Westinghouse ENGINEER January 1974

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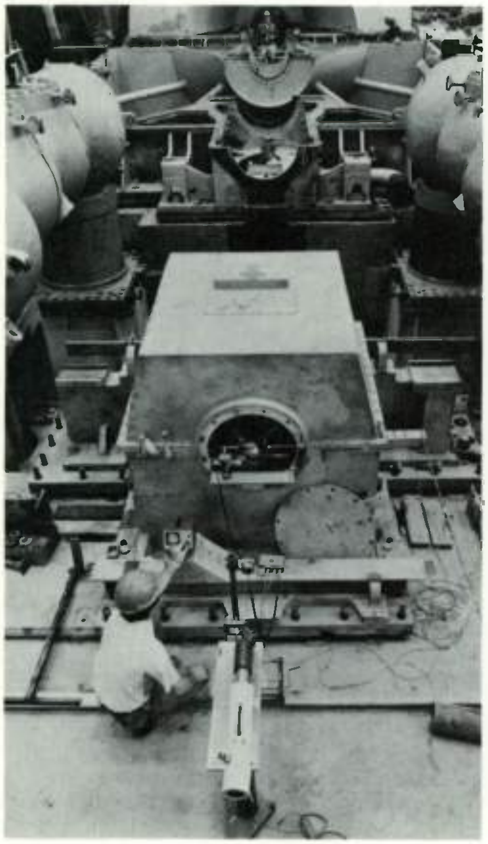

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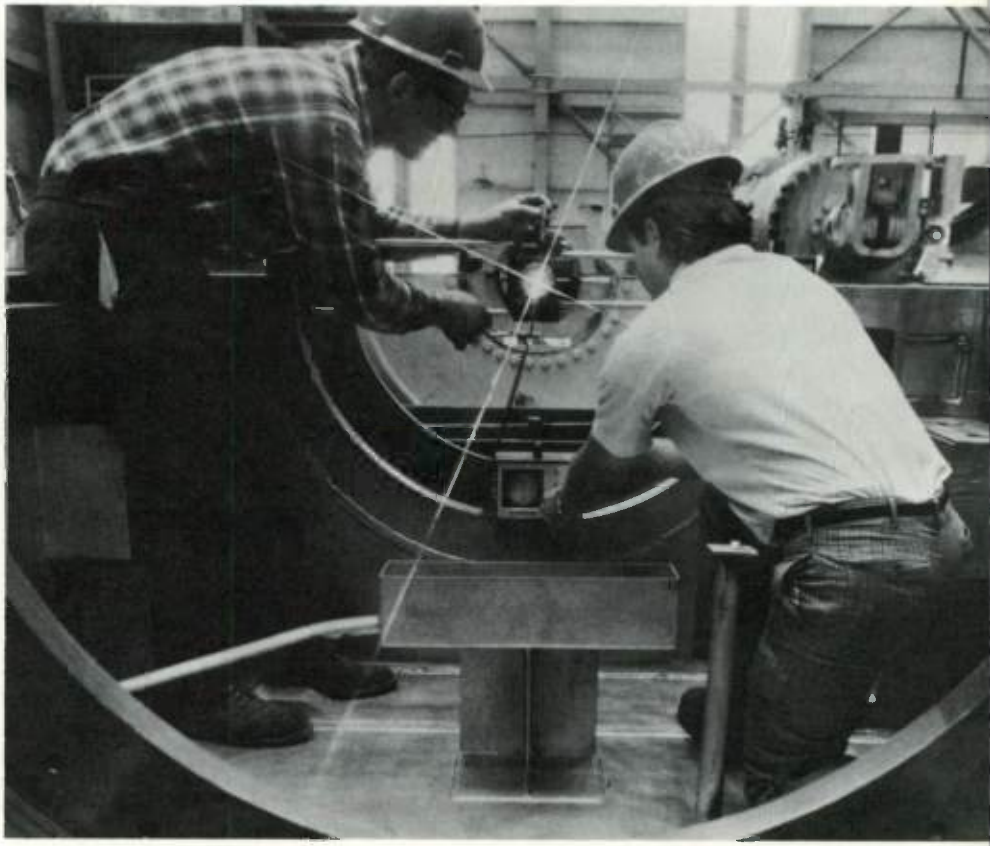

Turbine Generators Aligned and Leveled With Accurate Laser Beams

An alignment and leveling system employing a low-power gas laser is now used by the Westinghouse Power Generation Service Division to aid in aligning and leveling generators while they are being erected. The laser system is more accurate, faster, and more economical to use than the optical-level, optical-borescope, and tight-wire methods that it replaces.

Laser systems have previously been used to align stationary blade rings in the low-pressure cylinders of large steam turbines. The new Westinghouse system, however, is also capable of leveling the seating plates in the early stages of turbine erection and leveling the outer cylinders during later stages in addition to its alignment functions.

The setup time required has proved significantly shorter than that needed with the earlier methods, resulting in a considerable saving of man-hours. The laser beam can be positioned as desired with vertical and horizontal beam translators, eliminating any need to move the laser once it is mounted. A dual sweep device attached to the front end of the laser is capable of sweeping the beam through 360 degrees to establish a reference plane.

The accuracy and repeatability of the laser method have been verified in field tests. It is accurate to within 0.0015 inch at a distance of more than 100 feet.

The system was used in erecting the 926-MW turbine generator at Metropolitan Edison Company's Three Mile Island Nuclear Generation Station. For alignment, the laser beam was brought into the turbine-generator centerline position (Fig. 1). Field engineers are shown directing the beam into two height gauges to establish the centerline reference; one gauge is mounted at the governor end of the turbine generator and the other between the two low-pressure turbines. Once the centerline reference has been established, the height-gauge targets can be flipped out of the way to minimize beam dispersion.

Vertical and horizontal alignment of the bore were measured with a dial-indicator bore-sweep unit. In Fig. 2, field engineers are measuring the amount of misalignment of an outer low-pressure cylinder.

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Front Cover: The digital controller of the Westinghouse DEH control system provides the capability to perform valve characterization, and it thereby makes valve management possible while the turbine-generator unit is operated under load. An end view of the turbine-generator unit, two basic curves used in valve characterization, and a flow diagram of the valve management program are the elements chosen by artist Tom Ruddy for this month's cover design. The role that these elements play in the DEH control system is described in the article that begins on the next page.

Digital Electro-Hydraulic Control Improves Turbine-Generator Unit Performance

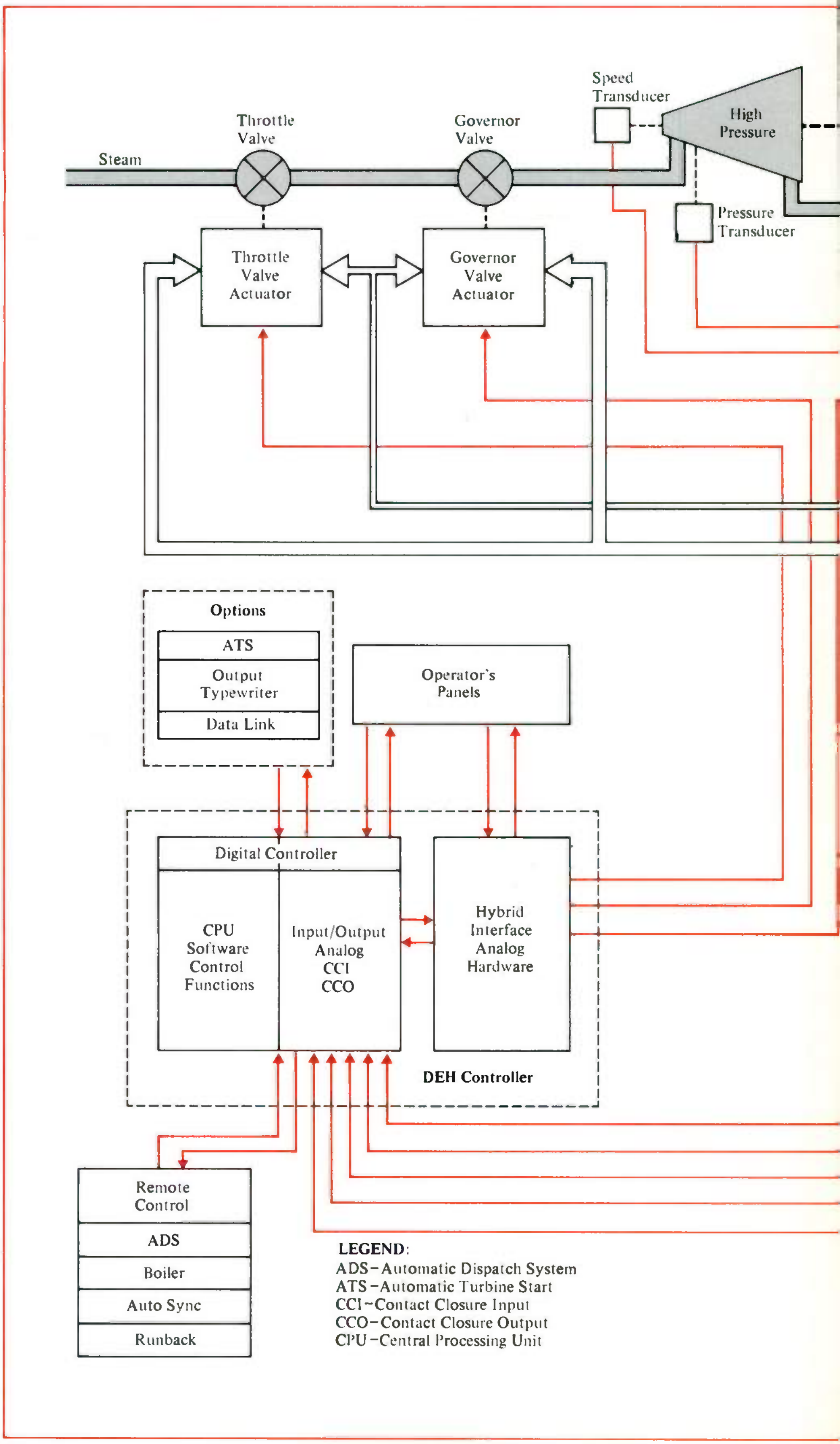
D. P. McFadden

Speed and load control systems for today's large turbine-generator units must accommodate the increasing complexity of the turbine control function as units increase in size, along with the interfacing and monitoring requirements of large interconnected utility systems. The Digital Electro-Hydraulic (DEH) control system, with several years of operating experience, has demonstrated the advantages of combining a programmable digital controller with an analog control system.

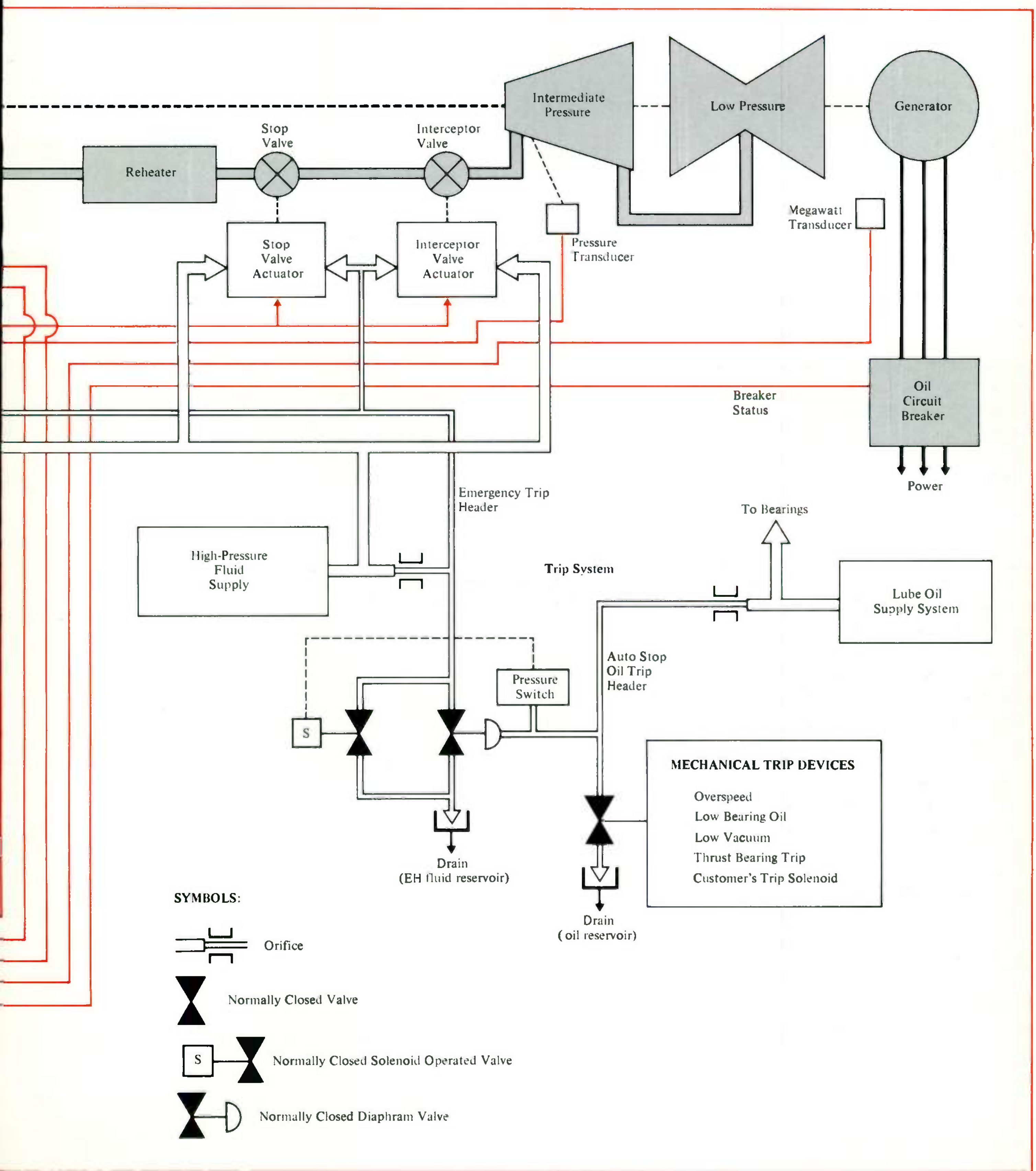
The Westinghouse Digital Electro-Hydraulic (DEH) control system[1] uses the digital controller's ability to monitor, memorize, calculate, and make decisions instantly to provide faster more accurate steam turbine control than was previously possible with manually controlled mechanical-hydraulic systems.

The first step in the improved control system came in the early 1960's when solid-state electronic techniques were combined with a high-pressure hydraulic actuator system to provide an analog Electro-Hydraulic (EH) system.[2] The basic functions of controlling speed and load have not changed appreciably since the introduction of the EH control system, but the interfacing, monitoring, and operating requirements have become increasingly complex. Furthermore, those requirements become more stringent with each new installation. Since the electronic controller used in the EH system is basically a wired-logic analog computer, it became apparent that a control system supervised by a programmable digital controller could provide the additional flexibility needed to accommodate the specific control requirements of each new installation.

D. P. McFadden is a Control Engineer in Steam Turbine Engineering, Steam Turbine Division, Westinghouse Electric Corporation, Lester, Pennsylvania.



1—The basic DEH system consists of a digital controller, an analog hybrid interface, and a high-pressure valve actuator system. The high-pressure emergency trip system closes turbine valves in the event of a trip contingency.


Intermediate Pressure
Low Pressure
Generator
Stop Valve
Interceptor Valve
Reheater
Stop Valve Actuator
Interceptor Valve Actuator
Pressure Transducer
Megawatt Transducer
Breaker Status
Oil Circuit Breaker
Power
Emergency Trip Header
To Bearings
High-Pressure Fluid Supply
Trip System
Lube Oil Supply System
Auto Stop Oil Trip Header
Pressure Switch
S
MECHANICAL TRIP DEVICES
Overspeed
Low Bearing Oil
Low Vacuum
Thrust Bearing Trip
Customer's Trip Solenoid
Drain (EH fluid reservoir)
Drain (oil reservoir)
SYMBOLS:
Orifice
Normally Closed Valve
S
Normally Closed Solenoid Operated Valve
Normally Closed Diaphram Valve

The first Westinghouse Digital Electro-Hydraulic (DEH) system was placed in service[3] in early 1971, eight are now operating with excellent service records, and more than 70 units are presently on order. Operating experience has verified the reliability and flexibility of the basic DEH system. Experience has also shown that this flexibility lends itself to the integration of additional control functions. Some, such as valve management[4], automatic turbine starting, and turbine water detection, have already been incorporated in DEH systems being installed. Others, such as turbine performance remote monitoring, are under investigation for possible application to future DEH systems.

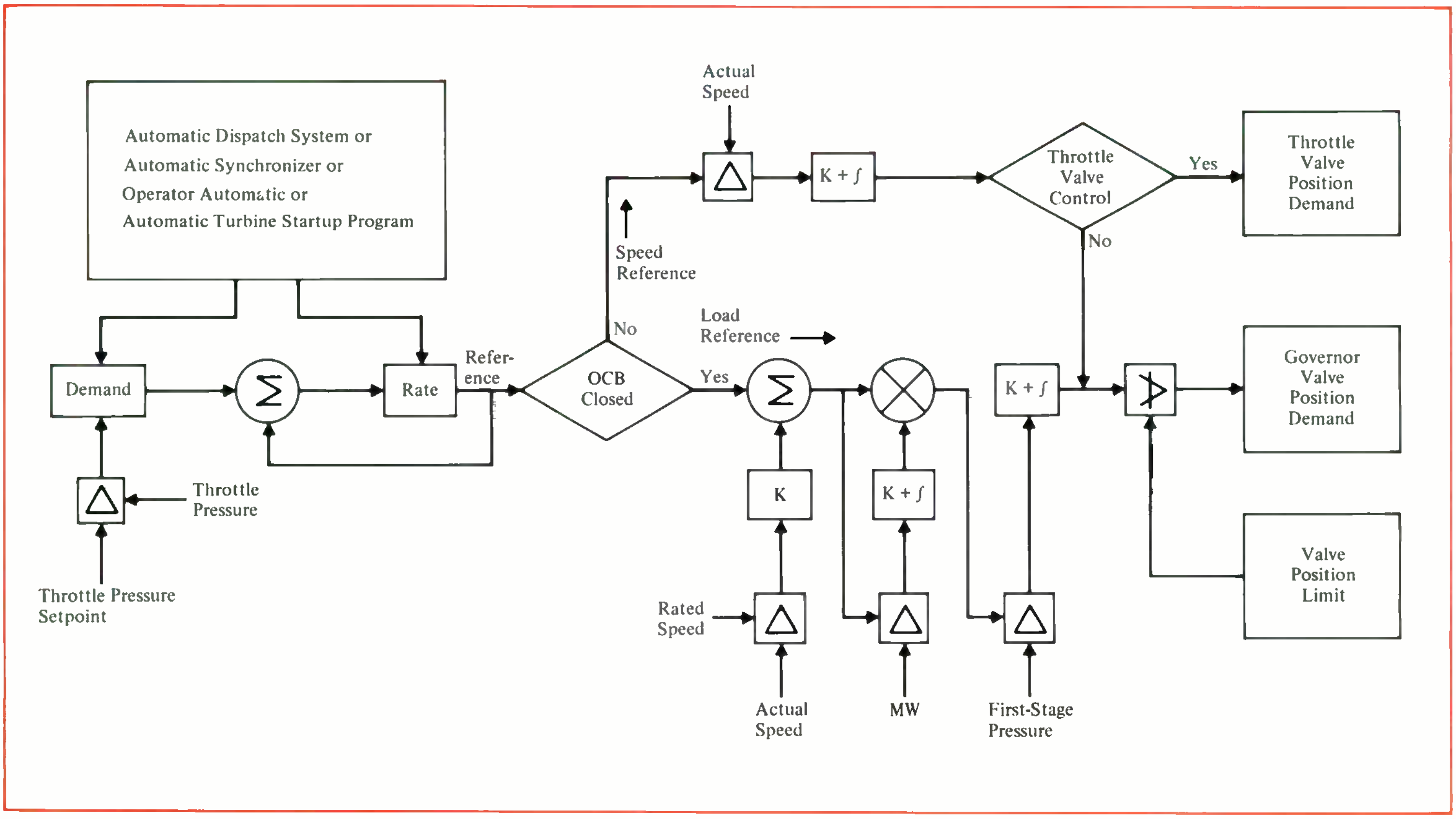
Basic DEH Control System

A simplified schematic of the DEH control system with its subsystems is shown in Fig. 1. The control system includes a Westinghouse digital controller, which is interfaced with the turbine valve actuators through an analog hybrid section. Digital-to-analog conversion provides the analog signal that positions hydraulic valve actuators by means of servo amplifiers. The valve actuators receive their motive fluid from a high-pressure fluid supply system and position the spring-loaded steam valves that control steam flow to the turbine. In the event of a trip contingency, the high-pressure emergency trip system causes a loss of motive fluid pressure, allowing the spring-loaded valves to close.

Software—The standard software package consists of the controller monitor system program and the basic DEH application program.

Briefly, the *DEH application program* must accomplish three basic steps: (1) compute a setpoint or reference; (2) compare the reference with turbine-generator feedbacks (speed, load, and first-stage steam pressure); and (3) compute a valve position demand signal that causes the electro-hydraulic servo loops to position turbine valves to satisfy the computed reference.

The reference is calculated by means of a logic program stored in the digital controller. If the turbine generator breaker is



2—The computer uses one of several stored programs to compute a reference (and rate of change of reference). Feedback loops, when in service, trim the reference as it is translated to valve-position demand.

closed, the reference is a load setpoint (either the desired turbine load when load feedback loops are in service or an approximate desired load based on turbine valve position when load feedbacks are out of service); if the generator breaker is open, the reference is a speed setpoint.

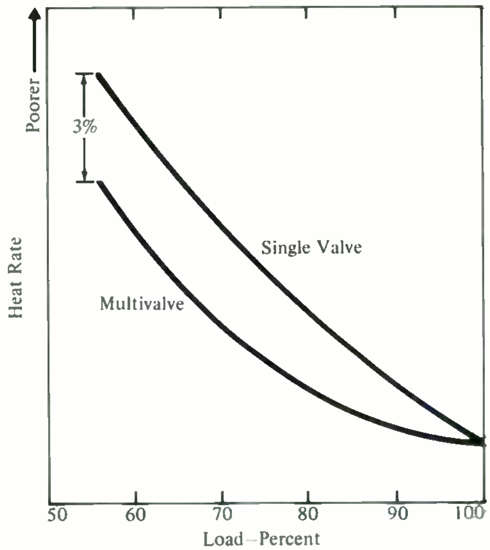
The logic for translating the computed reference to valve position demand is diagrammed in Fig. 2. When the turbine is in *load control* (turbine-generator breaker *OCB* is closed), the calculated reference is modified by frequency error (raised frequency lowers the reference, lowered frequency raises the reference) to provide load-frequency control. The modified reference is then compared with generator megawatt output and the turbine's first-stage steam pressure. Any load error initiates a change in governor valve position demand so long as the new value does not exceed the governor valve position-limit setpoint.

When the turbine is in *speed control* (turbine-generator breaker open), the reference is a speed setpoint that is compared with turbine speed (Fig. 2). In throttle valve control (below 90 percent rated speed), any speed error results in a change of throttle valve position demand, and the software ends with an output of that position demand signal. At 90 percent rated speed, steam flow control is transferred from throttle valves to governor valves (throttle valves are fully opened), and speed error results in a change in governor valve position demand.

Since the digital controller has more capability than is required for basic DEH control, other predefined control tasks can be included.

A *valve management program* is available to control *sequential* valve operation (partial-arc admission) or *single-valve* operation (full-arc admission) and the transfer between those two types of operation while the turbine is carrying load.

An *automatic turbine starting program* can control steam inlet flow to accelerate the turbine from turning-gear speed to synchronous speed, where control is transferred to an automatic synchronizer or the operator. During acceleration or during soak periods, critical parameters such as rotor stress, vibration, and turbine metal temperatures are continually monitored.



3—Representative differential heat-rate curves for sequential- and single-valve (full arc) operation illustrate the improved efficiency of sequential-valve operation at partial load. Although absolute levels of heat rate vary with turbine arrangement and plant operating cycle, the relative difference remains essentially as shown.

Advantages of Valve Management

Large steam turbines are operated under load with the governor valves opened in a predetermined sequence. The total number of open governor valves is proportional to the load being carried. This sequential arrangement minimizes losses due to throttling (losses that occur when valves are operated partially open) and thereby provides the best possible operating efficiency at partial loads (Fig. 3).

However, under cold startup conditions, or where turbine-generator units are used in peaking service, it is desirable to start the turbine with all governor valves opening together to provide a full arc of steam admission and thereby minimize temperature differentials on both rotating and stationary parts. Also, there are occasions when the system demands rapid increases and/or decreases in load. These changes produce a severe temperature change in the first-stage zone of the high-pressure turbine element. Full-arc admission can accommodate larger load changes for a given temperature differential than can partial-arc admission.

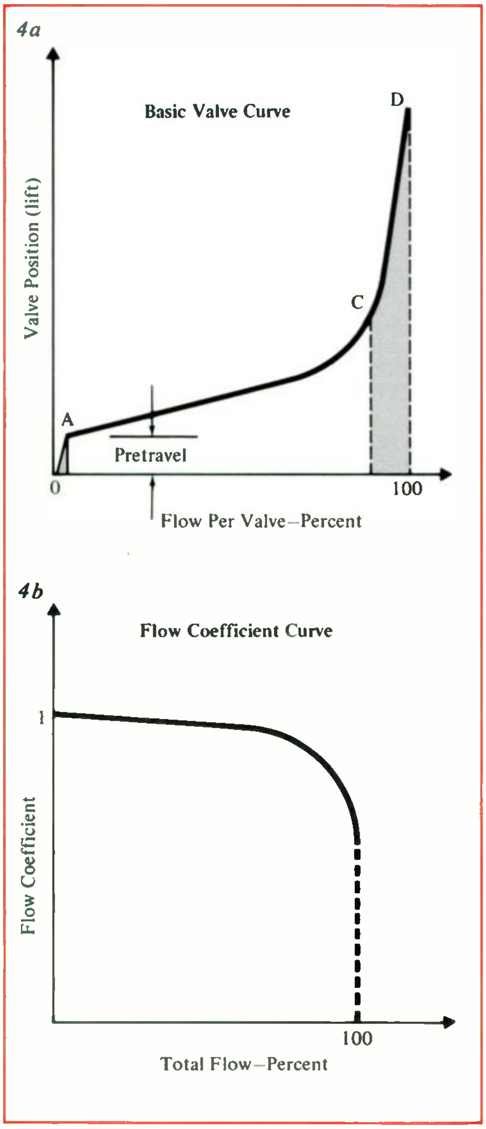
Unfortunately, in mechanical-hydraulic or electro-hydraulic control systems, the opening of governor valves is fixed to a given grouping and sequence, either by a linkage arrangement or by electric function generators. If it is necessary to change the sequence of governor valve opening, as from partial-arc admission to full-arc admission, a shutdown and recalibration is required. Any control system for changing from full-arc to partial-arc admission (or vice versa) while the turbine-generator unit is on line requires a complex form of valve characterization to relate valve position to steam flow because flow is not linearly related to position. With the DEH control system, the digital controller provides the capability to perform that valve characterization and thereby makes valve management possible with no change in load.

Valve Position/Flow Relationships

For a valve operating in conjunction with a group of nozzles, the position/flow relationship remains linear as long as there is critical flow* across the valve. However, the valve characteristic begins to change as soon as the pressure drop across the valve is reduced below critical. The maximum flow for nozzles, and thus for the valve, is a function of the combined flow coefficient of the nozzles. The basic position/flow relationship for a governor valve in the region where the pressure drop across the valve is critical is given by the curve in Fig. 4a. However, this position/flow relationship is also affected by total inlet steam flow and by throttle pressure. Thus, to determine valve position for a given flow, the position/flow curve shown in Fig. 4a must be dynamically adapted to the prevailing inlet steam conditions of flow and pressure.

The effect of total steam inlet flow can be represented by a flow coefficient curve (Fig. 4b). The governor valve flow characteristic is determined for any given flow

*Critical flow is the maximum flow that can be passed by an orifice with a fixed upstream temperature and pressure.



4—Two curves are needed to develop a dynamic position/flow relationship for a governor valve on line: the basic valve curve (a) *provides the position/flow relationship for critical flow through the valve; the flow coefficient curve* (b) *provides the multiplier by which the basic valve curve must be corrected for a given total steam flow in the turbine.*

value in the turbine by multiplying the basic valve curve by the coefficient for that flow.

A second correcting multiplier for inlet pressure is applied as a ratio of actual pressure to rated pressure. When throttle pressure is different from rated pressure, the correction is included. To avoid upsetting the boiler control system, an adjustable deadband and incremental change limit are included in the program for pressure correction.

The basic position/flow curve for the governor valve in the region where the pressure drop across the nozzles is critical (Fig. 4a) and the flow coefficient curve (Fig. 4b) are entered as data in the valve management program. The governor valve flow characteristic is determined for any flow value in the turbine by correcting the basic valve curve with the flow coefficient.

Valve Management Program

The objective of the basic DEH application program is to position governor valves in a feedforward manner in response to load demand by the operator, change in speed, or a remote demand signal. The complementary function of the valve management program is to distribute steam flow through the governor valves, based on load demand and the desired mode of valve operation.

A general flow diagram of the valve management program used in the Westinghouse DEH control system is shown in Fig. 5. As indicated, the program consists of a number of functional modules that combine as required to supervise the various modes of operation and transfer between modes.

Tracking—After a period of manual operation, before returning to automatic control, the digital controller through the valve management system must track itself to existing valve positions so that a bumpless transfer can be effected from manual to automatic control. The tracking method used is based on an adaptive scheme, as indicated in Fig. 5.

The essence of the method is an iterative search for the dynamic valve curve that, when used with existing valve positions, will provide the flow assumed to determine the valve curve. As soon as the tracking search is completed (usually within 60 seconds), a valve mode change is initiated automatically to align governor valves in their proper positions corresponding to the single or sequential mode of operation. In this way, the transfer from manual to automatic control is made without changing the steam inlet flow to the turbine. Since tracking is based on an iterative adaptive scheme, it is applicable regardless of the availability of the throttle-pressure, megawatt, and impulse-pressure inputs.

Flow Change—When valves are in either of the two modes of operation, changes in flow demand (reference) are accomplished through the following steps (Fig. 5): (1) the dynamic valve curve is recomputed for the new inlet condition; (2) target flow for each valve is determined; and (3) new valve positions are established based on the respective target flows and the dynamic valve curve. The computed valve positions are output to individual governor valves through the analog output system and the hydraulic servo positioning system.

For single-valve (full arc) operation, target flow through each valve is computed by dividing the total flow demand by the number of valves. For sequential-valve operation, since valves are opened in a predetermined sequence, the number of valves to be fully open is determined from the maximum flow per valve obtained from the valve characteristic curve and the total flow demand.

The portion of flow demand not provided by fully opened valves must be satisfied by proper positioning of the remaining valves in the controlling sequence. However, if the controlling sequence were followed directly, a situation could occur where valves of the controlling sequence must operate in one of the nonlinear zones (*OA* or *CD* in Fig. 4a) where a small flow change requires a large change in valve position, a potentially unstable condition. To avoid this situation, a "valve overlap" approach has been adopted. Rather than controlling valves through nonlinear zones, valves are step-changed across those zones when the next valve to control (or the previous valve) is capable of supplying the flow demand change in a linear zone. By

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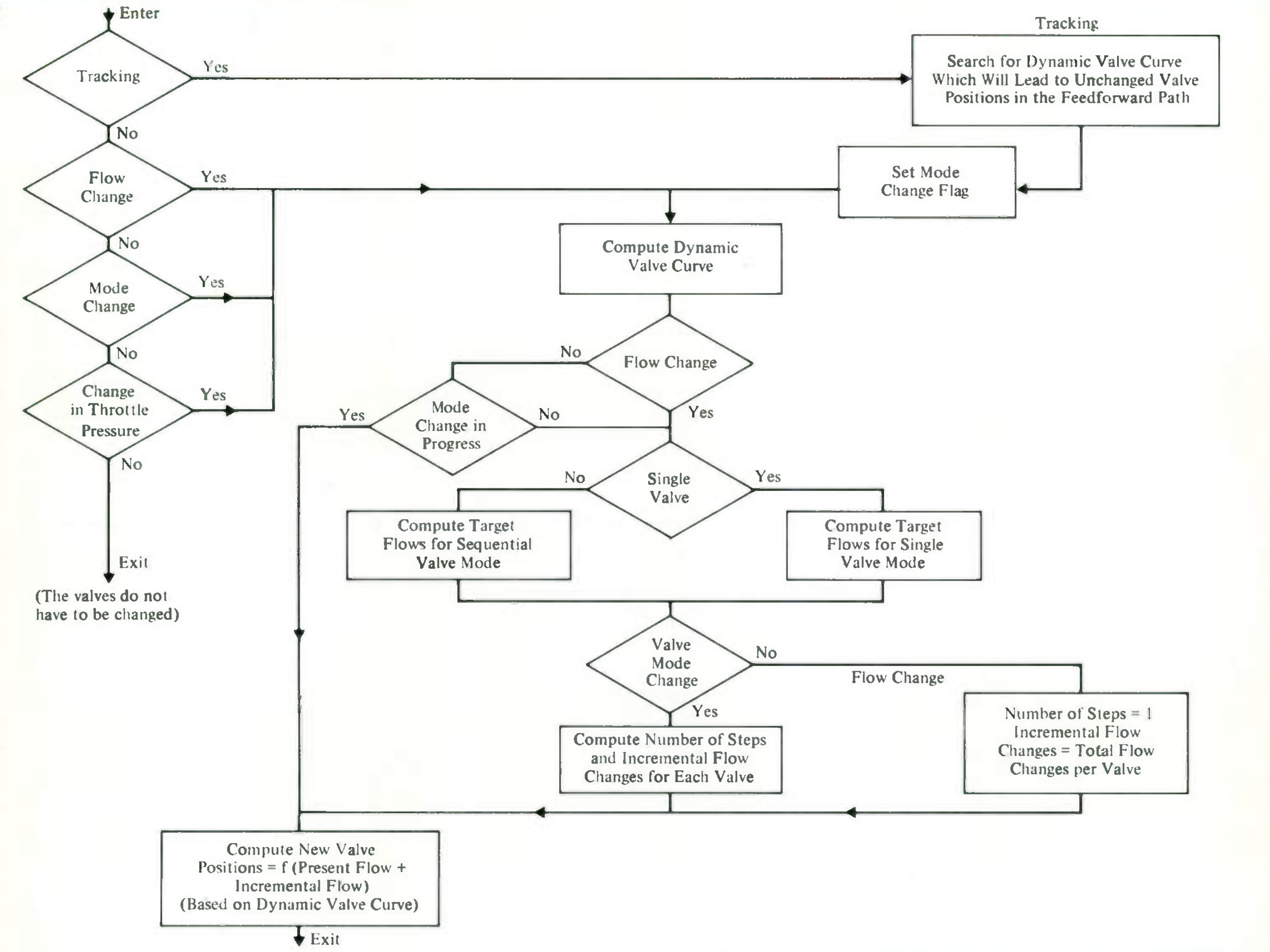


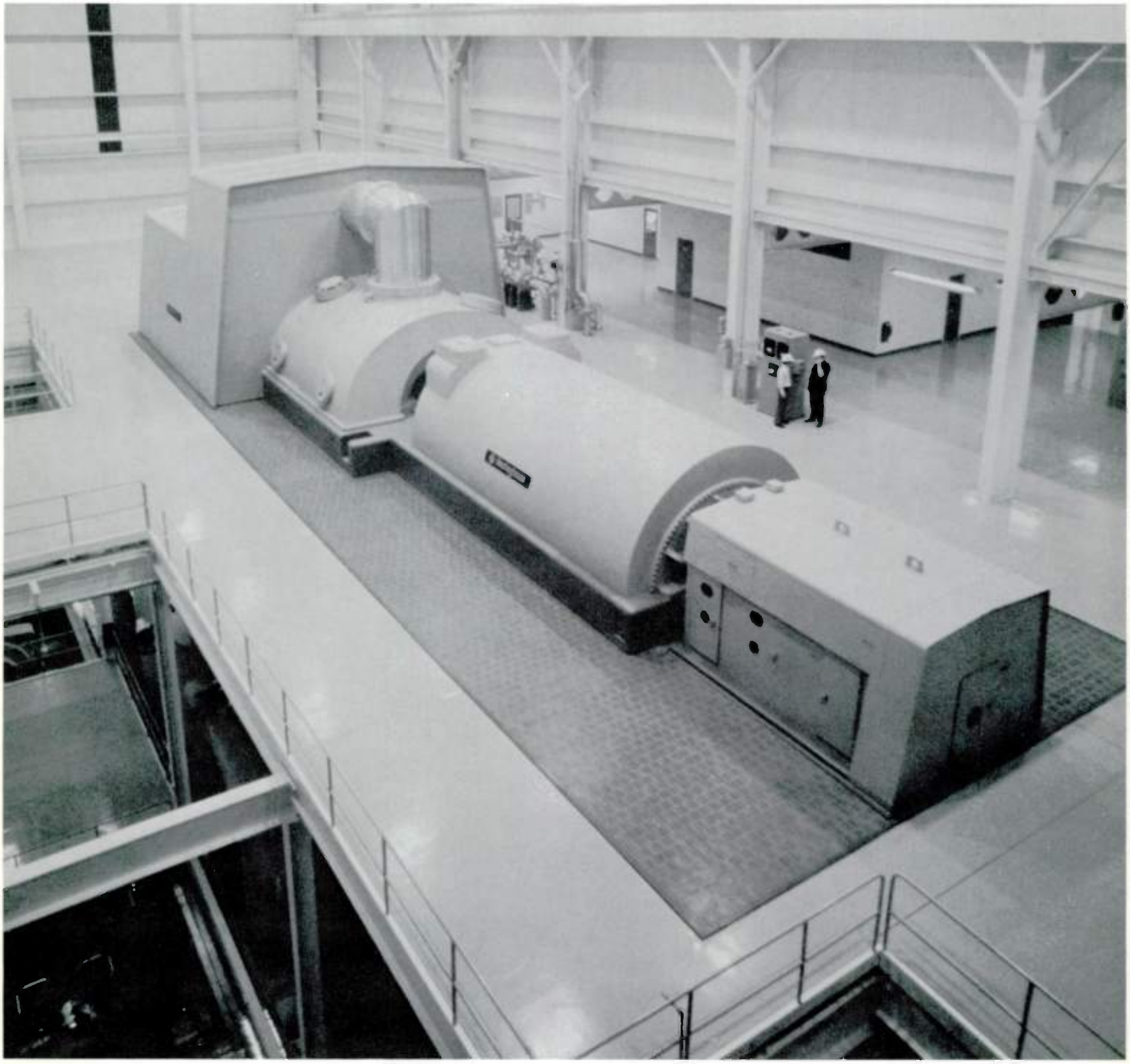
5—General flow diagram for the valve management program illustrates the control logic for tracking, making flow changes in response to a reference change, and changing from sequential- to single-valve mode of operation. As indicated, mode and flow changes can occur simultaneously.

this process, the frequency of opening or closing valves is minimized in regions where flow is near the maximum or minimum flow of a sequence of valves.

Mode Change—To accomplish an acceptable on-line transfer from one mode of valve operation to the other, two conditions must be met: total inlet steam flow must not change as a result of the transfer, and total flow must remain essentially constant during the transfer. Those requirements are met by use of the dynamically adapted valve curves.

First, target flow—the future flow through each valve when the transfer is complete—is computed. Second, differences between actual flow and target flow are computed for each valve. Third, the number of steps required to implement the mode transfer is computed by dividing the largest valve flow change by the maximum incremental flow change allowed. The maximum incremental flow change per step is selected to minimize disturbances in steam flow to the turbine. The incremental flow change during each step in the transfer is computed by dividing the total flow change for each valve by the number of steps required to complete the transfer.

During each step in the transfer, the new actual flow through each valve is computed by adding the incremental flow changes to the old actual flows for each step so that new valve positions can be



The first Westinghouse turbine-generator unit using the DEH turbine control system was Southwestern Public Service's C. B. Jones No. 1 Station. This unit was placed in service in April 1971.

determined using the dynamic valve curves. New valve positions are output to the governor-valve positioning servo system.

Since the sum of incremental flow changes must equal zero for any step in the transfer, total flow remains essentially constant so long as flow demand (reference) does not change. The length of time required to complete a transfer depends on the maximum change in steam flow in any one of the governor valves.

If a change in flow demand is requested during a mode change, it is implemented as previously described for a flow change and the mode transfer continued. Thus, the valve management program insures a bumpless transfer between single and sequential modes with or without a flow change.

With the DEH feedforward approach, the response of governor valves is improved considerably. Feedback loops (when in service) have a trimming function only since valves are directly positioned to obtain essentially the required flow.

Automatic Turbine Starting Programs

An automatic turbine starting (ATS) program controls the turbine-generator speed and rate of acceleration automatically from turning gear speed (approximately 3 r/min during unit shutdown periods) to synchronous speed (3600 r/min for fossil units). Upon reaching synchronous speed, control is turned over to the operator or an automatic synchronizer for subsequent tying to the power system. During the acceleration period, the speed and rate of acceleration are determined by programs that monitor all critical turbine-generator parameters, such as rotor stress, steam and metal temperatures, pressures, vibration, and thermal expansions. In addition to monitoring actual values of the turbine parameters, the controller computes anticipated values so as to take action to avoid getting into alarm conditions. This "preventive action" capability is a unique feature of the DEH system.

In addition to the ATS programs controlling the turbine during the acceleration period of operation, those same programs monitor performance continually during load-control operation of the unit. The operator is kept advised of all abnormal conditions by means of messages printed on a typewriter.

Another advantage of ATS is the expanded capability of the digital display windows (reference and demand) located on the DEH panel. Any one of several hundred measured and computed turbine-generator operating parameters can be displayed in engineering units by the operator merely inputting a four-digit code on the operator's panel keyboard.

Also available from the keyboard is the ability to output on the typewriter up to 18 parameters. The values of these parameters are repeated periodically for trending purposes.

Another feature of ATS is the rotor stress program. Turbine rotors are subjected to severe temperature changes during startup as well as during normal load changing operations. The life of a rotor is determined by the severity and frequency of this thermal cycling. The final result of these stresses is the appearance of thermal fatigue cracks in the rotor surface. The rotor stress program calculates the rotor temperature gradient on the basis of actual temperature environment and either takes the appropriate steps (when the ATS is controlling) or advises the operator as to what steps to take to maintain the stress within allowable limits.

The ATS program is stored and executed in the same central processing unit (CPU) as other DEH programs.

ATS Supervision—The computer's function can also be limited to a supervisory role in which the various parameters are monitored and translated to messages to assist the operator. The strain calculation is continuously performed to advise the operator of the thermal condition of the rotor. However, it is the operator's responsibility to match steam and metal temperatures, set demands, select rates of speed and load change, determine the heat-soak requirements, and take all necessary sequential steps to bring the turbine up to speed and load it.

The supervisory mode is normally used for initial startups, and subsequent restarts are made under ATS control.

Future Expansion of DEH Control Systems

The DEH control system has flexibility for additions of future predefined programs. These additional programs can be added with software changes and a minimum of hardware changes, resulting in lower system costs over comparable expansions for nondigital systems.

Standard digital hardware consists of a central processor unit and a basic complement of input and output hardware. The software package contains the programs necessary for turbine control under operator supervision. Since the DEH controller is a modular design, optional control functions can be added by adding modular hardware and software packages. Thus, such predefined control functions as automatic starting, if not included in the initial installation, can be added at a later date. Similarly, data links to integrate turbine-generator unit functions with other power plant functions or remote system computers can be added as the need arises.

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Control of Energy Demand Reduces Plant Operating Costs

B. H. Murphy
Richard E. Putman

A computer control system continuously measures a plant's demand for electric power or gas, and it switches selected loads off to keep demand within a desired limit and thereby control demand charges. It also provides maximum utilization of plant equipment within the desired demand limit.

One of the quickest ways to substantially reduce the operating expense of a manufacturing plant is to reduce the demand charge placed on the use of electricity and gas. Demand charge is the utility's charge for the *maximum rate* of energy usage in addition to its charge for the *total amount* of energy used.

Energy demand is reduced by prohibiting simultaneous operation of devices, especially those that consume large amounts of energy, or by deferring the use of such equipment as air conditioners from one demand period to a subsequent period. To achieve that end, a control system can continuously measure the demand and turn off selected loads in accordance with established rules. Because of the complexity of most industrial plants, a computer is the best means of storing, measuring, calculating, and controlling the many variables associated with the many devices involved. A computer system for that use has been developed by the Westinghouse Computer and Instrumentation Division in Orlando, Florida. For most applications, this demand control system can be installed and operated by industrial plant engineering personnel with no special knowledge of computer technology. It can be used with both electrical and gas service. For simplicity, it is discussed here only in terms of electrical service.

Demand Charges

The need for demand charges is due to the utility's investment required to serve each customer. As an extreme example, a customer might need to use a 1000-hp pump for one hour per month. Assume that the load with all losses is 900 kW and the energy charge is 2 cents per kWh. At that rate, the energy charge for the one hour's use per month would be $18.00. To serve the load, however, the utility must invest in a 1000-kVA transformer, breakers, some transmission line, and a portion of a substation and generating plant. A monthly bill of $18.00 cannot support such an investment; the customer would, in effect, be subsidized by other customers of the utility.

Therefore, a typical actual charge for the large pump load might consist of a demand charge of $1.50 per kilowatt plus an energy charge of 2 cents per kilowatt hour. The total charge then would be:

900 kW at $1.50	$1350
900 kWh at $0.02	18
	$1368

While rate structures vary, in general all electric and gas utilities have industrial rates that incorporate both demand and energy-use components. More information is given in *Saving Money by Reducing Demand*, p. 15, which also gives a typical example.

Viewed from the utility's side, demand charging is a way of avoiding class subsidies. It may also be used by utilities to discourage excessive demand peaks that would require system expansion. Viewed by an alert plant management, however, it is an opportunity to save considerably on energy costs.

Moreover, even though the demand control system is not designed to reduce energy consumption directly, its use usually does result in some reduction. The reason probably is that the constraints established for the system tend to operate all devices at their minimum rather than maximum operating levels, thus reducing waste. With the energy shortage existing now, that effect may well be an important part of the justification for a demand control system. In addition, an option available with the system provides for an hourly schedule over an extended period (week, month, or year) for shutting off unnecessary lights, heaters, coolers, and ventilators when areas are not in use or when solar heat and light are available. Savings of more than 15 percent in energy use have been reported from this program alone.

Demand Patterns

While each plant has a unique demand situation, most can be grouped for convenience in one of three categories so far as the pattern of energy use is concerned (Fig. 1). Fig. 1a is a good example of the need for some type of electrical demand control. The peaks are caused by simultaneous use of two arc furnaces in addition to the base load of the plant. (Base load is the sum of all loads for which demand control is impossible or uneconomical—lighting and heating, for example.) New operating rules could solve a major portion of the problem.

Fig. 1b shows a more usual situation. The steps that do not require computer control have been taken to hold demand down, such as manually controlling large loads to prevent their simultaneous application and transferring such activities as pumping, battery charging, and testing to the night shift. However, there still are peaks to reduce, and there are valleys to accept the redistributed loads.

Fig. 1c represents by far the greatest challenge to management trying to reduce demand. The weekday load is quite uniform, so demand for the whole day must be reduced to achieve any savings.

Because of such differences, it is not possible to predict the reduction in demand that can be expected by all or even most plants. A 40-percent reduction does not seem impossible for the plant represented in Fig. 1a, while even a 10-percent reduction seems optimistic for the one in Fig. 1c.

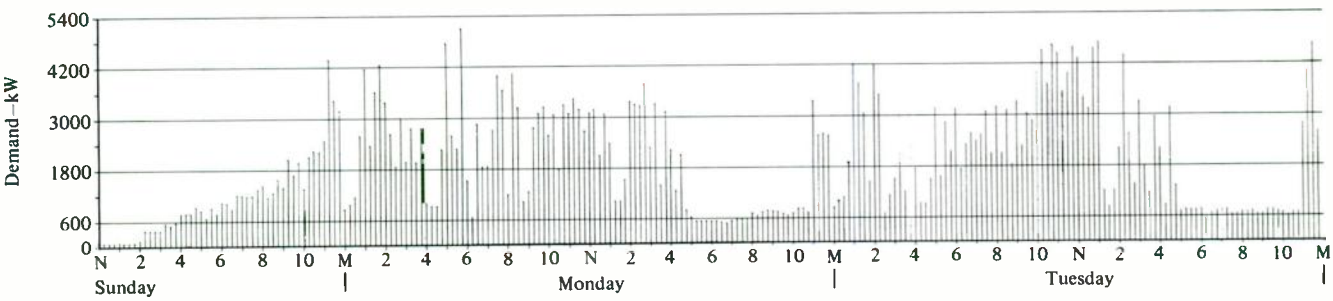
Demand Control System

The Westinghouse demand control system is a W-2500 computer housed in a steel

1—Electric power demand profiles for three actual manufacturing plants illustrate the range of patterns encountered. In (a), *the demand peaks are virtually uncontrolled;* (b) *is much better, and* (c) *is better still—approaching the pattern of demand that can be achieved with the demand control system and illustrating why that sophisticated system would be needed to achieve any improvement.*

B. H. Murphy is Manager, Marketing Communications, Computer and Instrumentation Division, Westinghouse Electric Corporation, Pittsburgh, Pennsylvania. Richard E. Putman is a Fellow Engineer at the Computer and Instrumentation Division.

1a


Demand—kW
5400
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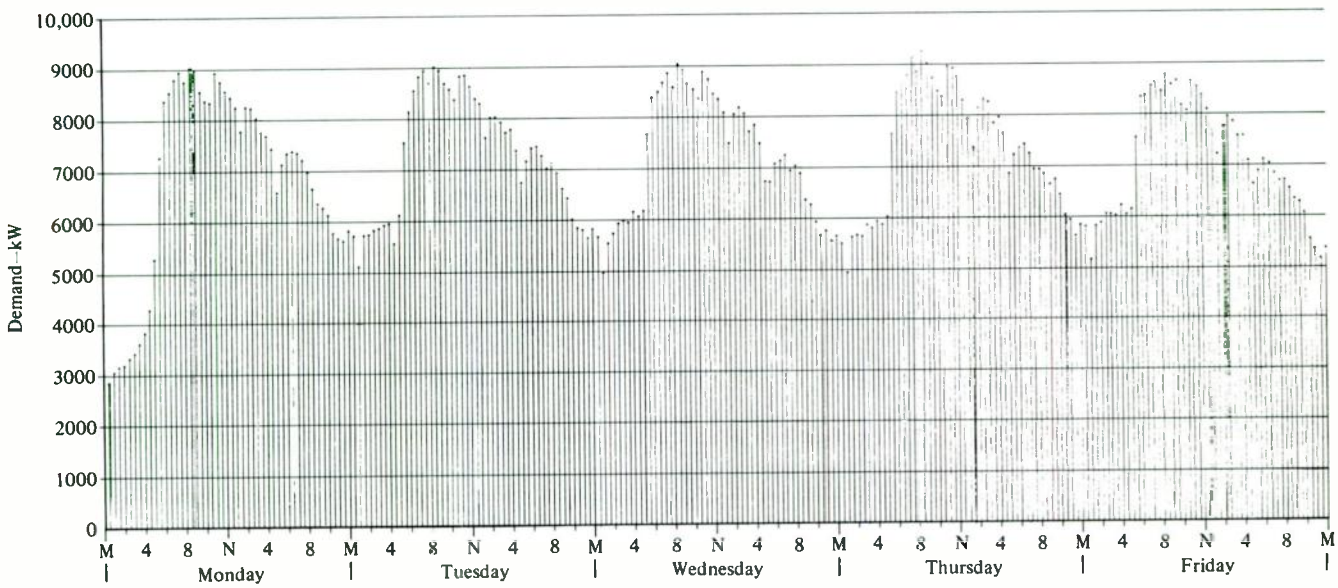
Sunday
Monday
Tuesday

1b


Demand—kW
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Monday
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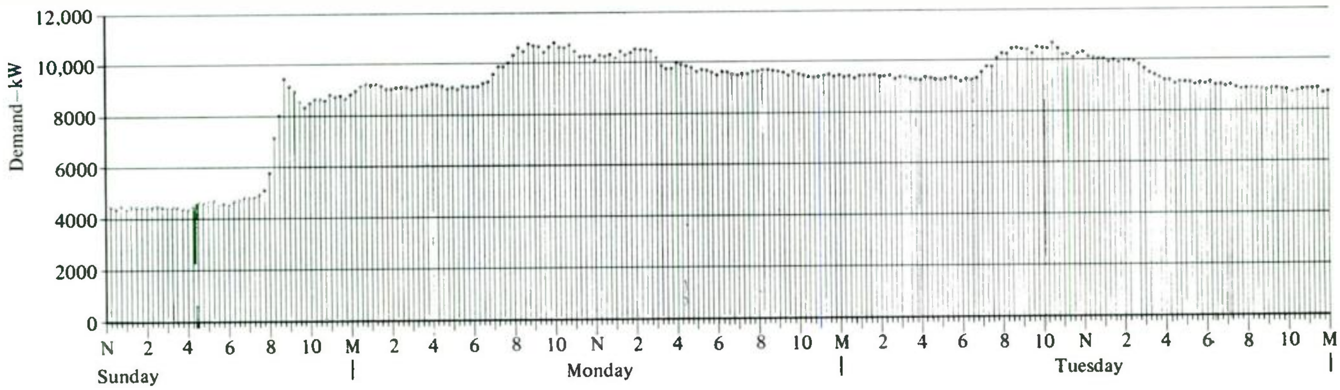
Wednesday
Thursday
Friday

1c


Demand—kW
12,000
10,000
8000
6000
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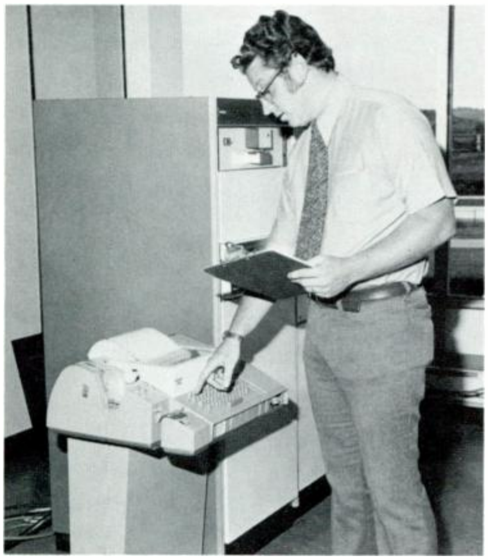
2000
0
N 2 4 6 8 10 M 2 4 6 8 10 N 2 4 6 8 10 M 2 4 6 8 10 N 2 4 6 8 10 M
Sunday
Monday
Tuesday



2—The demand control system's computer is programmed before it is shipped to the user. Then the user puts in the information describing his particular plant and telling how he wants demand controlled.

cabinet suitable for use in an office area, a control room, or on the production floor (Fig. 2). Interconnection cables are already in place and are tested before shipment. A Teletype ASR-33 unit is included for communication between the system and the operator. It incorporates a keyboard with which the operator enters data peculiar to his plant, a printer used mainly to print out logs, a tape punch used to unload the programs, and a tape reader for putting programs back into the system.

Operating programs are completely written and stored in the computer memory before shipment. In addition, a paper tape containing the same programs is provided for reloading if the programs are accidentally wiped out.

Since the demand control system is shipped with the control programs already loaded in memory, installation normally requires only the connection of plant wiring to screw connections in the back of the cabinet. Step-by-step instructions in the owner's manual show exactly how to enter system data through the keyboard.

In use, the system receives information from the power company in the form of pulses from a demand meter (or from two as an option) and clock signals that indicate the start of each demand period (Fig. 3). Each demand-meter pulse represents a fixed number of kilowatt hours. The system's computer calculates the load switching required, and its contact outputs turn plant loads on or off as necessary. (Eight outputs are provided as standard.) At the end of every demand period, a single-line log is printed to show the date, time, kilowatt hours used, and actual demand during that period.

Initializing—Since each plant is unique, the demand controller must be given all the information about the plant in which it will be used, and how the plant must be controlled. Those data and rules can only be supplied by plant operating personnel, so they are put in after the user gets his system. They are given to the computer through the teletype and are stored in appropriate tables in computer memory.

The rules are, in effect, constraints on the load-shedding to be done. To establish them, the user must first identify each load as to the following categories:

1) Those to be inhibited, that is, prevented from being turned on until the computer gives a "permit" signal, which it does only when prescribed conditions are met. An example of such a load is the large motor that spins rotors for testing in a turbine manufacturing plant.

2) Those that are sheddable, that is, switchable entirely under the control of the demand control program. Ventilating fans are examples, because they usually can be turned off for a time without seriously affecting air quality in a plant.

3) Those that are switchable but are also subject to additional local controls. Examples are compressors that turn on in response to a pressure signal; the computer says it is either permissible or not permissible to turn on.

4) Base loads, to which demand control is not applied.

For each load, the user must also state the power drawn by it, maximum or minimum on/off times, load size, minimum on/off time ratio, permissible number of starts per hour, and priority (order of expendability). For the total system, the user must provide a demand-meter constant (kilowatt hours per pulse), the length of the demand period, and the desired demand limit (in kW or kVA).

Operation—With the plant data and rules entered, the control program runs on receipt of each demand-meter pulse to perform the following steps:

1) It prevents inhibited loads from being switched on except at the very beginning of a demand period so that the desired demand limit will not be exceeded by loads turning on during a period. Only one such load is permitted to be switched on at any given time.

2) It switches that load off after a percentage of the demand period (determined by the user) has elapsed.

3) It switches on those loads whose off time has equaled or exceeded a user-established maximum off time.

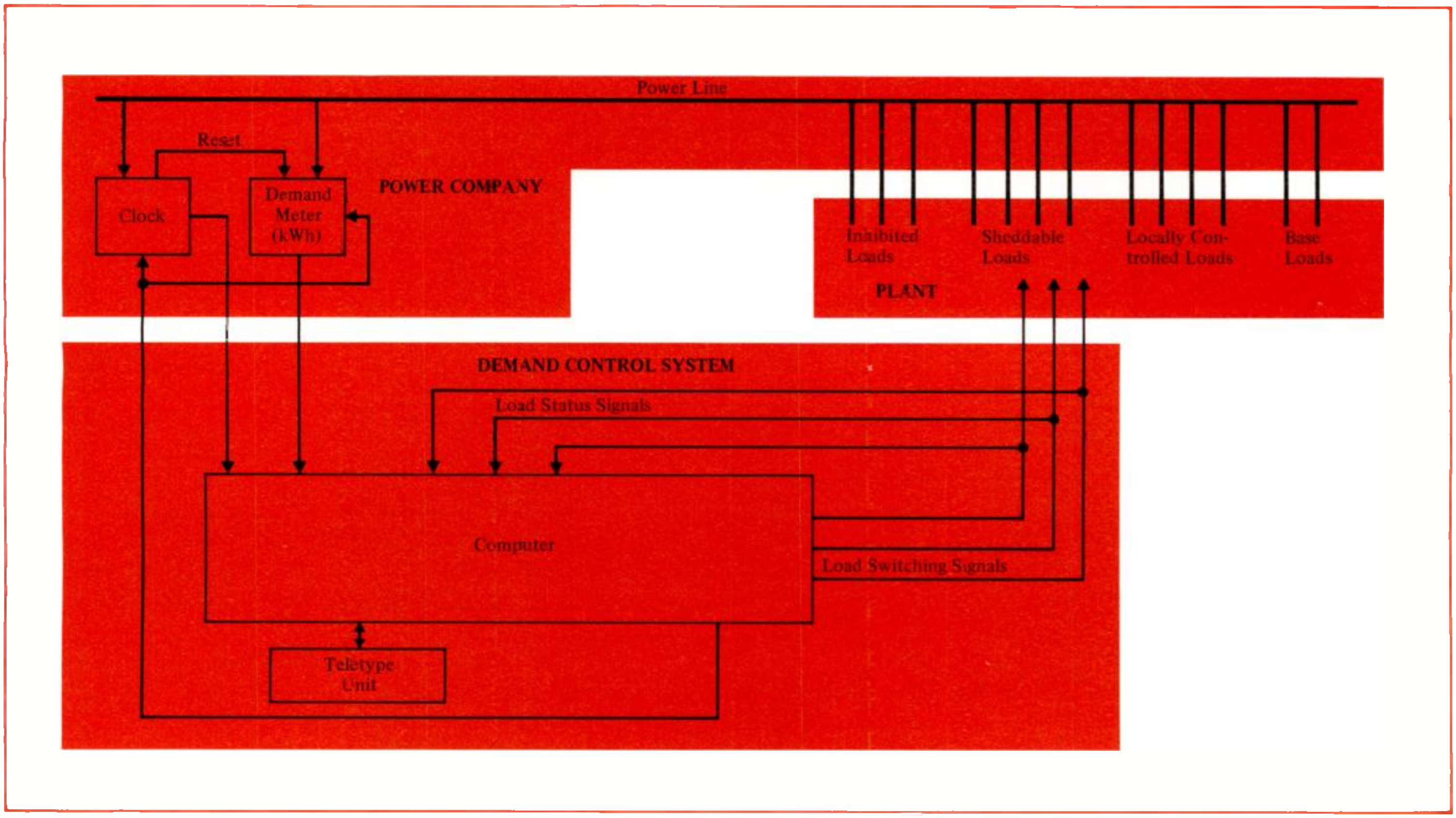
4) It prevents loads being switched off unless the on/off time ratio (determined by the user) has been exceeded. [The product of *off time*$\times$(1+*on/off ratio*) should be greater than or equal to the maximum interval between starts.]

5) It selects the most sheddable load and the least sheddable load by examining the above constraints together with the priorities assigned by the user. It also selects the switched-off load that would most benefit plant production if switched on. The object is both to stay within the set maximum demand and to permit maximum utilization of the plant equipment within that limit.

6) It constantly predicts what the demand will be at the end of the current period (if nothing is changed) on the basis of the energy consumed up to that point in the period and the present rate of consumption. It calculates the error between that value and the desired demand limit. After comparing the error with the anticipated change in demand on picking up or shedding loads (as selected in step 5), the computer decides whether to switch a load or not. If it switches a load, the program returns to step 5. Otherwise, it stops until the next demand-meter pulse is received.

Application

The success of the demand controller in reducing costs for any given plant depends



3—The demand control system receives signals from the power system that define the demand periods and show how much power is being used. Its computer determines whether or not a desired demand limit will be exceeded in each period. If the limit will be exceeded, the computer switches loads off according to programmed constraints; if it will not be exceeded, the computer either lets well enough alone or switches loads on for maximum utilization of plant equipment.

on the quality of the information supplied by plant personnel. Careful attention must be paid to the constraints applied to the system, and many questions must be considered by production and works-engineering personnel before decisions are made.

Some typical questions are: How much of the time do we need ventilating fans? (The health and comfort of personnel as well as the quality and quantity of their work may suffer if ventilating air is reduced too far.) How many times an hour or a shift can we restart a motor without shortening its life too much? (The cost of a replacement motor might well be greater than the savings in electric bills effected by turning it off frequently.) How many loads can be dropped or delayed without loss of production? And how much, if any, can we afford to reduce production? (In past years, the thought of any loss of production would have been considered heresy; more recently, that approach has been considered less emotionally on a purely economic basis—finding the level of production that returns the greatest profit.) And, how much will demand increase or decrease if the on/off ratio of a given load is increased or decreased?

To help answer those and similar questions even before a system is purchased, the Computer and Instrumentation Division has developed a simulator. It is a program that accepts plant load information along with the constraints being considered and returns data on the resulting increases or decreases in energy charges. For such purposes, the simulator is operated from a time-sharing terminal or on a business computer. Step-by-step operating instructions are provided.

The simulator can calculate the minimum demand that can be achieved with the constraints imposed. To determine the validity of its calculation, it can also calculate uncontrolled demand for comparison with actual experience.

Output from the simulator shows the status of each device under control and the projected demand for each time the calculation is run (Fig. 4). Thus, it is possible to study each demand period to see how the demand builds, the effect of the constraints, and how much of the time loads are switched off to maintain the desired limit.

The simulator can also be used after installation of a demand control system. Its main use at that time is to study the effect of changes without the risk of exceeding the desired demand limit and without having to wait a month or more to find the results. The operator unloads the demand-control programs from the system computer, and loads the simulator in, during a time when demand is low. He then runs the simulator with the computer in an off-line mode. This use permits evaluation of such things as the effect of changing on/off ratios, the effect of uncontrolled operation

END OF DEMAND PERIOD LOG: TARGET 4650KW ACTUAL 4586KW ENERGY 1146KW of equipment that consumes large amounts of power, and the benefits of bringing more loads under control. If the results indicate that such changes would be beneficial, the changes can be incorporated after the control programs are loaded back into the system and it is again controlling plant demand.

Custom Systems

Some large or exceptionally complex plants may present special problems beyond the scope of the standard demand control system. Also, many old plants in which the electrical load has increased enormously over the years may not have complete records of all the wiring changes that were made. Dropping a feeder could have unwanted side effects in those plants. For such users, the Westinghouse Industry Systems Division provides custom-designed demand control systems (using one or more standard systems) to meet any requirements.

Users of custom systems can add functions not directly associated with demand control. For example, where several divisions or companies share a single plant with a common billing record, the demand control computer can be programmed to check and record actual energy use for each so that costs can be allocated accurately.

4—(Left) *A simulator program generates plots of power use for any plant conditions the user wants to evaluate, permitting the user to learn in advance how any change in plant operating conditions will affect his power bill. It prints out the plots three times faster than real time. In this sample printout for a 15-minute demand period, demand in kW is expressed as energy × 10³ on the horizontal axis, with the symbol Y indicating the points where the figures apply. Time is expressed in seconds on the vertical axis. Plant base load is represented by +, and the symbols *,), #, and @ represent the controllable loads. When a controllable load is off, its symbol appears on the zero line of the plot; when it is on, it appears within the plot to show the amount of power it is using. The % symbol shows the total amount of power being used at that second, while & shows the integration of power use over the period. The column of $ symbols is the target demand limit.*

Saving Money by Reducing Demand

Electric power bills are calculated from two factors: the total energy consumed, measured by the kilowatt hour (kWh), and the maximum rate at which it was used, measured in kilowatt hours per hour and stated in kilowatts (kW). The latter factor is called *demand*. (If power factor is part of the rate, kVA is used instead of kW.) The time period during which the kilowatt-hour rate is measured, commonly 15 or 30 minutes, is called the *demand period*. The demand meter integrates the kW for the period, sets an indicator or marks a strip chart, and resets itself at the beginning of the next period.

The *billing demand* is commonly the average of the two highest demands during the month. Many utilities also differentiate between on-peak and off-peak demands. In that case, peak hours are defined (for example, 8 am until 9 pm on all weekdays except major holidays), and off-peak demand is charged for at a lower rate so long as the utility is not required to increase the capacity of the service facilities to meet the demand.

The example below, based on actual rates in a typical industrial area, shows what happens to the electric bills of one user when billing demand is dropped 20 percent even though the amount of energy used remains the same.

Monthly Use—1,400,000 kWh	*Billing Demand 5000 kW*	*Billing Demand 4000 kW*
Demand Charges		
$2.00 × first 100 kW	200	200
1.60 × next 300 kW	480	480
1.40 × next 1100 kW	1540	1540
1.25 × next 2500 kW	3125	3125
1.20 × next 5000 kW	1200	—
Total	$ 6,545	$ 5,345
Energy Charges		
Demand factor × first 250 kWh × 1 cent	$12,500	$10,000
Next 50,000 kWh × 0.9 cent	450	450
Next kWh × 0.8 cent (up to 200,000 kWh)	800	1600
Remaining kWh × 0.7 cent	—	1050
Total	$13,750	$13,100
Total energy and demand charges	$20,295	$18,445

Annual saving due to reduced billing demand: (20,295 − 18,445) × 12 = $22,200.

The Fused Distribution Limiter— A New Protective Device for Distribution Systems

F. L. Cameron
D. R. Smith
J. A. Carey, Jr.

The fused distribution limiter is a new overcurrent protective device that combines the desirable characteristics of an expulsion fuse with those of a full-range current-limiting fuse. The device uses standard "K" or "T" fuse links to achieve coordination with other protective devices, and yet it limits (with a back-up current-limiting fuse) the let-through current to the protected apparatus.

In today's distribution systems, the use of increasingly large substation transformers and conductors, underground construction, and other factors have significantly increased available fault currents. As a result, pad-mounted and pole-top distribution transformers can fail disruptively more frequently than ever before. To minimize the probability of disruptive failure, the transformers are applied with protective fuses or circuit breakers. Those protective devices must coordinate selectively with other protective devices in the distribution system to achieve the desired levels of system reliability and service continuity.

The fused distribution limiter (FDL) is a new protective device uniquely suited for solving many of the problems associated with high available fault currents and for satisfying the requirements for selective coordination in the distribution system. The FDL is made up of an expulsion fuse in series with a back-up current-limiting fuse, all mounted in a standard cutout assembly to provide drop-out action. For overloads and low fault currents, the interruption characteristics of the FDL are the same as those of a normal cutout. Thus, it is easily coordinated in that current range with other protective devices in the system. For high fault currents, the FDL responds in the same manner as a current-limiting fuse, i.e., limiting the peak of the available current and the amount of energy released into faulted equipment. This current- and energy-limiting action greatly reduces the probability of disruptive transformer failure.

F. L. Cameron is Manager, Fuse Development, Switchgear Division, Westinghouse Electric Corporation, East Pittsburgh, Pennsylvania. D. R. Smith is a Distribution Engineer, Distribution Systems, Westinghouse Electric Corporation, East Pittsburgh, Pennsylvania. J. A. Carey, Jr., is Product Marketing Manager, Distribution Apparatus Division, Westinghouse Electric Corporation, Bloomington, Indiana.

Transformer Disruptive Failure

Disruptive failure in distribution transformers usually results from internal faults that cause more pressure than the tank can withstand. Pressure relief devices installed on some transformer tanks may alleviate the hazard. For a low-current high-impedance fault, especially faults in the secondary winding, evolvement of gas is slow and the pressure relief devices can at least reduce the possibility of tank rupture. However, during a high-current fault or in the event of certain types of relatively low-current internal arcing faults, the relief devices cannot respond fast enough to cope with the rapid pressure buildup. The only way to restrict rapidly rising pressures associated with high-current internal faults is to limit the energy available from the system.

The obvious key to reducing the total energy input to the transformer under high-current faults is the current-limiting fuse[1]. A current-limiting fuse frequently is considered for use only when the available fault current from the system exceeds the interrupting ratings of the available fuse cutouts and/or expulsion fuses. However, greater application benefit can be realized from current-limiting fuses by also taking advantage of their energy-limiting capability and ability to coordinate with other fuses even at fault-current levels significantly below the maximum rating of the current-limiting fuses. In operation, the current-limiting fuse forces a current zero in one-half cycle or less, and reduces the energy input, I^2t, to the protected equipment to a level that is a function of the available fault current, the applied voltage, and the fuse design. Thus, current-limiting fuses can be designed to restrict energy input at the fault point for a wide range of fault currents. Fault-current levels may be well within the interrupting ability of a fuse cutout, and yet the system energy might exceed the withstand capability of an internally shorted transformer.

Full-Range Current-Limiting Fuse

Since the energy limiting capability of the current-limiting fuse eliminates or greatly reduces the probability of disruptive failure in transformers, it might appear that placing a full-range current-limiting fuse with drop-out features in a cutout assembly would be an optimum solution. However, this is not the case because such fuses possess a very steep inverse time-current characteristic, which does not always coordinate well with the characteristics of other fuses, reclosers, and breaker tripping devices commonly used. For example, the difficulty in coordinating a full-range current-limiting fuse with expulsion fuses employing standard K (fast) and T (slow) fuse links is illustrated in Fig. 1.

Another potential deterrent to use of a drop-out full-range current-limiting fuse is the problem of interrupting low-current faults. To effectively interrupt such faults, the full-range current-limiting fuse must incorporate some supplemental internal means of melting, ranging from low-temperature additives and gas-producing agents on the fuse element to sophisticated filler additives or means for producing series arcs. Despite those efforts, arcing time is always long (typically two seconds) in clearing low-current full-voltage faults. The arcing produces great internal heat and complicates the design of a drop-out device by necessitating an intentional time delay before drop-out is permitted.

Fused Distribution Limiter

The fused distribution limiter combines the desirable characteristics of the current-limiting fuse and the expulsion fuse into a single package (Fig. 2). Installed in a standard loadbreak or nonloadbreak cutout assembly is a current-limiting fuse in series with an expulsion fuse that can employ either a K or T link. A locating pin on the expulsion tube and a contoured stud atop the current limiter simplify re-fusing and assure proper alignment of the two fuses in the cutout assembly.

A key advantage of the FDL is that the current-limiting fuse operates only during high-current faults. For low-current faults and overloads, only the expulsion fuse operates and clears the circuit, while the more expensive current-limiting fuse remains intact and undamaged. Thus, for many interruption conditions, it is necessary to replace only the low-cost fuse link.

In operation, the FDL is a drop-out indicating device. The expulsion fuse is designed to operate under all fault or overload conditions, assuring the untoggling action necessary to effect drop-out. The expulsion fuse section interrupts low-current faults effectively and immediately with a total arcing time of perhaps two cycles, in contrast to the two-second arcing times typical of a full-range current-limiting fuse. Drop-out action with the FDL is assured at low currents without any intentional time delay: the device is fully cleared and hanging in the open position for many faults that leave a full-range current-limiting fuse still intact in its mounting and arcing internally.

At the higher values of fault current that cause current-limiter operation, the expulsion link also melts to assure drop-out; however, even for currents up to the maximum interrupting rating of the FDL (25 kA symmetrical, 40 kA asymmetrical), the expulsion still is much less than that from conventional cutouts and power fuses. The major expulsion is deionized water vapor released from the solid boric-acid liner, which is innocuous both in appearance and in effect on any nearby apparatus. High-speed films demonstrate the significant reduction in expulsion when a fault is interrupted by a fused distribution limiter as opposed to interruption by a standard fuse cutout.

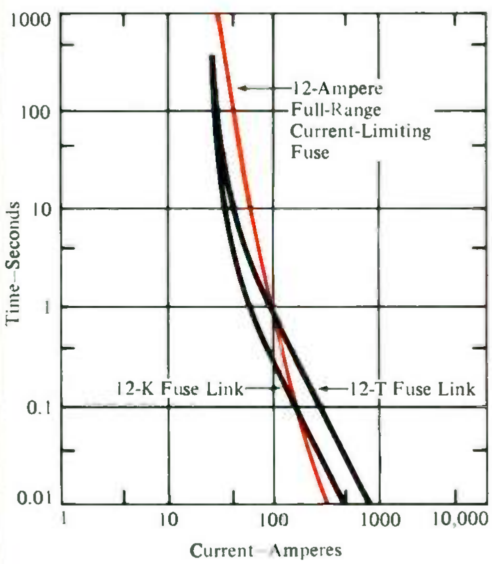
When the available fault current is high enough to cause the current limiter to operate, the maximum expulsion occurs when using the smallest size expulsion link with a given size current limiter. This is caused by a longer period of arcing in the expulsion fuse section before the current limiter becomes fully effective. Even during those conditions, no significant pieces of debris are expelled.

Design Considerations

For appearance, economy, and ease of handling, the FDL and its mounting were made basically the same size as conventional fuse cutouts. Further, to limit capital investment and system uprating costs to the customer, the FDL fuse combination is suitable for direct replacement of the expulsion fuse in Westinghouse LDX and LBU cutouts manufactured since 1962. Such an approach presented some challenging design problems. To accommodate both the current limiter and the expulsion fuse in a cutout-sized fuse package, the current limiter and the expulsion fuse had to be made smaller than anything available. The length of the expulsion tube was reduced by changing the interrupting medium from the commonly used horn-fiber material to a more sophisticated solid boric-acid block liner. This material not only made the arcing time shorter than that of conventional expulsion fuses, but also made interruption more effective and accompanied by considerably less discharge and noise.

Miniaturizing the current limiter required making the most effective use of fuse element, core, and sand fill. Moreover, it was necessary to insure that the current limiter would not partially open during low-current faults and thus be unsuited for subsequent full-load operation. That was done by use of a sophisticated single fuse element, which was a departure from the multiple-element array often used in full-range current-limiting fuses.

No temperature-lowering materials were used on the current-limiter element, as is often done with full-range current-limiting fuses to enable low-current operation. Thus, the current-limiter element is impervious to temperatures less than 900 degrees C, and it either opens completely or remains intact (reuseable) with no question as to its suitability for further service. Thorough testing of the FDL throughout its interrupting range, including many tests at or near the "crossover" point between the current limiter and expulsion link, has either caused the current limiter to open or left it intact and undamaged.



1—The more inverse time-current characteristic of a full-range current-limiting fuse makes coordination difficult with other devices, such as K-link or T-link expulsion fuses. Minimum melting curves are shown for a 12-ampere 8.3-kV full-range current-limiting fuse (color), a 12-ampere K-link (12 K) expulsion fuse, and a 12-ampere T-link (12 T) expulsion fuse.

2—The fused distribution limiter employs a series combination of current-limiting fuse (larger diameter) and expulsion fuse (smaller diameter). The fuse combination is sized for direct replacement of the standard expulsion fuse in all Westinghouse loadbreak and nonloadbreak assemblies manufactured since 1962.

FDL Characteristics and Coordination

The FDL is designed for three-phase applications on 8.3- and 17.1-kV distribution systems. Presently available at 8.3 kV is a 15-ampere current limiter that can be combined with K links rated 6 through 15 amperes, and a 40-ampere limiter for use with K links of 20 through 40 amperes.

The 8.3-kV FDL can be used on 13.8-kV effectively grounded systems to protect single-phase loads connected from line-to-neutral. Also available is a 15-ampere 17.1-kV current limiter for K links rated 6 through 15 amperes; under development is a 40-ampere 17.1-kV limiter for use with 20- through 40-ampere K links. The 17.1-kV FDL is also suitable for single-phase taps of 25-kV systems where maximum line-to-ground voltage does not exceed 17.1 kV. At either of the two system voltages the appropriate 40-ampere current limiters could be used with all link sizes. However, use of 15-ampere limiters, where adequate, reduces both the cost and the amount of expulsion because of the lower rated links used.

The time-current characteristic curves of a fused distribution limiter are plotted in terms of virtual time* in Fig. 3 to illustrate the performance of the current-limiter portion of the device in the subcycle region as well as in the region of longer melting time (up to 0.1 second). For times longer than about 0.1 second, the characteristic is that of the K link alone, permitting coordination with other devices in the normal manner on the basis of the standard 0.01-to-1000-second time-current curves.

Although discussion of the FDL thus far has assumed the use of the popular K link in the expulsion fuse section, the device can be fused with other links as well. For example, a T link can be used. However, since slower fuse links such as the T link have a less inverse characteristic, links of smaller maximum size must be used to assure proper coordination with the current limiter and drop-out action of the FDL. Whereas a 15-ampere K link is recommended as the maximum size to be applied with the 15-ampere limiter, the maximum size of T link for use with that limiter is rated 10 amperes; the maximum size T link that should be applied with a 40-ampere current limiter is rated 20 amperes.

A major benefit of the FDL is its ability to coordinate with other fuses at high fault currents. Consider a circuit in which a single-phase lateral supplies a distribution transformer in addition to various other loads; a standard 15-ampere K-link fuse (15 K) protects the transformer and a 40-K or 100-K link protects the source end of the lateral (Fig. 4a). As shown by the characteristic curves (Fig. 4b), coordination between the 15-K transformer fuse and the lateral fuse exists only for fault currents less than 1400 amperes for the 40-K fuse link or 3900 amperes for the 100-K link. For transformer fault currents greater than those values, the lateral fuse as well as the transformer fuse may operate, resulting in unnecessary outages to the other customers served from that lateral. If an FDL with a 15-K link and 15-ampere current limiter is used at the distribution transformer, it coordinates with the 40-K or 100-K lateral fuse for all values of available fault current up to the 25-kA interrupting rating of the FDL current limiter. The time-current curves in Fig. 3, for example, clearly show that the 15-ampere current limiter would clear high-current faults well before the 40-K link would begin to melt, thus maintaining service to the other customers served from the lateral. The same coordination exists for the FDL and a 100-K lateral fuse.

Test data illustrate the current- and energy-limiting capability of the FDL in minimizing the probability of disruptive transformer failure. Recent tests conducted in the Westinghouse East Pittsburgh High Power Laboratory revealed that when a

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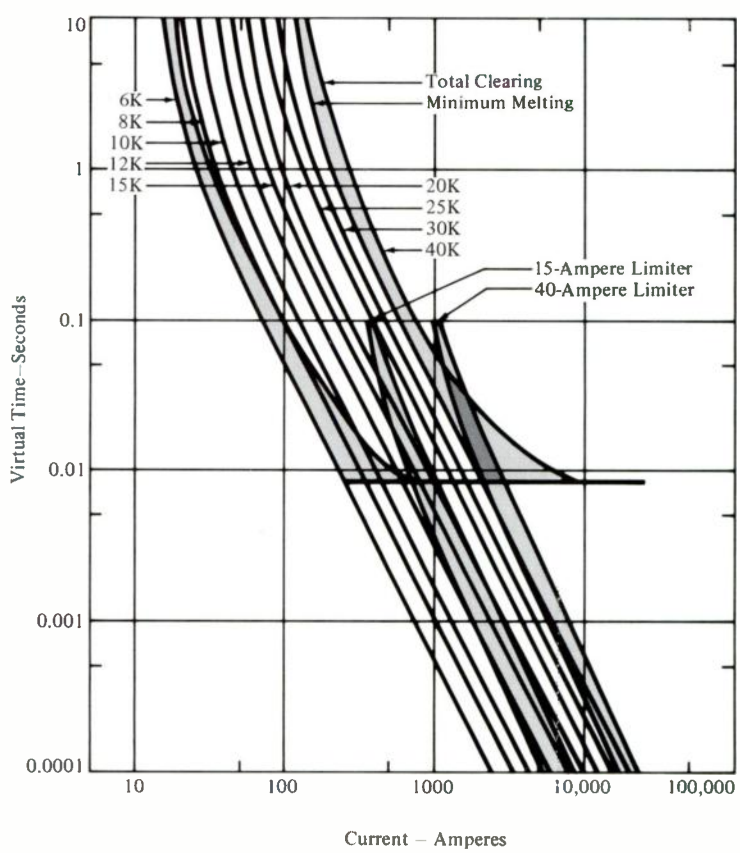


*Virtual time is defined in IEC Publication 282-1, 1968.

transformer prepared with a 3-inch internal arcing fault was protected by a fuse cutout containing a 12-K link, a fault level of only 6500 amperes caused disruptive failure of the transformer. The total energy input was 705,000 ampere-squared seconds. On the same circuit, when an FDL was used, equipped with the same 12-K link, the total energy was limited to only 15,700 ampere-squared seconds with the 15-ampere limiter and to 129,000 ampere-squared seconds with the 40-ampere limiter. In neither case did disruptive failure occur.

Additional Applications

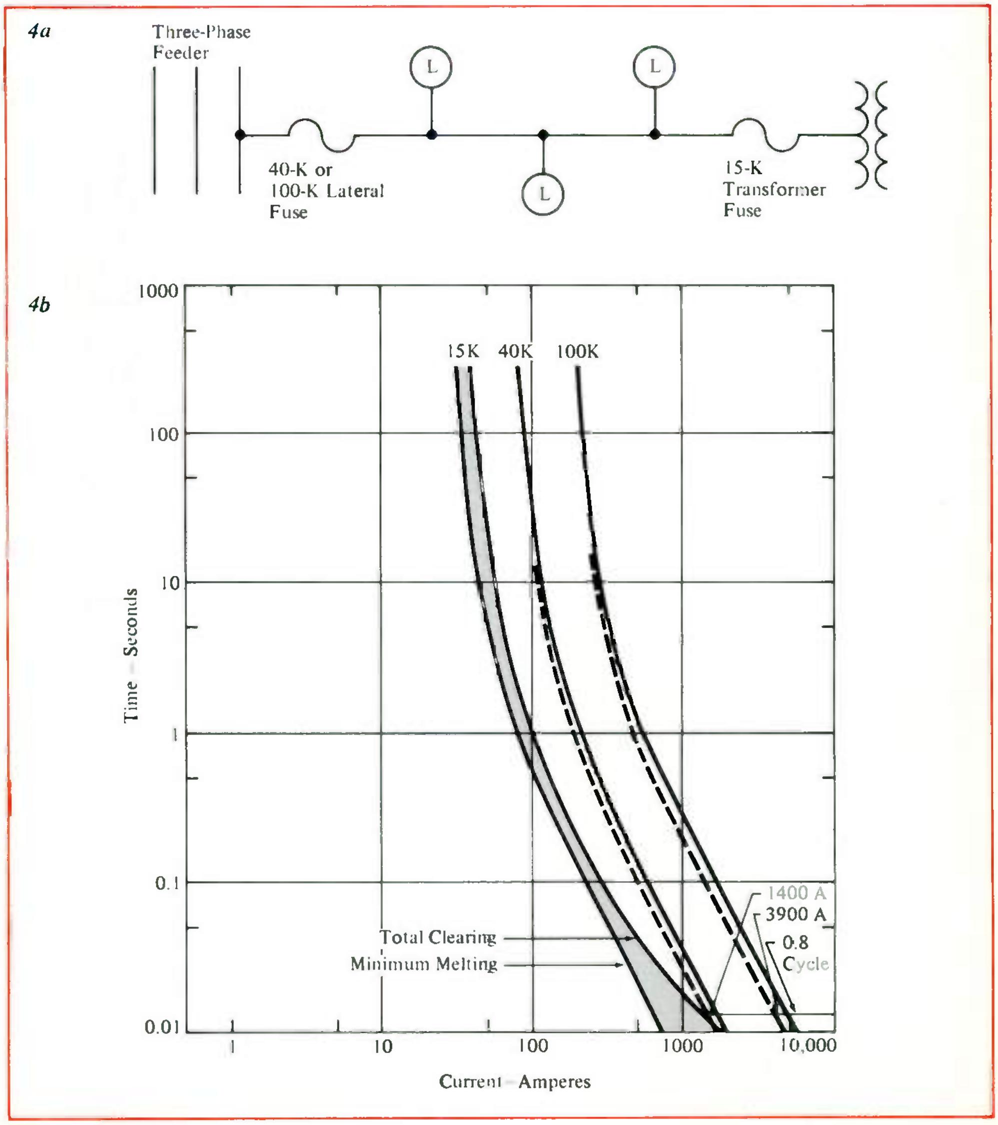
Although the main application for the FDL is protecting distribution transformers, it is also suitable for applications such as protecting three-phase capacitor banks, where power expulsion fuses have often been applied. A three-phase capacitor bank rated 12 kV, 600 kVAR can be adequately protected by three FDL's equipped with 40-ampere K links. Even larger banks can be protected by parallel combinations of the device. Another application is sectionalizing lightly loaded laterals by using an FDL with a 40-ampere current limiter and the necessary size K link.

In all applications, the FDL offers the advantages of high-current interruption, restriction of energy transfer, reduction of fuse expulsion, and a time-current characteristic that facilitates coordination with other protective devices. In addition, only the expulsion link need be replaced for many faults and overloads, making the cost of re-fusing the FDL less than that for a full-range current-limiting fuse.

REFERENCE:
[1]F. L. Cameron and D. R. Smith, "Power Fuse Design and Application," *Westinghouse ENGINEER*, May 1972, pp 87-92.

3—Time-current characteristic curves of the fused distribution limiter (FDL) illustrate its capability for high-current interruption and the less inverse characteristic that facilitates coordination with other devices. For times less than about 0.1 second, the FDL characteristics are those of the current limiter; for times greater than 0.1 second, the characteristics are those of the expulsion link used with a given size limiter. Expulsion K links rated 6 through 15 amperes are used with the 15-ampere current limiter, and K links rated 20 through 40 amperes are used with the 40-ampere limiter.

4—On a typical distribution system (a), *a single-phase lateral might be protected by a 40-K or 100-K expulsion fuse link and the distribution transformer by a 15-K link. Minimum melting and total clearing times are shown for the 15-K link, and minimum melting times and 75 percent of minimum melting times (dashed lines) are shown for the 40-K and 100-K links* (b). *For transformer fault currents greater than about 1400 amperes for the 40-K link or 3900 amperes for the 100-K link, coordination between the lateral fuse and the transformer fuse is lost. Thus, both fuses might operate, causing unnecessary outages to other customers supplied from the lateral. However, proper coordination up to 25 kA can be obtained by replacing the transformer fuse with a fused distribution limiter. As shown in Fig. 3, the 15-ampere current limiter section of an FDL would quickly clear high-current transformer faults, leaving the 40-K lateral fuse intact. Similar high-fault-current coordination exists between the FDL and a 100-K lateral fuse.*



Segregated Phase Comparison Relaying Facilitates Independent-Pole Protection

W. L. Hinman

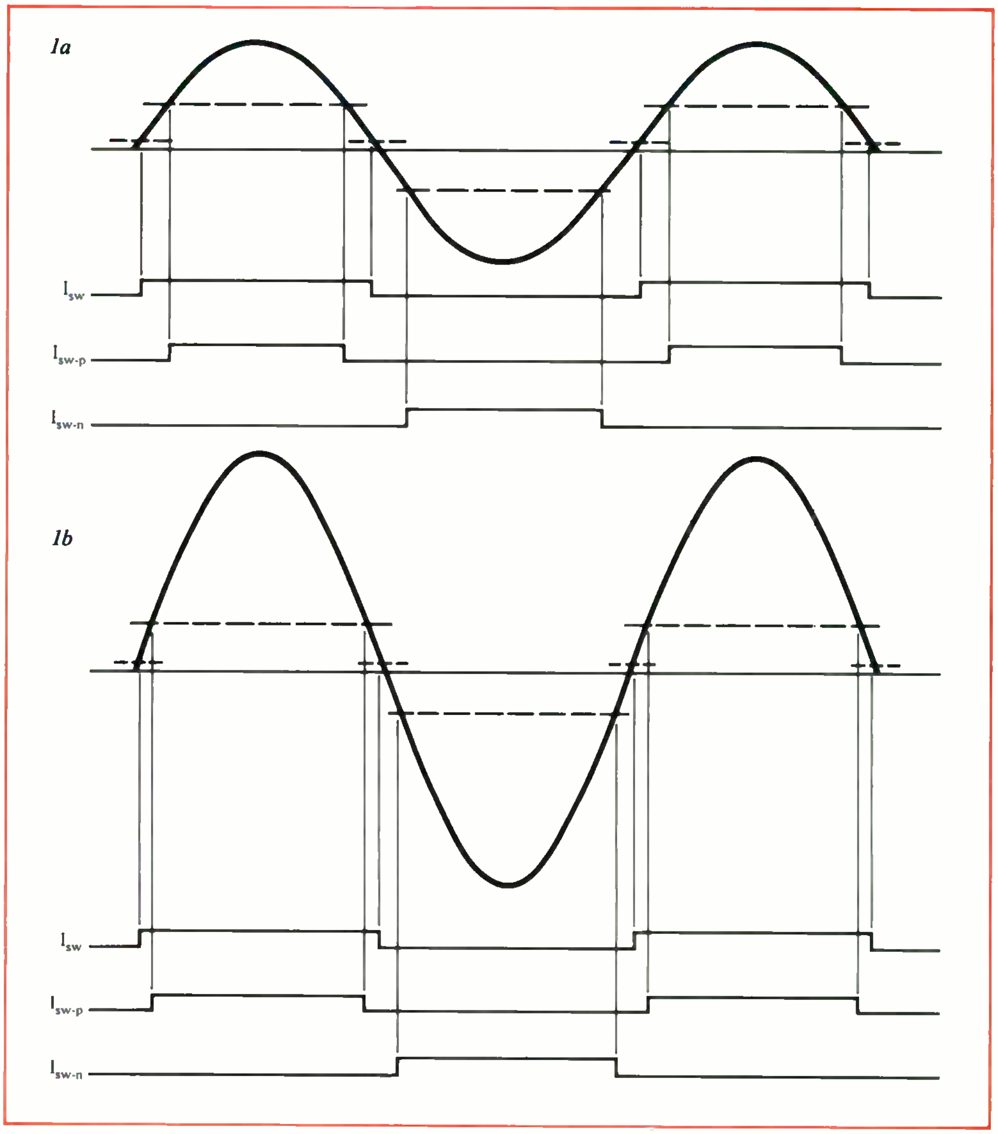
Independent-pole operation of power circuit breakers offers the most realistic solution in the continuing effort to achieve electrical power system stability under the worst-case fault conditions.

The two previous articles in this series[1,2] described the system concepts of independent-pole breaker operation and the relaying technique used to detect and clear the pole disagreement condition. This article, the third and last in the series, describes how a recently developed phase-isolated relaying system extends the concept of the phase-isolated circuit breaker to include the entire protection system (relaying, control circuitry, and breaker) and thereby obtains the ultimate in independent-pole protection.

The fundamental advantage of the independent-pole technique in helping to assure system stability is its ability to *downgrade* the three-phase fault. Avoiding this worst-case condition is achieved by keeping all phases separate and thereby minimizing the chance that a failure of any one element in the protective system would affect the clearing of more than one phase (i.e., pole). By downgrading the three-phase fault to a less severe fault (double-line-to-ground, phase-to-phase, or single-line-to-ground), longer critical fault clearing times are obtained, thus permitting a longer breaker failure time setting and still assuring power system stability.

Segregated Phase Comparison Relaying

The new phase-isolated relaying system, built around the SPCU relay[3], was originally developed to provide a straightforward solution to the many complexities of protecting series-compensated transmission lines. The new system was needed because the use of series capacitors introduces three major problem areas for relays: *abnormal frequencies* above and below 60 Hz are generated during the fault and postfault intervals, *phase impedance imbalance* results from series capacitor protective gaps flash-



1—Square-wave pulse trains are developed from phase- and ground-current wave forms for both positive (I_{sw-p}) *and negative* (I_{sw-n}) *threshold levels. The third square-wave train* (I_{sw}) *is basically derived from the zero crossings of the current wave form and is used for keying the channel transmitter.*

Pulse trains developed by the local relay are compared (Fig. 2b) with corresponding pulse trains from the remote relay; a local timer delays the local pulse train for a period equal to channel delay.

For an unfaulted system with normal load flow, or a system experiencing an external fault, the local and remote square-wave trains are in opposition so that tripping is not allowed. The square-wave coincidence timer (3 milliseconds for phase, 4 milliseconds for ground) provides margin to allow for generator voltage angle difference, dissimilar impedance angles, imperfect compensation of channel delay time, etc.

As seen by comparing wave forms (a) *and* (b), *the higher the current, the squarer the positive and negative pulse trains. The purpose of desensitizing the pulse train for low current is to provide security during the "light crossover" condition that can occur when differential currents (associated with long transmission lines and high line-charging current) are large relative to low through currents. The "light crossover" typically may occur during the clearing of a fault external to a long EHV line.*

When both positive (I_{sw-p}) *and negative* (I_{sw-n}) *pulse trains are compared, the system will allow a trip on either positive or negative half cycle (dual-comparer SPCU). If only the positive square wave is compared, trips are allowed only on that half cycle (single-comparer SPCU).*

W. L. Hinman is a Relay Systems Consultant, Relay-Instrument Division, Westinghouse Electric Corporation, Newark, New Jersey.

ing and reinserting unsymmetrically, and *voltage reversals* are caused by the negative reactance of the series capacitor.

To overcome those three major problems, it was decided to develop a protection scheme that would eliminate positive- and negative-sequence networks and hence not be affected by abnormal frequencies, relay on a per-phase basis to avoid the problems caused by phase impedance imbalance, and relay using current only to avoid the problem of voltage inversion. As a result of the decision to develop a per-phase system, the new relaying scheme originally designed to protect series-compensated lines became a phase-isolated system ideally suited to the independent-pole application.

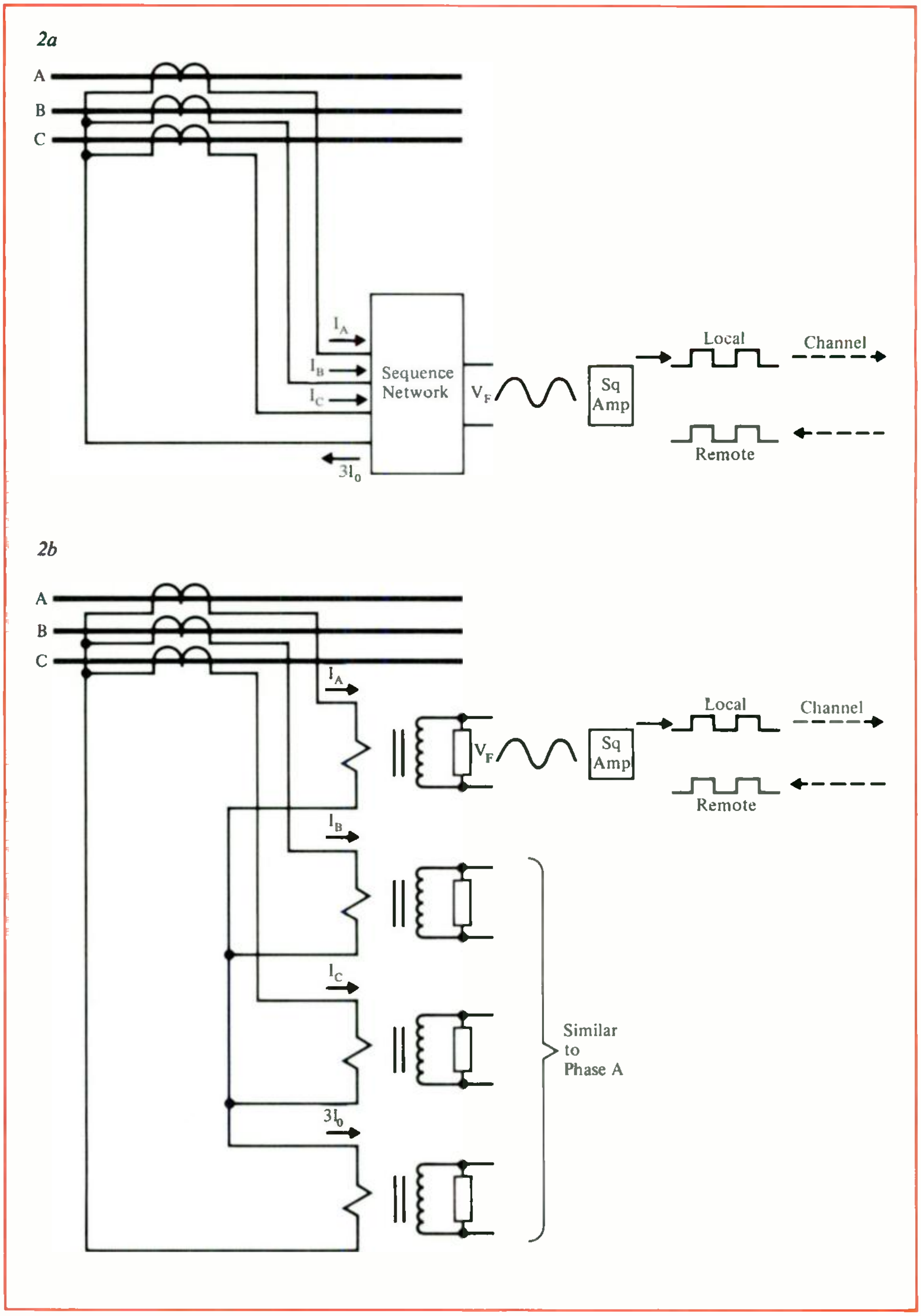
Basis of Relay Operation

Building on the system concepts stated above, the SPCU scheme compares the phase (angular) position of current in each phase (and ground) separately. The comparisons are based on square waves derived directly from raw (unfiltered) power system currents (Fig. 1). This approach contrasts with conventional phase-comparison schemes that compare a single square-wave train derived from a three-phase network of sequence filters and a mixing transformer, as depicted in Fig. 2a. There are many variations of that conventional phase-comparison technique—some use two separate comparisons, one for positive sequence and one for negative sequence. However, all incorporate positive-sequence and/or negative-sequence networks and therefore are vulnerable to abnormal frequencies and phase impedance imbalances.

The new approach, shown in Fig. 2b, consists of four separate subsystems—three phases and ground. The ground subsystem is included to protect against the single-line-to-ground fault with high fault resistance and heavy through-load, and to provide backup detection for all normal ground faults.

The main *disadvantage* of the isolated-phase approach is the requirement for four separate pilot signals (A, B, C, and G) per terminal. However, offsetting that disadvantage are many relaying *advantages:*

1) The SPCU approach overcomes the



2—Conventional phase-comparison schemes (a) *develop local and remote square-wave pulse trains from a three-phase network of sequence filters and a mixing transformer. The new segregated phase comparison (SPCU) scheme* (b) *develops square-wave pulse trains (Fig. 1) for each of the three phase currents and ground current.*

three major problem areas of series-compensated lines—abnormal frequencies, phase-impedance imbalance, and voltage reversals.

2) High speed of operation, due to angle diversity between phases (to be described) and to elimination of the filters required in conventional phase-comparison circuitry.

3) Inherent redundance because the four subsystems back up each other.

4) All the traditional advantages of current-only relaying: not responsive to system swings, not subject to mutual induction problems, unaffected by loss of potential, relays correctly for zero-voltage three-phase faults, and unaffected by potential transients such as subsidence transients associated with coupling capacitor potential devices.

5) Phase isolation, making it possible to extend the independent-pole concept to include the relaying as well as the circuit breaker; this characteristic of phase isolation is central to the theme of power system stability improvement with independent-pole protection (relaying and circuit breaker).

6) Inherent phase selectively for all fault types, which along with phase isolation offers the system designer great flexibility in arranging the relay/breaker trip circuitry to obtain any desired degree of pole-tripping selectivity. Some basic combinations are described later, in the section *SPCU Trip Arrangements*.

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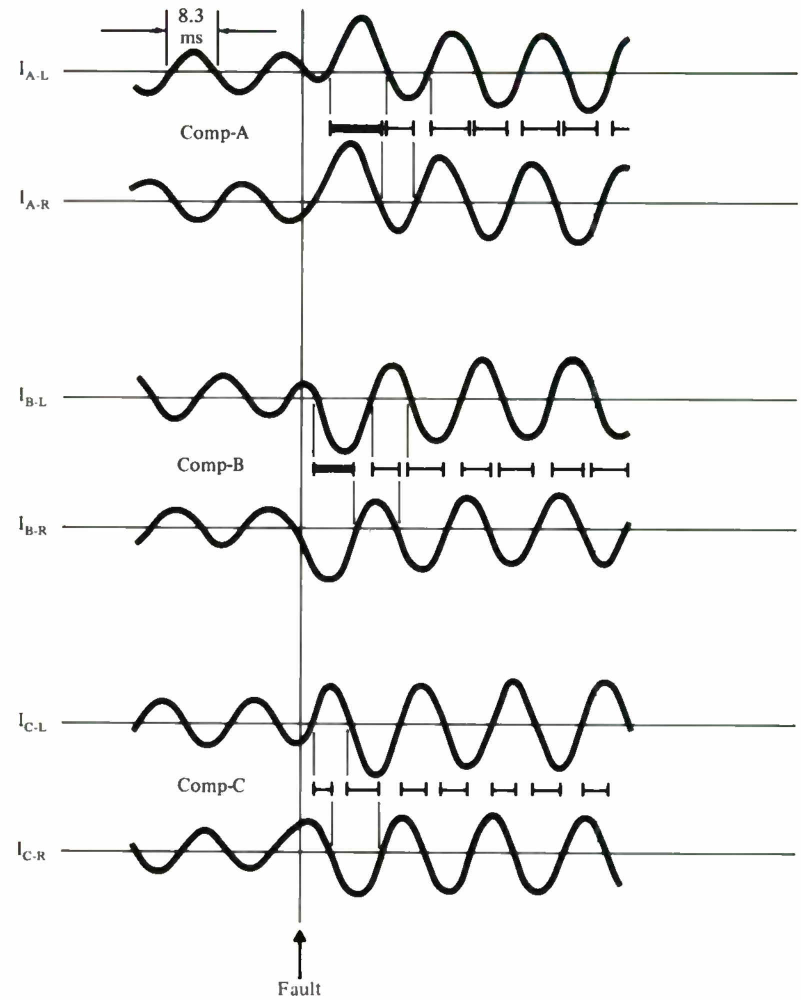

3—Phase-current oscillograms for an internal three-phase fault (generator voltage angle difference of 60 degrees) were developed on the Relay-Instrument Division's miniature power system. Prior to fault, A, B, *and* C *local subsystem square-wave trains developed from local phase currents are in opposition to remote square-wave trains. The three-phase internal fault changes the current phase relationship, causing coincidence periods indicated by* Comp-A, Comp-B, *and* Comp-C. *The nominal coincidence period during best-case (i.e., no generator angle difference, perfect compensation of the channel delay time, etc.) internal fault conditions is 8.3 ms. The nominal steady-state internal fault coincidence period for the condition shown is seen to be approximately 6 ms. Dc offset at fault inception results in longer coincidence periods, of over 8 ms, as indicated by the heavier line segments on* Comp-A *and* Comp-B. *SPCU phase relays are set to allow tripping after 3 ms of coincidence (when in the one-count mode).*

SPCU Internal Fault Sensing

The performance of the SPCU system for internal faults has been demonstrated on the miniature power system at the Relay-Instrument Division. Oscillograms of typical internal faults are shown in Figs. 3, 4, and 5. Even though the demonstration is idealized—it disregards channel delay, assumes zero arming time, and ignores the threshold level effect—it does illustrate the capability of the SPCU relaying system to detect internal faults.

Phase-current wave forms (local and remote) for an internal three-phase fault with the generator voltage angles differing by 60 degrees are shown in Fig. 3. The lines marked *Comp-A*, *Comp-B*, and *Comp-C*

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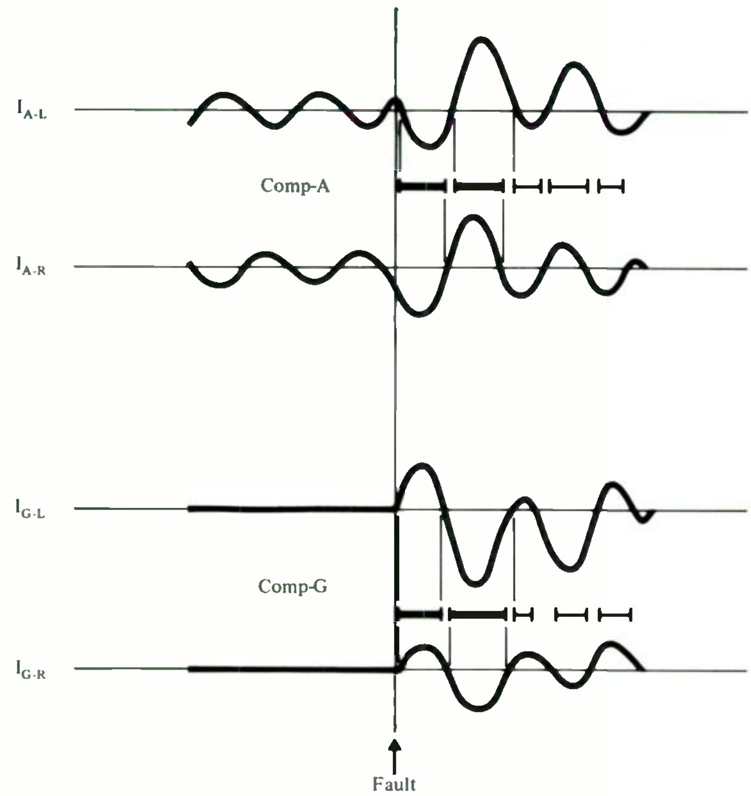

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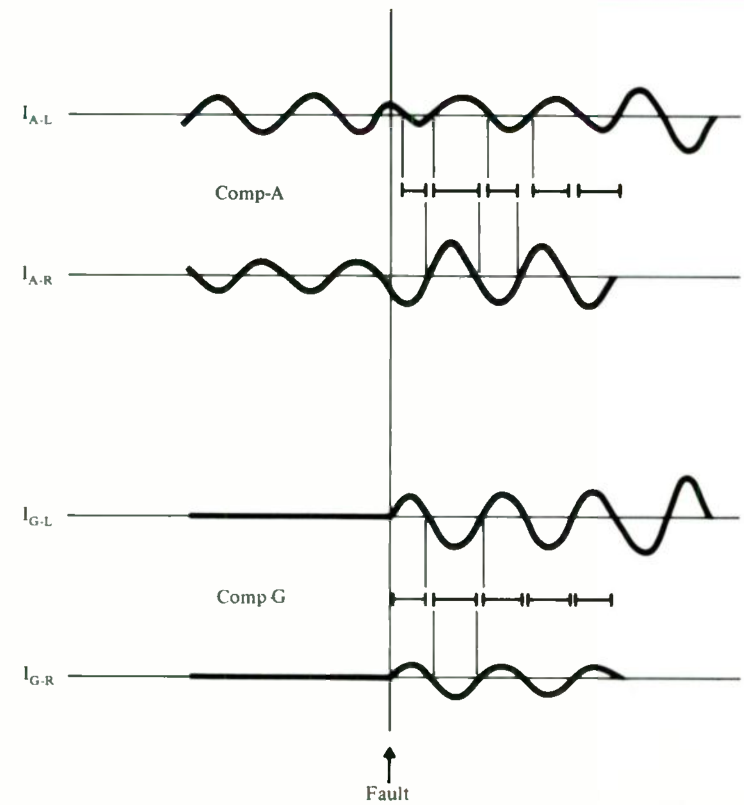

indicate the coincidence intervals of the phase-*A*, phase-*B*, and phase-*C* local and remote square wave trains. The heavier line segments indicate prolonged coincidence periods that result from the dc offset in phase-*A* and phase-*B* currents. The use of unfiltered current as the source of the square waves and the angle diversity among phases helps develop those prolonged coincidence intervals that assure positive and fast tripping during internal faults.

When operated in a "one-count" mode, SPCU comparison logic allows tripping after 3 ms of phase coincidence or 4 ms of ground coincidence. Additional security can be provided with a "two-count" mode, which requires two coincidence periods of more than 3 or 4 ms within 25 ms. However, even for the two-count mode, one large comparison 2 ms longer than the coincidence timer (i.e., 3+2=5 ms for phase or 4+2=6 ms for ground) allows a one-count trip.

A representative internal single-line-to-ground fault is shown in Fig. 4. Only the faulted phase *A* and the ground currents are shown because the unfaulted phases do not develop significant coincidence intervals. Again, low-frequency harmonics and dc offset cause prolonged coincidence intervals in both the faulted phase and ground subsystems, as indicated by the heavy line segments.

A high-resistance (equivalent to approximately 120 ohms at 500 kV) single-line-to-

4—Coincidence intervals of affected current wave forms are illustrated for an internal single-line-to-ground fault. As for the three-phase internal fault condition, dc offset causes long periods of coincidence and assures tripping. Ground current SPCU relay is set to allow tripping after 4 ms of coincidence (when in the one-count mode).

5—An internal single-line-to-ground fault with high fault resistance results in lower faulted-phase coincidence periods because through-current is large relative to fault current. However, nearly perfect coincidence of ground current wave forms assures SPCU relay operation. Although the magnitude of the ground current is reduced by the high fault resistance, the alignment of the ground current is not affected, since it does not contain a through-component caused by load.

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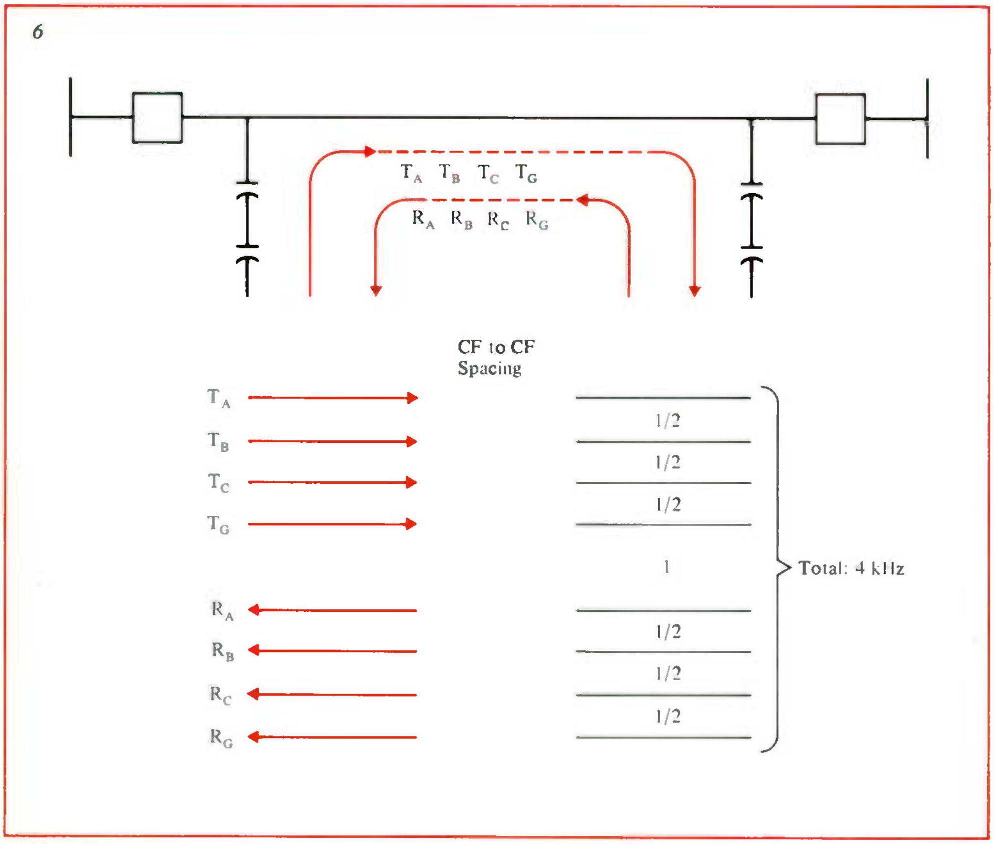

6—Frequency spectrum requirements for the four-subsystem (A, B, C, *and* G) *SPCU scheme using narrow-band TCF power line carrier total 4.0 kHz (for a two-terminal line).*

ground fault is illustrated in Fig. 5. Since fault current magnitude is low compared to that in Fig. 4, through-load causes resultant current wave forms for the faulted phase that no longer line up precisely as an internal fault condition. For the example shown, the coincidence intervals are long enough (approximately 5 ms) to cause tripping, but the phase-A subsystem is approaching a marginal condition. On the other hand, the ground subsystem is unaffected by through-load flow and therefore provides nearly perfect internal fault alignment to assure tripping.

Communication Channel Considerations

The dual-comparer SPCU scheme (comparison of both positive and negative pulse trains) utilizes a three-state (GUARD/TRIP-POSITIVE/TRIP-NEGATIVE) audio tone, type DIT-4. This digitally encoded tone equipment was specifically developed for the dual-comparer SPCU and offers exceptional communications reliability, which includes both security and dependability. The outstanding reliability of the DIT-4 equipment results from the use of parallel-coded tones to provide a high degree of noise immunity as well as the ability to relay properly in the presence of an interfering tone.

Other SPCU-plus-channel arrangements are available (dual- or single-comparer). These include three-subsystem (*A*, *B*, and *C*) schemes and SPCU over TCF power line carrier (narrow-band or wide-band). The four-subsystem narrow-band TCF scheme requires a total frequency spectrum of 4.0 kHz, as measured outer to outer, center frequency to center frequency (see Fig. 6). The four-subsystem wide-band TCF scheme, requiring a total frequency spectrum of 8 kHz, offers the fastest relaying speed—¾ cycle nominal. The three-subsystem arrangements require less carrier spectrum but are not redundant for single-line-to-ground faults. The SPCU relay that is used with TCF power line carrier contains "unblock" logic to supplement the normal phase comparison circuitry and permit tripping for a brief interval after loss of channel.

SPCU Trip Arrangements

Since the SPCU system has inherent phase isolation and faulted-phase selectivity, its output signals can be readily arranged to achieve virtually any degree of pole isolation or selectivity that may be needed to maintain power system stability.

Conventional Tripping—The SPCU system may be arranged to trip conventionally (all three poles for all faults, using mechanically ganged breaker mechanisms). This tripping arrangement is achieved with a four-input OR in the output (Fig. 7). It is primarily applied to the protection of series-compensated transmission lines where breakers with ganged mechanisms are already installed or where power system stability requirements do not dictate the need for fully independent-pole relaying as well as breaker operation.

Independent-Pole—As previously described, independent-pole tripping—three-pole tripping for all fault types with independent breaker mechanisms—minimizes the possibility of a three-pole "hung" breaker. The faults that require the highest

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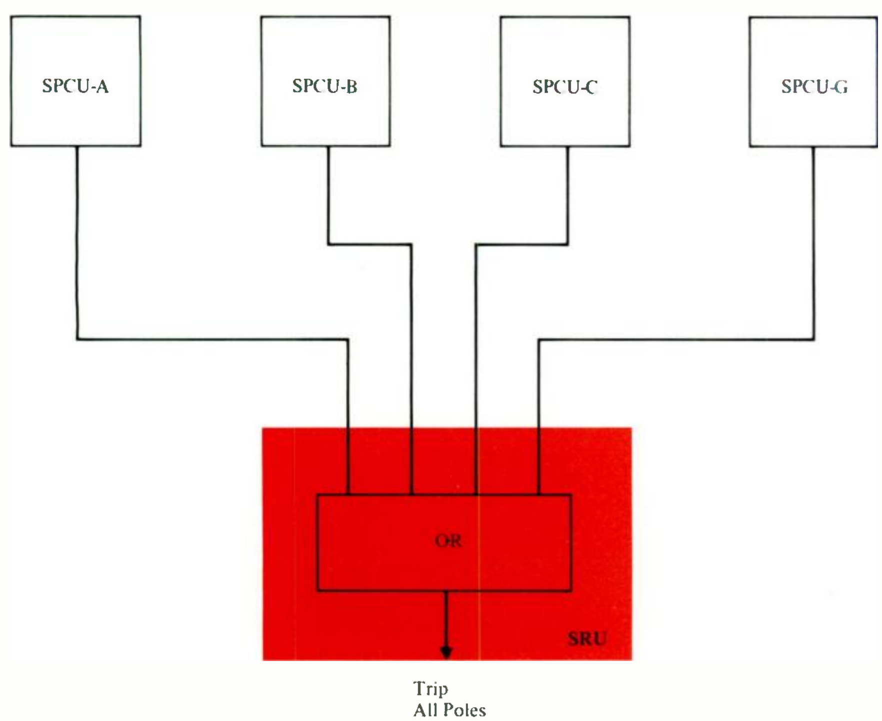

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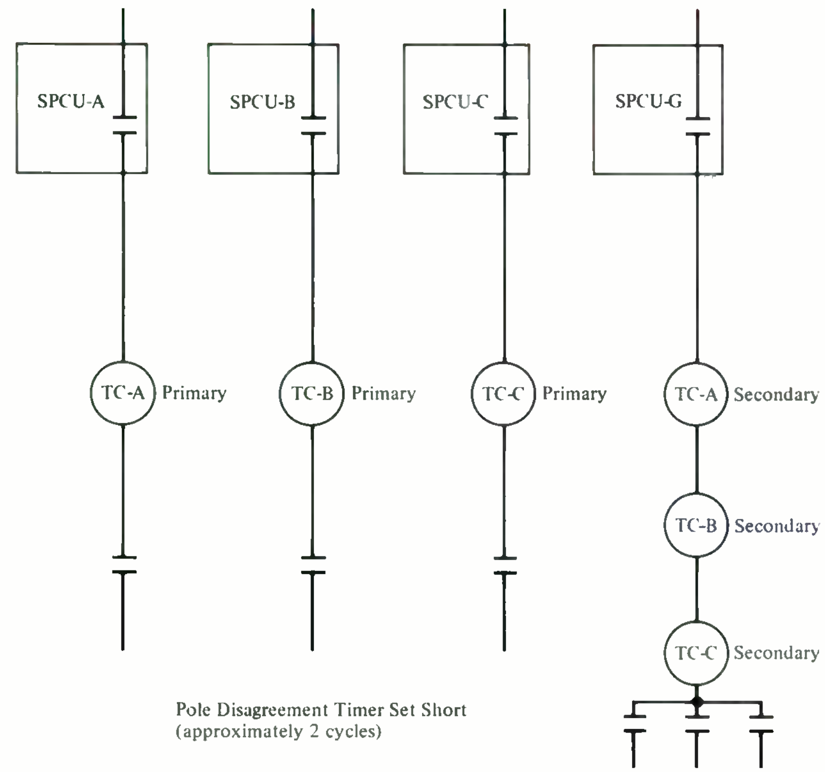


degree of clearing speed and dependability are the three-phase and double-line-to-ground faults. The SPCU system provides multiple (three subsystems) outputs for these critical fault types. Maximum advantage of this redundancy is taken by connecting the relay outputs for independent-pole operation (Fig. 8). This arrangement provides pole separation throughout (relay and breaker) and thereby assures high-speed downgrading of three-phase and double-line-to-ground faults. This allows a relatively slow setting of the breaker-failure timer and still assures system stability, even in critical applications.

Selective-Pole—This method of tripping clears only the faulted phase(s) for *all* fault types so that unfaulted phases (phase) are left in service as a stability tie during the fault-clearing interval. Selective-pole tripping is easily achieved with the SPCU system, as shown in Fig. 9a. The ground subsystem provides time-delay backup for all ground faults (five-cycle delay suggested for two-cycle breaker applications). A modified version of this selective-pole scheme (Fig.

7—SPCU output signals for all phase and ground subsystems are fed to a single OR logic element in the SRU output package to provide a single trip signal for all faults. This arrangement provides "conventional" tripping.

8—For independent-pole tripping, SPCU phase subsystems provide primary relaying, and the ground subsystem provides secondary relaying. This arrangement permits a pole disagreement timer setting of about two cycles.

9b) provides faster (one-cycle) ground subsystem backup.

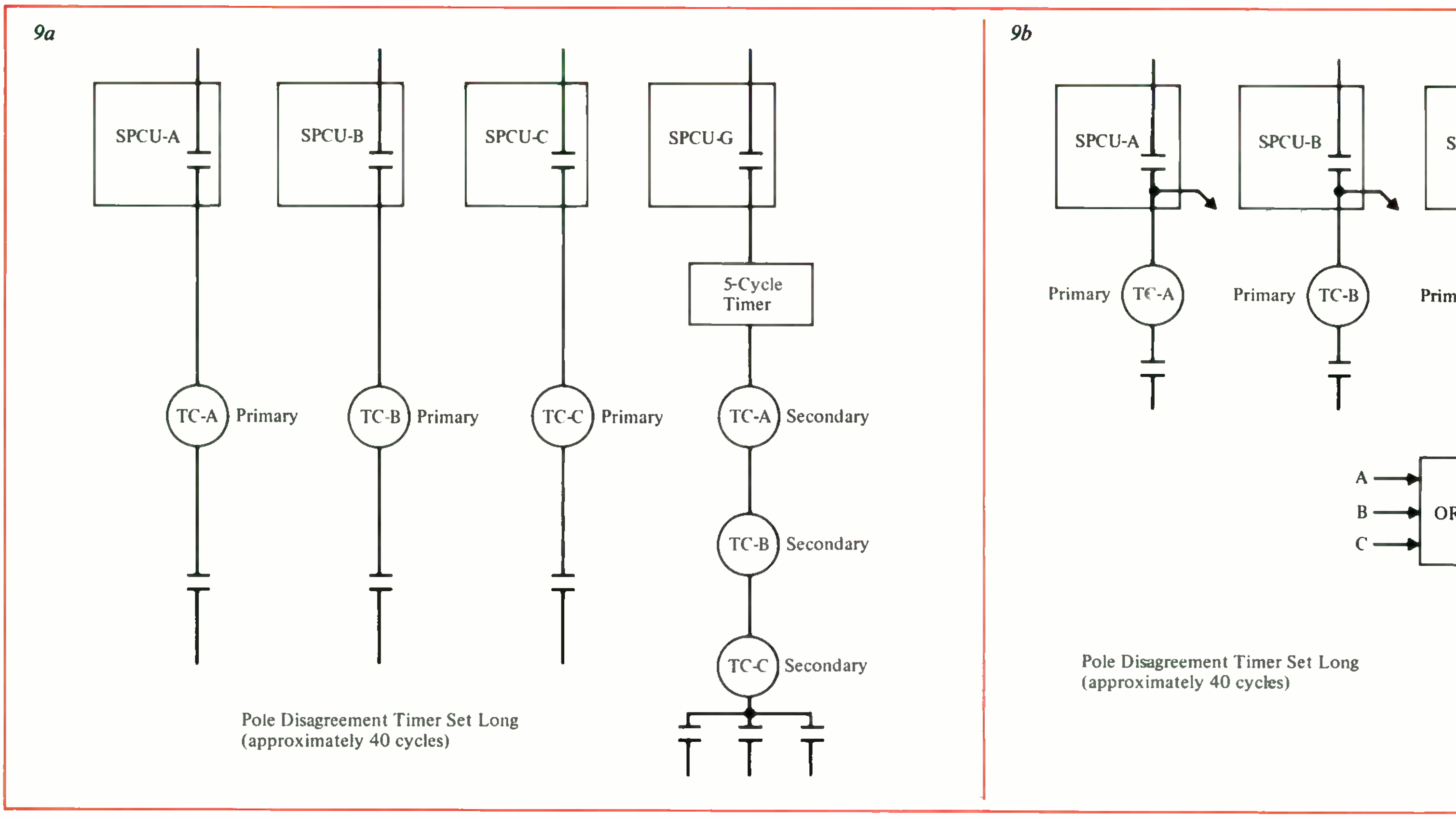
Single-Pole—Selective tripping for single-line-to-ground faults and three-pole tripping for all other faults can also be easily accomplished with the SPCU system. This technique is more conventional than selective-pole tripping, and it can be accomplished with the output arrangement shown in Fig. 10.

Many variations of that SPCU output arrangement are possible. They include special output circuits from each phase SPCU which, when supervised by a ground SPCU output, permit proper phase identification and tripping for high-resistance single-line-to-ground faults.

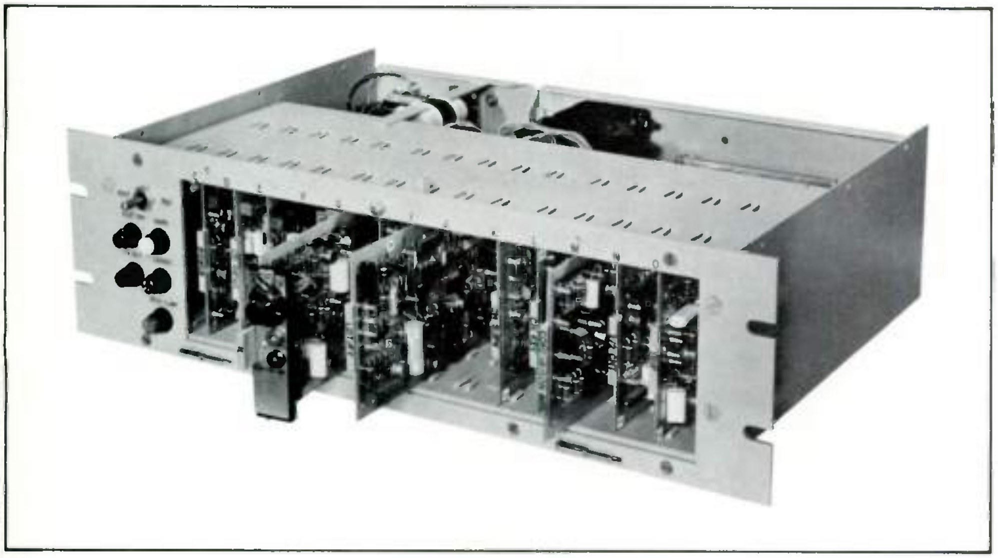
Conclusion

Independent-pole operation of the power circuit breaker minimizes the possibility of a three-phase fault with all three breaker poles stuck. By extending the principle of phase-isolation to include relaying and the associated control wiring, the entire protection system can be put on a per-phase redundancy basis. This technique positively assures rapid downgrading of the three-phase fault, thus lengthening the critical fault clearing time and allowing longer breaker-failure timer settings. For particularly critical power system applications (such as a large remote generator with a single tie line to the major power grid), the isolated-phase concept can be further enhanced by faulted-phase identification, inherent with the SPCU system, to permit selective phase fault clearing. Phase isolation can be implemented, as required, by various arrangements of the SPCU relaying outputs and the breaker trip circuits.

Photo—Front view of a phase subsystem SPCU relay. Each subsystem requires four basic settings: high-set direct trip, low-set current unit, local delay timer, and local threshold level. Hardware is a mixture of operational amplifiers for current-related functions, high-threshold digital integrated circuits for logic, and discrete circuitry for timing and buffering.



9—For selective-pole tripping (a), *faulted phases are tripped by SPCU phase subsystems, and the ground subsystem is delayed to permit fault clearing. The ground subsystem provides back-up for ground faults after this delay (five cycles for two-cycle breaker applications). Pole disagreement timer must be set at about 40 cycles to permit breaker reclosure. A modification of this scheme* (b) *provides faster one-cycle ground subsystem back-up. The OR/AND logic in the modified scheme enables the fast timer if none of the phase subsystems detects a fault within one cycle after ground SPCU operation (as, for instance, would be the case for an extremely high resistance SLG fault that cannot be recognized by the faulted phase SPCU).*



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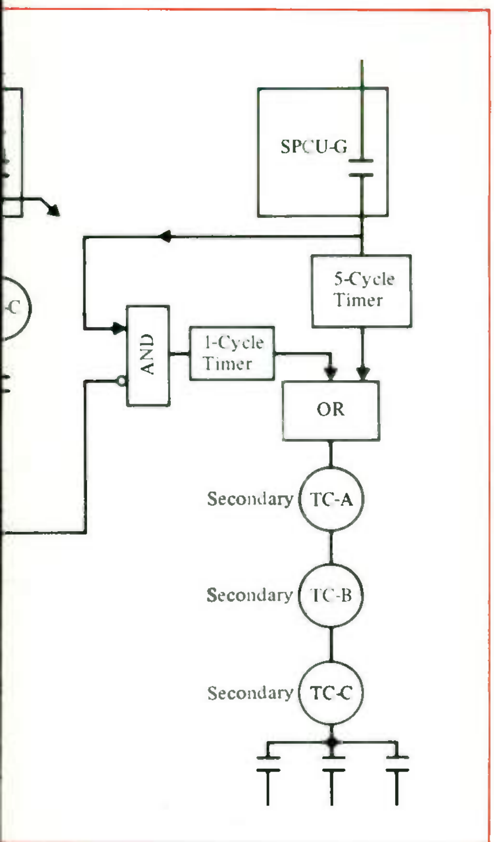
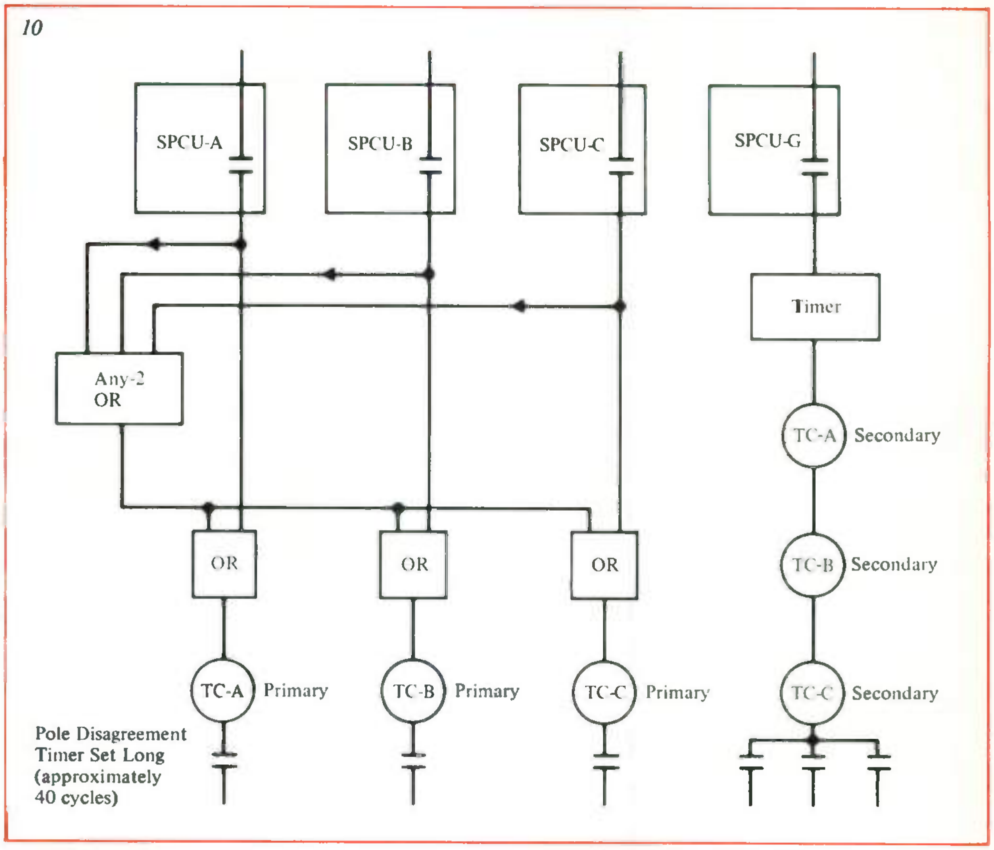




10—One of several variations for providing single-pole tripping is illustrated. This arrangement permits selective tripping of any single-phase-to-ground fault, with ground subsystem delayed to permit fault clearing by the affected phase subsystem. Any other type of fault trips all three breaker poles.

Technology in Progress

Fast Flux Test Facility Takes Shape at Hanford

The reactor containment vessel for the Fast Flux Test Facility (FFTF) is nearing completion at Hanford Engineering Development Laboratory near Richland, Washington. Constructed of 2250 tons of steel, the vessel stands 120 feet high. It will house a sodium-cooled nuclear reactor, test loops, and safety systems. In addition to the containment vessel, the facility will include adjoining structures that will house dump heat exchangers, water and sodium pumps, control and monitoring equipment, and offices.

In the aerial view below, a temporary construction bridge leads to a component access opening in the side of the containment vessel. The smaller circular opening in the vessel will become an equipment air lock for access to the reactor.

The FFTF is scheduled for completion in mid-1975. Experience gained in constructing and operating it will help develop the technologies needed for commercial liquid-metal-cooled breeder reactors. As presently envisioned, those reactors will produce large amounts of electrical power and, at the same time, produce additional fissionable material for fueling other reactors. The Westinghouse Hanford Company operates the Hanford Engineering Development Laboratory for the U.S. Atomic Energy Commission.

FFTF containment vessel is receiving final construction touches while other buildings go up.

Balloon Carries Wide-Area Communications System

A balloon-borne electronic system that can bring radio, television, and modern telecommunications to people in emerging nations is undergoing final test and checkout by TCOM (Tethered COMmunications) Corporation, a Westinghouse subsidiary. At least 15 conventional broadcast and microwave towers would be required to provide the coverage achieved by a single balloon-borne system.

Stability problems and life restrictions prevented much use of tethered balloons for communications until recently, when several technological breakthroughs were made. They include advances in materials technology, computer-aided aerodynamic design, and miniaturization of electronics.

The balloon used for the TCOM system, called an aerostat, resembles a blimp moored to the ground by a cable. It is designed to withstand severe weather conditions such as hurricanes, providing a stable high-altitude platform for the communications equipment.

Several AM radio, FM radio, and VHF or UHF television stations can broadcast simultaneously from the aerostat. Telecommunication capabilities include relaying several thousand channels of stationary telephone, ship-to-shore and mobile radiophone, teletype, telephoto, and analog and digital data transmissions. Navigation beacons can also be transmitted.

The aerostat can support 3500 pounds of transmitting and receiving equipment at altitudes of 10,000 to 15,000 feet. At such altitudes, the system can provide line-of-sight communications to an area of 50,000 to 70,000 square miles. To cover larger areas, information can be relayed from one aerostat to another.

Because the signals are broadcast through free space instead of along the ground, transmitter power requirements are substantially reduced. As an example, the signal strength received at a location 100 miles from a 1000-foot conventional broadcasting tower with a radiating power of 100,000 watts can be equaled with only 3.2 watts from the aerostat-supported transmitter.

A TCOM installation should initially cost about 20 percent as much as a conventional microwave and broadcast-tower system and have less than 10 percent of the operating costs. In addition, the aerostat system can be installed in less than half the time necessary for a conventional network and can be easily relocated if the need should arise.

The aerostat used is 175 feet long and has a volume of 250,000 cubic feet. A diaphragm separates the helium-filled part from the air-filled part, which acts as an expansion chamber for the helium-filled part as the aerostat gains altitude.

The communications package is protected from the elements by a weatherproof

A wide-area broadcasting and telecommunications system for developing countries is carried by a new type of balloon called an aerostat. The system can simultaneously broadcast radio, TV, and other signals.

enclosure on the underside of the aerostat. Electric power is supplied to the equipment by a lightweight engine-driven generator. More than a week's supply of gasoline can be carried by the aerostat. A tether cable that will conduct power to the aerostat from a source on the ground is being developed.

Fractionator/Concentrator Reclaims Valuable Products from Cheese Whey

High-quality protein and lactose are recovered from cheese whey by a new membrane system that includes both ultrafiltration modules to extract the protein and reverse-osmosis modules to extract the lactose. The processed whey has low biological oxygen demand (BOD) and no objectionable odor, so it can either be discharged or recycled in the plant as process water.

Hydraulic pressure is applied to the whey on the feed side of the ultrafiltration membranes (see diagram). The membranes allow the lactose, lactic acid, salt, and water components of the whey to pass through while retaining 95 to 99 percent of the protein (primarily lactoglobulin and lactalbumin) on the feed side. The protein solution has a total solids content of 20 to 40 percent, and it can be used as a supplement in many foods.

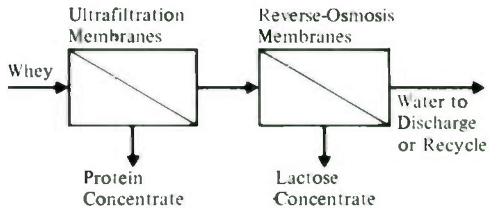
Deproteinized whey from the ultrafiltration modules is fed into the reverse-osmosis modules, where hydraulic pressure reverses the natural osmotic flow of water from the dilute to the concentrated side of the membranes. The membranes allow water and the small amount of lactic acid and salt present to pass through while retaining 98 to 99 percent of the lactose on the feed side, concentrated to a total solids content of 20 to 40 percent. Reclaimed lactose is finding expanded use in pharmaceuticals, infant foods, bakery products, and confections.

The membrane system can be designed to reclaim protein and lactose from either the sweet whey left after block or processed cheese production or the acid whey left after cottage cheese production. If lactose extraction is not desired, the whey can be partially processed by the ultrafiltration modules and then treated by conventional methods to lower the BOD content before disposal.

Both types of module consist of tubular semipermeable membranes bonded to a porous matrix of resin-bonded sand with a protective stainless-steel shell that supports the assembly and collects the processed whey.

The system has been designed to meet dairy industry construction requirements and can be cleaned in place during the normal cycles of operation. The modules have minimal maintenance requirements.

The system is supplied by the Westinghouse Heat Transfer Division. It is shipped in subsystem skids and requires only a few field interconnections, external piping, and electrical connections. After installation, it can easily be expanded to increase capacity. Various control systems are available, ranging from manual to fully automatic.



A typical configuration for a cheese whey fractionator/concentrator system is illustrated by the simplified diagram. The system has been used on a pilot-plant basis, as shown in the photograph, at a number of dairies to provide operating data and to assure conformance with dairy industry regulations. It economically reclaims valuable products while cleaning up dairy plant wastes.

Auto Headlighting Improved by Objective and Subjective Testing

In automotive headlighting, one of the most difficult problems is determining just what constitutes a good system. While instruments can be used to make objective measurements of both light and glare intensity, such measurements made with even the most sophisticated equipment may not agree with a subjective analysis by human beings operating vehicles under varying conditions.

To help in such evaluations, the Westinghouse Incandescent Lamp Division employs a lighting test vehicle that allows both dynamic and static evaluation of several different headlighting systems in quick succession and under different operating conditions. The vehicle's original four-headlamp system can be replaced with ten lamps of comparable size and rating or with six larger lamps such as those used with two-lamp systems. A matrix board allows connection of 20 filaments (ten lamps, two filaments per lamp) in various sequences to develop up to ten combinations of headlighting systems. The board is connected to a switching system beside the driver so that he can conveniently change between the different systems. A two-way radio allows communication between the test vehicle and an observer car to effectively evaluate the glare.

Use of the test vehicle has helped the Division develop an improved four-headlight system with three selections: two-lamp low beam for town driving, three-lamp mid beam for freeway driving, and four-lamp high beam for rural driving.

The system is composed of two dual-filament outboard lamps, a single-filament mid-beam lamp, and a single-filament high-beam lamp. The low-beam filaments of the two outboard lamps provide the low-beam mode. The mid-beam mode is made up of the new mid-beam headlamp plus the high-beam filaments of the outboard lamps (see photo). For high beam, the high-beam lamp is added to the mid-beam mode. The high-beam lamp has about twice the output of one of today's high-beam lamps

The low-beam mode extends total forward vision over present lows, and the beam is less intense and more spread out. Adding the mid beam superimposes light toward the center of the road; seeing distance approaches that of the current two-lamp and four-lamp high beams, but glare is no greater than that of present low beams. The high-beam mode adds concentrated light to the right and center of the roadway, increases illumination, and keeps glare at the level of present high beams. The high-beam filaments of the outboard lamps supply "surround" light to illuminate traffic signs on the side of the roadway.

Shown lighted on the test car are the three lamps that provide the mid beam for a proposed new three-beam headlight system.

Visitors Will Have Transportation at Newest Busch Gardens

A passenger transfer system will transport visitors between the new Busch Gardens and the Anheuser-Busch Hospitality Center at Williamsburg, Virginia, when the family entertainment complex opens in 1975. The automatic system will be capable of carrying 2000 visitors an hour over its 7000 feet of concrete guideway. It is being designed and installed by the Westinghouse Transportation Division.

The theme of the Gardens will be "The Old Country." It will combine educational experience with live entertainment, rides, and attractions on a wooded 300-acre site. Three entertainment nodes are being built as villages recreating the spirit of the towns in England, France, and Germany from which many American settlers came. Also featured will be the Busch Gardens Bird Circus, the Anheuser-Busch Clydesdale horses, trained animal shows, a 60-acre lake, and rides, shops, and eating facilities.

A train on the passenger transfer system will consist of two 90-passenger rubber-tired cars. At a speed of 30 miles an hour, a complete loop on the track will take less than five minutes, including stops. Half of the loop will be elevated on steel superstructures with concrete columns; the remainder will be at ground level.

The system will employ the Transit Expressway technology consisting of electrically powered rubber-tired vehicles operating under automatic control. Similar but larger and more sophisticated systems are in operation at the Tampa and Seattle-

Tacoma airports, and another is being built for the expanded Miami International Airport. Other applications are foreseen in such places as shopping centers, office complexes, and college campuses.

Advanced Steam-Turbine Test Facilities Being Installed

A major turbine development program at the Westinghouse Steam Turbine Division includes construction of the world's largest full-scale turbine test facility.

The new installation, to be completed by 1976, consists of a transonic cascade facility to determine the aerodynamic characteristics of new airfoil designs proposed for low-pressure turbine blading; a steam tunnel facility to evaluate the performance characteristics of low-pressure blades subjected to flow conditions that occur during off-design turbine operation; a single-stage aerodynamic facility to evaluate the influence of blading profiles, stage geometry, and flow conditions on the performance of low-pressure turbine stages; a small-scale multistage turbine test facility to verify design criteria and predict performance levels of individual and combined turbine components; and a large-scale multistage turbine test facility to verify both thermodynamic and mechanical design performance predictions for low-pressure blading under a wide range of operating conditions.

The large-scale test facility will be built with the cooperation of Philadelphia Electric Company and will use steam from that utility's Chester generating station. It will provide the ability to duplicate operating conditions, which is essential in verifying turbine designs and performance.

Frequency Changer Will Facilitate Use of Two Power Frequencies

Many large industrial plants that generate their own electric power do so at 25 hertz. The trend is toward greater use of purchased 60-hertz power, but it is often uneconomical to convert utilization equipment (mainly large motors) for 60-hertz operation. One steel mill is solving the problem by ordering a large static frequency changer from the Westinghouse Industry Systems Division. The frequency changer will be similar to an electric-utility high-voltage dc transmission system, except that the transmission line will be very short and different frequencies will be used at the two ends. It will be rated at 25 MW and will utilize 2500-volt thyristors of 50-mm diameter.

The static frequency changer will consist of five sections: a 60-hertz transformer, a 60-hertz to dc static converter, a dc link, a dc to 25-hertz static converter, and a 25-hertz transformer section. The frequency-conversion power flow can go in either direction, so a description of operation for one direction is valid for the other.

For the 60-hertz to 25-hertz flow, 60-hertz power at supply voltage level (138 kV) is transformed to the link voltage (4160 V). The transformer has two secondaries with a 30-degree phase displacement between them (one wye and one delta) so that 12-pulse rectifier operation can be effected, thereby achieving some ac harmonic cancellation. The transformed 60-hertz power from each transformer secondary goes to its own three-phase bridge converter for controlled rectification to direct current at approximately 4000 volts. The direct current flows through smoothing and isolating reactors to the inverter section, where another three-phase bridge converter provides controlled inversion of the dc power to 25-hertz power. The 25-hertz power is transformed from the link voltage (4160 V) to the utilization voltage (7200 V) by two transformers. These transformers are also connected with 30-degree phase displacement between the secondaries to achieve the effect of 12-pulse inverter operation.

The frequency converter will be operable either in a "fixed-power" mode or in a "floating" mode.

In the fixed-power mode, the voltages of the "sending-end" converters (rectifiers) and the voltages of the "receiving-end" converters (inverters) will be adjusted in response to a fixed power-reference signal. When ac system voltages on either side vary, the appropriate changes in rectifier-inverter gating angles will be made so as to maintain constant power flow through the link. Because of the essential symmetry of the system functioning, reversal of power flow will involve basically only a reversal in rectifier-inverter function.

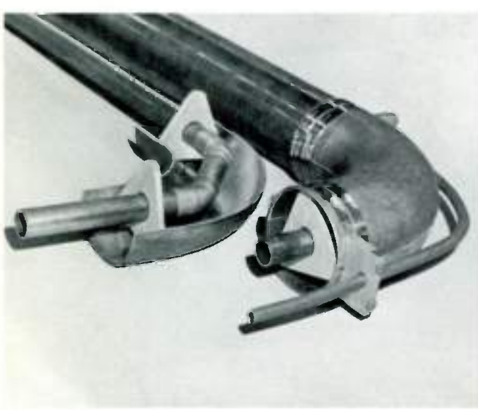
Operation in the floating or "swing" power mode is similar except that the power reference signal will vary continuously in response to the receiving-end load requirements rather than being preset and fixed.

Operation under abnormal conditions will be facilitated by the high speed and flexibility of the static control system. Current limit control of the dc link will protect against overloads. Protection against a dc fault or an ac fault in the converter equipment or on the immediate ac system buses is provided by gate pulse suppression. Protection and ride-through for less severe faults on the ac systems is provided by a coordinated reduction in the dc link voltage and current.

Products and Services

Groundgard system, consisting of a ground-fault relay and a current sensor, protects motors from destructive arcing ground faults. It is suited to installation in motor control centers and high-voltage starters. Tripping of the relay causes an operating mechanism such as a circuit breaker to trip and isolate the ground fault from the line. Among the options available are two types of relay: type GR operates instantaneously, and Type GRT incorporates an adjustable time delay. Both have reliable solid-state circuits and are self-powered by the fault current. Relay contacts are available both tripped open and tripped closed. Current sensors, which are window-type current transformers, are available in different window sizes. An optional test panel for testing the sensor and relay is also available. *Westinghouse General Control Division, 4454 Genesee Street, P.O. Box 225, Buffalo, New York 14240.*

RF transmission line for use with induction-heating generators can be quickly assembled on site to suit specific requirements. It is designed for low impedance, so voltage drop is only about a fifth that experienced with ordinary copper-tubing transmission line. The line is available in straight sections of various lengths, 45-degree bends, and 90-degree elbows, all with 4-inch outside diameter. *Westinghouse Industrial Equipment Division, P.O. Box 300, Sykesville, Maryland 21784.*



RF Transmission Line

"Catalog of Courses," 1974 edition, lists management and professional training and development courses available to business, industry, and government organizations. It also gives a brief description of subject matter and defines the learning objectives. More than 90 courses are included, covering such subjects as behavior, business environment, finance, management, skills development, presupervision, and problem solving and decision making. *Training and Development Division, Westinghouse Learning Corporation, Westinghouse Building, Pittsburgh, Pennsylvania 15222.*

Voltage-sensitive relay, Type PVR, protects three-phase electric motors and driven equipment from damage resulting from phase reversal and phase unbalance. It also protects against phase failure in most applications. The relay is designed for connection directly to a three-phase supply with no external power source necessary. When the supply is operating normally, the relay is picked up. If phases reverse, become unbalanced, or a phase is lost, the relay drops out and disconnects the motor or other equipment. A second electrical contact can be used to activate an alarm. A 2-second time delay safeguards against tripping caused by momentary voltage dips characteristic of normal motor start-up. Solid-state sensing circuits insure reliability and long service. Relays are available for 60-Hz supplies ranging from 120 to 600 volts and for 50-Hz supplies from 110 to 550 volts. They can be supplied either as open type for panel mounting or in a wide range of enclosures. *Westinghouse General Control Division, 4454 Genesee Street, P. O. Box 225, Buffalo, New York 14240.*

Voltage-Sensitive Relay

SR line of condensing units now extends from 7.5 to 80 tons with the addition of 50-, 60-, and 80-ton models for larger commercial and industrial air-conditioning applications. The air-cooled units feature industrial-duty compressors that are fully hermetic to improve reliability and performance and to seal out contaminants. Compressors are designed for low sound and vibration levels, and low-ambient control allows operation down to 0 degrees F. Direct-driven fans draw air through the bottom of the condensing units and discharge it upward. Protective devices include a lockout circuit, three compressor overload relays, high- and low-pressure cutouts, a pressure relief device, and motor winding thermostats. *Westinghouse Commercial/Industrial Air Conditioning Division, P. O. Box 2510, Staunton, Virginia 24401.*

Behavioral science approach helps industry deal with problems related to human behavior such as failing to comply with safety regulations, lagging productivity, high job turnover, and high rates of absenteeism. Specific diagnostic instruments such as worker health surveys, safety attitude surveys, and job safety analysis inventories are used with interviews of workers, union leaders, and management to determine the reasons for problems. The solutions suggested are based on the behavioral sciences, including organizational psychology and ergonomics (human engineering). A cost/benefit analysis of all the potential solutions is made to help determine the effectiveness of each solution. *Westinghouse Behavioral Safety Center, American City Building, Columbia, Maryland 21045.*

About the Authors

Daniel P. McFadden graduated from Villanova Jniversity in 1959 with a BSEE degree and soon became a Registered Professional Engineer in the tate of Maryland. He spent nine years at the Westinghouse Aerospace Division. As a Senior Engineer he was responsible for designing automatic test equipment and conducting environmental qualification tests on aerospace equipment, which included fire control systems, Gemini endezvous radar, and the Apollo television amera.

After two years away from Westinghouse, luring which time he worked in the sale of elecronic instrumentation, minicomputers, and comuter terminals, McFadden returned to the Westnghouse Steam Turbine Division. There he is n Advanced Engineer in control systems reponsible for defining and specifying all electrical nd electronic equipment required for the operaion of a large turbine generator.

3. H. Murphy graduated from the University of daho in 1949 with a BS degree in chemical engiteering. He joined Idaho Power Company as an ndustry representative in sales engineering. In 951, he moved to General Electric Company s an advertising account executive for the elecric utility industry. He became Manager, Adverising and Sales Promotion, for the company's ocomotive and car equipment department in 1956.

Murphy joined Westinghouse in 1960 at the ormer Standard Control Division, where he erved as Manager, Advertising and Sales Pronotion. He transferred in 1962 to the Computer ystems Division, a predecessor of the present Computer and Instrumentation Division, as an pplications engineer for computer control sysems. He is now Manager, Marketing Comnunications.

Richard E. Putman graduated from Paddington Technical College, London, in 1945 and joined Blaw-Knox Ltd. as a design engineer for earthnoving and concrete machinery. In 1947, he noved to James Gordon & Co., Ltd., to work as n instrument designer and systems engineer, ater becoming Assistant Chief Engineer. He also aught strength of materials and theory of machines t Hendon Technical College during that period, nd he was elected a chartered mechanical engiteer in 1952.

Putman joined Evershed and Vignoles Ltd. in 953, a manufacturer of analog control systems. As Manager, Power Plant Application Engineerng, he pioneered the engineering and commissionng of the first electronically operated power-plant ystems in North America (Newfoundland and Alberta, Canada) and also the first comprehenive electronic control system in the beet sugar ndustry. He became the company's resident ngineer for western Canada in 1958 and installed ome of the first lease automation systems for Mobiloil.

In 1960, Putman joined Elliott-Automation Ltd., a systems engineering firm, as Chief Engineer first of its James Gordon Division and then of its Swedish Division. He moved to The Austin Company in 1964 as Supervising Engineer in the Sydney, Australia, and Cleveland, Ohio, offices, responsible for development of taconite and chemical plants.

Putman joined Westinghouse in 1965 at the Hagan/Computer Systems Division, now the Computer and Instrumentation Division. There he has served in various engineering capacities related to development and application of process control and information systems. Among the projects he has contributed to are systems for industrial energy management, control of gasoline-truck loading terminals, process controls in various industries, and plant simulation including a training simulator for nuclear power plants.

Frank L. Cameron earned a BSEE from the University of Wisconsin in 1951 and joined Westinghouse on the graduate student training program. His first assignment was with the Switchgear Distribution Apparatus Department, where he worked on design and development of oil switches, reclosers, sectionalizers, and fuse cutouts. In 1958, he moved to the Assembled Switchgear and Devices Department to work on power fuses for motor starters and transformers.

Cameron assumed his current position of Manager, Fuse Development, Switchgear Division, in 1969. He is responsible for design and application of current-limiting and expulsion fuses and, most recently, the fused distribution limiter. Cameron holds 20 patents in his specialty and has been awarded the Westinghouse Order of Merit.

David R. Smith received a BSEE in 1963 from Pennsylvania State University, and in 1968 he earned his Master's degree from the University of Pittsburgh. He joined Westinghouse in 1963 on the graduate student training program and later worked as a distribution engineer for the Electric Utility Headquarters Department (now the Distribution Systems Department). In 1965, Smith transferred to the advanced development section to work on utility short-circuit, load-flow, loss-formula, and stability studies. He returned to distribution engineering in 1967 to work on design and application of grid and spot networks and application of fuses.

Smith's current responsibilities as a distribution engineer include working with the distribution divisions and utility customers on system problems and equipment application. He helped develop the sequence sensor for the network protector test kit and has developed a computer program to simulate simultaneous shunt and series unbalance in three-phase systems.

Joseph A. Carey, Jr., graduated from Purdue University in 1958 with a BSEE degree, and he earned an MBA from Lamar University in 1968. While in the U.S. Navy, he served as an instructor for the Guided Missile School.

Carey joined Westinghouse in 1960 on the graduate student training program. He worked as a power systems field salesman until 1968, when he transferred to the Transmission Business Development Department, Power Systems Planning, to work in long-range transmission planning. He became Sales Manager for lightning arresters for the Distribution Apparatus Division in 1970. Two years later at that division, Carey was appointed to his current position as Product Manager of cutouts, lightning arresters, switches, reclosers, and circuit breakers.

Walter L. Hinman is a Senior Design Engineer in the systems consulting group of the Westinghouse Relay-Instrument Division. He joined Westinghouse in 1955 upon graduation from Lehigh University (BSEE). After completing the graduate student training program, he was assigned to the relay design group of the Relay-Instrument Division. His principal assignment there from 1956 to 1962 was the design of distance relays. He participated in the development of some of the first static relays developed by Westinghouse, such as the SL broken conductor relay, the TD-4 and TD-5 timing relays, and the SD-1 and SD-2 distance relays.

Hinman moved to the systems consulting group in 1962, where his major assignment has been the application of pilot relaying to protection of transmission lines, particularly in the area of phase-comparison relaying. He has also worked on the application of breaker-failure relaying.

He received his MSEE from Newark College of Engineering in 1962.

Westinghouse Electric Corporation
Westinghouse Building
Gateway Center
Pittsburgh, Pennsylvania 15222

A Westinghouse nuclear reactor system rated at 1100 MW has gone into operation at Commonwealth Edison Company's Zion nuclear power station, Zion, Illinois. It is housed in the reinforced-concrete containment structure at right. A similar unit, in the structure at left, is scheduled for operation early this year.