DIGITAL TECHNIQUES IN THE SUBSTATION-
SUBSTATION AUTOMATION AND DIGITAL RELAYING

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INTRODUCTION

Progress in the development and availability of digital electronics has led to widespread interest and exploration of new electric utility applications. This interest and recognition of favorable decreasing cost trends for digital electronics prompted General Electric to initiate two research projects in 1973 with one to assess the economic and technical feasibility of substation automation and the second to explore digital techniques for protective relaying.

The PROBE (Power Resource Optimization By Electronics) substation automation project includes automation of a number of substation and distribution functions using digital techniques and a data base at the substation. PROBE includes several phases. Commonwealth Edison has participated in this project since shortly after its inception. Niagara Mohawk Power Corporation has participated in PROBE Phase 1 since early 1976, and Public Service Electric & Gas is participating in Phase 2 in addition to the other companies.

PROBE Phase 1 included 12 functions and a research installation at the LaGrange Park Substation of Commonwealth Edison Company. The second phase began in July 1977. It continues at LaGrange Park and will demonstrate automatic feeder sectionalizing and control of feeder capacitor banks in addition to a number of functions to be retained from Phase 1. Communications to feeder switching devices in Phase 2 will be via distribution carrier and radio. A planned third phase demonstration is being defined for PROBE to include emphasis on highest valued functions to utilities, substation control equipment reliability, and coordination between PROBE modules within a substation. Functions which are being considered in the PROBE evaluation include control, monitoring, instrumentation and metering, and data acquisition categories for both transmission and distribution substations. Functions in the protective category such as bus differential protection and transmission line protection are candidates for automation after experience with non-protective functions is obtained. In this connection, experience gained from the digital relaying project will be particularly helpful.

The digital relaying project is considering digital techniques for transmission line protection. The project, which is joint with Philadelphia Electric Company, has the objective of obtaining relaying speeds in a directional comparison scheme which are at least equal to contemporary static relay analog schemes.

The two projects are described in detail in this paper.

DIGITAL RELAYING CONCEPT

In recent years, many different algorithms have been proposed in theoretical papers for digital relaying. Each has its own advantages. After careful study, a differential equation algorithm was selected for the GE - Philadelphia Electric project. The algorithm uses the equation for voltage at the sending end of a transmission line,

$$v = Ri + L \frac{di}{dt}$$

where v and i are instantaneous voltages and currents obtained from waveform sampling of the 60 Hz waveforms.

An error analysis was conducted to determine the effect of sampling rate on the algorithm solution. Based on that analysis, a sampling rate of 960 Hz was selected. This provides a frequency response of up to the eighth harmonic, or 480 Hz, which is also adequate for most transmission line disturbances. With waveform sampling a snapshot is taken of the instantaneous value (with respect to zero) of the waveform at that instant in time. This value is stored in the digital memory. Then, after a time interval of approximately a millisecond, another snapshot is taken, and the new value is also stored. As this process continues, a digital (many discrete values) representation of the analog signal is created. The higher the sampling rate, the more perfect the representation will be. If the sampling rate is too low, high frequencies will not be detected. The Nyquist rate derivation states that the sampling rate must be equal to twice the maximum frequency of interest.

DIGITAL RELAYING SYSTEM DESCRIPTION

The first function of the hardware in the digital protection system shown in Figure 1 is to sample the seven input quantities - three phase voltages, three phase currents and neutral current. A snapshot is taken of all these quantities, and their values stored in sample-and-hold amplifiers.

Next the analog-to-digital coverters convert the snapshot values to 14-bit digital values, and store the results in seven 14-bit buffer registers. Conversion time is approximately 85 microseconds. At the end of the conversions, the digital multiplexer transfers the data to the computer memory via the block transfer controller (BTC) and the priority memory access (PMA) module. Total time to complete the data transfer is approximately 25 microseconds. After the data transfer is complete, the BTC signals the priority interrupt module (PIM) to issue a high priority interrupt to the processor. This interrupt initiates the data handling and fault detection routines of the protection program. This entire process is repeated 16 times each 60 Hz cycle.

The digital processors for this research project are a Varian V72 minicomputer for one terminal and a V73 mini for the other. The V62 has 16K core memory with a cycle time of 660 nanoseconds. The V73 has 16K semiconductor memory with 330 nanosecond cycle time as well as 16K core memory. These are commercially available minicomputers and were selected in 1973 on the basis of cycle time and programming ease. They require air conditioning and surge protection if they are to operate in a substation environment.

DIGITAL RELAYING SOFTWARE DESCRIPTION

The software program converts the digital samples into useful results. In the fault processing flow chart, shown in Figure 2, the processor is normally in the "Wait" loop, awaiting an interrupt. When the interrupt arrives, signaling that the transfer of all seven samples of data is complete, the processor goes first into the fault executive program. This program decides which of three states the power system is in - no fault, fault or recovery - and then calls upon the processor to execute the appropriate program.

In the normal "No Fault" state, all voltages and currents are slowly varying sinusoidal quantities. The routine compares the latest set of data with the corresponding set obtained one cycle (approx. 16 milliseconds) earlier. If the sets are within limits, there is no disturbance and the new set of data is stored to update the memory. The processor then returns to "Wait". However, if the sets of data between cycles differ by more than specified limits, a "Disturbance" is indicated and further processing is required. This is the "Fault" state.

If the "Fault" state is detected, the processor executes the steps shown in the center of the flow chart - fault analysis, calculation preparation, fault calculation and trip logic. These steps are executed for each new set of data until the fault executive detects the "Recovery" state. If a trip signal has been issued to the circuit breaker, the program monitors the current to detect breaker clearing and records the clearing time on each pole. Since a new set of data is arriving every millisecond, the processor must be fast enough to execute the entire string of programs and return to "Wait" before the next set of data arrives. Once the breaker has cleared, the system is in the "Recovery" state. In the "Recovery" state, a report is printed before returning to the "No Fault" state. However, incoming data is still processed through the fault executive program and stored.

DIGITAL RELAYING FAULT ANALYSIS

The fault analysis algorithm is used to determine the type of fault. With this information, the fault calculation algorithm only needs to compute the appropriate circuit parameters for the fault in question. Clarke components are used to derive a unified set of equations which can be used to determine the fault type. Neutral fault current is used to distinguish between ground and phase faults, and the derived equations define which phases are involved. The algorithm is described in Reference 3.

DIGITAL RELAYING CALCULATION PREPARATION

In order to determine the circuit parameters for distance relaying, it is desirable to use different combinations of current and voltage, depending on the fault type. These are the "Delta" quantities for phase faults and the zero sequence compensated currents for ground faults. The calculation preparation routine determines these quantities based on the results of the fault analysis routine, and hands them over to the fault calculation routine.

DIGITAL RELAYING FAULT CALCULATION

The basic equation for real power in a three phase circuit is often considered to be $P=\sqrt{3}EI \cos \theta$. However, this assumes that the currents and voltages are sinusoidal and that rms quantities and power factor are known. Using digital instantaneous quantities, the basic equation for real power is obtained by summing, for each phase, the product of the instantaneous values of current and voltage, and integrating these over one cycle. In a similar vein, and assuming a transmission line representation of a series R - L circuit, the equation for voltage at the sending end is a differential equation previously mentioned, $v = Ri + L \frac{di}{dt}$. The equation uses R and L, not the familiar R and X, and is not affected by high frequencies or transients. Instantaneous values of v and i are known from one snapshot of the waveform samples. With a second snapshot and its time, new values for v and i and $\frac{di}{dt}$ are known. A third snapshot yields a second complete set of data for v, i, and $\frac{di}{dt}$. Two simultaneous equations can now be used to solve for R and L, to determine if the fault is internal or external to the protected zone on the transmission line.

DIGITAL RELAYING TRIP LOGIC

The initial evaluation of this algorithm was in a two-zone step distance scheme, with different reach settings for phase and ground faults. The tripping characteristic is shown in Figure 3. This program determines whether the values of R and L derived in the "Fault Calculation Program" lie within this characteristic. If they do, a counter is incremented (increased by one). If they lie outside, the counter is decremented. With the next snapshot, new data is available and the process is repeated. When the counter reaches a set value (4 was the value used in all laboratory tests), a trip signal is issued to the circuit breaker. Since 3 snapshot samples are required to calculate the first value of R and L and three more to reach the count of 4, a minimum of 6 samples are required for tripping. In many cases, the observed trip times were this minimum of approximately 6 milliseconds.

In addition to the calculation of R and L, the program utilizes a sensitive directional indicator for close-in faults. In these cases, the voltage signal is quite low and the directional indicator provides improved sensitivity.

During power swings, the locus of R and L could enter the trip characteristic. To prevent tripping, a pair of blinders was set up in the program. The resistance calculation is made after each data interrupt, even under normal unfaulted conditions. The blinders are used to evaluate the movement of successive values of R to detect power swings. The out-of-step zone is located between the phase fault trip characteristic and the area of maximum permissible line loading. Under power swing conditions, R will enter the out-of-step zone before entering the trip characteristic. If R remains in this zone longer than the times for the highest slip frequency, no trip signal is issued when R finally enters the trip zone.

Since power swings will be diagnosed as three-phase faults by the fault analysis routine, only trip signals for three-phase faults are inhibited by this out-of-step blocking approach. Phase-to-phase and ground faults will initiate the trip logic even if they occur during power swings.

DIGITAL RELAYING RECOVERY REPORT

Additional advantages may be obtained from a digital protection system, as data is available to provide much more information. For example, after a trip signal has been issued, the processor will have available another two cycles of data with which to refine the calculated values of R and L. It can use statistical techniques to exclude transient values. In this project, a report is generated after each fault similar to Figure 4. The date and time to the nearest second, the fault type (in this case Phase A-G), the distance to the fault in miles, the relay trip time, the fault current, and the breaker clearing time are shown. The values of R and L computed for each of the samples, and indication that the fault remained Phase A-G and did not evolve are also shown. The actual values of the seven input quantities are also tabulated for each sample to aid in evaluating the algorithm, if required. All the quantities shown are in primary system values.

DIGITAL RELAYING LABORATORY TESTS

The minicomputer hardware, the algorithms and other computer programs are of no value if they cannot detect faults securely and dependably. This digital protection scheme has been exhaustively tested on a transmission line simulator, which is a scale model of Philadelphia Electric's 72 mile 500kV Peach Bottom - Whitpain line. This simulator incorporates the same techniques General Electric has used in its larger simulator to test static relay terminals and electromechanical relays. A low impedance polyphase power source is connected to each end of the line, as shown in Figure 5. Source impedance modules, representing the equivalent impedances at the Peach Bottom and Whitpain buses, are located between the power sources and the buses of the model. The line is composed of nine "pi" section modules scaled to the parameters of the 500kV lines. Each module represents eight miles of line.

Figure 6 indicates that R, L and C components are used in each "pi" section. In the discussion of the algorithm, it was stated that for differential equation purposes, it would be assumed that the line had only R and L components. But, of course, real transmission lines have significant shunt capacitance and so are a part of the simulator. In the simulator, power flow is also simulated, by controlling the phase difference between the two sources.

Relay potential is supplied through a model of the Hi-C 500kV CVT. This model faithfully reproduces - not the primary voltage - but the waveform obtained from the secondary of a full-size CVT, including all its transients at time of fault. Depending on the fault location and the initiation angle, the secondary voltage of a CVT can transiently be 180° out-of-phase with the primary, so it is unrealistic to assume perfect voltage transducers. The current transformers are also modelled, again to simulate typical CT's found in circuit breakers. The base phase - phase voltage of the system is 50 volts, base current is 50 milliamps.

Faults can be applied at any module by means of a precisely controlled switch. The fault inception angle and fault duration can be adjusted. The fault type and location are set with jumper cables. Trip signals from the digital system initiate the tripping of a model circuit breaker. This line circuit breaker is adjusted for two-cycle opening with interruption occurring at the point of current zero.

The objective of the laboratory test program was to demonstrate that the basic algorithms will work with actual data generated by the transmission system model.

During these tests, three-phase faults and all combinations of phase-to-phase, phase-to-ground, and double phase-to-ground faults were applied to various locations on the transmission line, beyond the far bus, and behind the relay. These included close-in faults just ahead of and behind the relay. Tests were performed with fault incidence angles of zero to 180 degrees in increments of 15 degrees, with fault resistance up to 30 ohms, and with power transfer angles of zero to 60 degrees in increments of five degrees. Normal line loading is achieved with a 15-degree angle. All these tests, performed with the relay location at Peach Bottom, were repeated with the relay location of Whitpain. The trip characteristics used during these tests are shown in Figure 3. The first-zone reach was set at X equals 190 ohms (actually L equals 0.50 H) corresponding to 88% (63 miles) of the line. The reach of the second zone was set at 270 ohms or 125% of the line. The left hand limit was set at R equals minus 20 ohms. The right hand limits have a slope of X over R equal to 5.4 (the line angle) and intercept the R axis at 50 ohms for phase faults and 200 ohms for ground faults. On the

R-L plot, the trajectories of the calculated values of R and L during the repetitive passes through the fault calculation algorithm are shown, and are actually the output of an X-Y plotter connected to the system. In this example, B to C phase faults were successively applied at eight-mile intervals through the protected line sections. All calculations - even the first - plot within the trip zone.

DIGITAL RELAYING TEST RESULTS

Laboratory tests were made to find out how effective the algorithm was in determining fault location and how often tripping would be initiated with a minimum of six samples of data. In this series of tests, faults were applied directly in front of the relay location (zero miles), and at eight miles, 40 miles and 72 miles (which is second zone). At each fault location, a minimum of three faults were applied for every 15-degree increment of fault inception angle from zero to 180 degrees - a minimum of 39 faults at each location. The number of data samples required to obtain a trip output was recorded. The test results are shown in Table I. In most cases, tripping occurred after six or seven samples. The actual trip time is the time from fault occurrence to trip output, and is the sum of the data acquisition time, the interval between the first and last sample, and the computation time after the last sample. Six samples to trip corresponds to 6.1 to 7.4 milliseconds and seven samples to 7.2 to 8.4 milliseconds. Because the faults at 72 miles are second zone, the operating times shown reflect an intentional second zone time delay of five cycles (83 milliseconds), a time chosen for convenience in testing. In actual applications, it would be set at 15 to 20 cycles.

It was also necessary to determine the accuracy of the fault location program. This program uses statistical methods to refine the results using the first 20 inductance calculations following the fault. This inductance value is used to determine the distance to the fault, in miles, which is printed in the report following each fault. The results of these tests are shown in Table II. Faults were applied at eight-mile intervals, with incidence angles from zero to 180 degrees in 15-degree increments. The average error - in miles - is tabulated and also the worst case for each fault type. The reported fault location is usually within a half mile of the actual distance, although errors of up to 1.7 miles sometimes occur.

The out-of-step blocking logic was also tested. The frequencies of the two power sources were set to produce an out-of-step condition with a slip frequency above the highest anticipated system slip frequency (6 Hertz). The out-of-step blocking logic successfully prevented tripping when the impedance entered the trip characteristic for all frequencies below the highest anticipated slip frequency.

During the testing period, the digital protection system exhibited the security required of a relaying system.

Following a few program modifications early in the project, the system properly refrained from initiating tripping during external faults, switching transients, and low system frequencies. For internal faults within the first zone, the operating time was consistently less than one cycle and usually less than a half-cycle. With faster processor speeds, higher sampling rates are possible which could provide, to a degree, shorter trip times. It was concluded that the algorithm is suitable for directional comparison relaying, and that the system provides the added benefits of an automatic oscillograph, an event recorder and a fault locator.

DIGITAL RELAYING FIELD TESTS

Tests in the laboratory can be used to explore performance under fault conditions, but they prove nothing about surviving in a substation environment. Both terminals of this digital protection system are now in service on the Philadelphia Electric system, one at Whitpain Substation and the other at Peach Bottom Generating Station. They are connected in a directional comparison scheme using CS-27 carrier as the channel. They are connected to the same CT's and PT's as the line relaying, and to automatic oscillographs at each station to monitor performance. Both terminals have been in service since July and have seen a number of external faults. In all cases when the computer was operational, the system performed properly. Due to the surge protection built into the data acquisition hardware (described in reference 3), no difficulties have been experienced from surges on the PT, CT, or battery leads. It is suspected that the uninterruptible power supply (UPS) for the minicomputers may be generating troublesome transients. There have been a few cases of computer stall that are under investigation.

The field tests will continue through the balance of 1977 and into 1978.

PROBE SUBSTATION AUTOMATION CONCEPT

Substation automation is now done by many separate devices and subsystems, electromechanical and analog solid state. There are limitations with this approach, including incomplete monitoring and transfer of an unnecessary number of decisions back to the central dispatcher. Using a common data base, substation automation can perform functions more effectively than separate subsystems that have less information to draw upon. Also, substation automation equipment can serve as the focal point for automation of distribution functions.

Projected benefits of substation and distribution automation include reduced operating expenses through better utilization of system investment, deferral of capital investment, more reliable system operation, reduced customer outage time, and energy conservation.

The basic concept of the PROBE system is that the common denominator to substation functions is the set of information that determines the state of the substation from moment to moment. This information is contained in the status of relays, switches, breakers, disconnects, etc., the instantaneous values of currents and voltages, the position of transformer LTC taps, temperatures, and the state of control commands (e.g. breaker trip order). If real time is quantized into intervals, there is a state set for each interval. A series of state sets represents the substation over some period of time.

PROBE implements this concept by maintaining an image of the real world state set in a memory. This is the data base. An objective of the PROBE project is to show that such a data base can be built, maintained in real time, and that it is accessible and useable by an array of applications functions. This data must be obtained on an instantaneous basis sufficiently often to constitute an accurate data base representation of dynamic system conditions. In the PROBE studies, the effect of different sampling rates is being considered and waveform sampling rates of up to 16 or more samples per cycle are being studied. This pooling of information into a data base common to all application functions provides advantages in terms of fewer wire terminations, less wire, fewer duplicate current transformers, reasonableness checks on the data validity, improved information quality and availability, and new uses of information such as transformer life evaluation. A modular control concept is proposed in which one PROBE module implements all of the application functions and data base associated with a substation transformer bank, including high-side and low-side switching, and its associated circuits. This modular approach will permit the system to include a lead module that is responsible for overlap areas in a substation with several transformers. Overlap areas include bus-tie breakers, parallel operation of transformer load tap changing, automatic feeder sectionalizing and communications with the higher level control center. In the event that one module is out of service in a multi-transformer substation, the remaining modules would be responsible for assuring continuity of service.

PROBE OBJECTIVES

The principal objectives visualized for the PROBE project include:

- Determine feasibility of substation as focal point for substation and distribution automation as opposed to a higher control center.

- Determine which functions are candidates for automation and develop functional specifications.

- Determine data sampling rate requirements and effects.

- Confirm data base concept and functional specifications in a research installation at a utility substation.

- Determine PROBE organization within the substation considering quantity of data inputs, required outputs, substation growth patterns and capacity.

- Determine cost/benefits of substation and distribution automation.

PROBE FUNCTIONS

Table III includes a listing of the functions included in the PROBE studies and identifies those chosen for implementation in Phase 1 and Phase 2.

The functions in Phase 1 were chosen on the basis of their adequacy to demonstrate the feasibility of the data base concept, capability of the commercially-available digital processor, and configuration of the Commonwealth Edison LaGrange Park Substation. Phase 2 extends control out to switching locations on the distribution feeders. Functional specifications were developed for the functions to be implemented. Electric utilities participating in the PROBE study have suggested valuable improvements to the functional specifications. An example of a simplified logic sequence diagram for one function, breaker failure protection, is shown in Fig. 7. These functional specifications are being confirmed by the results at LaGrange Park.

The Phase 1 area of substation control and monitoring at LaGrange Park is shown in the dashed portion of Fig. 8. Although not all 12 planned PROBE Phase 1 functions were fully implemented in that phase, testing is continuing on uncompleted functions during Phase 2. Seven of the functions planned for Phase 1 were control functions. Three of these were demonstrated in closed loop mode and included automatic bus sectionalizing for a simulated transformer fault on TR73, transformer LTC control for TR72, and remote control and data reporting. Two control functions, automatic reclosing and breaker failure protection, were tested successfully in closed loop using a simulated feeder breaker. Capacitor bank control for several remote capacitor banks on two feeders and synchronism check will undergo check-out in Phase 2.

The distribution feeder deployment and switching function to be demonstrated in Phase 2 will have a goal of restoring service in less than one minute to unfaulted feeder sections affected by a persistent fault on another feeder section while PROBE continues to perform its other application functions. During unfaulted periods, PROBE will check feeder loading and switch feeder sections to less heavily loaded feeders when possible during periods of load above specified limits on a given feeder. Phase 2 will also stress coordination between the transformer LTC function and feeder capacitor bank control from the substation. Data from several remote kwh meters will be accumulated in Phase 2.

A simplified one-line diagram for the Phase 2 feeders is also illustrated in Fig. 8.

PROBE RESEARCH IMPLEMENTATION

The PROBE feasibility demonstration equipment for Phases 1 and 2 is generally commercially available equipment such as a mini-computer and hand-built breadboard type equipment. It uses off-the-shelf components and sub-assemblies. Physical size, ease of use, reliability, power consumption, and temperature limits are not a major concern of the design in Phases 1 and 2 but will receive major emphasis in a planned later phase. A commercially available mini-computer (Varian V72) with 32K of core memory having a basic cycle time of 660 nanoseconds (similar to one terminal of the digital relaying project) is used, but a mini-computer may not necessarily be used in future phases.

PROBE is connected to 32 analog inputs and 112 status inputs from LaGrange Park Substation and utilizes 24 control outputs to the station. The analog inputs are three phase currents for two feeders, transformer primary and secondary currents, bus voltages, and transformer LTC tap and temperature signals. Status inputs represent breaker and switch position and protective or auxiliary relay operation in the LaGrange Park Substation. The control outputs are to close and trip breakers and switches, and control transformer LTC operation.

A termination assembly provides the physical terminations for station wiring and the surge and isolation withstand to buffer the PROBE electronics from the station environment. Status signals are processed through optic couplers. Measurements of currents and voltages are isolated by Faraday shielded transformers. Power is isolated through shielded transformers.

Special preprocessing electronics including microprogrammed special purpose ROM controllers are used to process the high sample rate data into variables directly useful to the applications functions (e.g. RMS currents, breaker status, feeder power, transformer temperature, fault record start). End actions from the applications functions in terms of control instructions are sensed by these units and deployed to the station. There are two redundant discrete output units to reduce the chance of false commands due to hardware glitches.

Individual application functions are software programs in Phases 1 and 2.

PROBE BENEFITS

Potential benefits from substation and distribution automation can be separated into several categories. These categories include hardware displaced by automation, deferred system investment, reduced operating expenses, and the added value of functions that either are not available with conventional equipment or are done better by automation.

Examples of potentially displaced hardware include the conventional SCADA terminal, separate fault recording and sequence of events monitoring subsystems, and a number of meters and relays. Many transducers are unnecessary since, in the PROBE approach, electrical quantities such as real and reactive power and RMS currents and voltages are calculated directly from instantaneous sampled values of substation and feeder currents and bus voltage.

Automation provides the capability to operate equipment closer to limits considering past loading history and projected loads. It can redistribute heavily loaded feeder sections and restore service to unfaulted feeder sections promptly in the event of a persistent fault. This results in improved feeder reliability and possible higher feeder loading with potential deferral of new feeder additions.

A reduction of feeder losses should be feasible by optimizing feeder voltage and var control through coordinated control of transformer load tap changing and capacitor and/or voltage regulator control. Savings in operating expense are expected through reduced communications requirements to a higher level control center as more decisions are made locally. Service crew time and expense will be reduced with automatic fault location on the distribution and on the transmission system. Improved logs for equipment operation will permit improved and more timely maintenance to help prevent unplanned outages. Potential benefits of approximately 10% of substation and feeder costs on a present worth basis over a 15 year period for a large distribution substation appear feasible on a conservative basis (not including load management or automatic meter reading).

PROBE PHASE 1 FIELD TESTING

To guide the field testing, a test plan outline was developed jointly with Commonwealth Edison and Niagara Mohawk. This test plan outline was general in scope and outlined performance to be achieved during the testing phase with specific details and test procedures to be completed for each application function.

The PROBE Phase 1 functions include 7 control and 5 data acquisition and monitoring functions. Closed loop control of automatic bus sectionalizing and transformer LTC have been demonstrated. In addition, the PROBE automatic reclosing and breaker failure protection functions have been tested and demonstrated using breaker simulation equipment supplied by Commonwealth Edison. These two latter functions have been integrated into a consolidated breaker operations algorithm. Concurrent operation of up to 7 of the 12 Phase 1 functions was demonstrated while sampling 60 Hz waveforms for the 32 analog inputs at 16 times per cycle, (approximately 30,000 analog input values per second).

PROBE has continued to operate normally through a number of disturbances to the 138 kV supply to the LaGrange Park Substation and for several feeder faults fed from the 12 kV bus indicating that the PROBE feasibility equipment has proven compatible with the distribution substation electrical environment. The PROBE equipment has been operating on a daily basis for approximately 12 months without evidence of interference from substation transients or electrical noise interference.

PROBE closed loop operation of the transformer LTC (load tap changing) function is illustrated in Fig. 9 for control of one substation transformer (TR72) at LaGrange Park. The procedure for the particular test was to manually change LTC tap position to purposely move the 12 kV bus voltage out of bandwidth. PROBE calculates an average RMS bus voltage based on each phase-to-neutral voltage from the instantaneous voltage samples. In the test illustrated, it found the average bus voltage out of limits and issued a corrective command to change tap position to restore voltage to within bandwidth.

The log shown in Fig. 9 is not intended to illustrate the format of desired display for a substation application but includes messages from the LTC function for diagnostic purposes during the testing.

SUMMARY

Experience from both the PROBE Project and the Digital Relaying Project confirm that the use of digital techniques for substation automation and for transmission relaying is viable. In both projects, performance improvements will result if faster computational hardware is available. Studies are continuing to define the requirements to accomplish these functions in an electric utility substation environment.

PROBE Phase 2 extends control, using the substation as the focal point, to include distribution feeder sectionalizing, redistribution of load and coordinated voltage/VAR control for feeders. Coordination with companion equipment for load management and automatic meter reading (AMRAC) is planned in future phases and PROBE Phase 2 will demonstrate coordination with AMRAC equipment for distribution carrier. Cost/benefit analyses are continuing to better identify the potential benefits in both transmission and distribution substations. A planned future PROBE phase will emphasize coordination between PROBE control modules within the substation and the equipment reliability required for the electric utility substation environment.

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TABLE I
TYPICAL TRIP DATA
NUMBER OF SAMPLES TO TRIP

FAULT TYPE		FAULT LOCATION (MILES) 0	8	40	72**
3 PHASE	AVG.	6.78	6.71	6.80	83.10
	MIN.	6	6	6	83
	MAX.	13	9	10	85
B - C	AVG.	6.31	6.33	6.13	88.05
	MIN.	6	6	6	86
	MAX.	7	9	7	92
A - G	AVG.	6.19	6.31	6.31	86.03
	MIN.	6	6	6	83
	MAX.	9	8	9	91
B - C - G	AVG.	9.00	9.00	8.11	87.82
	MIN.	6	6	6	86
	MAX.	15	16	13	95

**SECOND ZONE

TABLE II

FAULT LOCATION

DIFFERENCE OF CALCULATION FROM ACTUAL DISTANCE (IN MILES)

FAULT TYPE		ACTUAL DISTANCE (IN MILES) 0	8	16	24	32	40	48	56	64	72
3 0	AVERAGE	.0	.0	-.01	-.10	-.05	-.19	-.28	-.57	-.58	-.66
	EXTREME	.0	.1	-.1	-.2	-.2	-.4	-.4	-.9	-1.0	-1.0
B - C	AVERAGE	.0	.02	.02	-.10	-.10	-.18	-.05	-.10	-.67	-.64
	EXTREME	.0	.1	-.1	-.3	-.3	-.7	-.5	-.8	-1.1	-1.2
A - G	AVERAGE	.0	-.05	-.16	-.24	-.45	-.74	-.41	-.26	-.44	-1.12
	EXTREME	.0	-.2	-.5	-.8	-.9	-1.3	-1.1	-.8	-1.2	-1.7
B - C - G	AVERAGE	.0	.07	.08	-.02	-.15	-.16	-.24	-.27	-.25	-.12
	EXTREME	.0	.1	.2	-.2	-.5	-.4	-.5	-.7	-.7	-.7

TABLE III

PROBE STUDY FUNCTIONS

FUNCTION	PHASE 1	PHASE 2
AIR SYSTEM MONITOR		
ALARM ANNUNCIATION	*	*
AUDIBLE NOISE MONITOR		
AUTOMATIC RECLOSING	*	*
AUTOMATIC BUS SECTIONALIZING	*	
BREAKER FAILURE PROTECTION	*	
CAPACITOR BANK CONTROL (Substation and Feeder)	*	*
FAULT LOCATION		
FAULT RECORDING	*	*
FEEDER COMMUNICATIONS INTERFACE		*
FEEDER DEVELOPMENT & SWITCHING		*
INSTRUMENTATION & METERING	*	*
LOAD SHEDDING		
LOCAL LOAD AND CONTINGENCY EVALUATION		
MESSAGE BUFFERING		
RELATING RELAY SETTING TO LOAD		
REMOTE CONTROL & DATA REPORTING	*	*
SEQUENCE OF EVENTS RECORDING	*	*
SYNCHRONISM CHECK	*	
TRANSFORMER LOAD CAPABILITY MONITORING	*	*
TRANSFORMER LOAD FEEDER MATCHING		
TRANSFORMER LTC CONTROL	*	*
VOLTAGE REGULATOR CONTROL		

DIGITAL PROTECTION SYSTEM

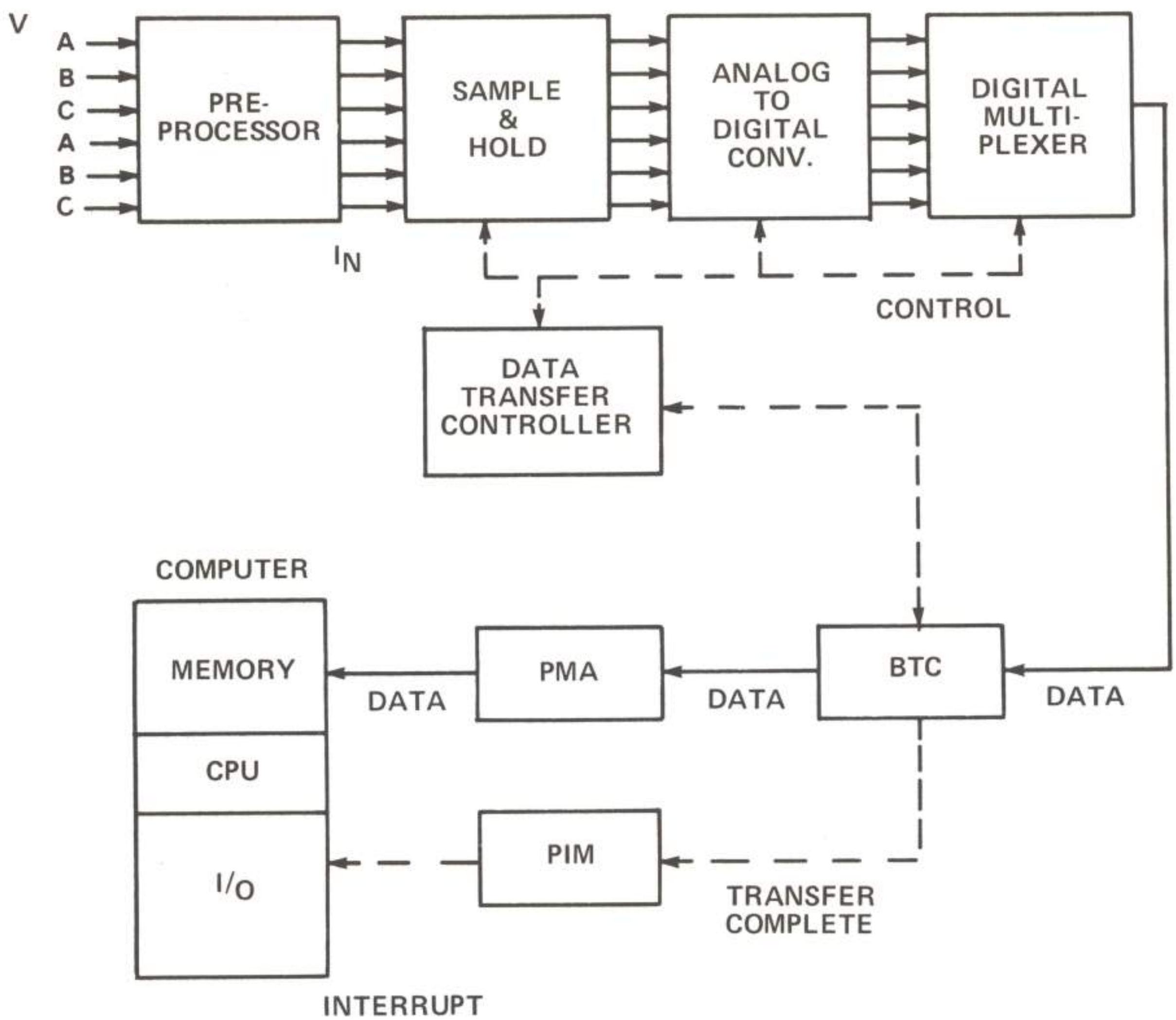


FIGURE 1

DIGITAL PROTECTION
FAULT PROCESSING FLOW CHART

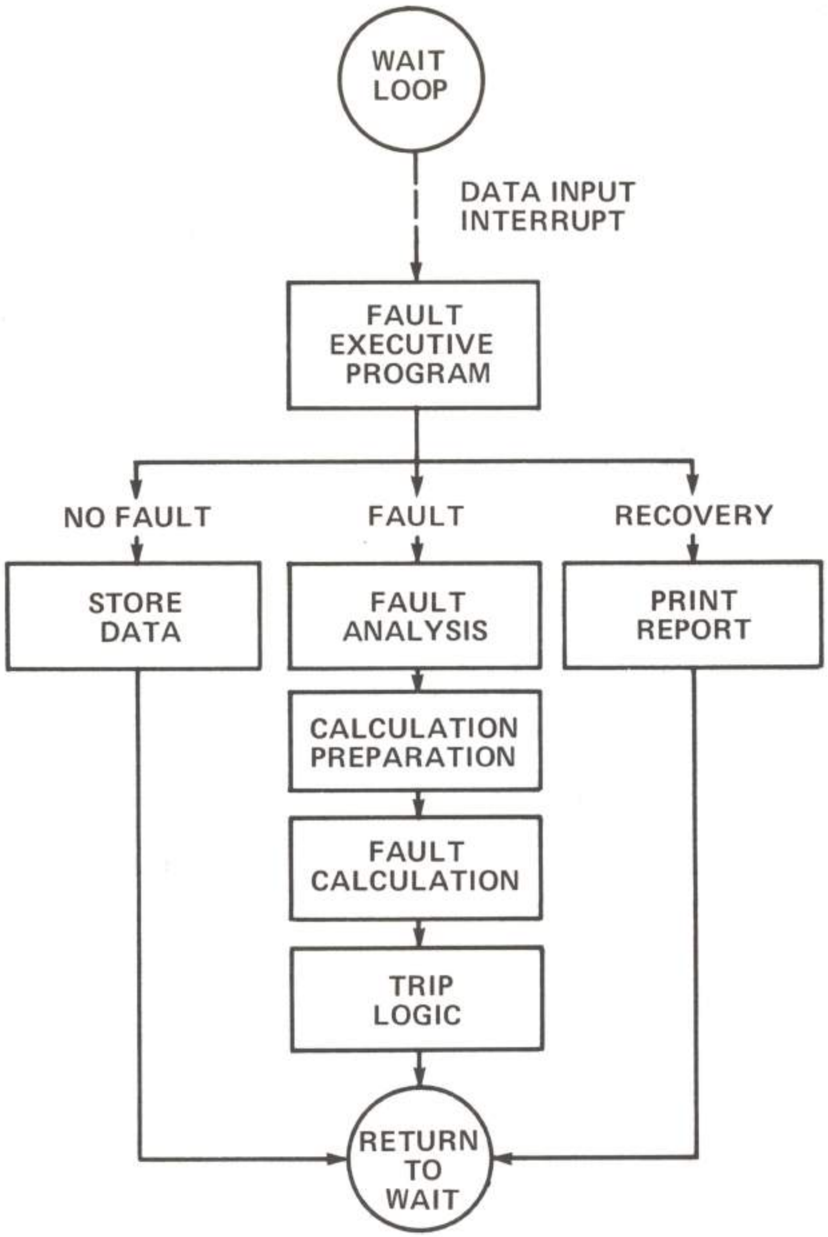
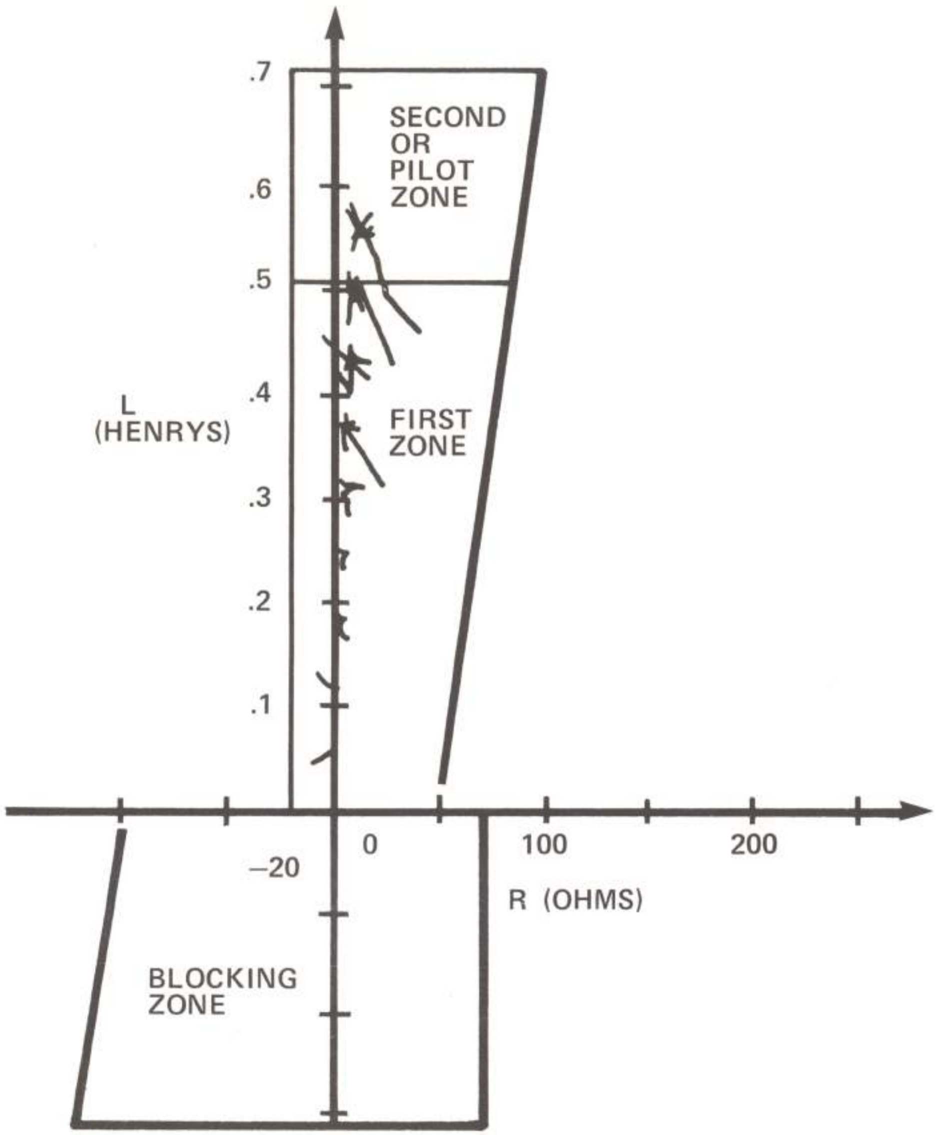


FIGURE 2



DIGITAL PROTECTION
TRIP AND BLOCK CHARACTERISTIC WITH TYPICAL R, L PLOT

FIGURE 3

DIGITAL PROTECTION

Mar 6 1977	15:19:25	Starting System
Mar 6 1977	15:19:31	System Stop

Fault occurred Mar 6 1977 15:19:31
Fault AG
Distance to fault 14.5 Miles
Trip Time .33 Cycles (6.25 MSec.)
Fault Current 13276 Amps (RMS)
Clearing Time 2.56 Cycles

SAMPLE	R	L	TYPE
1	*	*	AG
2	*	*	AG
3	6.6	.1071	AG
4	7.7	.1023	AG
5	7.6	.1064	AG
6	8.4	.1114	AG
7	9.2	.1137	AG
8	*	*	AG
9	9.5	.1133	AG
10	9.7	.1136	AG
11	9.4	.1136	AG
12	9.4	.1147	AG
13	9.3	.1110	AG
14	9.8	.1127	AG
15	9.9	.1130	AG
16	10.1	.1134	AG

FIGURE 4. TYPICAL TRIP REPORT

DIGITAL PROTECTION
TRANSMISSION SYSTEM MODEL

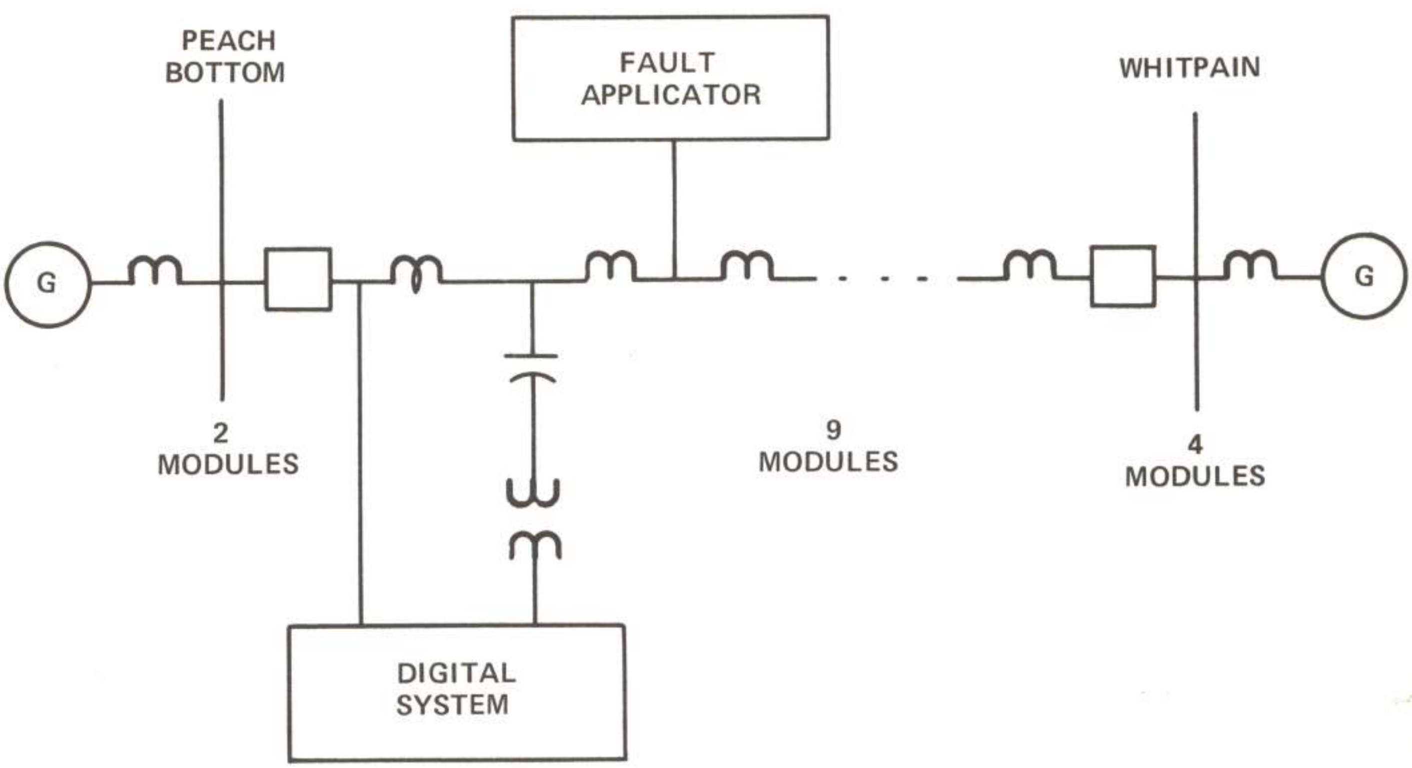


FIGURE 5

TRANSMISSION LINE MODULE

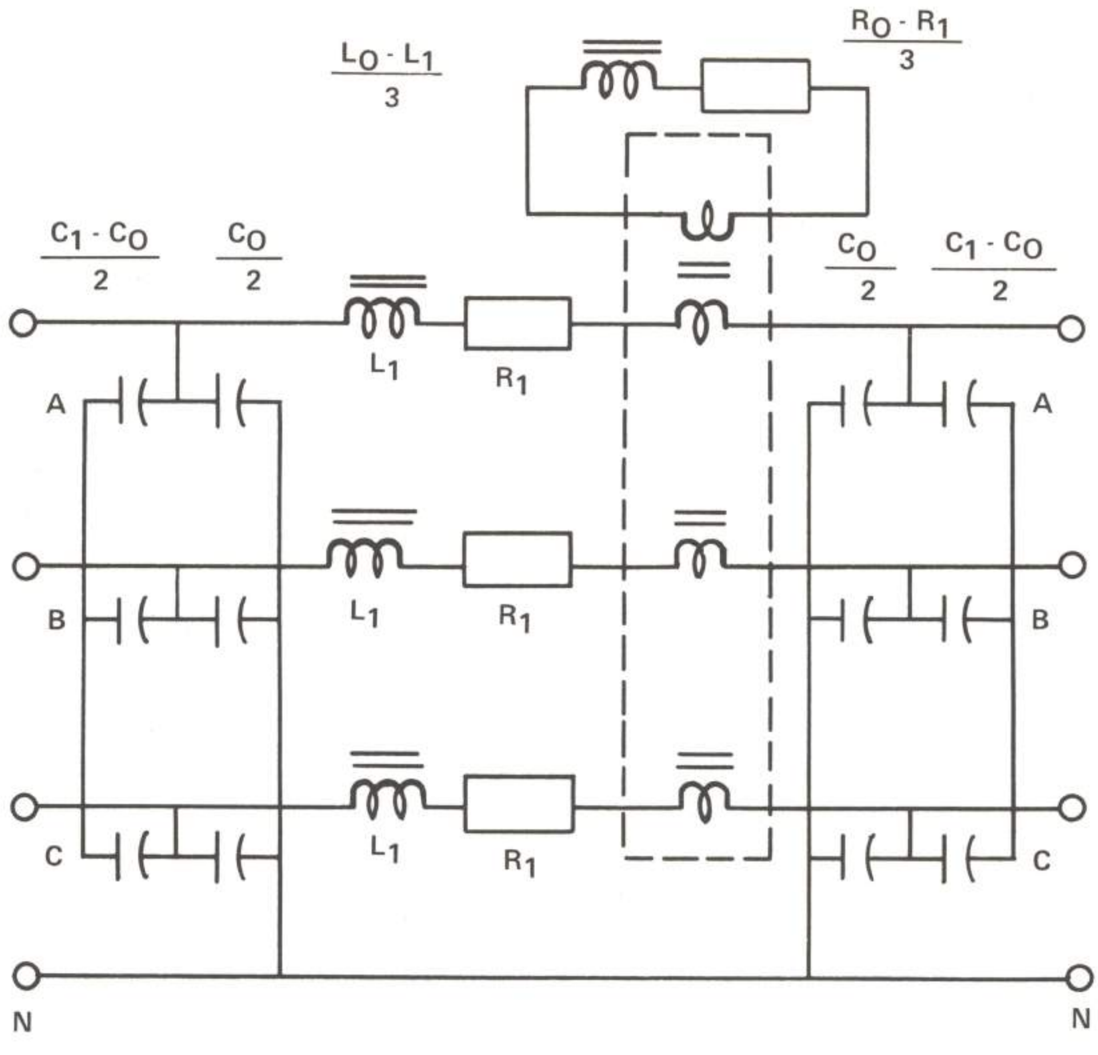


FIGURE 6

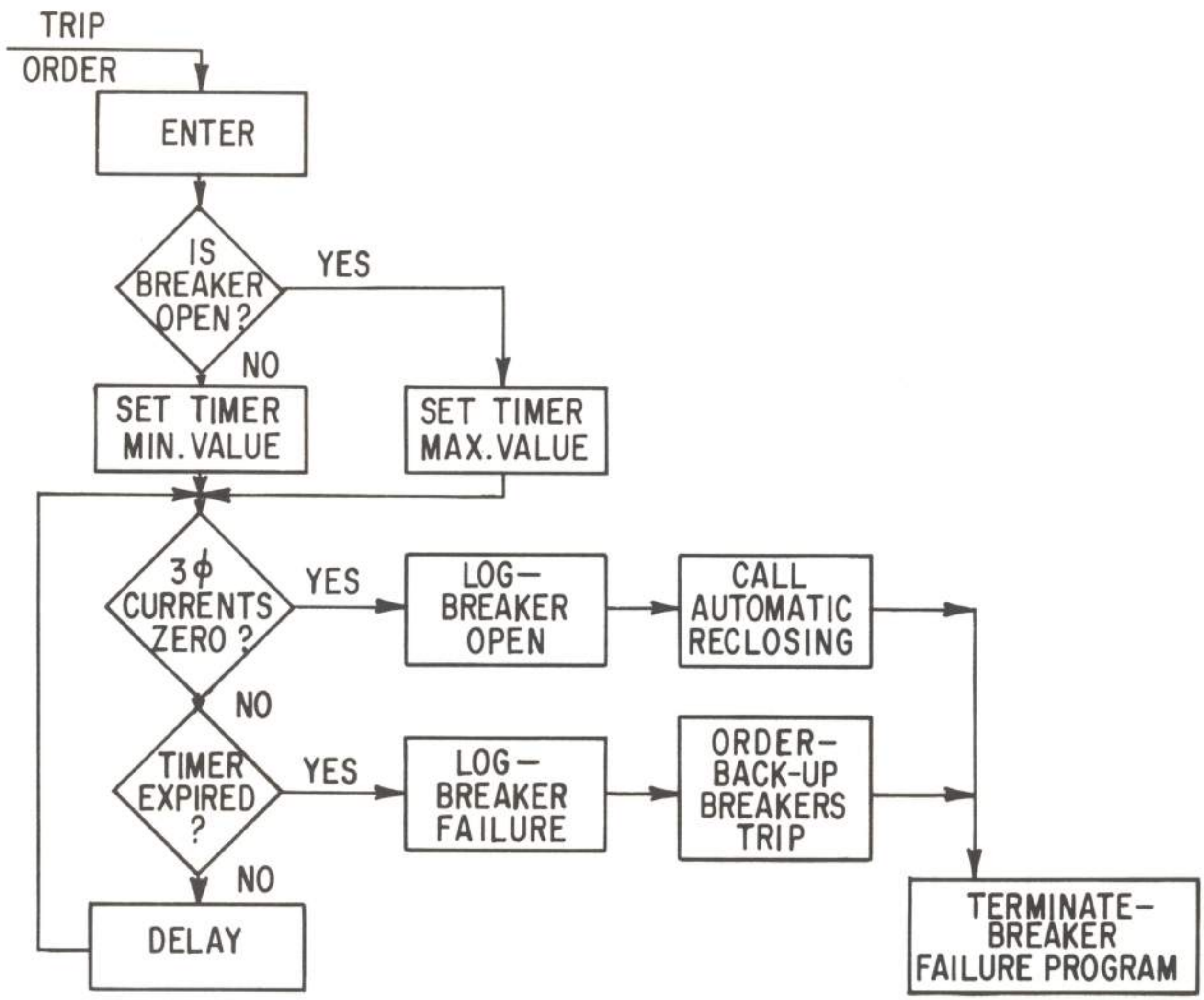
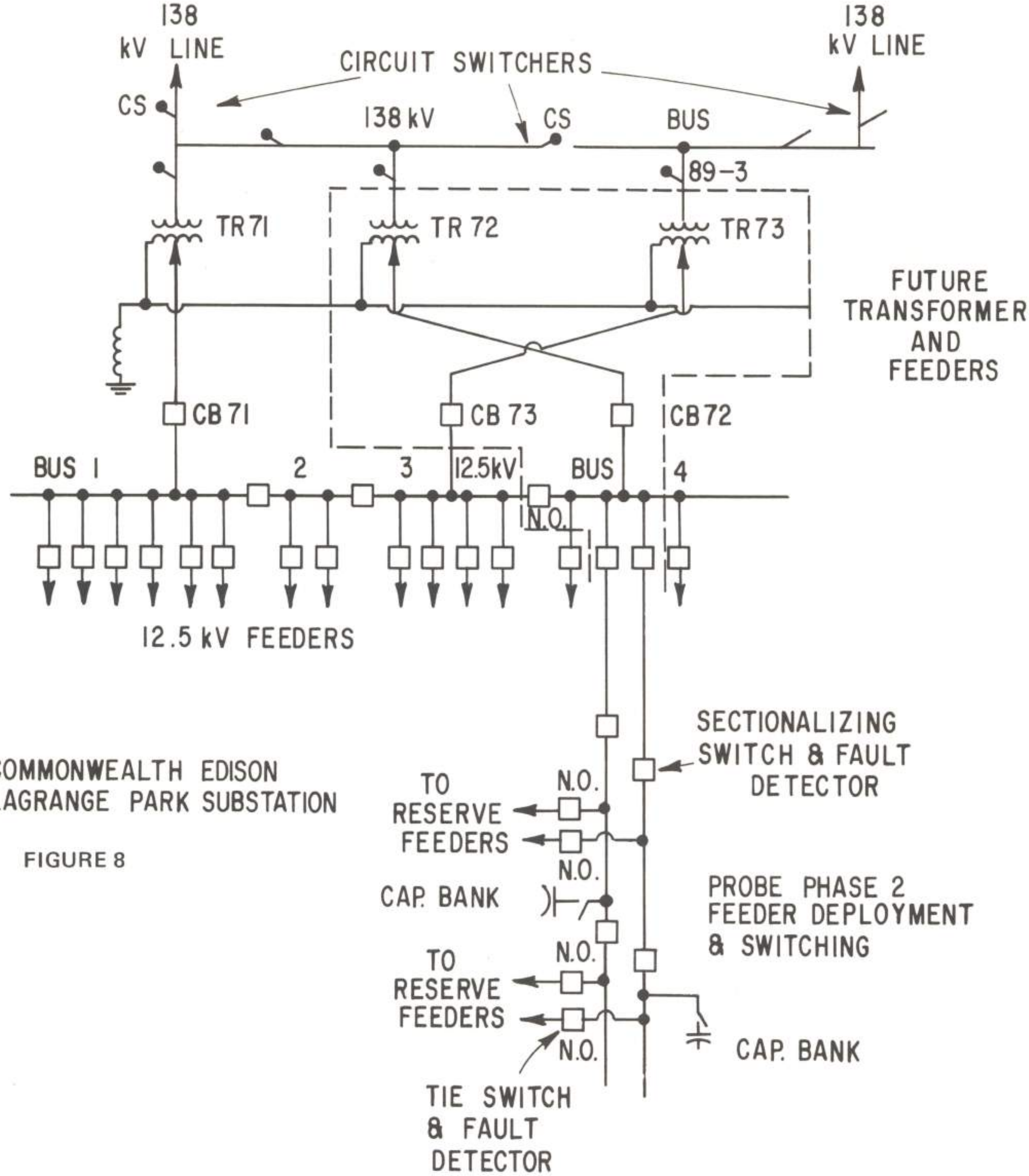


FIGURE 7. BREAKER FAILURE LOGIC SEQUENCE PROBE



COMMONWEALTH EDISON
LAGRANGE PARK SUBSTATION

FIGURE 8

PROBE I TEST

TRANSFORMER LTC CONTROL - CLOSED LOOP TEST
SINGLE TRANSFORMER CASE - TR72
LAGRANGE PARK SUBSTATION - 12 kV Bus 4

TEST# 4

June 1977

OPERATOR TO BRING BUS VOLTS OUT OF BANDWIDTH (LOWER) MANUALLY AT TR.---PROBE TO RESPOND

ACTION
SCA — LAGRANGE STATION CHECK - ANALOG POINTS

		POINT	DESCRIPTION	VALUE		
	01:44:57.1354	AVB3A	BUS 3 12KV N-A PHAS	7456.	VOLTS	
	01:44:57.2156	AVB3B	BUS 3 12KV N-B PHAS	7509.	VOLTS	
	01:44:57.2322	AVB3C	BUS 3 12KV N-C PHAS	7375.	VOLTS	
	01:44:57.2333	AVB4A	BUS 4 12KV N-A PHAS	7456.	VOLTS	Average Bus 4 Voltage Ph.-N 7401
	01:44:57.2343	AVB4B	BUS 4 12KV N-B PHAS	7401.	VOLTS	
	01:44:57.2343	AVB4C	BUS 4 12KV N-C PHAS	7337.	VOLTS	
	01:44:57.5588	ATPT2	TR-72 LTC TAP POSIT	-10.	STEP	
	01:44:57.5598	ATPT3	TR-73 LTC TAP POSIT	-5.	STEP	
	01:46:05.4438	SPR06	SPARE 06		STATUS LOGGD	Aux. Rel. P.U. & DO; TR72 LTC lowered 2 steps manually
	01:46:09.9923	SPR06	SPARE 06		STATUS LOGGC	
	01:46:43.6348	SPR06	SPARE 06		STATUS LOGGD	
	01:46:47.4395	SPR06	SPARE 06		STATUS LOGGC	

ACTION
SCA — LAGRANGE STATION CHECK - ANALOG POINTS

		POINT	DESCRIPTION	VALUE		
	01:47:31.1990	AVB3A	BUS 3 12KV N-A PHAS	7456.	VOLTS	
	01:47:31.2001	AVB3B	BUS 3 12KV N-B PHAS	7509.	VOLTS	
	01:47:31.2011	AVB3C	BUS 3 12KV N-C PHAS	7375.	VOLTS	
	01:47:31.2011	AVB4A	BUS 4 12KV N-A PHAS	7369.	VOLTS	Average Bus 4 Voltage Ph.-N 7319
	01:47:31.2021	AVB4B	BUS 4 12KV N-B PHAS	7332.	VOLTS	
	01:47:31.2032	AVB4C	BUS 4 12KV N-C PHAS	7256.	VOLTS	
	01:47:31.2188	ATPT2	TR-72 LTC TAP POSIT	-12.	STEP	
	01:47:31.2188	ATPT3	TR-73 LTC TAP POSIT	-6.	STEP	
ALRM	01:48:48.2505	DLTC2	TR 72 LTC		COMMANDED RAISE	← PROBE LTC Raise Command
	01:48:43.2765	SPR05	SPARE 05		STATUS LOGGD	
	01:48:53.2659	SPR05	SPARE 05		STATUS LOGGC	

ACTION
SCA — LAGRANGE STATION CHECK - ANALOG POINTS

		POINT	DESCRIPTION	VALUE		
	01:49:32.9851	AVB3A	BUS 3 12KV N-A PHAS	7493.	VOLTS	
	01:49:33.0163	AVB3B	BUS 3 12KV N-B PHAS	7530.	VOLTS	
	01:49:33.0402	AVB3C	BUS 3 12KV N-C PHAS	7391.	VOLTS	
	01:49:33.0413	AVB4A	BUS 4 12KV N-A PHAS	7450.	VOLTS	Average Bus 4 Voltage Ph.-N 7385
	01:49:33.0413	AVB4B	BUS 4 12KV N-B PHAS	7385.	VOLTS	
	01:49:33.0423	AVB4C	BUS 4 12KV N-C PHAS	7321.	VOLTS	

FIGURE 9