Siemens plc.

Technical Report
for

Electricity North West

Fault Current Active Management (FCAM)

Siemens Reference :
70PO-81118

	Issue Record			
Issue	Issued by	Checked By	Date	Reason
0	D York	V Thornley	11/04/2014	FIRST ISSUE
1	D York	O Olabisi	22/04/2014	Modified in line with customer comments
2	C More	O Olabisi	10/11/2014	61850 logic modified and test results added

1. Introduction

This report has been written to highlight different options available to Electricity North West (ENW) to manage fault levels on their 33kV and 6.6kV distribution systems. The introduction of embedded generation, being connected to the system at distribution level, has meant that the existing equipment fault ratings are being exceeded.

This report will look at the existing protection currently employed on sections of the ENW network. After reviewing the types of protection, recommendations will be made on how these can be utilised for adaptive protection schemes, to manage excessive fault levels. If this isn't possible an alternative offer will be proposed. As well as the existing protection on the primary substations, consideration will be given to the Generator protection feeding into the system to see what, if anything, can be done to limit the source current supplied during fault conditions.

ENW has a variety of relay types on their 33kV and 6.6kV distribution system. These protection devices range from the older static relays to the later numerical relays. The main differences between the two types is the hardware and processing power available. Numerical relays use microprocessing and have the flexibility and functionality to perform user defined logic functions such as blocking inputs to the protection elements or to have different setting groups for variations in operating conditions. The static relay is fixed in its functionality designed to perform a function, limitations in the hardware and processing mean they have limited flexibility. This difference in technology will be highlighted in the proposed solutions available at different parts of the network.

The next section of the report will look at the philosophy behind the current grading employed on the system and highlight the limitations it has with regards to the increased fault levels.

2. Problem Definition

ENW has a radial distribution system which has conventionally been fed from power stations supplied through National Grid's Transmission Network. This has meant that grading has been on a top to bottom philosophy, meaning that faults downstream are cleared first, as fault current levels are predictable and limited by the characteristics of the primary distribution system such as the transformers connected to it and the line impedances.
The equipment specified will have been based on the maximum fault level that can be supplied through the transformers connected to it. This is limited by the characteristics of the transformer to a large extent, these being the MVA rating, impedance and method of earthing. Figure 1 shows a section of the distribution network.

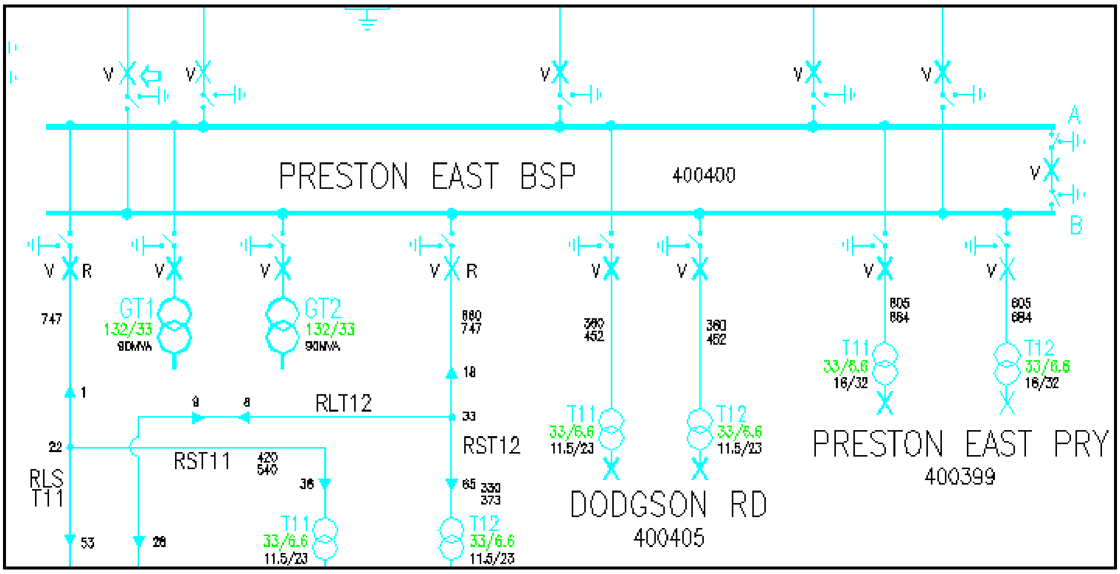


Figure 1: Section of ENW's 33kV network

The main fault contribution comes from the two connected 132k/33kV grid transformers. The highest fault level is when the transformers run in parallel as this is when the source impedance seen is smallest. The fault current seen through each transformer, assuming similar impedances, will be half the total fault current assuming no external in feed from interconnected circuits or any embedded Generation connected in at that voltage level.

The rating of the equipment defines the maximum currents that can safely be made and broken under fault conditions. The switchgear rating cannot be extended unless expensive retrofitting is carried out which often means the replacement of the equipment itself. For economic reasons it is therefore reasonable to look at alternative solutions in dealing with higher fault levels.

The options are twofold, limit the fault current through the switch by means of fault current limiting devices or use existing technology such as the protection relays to make intelligent decisions before they operate. The first option is not in the scope of this report so this report will focus on the protection relays currently in service and the latest relaying technology available to give recommendations, if current equipment cannot meet the solutions put forward.

3. Proposal

The following section will describe the options available to the different types of technology utilised on the current system. It will consider what options are available to reduce the risk of operating the switchgear above its rating. The current rating of switchgear typically used on ENW's distribution network can be seen in Table 1.

Busbar	Three Phase Fault Currents		Single Phase Fault Currents		Switchgear Ratings	
	Peak Make (kA)	Rms Break (kA)	Peak Make (kA)	Rms Break (kA)	Break Duty (kA)	Make Duty (kA)
Chapel Wharf / 6.6kV	35.65	12.82	5.12	1.96	20.0	50.0
Preston East / 6.6kV	43.42	15.44	4.86	1.89	25.0	62.5
Heywood / 6.6kV	31.21	10.65	4.68	1.94	20.0	50.0
Atherton TC / 11kV	37.82	13.18	5.20	1.96	20.0	50.0

Table 1: Typical Switchgear Ratings.

It is envisaged that the introduction of embedded generation may pose a problem on the network as the possible fault current may exceed the break capacity of the switchgear.

Therefore when proposing possible solutions, the main aim will be to manipulate other parts of the network in order to reduce the fault current to a suitable level, thus allowing the local breaker to clear the fault safely within the limits of the switchgear rating.

3.1 Existing Network Circuits

For locations of the ENW network where the switchgear rating may be exceeded it is proposed that a blocking scheme should be implemented in order to allow sections to be isolated with the least amount of disruption. This will involve signals being passed from one relay to another to block one relay from operating, and permitting the operation of another relay to reduce the possible fault level.

The information used for this report has been based on four of Electricity North West's network locations. These are

- Atherton Town Centre
- Heywood
- Preston East
- Chapel Wharf

At the Atherton Town Centre and Heywood locations the sites have mixed protection types. The protection relays are predominantly older types, such as GEC CDG overcurrent relays. As previously highlighted earlier in this report these relays have no flexibility and will only offer basic protection. The relays identified, for protection, in each location section are shown in Table 2.

Location	Relay Types	Binary Inputs	Binary Outputs	Type
Atherton Town Centre	MCVG 61	0	2	Static
	MCGG 52	0	4	Static
	Argus 1 (SBEF)	1	7	Numerical
	KCGG 140	8	8	Numerical
Heywood	CDG 36	0	2	Electromechanical
	Argus 1 (OCEF)	5	11	Numerical
	2DCC	0	3	Static
Preston East	Argus 1	5	11	Numerical
	Delta	19	21	Numerical
	Argus 2	5	11	Numerical
Chapel Wharf	Argus 1	5	11	Numerical
	Delta	19	21	Numerical
	Argus 2	5	11	Numerical

Table 2: ENW Relay types per location

As can be seen in Table 2 there is a limitation to what can be achieved using the existing relays.

3.2 Relay types

CDG 36

The transformer incomers on the Heywood circuit both have CDG 36 Overcurrent protection which is an electromechanical relay. Obviously this offers no binary inputs, which can be used to block protection from operating or change settings groups, and so cannot be manipulated for our consideration.

MCVG 61

The transformer incomers for the Atherton Town Centre circuit use a static type protection relay, the GEC Alsthom MCVG 61. This is a static 3 pole Voltage Controlled Overcurrent relay. The relay is set using switches on the front, and has fixed I/O offering no binary inputs. Therefore this relay cannot be manipulated for blocking schemes or alternating settings groups.

MCGG 52

The MCGG 52 is a two phase overcurrent plus earth fault relay, which again is a static type relay. Similarly to the MCVG 61 the settings are achieved using switches on the front and has limited functionality. The relay offers no binary inputs so cannot be considered in blocking schemes or schemes for changing setting groups.

KCGG 140

The KCGG 140 is a numerical relay and offers 3 pole overcurrent and earth fault protection. The relay has 8 binary inputs and 8 binary outputs which can be assigned to various functions, including blocking the protection elements and changing setting groups.

2DCC

The 2DCC is a static relay used for overcurrent and earth fault protection. The relay offers no binary inputs and 3 binary outputs. As per the previous static relay types this relay can’t be considered in blocking schemes or those involving setting group changes.

Argus 1

The Argus 1 relays are numerical type relays, which are used for overcurrent and earth fault protection. The relays have various options for binary inputs, and there are two options in use on the schemes reviewed for this report. The relay selected for SBEF has 1 binary input and 7 binary outputs. The relay used for OCEF has 5 binary inputs and 11 binary outputs. These can be assigned by the user for both blocking protection elements and changing setting groups so it is possible these relays may be used in blocking schemes, or used to change settings groups.

From the above section describing the relays that are currently in use on the ENW network, it can be seen that there are obvious limitations with the scope of using the relays in advanced schemes. The hardware for all protection relays is old and now outdated, and there are some relays that have no binary inputs which can be used to adapt the relay to different situations, such as blocking or changing settings groups. The newer relays that do offer binary inputs however, do not have logic capabilities which allow the user to define how the relay should operate.

The options for controlling the relays are outlined in section 3.3.

3.3 Relay Protection Schemes

3.3.1 Option 1 – Hardwired scheme

The first option to be evaluated is the possibility of using the existing relays and using binary inputs and binary outputs to block protection functions from operating on certain protection relays. This would require modifications to the site wiring. In a fault scenario block signals could be sent using the binary output of one relay to a binary input of another relay, in order to inhibit the protection operating at that location.

For the older type circuits this is a potential problem, as the relays in these locations are predominantly on older hardware platforms, and thus offer limited control. As an example, the CDG 36 is an electromechanical relay which can only be set to operate for basic overcurrent applications. With no binary inputs available to control the relay it won’t be possible to use this relay in a blocking scheme. This is also the case for the static type relays such as the 2DCC and the MCVG/MCGG relays.

The KCGG 140, Delta and Argus relays are newer relays which can be included in blocking schemes. However, whilst they will offer the possibility to block protection elements from operating, it will not be possible to programme conditioning logic, such as using AND gates for current level thresholds and CB position. The protection elements of the relays would need to be utilised to operate for values of fault current above the break duty. Presently, in newer circuits of the ENW network, there is already a busbar blocking scheme actively in service. The feeder relay is an Argus 1 type relay, with 5 Binary Inputs and 11 Binary Outputs, as shown in Table 3.2.

For the busbar blocking scheme, Binary Output 7 of the Argus 1 is used so that in the event of an overcurrent pickup the circuit is closed and a blocking signal is sent to Binary Input 2 of the busbar Argus 2 relay. Binary Output 3 has also been wired into this circuit and is used for Circuit Breaker Failure. The contact has the option of being wired normally closed or normally open, and in this circuit normally closed has been used. Therefore for healthy conditions Binary Output 3 will be closed and will block the bus section from operating. If however, there was a CB failure Binary Output 3 will open and remove the block to the bus.

This could be adapted for the FCAM project by routing a second stage of protection to operate when the fault current is higher than the break duty of the CB. This can then operate Binary Output 3 in parallel with the CB Fail protection function. If there is a fault that exceeds the break capacity of the breaker, Binary Output 3 will open and remove the inhibit to the Bus Section. Presently the terminals of the normally closed contact are wired for the busbar blocking signal for CB Fail. For the FCAM function, the terminals of the open contact would then need to be wired to energise one of the spare binary inputs, which will be used to block the Argus relay's overcurrent protection. Therefore Binary Output 3 will open to remove the blocking signal to the bus and at the same time inhibit the feeder overcurrent protection from operating. This will allow the bus to operate and reduce the fault level, which will in turn remove the block to the feeder overcurrent protection, allowing it to operate and clear the fault.

The same philosophy is used for the transformer incomer protection. A Delta relay is used for the protection at this point, but the principle would be the same. The Binary Output can be used for wiring back to a spare Binary Input to inhibit the Overcurrent protection, whilst at the same time removing the inhibit to the bus, allowing it to trip.

If the fault through the bus section is higher than the break capacity then a transformer could be tripped to allow fault reduction. The same blocking method used for the feeder relay, described above and in Figure 2, can be used on the bus section relay. With the bus protection element inhibited, either the transformer or generator protection would be required to operate. Obviously the overcurrent grading would have to be analysed to check this is feasible.

This option will require modifications to be carried out on wiring for the Binary Output and also for an inhibit to be configured on one of the spare Binary Inputs. The settings file for the existing schemes would also need to be modified for the new protection stage. This solution was tested successfully and the results can be found in Appendix 1.

For this scheme, reclosure of the breakers would have to be done manually.

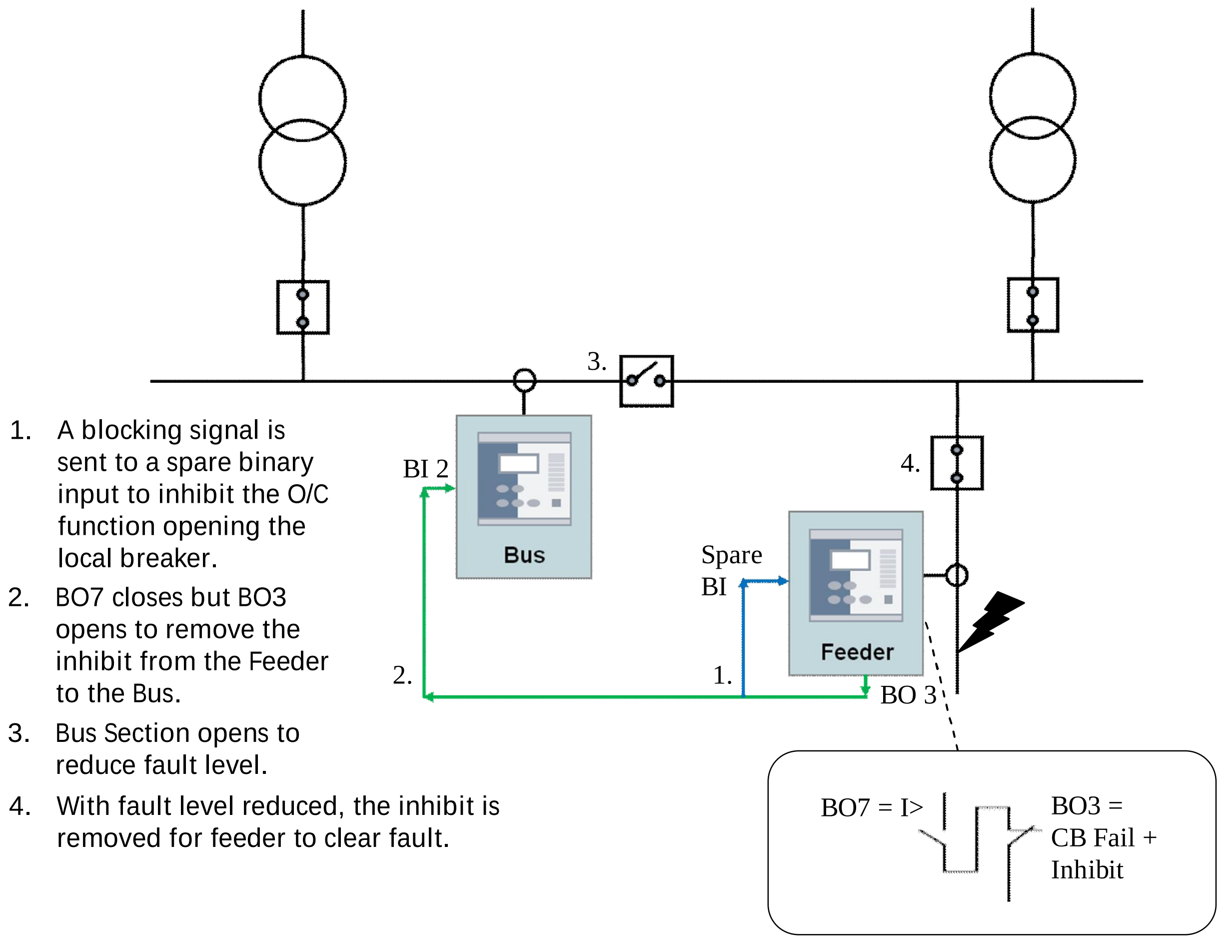


Figure 2: Busbar Blocking Scheme.

3.3.2 Option 2 – Siemens proposal for new relay schemes

Due to the limitations outlined in the previous section Siemens would propose implementing a new scheme to monitor the system currents and control the circuit breakers. This would be based on utilising the Reyrolle Argus M 7SR2 relays and using the IEC 61850 communications protocol. Using the IEC 61850 protocol would allow information to be passed from one relay to another in an ethernet network, with the use of switches.

One advantage of this type of scheme is that hardwiring would be kept to a minimum, with only circuit breaker indication, and binary outputs being used for tripping purposes. Therefore relays with a minimum I/O count could be specified, assuming a basic scheme. With this philosophy the cost of material as well as installation time spent wiring would also be greatly reduced, as traditional wiring for signals between the relays would be achieved with connection of a fibre or electrical RJ45 connection.

A second advantage is the GOOSE (Generic Object Oriented Substation Event) messages being used for interbay communication, to pass the information from relay to relay, are high speed. A typical operate time would be 8 ms.

The traditional system which is currently in use follows a structure similar to the one shown on the left hand side of Figure 3.

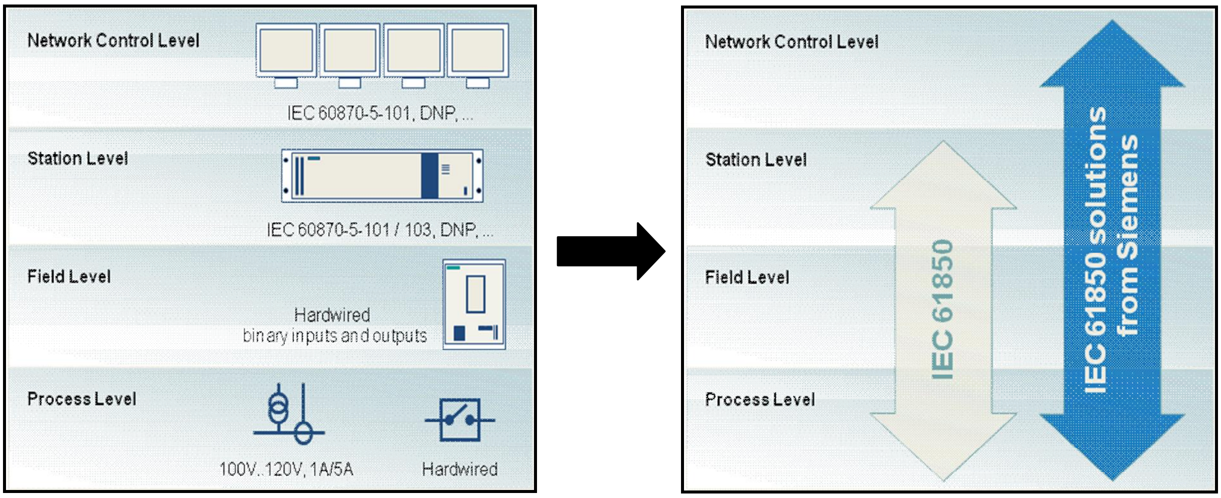


Figure 3: Scheme progression using IEC 61850

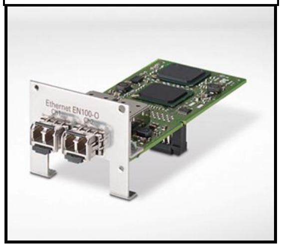
The devices of traditional schemes communicate to each other through wiring. The devices would be hardwired and the communications would be slow due to serial protocols using a master-slave technique.

The progression to IEC 61850 allows all devices to communicate over the different levels using the ethernet network. This allows greater control and faster operation, as there are no conversions taking place between levels.

4. 7SR21/7SR22 Relays and communication options

The Reyrolle 7SR2x relays are multifunctional overcurrent and earth fault protection relays, which offer a wide range of protection functions. There are two versions of the relay, the 7SR21 which is a non-directional version and the 7SR22, the directional version.
Using experience gained from many worldwide installations of the Siprotec relays, the Siprotec EN100 module has been integrated into the Reyrolle 7SR2 relays. There are two options of this module available, one providing fibre optic ethernet connection through LC type connectors, and the other providing electrical ethernet connection using RJ45. These are shown in Figure 4.

Fibre Optic Module



Electrical Module

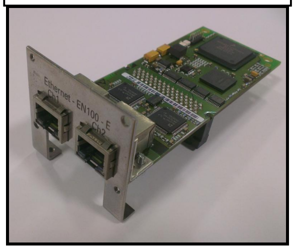


Figure 4: EN100 Communication Module Options

The Fibre Optic version of the EN100 module has an integrated switch, which can effectively allow some external switches to be omitted. Therefore the optic EN100 modules can also actively transfer data through both ports simultaneously. This will depend on the network configuration and what redundancy is selected.

The Electrical EN100 module does not have an integrated switch and therefore must use an external switch to pass the information. However, both modules offer redundancy as there are two ports on each. Only one of the two interfaces will be active at all times. Should one interface fail then switchover is automatic.

A typical ethernet network is shown in Figure 5. This is a simple ring structure with 4 switches used. The diagram in Field 1 shows an electrical star with two 7SR2 devices. In this configuration there would be no redundancy if the switch were to fail. Therefore the option in the Field n diagram could be used if the electrical EN100 module were to be selected. This will offer redundancy if one of the switches were to fail.

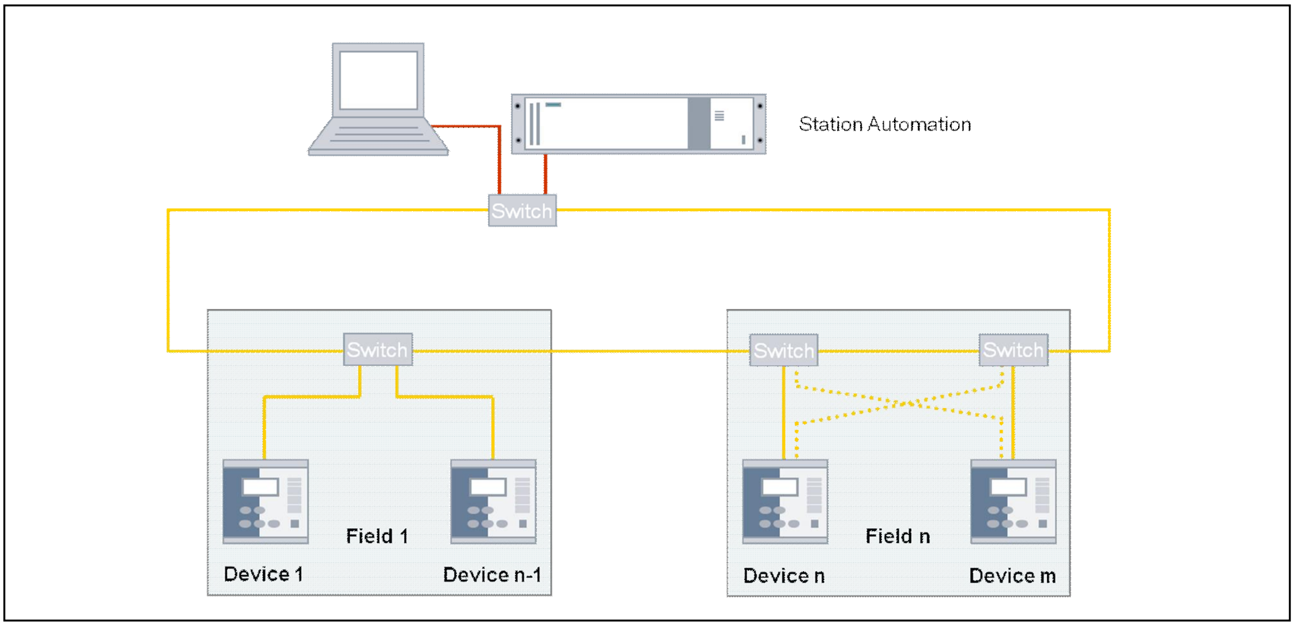


Figure 5: Simple Ethernet Network using the Electrical EN100 Module.

As previously mentioned the fibre optic EN100 module has the benefit of having an integrated switch. This makes the network configuration relatively simple and reduces the number of external switches required. By connecting the EN100 modules from one relay to the next, the external switches can be omitted all apart from the switch to the control centre. To aid in redundancy a second switch should be installed at this point. This is shown in Figure 6.

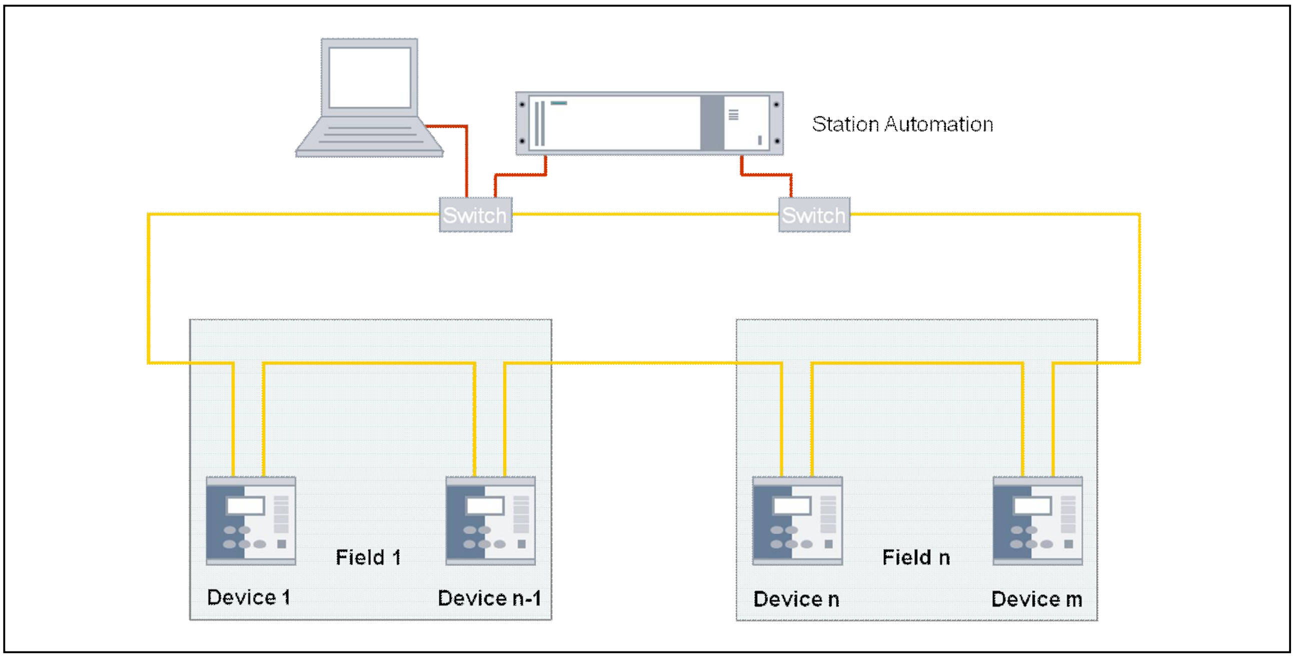


Figure 6: Ethernet Network using the Optic EN100 Module.

In Figure 6 the information is passed from device to device in the ring until it reaches its destination. If the ring structure shown is broken in one spot it becomes a line. The communication still continues to function, as the Rapid Spanning Tree Protocol (RSTP) allows fast automatic rerouting of information. However, a second error in the line or in one of the devices cannot be compensated for.

4.1 7SR2x relay proposal for FCAM

Based on the information in the previous sections Siemens propose using 7SR2102 relays for all non directional overcurrent and earth fault locations. If directional protection is required then this would change the relay type to 7SR2203 relays. The full MLFB ordering codes are as follows.

For non directional protection: 7SR2102-1AA87-0CA0
For directional protection: 7SR2203-2AA87-0CA0

These can be broken down to show the detail of the relays as shown in Table 3 and Table 4

7SR210	Non Directional O/C Protection
2	E6 Case, 4 CT, 9 Binary Inputs/8 Binary Outputs, 8 LEDs
1	1/5A, 50/60Hz
A	30 to 220V DC, Binary Input threshold 19V DC
A	(Standard)
8	Standard version – plus additional rear 2 x Optical Ethernet
7	IEC 60870-5-103, Modbus RTU, DNP3.0 and IEC 61850 Protocols (user selectable setting)
0	(Standard)
C	Standard protection functions for O/C and E/F (please refer to catalogue for full list)
A	No Additional Functionality
0	(Standard)

Table 3: 7SR21 MLFB code and functions.

7SR220	Directional O/C Protection
3	E8 Case, 5 CT, 4 VT, 13 Binary Inputs/14 Binary Outputs, 8 LEDs
2	1/5A, 63.5/110V, 50/60Hz
A	30 to 220V DC, Binary Input threshold 19V DC
A	(Standard)
8	Standard version – plus additional rear 2 x Optical Ethernet
7	IEC 60870-5-103, Modbus RTU, DNP3.0 and IEC 61850 Protocols (user selectable setting)
0	(Standard)
C	Standard protection functions for Directional O/C and E/F (please refer to catalogue for full list)
A	No Additional Functionality
0	(Standard)

Table 4: 7SR22 MLFB code and functions.

With the inclusion of the EN100 modules for IEC 61850 the 7SR2 relays can now be programmed using Reydisp Manager, as shown in Figure 7. This software creates a project environment for the relays and due to the signal requirements for IEC 61850, logic has been included so that the user can freely programme the relay, as well as publish and subscribe to GOOSE messages from other relays.

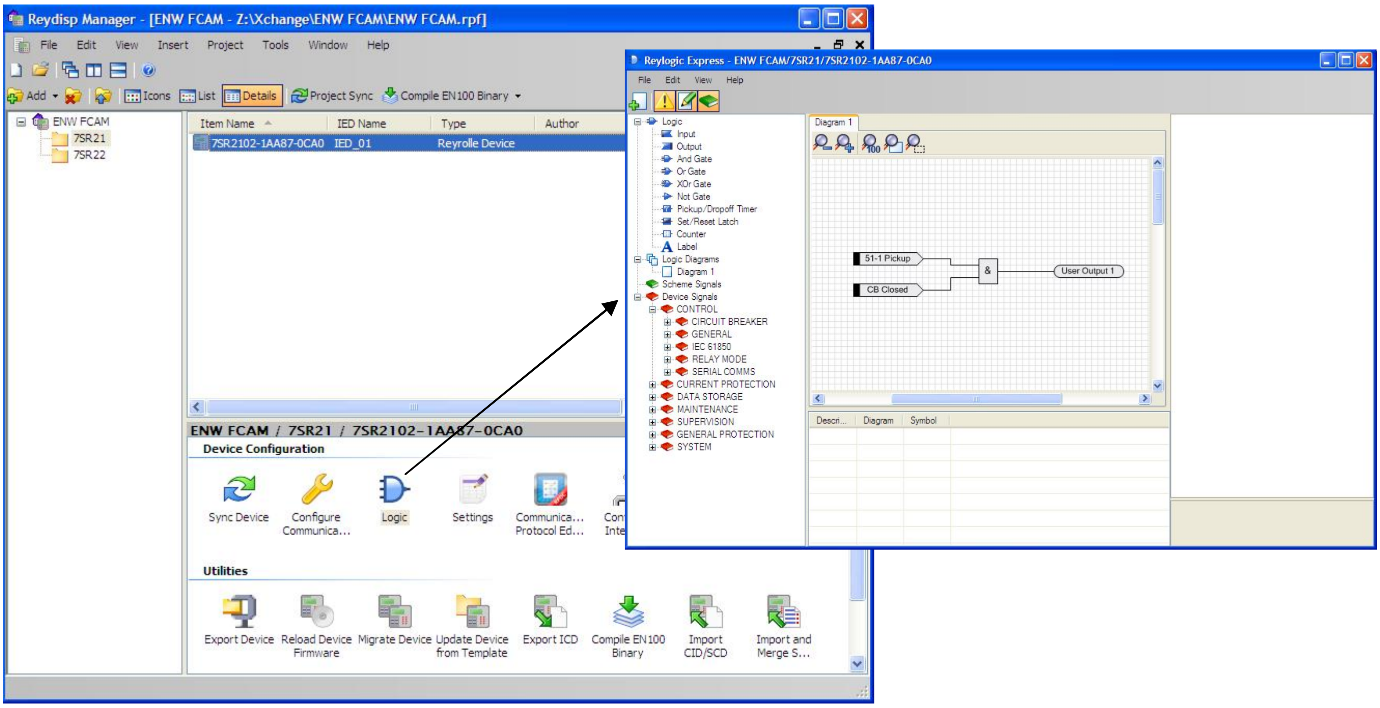


Figure 7: Reydisp Manager Software

There are a wide range of signals available in the programmable logic. These include the protection elements of the relay such as overcurrent pickup and trip signals, circuit breaker status and inhibit signals. To publish and subscribe to GOOSE messages user inputs and user outputs are also available in the logic. This gives a wide scope of signals to use in adapting the relays for fault level management, utilising IEC 61850.

4.2 Relay Logic

The 7SR2x relays have a number of protection elements available for the overcurrent and earth fault protection. The 7SR21 relays have 2 elements for IDMT overcurrent, and 2 elements for DMT overcurrent, giving 4 elements in total. This is duplicated for the earth fault protection. Due to the 7SR22 being a directional relay, more elements are available. The 7SR22 has 4 elements for IDMT overcurrent, and 4 elements for DMT overcurrent, giving 8 elements in total. This is also the case for the earth fault protection.
Presently it is not possible to monitor the currents of each relay and pass this information over GOOSE to other relays. Therefore Siemens propose to use the different protection elements of the relays for both protection and for monitoring use to communicate current levels with other relays.

As an example, part of the circuit at Heywood 200115 is illustrated in Figure 8.

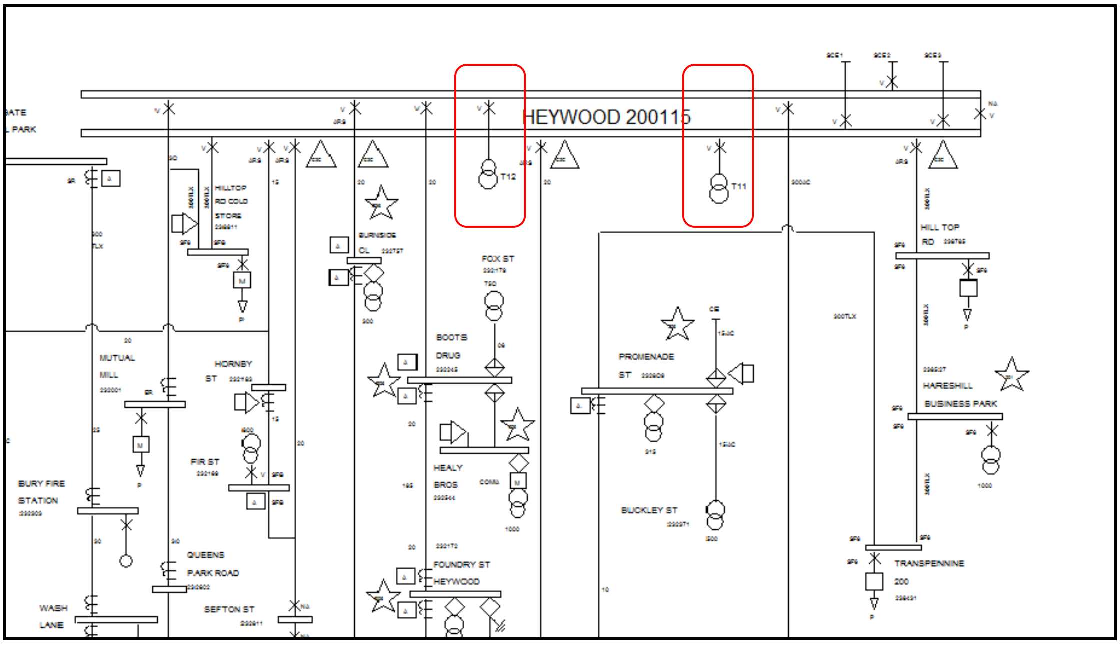


Figure 8: Heywood 6.6kV.

T11 and T12 are the transformer incomers, stepping down the volts from 33kv to 6.6kV. Presently these incomers have CDG 36 overcurrent relays as part of their protection. As illustrated in section 3.2 these relays offer no flexibilty to be adapted for the fault management. The feeders in the circuit above have a mixture of 2DCC relays, and newer Argus 1 relays.

To allow Fault Current Active Management the relays would have to be replaced with the 7SR2 relays proposed in section 4.1. All the older relays mentioned above could be replaced with the 7SR21 relays, as there is no directional protection on these circuits.

We will consider the implications of a fault on one of the feeders, for example on the Hill Top Road circuit. Assuming that the fault current is being fed from both the source and the generation on the LV network, and is higher than the rated switchgear break duty, the relays will be required to assess the conditions of the other circuits and make a decision on whether to inhibit/trip. The possible sequence of events would be

- To trip the Bus Section
- If fault current is higher than BS switchgear rating, trip the Transformer incomer
- If this is not viable, trip the generator.

To be able to do this, logic will need to be set up using the protection elements of each device. The proposed logic is detailed in the following sections.

Please note that this logic is based on the Overcurrent protection elements. This can be replicated for the earth fault protection using the same philosophy.

Prerequisites

i. For each relay the circuit breaker Open/Closed status will need to be routed to binary inputs.
ii. One stage of overcurrent will be used for protection purposes (51-1), a second (50-2)will be used for current monitoring. The same will be done for earth faults.
iii. Inhibits to other relays will be conditioned via GOOSE.
iv. Reclosure can be achieved when certain system conditions have been met.

4.2.1 Inhibit Protection Logic

Feeder 7SR21 Relay

The first Overcurrent element (51-1) will be set as per the original settings of the CDG 36. This will leave the first DMT element (50-1), a second IDMT element (51-2) and a second DMT element (50-2) available to be used for FCAM purposes. As in the hardwired scheme, a pick-up of the 51-1 element will block the bus section and transformer relays and operate first; this block is released should the relay detect a circuit breaker fail condition. The logic for this is shown in Figure 9.

The 50-2 element of the overcurrent protection will be set to operate for the higher fault level, there is no need for a time setting for this element as it used for monitoring the fault level, and won't be used to operate the breaker. This information will be passed to the Bus Section relay, where it can be used to assess the system conditions. The logic for this relay to detect the fault above the break capacity and send a GOOSE to the Bus Section is also shown in Figure 9.

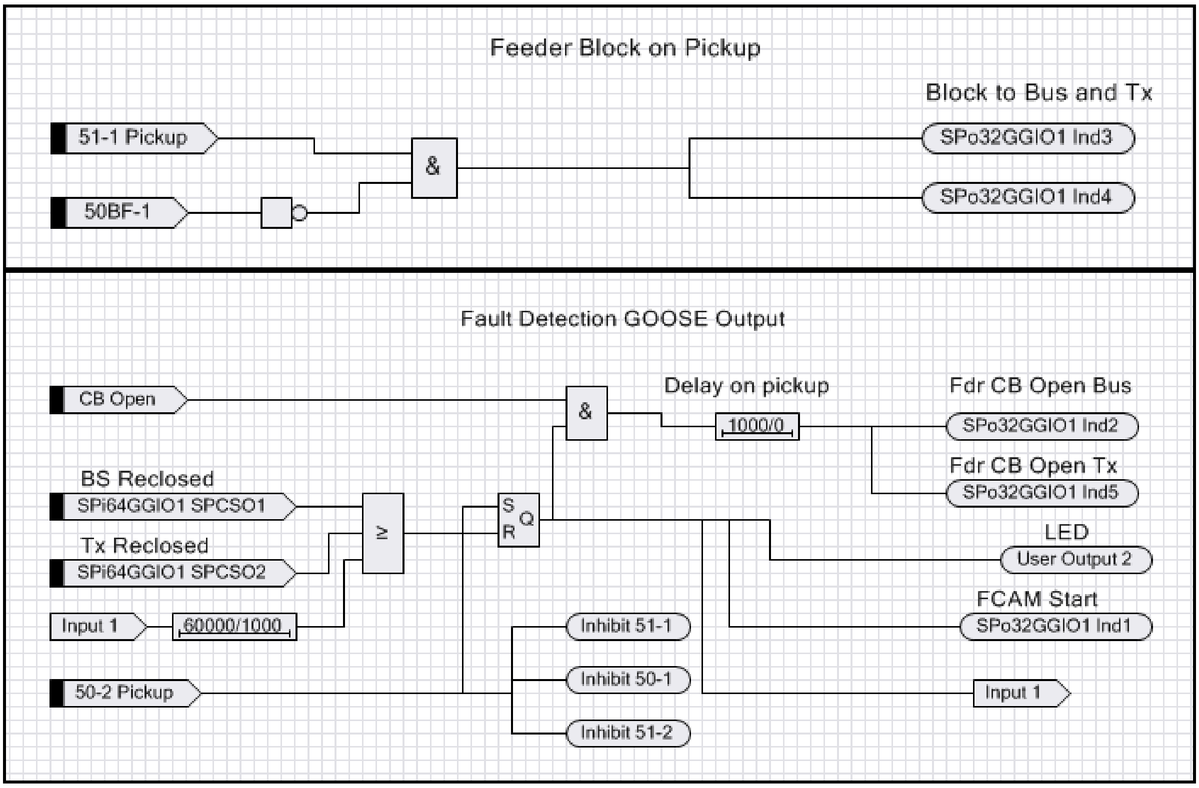


Figure 9: Feeder GOOSE Output Logic Chart.

The 51-1 element of the feeder relay will operate as per the original scheme. If there is an overcurrent condition and the fault current is within the break duty switchgear rating, the overcurrent element will operate as normal and close its designated Binary Output to open the breaker.

The logic in Figure 9 shows that if there is a pickup of the 50-2 element, a GOOSE message will be generated and sent to the bus section and the transformer incomers (FCAM Start). It's overcurrent protection elements 51-1; 50-1 and 51-2 will be inhibited, to allow one of the upstream relays to operate.

The feeder relay will continuously monitor the current, and as soon as it drops below the 50-2 threshold the 51-1 element with operate, open the breaker and clear the fault.

Bus Section 7SR21 Relay

The Bus Section relay will operate in a similar manner to that of the Feeder 7SR21. The first overcurrent element 51-1 will be used for protection and the second DMT element 50-2 will be used for FCAM purposes. On receipt of the GOOSE message from the feeder protection, the Bus Section will perform a check, and if the 50-2 element is below the threshold, the bus section will be tripped; the trip output will also prime the closing logic. If the current level is above the 50-2 threshold the bus will inhibit it's overcurrent elements and send a GOOSE message to the Transformer Incomers. This is shown in Figure 10.

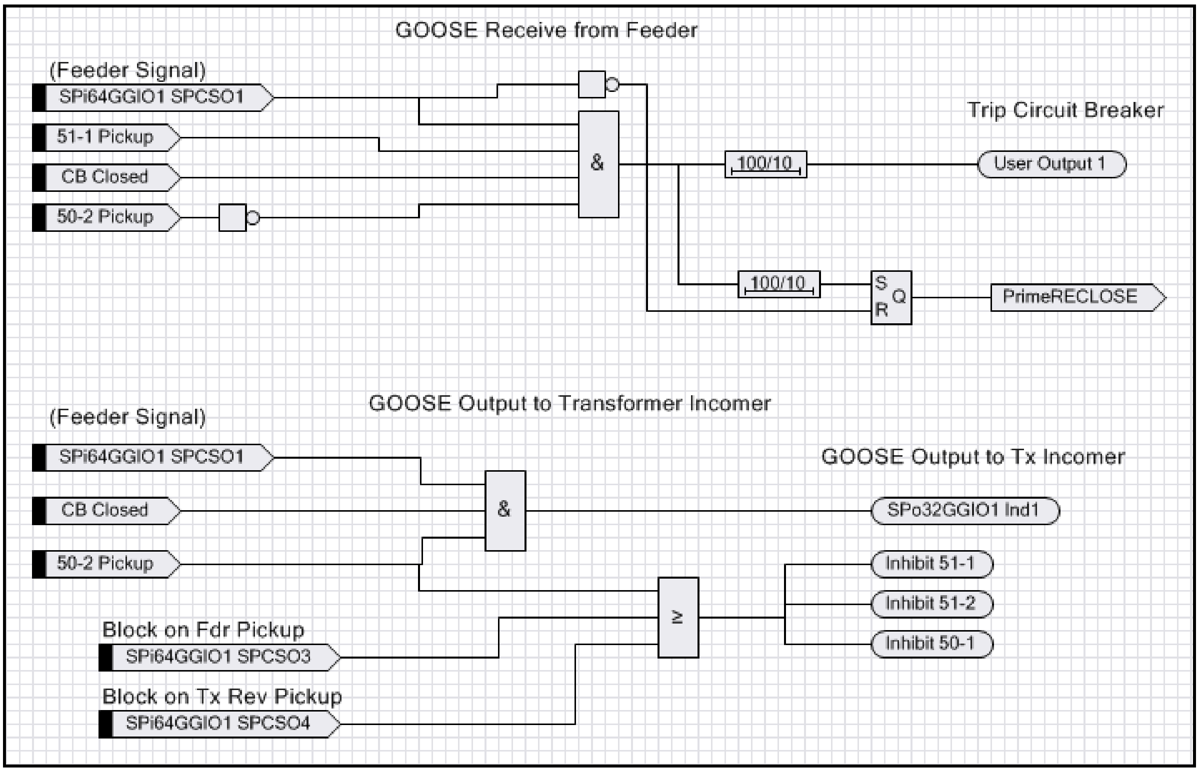


Figure 10: Bus Section GOOSE Logic Chart.

Transformer Incomer 7SR22 Relay

The transformer incomer logic will be the same as the bus section with the exception that it will not send a further GOOSE message on to another relay. If a GOOSE message is received from the Bus Section there will be a check to verify that the current is lower than the break capacity (50-2), which we would expect. If this is not true, the local overcurrent elements will be inhibited to allow fault clearance upstream, or by any distributed generation supplying the fault.

In the transformer 7SR21 one of the spare binary inputs, for example binary input 3, can also be used as a selected to trip input. This means that both transformer relays can subscribe to the GOOSE message from the bus, but only one will be primed to operate and open the breaker. If selected to trip, the relay will open the breaker and reduce the fault level, which will in turn allow the bus section or feeder to clear the fault; this action will also prime the local reclosing logic. Once the fault has been cleared the transformer relay can auto-reclose. The trip logic is illustrated in Figure 11, an example of the reclose logic can be seen in section 4.2.2.

If either transformer relay is not selected to trip then we would wait for the transformer to operate on it's own 50-1 characteristic or alternatively for the generator protection to operate.

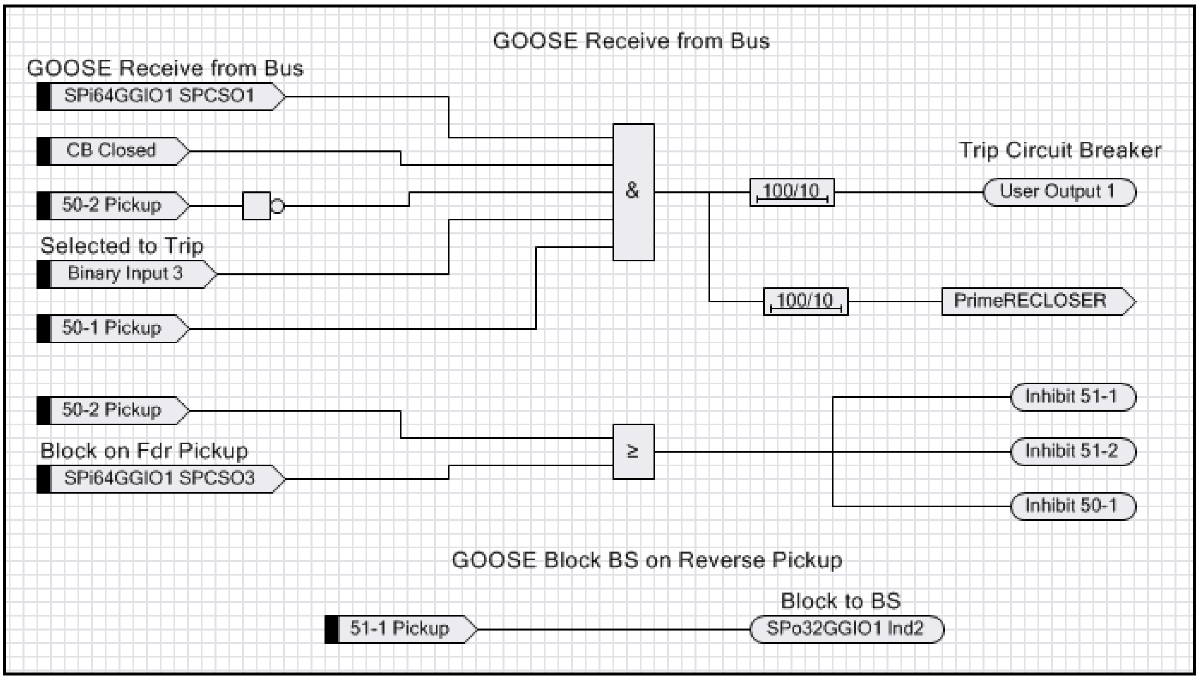


Figure 11: Transformer Incomer GOOSE Logic Chart.

4.2.2 Protection Operated and Reclose Logic

In order to reduce the fault level to a suitable value for the feeder protection to safely open the breaker, it is possible that the bus section has had to be opened and also one of the transformer incomers. Once the fault has been cleared, and the feeder CB has opened, the bus section and (if applicable) the transformer incomer will need to be reclosed to regain normal system conditions. This can be done via GOOSE signalling, so that when the feeder 7SR21 protection has operated and opened the breaker, it's status is acknowledged in the bus section and transformer relays; this logic is shown in Figure 9, where the same logic, which sends the FCAM Start GOOSE message, also combines with the local open status to indicate to the bus section and transformer that the protection has operated.

Figure 12 and Figure 13 shows the receiving logic in the bus section and transformer; note the primer signal is generated from the relays after a FCAM trip meaning that a reclose is only carried out after a trip command from a relay downstream. The FCAM Start GOOSE signal is generated by the feeder originally picking up on 50-2; note this is not needed for the transformer. The Feeder Open signal is generated when the feeder 51-1 element operates after the fault level is reduced by either the bus section or the transformer hence allowing the reclose of the upstream circuit breakers.

Bus Section 7SR21 Relay

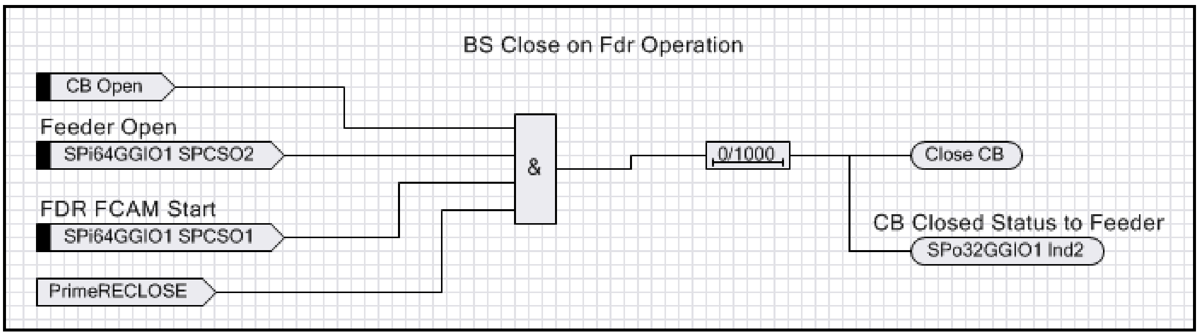


Figure 12: Auto Reclose Logic.

Transformer 7SR21 Relay

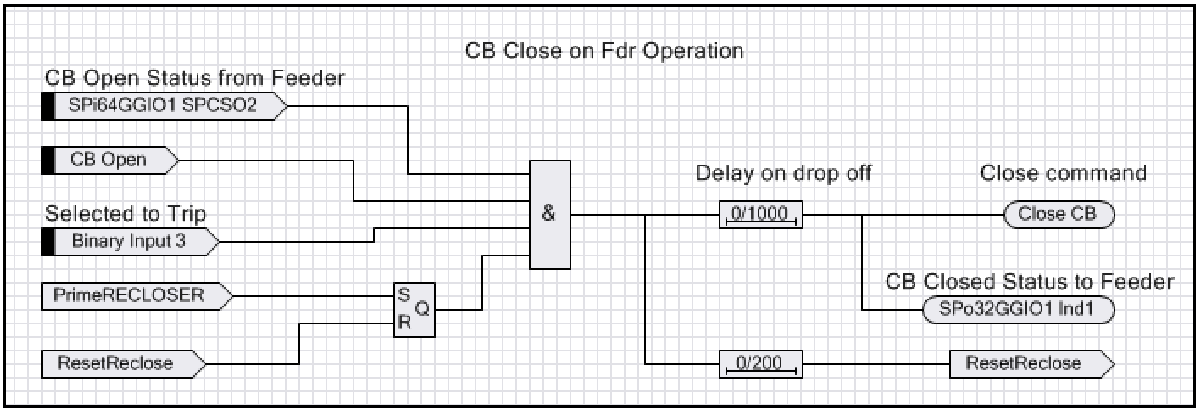


Figure 13: Tx Auto Reclose Logic

When a relay recloses, a GOOSE message is returned to the feeder, as shown in the figure above, to turn off the reclosing logic. Should the CB that has issued the close command fail to close the logic is designed to self reset after a period of 60s to allow future FACAM events, this can be seen in Figure 9.

4.2.3 Linking the GOOSE Messages

With the logic of the relays set up, the GOOSE messages need to be linked together. This is achieved using the IEC 61850 System Configurator. This software allows the IEC 61850 network to be set up, including selecting which relays communicate in the network, IP address set up, reporting and linking the GOOSE messages.

Figure 14 below shows the IEC 61850 system configurator software and how the GOOSE messages are linked together. A GOOSE message can be inserted for each function and the source and destination relay signals populated from the catalogues provided.

Once the network has been set up and the GOOSE messages configured, the station can be saved and closed down. The settings will then need to be transferred to the devices.

The logic described was setup and tested successfully. The results can be seen in Appendix 1.

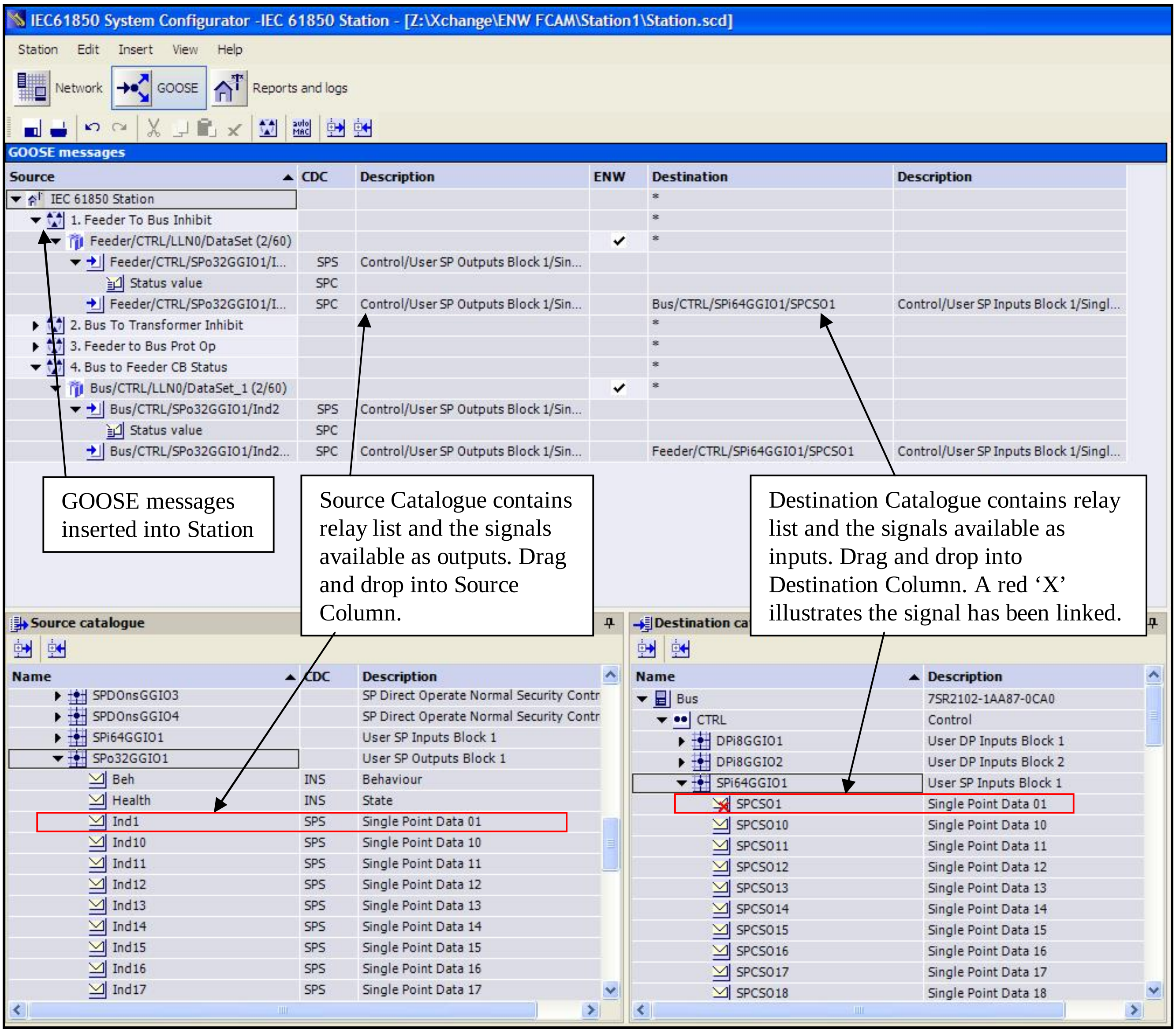


Figure 14: IEC 61850 System Configurator.

5. SCADA Control - Option 3

A third option for FCAM would be the use of SCADA control to issue commands to the relays, in order to change setting groups. For this the fault levels would need to be monitored and, if exceeded, SCADA would be used to issue commands to the relative protection devices . This in turn will prompt the relays to change settings to an alternative settings group, and the grading of the system will be altered. This will ensure that one of the incomers operates and opens before the feeder Circuit Breakers.

With reference to the information outlined in section 3, modifications will need to be carried out to existing site protection schemes.

1. For older sites with all electromechanical relays, the protection setting on the CBs would need to be changed. The time delay would be increased on the circuits with the potential of exceeding the fault level. This would be a permanent change.
   On one of the transformer incomer circuits a numerical relay would need to be installed in order to allow a change of setting groups. Setting Group 1 would be for normal operation, and the second, Setting Group 2, would be with a reduced time setting for operation where the fault level is exceeded. SCADA would be used to remotely switch between the two groups, depending on the network conditions.

2. For sites with newer numerical types of relays, it will be possible to programme these with two settings groups to allow different settings dependent on the network conditions. As before, Setting Group 1 will be for normal operation, and Setting Group 2 will be with a reduced time setting for when the fault level is exceeded. SCADA will be used to issue commands to switch between the groups. This method was tested successfully and the results can be seen in Appendix 1.

6. Generator Contribution

With the inclusion of embedded generation on the ENW network, consideration will also need to be given to reducing the generator's fault contribution.

One possibility considered was to trip the field winding of the generator, however this isn't feasible due to the insulation rating.

The second possibility is to alter the protection settings and reduce the trip time on the generator protection, so that the generator trips before the network protection to clear the fault. However, this will require discussions and permissions from the suppliers.

7. Conclusion

With the introduction of embedded generation to the ENW network, it is envisaged that adaptive protection schemes will need to be implemented to control increasing fault levels. At present, there is a mix of different relay protection hardware being used on the ENW network, which limits the options available, for fault management.

The newer substations identified from the information provided have numerical type relays, but even these, due to their age and technology, have limitations. However it is possible to adapt these relays, within reason, to be used in FCAM schemes. The older substations have a number of electromechanical and static relays, which are fixed functionality and offer no flexibility for the schemes in question. In order to provide FCAM at these locations modifications to the existing scheme would have to be implemented, either to increase protection settings and install new relays for use with SCADA control, or by using IEC 61850 protocol.

It is proposed by Siemens that the Reyrolle 7SR21/7SR22 multifunctional Overcurrent relays would be best suited to provide the required functionality for blocking and reclosing schemes for FCAM, using IEC 61850 as the communications protocol.

The testing of each solution described in the report proved that in situations where the fault level exceeds the circuit breaker rating the protection is inhibited preventing operation of the breaker allowing upstream protection to operate their circuit breakers to reduce the current flowing through the faulted feeder. The advantage of the hardwired solution and group setting change option is that it can be applied on some of the currently installed ENW protection devices. The disadvantage is the limited restoration capability and flexibility it gives the operator compared with the IEC61850 solution.

APPENDIX 1 – TEST RESULTS

The test set up as shown in Figure 15 simulated the substation settings applied on Preston East. For test purposes some of the CT ratio's were changed and the Circuit Breaker break capacity was reduced to 9kA to limit the amount of test current required to operate the FCAM scheme. The distributed generator fault current was simulated to be the contributing factor in exceeding the CB break capacity.

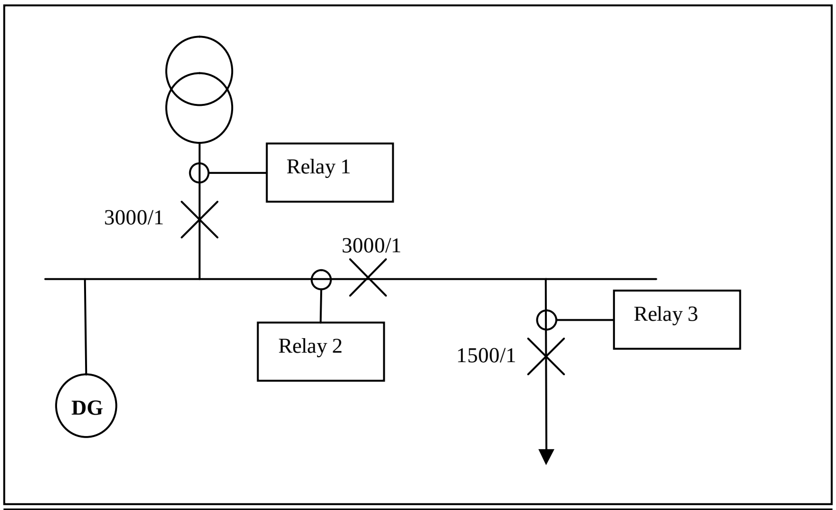


Figure 15: Test Setup

OPTION 1 – HARDWIRED SCHEME

The blocking scheme was set up as described in Section 3.3.1 with the relays set up with the test settings detailed in Table 5.

Relay	Type	P/F	TMS / Time	Curve	HS1	Time	HS2	Time
1	Argus 2	1500A (Rev)	0.5	SI	3600A (Fwd)	0.5s	9000A	0s
2	Argus 2	3750A	0.2s	DT	9000A	0s	N/A	N/A
3	Argus 2	750A	0.4	SI	9000A	0s	N/A	N/A

Table 5: Relay Protection Test Settings.

To show how the interfacing works between each relay Figure 16 illustrates the concept.

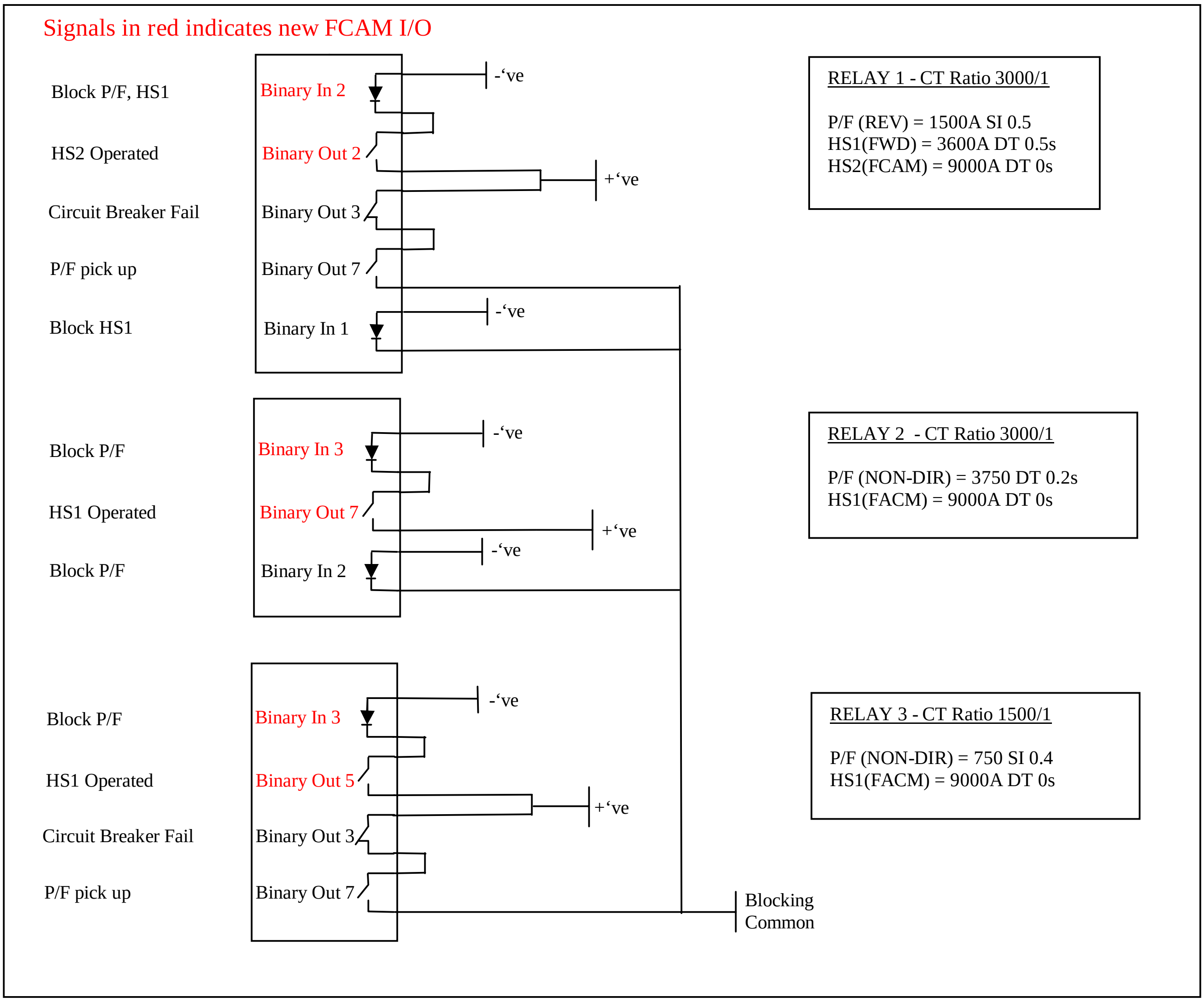


Figure 16: FCAM Blocking Signalling

As can be seen for a feeder fault through Relay 3 the IDMT curve would normally pickup and block the protection elements on Relays 1&2 by operating binary output 7. Should the fault level exceed 9kA on any relay the block is removed upstream and the relay is blocked by means of a contact driven back to an opto input by its HS element. This allows for upstream protection namely the Tx incomers (Relay 1) to trip and reduce the fault current supplied. Once the level is reduced below the feeder HS1threshold the block will automatically be removed and the feeder can open to clear the fault.

To prove correct operation of the modified scheme secondary injection tests were carried out simulating fault levels exceeding the maximum allowable capacity which in this case was set at 9kA. The results are shown in Table 6.

		Primary Injected Current (A)			Tripping		
Test		Incomer	Bus Section	Feeder	Incomer Trip	Bus Section	Feeder Trip
Feeder Breaker Exceeded	Stage 1	7500	7500	13500	No Trip	317ms	No Trip
	Stage 2	0	0	6000	No Trip	Tripped	1.35s
Feeder/Bus Breaker Exceeded	Stage 1	7500	12000	13500	633ms	No Trip	No Trip
	Stage 2	0	4500	6000	Tripped	No Trip	1.35s
Feeder/Bus > Feeder only	Stage 1	7500	12000	13500	633ms	No Trip	No Trip
	Stage 2	0	4500	9750	Tripped	228ms	No Trip
	Stage 3	0	0	5250	Tripped	Tripped	1.43s
Rev Fault through Incomer	Stage 1	13000	12000	375	No Trip	No Trip	No Trip
	Stage 2 (Generator Trip after 1s)	7500	7500	375	2.152s	No Trip	No Trip
Normal Fault below FCAM CBF	Stage 1 (CBF 150ms)	4200	4200	4200	No Trip	No Trip	Trip Fail
	Stage 2	4200	4200	4200	No Trip	347.6ms	Trip Fail

Table 6: Test Results for Hardwired Scheme

OPTION 2 – IEC61850 SCHEME

Section 3.3.2 describes the operation of the blocking scheme proposed using the blocking signals being sent over the communications protocol IEC61850 this also includes the added benefit that once a breaker has operated upstream to reduce the fault level for the outgoing feeder to operate the breakers can be set to automatically reclose.

Relay	Type	51-1	TMS / Time	Curve	50-1	Time	50-2	Time
1	7SR2	1500A (Rev)	0.5	NI	3510A (Fwd)	0.5s	9000A	0s
2	7SR2	3750A	0.2s	DTL	N/A	N/A	9000A	0s
3	7SR2	750A	0.4	NI	N/A	N/A	9000A	0s

Table 7: Relay Protection Test Settings

Again secondary injection tests were carried out to prove operation of the scheme and this can be seen in Table 8.

		Primary Injected Current (A)			Tripping/Closing		
Test		Relay 1	Relay 2	Relay 3	Relay 1	Relay 2	Relay 3
Feeder Breaker Exceeded	Stage 1	6000	8400	9300	No Trip	166.4ms	No Trip
	Stage 2	0	0	3000	No Trip	Tripped	2s
	Stage 3	600	0	0	No Trip	Reclose (12.1s)	Tripped
Feeder/Bus Breaker Exceeded	Stage 1	6000	13500	10500	171.6ms	No Trip	No Trip
	Stage 2	0	4500	4500	Tripped	No Trip	1.55s
	Stage 3	0	0	0	Reclose (12.1s)	No Trip	Tripped
Feeder/Bus > Feeder only	Stage 1	6000	13500	13500	159.5ms	No Trip	No Trip
	Stage 2	0	8250	9750	Tripped	145ms	No Trip
	Stage 3	0	0	1500	Tripped	Tripped	4.02s
	Stage 4	0	0	0	Reclose (12.1s)	Reclose (12.1s)	Tripped
Rev Fault through Incomer	Stage 1	13000	12000	375	No Trip	No Trip	No Trip
	Stage 2 (Generator Trip after 1s)	7500	7500	375	2.149s	No Trip	No Trip
Normal Fault below FCAM CBF	Stage 1 (CBF 150ms)	6000	6000	3000	No Trip	No Trip	Trip Fail
	Stage 2	6000	6000	3000	No Trip	349ms	Trip Fail

Table 8: Test Results for 61850 Scheme

<u>OPTION 3 – Setting Group Change From SCADA</u>

To simulate the relay reacting to a group change from SCADA over the protocol IEC60870-103 an Argus 1 SEF relay was used and connected to a laptop simulating the substation control system (SCS) Using test protocol software, commands were sent to the Argus 1 relay to initiate setting group change, two setting groups were simulated successfully.

	Command from SCS				Feedback to SCS				
Command	Function	Information	Type	COT	Argus 1	Function	Information	Type	COT
Group2 Select	160	24	20	20	G2 Selected	160	24	1	12
					G1 Off	160	23	1	12
Group1 Select	160	23	20	20	G1 Selected	160	23	1	12
					G2 Off	160	24	1	12

Table 9: Group Select From SCS