Application of Peer-to-Peer Communication for Protective Relaying

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***Abstract*—This paper presents a series of protective relay applications that use peer-to-peer communications to transmit data among protective relays and other intelligent electronic devices (IEDs). Applications are selected from various categories such as transmission line, transformer, breaker, bus, substation, and distribution feeder.**

***Index Terms*—Power system communications, protective relaying.**

I. Introduction

THE ADVANCEMENT of digital protective relaying technology allows high-speed communications among protective relays. When relays can communicate with each other, they can share information which can enhance the overall protection of the power system. Peer-to-peer communications using local area network (LAN) technology (fiberoptic, metallic, or wireless) is being deployed in substations in North America and other sites around the world [1]. In some of these installations, protective relays are using a LAN as the high-speed media for the control, interlocking, and tripping of circuit breakers.

The purpose of this paper is to describe the possible application of peer-to-peer communications technology to power system protection. This paper presents only a subset of applications described in the report [2] "Application of Peer-to-Peer Communications for Protective Relaying" prepared by the IEEE PSRC H5 working group to the Communications Subcommittee of the PSRC.

The application examples assume that a communications media exists between IEDs and that the IEDs can communicate with each other. Each application example includes a description followed by a list of IEDs involved and parameters required which include expected input/output signals and settings. Note that specific implementations may vary from these guidelines. Performance requirements such as the response time and the accuracy of measurements are also discussed and finally the benefits such as improved protection, cost savings, space savings, etc., are discussed.

These generic application descriptions can be applied irrespective of the communications technology (software protocols, hardware media, device object models, etc.) being applied in a specific protective relaying application.

One example from each of the six categories of power system protective relaying applications *viz*, (transmission line, transformer, breaker, bus, substation, and distribution feeder) is described. Several other applications can be found in the report [2].

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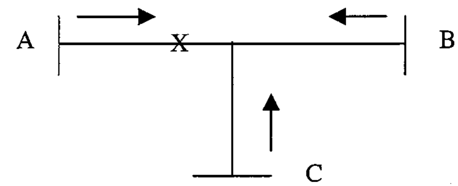

Fig. 1. Internal fault.

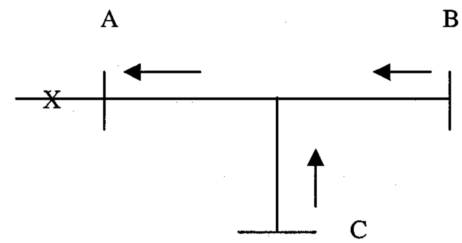

Fig. 2. External fault.

II. Peer-to-Peer Communication Applications

A. Transmission Line Application

Transfer Trip and Directional Comparison Tripping:

Description: In this application, LANs in three substations and a corporate wide area network (WAN) are used for teleprotection functions on a three-terminal line. The scenario assumes IEDs at each end that can determine the direction of the fault from all ends of the protected line.

The first scenario (Fig. 1) assumes a fault occurs that is within the forward reach of all three terminals. The second scenario (Fig. 2) assumes that the fault occurs just behind Terminal A (outside the three-terminal line) but inside the forward reach of the relays at terminals B and C.

IEDs Required at Each Substation:

- Two line relay IEDs (if redundant protection is required).
- Substation LAN and substation Host.
- LAN/WAN Bridge/Router connected to the WAN.

Parameters:

Inputs (Scenario 1):

- From line relay IEDs (local substation A): Forward fault state change messages to substations B and C when fault is detected.
- From line relay IEDs (remote substation B): Forward fault state change messages to substations A and C when fault is detected.

- From line relay IEDs (remote substation C): Forward fault state change messages to substations A and B when fault is detected.

Inputs (Scenario 2):

- From line relay IEDs (local substation A): Reverse fault state change (blocking) messages to substations B and C when fault is detected.
- From line relay IEDs (remote substation B): Forward fault state change messages to substations A and C when fault is detected.
- From line relay IEDs (remote substation C): Forward fault state change messages to substations A and B when fault is detected.

Outputs (All Using LAN Protocol):

From Substation A

- State change messages (forward or reverse fault) to substations B and C when faults are detected.
- Under no-fault conditions, guard (keep alive) messages to substations B and C at specified intervals.

From Substation B

- State change messages (forward or reverse fault) to substations A and C when faults are detected.
- Under no-fault conditions, guard (keep alive) messages to substations A and C at specified intervals.

From Substation C

- State change messages (forward or reverse fault) to Substations A and B when faults are detected.
- Under no fault conditions, guard (keep alive) messages to substations A and B at specified intervals.

Settings:

- Normal reach settings on line relays.
- Refresh interval for guard messages (i.e., 1 second, 10 seconds, etc., user's choice).

Performance Requirements: Total LAN/WAN time, from the issuance of a state change message by a protection IED to its receipt and message processing time in both remote substations: *Less than 15 ms under worst-case WAN-loading assumptions*. This time is based on typical PLC or audio tone channel times in existing applications. *Note: May require a means of prioritizing such protection messages on the WAN*.

Benefits/Hardware Replaced:

- Allows use of corporate WAN for teleprotection.
- Replaces hardware related to audio tone channels.

B. Transformer Application

Differential Protection:

Description: The pickup and slope of a percentage differential relay are set to prevent relay misoperation due to transformer magnetizing current, CT ratio mismatch, transformer tap changing, and CT saturation during through faults. The transformer ratio can change by as much as $\pm 10\%$ due to load tap changer (LTC) operation. In order to prevent misoperation of the differential relay, the slope must be set much higher than 10% when the transformer is equipped with an LTC. Setting the slope of the percentage differential relay to higher values reduces the relay sensitivity for turn-to-turn and high-resistance faults in the transformer. The transformer ratio error introduced by the LTC operation can be digitally corrected in the differential relay if the tap position of the LTC is known to the differential relay.

IEDs/Devices Involved: Transformer differential relay, LTC control or tap position sensor.

Parameters:

Inputs/Outputs: Tap position is the output from the LTC control (or tap position sensor) and input to the transformer differential relay. Dynamic range of the tap position is -16 to 16, 1 to 33, or another range specific to the tap changer. The range should be within -128 to $+127$ and fit in a single 8-bit byte.

Settings: Slope 1 setting is used when the CT ratio correction for tapchanger operation is operational and Slope 2 setting is used when the CT ratio correction for tapchanger operation is not operational.

Performance Requirements: The accuracy of the tap position measurement is not critical for this application. Typically, ± 1 tap is achieved with the present technology. The tapchanger of an LTC transformer typically takes more than 1 second to move from one tap to the next after a tap change command is issued; therefore, a response time of 0.25 s is acceptable.

Evaluation Requirements:

- Transformer relay should identify the LTC control or tap position sensor connected on the same transformer.
- Check if the transformer tap position is correctly being read by the differential relay and the differential relay percent slope is set to Slope 1.
- Simulate a communications failure and check to see if the differential relay slope is reset to Slope 2.

Benefits/Hardware Replaced: Higher sensitivity of differential protection is achieved.

C. Breaker Application

Breaker Failure:

Description: Breaker failure is the condition of a breaker which, when called to trip, fails to interrupt the current flowing through the breaker. Breaker Failure Initiation (BFI) is issued in conjunction with a breaker trip signal. BFI then starts a timer (typically 7 to 15 cycles). If, at the expiration of the timer, current is still flowing through the monitored breaker, a "Breaker Failure" trip is then issued. This trip signal is to be logically "sealed in." If the breaker current falls below the reset threshold or a breaker change of state is detected, a "Breaker Failure Reset" is issued. A Breaker Failure Trip can affect as little as one breaker or as many breakers as are connected to a bus (10 to 20).

IEDs/Devices Involved:

- protective relays;
- breaker controllers;
- breaker failure relay.

Parameters:

Inputs (Unsolicited):

- BFI (per Phase/3 Phase);
- breaker current (1 cycle RMS);
- 52 A/B.

Outputs:

- list of breakers to trip—local;
- list of breakers to trip—remote;
- list of breakers—retrip;

- list of “new” breaker failure breakers;
- list of recloses to block;
- list of other functions to perform;
- SOE log entry.

Settings:

- BFI time;
- minimum current sensitivity;
- fault type/fault severity.

Performance Requirements:

- timer accuracy: $\pm$4 ms;
- current measurement resolution: 0.1 A;
- communication response time: $<$8 ms.

Evaluation Requirements: The protective relays should send a breaker “X” protective trip message to the breaker failure relay. The time period between when the protective relays send the message and when the breaker failure relay responds should be within the performance criteria stated.

The breaker failure relay then begins to acquire breaker current magnitude and breaker status data. The current should be reduced below the current detector threshold and/or the breaker status change state before the breaker failure time delay expires. The breaker failure relay must receive this information and not issue a “breaker failure” Trip message. If the breaker failure relay does not receive this message and causes a trip, the scheme has failed.

Once the breaker failure relay issues a “breaker failure” trip message, only the appropriate breakers as determined by the tripping list (local and remote) must operate. The timing of when the breaker failure relay sends the message to when each of the breaker control IEDs respond should be within the performance criteria stated.

Benefits/Hardware Replaced: A LAN implementation of the above eliminates a separate timer/current measurement function, a breaker failure lock-out relay and all the wiring associated with it.

D. Bus Application

Fast Bus Overcurrent Trip:

Description: It is desirable to provide high-speed protection for bus faults. The normal method for this has been to use differential protection due to its high selectivity and therefore high speed. In applications where the cost of differential protection is not warranted, protection of the bus is often provided by overcurrent relays on the bus mains. Normally in this case, the coordination interval required to coordinate with the feeder relays would lead to clearing times in the order of 400 to 500 ms or more.

In applications where the loads on the bus are fed radially, as is typically the case on distribution and often sub-transmission, the fast bus overcurrent trip method has been gaining popularity. In this scheme, the feeder protection relays must signal their status to the bus main relay. When a fault occurs on a feeder, both the feeder relay and the bus main relay will detect it. The bus main relay is set with a time delay only long enough to give the feeder relay time to signal that it has detected the fault also.

If the bus relay does not receive the signal (indicating that the fault is not on a feeder and therefore on the bus), it trips. This high speed blocking scheme allows the bus relay to trip much faster than if it had to rely on traditional coordination intervals.

In this scenario, the assumption is made that feeder protection is adequately redundant so that reliable detection of feeder faults can be assumed.

IEDs/Devices Involved:

- feeder overcurrent relays;
- bus overcurrent relays.

Parameters:

Inputs (Unsolicited):

- Feeder relay protection picked up status: A, B, C, N and Q (negative sequence) from each relay on each feeder on the bus.
- Messages for both set and reset of these points should be included. There should be a periodic refresh time for each point.
- Feeder relay fault type identifier: AG, BG, CG, AB, BC, CA, ABC, ABG, BCG, CAG from each relay on each feeder on the bus.
- Feeder breaker failure status from each relay on each feeder on the bus.

Outputs:

- Bus main breaker trip.
- Bus main breaker close block.
- Messages for both set and reset of these points should be included. There should be a periodic refresh time for each point.
- Bus fault alarm.
- Feeder breaker trip (optional in this radial application).
- Feeder close block (required if feeder breakers are tripped).
- Messages for both set and reset of these points should be included. There should be a periodic refresh time for each point.
- Sequence of events recorder (SER) log event entry.
- Trigger command for fault recording of each circuit into and out of the bus.

Performance Requirements:

- The speed of the pickup message from the feeder relays governs how long the bus relay must be delayed which affects how fast a bus fault can be cleared. Pickup message should be sent and acted upon within 8–20 ms.
- The relays must be capable of identifying the faulted phases or have independent phase protective elements.
- The relays must have programmable logic capability.

Evaluation Requirements: It should be possible to inject current into the bus main and feeder relays simultaneously and determine that a message to trip the bus main breaker is not generated. Simulation of simultaneous and evolving faults should also be done to verify dependability and security.

Benefits/Hardware Replaced: One limitation of current implementations is that hardwired logic limits the number of bits of information that can be exchanged between the feeder relays and the bus main relay. In an evolving fault or during simultaneous faults, the logic can get mixed up and cause a misoperation. The benefit of this implementation is that the bus relay can know which feeder is signaling and which phases are faulted. Thus, if the bus relay detects that a fault exists on both A and B phases, but it is only signaled that a fault exists on A phase of a feeder, it could determine that a bus fault exists on B phase and trip. In existing schemes, it would be blocked.

- This logic currently requires use of output relays on the feeder relays hardwired to contact sensing inputs on the bus main relay. The number of inputs and outputs on each relay could be reduced making these devices more compact and less expensive.
- Extensive interconnect wiring and auxiliary relays could be eliminated.

E. Substation Applications

Interlocking in Utility Substations:

Description: Interlocking refers in general to the mechanisms for blocking or permitting the operation of a particular power-switching device (circuit breaker, disconnect/isolator switch or earth switch), based on the status of other switches or of control and protection functions. The most common applications are discussed here.

Interlocking Breakers, Disconnect Switches, and Earth Switches: High-voltage disconnect switches are not capable of safely closing on or interrupting loads in the circuits they isolate. These operations are the task of the circuit breaker. Untimely disconnect operation can draw rising, uninterrupted arcs which can merge or reach grounded structures to cause faults.

Accordingly, the opening and closing control circuits of motor-operated disconnect switches are often interlocked with contacts reflecting the state of the circuit breaker and related earth switches. In other words, if the breaker and the related earth switches are open, it is safe to operate the disconnect; a closed breaker or earth switch blocks disconnect switch operation.

Breaker 52b contacts can be used for interlocking disconnects. However, breaker auxiliary contacts can be troublesome. An IED monitoring breaker state can better determine the state using both 52a and 52b contacts. A safer but rarely used supplemental approach is to base the interlocking on sensitive current-flow measurement (line charging current) in the breaker CT.

Switching of voltage to earth or vice versa should be prohibited. Therefore the opening and closing of earth switches are often interlocked with contacts reflecting the state of the related disconnect switches. In other words, a closed disconnect switch blocks earth switch operation.

Interlocking Breaker Closing Circuits and Substation Relaying Zone Operations: Faults or failures other than those on transmission lines are generally permanent, and are presumed to be permanent until investigated by personnel and determined to be clear. The most common of such events include the following.

- Bus fault.
- Transformer fault.
- Breaker failure following tripping command for any type of fault.
- Fault in freestanding current transformer, or other apparatus whose frame-to-ground current is monitored for protection.
- Received transfer-trip command, triggered by one of the just-listed events at a remote station requiring local breaker tripping.

If any of these occur, the relay operates a control scheme, which trips some number of circuit breakers to isolate the problem. The tripping command is sustained indefinitely to the breakers, although it is ignored by the breakers once they have opened. In addition, the interlocking or lockout portion of the scheme blocks or interrupts the breaker closing circuits so that an operator cannot inadvertently energize the permanently-faulted zone.

To remove the interlocking or lockout, a separate purposeful action must be executed. An operator visits the substation site, investigating the fault or failure and taking responsibility for deciding that the fault condition has been cleared. The operator must then exert a purposeful action to remove the lockout condition or clear the interlocks in the control scheme. This unblocks the closing circuits of each breaker, and removes the sustained tripping command. It does not actually close the breakers; each must be individually closed by a local or remote operator.

Present-Generation Implementation: Typically, a differential or other relay protecting against substation faults and failures has only one or two trip contacts. The relay must trip a number of breakers and separately block their closing circuits; it may also need to transfer-trip breakers at a remote station via communications. The task is handled by a large electromechanical multitrip switch, whose tripping solenoid is energized by the relay and which operates a large bank of contacts, both normally-open and normally-closed. Operating time is on the order of one power cycle. The force of a heavy spring then holds the contacts in the operated state until an operator twists a panel-mounted handle to reset the switch. Newer electronic versions are available with faster operation.

> *Note*: *This is done differently in Europe where interposing relays or software are used to trip various breakers. The closing of breakers is prohibited until the trip condition is removed*.

One such lockout switch is normally used for the output of each relay. When the relay trips, it energizes the lockout switch to trip all necessary breakers and key transfer-trip channels, keeping those trip circuits closed so that the breaker will trip free if a close by any means is attempted. Furthermore, normally-closed contacts of the lockout switch, in series with the closing circuits, open to block any possibility of breaker closing either by normal breaker control switches or by remote operators working through SCADA.

A particular relay with its lockout switch yields a specific interlocking pattern, which can be executed independently of, and at the same time as, any other such pattern.

Important: Note that each breaker in the station may be asked to trip by any of a number of differential or breaker-failure relays. Accordingly, the close circuit of such a breaker will have a number of lockout switch normally-closed contacts in series, any one of which can block closing.

The breaker cannot be closed unless ***all*** *zone interlocks or lockouts have been reset*.

Interlocking via Substation LAN: Important requirements to capture in LAN-based peer-to-peer communications design include the following.

1) Users can specify an *action table* or list of tripping, sustained tripping, keying, or blocking actions to be executed for breakers, switches, and channels. This has been

hard-wired by users in the past, but now require the ability to enter lists of actions in the substation control system, in the field, probably via normal relay setting procedures. Dozens of actions may be required for the trip of one differential or breaker failure relay function. The majority of these may need to go over the LAN in an all-LAN substation control scheme.

2) Trip-commands and close-blocking commands must be sustained by the executing IEDs until an operator checks the site and purposefully resets a zone lockout through a local IED interface. (This must be sustained by the executing IED during a remotely adjustable time. If the time is set to infinite (or zero) a reset of a zone lockout is done either locally through a human machine interface (HMI) or remotely by means of the EMS/SCADA system.)
3) The zone lockout state memory must be nonvolatile.
4) For each breaker, the knowledge of which zones have lockouts in effect must be individually tracked or flagged, so that closing is not possible until each and every one is cleared. A single shared flag for lockout state of a breaker is not acceptable. (If the lockout flag is shared, internal logic should be available within the IED to assure that a reset of the lockout condition is only possible when all zone lockouts have been removed.)
5) A number of designs for the broadcasting of lockout state knowledge in a LAN environment are possible.
   a) The information may be distributed to the executing IEDs.
   b) All interlocking data can be kept in the database of a dedicated interlocking server, through which all closing commands must be passed or checked.
   c) Both methods can be used together with periodic crosschecking and rationalization logic. This scheme is more tolerant of possible messaging errors and maintenance activities (e.g., replacement of a failed breaker-control IED).
   d) In any case, the selected scheme must consider the possibility of a race between a LAN-transmitted blocking command, and an unanticipated close command from another source. The blocking should be in effect by the time the breaker has completed its tripping operation, so that a forbidden close operation will be denied by the interlocking.
6) As explained above, for a given breaker there must be a distinct zone interlocking block flag for each zone or protective function which trips and blocks the breaker. All must be reset to allow closing.
7) Similar rules and design approaches apply for disconnect switches, whose opening or closing operation is blocked when an adjacent circuit breaker is closed.

Note (*Belonging to items 2 and 3*): *It is not necessary to sustain a trip command if the close blocking is done by the receiving breaker or switch*.

IEDs/Devices Involved:

- All protective IEDs.
- All breaker control IEDs.

Parameters:

Inputs:

- Power system values (e.g., voltage on earthing switch).
- Protection states.
- Equipment status.

Outputs:

- Block/unblock states for each interlocked device.
- Non-volatile state memory for state changes.
- Latching output contacts.
- State change history.

Settings:

- Interlocking logic.

Performance Requirements:

- Status update on change of state of any interlocking parameter should be delivered in less than 16 ms.

Benefits/Hardware Replaced:

- Major savings can be achieved in design, wiring, and mostly in design changes. Interlocking of simpler systems can now be performed due to the simplicity of implementation. The present status of the entire system is easily monitored as well as easy archiving of state change information.

F. Distribution Feeder Applications

Distributed Generation on Utility Feeders:

Description: A customer (Merchant Generator) has installed generation at their facility and has capacity in excess of their load. The facility is served from a utility feeder that has only a few other customers on it with a total load less than available generation from the customer.

The utility would like access to this extra generating capability at times when capacity resources are low and will request customer to operate its generators. To maximize generation availability, the customer must run its generators in parallel with the utility feeder. This parallel operation and the likelihood of back-feeding into the utility's feeder bus suggests that a method of changing the characteristics of the utility's feeder overcurrent relay be adopted to backup the feeder fault detecting function of the customer's main circuit breaker protection.

IEDs/Devices Involved:

- Multifunction overcurrent relays.
- Multiunit I/O devices.

Parameters:

Inputs:

- Customer generator circuit breaker(s) status.
- Customer main circuit breaker(s) status.
- Utility feeder circuit breaker status.

Outputs:

- Trip customer main circuit breaker(s) via transfer trip over LAN/WAN connections.
- Block utility feeder breaker local or remote closing.
- Block utility feeder breaker auto-reclosing.
- Customer's equipment status into utility SCADA via LAN/WAN.
- Status of transfer trip channel.

Settings:

- Normal feeder configuration (no generation or customer main circuit breaker open).
- Normal overcurrent settings, normal reclosing sequence.

- Abnormal feeder configuration (generators are on-line and customer main circuit breaker closed).
- Modify feeder and customer's overcurrent relay settings.
- Feeder closing and auto-reclosing block.
- Trip customer main circuit breaker if utility experiences a trip on its feeder breaker.

Performance Requirements:

- Exchange of data to be completed within 0.2 s.

Benefits/Hardware Replaced:

- Use of peer-to-peer communications replaces dedicated communication link and I/O interface hardware.
- No need for costly dedicated transfer trip channel from utility substation to customer breaker.
- Logical elements can reside within the overcurrent relay rather than with external logic elements.
- No need to establish line-side voltage source for synchronism check or voltage block closing.
- No separate SCADA needed at customer's site.

III. Conclusion

A series of possible applications of peer-to-peer communications for protective relaying is presented in this paper. These applications promise a variety of benefits, which include improved overall protection, reduced cost of the protection scheme, reduction in wiring and space savings. Some of these applications are currently implemented and operating in North America and other parts of the world.

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