical function. In practice, it is the only substation system which must be absolutely maintained at the expense of all else.

Several other functions are important and should be maintained if possible during such contingencies as loss of a communication link. Pre/post-fault data recording and sequential event recording are very important and should not depend on inter-system communication links. This information is mandatory if an accurate picture of substation operation during an abnormal period is to be reconstructed.

Fault location, evaluation of subsystem and equipment operation and performance, analysis of power system response to a specific contingency, etc., may all depend on the availability of this data. It is desirable that these functions, along with the protection system, be maintained during any contingency which would isolate the substation from the rest of the power system.

Steps 3 and 4 call for an analysis of the appropriate distribution of control between the independent and integrated substation automation systems and a central control computer. When one considers that a utility may have several hundred substations, choices seem very limited. In the past, virtually all processing of data was done by a central computer (if it existed). This was possible due to the very limited number of functions these systems performed and the relatively small amount of monitoring and data collection done. With the proposed expansion of the functional capability of the substation systems, it is quite impossible to expect a central processor to handle this mass of data in an efficient manner with adequate speed. Therefore, an "intelligent" substation which combines the functions of data handling and preprocessing to relieve the burden placed on the central computer is the logical choice. This also reduces the reliability requirements on the intercomputer, long-distance communication links which, to date, have presented considerable problems.

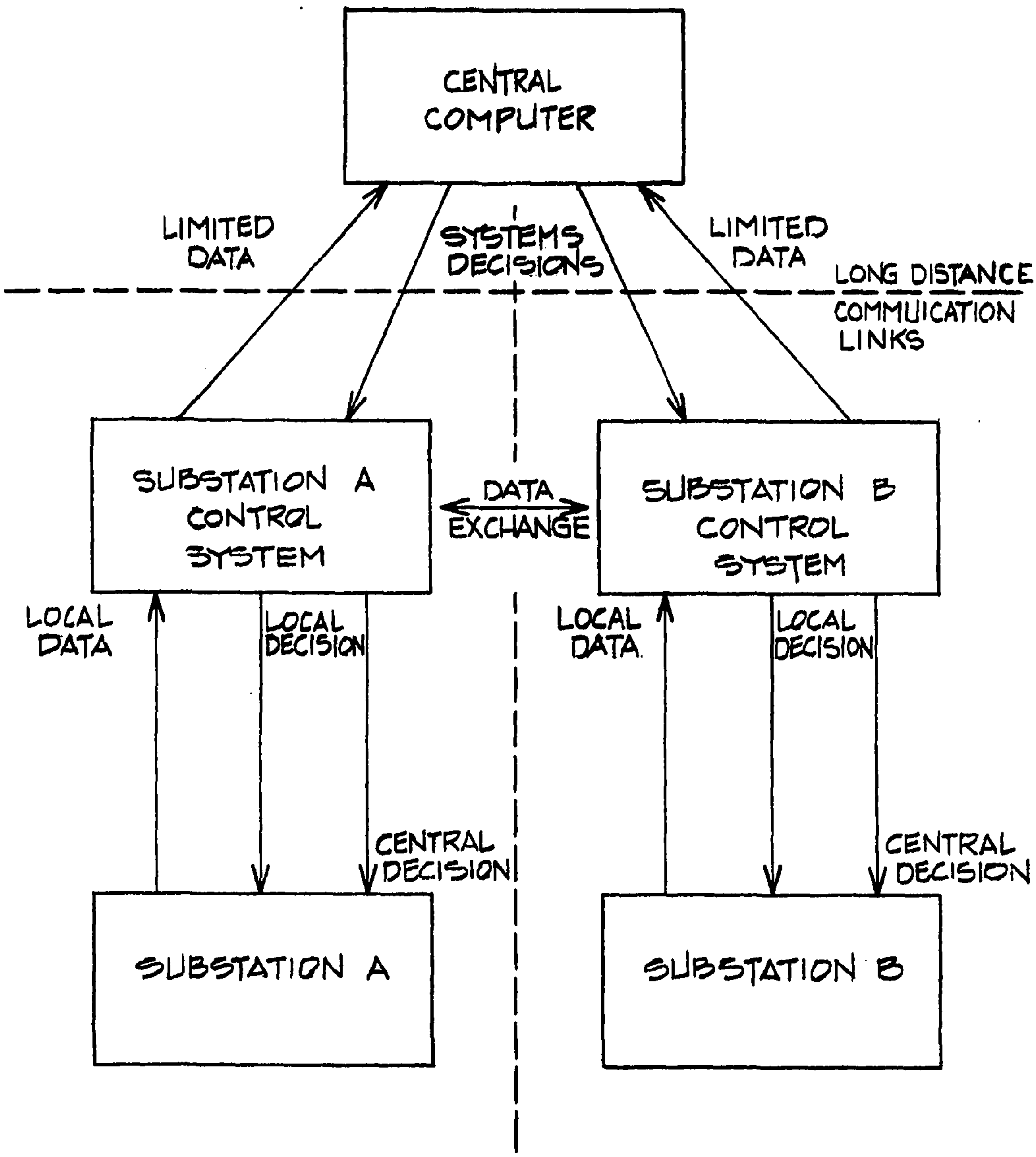
Consequently, the more preprocessing and decisions which can be made at the substation level, the more reliable and efficient will be the entire system. This distributed processing concept which concentrates much of the activity at the lower level of the computer hierarchy is ideally suited to our needs.

3.2 Proposed Hierarchy for Data Flow and Control Decisions

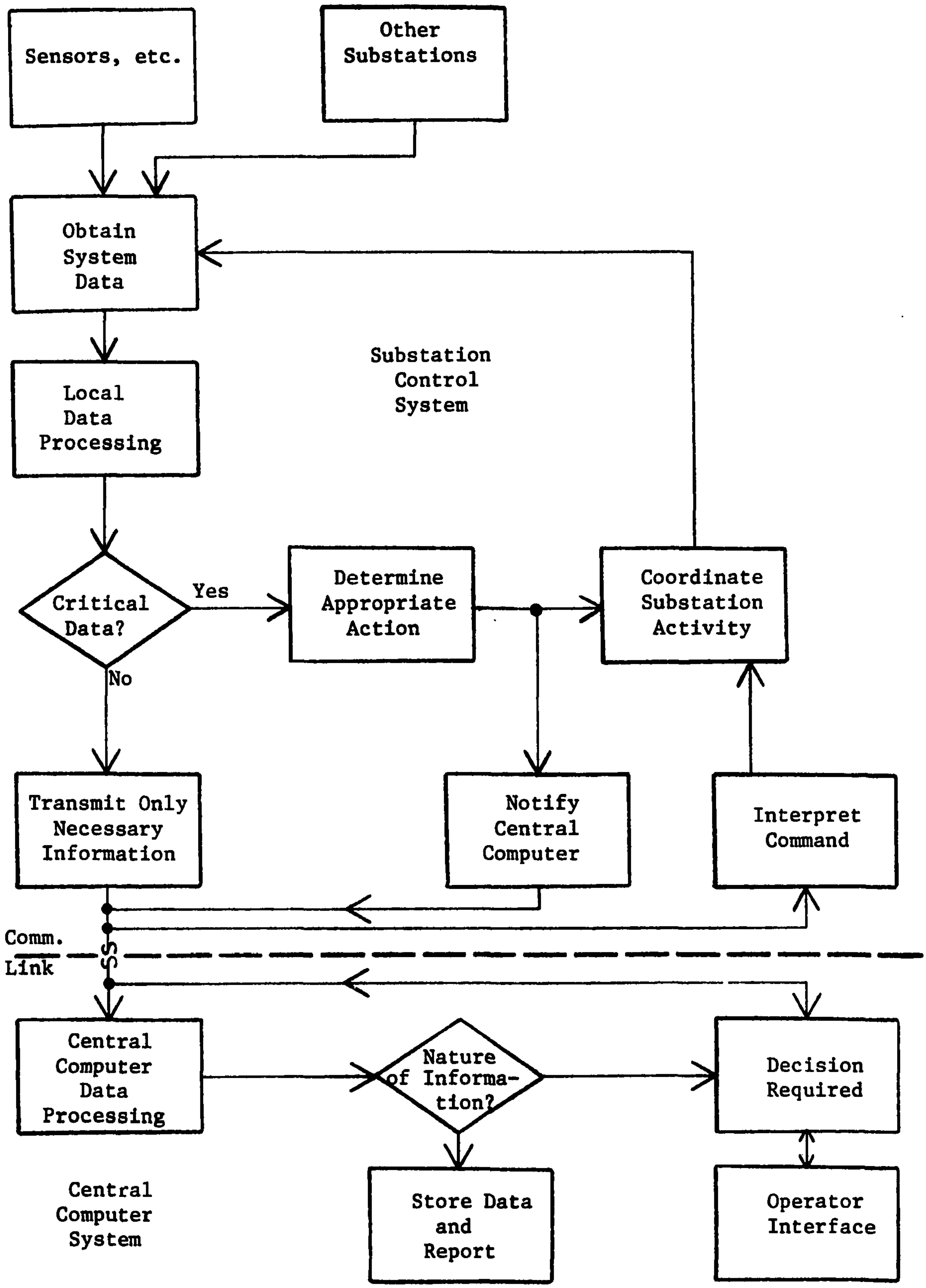
Flow Chart 1 and Figure 12 schematically depict a distribution of data and the decision-making process suggested by previously defined system constraints. As Flow-Chart 1 indicates, the substation control system receives system data and performs the limited preprocessing to determine if a critical function is involved. If so, an immediate decision is made by the local substation system and appropriate action is taken. If a control center decision is required, only the appropriate data is passed to the central computer over communication links. This information is again processed and a decision, based on this data, and that from other substations, is communicated to the subsystem which, in turn, initiates appropriate substation action.

It should be noted that this configuration meets all the requirements set forth previously. No critical substation operation would depend on a communication link, thus improving overall reliability. Only that information deemed necessary by the central computer is transmitted over communication channels, thus easing the burden placed on these channels and relieving the central computer of unnecessary processing.

At all levels, the central computer is kept informed of activity so that the state of the power system is readily available to system operators. Figure 12 further shows this hierarchy of decision-making. It is easily seen that the substation system has stand-alone capability to make all critical decisions. While viewing Figure 12, an example of system decision-making seems appropriate. Assume a large power auto transformer is over-heating. The oil temperature increase will be detected by temperature sensors and this information passed to the



DATA AND DECISION FLOW
FIGURE 12



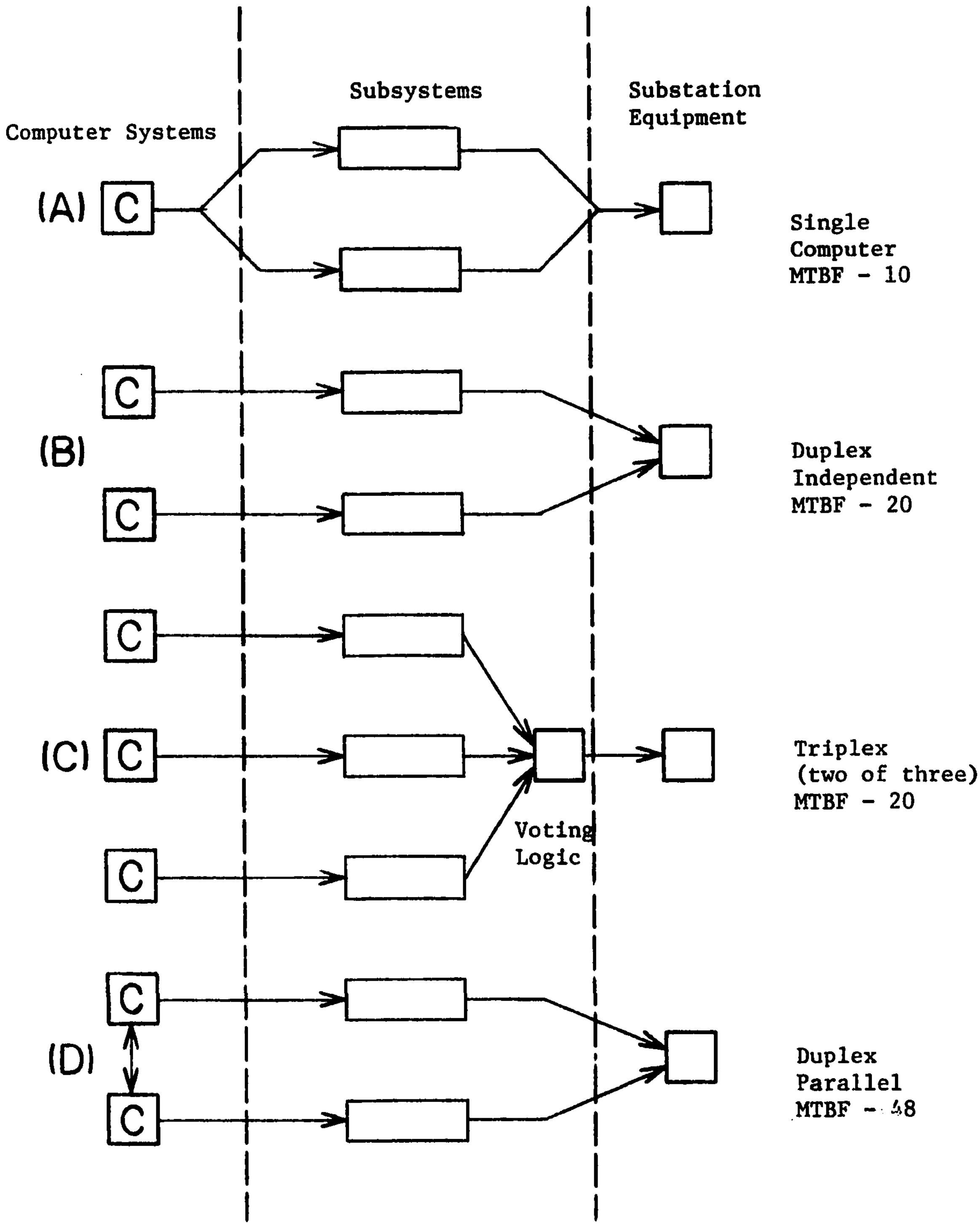
DECISION PROCESS
FLOW CHART 1

substation control system. At this point, the central computer system is notified of the condition and in turn alarms the condition to the system operator. Meanwhile, the local control system could take intermediate steps, such as turning on cooling fans, load management action to reduce the load on the transformer, or, if matters become critical, remove the transformer completely from the system.

Another contingency might be a faulted transmission line. Such a situation requires an immediate decision by the local unit. When this decision is made, appropriate action by substation equipment is initiated and simultaneously the central computer is notified of the condition and the subsequent substation activity. The central computer may deem additional action necessary, and upon receipt of a command from the central unit, the substation system can pursue additional measures. Again, processing of system data and decision-making on a local basis while interacting with the central computer over non-critical communication links result in a very reliable and practical system.

3.3 Possible Computational System Designs

Determination of a hardware configuration which is capable of meeting the functional requirements of our system in a reliable fashion is now appropriate. Referring to the work of Murray and Dromey shows that considerable attention has been given to single, double, and triple computer configurations to provide computational power in a reliable fashion. [27] No single computer system is acceptable, and even complete duplex operation or triplex (two out of three) have significant disadvantages--obvious ones being cost and the inability of such systems to efficiently handle multiple simultaneous contingencies with an acceptable speed. One system which does have a comparatively high reliability



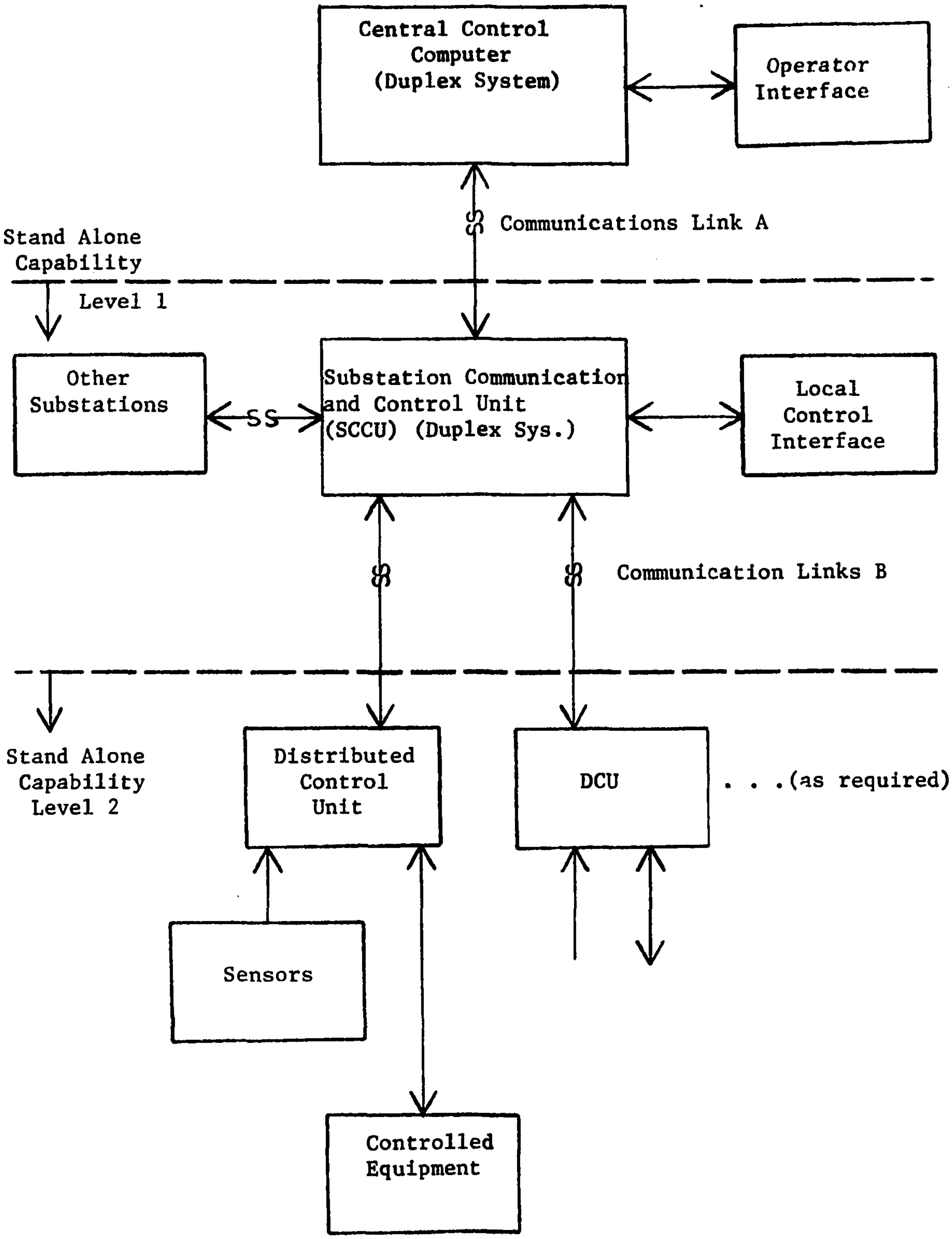
HARDWARE CONFIGURATION COMPARISON
FIGURE 13

factor is a duplex parallel configuration operating in a true multiprocessor mode. Machines can be multi-programmed such that each can perform any function. Figure 13 compares these systems and shows their relative MTBF (mean-time-between-failure). However, while the parallel duplex operation does offer a significant improvement over the other configurations, it still has serious drawbacks. Again, simultaneous contingencies and speed requirements would be serious problems for this system. It should be recognized that the system must, on a continuous basis, perform many different information processing functions and simultaneously protect all equipment and transmission lines associated with the substation. Walker has shown this to be an extreme computational burden which cannot be performed by a single computer of the type compatible by reason of cost and environmental considerations to the substation. [28] We are therefore forced to an alternate approach.

3.4 Proposed Subsystem Configuration for Distributed Processing

Analyzing the Decision Process Flow Chart, the previously set system functional requirements, and the required reliability standards result in the subsystem configuration for distributed processing shown in Figure 14.

While the central computer system is not of direct interest to this work, a brief analysis is appropriate. The configuration should be a duplex, multiprogrammed system, with dual peripheral equipment and interfaces to provide maximum mean time between failure (MTBF) and overall reliability. This technique, proposed by Murray and Dromay, would reduce by over fifty percent the system failure rate compared to that of the simpler single computer with redundant, independent back-up. [29] The operator interface block, shown in Figure 14, implies all



DISTRIBUTED PROCESS
FIGURE 14

necessary human interface and I/O, including graphic display and command capability. The communications link used could be telephone pair, microwave system, or hopefully a more reliable technique yet to be fully developed.

The central computer system would be capable of performing all the functions previously mentioned in the list in section 2.1. It is through this central computer that all substations would be accessed by system operators. All substation information is processed by the central computer for presentation to the operator in the form of logs, alarms, system network diagrams, etc. [30] Decisions affecting the operation of the whole power system or involving more than one substation could be made at this level and subsequent control activity transferred as appropriate to the individual substation.

The next level of control is physically located at the substation. Substation interface to the central computer is accomplished through a substation communications and control unit (SCCU). This "command center" coordinates all substation activity and handles all extra substation communications. Local control is accomplished by accessing the substation through this unit. Decisions are made at this level which involve several substation control points. This system is again a duplex, parallel configuration to provide maximum availability. Preprocessing of all data occurs at this level before transmission to the central computer. To provide maximum substation independence and critical function reliability, the SCCU has complete "stand alone" capability with respect to the central computer. Loss of communication link A will in no way degrade the substation control system response to a critical contingency, such as a transmission line fault. Hence, no critical control function depends on the availability of a long distance communication link, as stated in our previous system requirements.

Direct control and monitoring of the substation is accomplished using subsystems called dedicated control units (DCU) which interface directly with substation equipment and all sensors and transducers. It is at this level that the bulk of information processing and decision making is accomplished. For example, a DCU could be used to scan all substation transducers such as those for temperature, pressure, humidity, gas analysis, and fluid level. Should an abnormal condition be detected, predetermined action for that contingency can be immediately initiated while the SCCU is notified of the condition, where it is located, and what action has been taken. This information would subsequently be transmitted to the central computer and the operator would be notified. Maximum speed is achieved using this technique and since the communication link is not required by the operation, a high degree of critical function reliability is achieved. A DCU could also be dedicated to each transmission line for fault detection and classification and to indicate loading trends. Note that this dedicated hardware duplicates the configuration currently used for protection hardware, but provides the system integration and remote addressability to the protection equipment which is totally missing in present systems.

3.5 Division of Control Functions by Subsystems

A determination of the nature and required number of subsystems at the substation is now appropriate. As stated in our previous system analysis, each transmission line would receive primary protection from a single DCU (dedicated control unit). This DCU would have complete "stand alone" capability to assure independence and isolation from failures in other substations. Under fault conditions, it would be required to perform fault protection and classification, breaker trip initiation, breaker failure analysis and fault location. Under normal conditions, it would perform loading trend analysis, overload alarming, and self diagnosis. The secondary relaying DCU is necessary to perform back-up protection for the transmission lines. This unit would do multiple line protection by scanning various lines on a regular basis for abnormal conditions. Since the unit would only see service in the unlikely event of primary DCU failure, the degree of degradation of protection speed introduced by the scanning technique is deemed acceptable. Additional DCU's would be required to perform transformer, bus, and equipment protection. The size and number of these units is a function of the size of the substation.

A DCU is required to perform system diagnostics and monitor substation security. This unit would detect failure of other subsystems, alarm the condition, and initiate corrective action, such as switching in a spare DCU. A dedicated control unit would also be required to perform data acquisition, sequence of events recording, alarming, and "switching" type control. This unit would be interfaced to a logger for permanent substation information records and interfaced for control to all tap changing transformers, motor operated switches, switched reactors and capacitors, etc. A parallel, duplex configuration is recommended for this subsystem. Separate DCU's would be provided, if required, for environmental monitoring, real time, system state estimation, or other desired functions.

The SCCU (Substation Communication Control Unit) subsystem would require interfacing to all protection, security, data acquisition, and control DCU's. It would have a local teletype and logger capability and would preprocess all data going to the central computer and appropriately distribute all incoming commands and requests from the communication links. Again, this unit should have a duplex, parallel hardware configuration. The segregation of substation functions into the various subsystems previously mentioned follows.

<u>Division of functions by subsystem</u>

1. Data and Control DCU (two per substation)

   Data Acquisition
   - Fault data collection
   - MW, MVAR, V, I
   - etc.

   Sequence of Events

   Alarming
   - Breaker Gas Pressure
   - High Temperature

   Control
   - Reactive Control
   - Remote Breaker Trip
   - Motor Operated Switches
   - Transformer Tap Settings
   - Load Rejection
   - Sectionalizing
   - Load Management
   - etc.

2. Primary Relaying DCU (one per line)

   Single Line Protection
   - Fault Detection
   - Fault Classification
   - Breaker Trip Initiation
   - Breaker Failure Analysis
   - Fault Location

   Loading Trend Analysis
   - Overload Alarming

   Self Diagnostics

3. Secondary Relaying DCU

   Multiple-line Protection

4. Protection DCU

   Transformer Protection

   Bus Bar Protection

   etc.

5. Security DCU

   Protection System Diagnostics

   Environmental Control

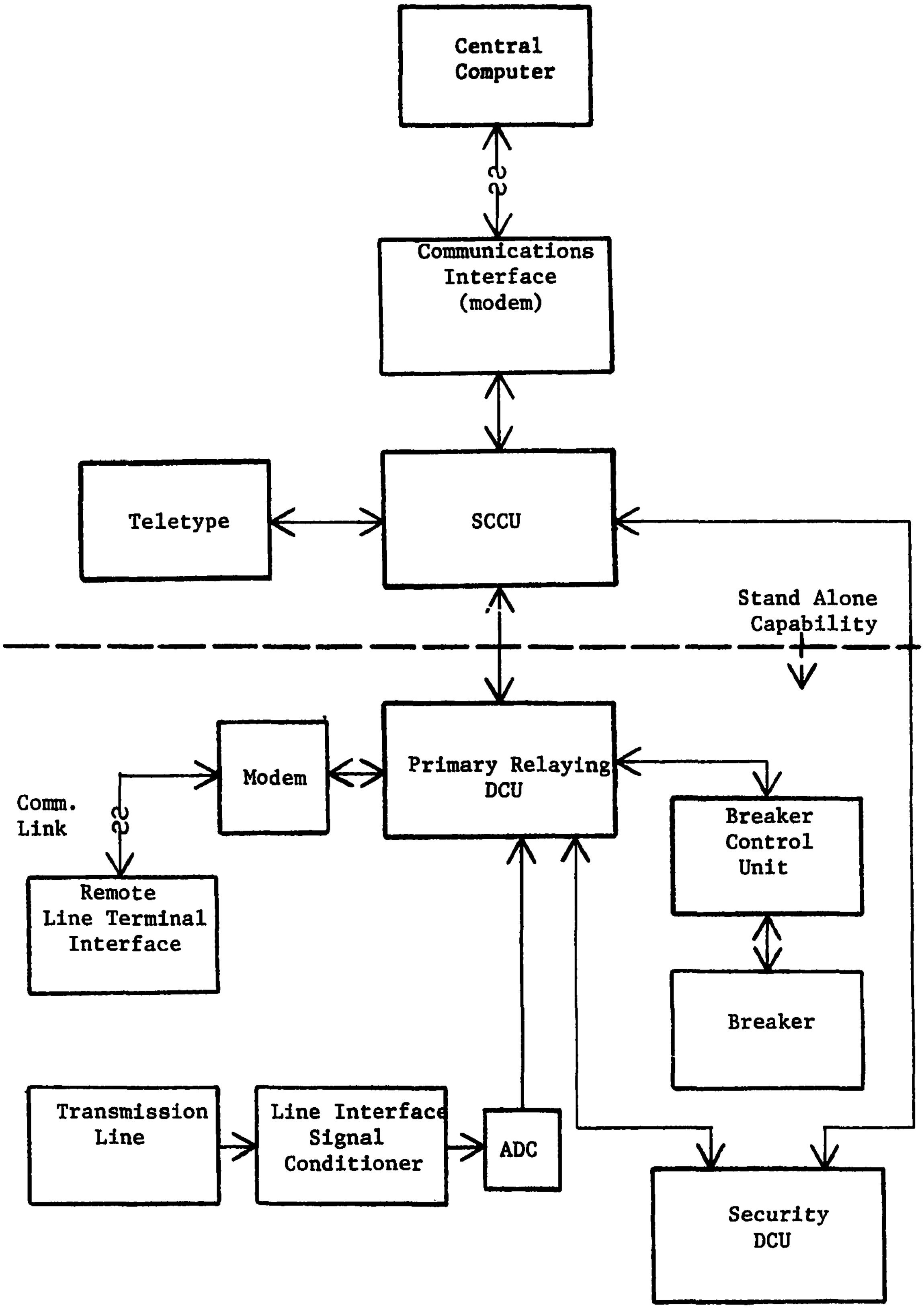
   Substation Security

CHAPTER IV

HARDWARE AND SOFTWARE SYSTEM CONSIDERATIONS

4.1 Subsystems With Peripheral Equipment

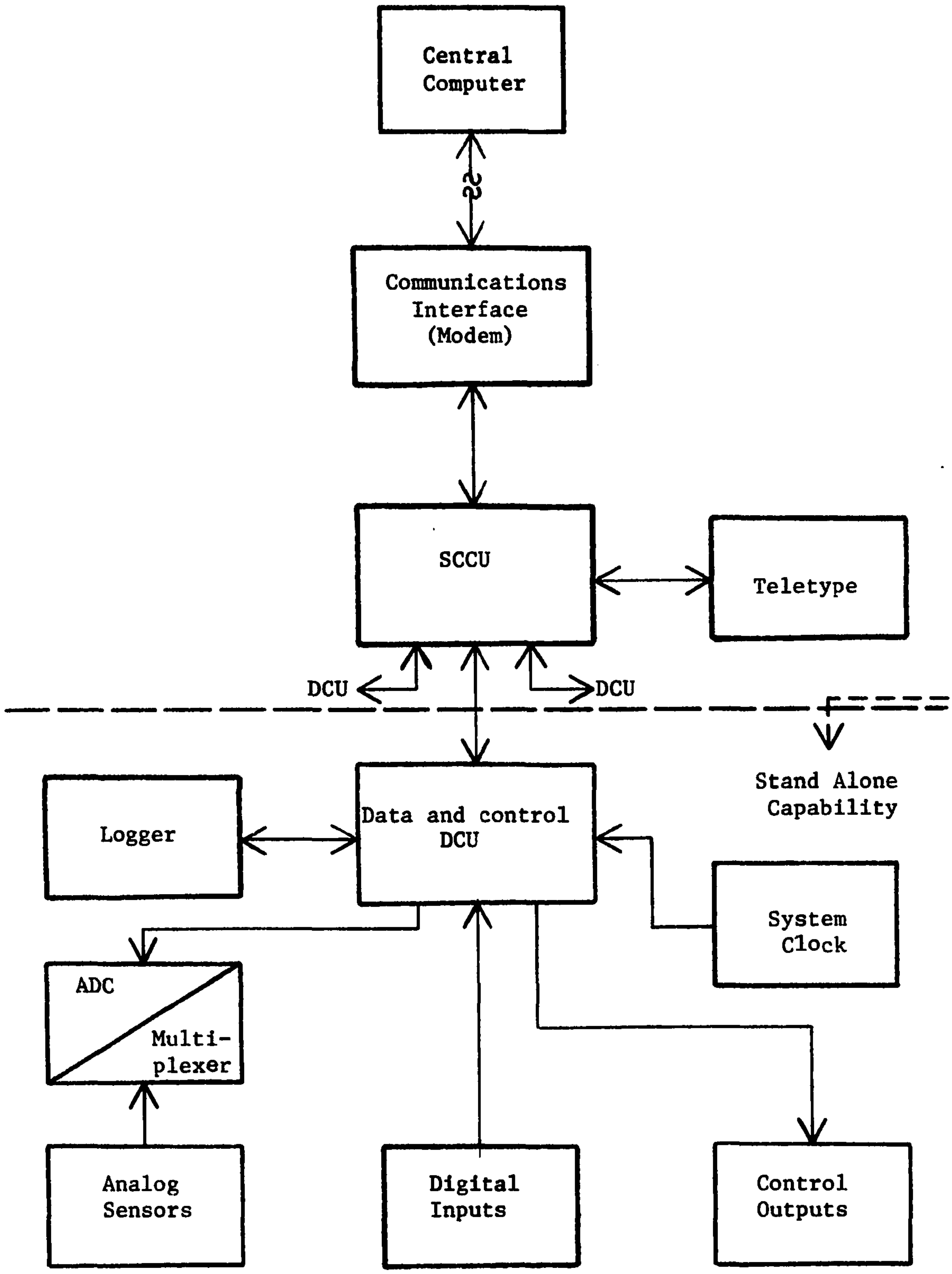
The interconnection of the various subsystems with the required peripherals is shown in the following diagrams. Figure 15 shows the primary relaying configuration. The primary relaying DCU receives information from a single three-phase transmission line. This information is tapped from the lines through appropriate transducers, signal conditioners and analog-to-digital converters. Projecting the availability of new high voltage transducers currently being developed by General Electric and Westinghouse, it is assumed that the above mentioned functions would occur at line potential.[31] Transmission of the information would occur over multiple channel data links using optical waveguide techniques and would be accumulated at ground potential by appropriate electronics. From this point, information transmittal would be made over a secure data link in a parallel fashion to the primary relaying DCU located in the substation control house. For certain types of relay schemes, the primary relaying DCU also requires information from nearby substations. Specifically, in certain types of protection schemes, information from both line terminals is required to make an appropriate protection decision. Should such a scheme be chosen, a necessary communications link and model is required to inferface the local primary relaying DCU to the remote line terminal. The primary DCU



PRIMARY RELAYING DCU
FIGURE 15

is also interfaced to a breaker control unit for the obvious purpose of tripping the appropriate breaker or breakers should fault conditions occur. For purposes of alarming conditions and receiving commands, the primary DCU is interfaced to the substation communication and control unit (SCCU). This unit in turn is connected through appropriate communications interfacing and modems to the central control computer over a long distance communication link. The SCCU has teletype capability which can be used to address the primary DCU and alter protection parameters. The security DCU is interfaced both with the primary relaying DCU and the substation communication and control unit. The security DCU runs a regular check on the availability of the primary DCU to perform the protection function. Should the primary DCU fail for any reason, the security DCU takes appropriate action including alarming the condition to the SCCU for relaying to the central computer and subsequently to the system operator. It should be noted that the primary relaying DCU and its associated peripherals, excluding the SCCU, have stand alone capability. This means that should the communications interface to the SCCU fail, or the SCCU itself experience failure, line protection is not affected.

Figure 16 shows the data and control DCU and its associated peripherals and interconnections. This unit is interfaced to the transmission lines and all substation equipment for purposes of obtaining system data to be passed to the central operator and/or logged on a local logger. Analog sensors are addressed sequentially using a scanning technique and a multiplexer and analog-to-digital converter prepares the information for presentation to the data and control DCU. Certain digital inputs and interrupts from the substation are introduced



DATA AND CONTROL DCU
FIGURE 16

directly. The DCU has a logger, probably a cassette type data storage device, to store certain types of local information. Other information is transmitted through an interface to the SCCU to the central computer over the long distance communication link. This data is preprocessed before transmittal by both the data DCU and the SCCU. Only that information which is of a critical nature or requested by the central computer is transmitted to ease the communication burden on the data links. Should an abnormal condition occur (e.g. transformer overheating), the data DCU alarms the condition immediately to the central computer, which in turn alarms the system operator. Should appropriate action be possible, the data DCU initiates this action through an interface to control outputs. For purposes of restructuring a picture of substation activity, the data DCU keeps a chronological record of events timed by a system clock module. This function is of specific importance under fault conditions when information concerning substation activity may help determine the reason for the fault and whether the substation took appropriate action. The specific control of such devices as tap changing transformers, switched reactor banks, motor operated switches, switched capacitors, etc. is controlled by this DCU. It may be addressed by the central computer and given certain activity commands or, if programmed appropriately, may initiate such commands in response to specific substation conditions.

4.2 Selection of Fault Analysis Techniques

The question arises as to the most appropriate protection schemes for implementation in the aforementioned subsystem configuration. A list of the standard classes of line protection, as given by Westinghouse, [32] is:

a) Instantaneous overcurrent

b) Time overcurrent

c) Directional overcurrent

d) Current balance

e) Distance

f) Pilot (pilot wire, power line carrier, or microwave)

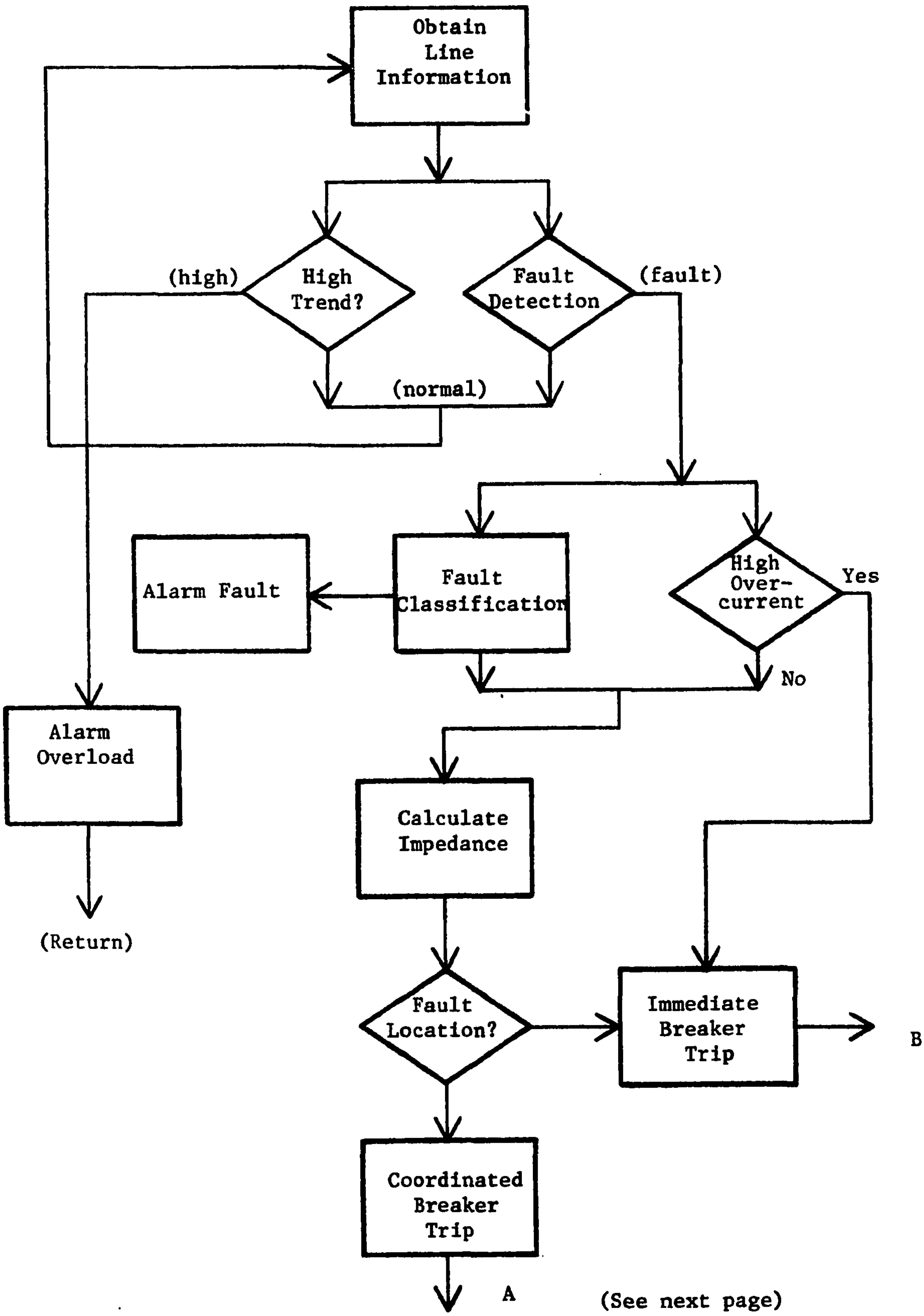
The line protection schemes can be represented by two groups: those which use only local substation data (a - e) or those which require information from both terminals of the line (f). The first technique is very popular because it requires no communication links between substations, however, as will be seen, distinct advantages exist with the latter systems. Recent surveys have shown that with most major utilities virtually all transmission lines (345 kv and above) are protected using some form of intersubstation communication link. [33] Since both of these techniques are widely used, our primary protection DCU should be capable of carrying out both, as well as some of the newer techniques recently proposed.

Of the first group suggested by Westinghouse, distance (impedance) relaying is the most popular and offers the greatest advantage. As typically implemented, these relays use V, I information to calculate the impedance to the fault. Knowing the impedance of the healthy line, it is easily determined whether the fault is internal or external to the protection transmission line segment. We have shown that considerable effort has been expended in applying numerical analysis techniques to implement the required impedance calculation on a digital computer. These efforts have shown the job can be accomplished but offers few performance advantages over present systems, other than the distinct and necessary advantage of system integration. It seems logical, however, that for back-up protection where speed is not of primary importance, impedance relaying will prove an excellent technique.

To implement the system, two basic functions are required: fault detection and impedance calculation. Fault detection could be derived from dedicated analog hardware which determines the existence of high frequency transients on the line during fault periods. However, if total implementation in software is desired, the cycle-to-cycle comparison technique would be quite acceptable, particularly for back-up protection. The impedance calculation could use one of the more sophisticated numerical analysis techniques pursued by numerous researchers. However, distinct advantages seem to be gained from using the recent IBM suggestion of Walsh function calculations. [34] Software implementation could be as follows.

4.3 Protection Software Requirements for Distance Relaying

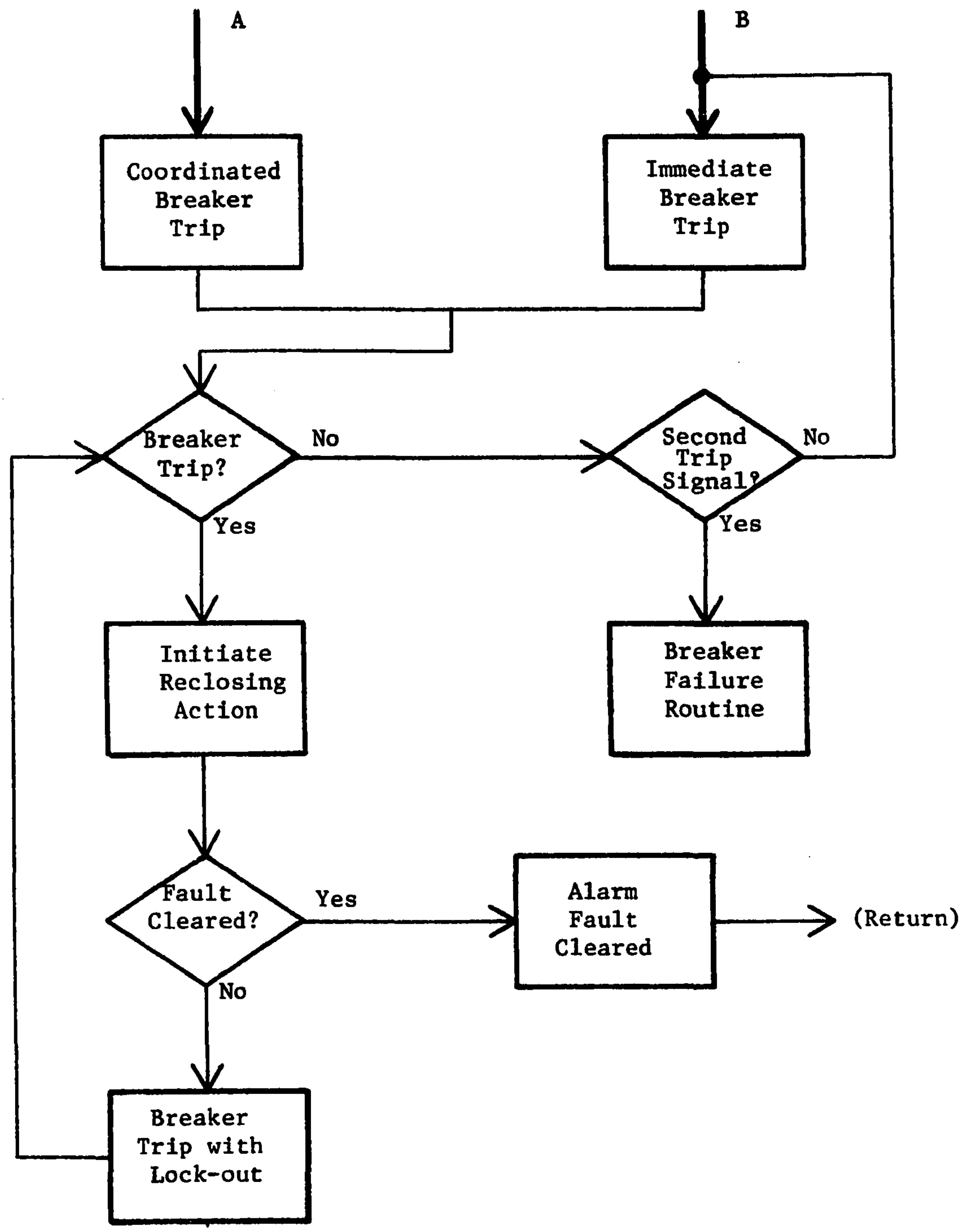
A consideration of the software requirements for the individual DCU subsystems is now appropriate. As shown in Flow Chart 2, the back-up protection DCU must receive line information in order to determine the existence of a fault. This information comes in the form of three-phase voltages, three-phase currents, and a residual current. This information would be treated by the DCU in the following fashion. A fault detection subroutine would analyze the data to determine if a fault has occurred. In a parallel sense, as a part of the fault detection routine, a high current trend analysis could be performed to determine if line loading was approaching a maximum limit defined either by line capacity or protection settings. Should a fault be detected, another set of parallel operations takes place. The data is processed immediately to determine



(See next page)

BACK-UP PROTECTION

FLOW CHART 2



FLOW CHART 2 (CONT.)

the type and nature of fault on the transmission line. The existence of the fault is alarmed through the SCCU to the central dispatcher. An interrupt to the data and control DCU initiates appropriate fault data collection. If a high overcurrent check is negative, a subsequent routine to calculate impedance to perform zone discrimination is initiated. Once the impedance has been determined and the appropriate zone for the fault selected, appropriate action is determined according to fault location and the breakers are either tripped or a time delay trip is initiated to allow remote terminal clearing. At this point, a breaker trip check is performed to detect a failure of the circuit breaker to de-energize the line. Two trip signal attempts are made and if breaker activity is not detected, a breaker failure routine is initiated. If the trips are successful, a synchronized reclosing action is initiated. This is to allow for the possibility of the existence of a temporary fault. Westinghouse reports that less than ten percent of all faults are of a permanent nature. [35] Therefore, a reclosing attempt is justified. If the fault is cleared after reclosing, the fault clearing is alarmed and the primary protection DCU returns to a normal state. If the fault is not cleared, a breaker trip signal with lockout is initiated and another breaker trip check is performed. Again, if the breaker fails, the breaker failure routine is initiated. However, if the second trip is successful, the breaker locks out, permanently de-energizing the line.

4.4 Evaluation of Trend Analysis and Fault Detection Routine

To prove the feasibility of simultaneous fault detection and trend analysis, an algorithm was developed and tested on a Digital Equipment Corporation PDP-8 computer. The basis for the fault detection routine is the previously discussed work by Mann and Morrison (See Section 2.2). [36]

The purpose of this routine is to rapidly detect a fault condition and initiate appropriate action. The trend detection routine is likewise exercised on a regular basis to detect an overload trend and provide an interrupt to the security DCU, which performs a detailed trend analysis. Since no microcomputer equipment was available for use, the PDP-8 was chosen. While it differs considerably from most microcomputers, it is possible to program the machine using an instruction set somewhat like a typical microcomputer. An experienced programmer will immediately notice that the routine is inefficient and crude by PDP-8 standards. Indulgence is asked on this point, since an attempt was made to formulate the routine using only fundamental commands and operations.

Present cycle to past cycle amplitude comparison was used to monitor the voltage of all three phases of a single transmission line. Since each phase must be monitored, from a programming viewpoint the amplitude comparison scheme consists of three identical routines. For this reason, a single phase routine was devised and tested. Three of these routines (1 per phase) would be used for total fault detection on a transmission line.

Trend detection was performed by successive application of the derivative approximation technique given by [37]

$$\left.\frac{dx}{dt}\right|_{t = tn} \approx \frac{Xn - Xn\text{-}1}{h}$$

where h is the time increment between successive samples. If the sample rate is periodic and synchronized to 60 hertz, "h" is constant and, since only relative derivative calculations are required, it can be ignored. Hence to approximate the envelope of the current sinusoid by a straight line requires a simple data subtraction. The result of this subtraction can be compared to some pre-set minimum. If the minimum is exceeded, a high trend condition is indicated. To secure from false indications due to transient conditions, the routine would be exercised successively and several positive indications of high trend would be required before the condition was indicated.

Note that considerable "data handling" programming was required, due to the limited capability of the PDP-8 facility which was used. Definitions of program variables are as follows:

LI: Number of non-correlating samples required to indicate a fault.

OL: Number of samples per cycle.

TO: Allowable degree of non-correlation between fault samples.

CO: Cumulative total of non-correlating fault samples.

OD: Array or data "stack".

OC: "Stack" pointer.

DA: Value of last sample.

TD: Allowable degree of non-correlation between trend samples.

TR: Number of non-correlating samples required to indicate high trend.

TN: Cumulative total of non-correlating trend samples.

For purposes of evaluation, the variables were set at the following values:

LI = 5 OL = 15 TO = 0.10 TR = 3 TD = 0.02

With these variables, the routine assumes 15 samples per cycle and will compare these samples on a regular basis until 5 fault samples are out of tolerance by the value $\pm$ 10%. When 5 non-correlating samples are reached, a fault is indicated. Trend tolerance is set at +2% and high trend is indicated when 3 excessive samples occur.

To provide a test for this routine, fault data was obtained from Oklahoma Gas & Electric Company. This data was for a phase to ground fault recorded at Seminole substation in 1974, as shown in Figure 18. Data samples were taken from the output of a high resolution analog recorder. [38] The successful performance of the routine in detecting the line to ground fault condition and in detecting high load trend is indicated by the program outputs shown in Tables 1-3.

Table 1 shows simulated fault data samples for the phase to ground fault shown in Figure 18. The first 21 samples represent a healthy sinusoid and samples 22-26 represent fault data. As shown, the fault routine detects the presence of the fault samples and the fault counter is successively incremented until the preset number of 5 fault samples is reached. At this point, the fault alarm is generated. Table 2 includes sinusoidal data upon which a slow loading trend has been superimposed. The fault routine ignores this loading trend while the trend analysis routine detects the condition. Following the preset number of 3 successive positive trend tests, the high trend condition is indicated.

Table 3 shows sinusoidal data which has been "spiked" with individual samples of spurious data. These could represent single A/D misconversions, transient line conditions, line switching surges, lightning surges, etc. The fault routine detects the samples but automatically decrements and resets the counter upon encountering subsequent healthy samples. No fault is indicated.

Fault Detection and Trend Analysis Program

Figure 17

```
01.01  S LI=5; S OL=15; S TO=.1; S TR=3; S CO=0; S TD=.02; S TN=0
01.20  F OC=1,OL; DO 10.1; S OD(OC)=DA
01.25  S TS=-2
01.30  S OC=OL
01.70  S DA=-4000; A DA
01.80  I (DA+1000)8.5,2.1,2.1

02.10  S OC=OC+1
02.20  S S1=OC
02.30  S S2=OL+1
02.40  D 10.3
02.50  I (S1)3.1,2.7,2.7
02.70  S OC=S1
02.80  S OC=1

03.10  S S1=DA
03.20  S S2=OD(OC)
03.30  D 10.3
03.35  S OD(OC)=DA
03.40  I (S1)3.5,3.6,3.6
03.50  D 11
03.60  S  D1=S1
03.70  D 7

04.10  S S2=TO*FABS(DA)
04.20  D 10.3
04.30  I (S1)4.5,5.1,5.1
04.50  I (CO)4.7,4.6,4.7
04.60  D 10.4; G 1.7
04.70  S CO=CO-1
04.80  D 10.4; G 1.7

05.10  S CO=CO+1
05.15  D 10.4
05.20  S S1=CO
05.30  S S2=LI
05.40  D 10.3
05.50  I (S1)1.7,8.1,8.1

07.10  I (DA)7.15,7.2; S TS=TS+1
07.13  G 7.2
07.15  S TS=-2
07.20  I (TS-1)7.9,7.3,7.9
07.30  S S2=TD*FABS(DA)
07.40  D 10.3
07.50  I (S1)7.6,7.6;S TN=TN+2
07.60  I (TN)7.9,7.9; S TN=TN-1
```

```
07.65  S S1=TN
07.70  S S2=TR
07.75  D 10.3
07.80  I (S1)7.9,7.9; T "ALARM"!
07.90  S S1=D1

08.10  T ". . FAULT . ."!
08.15  G 1.7
08.50  T !!"END"!;Q

10.10  A "DATA=",DA
10.30  S S1=S1-S2
10.40  T #"     TREND", TN,%3.00,"   COUNTER",CO,!

11.10  S S2=S1
11.20  S S1=0
11.30  D 10.3
*
```

400 (345 KV) amps/inch 945 (138 KV) amps/inch (0.4 Attenuation)	345/138 tertiary current	
96,500 volts/inch (0.2 Attenuation)	345 KV pot Arcadia A phase	
96,500 volts/inch (0.2 Attenuation)	345 KV pot Arcadia B phase	
96,500 volts/inch (0.2 Attenuation)	345 KV pot Arcadia C phase	
2,600 amps/inch (0.4 Attenuation)	Arcadia A phase current	
3,300 amps/inch (0.4 Attenuation)	Arcadia neutral current	
2,600 amps/inch (0.4 Attenuation)	Unit #2 line neutral	

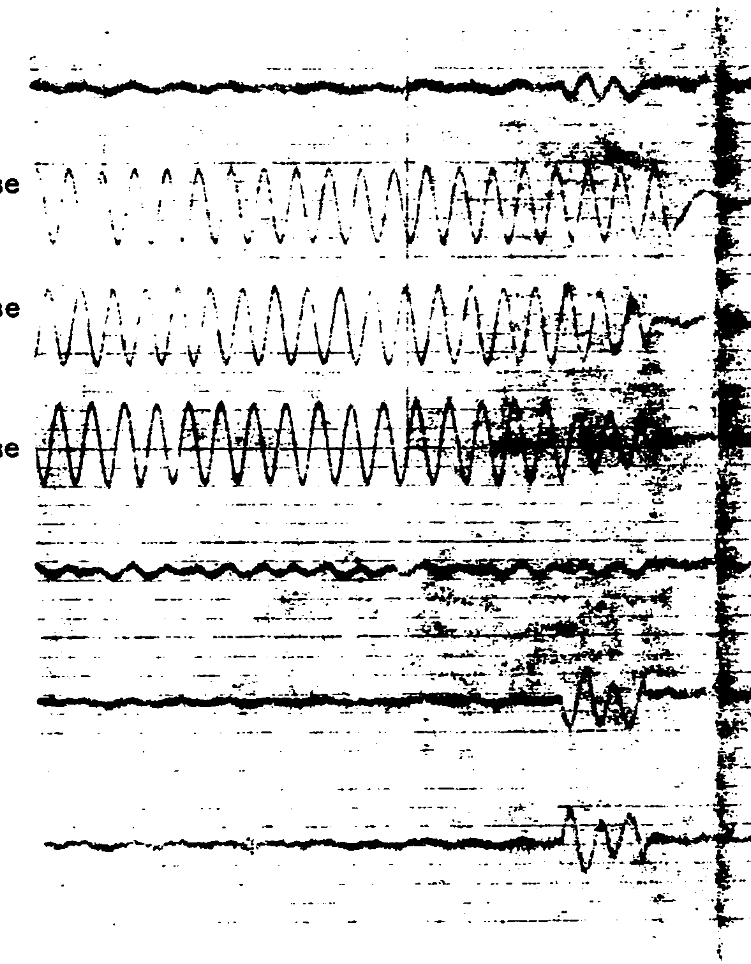


Figure 18

Fault Data and Output

Table 1

```
*L  0  4
*G
DATA=:0.3335
DATA=:0.6881
DATA=:0.9238
DATA=:0.9997
DATA=:0.9027
DATA=:0.6497
DATA=:0.2843
DATA=:-0.1302
DATA=:-0.5223
DATA=:-0.8240
DATA=:-0.9832
DATA=:-0.9724
DATA=:-0.7935
DATA=:-0.4774
DATA=:-0.0787
:0.3335
0     TREND=     0    COUNTER=     0
:.6882
0     TREND=     0    COUNTER=     0
:.9238
0     TREND=     0    COUNTER=     0
:.9997
0     TREND=     0    COUNTER=     0
:.9027
0     TREND=     0    COUNTER=     0
:.6497
0     TREND=     0    COUNTER=     0
:.8529
-     TREND=     0    COUNTER=     1
:0.3908
-     TREND=     0    COUNTER=     2
:1.5678
-     TREND=     0    COUNTER=     3
:2.4719
-     TREND=     0    COUNTER=     4
:2.9496
-     TREND=     0    COUNTER=     5
. . FAULT . .
```

Trend Data and Output

Table 2

```
*G
DATA=:0.3335
DATA=:0.6893
DATA=:0.9268
DATA=:1.0047
DATA=:0.9088
DATA=:0.6551
DATA=:0.2872
DATA=:-0.1317
DATA=:-0.5292
DATA=:-0.8363
DATA=:-0.9997
DATA=:-0.9904
DATA=:-0.8095
DATA=:-0.4878
DATA=:-0.0806
:0.3419
0     TREND=    0    COUNTER=    0
:.7066
0     TREND=    0    COUNTER=    0
:.9500
1     TREND=    1    COUNTER=    0
:.0298
0     TREND=    1    COUNTER=    0
:.9315
0     TREND=    1    COUNTER=    0
:.6715
0     TREND=    1    COUNTER=    0
:.2943
-     TREND=    1    COUNTER=    0
:0.1350
-     TREND=    1    COUNTER=    0
:0.5423
-     TREND=    1    COUNTER=    0
:0.8571
-     TREND=    1    COUNTER=    0
:1.0243
-     TREND=    1    COUNTER=    0
:1.0148
-     TREND=    1    COUNTER=    0
:0.8294
-     TREND=    1    COUNTER=    0
:0.4998
-     TREND=    1    COUNTER=    0
:0.08260
0     TREND=    1    COUNTER=    0
:.3503
0     TREND=    1    COUNTER=    0
:.7238
0     TREND=    1    COUNTER=    0
:.9732
1     TREND=    2    COUNTER=    0
:.0549
0     TREND=    2    COUNTER=    0
:.9541
0     TREND=    2    COUNTER=    0
:.6878
0     TREND=    2    COUNTER=    0
:.3015
-     TREND=    2    COUNTER=    0
:0.1383
-     TREND=    2    COUNTER=    0
:0.5555
-     TREND=    2    COUNTER=    0
:0.8778
-     TREND=    2    COUNTER=    0
:1.0491
-     TREND=    2    COUNTER=    0
:1.0392
-     TREND=    2    COUNTER=    0
:0.8494
-     TREND=    2    COUNTER=    0
:0.5118
-     TREND=    2    COUNTER=    0
:0.0846
0     TREND=    2    COUNTER=    0
:.3587
0     TREND=    2    COUNTER=    0
:.7412
0     TREND=    2    COUNTER=    0
:.9965
1     TREND=    3    COUNTER=    0
:.0801
0     TREND=    3    COUNTER=    0
:.9768
0     TREND=    3    COUNTER=    0
:.7041
0     TREND=    3    COUNTER=    0
:.3086
-     TREND=    3    COUNTER=    0
:0.1416
-     TREND=    3    COUNTER=    0
:0.5686
-     TREND=    3    COUNTER=    0
:0.8985
-     TREND=    3    COUNTER=    0
```

```
:1.0738
-      TREND=    3    COUNTER=    0
:1.0637
-      TREND=    3    COUNTER=    0
:0.8693
-      TREND=    3    COUNTER=    0
:0.5238
-      TREND=    3    COUNTER=    0
:0.0865
0      TREND=    3    COUNTER=    0
:.3671
0      TREND=    3    COUNTER=    0
:.7585
1      TREND=    3    COUNTER=    0
:.0197
1ALARM
       TREND=    4    COUNTER=    0
:.1051
0      TREND=    4    COUNTER=    0
:.9995
0      TREND=    4    COUNTER=    0
:.7204
0      TREND=    4    COUNTER=    0
:.3157
-      TREND=    4    COUNTER=    0
:0.1448
-      TREND=    4    COUNTER=    0
:0.5818
-      TREND=    4    COUNTER=    0
:0.9192
-      TREND=    4    COUNTER=    0
:1.0985
-      TREND=    4    COUNTER=    0
:1.0881
-      TREND=    4    COUNTER=    0
:0.8892
-      TREND=    4    COUNTER=    0
:0.5357
-      TREND=    4    COUNTER=    0
:0.0885
0      TREND=    4    COUNTER=    0
:.3754
0      TREND=    4    COUNTER=    0
:.7758
1      TREND=    4    COUNTER=    0
:.0429
1ALARM
       TREND=    5    COUNTER=    0
:.1303
1      TREND=    5    COUNTER=    0
:.0221
0      TREND=    5    COUNTER=    0
:.7367
0      TREND=    5    COUNTER=    0
:.3228
       TREND=    5    COUNTER=    0
:

END
```

Transient Data and Output

Table 3

```
G
DATA=:.33349
DATA=:.68811
DATA=:.92375
DATA=:.99967
DATA=:.90273
DATA=:.64970
DATA=:.28434
DATA=:-0.13020
DATA=:-0.52221
DATA=:-0.82394
DATA=:-0.98320
DATA=:-0.97245
DATA=:-0.79355
DATA=:-0.47745
DATA=:-0.07878
:0.33350
0     TREND=     0     COUNTER=     0
:.68812
0     TREND=     0     COUNTER=     0
:.92376
0     TREND=     0     COUNTER=     0
:.99967
0     TREND=     0     COUNTER=     0
:.90272
0     TREND=     0     COUNTER=     0
:.64970
0     TREND=     0     COUNTER=     0
:.28432
-     TREND=     0     COUNTER=     0
:0.00021
-     TREND=     0     COUNTER=     1
:0.52223
-     TREND=     0     COUNTER=     0
:0.82394
-     TREND=     0     COUNTER=     0
:0.98320
-     TREND=     0     COUNTER=     0
:0.97244
-     TREND=     0     COUNTER=     0
:0.79354
-     TREND=     0     COUNTER=     0
:0.47744
-     TREND=     0     COUNTER=     0
:0.78770
0     TREND=     0     COUNTER=     1
:.33352
0     TREND=     0     COUNTER=     0
:.68813
0     TREND=     0     COUNTER=     0
:.92376
1     TREND=     0     COUNTER=     0
:.0
0     TREND=     0     COUNTER=     0
:.90271
1     TREND=     0     COUNTER=     0
:.0
0     TREND=     0     COUNTER=     1
:.28431
-     TREND=     0     COUNTER=     0
:0.13023
-     TREND=     0     COUNTER=     1
:0.52224
-     TREND=     0     COUNTER=     0
:0.82395
-     TREND=     0     COUNTER=     0
:0.98320
-     TREND=     0     COUNTER=     0
:0.97244
3     TREND=     0     COUNTER=     0
:.0
-     TREND=     0     COUNTER=     1
:0.47742
-     TREND=     0     COUNTER=     0
:0.07875
0     TREND=     0     COUNTER=     1
:.33352
2     TREND=     0     COUNTER=     0
:.0
0     TREND=     0     COUNTER=     1
:.92377
3     TREND=     0     COUNTER=     0
:.0
0     TREND=     0     COUNTER=     1
:.90271
0     TREND=     0     COUNTER=     0
:.64967
1     TREND=     0     COUNTER=     1
:1.0
-     TREND=     0     COUNTER=     2
:9.0
-     TREND=     0     COUNTER=     3
:0.52225
-     TREND=     0     COUNTER=     2
:0.82396
-     TREND=     0     COUNTER=     1
:0.98320
8     TREND=     0     COUNTER=     0
:.0
```

4.5 Selection of Primary Protection Technique

As pointed out in Section 4.2, digital distance relaying is most appropriate for backup schemes. The selection of a primary protection technique is therefore necessary. An analysis of the protection schemes used by utilities on EHV lines shows a preference for "pilot" type protection utilizing intra-substation communication links. [39] The availability of high speed, secure digital data links makes implementation of pilot relaying schemes on digital computers quite possible. Numerous relaying techniques fall into this category, including pilot wire differential, amplitude comparison, phase comparison, remote transfer tripping, directional comparison, etc. A technique used by such companies as American Electric Power, Commonwealth Edison, and Southern California Edison is phase comparison relaying. This is a very reliable and secure technique, as pointed out by Van C. Warrington, and has numerous advantages, including immunity to such effects as power swings, switching of series capacitors, loss of potential, and mutual inductance of zero sequence currents from parallel lines. [40] He points out these disadvantages due to the usual practice of reducing phase and residual currents to a single transmitted signal: loss of discriminating margin and delay in carrier operation. Both of these disadvantages are easily overcome using multiple channel or high speed serial, continuous data links. With these advantages and ease of implementation, the phase comparison scheme seems, at face value, a logical choice for digital relaying.

The concept of amplitude comparison, the dual of phase comparison, is quite simple. Voltage and/or currents from both terminals of the line are compared on a continuous basis to detect abnormal phase or amplitude relationships. For amplitude comparison, as traditionally applied, two current signals of amplitudes A and B would be rectified and subtracted and the result squared to produce a trip signal.

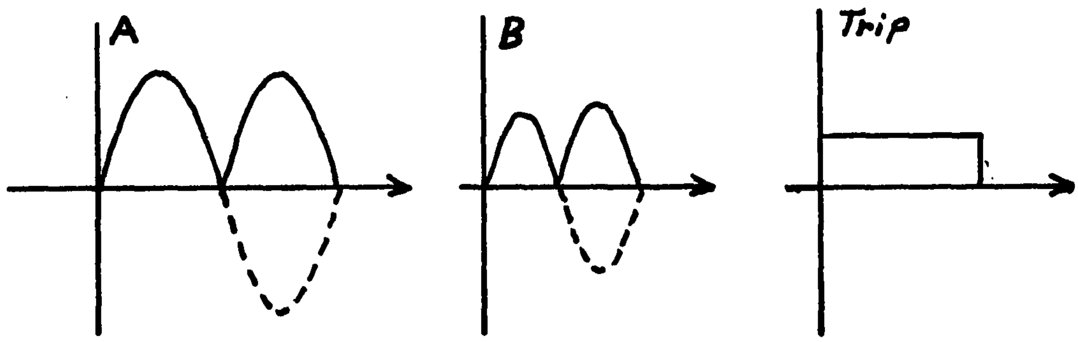
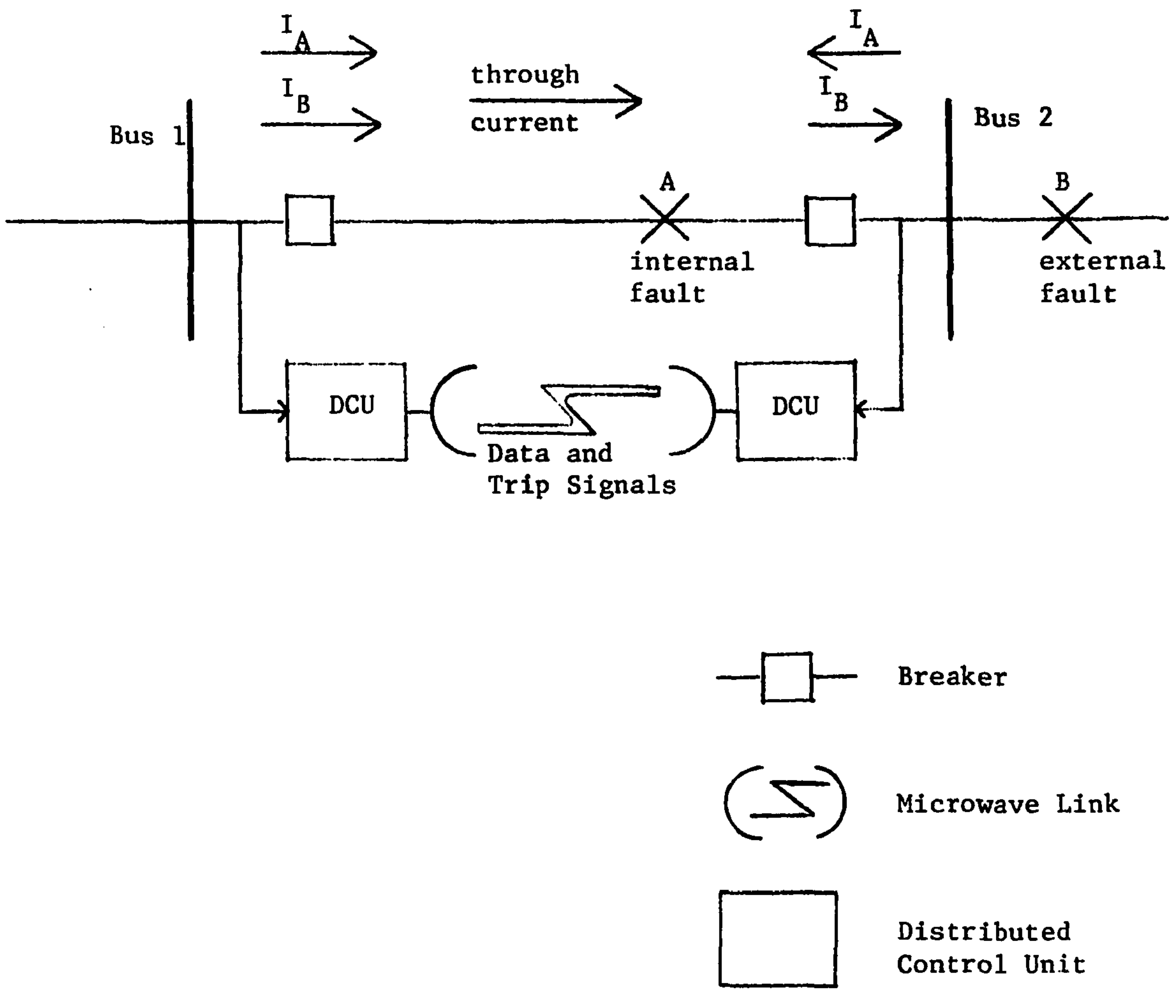


Figure 19

The attenuation and phase displacement of long-distance communication links previously prevented the use of this scheme for most lines. Since attenuation is of little consequence to phase comparison schemes, they were used, but compensation for phase shift was necessary. Since phase comparison is basically a comparison of wave forms in time, this technique introduces delay in tripping. However, a modification of these techniques can be applied to digital relaying quite successfully. The amplitudes of the waveforms can be synchronously sampled at both terminals of the transmission line and the data from one terminal transmitted over a high speed data link to the other terminal for comparison. Transmission of information would be digital rather than the actual analog signal, therefore attenuation would not be a problem. A schematic representation of a digital amplitude comparison relaying scheme is shown in Figure 20. Each terminal of the line is protected by a dedicated amplitude comparison DCU. These units are linked by a high speed, microwave communication system. As indicated, each DCU receives data from the opposite line terminal and compares this data, taking into account



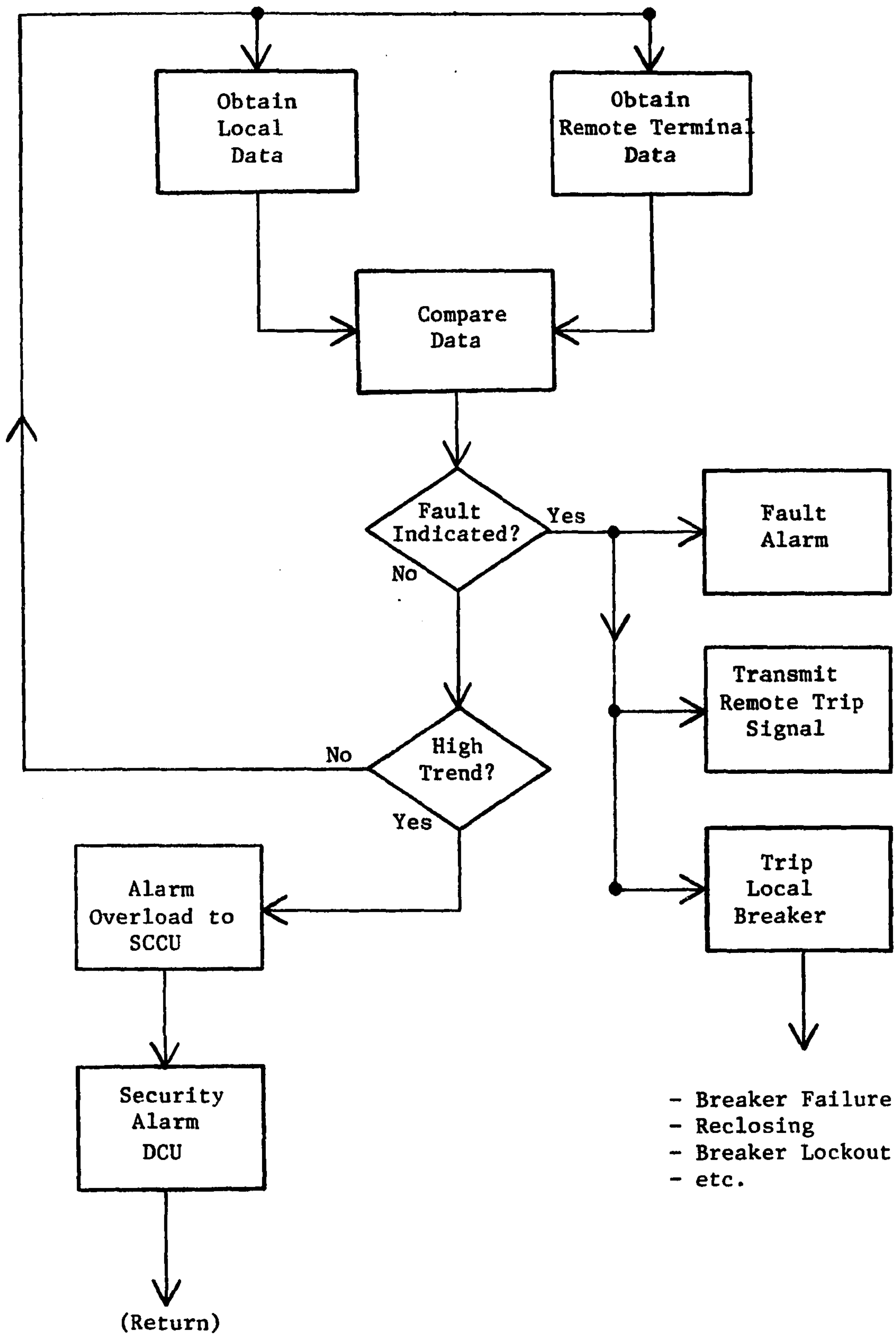
Digital Amplitude Comparison Technique

Figure 20

necessary transmitting time adjustments. Through current or an external fault at point B will generate similar waveforms at bus 1 and bus 2. However, an internal fault would be immediately detected due to the shift in currents indicated by the arrow labeled I_A. Virtually simultaneous tripping of both terminals would be accomplished, but as a precaution, additional trip signals would be transmitted over the communication link by both DCU's. Operation could be extremely fast by current standards, and immunity to power swings should be exhibited.

4.6 Software Requirements for Amplitude Comparison Relaying

The primary protection scheme outlined in Flow Chart 3 represents the necessary steps the protection DCU would take for amplitude comparison protection. Local line terminal information, as well as remote terminal information, would be obtained by the computer in a synchronous fashion. This data would be compared, as shown, and analyzed to determine if a fault exists internal to the protected line segment. If no fault exists, a check for high trend is made to determine a dangerous overload possibility. Should an overload exist, the overload is alarmed to the SCCU for passing to the central computer and subsequently to the system operator. In addition, the high trend is flagged to the security DCU which does a detailed overload analysis and projects time to trip. Should no high trend exist, of course, the system returns to its beginning state and compares a new set of data. Should a fault be indicated, the system protection DCU flags the fault to the SCCU, transmits a remote trip signal, and trips the local breaker. Subsequent to initiating a breaker trip signal, a breaker failure reclosing routine is initiated, as was previously discussed. Once the system is clear of the fault, a return



PRIMARY PROTECTION
FLOW CHART 3

is made to obtain new system data. Should the fault be of a permanent nature, of course a breaker lockout is indicated.

The fault detection routine has, as yet, not been defined. It is necessary that we efficiently compare the local and remote data to detect an internal fault condition, while maintaining insensitivity to all high through currents and external faults. The fastest and most secure way of accomplishing this task seems to be an instantaneous sample comparison routine, similar in theory to the single terminal, cycle-to-cycle fault detection technique previously discussed.[41]

It would be necessary that the waveform samples taken at each line terminal be time synchronized to make the comparison valid. This could be easily accomplished using several available techniques. A synchronizing signal could be transmitted between the respective DCU's to keep them and their peripherals locked in time. Should this sync channel be undesirable, a local stable oscillator, synchronized by reference to WWVB is quite feasible. [42] The National Bureau of Standards has shown that time readings of $\pm$ 50 microseconds accuracy are possible. Recall that 1° of phase shift of 60 hertz is approximately 46 microseconds. Hence, $\pm$ 1° sample time synchronization should be possible. This is well within our system requirements.

Assuming that time synchronized samples are available, they must be transmitted to the opposite line terminal. Transmission time is not negligible and introduces a delay which must be recognized. However, since execution time for the fault detection routine is long compared to the transmission time of the coded instantaneous values, no problems will exist as long as the correct samples are compared. To assure comparison of samples collected at the same point in time, the sample can carry a time "address" indicating the point in cycle when it was taken. This check, along with the synchronized DCU's, should assure proper comparison of data. Since samples will not exactly compare, a tolerance must be set. This tolerance can also serve as a control on comparison sensitivity. Tripping on brief transients can be eliminated by the integrating effect achieved when several non-correlating samples are required to indicate a trip. Controlling the number of negative comparisons required to trip will also control sensitivity and provide discrimination between faults and pseudo-faults.

4.7 Microcomputer Selection

Numerous factors must be considered when selecting a microcomputer system. Some of these factors are listed below:

1. Word length
2. Memory type and size
3. Power supply
4. Instruction set
5. Speed
6. Internal registers
7. Stacks
8. Address modes
9. Interrupt capabilities
10. Peripheral support devices
11. Input/output requirements

The optimum architecture and set of characteristics for the DCU and SCCU microcomputers can only be achieved by specific designs which meet the special data handling, interrupt, and other requirements unique to each subsystem. However, it is possible to use commercially available microcomputers to achieve a functional hardware configuration. The requirements a microprocessor must meet to perform the various functions of the DCU's are specific, but not harsh. A priority interrupt system is absolutely necessary in this application. It may be necessary in complex control schemes for several DCU's (local and remote) to address a single DCU on an interrupt basis. A hierarchy must be established to handle these interrupts. Absolute priority must be given to communication between two DCU's protecting the terminals of a transmission line. The security DCU must also have a priority interrupt system. When a protection DCU detects a high trend condition, the security DCU must immediately perform a trend analysis routine and present the results to the SCCU for transmission. Programmed interrupts could be used, but cause unnecessary program complexity.

Word length may vary between eight to sixteen bits, according to the specific function of the DCU. A secondary protection DCU may be required to calculate impedance, therefore, a sixteen bit machine might be appropriate. For a DCU which primarily monitors the status of equipment, an eight bit machine would be fully adequate. There exists no requirement that all machines be identical, therefore machine specifications would be set according to functional requirements.

Due to the large degree of distributed processing, speed is not of primary importance for most of the DCU's. However, in the case of the protection units, the maximum speed practical is desired. A machine with better than 1 microsecond cycle time is preferred. While this is fast by today's standards, for microcomputers, several machines exist which can provide this speed.

A feature which will greatly increase the speed and efficiency of data handling by the DCU's is direct memory access (DMA). Normal input/output is accomplished by programmed word transfers supervised by the microprocessor. This is a time consuming operation when large amounts of data must be moved. DMA capability allows rapid transmittal of data between the microcomputer memory and peripheral devices. This could be especially helpful to the data DCU's which must output considerable information to magnetic tape storage units. The Rockwell PPS-8 system has a sophisticated DMA capability provided by a special peripheral device called a Direct Memory Access Controller. [43] To allow efficient programming, other features, such as multiple accumulaters, stack pointers, multiple address modes, etc. might be useful. Since several DCU's will be interconnected, such devices as Motorola's Peripheral Interface Adapter (PIA) could be very useful. This device would allow the interfacing of two systems over two bidirectional data buses and provide four separate control lines. [44]

Several commercial microprocessors exist having characteristics which meet most of our system requirements. Both Rockwell and Mostek offer machines with acceptable interrupt architecture and DMA capability. [45, 46] Both of these eight bit machines offer single chip CPU construction and utilize PMOS technology. While the speed of these machines is less than desirable, they would serve well for certain of the data and control DCU subsystems.

More stringent computational requirements may require a sixteen bit CPU machine. Several such microprocessors are available, including the National IMP-16 and the Western Digital 1600.[47, 48] Both of these machines are of multiple-chip construction. The Western Digital machine is of particular significance, since it offers an acceptable interrupt capability, DMA ability, 64k address capacity, and multiple CPU registers. The speed of this machine by microcomputer standards is exceptionally fast, offering a 0.6 microsecond per data word register add time. A chart showing the characteristics of this and several other microprocessors follows:

Table 4

Microprocessor *	CPU Size	Single or Multiple Chip	Word Size	Address Capacity	Add Time μsec	ALU Registers
Intel 8080	8 bit	S	8	64k	2	1
Mostek 5065	8 bit	S	8	32k	10	3
Motorola 6800	8 bit	S	8	64k	2	2
National IMP-16	16 bit	M	16	64k	4.6	2
Rockwell PPS-8	8 bit	S	8	16k	4	1
Western Digital 1600	16 bit	M	16	64k	0.6	16

* Each microprocessor listed has an interrupt structure and direct memory access.

It should be pointed out that judging by today's research, these machines may well be obsolete by the end of 1976. New developments in transistor-transistor logic (TTL) and injection-injection logic (IIL) could replace present large-scale integration (LSI) techniques. The result will probably be more versatile machines showing considerable speed improvement.

CHAPTER V

SYSTEM ADVANTAGES AND OPERATING EXAMPLES

5.1 Introduction

An overall list of the capabilities of the proposed substation automation system includes the following:

1. System monitoring, alarming, and indication
2. All supervisory control and data acquisition functions
3. Local emergency automatic control
4. Local data preprocessing
5. Load management
6. System state estimation
7. Line overload trend analysis
8. Interactive relaying (higher order protection)
9. Adaptive system protection
10. Self diagnostic and alarming.

While a number of these functions can be currently performed in a limited fashion, no integrated, interactive system exists capable of performing them all.

5.2 System Reliability

As was previously determined, the critical factor in any substation control system which includes system protection is the "availability" of the system to perform the protection function (i.e. system reliability).

A 1958 CIGRE study classified the causes for protection system misoperation during fault conditions. [49]

TABLE 5

CAUSE OF FAILURE	PERCENT
Relay failure	43%
Circuit breaker interrupter	13.5%
AC wiring	12%
Breaker trip mechanism	7%
Current transformers	7%
DC wiring	5%
Potential transformer	3%
Breaker auxiliary switches	2.5%
DC supply	1%

It can be seen that improvement in the sensitivity, selectivity, and reliability of the decision hardware (relays) would significantly improve overall system protection. To provide reliability, the system has five levels of security to assure 100% availability under fault conditions.

The first level of security is a function of the nature of the microcomputer based protection unit. The microcomputer has the capability of performing self checks and diagnostics and indicating abnormal conditions, taking corrective action, or failing "soft". For example, most systems have a power supply monitor capability which allows a coordinated switch-over to an alternate battery power supply in case of primary power supply failure. To protect its system from the consequences of power transients, power interruption, component failure, one manufacturer lists the following features: operation monitor alarm, system safe line, system reset line, power fail detection, and automatic restart.[50] Additional software programmed self checks and diagnostics can also be provided to maximize the possibility of detecting an individual protection unit failure.

A second level of security is the traditional back-up system or 100% redundancy concept. A secondary protection DCU has been provided whose operation is superimposed upon and parallel to the primary detection unit. This independence prevents dual failure and essentially eliminates most causes of overall protection system misoperation. A third level of defense is provided by the security DCU. This unit regularly accesses each protection DCU and checks operations from a terminal viewpoint. As previously explained, the unit would detect the ability of the protection DCU to trip the breaker in response to fault data. The security DCU could initiate corrective action where appropriate should it determine the "unavailability" of a protection DCU.

A fourth and fifth level of security is easily provided by taking advantage of the communication link to the central computer and the control capability of the security DCU. When a failure is determined at any level in the protection system, the SCCU can be addressed by the security DCU and a message describing the failure can be transmitted to the central computer via the communication link. The central computer would pass this message to the system operator who can take corrective action. While this operation is taking place, it would also be possible to switch in, for example, a spare CPU to take the place of the one which has failed. While requiring considerable ingenuity in proper switching and interfacing, it is certainly possible.

A very reliable system design with self checking and failure alarming capability has been provided, yielding the possibility of an acceptable operating reliability. However, to this point, adequate reliability on the part of individual components has been assumed. Obviously, overall system reliability is a direct function of individual subsystem and component reliability. Microcomputers have an industrial reputation as very reliable control devices, but due to the brief time most microcomputers have been in service, virtually no long-term evaluations have been made. Several subjective points can be made to support the conclusions that they offer high reliability. Appendix II is a list of successful microcomputer applications, some of which represent hostile environments. For example, a microcomputer has been used to control reactor vessel welding equipment. In this application, the computer was located on top of the welding apparatus in a high heat, high noise environment and operated continuously, performing without failure or misoperation. [51] In other applications, microcomputer systems have controlled glass bottle manufacturing, performed remote site environmental monitoring, functioned as urban traffic controllers, etc. All of these applications represent unique environmental conditions where microcomputer systems have functioned admirably.

Two other functions point to a high level of reliability from microcomputers when compared to either IC constructed solid-state devices or typical minicomputers. Microcomputers contain no moving parts, a high failure point for most minicomputer systems, and when compared to IC constructed devices, microcomputers have far fewer interconnections to fail. It has long been known that with IC systems, most failures are due to the interconnections between components, rather than failures of the components themselves. For example, a 16 pin IC will introduce about 30 interconnections to the system. There are 16 interconnections from the chip to the lead frame, 16 from the lead frame to the PC card, and approximately 2 interconnections from the PC card to the back plane and 2 interconnections from back plane to back plane point per IC. Obviously, the way to reduce failure and increase reliability is to simplify the IC system as much as possible. This can be done by replacing IC construction with LSI, microcomputer type construction. One ROM can replace 40 to 50 IC's, thus eliminating approximately 1800 interconnections. It is easy to see that superior reliability should result from microcomputer construction as compared to IC, solid-state construction.

A reliability evaluation of a microcomputer composed of the typical subsystem modules has been performed by LeRoy Anderson of the COMSTAR Corporation. [52] Dr. Anderson assumed that the failure of 1 subsystem of the microcomputer represented an overall system failure. He also assumed 100% use of all memory locations, continuous duty for each module of the system, and no redundancy or special system provisions to improve reliability. Even with this stringent set of conditions, he showed excellent reliability figures for a typical microcomputer. To arrive at his conclusions, he evaluated the machine based on the failure rate (FR) of the individual components found in each module. Such information is readily available from integrated circuit manufacturers, such as Texas Instruments and Fairchild. He then assumed that the failure rate of each module is then the sum of the failure rates of each individual component. A composite failure rate (CFR) can be derived by summing the individual module failure rates. Dividing the CFR into 10^6 hours yields an MTBF in hours for 100% duty cycle on all components. An example is given on the following page.

Microcomputer MTBF Calculation

MODULE	CFR
Power supply	11.08
regulator	24.15
CPU	21.55
RAM	7.97
PROM	12.44
Input/Output	12.19
	89.38

$$\text{MTBF} = 10^6 \text{ hours/CRF} = 10^6 \text{ hours/89.38} = 11{,}188 \text{ hours}$$

It should be noted that the figures for this evaluation are two years old and therefore do not reflect recent improvements by microcomputer manufacturers. One could only expect that these improvements have resulted in improved reliability.

A comparison of microcomputer and electromechanical system reliability is desirable. However, the lack of statistical data and the nature of reliability specifications for electromechanical relays prohibit such comparisons. No reliability or failure data is available on protective relays and successful performance in accelerated life tests (e.g. 10^6 contact closures) is no indication of in service reliability. Hence, no such comparisons can be made at this writing.

5.3 System Advantages

Economic evaluations must lead to an acceptable cost if acceptance by the utility industry is to be expected. While exact comparisons are impossible, relative cost estimates can be made. A review of the cost data included in several of the references shows complete microcomputer systems equivalent to the required capability of a protection DCU can be purchased quite economically. Even when one considers the required peripheral support equipment, the system cost should fall below the estimated cost per line terminal currently required for protection. Since the automation system's functional capability goes beyond protection, at this writing, the actual cost per function should prove approximately 20% less than current systems.

The configuration of the protection system interfaced through the substation communication and control unit to the central computer, yields several operating advantages. In addition to the capability of detecting protection system failure, the protection system can perform overload trend analysis and through the communication system warn the operator of impending line or equipment overloads. A trend detection routine was designed to operate in parallel with the fault detection routine. Since the line is continuously monitored for fault conditions, it is relatively easy to incorporate a trend monitor. A trend detector can be programmed with the line load capability, and since it contains the protection system limits, it can detect a line loading trend which is either approaching a line overload or protection system trip condition. This capability is totally lacking in present systems and would provide an extra degree of system security. Major system instabilities can result from the inadvertent tripping of a heavily loaded line. The resulting power surges can cause false operation of protective relays and result in a segmented system with severe generation-load imbalance. Forewarning a system operator of the impending overload or trip situation virtually eliminates the problem.

Certain operating procedures could give even greater security. An operator could enter his tie-line loading intentions into the central computer which could, in turn, check the proposed loading against the line capability and protection equipment settings. Should the proposed loading be acceptable, the computer could so indicate to the system operator. This simple step could eliminate the possibility of a major system collapse.

Another advantage of the proposed integrated automation system can be called adaptive relaying. As you recall, current protection system parameters are set by hand adjustment of the protection equipment. No provision is made for adjusting the parameters to fit specific situations or adjusting them in a remote fashion. Hence, considerable "tolerance" must be allowed in the protection schemes to cover a broad range of operating conditions. In certain operating situations, the ability to remotely alter the protection parameters could be valuable. Temporary line overload could be allowed simply by properly adjusting the protection system settings to allow the condition. While this function is virtually impossible with present systems, it is easily accomplished using the proposed digital protection scheme. Each protection DCU can be addressed individually by the system operator through the central computer-SCCU hardware and the protection settings can be set to any specified value. The operator need not be familiar with the line specifically, for all appropriate information can be stored in the central computer. A single entry in the form of the desired magnitude of temporary overload could be made. Appropriate protection settings would be generated by the central computer and the protection DCU located at the substation could be automatically reprogrammed to fit the situation. This could be of considerable value in the case of interconnections between systems, where emergency power flow might be required, but where light loading or no power flow is the normal condition. Under central computer control, the technique could also be used to adjust the protection system properly to break the system into matched generation-load segments under emergency conditions.

5.4 Case Study: Northeast Blackout

At 5:16:11 P.M. on November 9, 1965, 28 utilities were affected by the worst power failure in man's history. [53] Large sections of the northeast were without power for periods lasting up to one-half day. The conditions leading up to this situation are herein reviewed, since the cause of the outage is directly treated in this work.

Beck Station of Ontario Hydro provides power to the Toronto area over 5-230 kv transmission lines. An emergency outage at the Ontario Hydro steam plant at Lakeview had caused heavy loading of these lines in recent months. On the day of the failure, these lines carried 1500 megawatts. Immediately prior to the failure, an interconnection with PASNY (Power Authority State of New York) was carrying 1800 megawatts south and east over heavily loaded lines. The protection for Ontario Hydro's lines was provided by primary and back-up relaying systems. The back-up system had been installed in 1951 and reset in 1963 to its present protection settings. The level of protection of what we shall call line A had been set at 375 megawatts. It should be noted that this level was considerably below line capability, but operation at higher levels was never considered necessary. The setting was specifically low to extend protection past the next substation.

On the day of the outage, line A had averaged 356 megawatts power flow north. At 5:16:11 P.M. the loading on line A exceeded the back-up protection limits and line A tripped out. The load which had been carried by line A was immediately distributed over the remaining four lines. Each of these lines had similar protection settings and became overloaded and in 2.7 seconds, all five lines had tripped and locked out. The approximate 1500 megawatts being carried by these lines was superimposed on the 1800 megawatts flowing east and south in the PASNY system. At 5:16:14.5, this backbone 345 kv system was overloaded by the power surge and all breakers tripped, breaking the system into many segments, each with generation-load imbalance. Many utilities were forced to immediate emergency shutdown, while others were able to hold on for as long as 14 minutes. In short, inside of 15 minutes, the entire Northeast was blacked out. For some utilities, it would take as long as 12 hours to bring their systems back.

Several factors should be noted at this point. The power failure in this case was not precipitated by hardware failure. The back-up relay system functioned perfectly, tripping the breakers when protection limits were exceeded. While a more "intelligent" control system could have prevented the catastrophe, the cause of this failure was basically "human error". As pointed out in the report to the President, "personnel operating the Ontario Hydro system were not aware that the relay was set to operate at the 375 megawatt level". [54] Several congressmen were later to ask Federal Power Commission and Utility Representatives questions which can be summarized by "do you mean the people operating the utility systems don't know about their own equipment?" While the question reflects the uninformed nature of congressmen, it does have a degree of truth which should be pursued. Seldom do operating personnel and dispatchers have accurate, real-time information concerning the protection system. If the protection system is broad, allowing wide operating margins, this usually protects the system dispatcher and an uninformed dispatcher can therefore cause no problem. However, as in the case of the northeast blackout, a lack of knowledge concerning the protection system can be disastrous.

The power failure brought to light another serious problem. Many utilities were able to hold their systems together for several minutes (up to 14), plenty of time to take emergency corrective action. The fact that some of these utilities were pulled down at all can be directly attributed to human error or indecision. The Federal Power Commission report stated that much of the severity of the problem was caused by the failure of system operators to take immediate and decisive action. [55] Many did not believe their instrumentation was correctly indicating the situation and therefore took no corrective action. It should be noted that system dispatchers were in a highly unusual situation and faced with conditions and operating decisions which had never been seen before; therefore, no real blame should be placed on them. What is pointed out is the necessity of removing such critical decisions from operating personnel. Some utilities only had minutes to make the proper decision and carry out a complicated series of operations to save their systems. The speed requirements were far too severe for direct human decision making and control. Automation of the necessary operations and control decisions is therefore the only answer.

The recommendations of the Federal Power Commission included the following: [56]

"Close and frequent checks of relay settings"

"Load management"

"Review of relay applications"

While the northeast blackout precipitated major efforts by utilities to solve the problem of returning the system to a normal condition after a major catastrophe (e.g. under-frequency relaying and standby power), virtually no work has been done toward preventing the event from ever occurring again.

To show that the cause of the northeast failure was not totally unique, two other very similar events are cited. A six state area was affected on January 28, 1965, by a similar chain of events, precipitated by a loose connection in a protective relay circuit at Ft. Randall Power Plant, South Dakota. [57] On July 11, 1966, a major power outage in Nebraska was caused by "incorrect relay operation" at Ft. Randall-Columbus station under "heavy loading" conditions on a 230 kv line. [58] The relay had been operating "without fault" for six years. These and other instances point toward the need for system automation including more advanced protection systems, overload trend analysis, and emergency load control measures. The previously defined system has been specifically designed to offer these advantages.

5.5 Explanation of System Operation Using a Hypothetical Case

The sequence of events leading up to and following the northeast power failure would have been considerably different had the previously developed substation automation system been in operation on the Ontario Hydro system. The following is a hypothetical chain of events suggesting how the substation automation system might have handled the contingency. Assume the same operating conditions and relay settings prior to the failure.

Had the automation system been in operation, the system dispatcher could have presented his loading intentions to the central computer, which in turn could have checked the settings on all the lines and informed the operator that the protection settings would not allow this heavy loading. This could well have prevented the entire episode, since the lines had been loaded progressively higher over recent months. The dispatcher could have remotely changed the protection settings to allow this loading level.

Assume this previous step had not been taken. At some point prior to 5:16 P.M. on November 9, a protection DCU would have exercised its trend detection routine and recognized that a loading trend existed which was approaching protection system limits. The security DCU would have been accessed through priority interrupt and a trend analysis of the five-230 kv lines would have been performed. If the loading was slow, the central computer could have been accessed through the substation communication and control unit and informed of the dangerous trend and a projected time-to-trip for the lines. The central computer would have indicated this condition to the system dispatcher who could have taken immediate steps to prevent further loading. It is possible, though unlikely, that the loading trend was rapid, therefore, not allowing time for dispatcher action. Therefore, in parallel with the above activity, each protection DCU under the control of the security DCU could reset its protection settings to allow these temporary loading conditions rather than tripping out the lines. This is possible since each DCU can be programmed with the theoretical line loading limits of the transmission lines. Had line A tripped due to a permanent fault condition, the other lines could easily have readjusted their protective settings to handle the overload. Recall these facts: the lines took a full 2.7 seconds to trip out and each line was loaded well below its capabilities. Readjustment of the settings would have taken only a few milliseconds. Recall also that we are using a "pilot" comparison protection scheme for primary relaying which has an inherent immunity to power swings.

If these three levels of events had failed to prevent the catastrophe, the substation automation system could have aided in preventing total system collapse. Under central computer control, substation control systems could have performed emergency load management (load shedding) to prevent major load-generation imbalance. In addition, each substation could have been accessed by the dispatcher and appropriate network reconfiguration could have been performed in a matter of minutes rather than hours. In short, the system could have prevented the failure, but had it not, it could have lessened the impact and hastened service restoration.

CHAPTER VI

CONCLUSIONS AND RECOMMENDATIONS

Consideration of the research as a whole points to several advantages which would result from use of the proposed substation automation system. A list of these advantages would be extensive and would include:

1) Distributed Data Processing and Control.
2) Limited Transmission of Data to a Central Computer.
3) Hardware Configuration Offering High Reliability.
4) Trend Analysis and Overload Alarming.
5) Local Emergency Load Control.
6) Protection System Self-Checking and Diagnostics.
7) Remotely Adaptive Relaying Parameters.
8) Total Substation Stand-Alone Control Capability.
9) Reduced Electromagnetic Interference by Optical Waveguide Communications.
10) Improved System Protection by Digital Amplitude Comparison Relaying.

In addition, the system offers extreme flexibility by using advanced microcomputers as the major control hardware. The reliability, speed, and control versatility offered by the microcomputer based system should prove very attractive to utilities.

Obviously, much more work remains to prove the system and bring it to practical application and utility acceptance. Considerable work should be done to develop new digital protection techniques rather than relying on digital adaptions of classical methods. Work on modifying digital equipment for error-free operation in the hostile substation environment should be pursued. This should include work in optical waveguide communications between remote terminal units and the substation processors. Considerable attention should be given to special changes in microcomputer architecture to fit the special needs of the proposed system. Reliability data on electromechanical, static, and computer relay systems is either non-existent or unavailable, therefore, expansion of this data base would be a significant contribution. Finally, a major effort to hardware implement the proposed system in a substation is appropriate. Long-term field tests to improve the control and functional definition of the substation and prove system reliability and capabilities would be valuable indeed.

APPENDIX I

MICROCOMPUTER ANALYSIS

A computer system can be broken down into four basic components:

1. Input/output unit (IOU) for entering data and instructions and for obtaining results;

2. Memory unit for storage of programmed instructions, results of calculations, data, etc.;

3. Arithmetic and logic unit (ALU) for performing operations on data;

4. Control unit for instruction interpretation, instruction execution, control, data flow coordination, and general system timing.

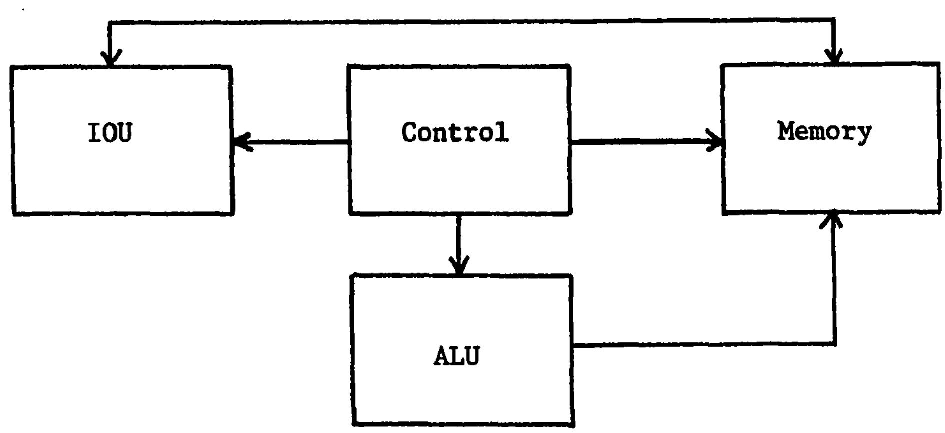


Figure 21

The physical construction and hardware configuration of each of these units varies considerably between computer types. For "microcomputers" as defined herein, large scale integration construction and solid-state memory devices are assumed. [59-61] A microcomputer, as the term is used here, is always built around a microprocessor chip(s). The microprocessor, or CPU, is connected by data buses to the control program stored in memory, the memory locations for storing data and results, and all input/output devices. A block diagram showing this configuration, including the clock which is necessary to synchronize all operations, follows.

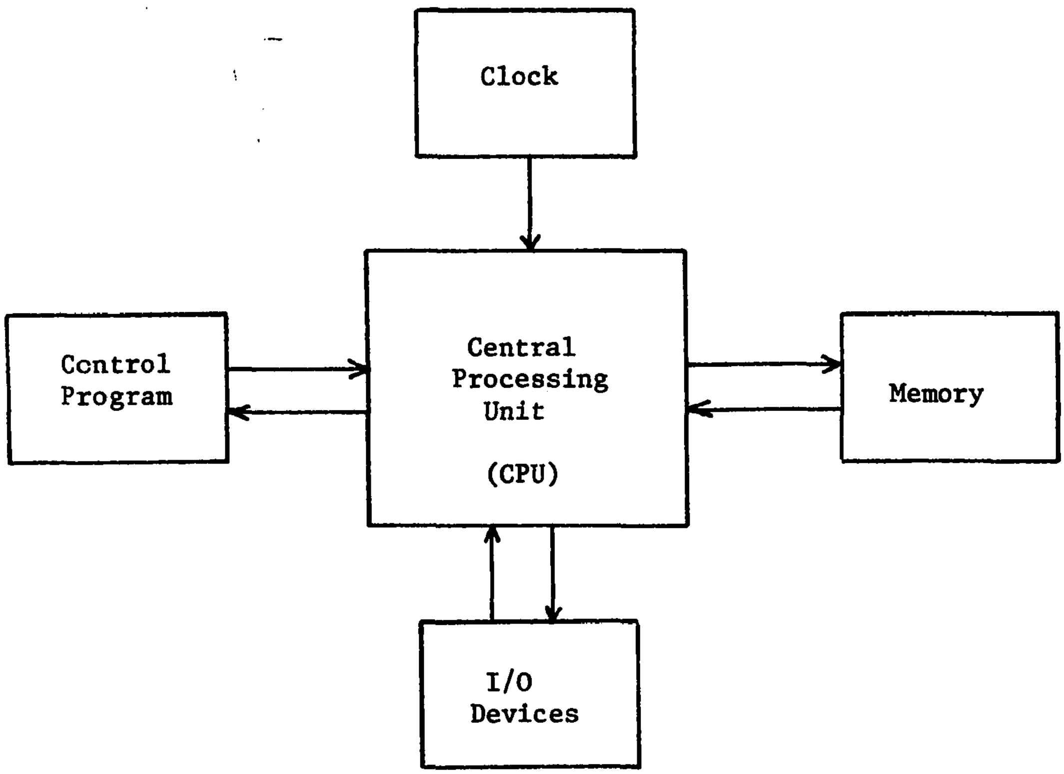
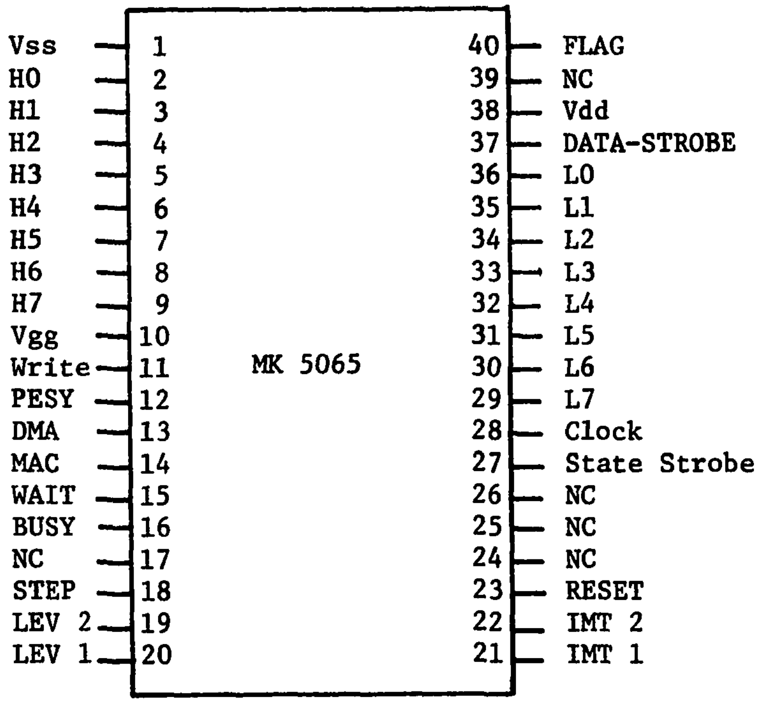


Figure 22

Central Processing Unit (CPU)

The heart of a microcomputer is its central processing unit (CPU) usually referred to as a microprocessor. This unit can be of single or multiple-chip construction. For example, the INTEL 8080 device uses a single, 40 pin chip, whereas the National IMP-8 is of multiple-chip design. [62] The pin configuration for another single chip microprocessor, the Mostek 5065, is shown in the following figure. [63]



NC = No Connection Figure 23

The function of the CPU is to interpret and implement the instructions stored in the control memory. As subsystems, it must include an arithmetic and logic unit (ALU), registers, I/O control logic, timing circuits, etc. A simplified block diagram showing the interconnection of these subsystems for a single chip CPU is shown in Figure 24.

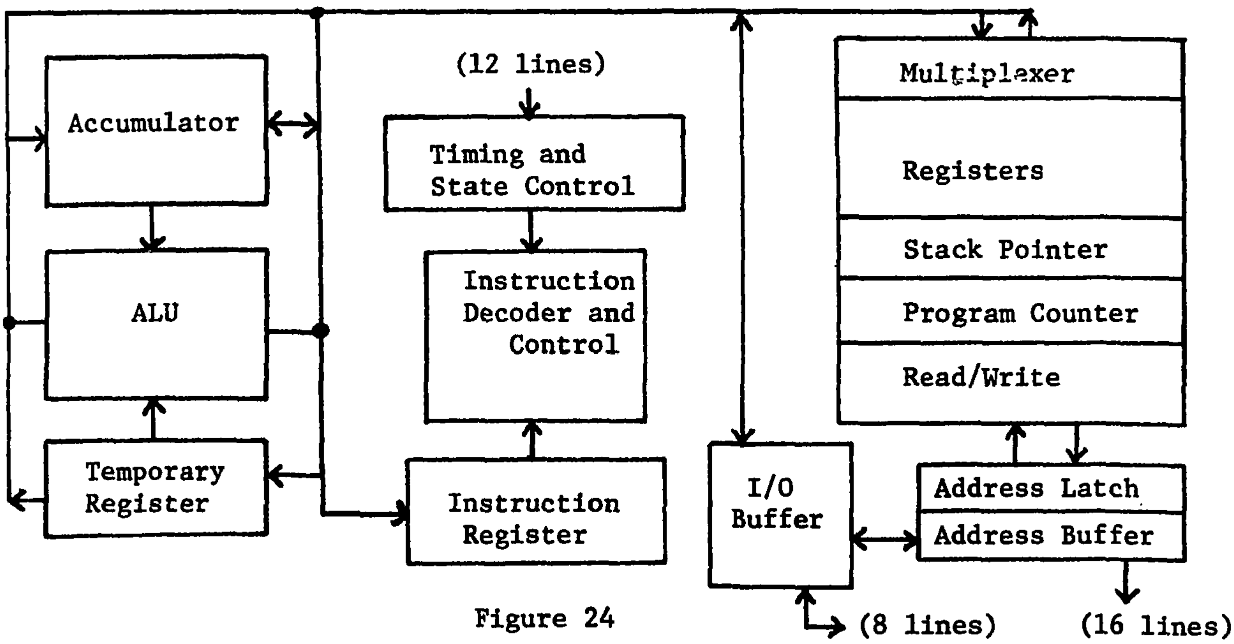


Figure 24

Memory

Memory is typically classified as either random access memory (RAM) or read only memory (ROM). This memory is generally defined by the following data: 1) word length in binary bits; 2) the number of words which can be stored in memory (word size is in powers of 2--e.g. 2^{10} = 1024 = 1k words); 3) speed, indicating the time to read (write) a word from memory.

The control program is typically stored in read only memory (ROM). It would be possible to store the control program in RAM, but it should be noted that RAM memory is usually volatile and therefore reloading of the program would be necessary after each power-down condition. Since ROM memory is usually of a permanent nature, it is used for this function. Since seldom are the memory locations for data storage needed on a permanent basis, random access memory (RAM) is used for this function. Since the read-write time to RAM memory is independent of memory location, RAM is ideally suited for data storage. Programmable and erasable ROM's are available which facilitate the programming function. Several manufacturers have also announced non-volatile RAM's which would allow memory to maintain during brief periods in a power-down condition. An example of a 1024 x 8 bit, static ROM is the MCM 6830 produced by Motorola. [64] It is constructed in a 24 pin ceramic package. Pin assignment and an explanatory block diagram follow.

PIN
ASSIGNMENT

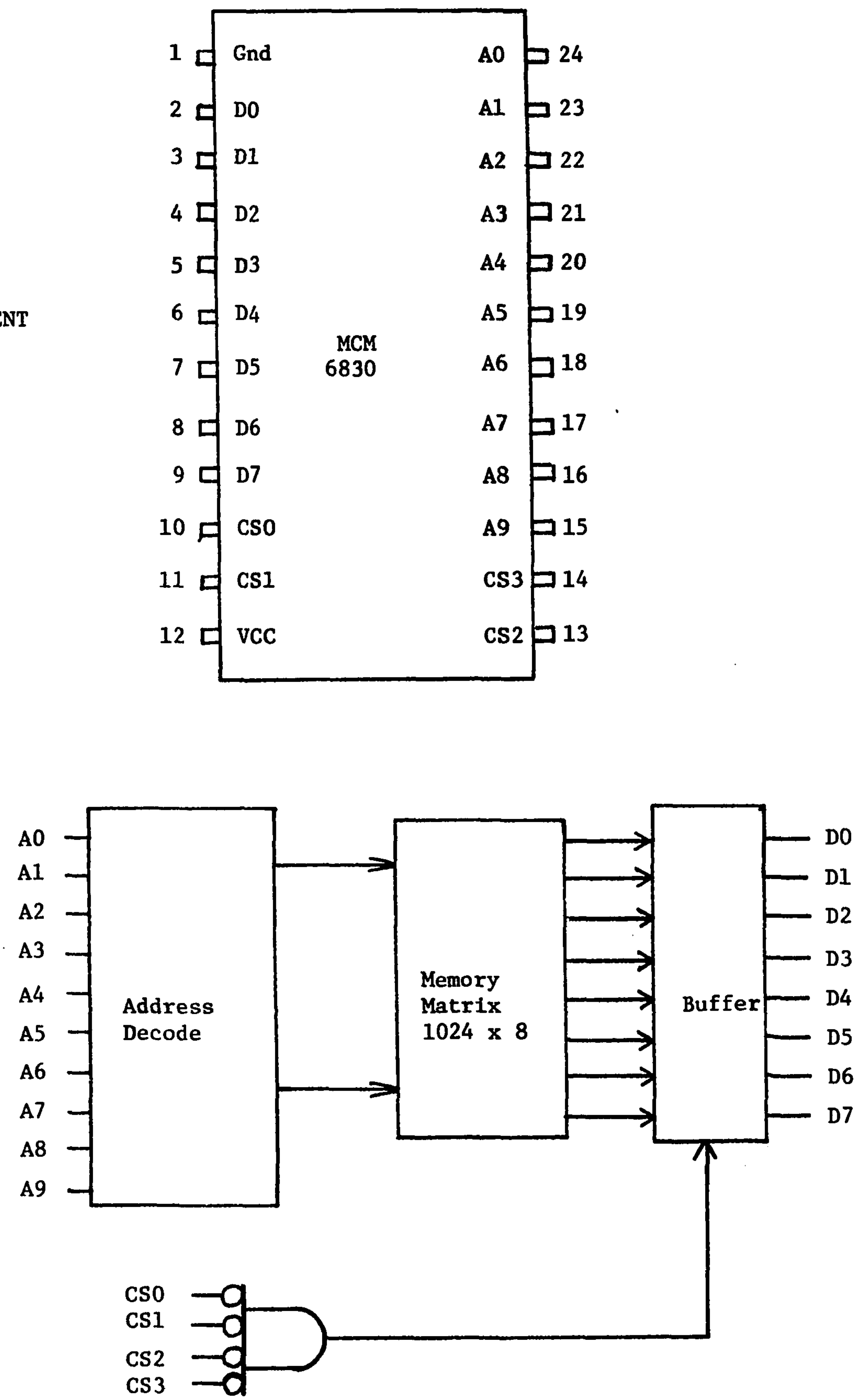


Figure 25

Microcomputer Hardware Configuration

A microcomputer is a combination of the CPU and various memories with buffers, latches, clock, and I/O devices to produce a functional computer. A block diagram of a simple microcomputer built around an INTEL 8080 microprocessor is shown below. [65]

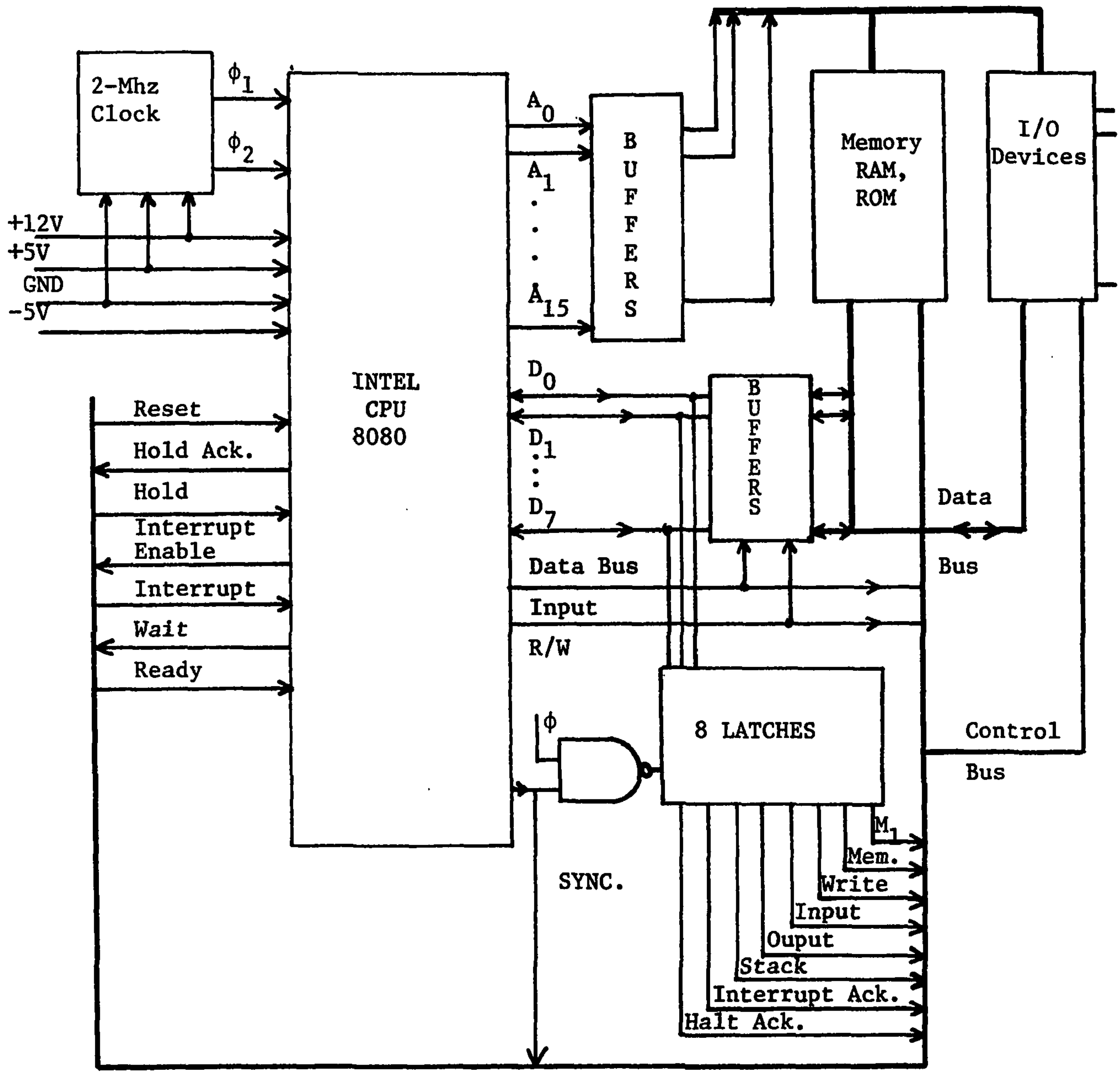


Figure 26

Microcomputer Characteristics

The features and characteristics of microprocessors vary considerably between manufacturers. For illustrative purposes selected information on the Mostek 5065 processor is herein presented.[66] Mostek lists these features for its microprocessors.

1. 8 bit parallel microprocessor on a single chip
2. 51 basic instructions/81 instructions with modifications
3. TTL compatible input and output
4. Directly addresses 32k x 8 bit memory
5. Triple level architecture for rapid interrupt servicing
6. Single 40 pin package
7. Direct memory access capability
8. Requires standard power supply voltages
9. Indirect addressing capability

Instructions for the MK 5065 can be divided into approximately 10 functional categories. These categories are:

1. Accumulator instructions
2. Immediate instructions
3. Memory instructions
4. Jump instructions
5. Shift instructions
6. Exchange instructions
7. Skip instructions
8. Status change instructions
9. Accumulator/link instructions
10. Input/output instructions

An instruction set table which classifies all instructions and gives a mnemonic and description of each is presented below.

TABLE 6 - INSTRUCTION SET

ACCUMULATOR INSTRUCTIONS

Mnemonic	Description
STM	Store accumulator contents into memory
LDM	Load memory contents into accumulator
ANM	"AND" memory contents with accumulator
EOM	Exclusive OR memory contents with accumulator
ADM	Add memory contents to accumulator
SBM	Subtract memory contents from accumulator
CAM	Compare memory contents with accumulator and skip if not equal
LDP	Load contents of pointer register into accumulator
	IMMEDIATE INSTRUCTIONS
LDI	Load immediate data into accumulator
ANI	"AND" immediate data with accumulator
EOI	Exclusive OR immediate data with accumulator
ADI	Add immediate data to accumulator
SBI	Subtract immediate data from accumulator
CAI	Compare immediate data with accumulator and skip if not equal
	MEMORY INSTRUCTIONS
INM	Increment contents of specified memory location by one.
DCM	Decrement contents of specified memory location by one
CLM	Clear memory location specified

JUMP INSTRUCTIONS

Mnemonic	Description
JPM	Unconditional jump to memory address specified by the instruction.
JPI	Unconditional jump to immediate memory address specified by the instruction
JDZ	Jump direct to the address on page zero that is specified by the contents of the accumulator
JDC	Jump direct to the address on the current page that is specified by the contents of the accumulator
JIZ	Jump indirect to the address on page zero that is specified by the contents of the accumulator
JIC	Jump indirect to the address on the current page that is specified by the contents of the accumulator
CSM	Call subroutine at memory location specified by instruction
CSI	Call subroutine at memory location specified by instruction
LCM	Shift the operating level down and call the subroutine at the memory location specified by the instructions
RET	Return from subroutine

SHIFT INSTRUCTION

RRS	Rotate contents of accumulator right
RRL	Rotate contents of accumulator and main link right
RLS	Rotate contents of accumulator left
RLL	Rotate contents of accumulator and main link left

EXCHANGE INSTRUCTION

XLL	Exchange contents of main link and auxiliary link

Exchange Instruction (Continued)

Mnemonic	Description
XAP	Exchange contents of accumulator and pointer
XAH	Exchange contents of accumulator halves

SKIP INSTRUCTIONS

SAZ	Skip the next instruction if the contents of the accumulator is all logical zeros
SNZ	Skip the next instruction if the contents of the accumulator is not all logical zeros
SAP	Skip the next instruction if the contents of the accumulator is positive
SAN	Skip the next instruction if the contents of the accumulator is negative
SLZ	Skip the next instruction if the contents of the main link is a logical zero
SLO	Skip the next instruction if the contents of the main link is logical one

STATUS CHANGE INSTRUCTIONS

NOP	No operation
ION	Interrupt ON
IOF	Interrupt OFF
HLT	Stop instruction execution
LUP	Shift operating level up
LDN	Shift operating level down

INPUT/OUTPUT INSTRUCTIONS

IAL	Input LBUS data to accumulator
IAS	Input LBUS to accumulator. Skip the next instruction if the contents of the main link is a logical one

Input/Output Instructions (Continued)

Mnemonic	Description
OAH	Output accumulator contents on HBUS
OAS	Output accumulator contents. Skip the next instruction if the contents of the main link is a logical one.

ACCUMULATOR/LINK INSTRUCTIONS

MAL	Modify accumulator, link

APPENDIX II

TYPICAL MICROPROCESSOR APPLICATIONS
(Present or Near Future

1. Desk Top Computers
2. Check Processors
3. Payroll Systems
4. Automatic Inventory Systems
5. Electronic Scales
6. Process Controllers
7. Chemical Analyzers
8. Urban Traffic Control
9. Automatic Type-setting
10. Point-of-sale Terminals
11. Compact Business Machines
12. Medical Instrumentation
13. Medical Diagnosis
14. Automobile Diagnostics
15. General Machine Diagnostics
16. Data Communications Processing
17. Optical Character Recognition
18. I/O Terminals for Computers
19. Electronic Office Files
20. Security Monitoring Devices
21. Environmental Control and Monitoring
22. Computer-controlled Artificial Organs
23. Collision Avoidance Systems
24. Automobile Ignition/Control Systems
25. Graphics Controllers
26. Industrial Equipment Controllers

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VITA

Billy Don Russell, Jr., was born in Denison, Texas, on May 25, 1948, the son of Billy Don Russell, Sr., and Mickye Saunders Russell. He was graduated highest male in his class from Denison High School in 1966. In 1966, he entered Texas A&M University at College Station, Texas, and in 1970 received a Bachelor of Science degree in Electrical Engineering. While an undergraduate, he participated in the Cooperative Engineering Program and was employed by Texas Instruments, Inc., of Dallas, Texas, for a period of fifteen months. In September, 1970, he entered Graduate School at TAMU, and was employed as an instructor and research assistant. He was awarded the degree of Master of Engineering in Electrical Engineering in 1971. In September, 1971, he was employed by Abilene Christian College of Abilene, Texas, as an instructor of Physics. His responsibilities included course instruction in electronics and physics, and he served as coordinator of the pre-engineering program. While at A.C.C., he completed all course work requirements for the degree of Master of Arts in Bible. In May, 1973, he was employed as a visiting instructor by the University of Oklahoma in Norman, Oklahoma, and in September, he entered Graduate School at OU. Since that time, he has served as a graduate teaching associate in Electrical Engineering. During the summer of 1974, he was employed by the Systems Laboratory of the Oklahoma Gas and Electric Company as a Power Systems Engineer. During the summer of 1975, he was employed as a Power Systems Consultant by the Electric Power Research Institute of Palo Alto, California.

During his college career, he has received several scholarships, research fellowships, and special awards. These include the TAMU Bolton Award as "Outstanding Electrical Engineering Senior" (1970), the OU Baldwin Award for "Outstanding Classroom Teaching" (1974), and the Electric Power Research Institute Award for "Employee Discovery Award" (1975). He is the author of several engineering publications and is a member of Tau Beta Pi, Eta Kappa Nu, and Sigma Pi Sigma Honor Societies and several professional societies. He has accepted a position with Texas A&M University as Assistant Professor of Electrical Engineering to begin January 1, 1976. He was married to Rebecca Joan Crawford in 1973. His permanent address is: 1211 Hull Street, Denison, Texas 75020.