How to Apply Process Bus in Breaker and a Half Applications

by Ian Young

Executive summary

Process Bus relays have been used for many years in trials all over the world. In most applications the focus has been to prove the concept of using sample values instead of instrument transformer secondaries to protect the power system. In most cases these trials were performed at small substations or on individual feeders. The trials were successful at proving the concept, however, the general use of this technology has been limited due to the practical requirements of real installations. This paper looks at some of the challenges introduced by breaker and a half substations and looks at methods available to allow process bus relays to be applied in a practical way.

Introduction

In many countries breaker and a half substations are used in most HV and EHV applications. From a primary perspective, they offer many benefits compared to double bus including:

- No loss of supply for busbar faults (if all zones in service). Since a breaker is available between each feeder and the supply buses a busbar fault can be isolated and the feeder will remain supplied from the other bus. In double bus applications a busbar fault is cleared by operating the feeder breakers. To return supply in double bus the isolators must be opened from the faulted bus then closed to the healthy bus before the feeder breaker can be closed.

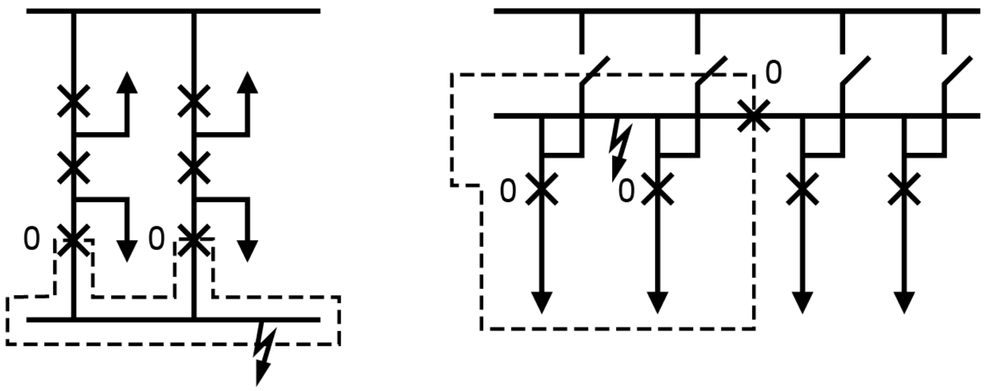


Figure 1

Tripping zone for busbar faults for breaker and a half and double

- No multiple zone loss for any circuit breaker failure (a bus and single feeder can be lost). Since the busbars are never directly joined in breaker and a half a backtrip will never take out both busbars. In double bus a breaker fail of the bustie can cause the loss of all loads.

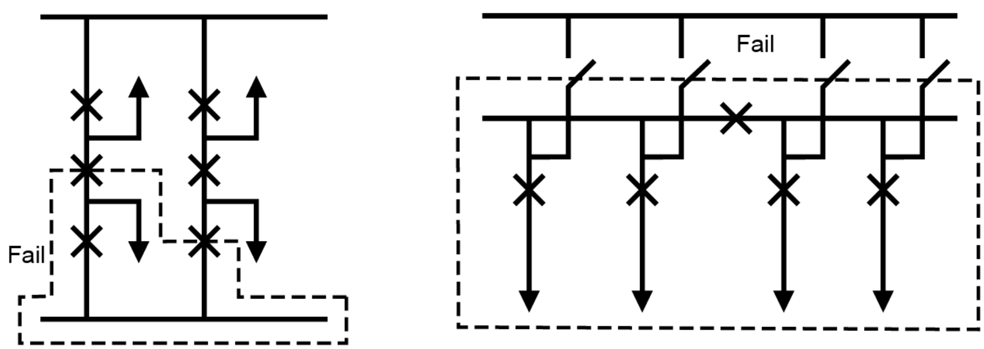


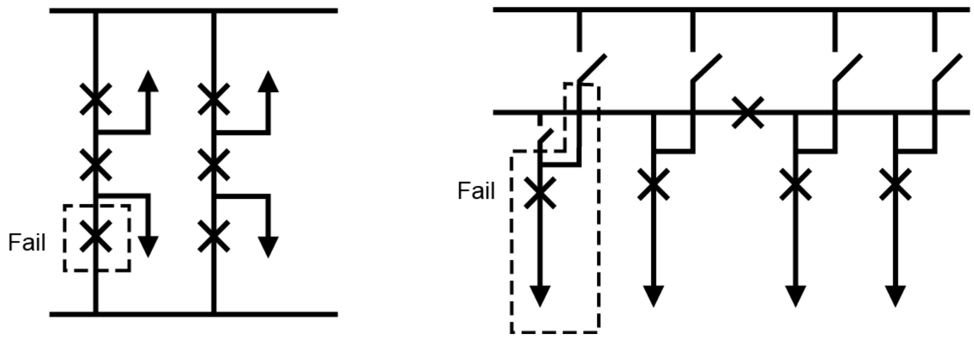
Figure 2

Tripping zone for circuit breaker failure on breaker and a half and double bus

- No loss of connection for any circuit breaker failure. Since each load is fed from 2 breakers, load can be rapidly returned for a failed breaker by isolating the affected breaker. In double bus the breaker must be replaced to restore load.

Figure 3

Zones affected by circuit breaker failure/maintenance on breaker and a half and double bus



These benefits often come at a slightly increased cost and size, however, to overcome the above double bus limitations, more complex bus structures such as transfer bus are often used negating some of the savings a simple double bus would offer.

From a secondary perspective, the busbar protection is greatly simplified whilst the feeder protection can be more complex depending upon the protection applied.

When applying process bus to these applications it must be ensured the benefits provided at the primary level are not limited in any way by the secondary protection scheme. In addition, the process bus devices must allow for maintenance and development during the life of the substation.

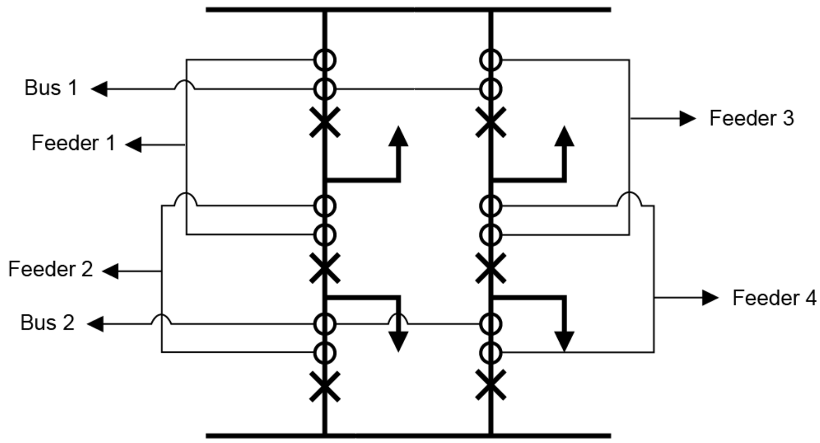
This paper looks at the specific requirements for process bus relays in these applications and provides examples of how to apply them.

Background

Breaker and a half installations have existed for many years. The location of the CTs in the main diameter meant that busbar protection was easily applied using high impedance schemes and the feeder schemes used were mainly distance protection. Both these schemes require the paralleling of CTs from different circuits.

Figure 4

CT paralleling required for typical breaker and a half protection



Other applications such as feeder differential and transformer differential require the diameter CTs segregated to avoid operation on diameter through faults. Even in these applications the CTs are often later paralleled and summated, for example, to provide mutual coupling currents for another feeder. This paralleling or addition of currents is traditionally done by simply connecting the CT wiring before or after the protection inputs as required.

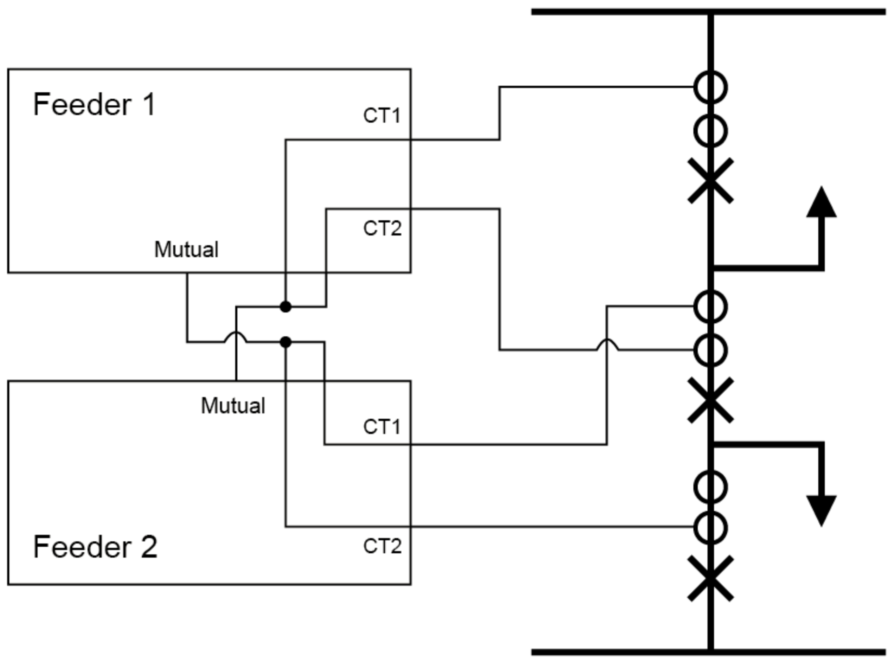


Figure 5

Dedicated breaker and a half relays with paralleled CT inputs used for mutual coupling

VTs offer a different challenge. In most substations, the line VTs are directly wired to the protection, however, the check synch VT will be selected using a Voltage Selection Scheme (VSS). In double bus applications, the VSS selects between the bus VTs depending upon the circuit isolator position. In breaker and a half substation the choice of VT is far more complex and the bus or adjacent line or other bus is usually used depending upon the status of all isolators (and breakers for the feeder). In both double bus and breaker and a half applications the cost of bus VTs can be avoided by using a more complex VSS to select from any available source. However, as the size of the substation grows the complexity of such schemes greatly increase and bus VTs become a more cost-effective solution.

Process Bus Implementations

Duplicating this CT & VT flexibility is a challenge for process bus devices and there are many options available to get a working system. However, the solution selected must be maintainable over the substation lifecycle. Future technologies, such as Non Conventional Instrument Transformers (NICTs) must also be considered.

Replication SAMUs

A simple solution is to install SAMUs at the same points as todays relay inputs. The benefit of such an approach is that it is well understood by all staff, has a well understood maintenance procedure and does not require any stream processing by the protection devices. An example of this would be implementing high impedance busbar protection. This can only be done by paralleling CTs and putting an impedance in circuit with the SAMU input.

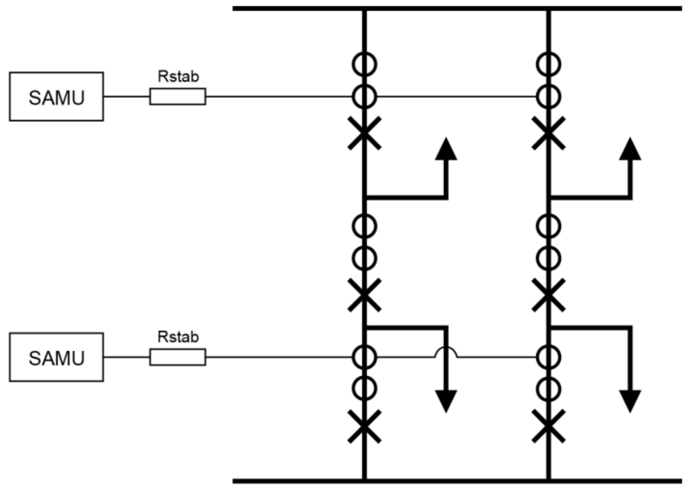


Figure 6

High Impedance protection with process bus using SAMUs

Such an approach could be applied to mutual currents and VSS schemes and may well be practical for retrofit applications. However, for a new installation it offers few benefits. The CTs cannot be used for other protection and therefore require additional cores. New technologies such as NCITs cannot be paralleled or switched and therefore such an approach cannot be used.

Stream Processing units

A possible solution would be to provide a computer to numerically handle the various streams to limit the streams sent to the protection to the values required. This would allow the protection devices to function in a similar fashion as today with the number of streams minimized and fixed for any application. In the case of the CTs this would provide minimal benefit for some streams like mutual currents. In the case of VTs this could allow very complex VSS schemes to be implemented, however, the processing unit would need to not just process streams but also equipment status. This becomes even more complex than today's schemes since the scheme needs engineering and testing for loss of communications and quality bits.

Ideally a single computer could be used for both Main 1 and Main 2 protection to minimize the cost, however, this would be unlikely to meet the reliability requirements of the substation depending upon what functions are using the processed streams. For protection, an acceptable solution considering all the reliability and maintenance requirements would likely require such a unit be used with each protection device. Providing the required stream summation and switching can be done in the relays then it is likely that this approach would not be used for protection. Complex VSS schemes may prove to be beyond the handling of the relay and providing it is only used for control applications like check synch then such units may be applied on a whole of substation basis.

Stream handling relays

Another option is to use relays which have built in arithmetic or selection functions for the streams. This allows for the sharing of single cores between many devices as well as allowing the use of conventional or non-conventional CTs. It does, however, require the relay to be programmable for the required stream handling allowing for routine testing and emergency switching situations.

The above options are not mutually exclusive and some installations may require a combination of the above.

Normal Stream processing

The processing required depends upon the application and may change if the streams are being used for multiple protections. The main point to consider is that the polarity of the stream is usually not settable and may need to be different for different protections. For example, if we consider the busbar protection the polarity of all CTs will normally be the same providing correct polarity. If the user has a particular standard such as toward or away from bus then it is a common feature for most relays to reverse the inputs numerically.

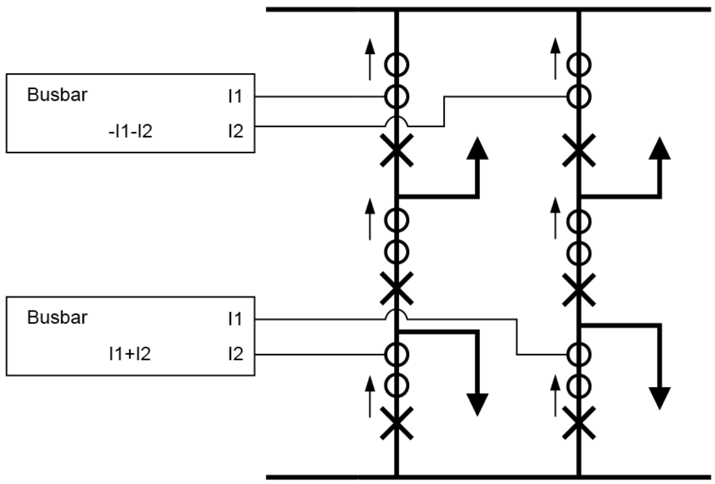


Figure 7

Using stream handling to meet CT polarity standards

Summated functions such as distance, directional protection or mutual coupling is more involved. Assume all CTs have the same primary polarity. For feeder protection, the feeder current is the difference between the feeder CTs considering the polarity. This summation is normally done in the CT wiring. Within the protection, it is usually possible to reverse the summated current but not the individual currents. An individual stream may also require different polarity in the same device. For example, if Line 2 is a parallel line to line 1 then the middle CT has a different polarity residual for mutual compensation and distance.

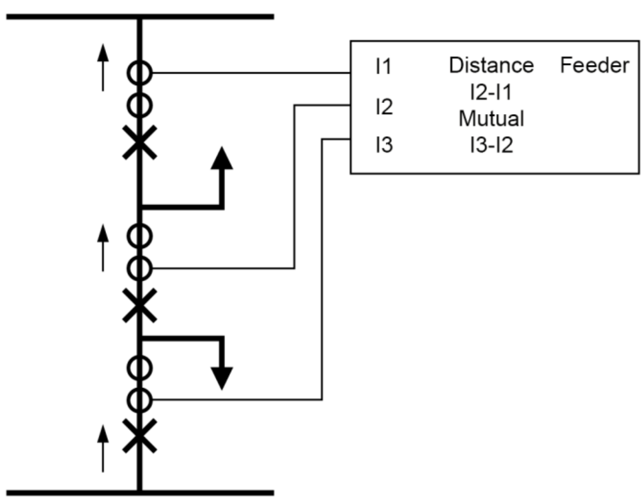


Figure 8

Vector stream differential example. The same stream may be used by different functions requiring different polarities.

Also, there may be cases where CT1 for example has its polarity reversed. In this case the protection needs CT2+CT1.

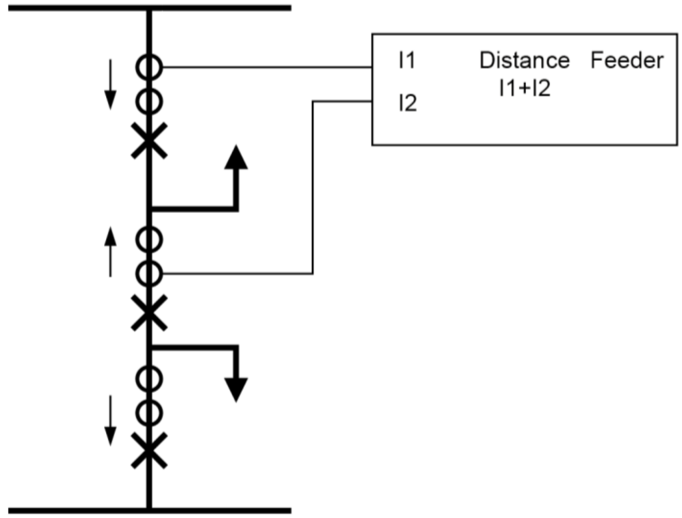


Figure 9

Vector stream addition example

So, in general the current processing will require the addition or subtraction of 2 streams. In some cases, CT reversal, may also be required.

In most breaker and a half substations a feeder VT will be used. So, for the protection functionality there is no stream processing required. The main consideration will normally be whether to bring the VT to a separate merging unit or share it with a CT using a common merging unit. From a cost perspective, a shared unit is usually cheaper even for NCITs, however, this may impact the options to operate the substation under emergency conditions.

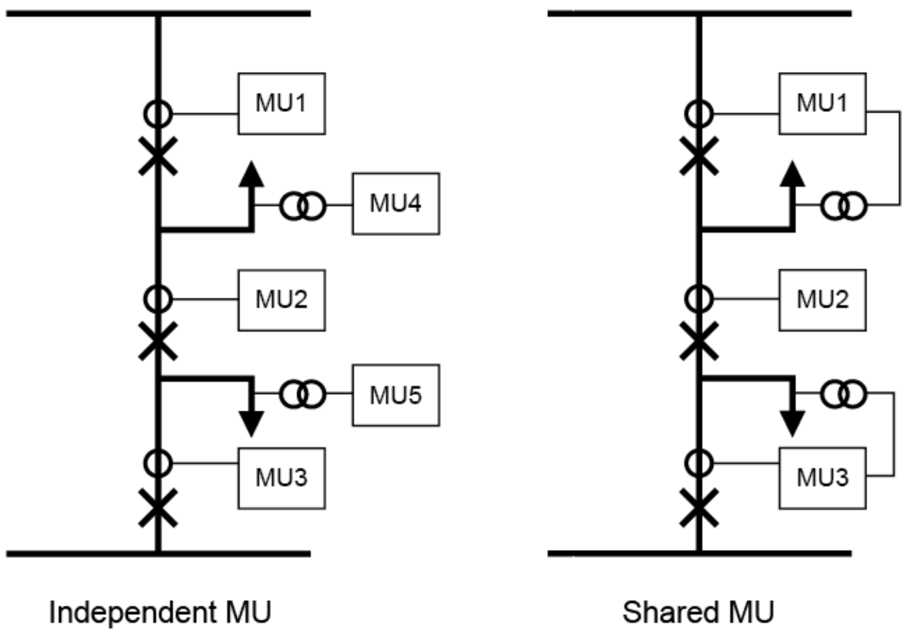


Figure 10

MU options for VT connections

For check synch the upper line and breaker will always use the upper bus VT if available. For the mid breaker, the relay will need to select between the adjacent line VT (if present) or the lower bus VT.

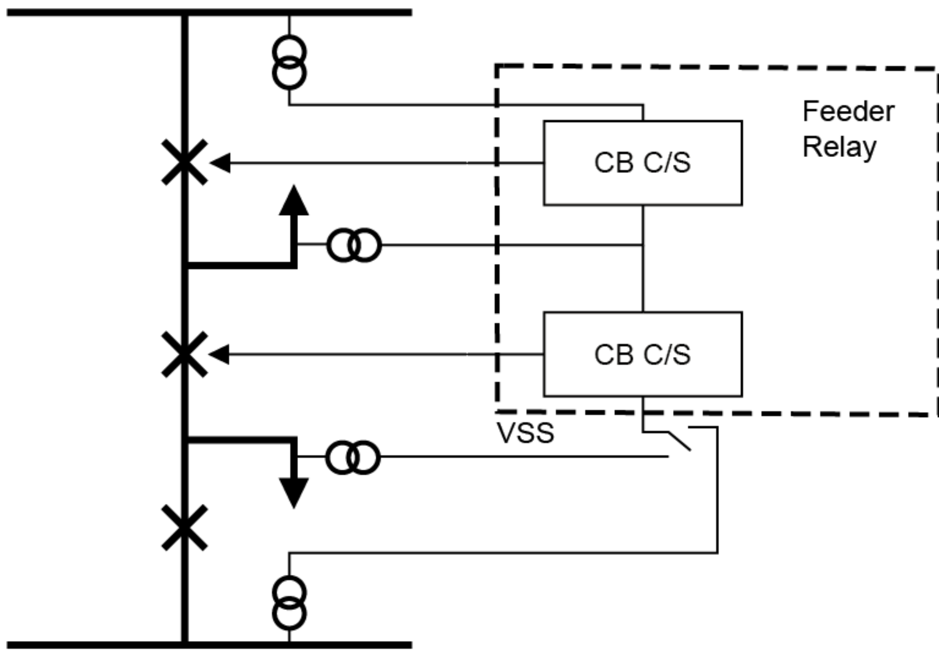


Figure 11

Check synch inputs for breaker and a half

In cases where bus VTs are not present then a more complex selection is used. In general, the number of possible sources is limited to avoid extra stream and position processing. The following shows a 2-diameter substation using only line VTs.

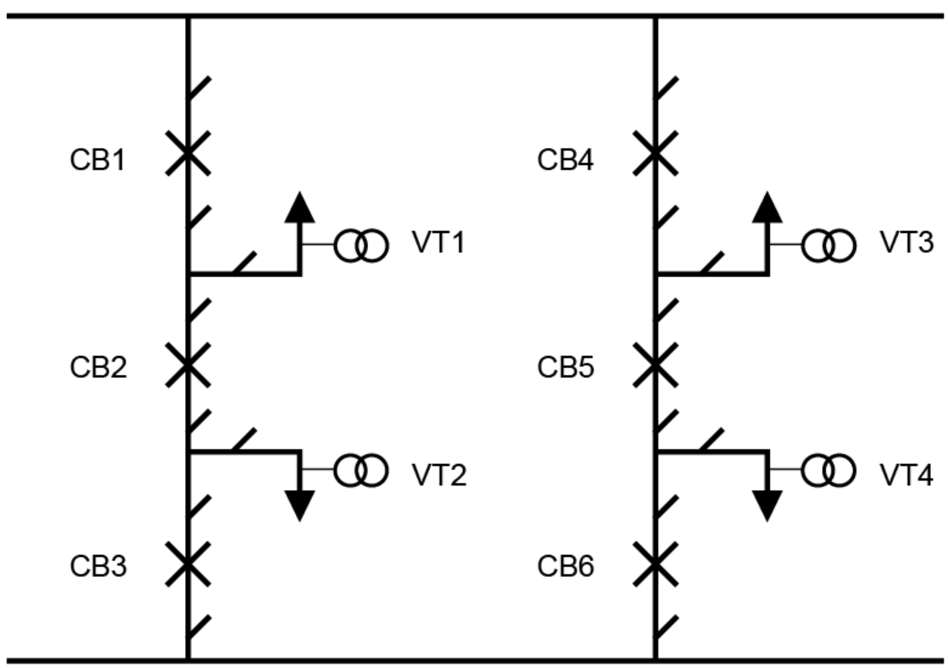


Figure 12

A 2-diameter substation using only line VTs

Under normal conditions to close CB1 a synch check would be done between VT1 and VT3, CB1s isolators would normally be checked as part of the close command, however, the line isolator would need to be checked to ensure VT1 was connected. The VSS would then confirm VT3 was connected to bus 1 by confirming the status of CB4 and its isolators as well as the isolator on VT3 line. If VT3 is not in service, then the scheme could use VT4 or VT2 checking all equipment status between CB1 and the VT to be used. Again, quality and absence needs to be considered adding complexity. The level of complexity multiplies as extra diameters are added. Finally, if operation as a bus tie is required (closing with feeder isolator open), then both check synch voltages are subject to similar complex logic.

It is likely that such complex schemes will not be performed within the protection relays to avoid repeated engineering and testing particularly during substation expansion. As mentioned above a stream processing unit could be used to provide the correct signals to the local CB control unit. Alternatively, a computer could be used to provide the check synch function for the substation. This would then provide a check synch OK signal to the local CB control greatly reducing the number of streams present.

Scheme Testing

The IEC61850 standard provides various methods for testing both GOOSE and Sampled Values using Test mode and Simulation. Edition 2 clarifies that the Test bit in the Quality byte should indicate that a device normally used for service is being tested. The Simulation bit in the message header indicates that a Test device is simulating the signals of a normal device. When applied to sampled values this means a MU being tested will generate the Test Bit and a SV simulator will send simulated messages.

For most busbar arrangements, these signals can be readily used to test the device. For example, if a feeder relay is used on single or double bus then it will always receive it's current from one CT and if that CT is under test then the protection should be disabled. This simplicity does not apply to breaker and a half substations. In these substations, the feeder can be fed from one breaker whilst the other breaker is under test. In this case one of the CT signals will indicate test and the other will indicate normal. In this situation, the protection needs to be enabled and ignore or zero the currents from the MU under test.

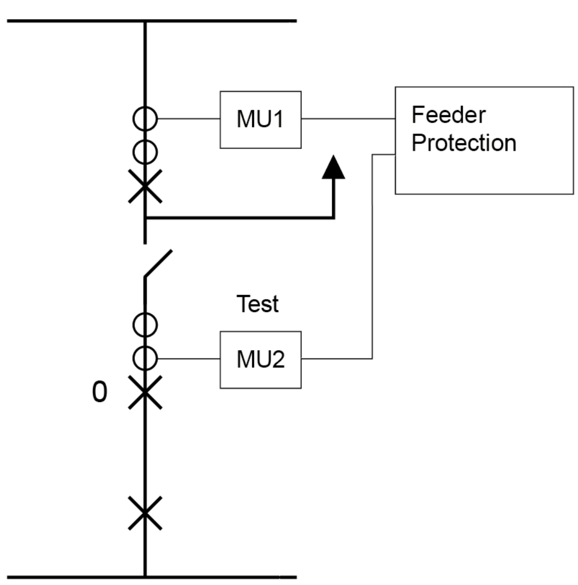


Figure 13

Feeder protection needs to remain active during MU testing

This can be achieved in several ways.

The MU under test could be removed from the network and substituted with a device publishing valid zero currents and voltages. This would disable the protection for a short period during the change and requires additional MUs.
A new configuration could be sent to the relay so that it no longer uses the stream under test. The downside of this approach is that the device would be offline during the change in configuration. Also, the staff applying the change would need to be familiar with the process of changing SV configuration. Whilst it is possible to do such changes remotely it is likely that users will continue to change configuration locally. This would likely require the skilled staff to attend site often just to apply this change. They would also be likely to test the changes further lengthening the time the line is not protected.

Another technique could be to have a manual override to mark streams Out Of Service (OOS). Any stream marked OOS would be replaced with zero value streams with good quality to allow protection functions to operate. Correct sequencing would still be required to avoid interruption to the protection – open breaker, check stream to be zeroed is measuring zero, mark stream OOS, place MU in test mode. Since incorrectly marking a valid stream OOS would likely lead to a maloperation, selecting OOS mode needs to have suitable security. This is very similar to the CT shorting process that would be applied today except that the OOS signal can be logged and visualized for the testers and operators.

It is also important that OOS is only used when primary equipment is out of service. If the MU on one protection is being tested whilst the breaker is live then test mode needs to be used and in this case the protection should be blocked automatically.

Finally, the VT testing must also be considered. Since the main VT is normally on the feeder it will only be tested with the line out of service. However, it is common to use a single MU to publish the VT streams with one of the diameter CT streams. Therefore, testing the diameter CT will normally put the VT streams into test mode. Whilst it is possible to publish test CT streams with normal VT streams it is unlikely for users to risk performing injections physically close to process values.

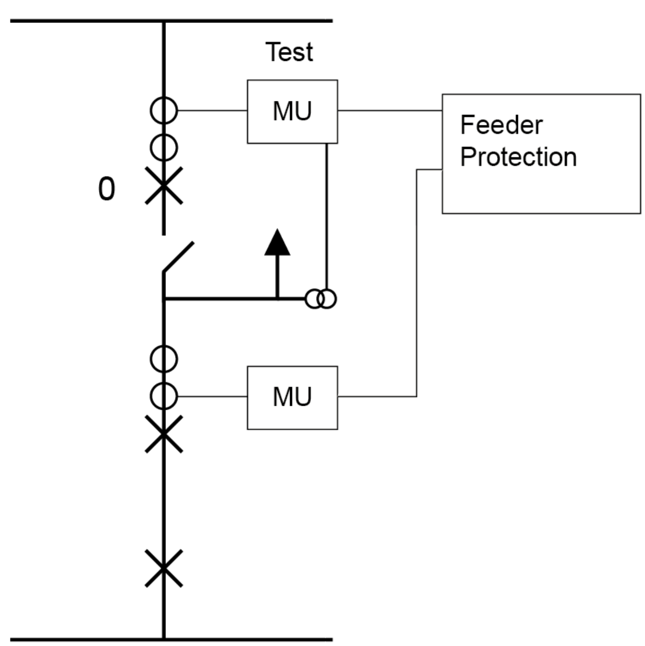


Figure 14

Testing a Shared MU will block voltage signal to feeder protection

To cater for the above situation the VT could also be physically wired to the middle breaker MU requiring additional wiring. The feeder protection VT would then need to be switched to the middle MU if the upper MU is OOS. This approach is limited since there may also be a lower line VT which would likely not be able to connect to the middle MU. Alternatively, the VT from the lower bus could be used since the feeder will normally be fed from this bus if the upper MU is being tested. This avoids the additional VT wiring. Again, such switching would need to be secure and only performed during maintenance.

The ease or otherwise of testing will depend upon the chosen MU arrangement. The sharing of MUs between protections such as busbar and feeder in any substation arrangement reduces the cost of CT or NCIT cores as well as MUs. This saving could well be lost if maintenance activities require both protections to be disabled or require additional equipment to perform the task. Also, some methods mentioned above may require a short period where the protection is unavailable. This may be acceptable for the feeder protection alone but not for the feeder and bus simultaneously.

Substation evolution

Due to their ease of expansion breaker and a half substations are usually commissioned in stages. Often diameters are partially installed (2 breakers to a single line) awaiting future lines that may be several years away. This flexibility is one of the main benefits of breaker and a half substations. It does, however, present challenges since the streams used by different protections will change.

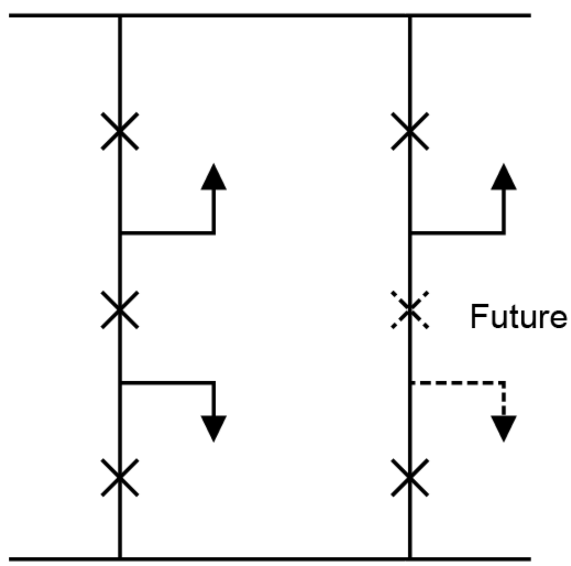


Figure 15

Example of a breaker and a half substation with an incomplete diameter

When the feeder is eventually added, there will be periods where the middle CT is unavailable and may then be tested. During this phase the upper line will be fed from the upper bus with the isolators to the middle breaker open. This phase is like testing the middle breaker except the MU streams are missing rather than being in test mode. As discussed in scheme testing above, the protection needs to maintain operation even though a key signal is OOS.

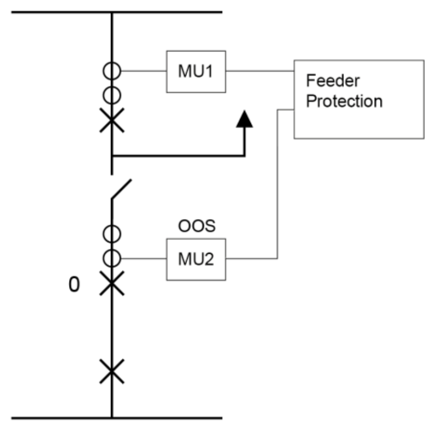


Figure 16

Feeder protection needs to remain active with MU out of service

Operation with a missing CT is not unique to breaker and a half substations, similar situations can occur with multiple winding transformers (dual secondary or tertiary windings). In these cases, the winding remains energised, however, it is unloaded by isolating the winding effectively taking it out of service.

Equipment failures

Breaker and a half substations are very fault tolerant. Most primary equipment faults can be bypassed by operators and lines returned to service. Some failures require technician intervention, however, faulted equipment can usually be bypassed to allow a rapid return to service for the feeders. The response to various conditions should be considered as part of the design process to ensure the process bus system does not limit the substation flexibility. In all situations, the use of conventional or process bus has little affect with regards to primary failures. They do introduce additional modes of failure (MU, Switch, Network) which needs to be considered. In most cases, duplicate protection will ensure the substation remains protected, however, running on reduced protection is often time limited and therefore the functionality loss should be kept to a minimum. For example, the loss of the check synch VT will affect multiple relays but they should only block check synch whilst maintaining their main protection.

For circuit breaker failure, the protection scheme will isolate the faulted breaker by clearing the surrounding breakers. This will also eliminate the current in the breaker isolators allowing the operators to open them and close the backtripped breakers to resupply load. The loss of the CB status MU may impact the check synch VSS and therefore the default status for VSS should be open.

Isolator failures are extremely rare in breaker and a half since they should not be operated on load. Therefore, the urgency to rectify a fail to open or fail to close is usually low. In extreme situations, primary jumpers can be applied and in these cases the status MU would need to have matching jumpers applied. Again, the loss of the status MU would effect check synch. Isolator status is often used for CT elimination in busbar schemes, however, this is not normally required on breaker and a half schemes since line earthing does not normally provide a current path through the diameter CTs.

Current transformer failures are thankfully very rare. The associated explosion normally requires site isolation and examination before returning the affected feeders/busbars to service. Once completed the affected CT can be easily isolated and the lines returned to service. At this point the CT and its associated MU are likely to be taken out of service for an extended period requiring facilities mentioned in substation evolution above. The loss of the CT MU will disable any protection using its stream. This would mean the simultaneous loss of both busbar and feeder protection if the MU is shared between these schemes. This risk may outweigh the benefit of sharing the streams and other options such as 2 MUs per CT or standby MUs may be considered.

With the move towards more differential protection the impact of voltage transformer failures is reducing affecting mainly control, monitoring and backup protection. This may allow short periods of operation without the VT being present, however, during this time both protections schemes are impacted. Some faults, such as blown fuses, may be quickly repairable but faults requiring a VT replacement will likely take longer than acceptable for the affected line. In conventional substations, a neighboring VT signal can be jumpered to the relay's VT input to allow the line to return to service. If SAMUs are used this can still be done but for NCITs this will require the relay to select a different stream. The loss of the VT MU has the same effect as losing the VT itself. If this occurs, then switching to a nearby VT would allow all functionality except check synch to be quickly restored. This could be via a manual operation or automatically on the detection of the VT loss. In this case the process bus solution offers an increased availability when compared to conventional substations.
A new item to consider is the loss of connectivity to MUs. The network must be considered to ensure that simultaneous loss of multiple MUs is avoided or at least the impact well understood. In addition, the network design needs to incorporate simulated messages from test sets which can double network traffic. In breaker and a half substations the network is normally configured such that additional diameters do not impact the traffic on existing diameters except for the busbar protection. This makes the initial design of the busbar protection and it's networking critical to ensure it can easily incorporate future expansion.

Practical Implementation

Any implementation is going to be a trade-off between providing the required complexity to meet the above needs whilst ensuring the user understands the settings and can confidentially apply them. This understanding applies to all the potential users such as designers, testers and post fault analyzers.

Easergy MiCOM P40 relays are widely used for conventional applications and therefore users are very familiar with their operation. The process bus versions offer the same settings so users can leverage their existing experience. This is achieved by using an IED configurator to assign the process bus streams to the existing conventional inputs. To allow for complex arrangements like breaker and a half each input can be a combination of 2 streams with a simple addition, subtraction or switch (OR) function.

E.g.
Ia1 = MU1/1 - MU2/1
Im = MU4/4 + MU5/4
Ubus = MU2/5 or MU3/5

This approach is easily understood by users and is suitable for most breaker and a half solutions without the need to apply external stream processing. Stream switching is achieved using three inputs in the relay's programmable scheme logic. One input switches the first check synch stream, the second switches the second check synch stream and the third switches the remaining inputs. The streams are only switched when the OR operator is used so in the above example the currents are never switched.

Other digital signals are required to allow the process bus to operate over the substation lifecycle. These include indication of stream quality, synchronization or absence. The relay automatically disables only affected functions and provides indication of which input is inhibited. So, for example, if the time synch was missing on the check synch bus voltage the relay will indicate that the source MU is missing synchronization and that the Check Synch VT signals are Invalid. This blocks any function using the Check Synch VT input but the relay will continue to display its measurement.

The relay also includes 2 specific settings to allow for the testing and lifecycle requirements detailed above. The first sets the relay to subscribe to simulation GOOSE and SV in accordance with IEC61850 edition 2. The second is used to select which merging units are out of service and replaces their outputs with zero values with good quality.

To demonstrate the above we will apply Easergy MiCOM P544 (breaker and a half feeder differential and distance), P643 (3 input transformer differential) and P746 (6/7 input busbar low impedance differential) to the following substation (one diameter shown).

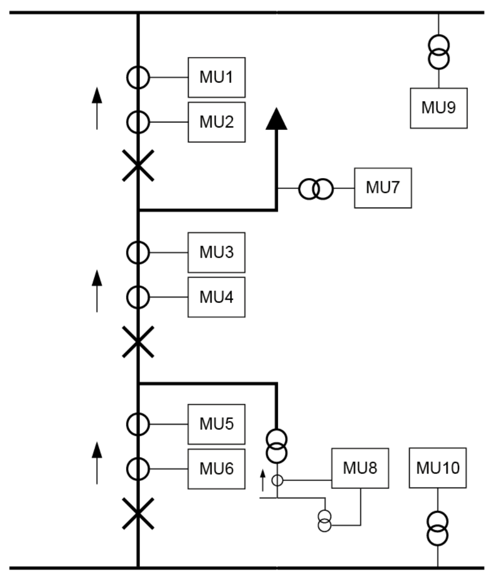


Figure 17

Example full diameter MU locations with feeder and transformer loads

The P544 protecting the upper feeder would be configured as follows
Ia1 = – MU1/1
Ib1 = – MU1/2
Ic1 = – MU1/3
Ia2 = MU4/1
Ib2 = MU4/2
Ic2 = MU4/3
Ua = MU7/5 (or MU10/5)
Ub = MU7/6 (or MU10/6)
Uc = MU7/7 (or MU10/7)
Ubus = MU9/5
Ubus2 = MU10/5

Any parallel feeder would then use a mutual coupling input from
Im = MU4/4 - MU1/4

Similarly, this relay would require a similar summation from the parallel lines CTs. The optional switching allows for the VT inputs to use the lower bus VT in case of VT failure. If the lower connection was a feeder instead of transformer then Ubus2 may also use switching to select this VT when the lower feeder is isolated from the bus. In total the relay is processing 5 or 7 streams depending upon whether a mutual coupling input is being used

The P643 protecting the lower transformer has a similar arrangement
Ia1 = – MU3/1
Ib1 = – MU3/2
Ic1 = – MU3/3
Ia2 = MU6/1
Ib2 = MU6/2
Ic2 = MU6/3
Ia3 = MU8/1
Ib3 = MU8/2
Ic3 = MU8/3
In3 = MU8/4
Ua = MU8/5
Ub = MU8/6
Uc = MU8/7
Finally, the P746 protecting the upper bus would be
Ia1 = MU2/1
Ib1 = MU2/2
Ic1 = MU2/3
(Ua = MU9/5)
(Ub = MU9/6)
(Uc = MU9/7)

The VT connection is optional providing a voltage check on the bus differential function. The remaining CTs would come from other diameters. The lower bus would be the same utilizing MU5 for currents and MU10 for voltages (if used).

Conclusion

Breaker and a half substations provide great flexibility, availability and maintainability which is why they are widely used for HV and EHV applications. It is important when applying process bus to these substations that these benefits are not lost.

Despite these complexities this paper shows that relays like the Easergy MiCOM P40 can provide the required protection without limitating substation operations. The configuration method used is easily understood yet provides great flexibility. The stream summation and switching required for breaker and a half substations is universally applicable providing solutions for most complex bus arrangements.

About the author

Ian Young is a Principal Application Design Engineer at Schneider Electric Australia's Energy Business. He holds a Bachelor of Electrical Engineering with first class honors from the University of Technology in Sydney, Australia. Ian is a past CIGRE study committee B5 member and convener of AP B5. He has presented papers at various industry conferences in the region including SEAPAC, APS, Machines and ESAA. He worked with Endeavour Energy to produce the paper 'FAT testing of 61850 concepts' which formed part of CIGRE's 2013 special report 'Acceptance, Commissioning and Field Testing for Protection and Automation Systems'. He also provides training at Schneider's Analysis and Protection of Power Systems (APPS), IEC61850 hands-on and Process Bus courses.

998-2095-05-30-18AR0_EN