FUNDAMENTALS AND ADVANCES IN BREAKER FAILURE PROTECTION

INTRODUCTION

One of the most difficult jobs of the protection engineer is contingency analysis. When plying his trade, the protection engineer must hold Murphy's Law at the same stature as Ohm's Law. The design and setting of the protective relaying system must account for what will happen for any type of fault that can occur on the power system and any type of failure that can occur in the power system protection system.

Many people involved in power system design and operation understand how their protective relaying systems operate when everything is working as it should. The real key to being a good protection engineer is to know how it operates when everything is *not* working as it should. To do this, a thorough understanding of each part of the protective system and how each interacts and overlaps is required. This depth of knowledge only comes with experience.

Fortunately, protection standards in most organizations have developed from many years of experience and ensure that adequate redundancy is designed into the protective schemes—allowing the new engineer the ability to do good design work while gaining this experience.

Breaker failure protection is a subset of the larger topic of contingency analysis and backup protection. Articles that discuss specific protection topics, such as generator or line protection, usually cover the subject of backup and overlapping of protective elements within the context of each topic. This paper will discuss backup protection in general and what issues need to be considered in deciding whether to apply dedicated breaker failure protection. It will then discuss breaker failure relays and how they work. Finally, consideration will be given to backup tripping logic.

DO I NEED BREAKER FAILURE PROTECTION?

Local Versus Remote Backup

For the purposes of this discussion, it is important to reiterate the obvious distinction between fault detection devices and fault interruption devices. The protective relays provide detection of power system disturbances such as faults. The circuit breaker interrupts the fault current or otherwise isolates the power system when called upon to do so by the relays. With the exception of series trip reclosers and fuses, these are separate and distinct functions that need to be considered in contingency analysis.

In applications where dedicated breaker failure protection is not applied, fault detection failure and fault interruption failure are often considered as the same contingency because there is no way to differentiate between the two. In this case, the normal technique for dealing with contingencies is to apply coordinated, overlapping relays tripping different devices. This is often referred to as remote backup because, in many cases, the coordinated, overlapping relays and their associated breakers are at different locations.

In applications where dedicated breaker failure protection is applied, it is possible to differentiate between the two types of failures in designing for contingencies. In this case, the failure of the fault detection function is generally covered by using redundant relay systems. Failure of the primary relay system is covered by the alternate relay system so reliable fault detection is assured for any single contingency failure. Similarly, for the fault interruption function, the circuit breaker is the primary fault interruption system and the breaker failure protection system is the alternate fault interruption system. Again, we have reliable fault interruption for any single contingency failure. The use of redundant relay systems with breaker failure protection is often referred to as local backup because the role of remote relays is minimized.

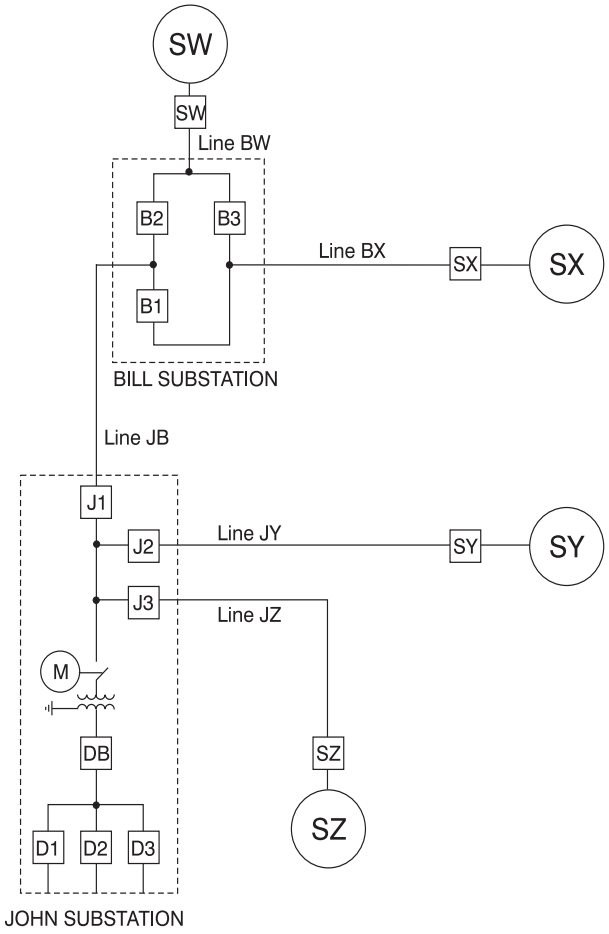


Figure 1: System 1 Line Diagram

For example, let's consider the networked system illustrated by the one line diagram in Figure 1. For the contingency of failure of breaker J3, all adjacent circuits need to be tripped. If we are using remote backup, we would need to rely on the relays at Substation Bill, Source Y, and Source Z to detect the uncleared fault and trip to isolate the failed breaker. If local backup, including a breaker failure protection system, is being used, we could directly trip Breaker J1 and J2. Breaker SZ would either trip by remote backup or be transfer tripped depending upon the situation.

How the breaker failure protection system works to detect failure of the fault interruption function and how it is applied is covered in the later sections of this paper. First, we are going to look at what issues should be examined in determining if a breaker failure protection system should be applied.

Issues To Consider In Deciding To Apply Breaker Failure Protection

The title of this section of this paper is, "Do I *need* breaker failure protection?" The answer to that question is, "It depends." Another question that the relay engineer may ask is, "Do I *want* breaker failure protection?" The answer to this question is, "Yes." In this section, we will attempt to elaborate on the reasoning behind the answers to these two questions. To do so, we will discuss three aspects of backup protection—sensitivity, speed, and ease of coordination analysis and maintenance.

Before entering this discussion, it is important to understand that one should not rely on local backup to the exclusion of remote backup and vice versa. As we will see in the following section of this paper, reliance on remote backup alone, especially in networked systems, can be very difficult. On the other hand, reliance on local backup alone is equally difficult. Before doing so, the protection engineer has to consider all possible contingencies to ensure adequate redundancy to the local system. This may include factors such as redundant relay systems, redundant instrument transformers, dual trip coils, and redundant battery systems. A prudent design usually relies on a combination of both local and remote backup capability. [1]

Sensitivity

The first thing to consider is, "Can the remote relays reliably detect faults in all adjacent zones of the power system should the relays or breaker that is intended to protect that zone fail?"

In radial systems, this is a relatively simple task. Can the upstream relay be set with adequate sensitivity to see to the end of the line or at least beyond the next fault detection and interruption device (e.g. a line fuse or recloser)? The main difficulty in this analysis is considering the range of possible source conditions. The main limitation here is usually with load encroachment. Generally, in radial systems, both the available fault current and the circuit loading are reduced with greater distance from the source.

The limitation on sensitivity of the upstream relay may be restricted by loading considerations.

In networked systems, the presence of in feed can severely limit the ability of relays to see faults beyond the remote bus. This is especially true of distance relays. Of course, highly selective relay systems such as current differential relays have no ability to see into adjacent zones.

Remote backup using distance relays requires the application of zone three, and sometimes zone four, relays. To counteract the effect of in feed, they often need to be set with very long reach settings. With these long reach settings, the relays can be susceptible to load encroachment and operation under power system swings. With the recent large scale disturbances on the West coast, the setting of zone three relays has come under increased scrutiny as they have been contributing factors in these blackouts.[2] If these zone three relays are the primary mode of backup protection, the sensitivity setting of these relays cannot be compromised. Use of local backup and breaker failure protection mitigates the reliance on zone three relays for remote backup.

Speed

The next thing to consider is the speed of clearing the fault in the event that the primary protection systems fail. Relays with zones of protection that overlap other zones have to rely on time coordination to prevent over tripping. The result is that remote backup can only come after a significant delay. On the other hand, a dedicated breaker failure relay can detect the failure of a breaker to interrupt with very precise timing coordination. Thus, the use of breaker failure protection can greatly speed up the tripping of backup circuit breakers.

When we consider the fundamental protection engineer's question of how fast is fast enough, we generally consider issues such as equipment damage, impact on power quality to the surrounding system, and system stability.

Given the reliability of protective relays and power circuit breakers, failures can be expected to be extremely rare over the life of the power system. For this reason, the issue of equipment damage and power quality caused by delayed clearing of the fault is generally not considered in looking at the need for breaker failure relaying.

When a breaker does fail, all adjacent circuits must be tripped in order to clear the faulted zone of the power system. This generally results in significant impact to the local system in customer outages and reduced transfer capability. The use of local versus remote backup usually has very little effect on this because many of the same elements of the power system need to be isolated around the failed breaker regardless of whether it is done by local or remote backup systems.

On the other hand, if the delayed clearing associated with remote backup from coordinated overlapping protection causes the system to go unstable, the impact can be far beyond the local system, causing wide spread blackouts. If system stability caused by delayed fault clearing is a concern in the application, breaker failure protection should be applied.

Ease of Analysis and Maintenance

Finally, one of the most compelling reasons that a protection engineer may wish to apply breaker failure relaying is that it greatly simplifies the task of contingency analysis and long term maintenance of the protection system coordination settings.

When local backup systems are used, each protection system can be designed and set to protect its specific zone of protection while the need to consider its coverage of adjacent zones under all possible contingencies is minimized. The ability of highly selective relaying systems such as current differential and distance relays to protect their zone of the power system is relatively immune from changes in the surrounding system and that is one reason they are applied.

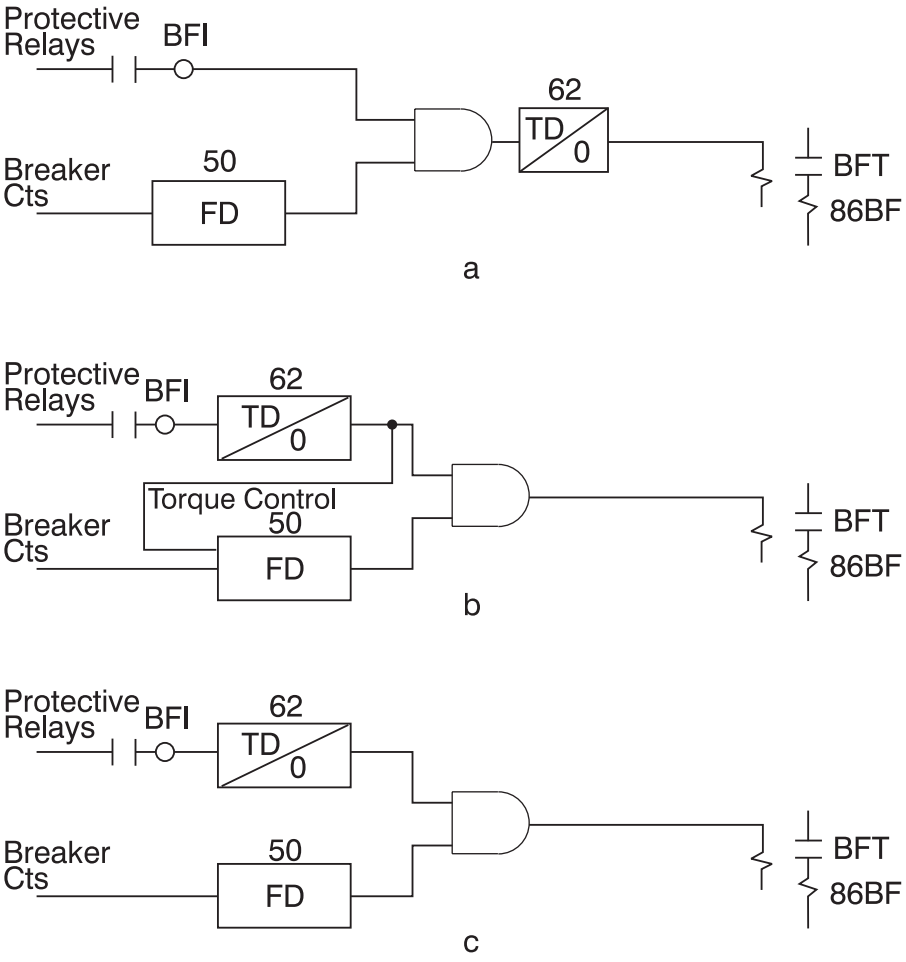
Let's assume that we have not applied a breaker failure protection system and that the initial design included careful analysis of all possible contingencies and ensured that the sensitivity and coordination of relay settings covered all of these for remote backup. As the power system changes, fault current levels and the distribution of in feed currents in networked systems change. This can have an adverse affect on the effectiveness of this careful analysis. The result is that, for any change in the power system, a complete study of all settings will be required to ensure that remote backup is still effective.

BREAKER FAILURE PROTECTION SYSTEM LOGIC

Before we go on to discuss the features of a breaker failure protection system, it is important to note that one of the primary considerations in the design and application of a breaker failure protection system is that it should be biased toward security. Since a true breaker failure occurrence is so rare, the breaker failure protection scheme will be called upon to not trip many more times than it will be called upon to trip. Also, since the failure of a breaker generally requires tripping out all adjacent circuits, the consequences of misoperation and over trip of the system are many times worse than misoperation and over trip of nearly any other protective scheme on the power system. For this reason, you will see that there are several features that are commonly included to enhance security from misoperation.

A separate breaker failure protection system is required for each breaker. Backup tripping systems such as lockout relays can be common within a substation depending on the circumstances. Tripping systems will be covered in more detail in a later section.

At its most elemental level, a breaker failure protection system consists of a timer. The timer is started at the same time that the trip signal is sent to the breaker and is used to precisely time the period that is allowed for the breaker to interrupt the fault. If the breaker does not operate by the expiration of the time delay, the breaker is determined to have failed and tripping of backup breakers occurs. The breaker failure protection system can determine if the breaker has tripped by monitoring a contact mounted to the breaker operating mechanism; however, it generally includes a current detector to confirm that the current flowing in the tripped breaker has been successfully interrupted.

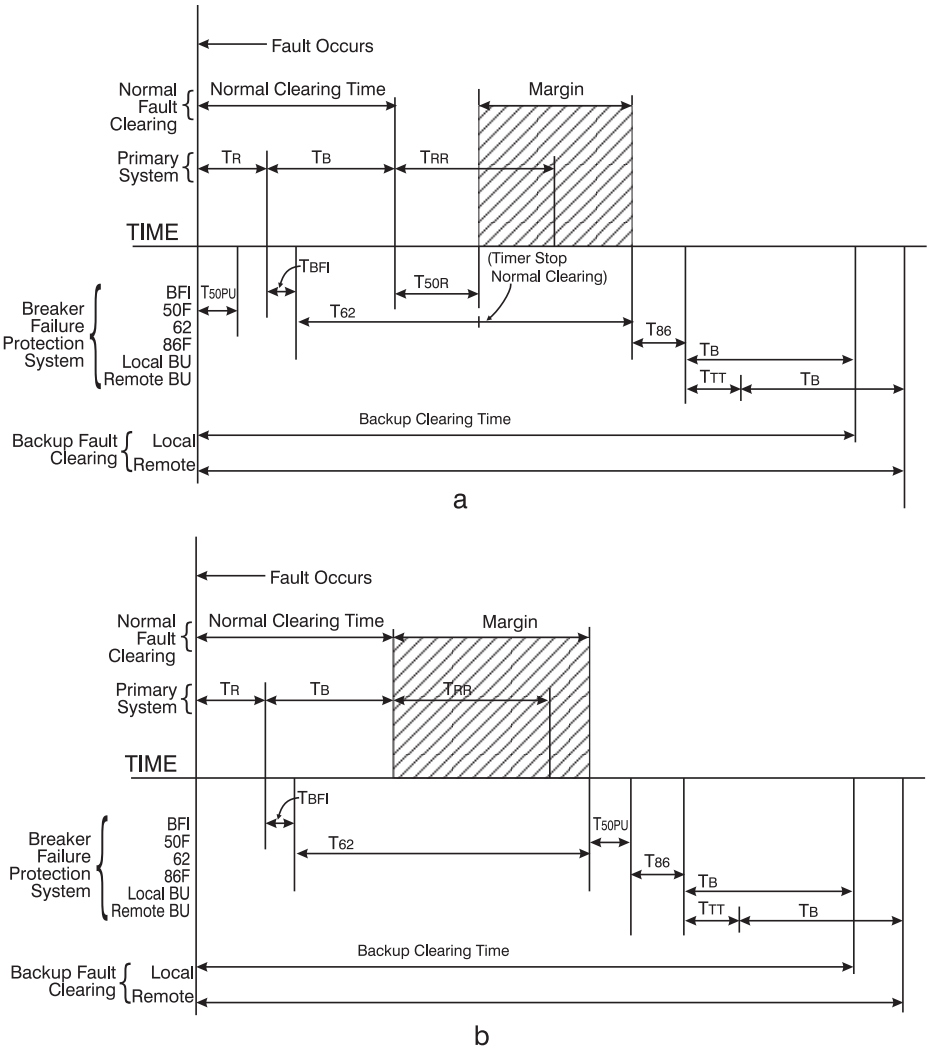


62 = Time delay pickup/inst. dropout timer
50 = Inst. overcurrent with high dropout ratio
BFI = Breaker Failure Initiate
BFT = Breaker Failure Trip
86BF = Breaker Failure lockout relay, trips backup breakers

Figure 2: Breaker Failure Logic

Beyond this simple concept, the timers and fault detectors in a breaker failure protection system can be combined in many different ways; but all can be simplified into a few common logic schemes. Figure 2 shows three of these basic logic schemes. The timing diagrams associated with these logic schemes are shown in Figure 3. [3]

Figure 2a shows a scheme where both the BFI (breaker failure initiate) and the fault detector must be true to start the timer. Successful interruption is indicated by either the fault detector dropping out or the protective relays dropping out and removing the BFI signal. The breaker failure fault detector is important here because it has a high dropout ratio and fast reset characteristic whereas the protective relays do not have such a constraint put upon them. They may be slow to drop out after the fault is cleared.



LEGEND

T_R = Relay Operate Time
T_{RR} = Relay reset time (can stop timer if BFI not sealed in)
T_B = Breaker Interrupt Time
T_{BFI} = 62X (BFI auxiliary) PU Time (if used)
T_{50PU} = Fault Detector PU Time
T_{50R} = Fault Detector Reset Time
T_{62} = Breaker Failure Time Delay
T_{86} = Lockout Relay Trip Time
T_{TT} = Transfer Trip Time

Figure 3: Timing Diagrams (a. Logic 2a and 2c, b. Logic 2b)

Figure 2b shows a scheme where the importance of the dropout/reset characteristics of the fault detector is minimized. The timer is initiated by the BFI signal from the protective relays. If the timer expires before the protective relays drop out, the fault detector is then started. If the breaker has interrupted successfully, the fault detector will not pick up at all. In this case, the fault detector should have a fast pickup time because that will be added to the time required to trip backup in the event of a failed breaker.

When considering the two timing diagrams, it is important to call attention to the time marked as the margin. The margin is the difference between normal clearing time and when the breaker failure protection system will cause backup tripping to occur. A larger margin will improve security from incorrect backup tripping. For Figure 3-b, it can be seen that the margin can be improved by the difference between the fault detector's pickup and drop out time for a given backup tripping time, or the backup tripping time can be reduced by this same amount for a given margin time.

Figure 2c is a subtle variation on scheme 2a. In this case, the timer is started by the BFI signal alone as in scheme 2b, so fault detector pickup time is not a factor in starting the timer. Breaker failure trip will occur if the timer expires and the fault detector is still picked up. The difference with this logic is that the effect of timer over travel (the timer continues for a short period after the input is removed) is minimized.

These basic schemes can be modified to accommodate additional situations. The most important modification to note is the need to also accommodate breaker failure protection with breaker status contact supervision instead of fault detector supervision. This modification would be used in situations where the faults being detected by the initiating relays may not involve high current. For example, initiation by transformer differential or sudden pressure relays or remote transfer trip. The example breaker failure relay logic in Figure 5 shows this logic being applied to BFI Input 7.

With modern, solid state and numerical breaker failure relays, issues such as fault detector and timer performance are minimized over breaker failure schemes built up using discrete electromechanical components. Programmable logic in solid state and numerical relays also makes it easy to customize the scheme as required for different applications.

BREAKER FAILURE RELAY FEATURES

This section will discuss several of the features found in modern breaker failure relays. Ways to use the standard and advanced features to enhance performance, security and flexibility are discussed and indicated in an example breaker failure logic diagram shown in Figure 5.

Timers

Breaker Failure Trip Timers

The timing functions of a breaker failure protection system must be very precise and repeatable with little or no over travel.[4] Static timers and numerical relays provide this. The typical timer used in a breaker failure relay is a delay timer. A delay timer's output changes state some time delay setting after the timer initiate input changes state. Figure 4 shows a timing diagram for the delay timers used in the example shown in Figure 5.

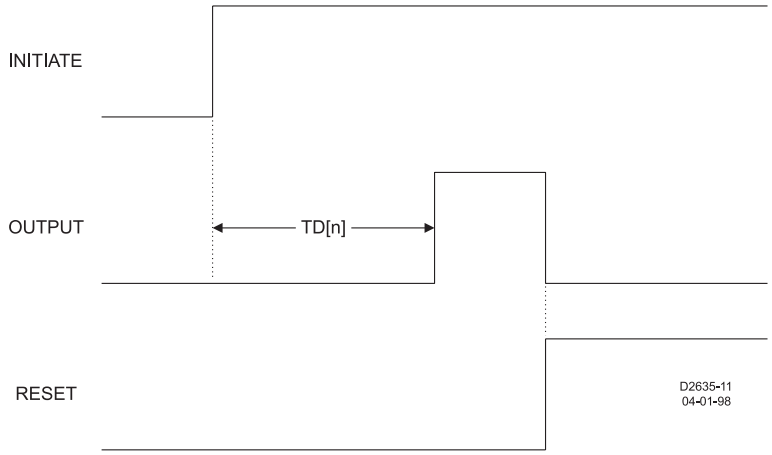
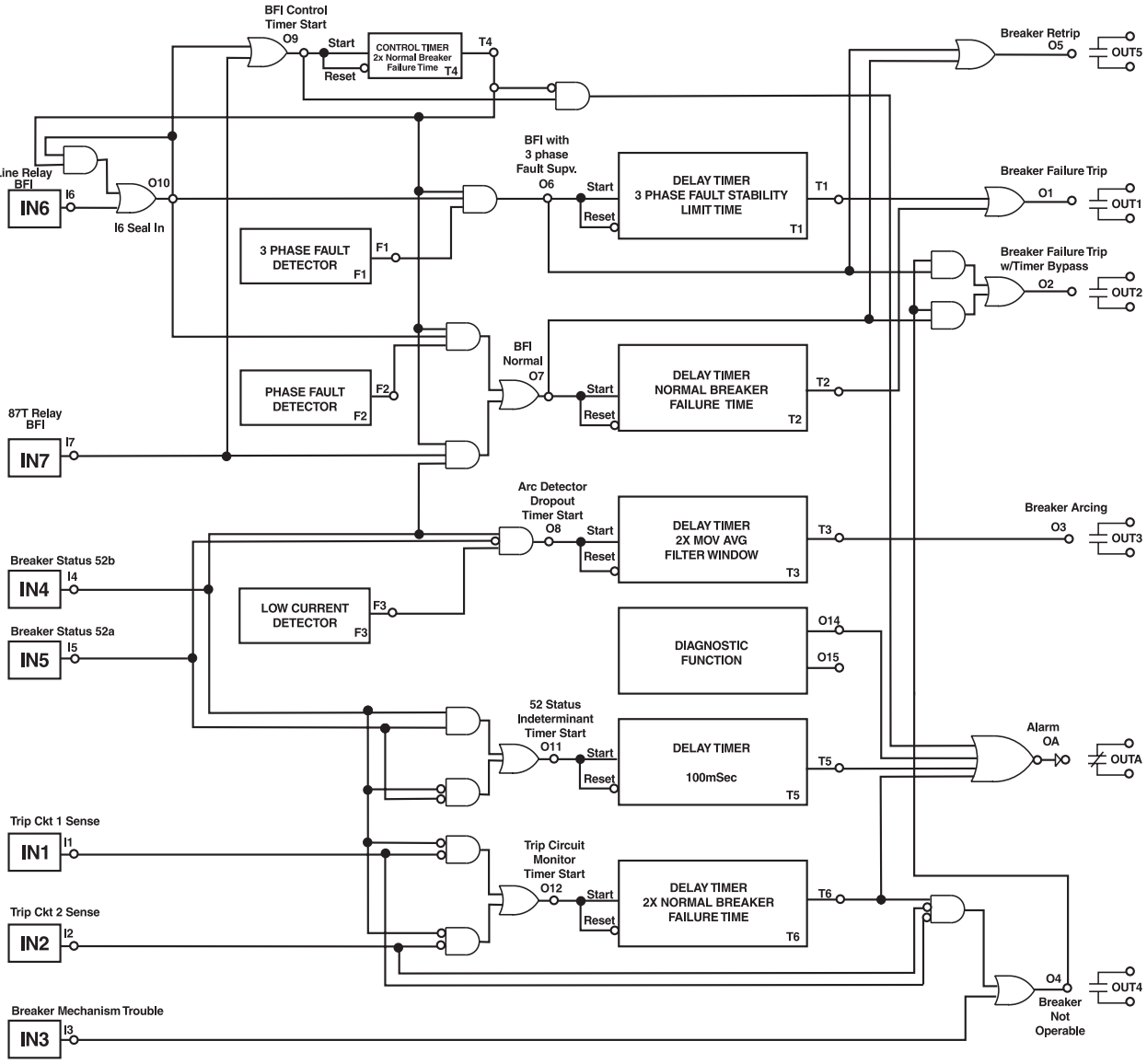


Figure 4: Delay Timer Operation

The setting of the time delays requires a careful analysis of the timing diagrams, such as those shown in Figure 3, and the performance requirements of the breaker failure protection system. To enhance security, greater time delay for backup tripping is desirable. This increases the margin to allow the breaker to trip and the fault detectors to drop out. On the other hand, when system stability is a concern, the time delay until backup trip must be reduced as much as possible.

Each parameter that affects the overall timing of the protection system cannot be known with certainty. This results in the need to set the timing with perhaps longer margin than is necessary. One important feature that can be provided in a numerical relay is the capability to monitor and report the timer margin after each breaker trip. The margin can be monitored by an alarm threshold so that if the relay ever gets close to misoperating, the system operators can be made aware. Then the timer log can be reviewed to determine if the protection system or circuit breaker is having a problem or if the timer settings must be adjusted. From a more proactive point of view, the timer log feature can allow the timer settings to be optimized based upon real world experience on each circuit. In the example shown in Figure 5, timers T1, T2, and T3 would be monitored.




```
LN=BRAS
LF1=PI,1
LF2=PI,3
LF3=PI,2
LI1=8,8
LI2=8,8
LI3=16,16
LI4=4,4
LI5=4,4
LI6=8,4
LI7=4,4
LR=0,0,0,0,0
LT1=D,O6,/O6
LT2=D,O7,/O7
LT3=D,O8,/O8
LT4=C,O9,/O9
LT5=D,O11,/O11
LT6=D,O12,/O12
LOA=O14+I3+T5+T6
LO1=T1+T2
LO2=O6*O4+O7*O4
LO3=T3
LO4=I3+T6*/I1*/I2
LO5=O6+O7
LO6=O10*T4*F1
LO7=O10*T4*F2+I7*T4*I4
LO8=I4*/I5*F3
LO9=I7+O10
LO10=I6+O10*T4
LO11=I4*I5+/I4*/I5
LO12=/I4*/I1+/I4*/I2
LOGIC=BRAS
PHOLD=11111
PTARGET=0000011,11101
PTLOG1=/O6,L,1C
PTLOG2=/O7,L,2C
PTLOG3=/O8,L,10C
PTLOG4=0,0,0m
PTLOG5=0,0,0m
PTLOG6=0,0,0m
TRIGGER=O5
BKROPS=,/I4
```

Figure 5: Example, Breaker Failure Logic Scheme

Figure 6 shows an example of a timer log for timer T2 in the example shown in Figure 5. The breaker failure time delay is set at 10 cycles with the alarm set at 1 cycle. For three successive operations, fault detector F2 drops out (making O7 False) and stops timer T2 with 25 msec., 13 msec., and 8 msec. respectively left on the timer. For two of these operations, the margin (time left on the timer) is less than 1 cycle (17msec.) so these operations are marked with an asterisk in the timer log and set a programmable alarm bit in the relay's diagnostics.

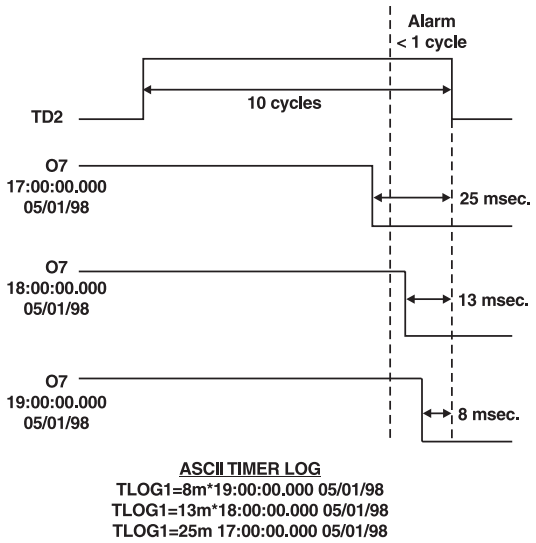


Figure 6: Margin Log Timing Sequence

Control Timer

A control timer feature is included in some modern breaker failure relays. A control timer's output changes state immediately after the timer initiate input changes state and stays in that state for some time delay setting. Figure 7 shows a timing diagram for the control timers used in the example shown in Figure 5. This timer provides a limited window of opportunity for tripping after the initial input of a BFI signal. If there is a problem in the BFI circuitry such as a stuck contact, the fault detector may be the only thing preventing a backup trip misoperation. If the fault detector picks up due to load or faults outside the breaker’s zone of protection, the relay could misoperate. The control timer feature adds security by preventing a misoperation in this situation. In Figure 5, BFI Inputs 6 and 7 start control timer T4 which is used to supervise the breaker failure timers T1 and T2.

It is important to note that the use of a control timer adds security. In the event that a stuck BFI contact occurs, the breaker failure protection system will be rendered inoperable instead of being armed for possible misoperation. Thus, in the example breaker failure logic shown in Figure 5, the alarm output contact will be closed in the event that you have BFI (virtual output 9) and the output of the control timer is false (T4).

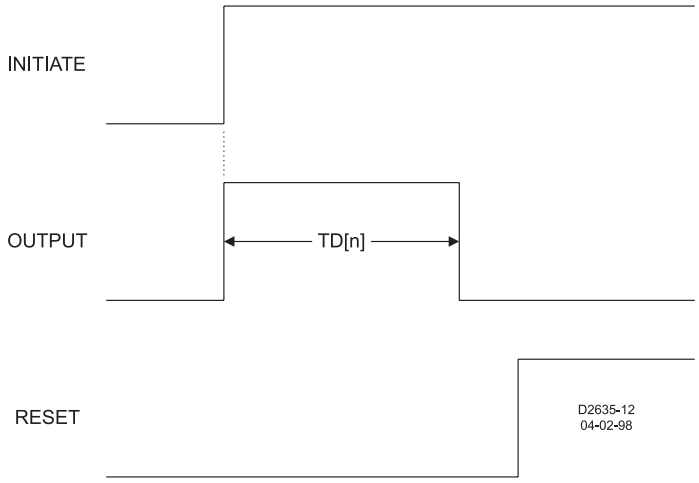


Figure 7: Control Timer Operation

Current/Fault Detectors

Up to this point, I have referred to the use of current detectors and fault detectors somewhat interchangeably. In most breaker failure protection schemes, the two functions are provided by the same device. In actuality, they are two separate functions.

The breaker failure function requires some means of quickly determining if the current flowing in the breaker being monitored has gone to zero. This current detector function is then used to stop the breaker failure output from occurring once the breaker tripping has been successful. In this case, it is desirable that the relay be able to determine this with good sensitivity. If a fault detector is used for this function, the sensitivity is limited to allow normal load current to flow without picking up.

On the other hand, the fault detector function serves the purpose of enhancing security by providing an independent confirmation that a fault actually exists. The fault detector by its very name should be set above maximum load current so that it is only picked up when a fault occurs on the system. This feature prevents misoperation of the relay due to inadvertent initiation of the breaker failure protection system—for example, while testing other relays.

Fault Detector Pickup Characteristics

Instantaneous overcurrent relays used for breaker failure fault detectors should have a very fast pickup characteristic. In relays using logic shown in Figure 2a, it is assumed that the fault detector will be faster than the initiating relays and BFI auxiliary relays (if used), such that timing is started as soon as the BFI signal is applied. In relays using logic 2b, the fault detector pickup time must be added to the backup clearing time after the timer has expired, emphasizing fast pickup over fast dropout.

Fault Detector Dropout Characteristics

The fault detector should have a high dropout ratio and fast reset. This last point is critical. In relays using the logic shown in Figure 2a and 2c, the dropout time of the fault detector is subtracted directly from the margin and, thus, has to included in the overall timer setting.

Dropout characteristics are related to the fault detector technology. Electromechanical relays must overcome inertia and lack of strong reset torque relative to pickup torque. With some fault detectors, dropout time can be a function of the number of multiples of pickup that were applied to the fault detector prior to interruption.

The pickup and dropout characteristics of a numerical relay are generally related to the current measurement algorithm being employed. If a one cycle algorithm is used and the fault current is many multiples of pickup, the pickup threshold may be reached quickly with just a few samples of fault current. Upon interruption of the current, the same factor works against you in that it may take almost a full cycle of post fault samples for the magnitude to return to below the threshold. The actual comparator function is just a quick mathematical comparison between the pickup level and the measured magnitude. Special fast dropout detection algorithms can be used in a numerical relay to mitigate this.

Dropout can also be delayed if the current does not immediately go to zero after trip. This can occur because some breakers insert resistors in series with the main contacts to reduce current level and transients prior to the main arcing contacts parting. [5] The reduced current may be below fault detector pickup; however, it helps contribute to slower dropout.

Another situation that may delay fault detector dropout is what is called the DC tail phenomenon. [6] This can occur if the current interruption does not occur at a zero crossing. While most interruptions do occur at a zero crossing of the primary current, it is possible that the current in the *secondary* of the breaker CTs is not at a zero crossing at the time of the interruption. This can be caused by CT saturation. When either of these situations occurs, a DC exponential decay in the relay's fault detector circuit occurs. Many static relays use a rectified signal with a DC level detector which is sensitive to this DC tail current. Numerical relays can use an algorithm that rejects this DC current or a special fast dropout algorithm that looks for this exponential characteristic.

One additional caution is offered in the application of breaker failure fault detectors. In ring bus or breaker and a half applications, CTs from two breakers are often connected in parallel. If the breaker failure relay is connected to these CTs as shown in Figure 8, low fault detector pickup settings should be used with caution. In this arrangement, the CT feeding the breaker failure relay fault detector can be energized on the secondary side from the CT on the adjacent circuit breaker. This results in current flowing in the

fault detector even when the protected circuit breaker has successfully interrupted the fault. This secondary excitation current is generally negligible except when flux remnants or high current/burden causes the CT to saturate. [4]

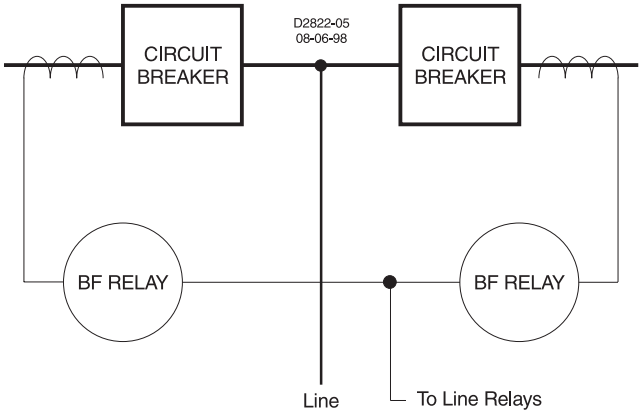


Figure 8: Multiple Breaker Arrangement

Phase and Ground Fault Detectors

Fault detectors typically include three phase elements or two phase and ground elements. Normally it is adequate to monitor the three phase currents as these represent the current in the poles of the breaker. However, if the sensitivity of the ground relays is significantly higher than the sensitivity of the phase relays, it may be desirable to apply a ground fault detector so that you can be assured that the breaker failure protection will pickup for any fault that is sensed by the initiating relays. In the example shown in Figure 5, fault detector F2 is used to monitor the fault current in the three phases and supervise BFI input 6 in starting timer T2.

Three Phase Fault Detectors

For system stability, a three phase fault is the worst case. The dynamic stability of the system is not affected as much by the other fault combinations. Since three phase faults are much rarer than the other fault combinations, it may be desirable to enhance security by treating three phase faults differently. If the breaker failure relay can be set up with a separate three phase fault detector, this could be used to supervise a timer set at the three phase fault, dynamic stability limit. The normal timer supervised by the other fault detectors could then be set with a longer time delay (with more margin) set at the two phase and ground fault (the next worst case), dynamic stability limit. Figure 5 shows this logic being applied to BFI Input 6 with fault detector F1 and timer T1.

Low Level Current Detector

If the breaker fails while being opened for normal load switching or due to restrike after the line has been isolated, the currents flowing across the failed interrupter may be too

low to reliably detect by conventional means. Numerical relays can use digital signal processing algorithms such as a moving average filter on the low level currents to discern the line charging current from the random noise.

This type of fault detector would be supervised by a breaker status contact so that it is only in service when the breaker is indicated to be open. Under these conditions, the failed interrupter with the low level arcing would eventually be destroyed unless the breaker is closed. After reclosing the breaker, if the line is still faulted, the failed breaker can be isolated by conventional breaker failure protection. If it is not, the failed breaker can be isolated by normal switching. In the example shown in Figure 5, this function is provided by fault detector F3, timer T3 and output O3.

Logic Inputs

BFI and Other Inputs

The breaker failure relay needs at least one initiate input to indicate when the protective relays are attempting to trip the monitored breaker. In addition, as indicated earlier, it may be necessary to provide a separate logic input for supervising breaker failure tripping without the use of the fault detectors.

As mentioned in the section discussing breaker failure protection system logic, additional inputs are also usually provided to allow for breaker failure trip supervised by breaker status instead of the fault detector. To enhance the reliability of this logic, it may be desirable to use both “a” and “b” contacts with both contacts having to be in congruence to indicate breaker opening. The example shown in Figure 5 monitors both a and b contacts to start breaker arcing detection protection. If the two inputs are not in congruence, this is indicated by the alarm output.

Input Conditioning

Security of the BFI input is extremely important. A recognition timer can be used to eliminate false initiate signals due to noise and transients, while a debounce timer can be used to fill in gaps due to contact bounce. In a numerical relay, these parameters can be customized to obtain the optimum tradeoff between speed and security. For example, if there is a problem with AC coupling in the sensing circuits, the recognition timer can be set to greater than one half cycle to reject the half cycle rectified signal coming from the opto isolator diodes.

Seal In of the BFI Signal

Some breaker failure relays provide the optional feature of sealing in the BFI input. This feature is useful in applications where electromechanical relays require memory voltage to operate during a close in fault where the local voltage has collapsed to zero. During the delayed clearing caused by the breaker failing, the memory voltage may expire and

cause the relay to drop out before backup tripping can be completed. This feature can also serve to debounce the BFI signal if the relay does not include a contact conditioning feature.

Seal in of the BFI signal should be used with caution since this feature can reduce the security of the breaker failure protection system. In this case, the timer can only be stopped by the supervisory function (fault detector or breaker status contact). For example, if seal in of the BFI input being used with breaker status supervision is used, a spurious BFI input will result in a backup trip every time. In the event that it is used on an input with fault detector supervision, a misoperation may be prevented by the use of a control timer. For this reason, it is recommended that BFI seal in not be applied to breaker failure logic with breaker status supervision.

This is illustrated in the example in Figure 5. BFI input 6 that is connected to the line relays is sealed in for the duration of the control timer by use of virtual output O10. BFI input 7 that is connected to the transformer lockout relay is not sealed in. It should be noted that the seal in and/or control timer function must be coordinated such that the BFI input is released prior to an automatic reclose. This is generally not a problem unless the breaker failure protection system is applied to a circuit breaker using a high speed reclose shot. An alternative to using the control timer to break the BFI seal in, the user might use fault detector dropout.

Breaker Retrip

An additional security feature that is often provided in modern breaker failure relays is the retrip function. This function sends an independent trip signal to the breaker if the breaker failure relay is initiated. This feature can enhance security in two ways. If, for some reason, the relays have tripped but there is a problem in the circuit such as with the 94 (auxiliary tripping) relay that prevents the trip from being sent to the breaker, the breaker failure relay will go ahead and trip the breaker instead of having to trip backup. The second way that this feature can enhance security is if the relay is inadvertently initiated such as during testing. In this case it will trip the circuit breaker, stopping the breaker failure relay from timing out and tripping backup. This feature is provided by output 5 in the example shown in Figure 5.

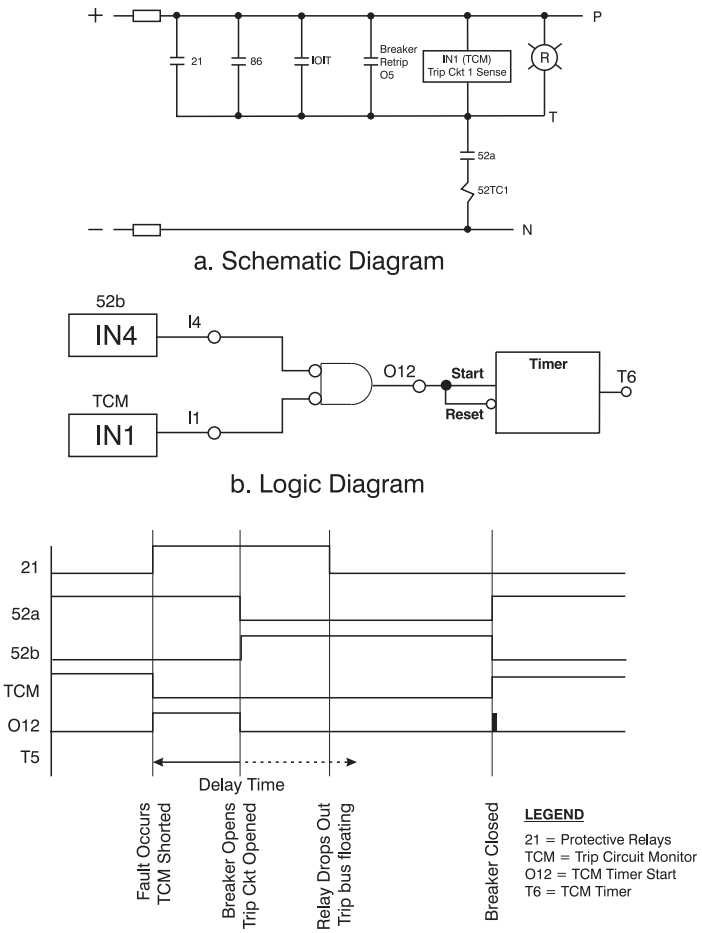


Figure 9: Trip Circuit Monitor

Monitoring the Trip Circuits and the Breaker

Trip Circuit Voltage and Continuity Monitor

A popular feature of many multifunction relays is the ability to monitor the trip circuit and alarm for loss of voltage (open fuse) or loss of continuity (open trip coil). Figure 9a shows a trip circuit monitor (TCM) sensing element (IN1) placed in parallel with the tripping output of the relay. Figure 9b shows a diagram of the logic.

When the breaker is closed, the trip bus, T, is at negative potential through the low impedance path of the trip coil. The TCM senses a logic 1. Figure 9c shows a timing diagram of the operation of this logic. When a trip occurs, the trip bus is at positive potential, the voltage across the TCM is shorted, and it senses a logic 0. When the breaker opens, the 52a contact in series with the trip coil opens, the protective relay drops out, the trip bus is at positive potential through the high impedance of the red

indicating light or the TCM sensing element, and the TCM continues to sense a logic 0. The breaker status input (IN4) in the logic diagram is used to block the function while the breaker and, therefore, the trip circuit is open. The timer is used to prevent an alarm output during the transition between closed and open.

In the example illustrated in Figure 5, each trip circuit of the breaker is monitored by input 1, and input 2 respectively with timer T6. If either trip circuit has a problem, the alarm output is closed.

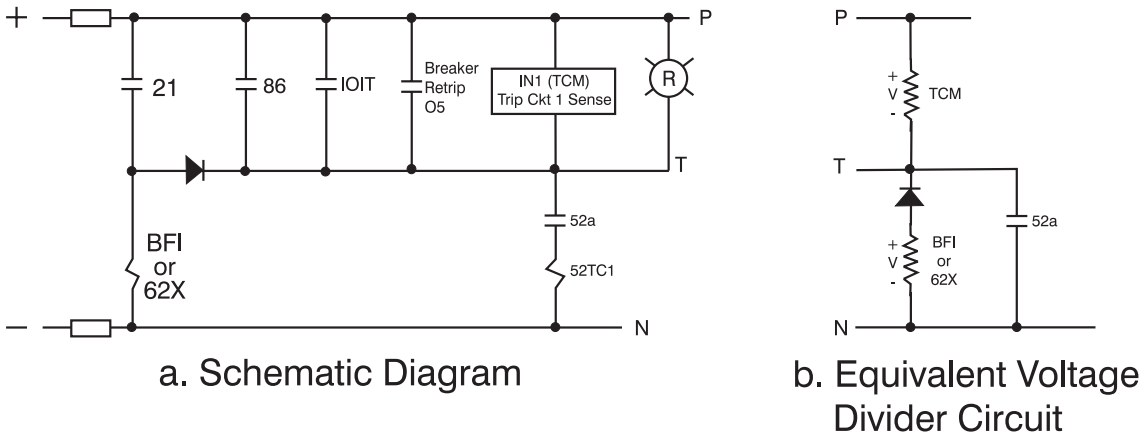


Figure 10: Trip Circuit Monitor with BFI Sensing

Figure 10 illustrates a problem that can occur when using this feature in conjunction with a breaker failure relay. If the breaker failure initiate sensing is connected directly to the breaker's trip bus as shown in Figure 10a, the equivalent circuit shown in Figure 10b occurs. If the diode is not included in the circuit as shown, a voltage divider circuit will be created between the BFI sensing and the TCM sensing when the 52a contact or the trip coil is open. It should be noted that the placement of the diode in the example is such that breaker failure will not be initated due to control switch trip (101T) or by the BF relay's retrip output. Also, the 86 tripping contact is placed to the right of the diode since it is assumed that one of the 86's contacts will be directly connected to the "initiate with breaker status supervision" input and that the 62X contact will be connected to the "initiate with fault detector supervision" input.

In the example, a 62X BFI auxiliary relay is shown. In this case, the impedance of the 62X coil will be small compared to the impedance of the TCM circuit so the TCM will always be at logic 1. This will prevent the TCM logic from working, even if the trip coil is open. In the case that a high impedance BFI sensing input is used, the TCM and the BFI impedances may be of similar magnitude, causing the voltage to be divided nearly equally. This can result in spurious BFI signals to the breaker failure protection scheme when the breaker is open. Normally, when redundant systems are used, each relay system will be on its own circuit and the BFI sensing for each relay system will be isolated from the tripping circuit, so this is not a problem.

Breaker Mechanism Monitoring

Traditionally, circuit breakers operating mechanisms were a very fail safe device. For example, the energy for interruption of the current in an oil interrupter is provided by the arc itself. Therefore, the mechanisms relied on stored energy (pneumatic, hydraulic, or spring charging motor) to close the breaker. Opening was provided by gravity with perhaps the assistance of an opening or accelerator spring. The opening spring was charged by the closing stroke of the mechanism. If there was a problem with the operating mechanism, the breaker could always be relied upon to trip at least once.

With the advent of air blast, and now SF6 breakers, the energy for opening and interruption of the current is provided by external means. In the case of air blast breakers, stored air pressure. In the case of two presure SF6 breakers, stored gas pressure. In the case of puffer style SF6 breakers, stored energy (pneumatic, hydraulic, or spring charging motor) in the mechanism. Many of the puffer style breakers use power closed, power open mechanisms, or even spring closed, power open mechanisms instead of the traditional power closed, spring open mechanisms used in oil breakers. In the case of puffer style SF6 breakers, besides providing dielectric strength, the SF6 gas provides dampening of the operating mechanism by the gas being forced through the puffer nozzles. For this reason, the loss of SF6 density (temperature compensated pressure) can also disable the mechanism. The result is a somewhat less fail safe device.

Because of this, these types of breakers are often designed with monitoring systems that can warn when the breaker is no longer capable of tripping. Depending upon the philosophy of the operating company, this logic can be set up to do one of three things. It can automatically trip out the breaker before total loss of gas pressure or stored energy. It can be set to alarm only and rely upon the breaker failure protection system to trip should a fault occur before the breaker can be isolated and taken out of service. Or it can even be set to trip the breaker failure lockout to isolate the breaker. This last response may be considered extreme since an SF6 breaker with zero pressure still generally has adequate dielectric strength to withstand normal system voltage.

Use of Monitoring in Breaker Failure Logic

In the example shown in Figure 5, output 4 is used to indicate that the breaker is not capable of tripping. This logic is true if both trip circuits are bad as indicated by the trip circuit monitoring function, or the breaker monitoring function indicates that the breaker mechanism has been disabled as indicated by a contact connected to input 3.

Under the situation where it is known that the breaker will not trip, it may be desirable to trip backup without waiting for the breaker failure time delay. In the example illustrated in Figure 5, output 4 is used for tripping of backup with bypass of the breaker failure timers through output 2.

Pole Disagreement Protection

Pole disagreement occurs when one pole becomes stuck closed or open resulting in all three poles of the breaker not being in the same state. On a networked system or ring bus application, this condition can be difficult to detect and can result in tripping of ground and negative sequence relays throughout the system due to the series unbalance. This type of protection is usually applied to circuit breakers that have independent pole operators. A breaker with independent pole operators has a separate operating mechanism on each pole of the breaker.

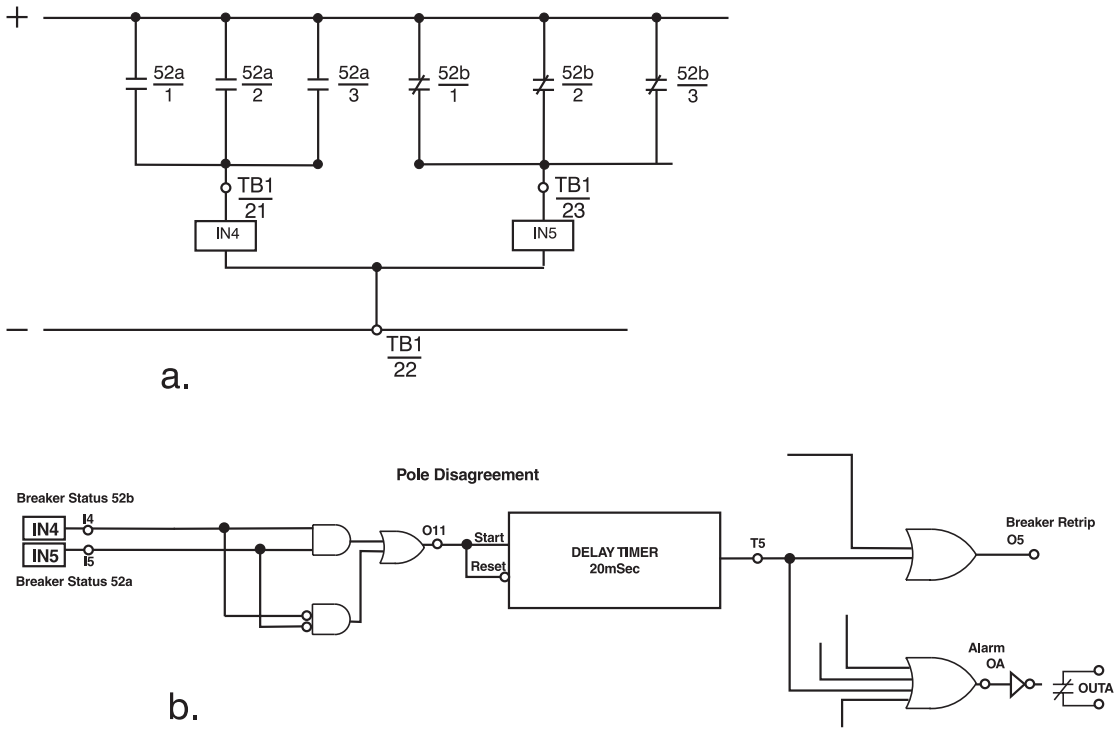


Figure 11: Example, Pole Disagreement Logic

Pole disagreement for this type of breaker can be relatively reliably detected using mechanism auxiliary contact logic. For example, the user could connect contacts as shown in Figure 11. In the example shown in Figure 5, Input 4 and 5 would provide sensing and Timer T5 would ride through the slight variation in timing of the various contacts. The example logic diagram would be modified to connect the timer output T5 to the logic expression for breaker retrip so that the breaker will be opened if both inputs are true at the same time.

During a closing operation, the pole disagreement would be caused by a pole being stuck open and the disagreement condition would be removed by breaker opening. During a tripping operation, disagreement would be caused by a pole being stuck closed. Normal breaker failure protection will cover this condition during a fault. However, during a switching operation, the breaker failure protection may not be initiated.

Thus, this condition might be used to alarm so that corrective action could be taken. It could even be used to trip backup to isolate the breaker with the pole stuck closed.

Single pole operator breakers are sometimes used in single pole tripping applications where only the faulted phase is tripped during a single phase fault. Pole disagreement protection for this application is beyond the scope of this discussion.

For standard circuit breakers with three pole operators, pole disagreement can occur due to failures in the interpole linkages. Pole disagreement for this type of breaker can be detected using sensitive current detectors to measure the current in each pole of the breaker. The low level current detector feature mentioned earlier in the paper provides this protection when the breaker is supposed to be in an open state.

For pole disagreement protection when the breaker is in a closed state, pole disagreement is detected if the current level in one pole is significantly different than the current level in the other two. The difference criteria must be a ratio of current in each pole to some average of the current in all poles so that it automatically adjusts its sensitivity for circuit loading. Additionally, it is necessary to reject current unbalance caused by system disturbances. This is done by adding a time delay longer than the typical fault clearing time for the surrounding circuits. Since pole disagreement while the breaker is closed will most likely be caused by a pole not closing, additional security can be provided by only enabling the protection using a control timer that enables it for a short period of time after a closing operation.

BACKUP TRIPPING

Once a breaker failure system has been applied, it is necessary to look at the backup tripping logic that needs to be implemented. This will differ with bus configuration, system requirements, operating practices and the amount of risk that the system operator is willing to take.

Lockout Relay

Breaker failure protection systems usually use a lockout relay (device 86) to handle the backup tripping chores. Lockout relays are ideally suited for this purpose because they can have many decks that can provide for keying transfer trip and tripping and preventing automatic or manual reclosing of the many adjacent breakers required to be tripped when a breaker fails. The adjacent breakers cannot be closed until the failed breaker has been isolated and the lockout relay reset.

It is not necessary to apply a separate lockout relay for each breaker if all of the same breakers on the bus are to be tripped for any one breaker failure. If this is not the case or if transfer trip systems are used to trip the remote breaker on the particular line with the failed breaker, it is usually desirable to apply separate lockout relays. This is generally the case in a straight bus arrangement. In more complex bus arrangements, a

lockout relay for each breaker may need to be applied so that backup tripping logic can be applied specifically to each breaker.

Transfer Trip or Remote Backup?

In nearly every case of a networked system application, at least one of the adjacent breakers that must be opened is at a remote location. Is a transfer trip system required? In the case where stability is a concern, delayed tripping cannot be tolerated, so a pilot system will most likely be applied for line protection. If this is the case, the additional cost of a transfer trip system across the pilot channel is usually minimal, so complete local backup can be achieved.

In the case where stability is not a concern, other considerations apply to answering this question. Many configurations are possible but the following examples illustrate the concepts that should be applied.

Straight Bus Applications

In the example system illustrated in Figure 1, let us consider breaker failure protection for John Substation. Under normal situations, the line breakers J1, J2, and J3 will be called upon to trip: for faults on their respective line; for faults on the bus; and for faults within the transformer zone of protection. For a transformer fault, the breakers are tripped, the MOD (motor operated disconnect) is opened, and the breakers automatically reclosed.

Let us consider each of these situations in turn. If breaker J3 fails, breaker J1 and J2 are tripped and locked out, removing those sources to all zones protected by the failed breaker. The only breaker that must be considered in the contingency analysis is the remote breaker SZ.

- If the fault is on line JZ, the relays at SZ will trip normally.

- If the fault is on the bus, the relays at SZ can easily detect it in zone 2. Sensitivity is not a concern. The addition of transfer trip can provide faster clearing and can prevent the automatic reclose of breaker SZ into the bus fault.

- If the fault is in the transformer zone, sensitivity is a concern because the relays at SZ cannot be counted on to see the fault. In this case, the addition of transfer trip should also be considered. An alternative is reliance upon the so-called “sacrificial lamb”. In this case, the MOD is started at the same time that the breakers are tripped. If one of the breakers does not trip, the MOD will flash over, causing a bus fault that can be detected remotely. The clearing will be slow and damage considerable. In applying this protection concept, the protection engineer is relying on probabilities to justify the savings of not applying a transfer trip system. Transformer faults are relatively rare and breaker failure operations are rarer still.

Ring Bus Applications

In the example system illustrated in Figure 1, let us consider breaker failure protection for Bill Substation. With a ring bus or breaker and a half bus, multiple breakers have to be tripped for any fault. For example, for a fault on the bus sections between breakers B1 and B2 or a fault on line JB, breakers B1 and B2 are tripped.

Let us consider the situation where breaker B1 fails for a fault on line JB. Breaker J1 is tripped normally by the line relays at John. Breaker B2 is already open from the line relays at Bill, but it is prevented from reclosing by the lockout relay. The adjacent breaker B3 is tripped by the local breaker failure protection scheme which removes the in feed from source SW.

The problem breaker for this contingency is SX. With remote backup, the relays at SX must be capable of sensing faults on 100% of line JB (and line BW when we consider the case of failure of breaker B3). Since we are using breaker failure protection at Substation Bill, we are able to trip breaker B3 and remove the in feed from source SW. This enormously helps our cause. Now the consideration is that most of line JB will be covered in zone 3 time from SX. The addition of transfer trip can provide faster clearing and can prevent the automatic reclose of breaker SX.

A compromise alternative would be to apply high speed ground switches at Bill Substation. This would enable remote clearing in zone 2 time for any fault on line JB.

APPLICATION ON A RADIAL SYSTEM

I have given several examples of application of breaker failure protection on networked systems. For the sake of completeness, the following is an example of application of breaker failure protection on a radial system.

Consider the application of breaker failure protection for Breaker D1, D2, or D3 at John Substation. These breakers feed a radial distribution system off the distribution bus.

The first step is to consider sensitivity of backup relays. You determine that the bus main overcurrent relay that is on the transformer low side breaker can be set with adequate sensitivity to see faults on all of the feeders up to and beyond at least the first line recloser.

Next, you consider the speed of backup clearing. The worst case situation would be a fault on the feeder exit cable that is not cleared by the feeder breaker but must be cleared by the bus overcurrent relay after a 300-500 mSec. coordination interval. However, since the failure of the relays and breaker will only happen on a rare occasion and the fault magnitudes are not sufficient to cause catastrophic failure of the transformer in this event, you decide that you will live with this slow clearing if this should occur. There is no system stability concern for faults at this location on the system.

After the forgoing analysis, you determine that you will not apply a dedicated breaker failure protection system in this application due to the added cost and complexity. However, you are considering using a multifunction overcurrent protection system that includes a breaker failure function block. How can the protection be improved by using this feature?

From the preceding discussion, we know that the failure of the relay is a separate contingency from failure of the circuit breaker. If we can detect the difference between these two contingencies, it is not necessary to take the same corrective action for both failures. For instance, if a feeder relay has failed, the bus overcurrent relay can be programmed to attempt to trip that feeder before tripping off the whole bus. This would reduce the outage to only the feeder with the failed relay as would happen if both failures are treated the same. On the other hand, if the feeder breaker fails, the bus breaker can be directly tripped in breaker failure time instead of having to wait for the traditional coordination interval of the bus overcurrent relay. This would result in faster clearing of the fault—reducing equipment damage and through fault duty on the transformer.

SUMMARY

Contingency analysis is the most difficult job of the protection engineer. Careful analysis of all contingencies under all possible system conditions is necessary if reliance is made on remote backup with coordinated relays. Application of dedicated breaker failure protection systems can greatly simplify this task.

When determining if breaker failure relaying should be applied, sensitivity and speed are the primary concerns. Breaker failure protection systems can improve both of these at the expense of greater cost and complexity in the relaying systems.

The design of breaker failure protection systems is generally biased toward security. Modern breaker failure relays have a great number of features to enhance security and improve protection over the use of discrete fault detector and timer relays.

To emphasize the point of how difficult the job of contingency analysis can be, I would like to leave you with an example of how things can bite you in the behind even if you have done a thorough job of it.

Consider the protective relaying system where you have applied complete redundancy. Your substation protection system has redundant instrument transformers connected to redundant relay systems, feeding redundant trip circuits that are fed by redundant battery supplies. You fully test each and every system including trip testing each system individually so that you prove each and every device trips the breaker. You turn the substation over to the operator and it is put in service.

The first time there is a fault on the system, the breaker fails to trip. Where did you go wrong? In a breaker with dual trip coils, any one coil will trip the breaker. When an

actual fault occurred, the redundant systems responded simultaneously and energized both coils simultaneously. If one of the coils was inadvertently put in upside down, the magnetic fields canceled and the trip latch was not released. This situation only occurs during a fault because such non-critical items as the control switch are typically included only in the one of the trip coil circuits. The breaker operated fine under normal system switching. Unless your trip test procedure calls for testing both trip circuits simultaneously at least once, this could happen.

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