MiCOM P14x
(P141, P142, P143 & P145)

Feeder Management Relay

P14x/EN M/Hg8

Version	Software Version	A0
	Hardware Suffix	L (P141, P142 & P143) & M (P145)

Technical Manual

Note The technical manual for this device gives instructions for its installation, commissioning, and operation. However, the manual cannot cover all conceivable circumstances or include detailed information on all topics. In the event of questions or specific problems, do not take any action without proper authorization. Contact the appropriate Schneider Electric technical sales office and request the necessary information.

Any agreements, commitments, and legal relationships and any obligations on the part of Schneider Electric including settlements of warranties, result solely from the applicable purchase contract, which is not affected by the contents of the technical manual.

This device MUST NOT be modified. If any modification is made without the express permission of Schneider Electric, it will invalidate the warranty, and may render the product unsafe.

CONTENTS

Important	**Previous versions of this manual supported these products: MiCOM P141, P142, P143, P144 and P145. As from Software Version 46Y, the P144 product is no longer supported. Accordingly, any references to the P144 product do not apply to any software later than 46Y. A list of the software releases is given in the Version History chapter.**

Date:	10/2014
Products covered by this chapter:	This chapter covers the specific versions of the MiCOM products listed below. This includes ***only*** the following combinations of Software Version and Hardware Suffix.
Hardware Suffix:	L (P141, P142 & P143) & M (P145)
Software Version:	A0 - P14x (P141, P142, P143 & P145)
Connection Diagrams:	10P141xx (xx = 01 to 07) 10P142xx (xx = 01 to 07) 10P143xx (xx = 01 to 07) 10P145xx (xx = 01 to 07)

SAFETY INFORMATION

CHAPTER SI

Date:	01/2014
Products covered by this chapter:	This chapter covers the specific versions of the MiCOM products listed below. This includes ***only*** the following combinations of Software Version and Hardware Suffix.
Software Version:	All MiCOM Px4x products
Hardware Suffix:	All MiCOM Px4x products

CONTENTS

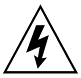
Notes:

1 INTRODUCTION

This guide and the relevant equipment documentation provide full information on safe handling, commissioning and testing of this equipment. This Safety Information section also includes reference to typical equipment label markings.

Documentation for equipment ordered from Schneider Electric is dispatched separately from manufactured goods and may not be received at the same time as the equipment. Therefore this guide is provided to ensure that printed information which may be present on the equipment is fully understood by the recipient.

The technical data in this Safety Information section provides typical information and advice, which covers a variety of different products. You must also refer to the Technical Data section of the relevant product publication(s) as this includes additional information which is specific to particular equipment.



WARNING **Before carrying out any work on the equipment all people should be familiar with the contents of this Safety Information section and the ratings on the equipment's rating label.**

You also need to make reference to the external connection diagram(s) before the equipment is installed, commissioned or serviced.

Language-specific, self-adhesive User Interface labels are provided in a bag for some equipment.

2 HEALTH AND SAFETY

The information in the Safety Information section of the equipment documentation is intended to ensure that equipment is properly installed and handled in order to maintain it in a safe condition.

People

Schneider Electric assume that everyone who will be associated with installing, commissioning or working on the equipment will be completely familiar with the contents of this Safety Information section, or the Safety Guide. We also assume that everyone working with the equipment will have sufficient knowledge and experience of electrical systems. We also assume that they will work with a complete understanding of the equipment they are working on and the health and safety issues of the location in which they are working.

Planning

We recommend that a detailed plan is developed before equipment is installed into a location, to make sure that the work can be done safely. Such a plan needs to determine how relevant equipment can be isolated from the electrical supply in such as way that there is no possibility of accidental contact with any electrical live equipment, wiring or busbars. It also needs to take into account the requirements for people to work with tools/equipment a safe distance away from any hazards.

Live and Stored Voltages

When electrical equipment is in operation, dangerous voltages will be present in certain parts of the equipment. Even if electrical power is no longer being supplied, some items of equipment may retain enough electrical energy inside them to pose a potentially serious risk of electrocution or damage to other equipment.

Important	**Remember that placing equipment in a “test” position does not normally isolate it from the power supply or discharge any stored electrical energy.**

Warnings and Barricades

Everyone must observe all warning notices. This is because the incorrect use of equipment, or improper use may endanger personnel and equipment and also cause personal injury or physical damage.

Unauthorized entry should also be prevented with suitably marked barricades which will notify people of any dangers and screen off work areas.

People should not enter electrical equipment cubicles or cable troughs until it has been confirmed that all equipment/cables have been isolated and de-energised.

Electrical Isolation

Before working in the terminal strip area, all equipment which has the potential to provide damaging or unsafe levels of electrical energy must be isolated. You will need to isolate and de-energize the specific item of equipment which is being worked on.

Depending on the location, you may also need to isolate and de-energize other items which are electrically connected to it as well as those which are close enough to pose a risk of electrocution in the event of accidental physical or electrical contact.

Remember too that, where necessary, both load and line sides should be de-energized.

Before you make contact with any equipment use an approved voltage detection device to reduce the risk of electric shock.

Risk of Accidental Contact or Arc Flash

Be aware of the risk of accidental contact with hands, long hair, tools or other equipment; and be aware of the possibility of the increased risk of arc flash from areas of high voltage.

Always wear appropriate shock and arc flash personal protective equipment while isolating and de-energizing electrical equipment and until a de-energized state is confirmed.

Temporary Protection

Consider to the use of temporary protective Grounding-Short Circuiting (G-SC). This is required to establish and maintain de-energization when electrical equipment operates at greater than 1000 volts or there is potential for back-feed at any voltage.

Temporary protective G-SC can be accomplished by installing cables designed for that purpose or by the use of intrinsic G-SC equipment. Temporary protective G-SC equipment must be able to carry maximum fault current available and have an impedance low enough to cause the applicable protective device to operate.

Restoring Power

To reduce the risks, the work plan should have a check list of things which must be completed and checks made before electrical power can be restored.

Be aware of the risk that electrical systems may have power restored to them at a remote location (possibly by the customer or a utility company). You should consider the use of lockouts so that the electrical system can be restored only when you unlock it. In any event, you should be aware of and be part of the process which determines when electrical power can be restored; and that people working on the system have control over when power is restored.

Inspect and test the electrical equipment to ensure it has been restored to a “safe” condition prior re-energizing.

Qualified Personnel

Proper and safe operation of the equipment depends on appropriate shipping and handling, proper storage, installation and commissioning, and on careful operation, maintenance and servicing. For this reason only qualified personnel may work on or operate the equipment.

Qualified personnel are individuals who:

- Are familiar with the installation, commissioning, and operation of the equipment and of the system to which it is being connected;
- Are able to safely perform switching operations in accordance with accepted safety engineering practices and are authorized to energize and de-energize equipment and to isolate, ground, and label it;
- Are trained in the care and use of safety apparatus in accordance with safety engineering practices;
- Are trained in emergency procedures (first aid).

Documentation

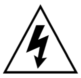
The equipment documentation gives instructions for its installation, commissioning, and operation. However, the manuals cannot cover all conceivable circumstances or include detailed information on all topics. In the event of questions or specific problems, do not take any action without proper authorization. Contact the appropriate Schneider Electric technical sales office and request the necessary information.

3 SYMBOLS AND LABELS ON THE EQUIPMENT

For safety reasons the following symbols and external labels, which may be used on the equipment or referred to in the equipment documentation, should be understood before the equipment is installed or commissioned.

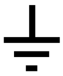
3.1 Symbols

Caution: refer to equipment documentation



Caution: risk of electric shock

Protective Conductor (*Earth) terminal



Functional/Protective Conductor (*Earth) terminal

Note:	*This symbol may also be used for a Protective Conductor (Earth) Terminal if that terminal is part of a terminal block or sub-assembly e.g. power supply.*

***CAUTION:**	**The term "Earth" used throughout this technical manual is the direct equivalent of the North American term "Ground".**

3.2 Labels

See Safety Guide (SFTY/4L M) for typical equipment labeling information.

4 INSTALLING, COMMISSIONING AND SERVICING

Manual Handling

Plan carefully, identify any possible hazards and determine whether the load needs to be moved at all. Look at other ways of moving the load to avoid manual handling. Use the correct lifting techniques and Personal Protective Equipment to reduce the risk of injury.

Many injuries are caused by:

- Lifting heavy objects
- Lifting things incorrectly
- Pushing or pulling heavy objects
- Using the same muscles repetitively.

Follow the Health and Safety at Work, etc Act 1974, and the Management of Health and Safety at Work Regulations 1999.

Equipment Connections

Personnel undertaking installation, commissioning or servicing work for this equipment should be aware of the correct working procedures to ensure safety.

The equipment documentation should be consulted before installing, commissioning, or servicing the equipment.

Terminals exposed during installation, commissioning and maintenance may present a hazardous voltage unless the equipment is electrically isolated.

The clamping screws of all terminal block connectors, for field wiring, using M4 screws shall be tightened to a nominal torque of 1.3 Nm.

Equipment intended for rack or panel mounting is for use on a flat surface of a Type 1 enclosure, as defined by Underwriters Laboratories (UL).

Any disassembly of the equipment may expose parts at hazardous voltage, also electronic parts may be damaged if suitable ElectroStatic voltage Discharge (ESD) precautions are not taken.

If there is unlocked access to the rear of the equipment, care should be taken by all personnel to avoid electric shock or energy hazards.

Caution	*Voltage and current connections shall be made using insulated crimp terminations to ensure that terminal block insulation requirements are maintained for safety.*

Watchdog (self-monitoring) contacts are provided in numerical relays to indicate the health of the device. Schneider Electric strongly recommends that these contacts are hardwired into the substation's automation system, for alarm purposes.

To ensure that wires are correctly terminated the correct crimp terminal and tool for the wire size should be used.

The equipment must be connected in accordance with the appropriate connection diagram.

Protection Class I Equipment

- Before energizing the equipment it must be earthed using the protective conductor terminal, if provided, or the appropriate termination of the supply plug in the case of plug connected equipment.
- The protective conductor (earth) connection must not be removed since the protection against electric shock provided by the equipment would be lost.
- When the protective (earth) conductor terminal (PCT) is also used to terminate cable screens, etc., it is essential that the integrity of the protective (earth) conductor is checked after the addition or removal of such functional earth connections. For M4 stud PCTs the integrity of the protective (earth) connections should be ensured by use of a locknut or similar.

The recommended minimum protective conductor (earth) wire size is 2.5 mm² (3.3 mm² for North America) unless otherwise stated in the technical data section of the equipment documentation, or otherwise required by local or country wiring regulations.

The protective conductor (earth) connection must be low-inductance and as short as possible.

All connections to the equipment must have a defined potential. Connections that are pre-wired, but not used, should preferably be grounded when binary inputs and output relays are isolated. When binary inputs and output relays are connected to common potential, the pre-wired but unused connections should be connected to the common potential of the grouped connections.

Pre-Energization Checklist

Before energizing the equipment, the following should be checked:

- Voltage rating/polarity (rating label/equipment documentation);
- CT circuit rating (rating label) and integrity of connections;
- Protective fuse rating;
- Integrity of the protective conductor (earth) connection (where applicable);
- Voltage and current rating of external wiring, applicable to the application.

Accidental Touching of Exposed Terminals

If working in an area of restricted space, such as a cubicle, where there is a risk of electric shock due to accidental touching of terminals which do not comply with IP20 rating, then a suitable protective barrier should be provided.

Equipment Use

If the equipment is used in a manner not specified by the manufacturer, the protection provided by the equipment may be impaired.

Removal of the Equipment Front Panel/Cover

Removal of the equipment front panel/cover may expose hazardous live parts, which must not be touched until the electrical power is removed.

UL and CSA/CUL Listed or Recognized Equipment

To maintain UL and CSA/CUL Listing/Recognized status for North America the equipment should be installed using UL or CSA Listed or Recognized parts for the following items: connection cables, protective fuses/fuseholders or circuit breakers, insulation crimp terminals and replacement internal battery, as specified in the equipment documentation.

For external protective fuses a UL or CSA Listed fuse shall be used. The Listed type shall be a Class J time delay fuse, with a maximum current rating of 15 A and a minimum d.c. rating of 250 Vd.c., for example type AJT15.

Where UL or CSA Listing of the equipment is not required, a high rupture capacity (HRC) fuse type with a maximum current rating of 16 Amps and a minimum d.c. rating of 250 Vd.c. may be used, for example Red Spot type NIT or TIA.

Equipment Operating Conditions

The equipment should be operated within the specified electrical and environmental limits.

Current Transformer Circuits

Do not open the secondary circuit of a live CT since the high voltage produced may be lethal to personnel and could damage insulation. Generally, for safety, the secondary of the line CT must be shorted before opening any connections to it.

For most equipment with ring-terminal connections, the threaded terminal block for current transformer termination has automatic CT shorting on removal of the module. Therefore external shorting of the CTs may not be required, the equipment documentation should be checked to see if this applies.

For equipment with pin-terminal connections, the threaded terminal block for current transformer termination does NOT have automatic CT shorting on removal of the module.

External Resistors, including Voltage Dependent Resistors (VDRs)

Where external resistors, including Voltage Dependent Resistors (VDRs), are fitted to the equipment, these may present a risk of electric shock or burns, if touched.

Battery Replacement

Where internal batteries are fitted they should be replaced with the recommended type and be installed with the correct polarity to avoid possible damage to the equipment, buildings and persons.

Insulation and Dielectric Strength Testing

Insulation testing may leave capacitors charged up to a hazardous voltage. At the end of each part of the test, the voltage should be gradually reduced to zero, to discharge capacitors, before the test leads are disconnected.

Insertion of Modules and PCB Cards

Modules and PCB cards must not be inserted into or withdrawn from the equipment whilst it is energized, since this may result in damage.

Insertion and Withdrawal of Extender Cards

Extender cards are available for some equipment. If an extender card is used, this should not be inserted or withdrawn from the equipment whilst it is energized. This is to avoid possible shock or damage hazards. Hazardous live voltages may be accessible on the extender card.

External Test Blocks and Test Plugs

Great care should be taken when using external test blocks and test plugs such as the MMLG, MMLB and MiCOM P990 types, hazardous voltages may be accessible when using these. *CT shorting links must be in place before the insertion or removal of MMLB test plugs, to avoid potentially lethal voltages.

> **Note:* *When a MiCOM P992 Test Plug is inserted into the MiCOM P991 Test Block, the secondaries of the line CTs are automatically shorted, making them safe.*

Fiber Optic Communication

Where fiber optic communication devices are fitted, these should not be viewed directly. Optical power meters should be used to determine the operation or signal level of the device.

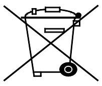
Cleaning

The equipment may be cleaned using a lint free cloth dampened with clean water, when no connections are energized. Contact fingers of test plugs are normally protected by petroleum jelly, which should not be removed.

5 DE-COMMISSIONING AND DISPOSAL

De-Commissioning

The supply input (auxiliary) for the equipment may include capacitors across the supply or to earth. To avoid electric shock or energy hazards, after completely isolating the supplies to the equipment (both poles of any dc supply), the capacitors should be safely discharged via the external terminals prior to de-commissioning.



Disposal

It is recommended that incineration and disposal to water courses is avoided. The equipment should be disposed of in a safe manner. Any equipment containing batteries should have them removed before disposal, taking precautions to avoid short circuits. Particular regulations within the country of operation, may apply to the disposal of the equipment.

6 TECHNICAL SPECIFICATIONS FOR SAFETY

Unless otherwise stated in the equipment technical manual, the following data is applicable.

6.1 Protective Fuse Rating

The recommended maximum rating of the external protective fuse for equipments is 16A, High Rupture Capacity (HRC) Red Spot type NIT, or TIA, or equivalent. Unless otherwise stated in equipment technical manual, the following data is applicable. The protective fuse should be located as close to the unit as possible.

DANGER	**CTs must NOT be fused since open circuiting them may produce lethal hazardous voltages.**

6.2 Protective Class

IEC 60255-27: 2005	Class I (unless otherwise specified in the equipment documentation).
EN 60255-27: 2005	This equipment requires a protective conductor (earth) connection to ensure user safety.

6.3 Installation Category

IEC 60255-27: 2005	Installation Category III (Overvoltage Category III)
EN 60255-27: 2005	Distribution level, fixed installation.
	Equipment in this category is qualification tested at 5 kV peak, 1.2/50 µs, 500 Ω, 0.5 J, between all supply circuits and earth and also between independent circuits.

6.4 Environment

The equipment is intended for indoor installation and use only. If it is required for use in an outdoor environment then it must be mounted in a specific cabinet of housing which will enable it to meet the requirements of IEC 60529 with the classification of degree of protection IP54 (dust and splashing water protected).

Pollution Degree	Pollution Degree 2 Compliance is demonstrated by reference to safety standards.
Altitude	Operation up to 2000m

Notes:

INTRODUCTION

CHAPTER NO 1

Date:	10/2014
Products covered by this chapter:	This chapter covers the specific versions of the MiCOM products listed below. This includes ***only*** the following combinations of Software Version and Hardware Suffix.
Hardware Suffix:	L (P141, P142 & P143) & M (P145)
Software Version:	A0 - P14x (P141, P142, P143 & P145)
Connection Diagrams:	10P141xx (xx = 01 to 07) 10P142xx (xx = 01 to 07) 10P143xx (xx = 01 to 07) 10P145xx (xx = 01 to 07)

CONTENTS

TABLES

FIGURES

Notes:

1 DOCUMENTATION STRUCTURE

This manual provides a functional and technical description of this MiCOM device, and gives a comprehensive set of instructions for it's use and application. A summary of the different chapters of this manual is given here:

	Description	Chapter Code
	Safety Information	**Px4x/EN SI**
	A guide to the safe handling, commissioning and testing of equipment. This provides typical information and advice which covers a range of MiCOM Px4x products. It explains how to work with equipment safely.	
1	**Introduction**	**P14x/EN IT**
	A guide to the MiCOM range of relays and the documentation structure. General safety aspects of handling Electronic Equipment are discussed with particular reference to relay safety symbols. Also a general functional overview of the relay and brief application summary is given.	
2	**Technical Data**	**P14x/EN TD**
	Technical data including setting ranges, accuracy limits, recommended operating conditions, ratings and performance data. Compliance with norms and international standards is quoted where appropriate.	
3	**Getting Started**	**P14x/EN GS**
	A guide to the different user interfaces of the IED describing how to start using it. This chapter provides detailed information regarding the communication interfaces of the IED, including a detailed description of how to access the settings database stored within the IED.	
4	**Menu Maps**	**P14x/EN ST**
	This is a series of charts of the various menus which are contained in this IED. This shows you how to move from one menu option to another, if you are using the IED at the front panel.	
5	**Settings**	**P14x/EN ST**
	List of all relay settings, including ranges, step sizes and defaults, together with a brief explanation of each setting.	
6	**Operation**	**P14x/EN OP**
	A comprehensive and detailed functional description of all protection and non-protection functions.	
7	**Application Notes**	**P14x/EN AP**
	This section includes a description of common power system applications of the relay, calculation of suitable settings, some typical worked examples, and how to apply the settings to the relay.	
8	**Using the PSL Editor**	**Px4x/EN SE**
	This provides a short introduction to using the PSL Editor application.	
9	**Programmable Logic**	**P14x/EN PL**
	Overview of the Programmable Scheme Logic (PSL) and a description of each logical node. This chapter includes the factory default and an explanation of typical applications.	
10	**Measurements and Recording**	**P14x/EN MR**
	Detailed description of the relays recording and measurements functions including the configuration of the event and disturbance recorder and measurement functions.	
11	**Product Design**	**P14x/EN PD**
	Overview of the operation of the relay's hardware and software. This chapter includes information on the self-checking features and diagnostics of the relay.	
12	**Commissioning**	**P14x/EN CM**
	Instructions on how to commission the relay, comprising checks on the calibration and functionality of the relay.	

	Description	Chapter Code
13	**Test and Setting Records** This is a list of the tests made and the settings stored on the MiCOM IED.	**P14x/EN RC**
14	**Maintenance** A general maintenance policy for the relay is outlined.	**Px4x/EN MT**
15	**Troubleshooting** Advice on how to recognize failure modes and the recommended course of action. Includes guidance on whom within Schneider Electric to contact for advice.	**Px4x/EN TS**
16	**SCADA Communications** This chapter provides an overview regarding the SCADA communication interfaces of the relay. Detailed protocol mappings, semantics, profiles and interoperability tables are not provided within this manual. Separate documents are available per protocol, available for download from our website.	**P14x/EN SC**
17	**Installation** Recommendations on unpacking, handling, inspection and storage of the relay. A guide to the mechanical and electrical installation of the relay is provided, incorporating earthing recommendations.	**Px4x/EN IN**
18	**Connection Diagrams** A list of connection diagrams, which show the relevant wiring details for this relay.	**P14x/EN CD**
19	**Version History (of Firmware and Service Manual)** This is a history of all hardware and software releases for this product.	**P14x/EN VH**
	Symbols and Glossary List of common technical terms, abbreviations and symbols found in this documentation.	**P14x/EN SG**

Some of these chapters are *Specific* to a particular MiCOM product. Others are *Generic* – meaning that they cover more than one MiCOM product. The generic chapters have a Chapter Code which starts with Px4x.

2 INTRODUCTION TO MiCOM

About MiCOM Range

MiCOM is a comprehensive solution capable of meeting all electricity supply requirements. It comprises a range of components, systems and services from Schneider Electric.

Central to the MiCOM concept is flexibility. MiCOM provides the ability to define an application solution and, through extensive communication capabilities, integrate it with your power supply control system.

The components within MiCOM are:

- P range protection relays;
- C range control products;
- M range measurement products for accurate metering and monitoring;
- S range versatile PC support and substation control packages.

MiCOM products include extensive facilities for recording information on the state and behaviour of the power system using disturbance and fault records. They can also provide measurements of the system at regular intervals to a control centre enabling remote monitoring and control to take place.

For up-to-date information, please see:

www.schneider-electric.com

Note	*During 2011, the International Electrotechnical Commission classified the voltages into different levels (IEC 60038). The IEC defined LV, MV, HV and EHV as follows: LV is up to 1000V. MV is from 1000V up to 35 kV. HV is from 110 kV or 230 kV. EHV is above 230 KV.* *There is still ambiguity about where each band starts and ends. A voltage level defined as LV in one country or sector, may be described as MV in a different country or sector. Accordingly, LV, MV, HV and EHV suggests a possible range, rather than a fixed band. Please refer to your local Schneider Electric office for more guidance.*

3 PRODUCT SCOPE

The MiCOM P14x feeder management relay has been designed for the protection of a wide range of overhead lines and underground cables from distribution to transmission voltage levels. The relay includes a comprehensive range of non-protection features to aid with power system diagnosis and fault analysis. The P14x offers integral overcurrent and earth-fault protection and is suitable for application on solidly grounded, impedance grounded, Petersen coil grounded and isolated systems. The P145 relay model is especially suitable where a complete scheme solution is required and has 10 function keys for integral scheme or operator control functionality such as circuit breaker control, auto-reclose control and remote communications control.

3.1 Functional Overview

The P14x feeder management relay contains a wide variety of protection functions. The protection features are summarized below:

PROTECTION FUNCTIONS OVERVIEW		P14x
50/51/67	Six overcurrent measuring stages are provided for each phase and are selectable to be either non-directional, directional forward or directional reverse. Stages 1, 2 and 5 may be set Inverse Definite Minimum Time (IDMT) or Definite Time (DT); stages 3, 4 and 6 may be set DT only.	X
50N/51N/67N	Three independent earth fault elements are provided; derived, measured and sensitive earth fault protection. Each element is equipped with four stages which are independently selectable to be either non-directional, directional forward or directional reverse. Either Zero sequence or negative sequence polarizing are available for the earth fault elements.	X
67N/67W	The Sensitive Earth Fault element can be configured as an $I\cos\phi$, $I\sin\phi$ or $VI\cos\phi$ (Wattmetric) element for application to isolated and compensated networks.	X
51V	Voltage dependent over current which can be set as voltage controlled or restrained overcurrent functionality is available on the first two stages of the overcurrent function. It provides backup protection for remote phase to phase faults by increasing the sensitivity of stages 1 and 2 of the overcurrent protection.	X
YN	Neutral admittance protection - operates from either the SEF CT or EF CT to provide single stage admittance, conductance and susceptance elements.	X
64	Restricted earthfault is configurable as a high impedance or low impedance element.	X
BOL	Blocked overcurrent logic is available on each stage of the overcurrent and earth fault, including sensitive earth fault elements. This consists of start outputs and block inputs that can be used to implement busbar blocking schemes for example.	X
SOL	Selective overcurrent provides the capability of temporarily altering (e.g. raise) the time settings of stages 3 and 4 of the phase overcurrent, earth fault and sensitive earth fault elements.	X
CLP	Cold load pick-up may be used to transiently raise the settings, for both overcurrent and earth fault protection elements, following closure of the circuit breaker.	X
46	Four stages are provided and can be selected to be either non-directional, directional forward or directional reverse and provides remote backup protection for both phase to earth and phase to phase faults.	X
49	RMS thermal overload (single/dual time constant) protection that provides thermal characteristics, which is suitable for both cables and transformers. Both Alarm and trip stages are provided.	X
37P/37N	Phase, neutral and sensitive earth fault undercurrent elements are available for use with for example the circuit breaker fail function.	X
27	Undervoltage 2-stage element, configurable as either phase to phase or phase to neutral measuring. Stage 1 may be selected as either IDMT or DT and stage 2 is DT only.	X
59	Overvoltage (2-stage), configurable as either phase to phase or phase to neutral measuring. Stage 1 may be selected as either IDMT or DT and stage 2 is DT only.	X
59N	Residual overvoltage (Neutral displacement) is a two-stage element selectable as either IDMT or DT.	X

PROTECTION FUNCTIONS OVERVIEW		P14x
47	Negative sequence overvoltage protection with a definite time delayed element, to provide either a tripping or interlocking function upon detection of unbalanced supply voltages.	X
81U/O/R	A 4-stage underfrequency and 2-stage overfrequency.	X
81U/O (Adv)	9-stage underfrequency and 9-stage overfrequency (advanced).	X
81R (Adv)	9-stage advanced rate of change of frequency element (df/dt) (advanced).	X
81RF (Adv)	9-stage Frequency supervised rate of change of frequency element (f + df/dt) (advanced).	X
81RAV (Adv)	9-stage Average rate of frequency (f + ΔF / Δt) (advanced).	X
	9-stage automatic Frequency based load restoration (advanced).	X
46BC	Broken conductor (open jumper) used to detect open circuit faults using the ratio of I2/I1.	X
32R/32L/32O	Phase segregated Under/Overpower protection Two stages of power protection are provided and each stage can be independently configured to operate as Over power or Under Power and Forward or Reverse direction. The relays provide a standard 3 phase power protection element and also a single phase power protection element.	X
	Sensitive Power Protection.	X
	A 2-stage rate of change of voltage (dv/dt) protection.	X
50BF	A 2-stage circuit breaker failure with 1 or 3 pole initiation inputs.	X
VTS	Voltage transformer supervision (1, 2 & 3 phase fuse failure detection) to prevent mal-operation of voltage dependent protection elements upon loss of a VT input signal.	X
CTS	Current transformer supervision to prevent mal-operation of current dependent protection elements upon loss of a CT input signal.	X
49SR	Silicon rectifier overload protection.	X
79	4 shot three pole auto-reclose with check sync., external initiation and sequence co-ordination capability. (P142/3/4/5 only).	X
25	Check synchronizing (2-stage) with advanced system spilt features and breaker closing compensation time (P143 and P145 models only).	X
	2nd Harmonic Blocking.	X
	Programmable function keys (P145 model only).	10
	Programmable LED's (P145 offers tri-color LEDs).	Up to 18
	Digital inputs (model and order option dependent).	8 to 32
	Output relays with an option for Hi speed/Hi break contacts (model and order option dependent).	7 to 32
	Front communication port (EIA(RS)232).	X
	Rear communication port (KBUS/EIA(RS)485).	X
	Rear communication port (Fiber Optic).	Option
	Rear IEC 61850 Ethernet port.	Option
	Rear Redundant Ethernet port (optical).	Option
	Second rear communication port (EIA(RS)232/EIA(RS)485).	Option
	InterMiCOM teleprotection for direct relay-relay communication. EIA(RS)232 for MODEM links up to 19.2 kbit/s.	Option
	Time synchronization port (IRIG-B modulated/un-modulated).	Option
	A facility is provided using an offline graphical programmable curve tool. This enables the user to configure a customized multiples of a current setting versus operating time curve and an associated reset curve. The curves can be defined as a number of curve points or a user defined formula. The curves can then be downloaded to the relay and can also be extracted from the relay. To find out how to use the tool, see the Px4x/EN UPCT/A11 document.	X
	Load Blinder	X

Table 1 - Functional overview

The P14x supports the following relay management functions in addition to the functions shown above.

- Measurement of all instantaneous & integrated values
- Circuit breaker control, status & condition monitoring
- Trip circuit and coil supervision
- Four alternative setting groups
- Programmable function keys (P145 only)
- Control inputs
- Fault locator
- Programmable Scheme Logic (PSL)
- Programmable allocation of digital inputs and outputs
- Sequence of event recording
- Comprehensive disturbance recording (waveform capture)
- Fully customizable menu texts
- Multi-level password protection
- Power-up diagnostics and continuous self-monitoring of relay
- Read only mode
- Enhanced opto- input time stamping

3.2 Application Overview

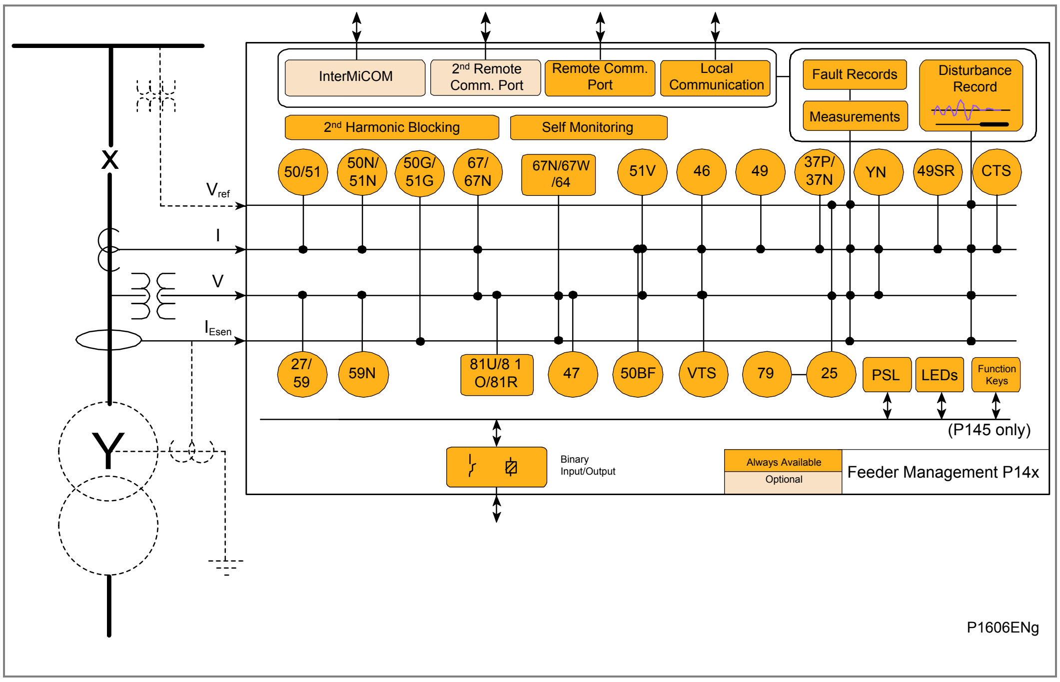


Figure 1 - Functional diagram

Note	*A summary of ANSI codes for protection devices is given in the Symbols and Glossary chapter.*

3.3 Ordering Options

3.3.1 Information Required with Order for P141

Feeder Management		P141					M		* *		
Design Suffix											
CPU3											L
Grey/Grey case, dual characteristic opto inputs, IEC61850, InterMICOM											J
Vx Auxiliary Rating											
24 - 32Vdc		9									
48 - 110Vdc		2									
110 - 250Vdc (100 - 240Vac)		3									
In/Vn Rating											
In = 1/5A, Vn = 100 - 120Vac			1								
In = 1/5A, Vn = 380 - 480Vac (Min 196Vac Max 560Vac)			2								
Hardware Options	Protocol Compatibility										
Standard - None	1, 2, 3 & 4			1							
IRIG-B - (Modulated) Only	1, 2, 3 & 4			2							
Fibre Optic Port (ST) for SCADA Protocols (Courier,Modbus,IEC60870-5-103 or DNP3)	3 1, 2 & 4			3							
Fibre Optic Port (ST) for SCADA Protocols (Courier,Modbus,IEC60870-5-103 or DNP3) + IRIG-B (Modulated)	3 1, 2 & 4			4							
Ethernet (10 Mbps)	5			5							
Ethernet (100 Mbps)	5, 6, 7 & 8			6							
Courier Rear Port	1, 2, 3 & 4			7							
IRIG-B (Modulated) & Courier Rear Port	1, 2, 3 & 4			8							
Ethernet (100Mbit/s) plus IRIG-B (Modulated)	6, 7 & 8			A							
Ethernet (100Mbit/s) plus IRIG-B (De-modulated)	6, 7 & 8			B							
InterMiCOM + Courier Rear Port	1, 2, 3 & 4			E							
InterMiCOM + Courier Rear Port + IRIG-B modulated	1, 2, 3 & 4			F							
Redundant Ethernet Self-Healing Ring, 2 multi-mode fibre ports + Modulated IRIG-B	6, 7 & 8			G							
Redundant Ethernet Self-Healing Ring, 2 multi-mode fibre ports + Un-modulated IRIG-B	6, 7 & 8			H							
Redundant Ethernet RSTP, 2 multi-mode fibre ports + Modulated IRIG-B	6, 7 & 8			J							
Redundant Ethernet RSTP, 2 multi-mode fibre ports + Un-modulated IRIG-B	6, 7 & 8			K							
Redundant Ethernet Dual-Homing Star, 2 multi-mode fibre ports + Modulated IRIG-B	6, 7 & 8			L							
Redundant Ethernet Dual-Homing Star, 2 multi-mode fibre ports + Un-modulated IRIG-B	6, 7 & 8			M							
Redundant Ethernet Parallel Redundancy Protocol (PRP), 2 multimode fibre ports + Modulated IRIG-B	6, 7 & 8			N							
Redundant Ethernet Parallel Redundancy Protocol (PRP), 2 multimode fibre ports + Un-modulated IRIG-B	6, 7 & 8			P							
Product Specific Option											
8 logic inputs & 7 relay outputs					A						
8 logic inputs & 8 relay outputs					N						
Protocol / Communications Options	Hardware Compatibility										
K-Bus/Courier	1,2,3,4,7,8,C,E or F					1					
Modbus	1,2,3,4,7,8,C,E or F					2					
IEC 60870-5-103 (VDEW)	1,2,3,4,7,8,C,E or F					3					
DNP3.0	1,2,3,4,7,8,C,E or F					4					
UCA2	5 & 6					5					
IEC 61850 over Ethernet and Courier via rear K-Bus/RS485	6, A, B, G, H , J, K, L, M, N or P					6					
IEC61850 over ethernet with CS103 rear port RS485 protocol	6, A, B, G, H , J, K, L, M, N or P					7					
DNP3 over Ethernet with Courier rear port K-Bus/RS485 protocol	6, A, B, G, H , J, K, L, M, N or P					8					
IEC 61850 + DNP3.0 via rear RS485 (*available with Design Suffix L*)	6, A, B, G, H , J, K, L, M, N or P					9					
* NB: UCA2 option is not available with software versions 32, and later											
Mounting Option											
Flush Panel Mounting,							M				
Multilingual Language Option											
English, French, German, Spanish								0			
English, French, German, Russian								5			
Chinese, English or French via HMI, with English or French only via Communications port								C			
Software Issue									* *		
Customisation											
Default										8	
Customer specific										9	

Table 2 - Ordering options for P141

3.3.2 Information Required with Order for P142

Feeder Management	P142	Order code: _ _ _ _ _ M _ ** _ _
Design Suffix		
CPU3		L
Grey/Grey case, dual characteristic opto inputs, IEC61850, InterMICOM		J
Vx Auxiliary Rating		
24 - 32Vdc		9
48 - 110Vdc		2
110 - 250Vdc (100 - 240Vac)		3
In/Vn Rating		
In = 1/5A, Vn = 100 - 120Vac		1
In = 1/5A, Vn = 380 - 480Vac (Min 196Vac Max 560Vac)		2
Hardware Options	Protocol Compatibility	
Standard - None	1, 2, 3 & 4	1
IRIG-B Only (Modulated)	1, 2, 3 & 4	2
Fibre Optic Port (ST) for SCADA Protocols (Courier,Modbus,IEC60870-5-103 or DNP3)	3 1, 2 & 4	3
Fibre Optic Port (ST) for SCADA Protocols (Courier,Modbus,IEC60870-5-103 or DNP3) + IRIG-B modulated	3 1, 2 & 4	4
Ethernet (10 Mbps)	5	5
Ethernet (100 Mbps)	5, 6, 7 & 8	6
Courier Rear Port	1, 2, 3 & 4	7
IRIG-B (Modulated) & Courier Rear Port	1, 2, 3 & 4	8
Ethernet (100Mbit/s) plus IRIG-B (Modulated)	6, 7 & 8	A
Ethernet (100Mbit/s) plus IRIG-B (De-modulated)	6, 7 & 8	B
InterMiCOM + Courier Rear Port	1, 2, 3 & 4	E
InterMiCOM + Courier Rear Port + IRIG-B modulated	1, 2, 3 & 4	F
Redundant Ethernet Self-Healing Ring, 2 multi-mode fibre ports + Modulated IRIG-B	6, 7 & 8	G
Redundant Ethernet Self-Healing Ring, 2 multi-mode fibre ports + Un-modulated IRIG-B	6, 7 & 8	H
Redundant Ethernet RSTP, 2 multi-mode fibre ports + Modulated IRIG-B	6, 7 & 8	J
Redundant Ethernet RSTP, 2 multi-mode fibre ports + Un-modulated IRIG-B	6, 7 & 8	K
Redundant Ethernet Dual-Homing Star, 2 multi-mode fibre ports + Modulated IRIG-B	6, 7 & 8	L
Redundant Ethernet Dual-Homing Star, 2 multi-mode fibre ports + Un-modulated IRIG-B	6, 7 & 8	M
Redundant Ethernet Parallel Redundancy Protocol (PRP), 2 multimode fibre ports + Modulated IRIG-B	6, 7 & 8	N
Redundant Ethernet Parallel Redundancy Protocol (PRP), 2 multimode fibre ports + Un-modulated IRIG-B	6, 7 & 8	P
Product Specific Option		
8 logic inputs & 7 relay outputs		A
12 logic inputs & 11 relay outputs		B
16 logic inputs & 7 relay outputs		C
8 logic inputs & 15 relay outputs		D
8 logic inputs & 11 relay outputs (including 4 High Break)		H
Protocol / Communications Options	Hardware Compatibility	
K-Bus	1,2,3,4,7,8,C,E & F	1
Modbus	1,2,3,4,7,8,C,E & F	2
IEC 60870-5-103 (VDEW)	1,2,3,4,7,8,C,E & F	3
DNP3.0	1,2,3,4,7,8,C,E & F	4
UCA2	5 & 6	5
IEC 61850 over Ethernet and Courier via rear K-Bus/RS485	6, A, B, G, H , J, K, L, M, N or P	6
IEC61850 over ethernet with CS103 rear port RS485 protocol	6, A, B, G, H , J, K, L, M, N or P	7
DNP3 over Ethernet with Courier rear port K-Bus/RS485 protocol	6, A, B, G, H , J, K, L, M, N or P	8
IEC 61850 + DNP3.0 via rear RS485 (*available with Design Suffix L*)	6, A, B, G, H , J, K, L, M, N or P	9
* NB: UCA2 option is not available with software versions 32, and later		
Mounting Option		
Flush Panel Mounting,		M
Multilingual Language Option		
English, French, German, Spanish		0
English, French, German, Russian		5
Chinese, English or French via HMI, with English or French only via Communications port		C
Software Issue		**
Customisation		
Default		8
Customer specific		9

Table 3 - Ordering options for P142

3.3.3 Information Required with Order for P143

Feeder Management	P143	Code
Design Suffix		
CPU3		L
Grey/Grey case, dual characteristic opto inputs, IEC61850, InterMICOM		J
Vx Auxiliary Rating		
24 - 32Vdc		9
48 - 110Vdc		2
110 - 250Vdc (100 - 240Vac)		3
In/Vn Rating		
In = 1/5A, Vn = 100 - 120Vac		1
In = 1/5A, Vn = 380 - 480Vac (Min 196Vac Max 560Vac)		2
Hardware Options	Protocol Compatibility	
Standard - None	1, 2, 3 & 4	1
IRIG-B Only (Modulated)	1, 2, 3 & 4	2
Fibre Optic Port (ST) for SCADA Protocols (Courier,Modbus,IEC60870-5-103 or DNP3)	3 1, 2 & 4	3
Fibre Optic Port (ST) for SCADA Protocols (Courier,Modbus,IEC60870-5-103 or DNP3) + IRIG-B modulated	3 1, 2 & 4	4
Ethernet (10 Mbps)	5	5
Ethernet (100 Mbps)	5, 6 & 7	6
Rear Comms	1, 2, 3 & 4	7
IRIG-B (Modulated) & Rear Comms	1, 2, 3 & 4	8
Ethernet (100Mbit/s) plus IRIG-B (Modulated)	5, 6 & 7	A
Ethernet (100Mbit/s) plus IRIG-B (De-modulated)	5, 6 & 7	B
InterMiCOM + Courier Rear Port	1, 2, 3 & 4	E
InterMiCOM + Courier Rear Port + IRIG-B modulated	1, 2, 3 & 4	F
Redundant Ethernet Self-Healing Ring, 2 multi-mode fibre ports + Modulated IRIG-B	6, 7 & 8	G
Redundant Ethernet Self-Healing Ring, 2 multi-mode fibre ports + Un-modulated IRIG-B	6, 7 & 8	H
Redundant Ethernet RSTP, 2 multi-mode fibre ports + Modulated IRIG-B	6, 7 & 8	J
Redundant Ethernet RSTP, 2 multi-mode fibre ports + Un-modulated IRIG-B	6, 7 & 8	K
Redundant Ethernet Dual-Homing Star, 2 multi-mode fibre ports + Modulated IRIG-B	6, 7 & 8	L
Redundant Ethernet Dual-Homing Star, 2 multi-mode fibre ports + Un-modulated IRIG-B	6, 7 & 8	M
Redundant Ethernet Parallel Redundancy Protocol (PRP), 2 multimode fibre ports + Modulated IRIG-B	6, 7 & 8	N
Redundant Ethernet Parallel Redundancy Protocol (PRP), 2 multimode fibre ports + Un-modulated IRIG-B	6, 7 & 8	P
Product Specific Options		
60TE Case, 16 logic inputs & 14 relay outputs		A
60TE Case, 24 logic inputs & 14 relay outputs		C
60TE Case, 16 logic inputs & 22 relay outputs		D
60TE case, 24 logic inputs & 22 relay outputs		E
60TE case, 32 logic inputs & 14 relay outputs		F
60TE Case, 16 logic inputs & 30 relay outputs		G
60TE Case, 16 logic inputs & 18 relay outputs (including 4 High Break)		H
60TE Case, 24 logic inputs & 18 relay outputs (including 4 High Break)		J
60TE Case, 16 logic inputs & 26 relay outputs (including 4 High Break)		K
60TE Case, 16 logic inputs & 22 relay outputs (including 8 High Break)		L
80TE Case, 32 logic inputs & 32 relay outputs		M
Protocol / Communications Options	Hardware Compatibility	
K-Bus	1,2,3,4,7,8,C,E or F	1
Modbus	1,2,3,4,7,8,C,E or F	2
IEC 60870-5-103 (VDEW)	1,2,3,4,7,8,C,E or F	3
DNP3.0	1,2,3,4,7,8,C,E or F	4
UCA2	5 & 6	5
IEC 61850 over Ethernet and Courier via rear K-Bus/RS485	6, A, B, G, H , J, K, L, M, N, P	6
IEC61850 over ethernet with CS103 rear port RS485 protocol	6, A, B, G, H , J, K, L, M, N, P	7
DNP3 over Ethernet with Courier rear port K-Bus/RS485 protocol	6, A, B, G, H , J, K, L, M, N, P	8
IEC 61850 + DNP3.0 via rear RS485 (*available with Design Suffix L*)	6, A, B, G, H , J, K, L, M, N, P	9
* NB: UCA2 option is not available with software versions 32 and later		
Mounting Option		
Flush Panel Mounting		M
Rack Mounting, (80TE only)		N
Multilingual Language Option		
English, French, German, Spanish		0
English, French, German, Russian		5
Chinese, English or French via HMI, with English or French only via Communications port		C
Software Issue		**
Settings/Customisation		
Default		8
Customised		9

Table 4 - Ordering options for P143

3.3.4 Information Required with Order for P145

Directional Phase O/C and E/F with Auto-Reclose and Check Synch with Extended Function User Interface	P145								x	x		
Vx Auxiliary Rating												
24-32Vdc		9										
48-110Vdc		2										
110-250Vdc (100-240Vac)		3										
In/Vn Rating												
In = 1/5A, Vn = 100 - 120Vac			1									
In = 1/5A, Vn = 380 - 480Vac (Min 196Vac Max 560Vac)			2									
Hardware Option												
None				1								
IRIG-B Only				2								
Fibre Optic Port (ST) for SCADA Protocols (Courier,Modbus,IEC60870-5-103 or DNP3)				3								
Fibre Optic Port (ST) for SCADA Protocols (Courier,Modbus,IEC60870-5-103 or DNP3) + IRIG-B				4								
Ethernet with 10Mbps fibre optic port				5								
Ethernet with 100Mbps fibre optic port				6								
Courier Rear Port				7								
IRIG-B (Modulated) & Courier Rear Port				8								
Ethernet (100Mbit/s) plus IRIG-B (Modulated)				A								
Ethernet (100Mbit/s) plus IRIG-B (De-modulated)				B								
InterMiCOM + Courier Rear Port				E								
InterMiCOM + Courier Rear Port + IRIG-B modulated				F								
Redundant Ethernet Self-Healing Ring, 2 multi-mode fibre ports + Modulated IRIG-B				G								
Redundant Ethernet Self-Healing Ring, 2 multi-mode fibre ports + Un-modulated IRIG-B				H								
Redundant Ethernet RSTP, 2 multi-mode fibre ports + Modulated IRIG-B				J								
Redundant Ethernet RSTP, 2 multi-mode fibre ports + Un-modulated IRIG-B				K								
Redundant Ethernet Dual-Homing Star, 2 multi-mode fibre ports + Modulated IRIG-B				L								
Redundant Ethernet Dual-Homing Star, 2 multi-mode fibre ports + Un-modulated IRIG-B				M								
Redundant Ethernet Parallel Redundancy Protocol (PRP), 2 multimode fibre ports + Modulated IRIG-B				N								
Redundant Ethernet Parallel Redundancy Protocol (PRP), 2 multimode fibre ports + Un-modulated IRIG-B				P								
Product Specific Option												
16 logic inputs and 16 relay outputs					A							
12 logic inputs and 12 relay outputs with ANSI Symbol Terminal labelling					B							
24 logic inputs and 16 relay outputs					C							
16 logic inputs and 24 relay outputs					D							
24 logic inputs and 24 relay outputs					E							
32 logic inputs and 16 relay outputs					F							
16 logic inputs and 32 relay outputs					G							
16 logic inputs and 20 relay outputs (including 4 High Break)					H							
24 logic inputs and 20 relay outputs (including 4 High Break)					J							
16 logic inputs and 28 relay outputs (including 4 High Break)					K							
16 logic inputs and 24 relay outputs (including 8 High Break)					L							
Comms Protocol												
K-Bus - (NOT with Hardware Options 5 & 6)						1						
Modbus - (NOT with Hardware Options 5 & 6)						2						
IEC60870 - (NOT with Hardware Options 5 & 6)						3						
DNP3- (NOT with Hardware Options 5 & 6)						4						
UCA2 over Ethernet and Courier via rear K-Bus/RS485 - (ONLY with Hardware Options 5 & 6) *						5						
IEC 61850 over Ethernet and Courier via rear K-Bus/RS485						6						
IEC61850 over ethernet with CS103 rear port RS485 protocol						7						
DNP3 over Ethernet with Courier rear port K-Bus/RS485 protocol						8						
IEC 61850 + DNP3.0 via rear RS485 (*available with Design Suffix L*)						9						
* NB: UCA2 option is not available with software versions 35 & later (Design Suffix J)												
Case Size / Mounting / Livery												
Flush Panel Mounting							M					
Language Option												
Multilingual - English/French/German/Spanish								0				
Multilingual - English/French/German/Russian								5				
Chinese, English or French via HMI, with English or French only via Communications port *								C				
* NB: Chinese etc. HMI is not available with 12 logic inputs and 12 relay outputs with ANSI Symbol Terminal labelling												
Software Version												
Date Dependent									*	*		
Customisation												
Default											8	
Customised											9	
Hardware Design Suffix												
XCPU3												M
Grey/Grey case, dual characteristic opto inputs, IEC61850, InterMICOM												J

Table 5 - Ordering options for P145

TECHNICAL DATA

CHAPTER NO 2

Date:	10/2014
Products covered by this chapter:	This chapter covers the specific versions of the MiCOM products listed below. This includes ***only*** the following combinations of Software Version and Hardware Suffix.
Hardware Suffix:	L (P141, P142 & P143) & M (P145)
Software Version:	A0 - P14x (P141, P142, P143 & P145)
Connection Diagrams:	10P141xx (xx = 01 to 07) 10P142xx (xx = 01 to 07) 10P143xx (xx = 01 to 07) 10P145xx (xx = 01 to 07)

CONTENTS

Notes:

1 MECHANICAL SPECIFICATIONS

1.1 Design

Modular MiCOM Px40 platform relay, P141/142-40TE (206 mm (8“)) case and P143/P145 (309.6 mm (12“)) case. Mounting is front of panel flush mounting, or 19“ rack mounted (ordering options).

1.2 Enclosure Protection

Per IEC 60529: 1992:

- IP 52 Protection (front panel) against dust and dripping water.
- IP 50 Protection for the rear and sides of the case against dust.
- IP 10 Product safety protection for the rear due to live connections on the terminal block.

1.3 Weight

Case 40TE: approx. 7.3 kg

Case 60TE: approx. 9.2 kg

2 TERMINALS

2.1 AC Current and Voltage Measuring Inputs

Located on heavy duty (black) terminal block:
Threaded M4 terminals, for ring terminal connection.
CT inputs have integral safety shorting, upon removal of the terminal block.

2.2 General Input/Output Terminals

For power supply, opto inputs, output contacts and RP1, COM1 and optional COM2 rear communications.
Located on general purpose (grey) blocks:
Threaded M4 terminals, for ring lug/terminal connection.

2.3 Case Protective Earth Connection

Two rear stud connections, threaded M4.
Must be earthed (grounded) using the protective (earth) conductor for safety, minimum earth wire size $2.5mm^2$.

2.4 Front Port Serial PC Interface

EIA(RS)-232 DCE, 9 pin D-type female connector Socket SK1.
Courier protocol for interface to MiCOM S1 Studio software.
Isolation to SELV/ELV (Safety/Extra Low Voltage) level / PEB (Protective Equipotential Bonded).
Maximum cable length 15m.

2.5 Front Download/Monitor Port

EIA(RS)-232, 25 pin D-type female connector Socket SK2.
For firmware and menu text downloads.
Isolation to SELV/PEB level.

2.6 Rear Communications Port

EIA(RS)-485 signal levels, two wire connections located on general purpose block, M4 screw.
For screened twisted pair cable, multidrop, 1000 m max.
For Courier (K-Bus), IEC-60870-5-103 (not for P746/P849), MODBUS (not for P14x/P445/P44x/P54x/P547/P746/P841/P849) or DNP3.0 protocol (not for P24x/P746/P849) (ordering options).
Isolation to SELV (Safety Extra Low Voltage) level. Ethernet (copper and fibre).

2.7 Optional Second Rear Communications Port

EIA(RS)-232, 9 pin D-type female connector, socket SK4.
Courier protocol: K-Bus, EIA(RS)-232, or EIA(RS)485 connection.
Isolation to SELV level.
Maximum cable length 15m.

2.8 Optional Rear IRIG-B Interface modulated or un-modulated

BNC plug
Isolation to SELV level.
50 ohm coaxial cable.

2.9 Optional Rear Fiber Connection for SCADA/DCS

BFOC 2.5 -(ST)-interface for multi-mode glass fiber type 62.5, as for IEC 874-10.
850nm short-haul fibers, one Tx and one Rx. For Courier, IEC-60870-5-103, MODBUS or DNP3.0 (but, see different ordering options for each model).

2.10 Optional Rear Ethernet Connection for IEC 61850 or DNP3.0

2.10.1 Optional Redundant Rear Ethernet Connection (optical)

2.10.1.1 10BaseT/100BaseTX Communications

Interface in accordance with IEEE802.3 and IEC 61850

Isolation:	1.5 kV
Connector type:	RJ45
Cable type:	Screened Twisted Pair (STP)
Max. cable length:	100 m

2.10.1.2 100 Base FX Interface

Interface in accordance with IEEE802.3 and IEC 61850

Wavelength:	1310 nm
Fiber:	multi-mode 50/125 µm or 62.5/125 µm
Connector type:	ST/LC Connector Optical Interface (depending on model)

3 RATINGS

3.1 AC Measuring Inputs

Nominal frequency:	50 and 60 Hz (settable)
Operating range:	45 to 66 Hz
Phase rotation:	ABC or ACB (ABC only for P14x)

3.2 AC Current

Nominal current (In): 1 and 5 A dual rated. (1A and 5A inputs use different transformer tap Connections, check correct terminals are wired).

Nominal burden per phase:	< 0.15 VA at In	
Thermal withstand:	continuous 4 In	for 10 s: 30 In for 1 s; 100 In

Linear to 64 In (non-offset AC current).

3.3 AC Voltage

Nominal voltage (Vn):	100 to 120 V or 380 to 480 V phase-phase (min. 196 Vac, max. 560 Vac).
Nominal burden per phase:	< 0.02 VA at Vn.
Thermal withstand:	continuous 2 Vn for 10 s: 2.6 Vn

4 POWER SUPPLY

4.1 Auxiliary Voltage (Vx)

Three ordering options:
(i) Vx: 24 to 48 Vdc
(ii) Vx: 48 to 110 Vdc, and 40 to 100 Vac (rms)
(iii) Vx: 110 to 250 Vdc, and 100 to 240 Vac (rms)

4.2 Operating Range

19 to 65 V (dc only for this variant)
37 to 150 V (dc), 32 to 110 V (ac)
87 to 300 V (dc), 80 to 265 V (ac)
With a tolerable ac ripple of up to 12% for a dc supply, per IEC 60255-11: 1979.

4.3 Nominal Burden

Quiescent burden: 11 W. (Extra 1.25 W when fitted with second rear Courier)
Additions for energized binary inputs/outputs:

Per opto input:	0.09 W	(24 to 54 V)
	0.12 W	(110/125 V)
	0.19 W	(220/120 V)

Per energized output relay: 0.13 W

4.4 Power-up Time

Time to power up < 11 s.

4.5 Power Supply Interruption

Per IEC 60255-11: 1979

The relay will withstand a 20 ms interruption in the DC auxiliary supply, without de-energizing.

Per IEC 61000-4-11: 1994

The relay will withstand a 20 ms interruption in an AC auxiliary supply, without de-energizing.

4.6 Battery Backup

Front panel mounted.
Type ½ AA, 3.6 V Lithium Thionyl Chloride (SAFT advanced battery reference LS14250).
Battery life (assuming relay energized for 90% time) >10 years.

4.7 Field Voltage Output

Regulated 48 Vdc
Current limited at 112 mA maximum output

4.8 Digital ("Opto") Inputs

Universal opto inputs with programmable voltage thresholds (24/27, 30/34, 48/54, 110/125, 220/250 V). May be energized from the 48 V field voltage, or the external battery supply.

Rated nominal voltage: 24 to 250 Vdc

Operating range: 19 to 265 Vdc

Withstand: 300 Vdc, 300 Vrms.

Peak current of opto input when energized is 3.5 mA (0-300 V)

Nominal pick-up and reset thresholds:

Pick-up approx 70% of battery nominal set

Reset approx 66% of battery nominal set

Nominal battery 24/27:	60 - 80% DO/PU
(logic 0) <16.2	(logic 1) >19.2
Nominal battery 24/27:	50 - 70% DO/PU
(logic 0) <12.0	(logic 1) >16.8
Nominal battery 30/34:	60 - 80% DO/PU
(logic 0) <20.4	(logic 1) >24.0
Nominal battery 30/34:	50 - 70% DO/PU
(logic 0) <15.0	(logic 1) >21.0
Nominal battery 48/54:	60 - 80% DO/PU
(logic 0) <32.4	(logic 1) >38.4
Nominal battery 48/54:	50 - 70% DO/PU
(logic 0) <24.0	(logic 1) >33.6
Nominal battery 110/125:	60 - 80% DO/PU
(logic 0) <75.0	(logic 1) >88.0
Nominal battery 110/125:	50 - 70% DO/PU
(logic 0) <55.0	(logic 1) >77.0
Nominal battery 220/250:	60 - 80% DO/PU
(logic 0) <150.0	(logic 1) >176.0
Nominal battery 220/250:	50 - 70% DO/PU
(logic 0) <110	(logic 1) >154

Recognition time: 7 ms

<2 ms with long filter removed,
<12 ms with half cycle ac immunity filter on

5 OUTPUT CONTACTS

5.1 Standard Contacts

General purpose relay outputs for signaling, tripping and alarming:

Continuous Carry Ratings (Not Switched):

Maximum continuous current:	10 A (UL: 8 A)
Short duration withstand carry:	30 A for 3 s or 250A for 30ms
Rated voltage:	300 V

Make & Break Capacity:

DC:	50 W resistive	
DC:	62.5 W inductive	(L/R = 50 ms)
AC:	2500 VA resistive	(cos ϕ = unity)
AC:	2500 VA inductive	(cos ϕ = 0.7)

Make, Carry:

30 A for 3 secs, dc resistive, 10,000 operations (subject to the above limits of make/break capacity and rated voltage)

Make, Carry & Break:

30 A for 200 ms, ac resistive, 2,000 operations (subject to the above limits of make/break capacity & rated voltage)
4A for 1.5 secs, dc resistive, 10,000 operations (subject to the above limits of make/break capacity & rated voltage)
0.5 A for 1 sec, dc inductive, 10,000 operations (subject to the above limits of make/break capacity & rated voltage)
10 A for 1.5 secs, ac resistive/inductive, 10,000 operations (subject to the above limits of make/break capacity & rated voltage)

Durability:

Loaded contact:	10 000 operations minimum
Unloaded contact:	100 000 operations minimum
Operate Time	Less than 5 ms
Reset Time	Less than 5 ms

5.2 High Break Contacts (Model D only)

Continuous Carry Ratings (Not Switched):

Maximum continuous current:	10 A dc
Short duration withstand carry:	30 A dc for 3 s 250A dc for 30ms
Rated voltage:	300 V

Make & Break Capacity:

DC:	7500 W resistive	
DC:	2500 W inductive	(L/R = 50 ms)

Make, Carry:

30 A for 3 secs, dc resistive, 10,000 operations (subject to the above limits of make/break capacity & rated voltage)

Make, Carry & Break:

30 A for 3 secs, dc resistive, 5,000 operations (subject to the above limits of make/break capacity & rated voltage)

30 A for 200 ms, dc resistive, 10,000 operations (subject to the above limits of make/break capacity & rated voltage)

10 A (*), dc inductive, 10,000 operations (subject to the above limits of make/break capacity & rated voltage)

*Typical for repetitive shots - 2 minutes idle for thermal dissipation

Voltage	Current	L/R	No. of Shots in 1 sec
65 V	10 A	40 ms	5
150 V	10 A	40 ms	4
250 V	10 A	40 ms	2
250 V	10 A	20 ms	4

MOV protection: Max Voltage 330 V dc

Durability:
Loaded contact: 10 000 operations minimum
Unloaded contact: 100 000 operations minimum
Operate Time: Less than 0.2 ms
Reset Time: Less than 8 ms

5.3 Watchdog Contacts

Non-programmable contacts for relay healthy or relay fail indication:
Breaking capacity: DC: 30 W resistive
DC: 15 W inductive (L/R = 40 ms)
AC: 375 VA inductive (cos ϕ = 0.7)

5.4 IRIG-B 12X Interface (Modulated)

External clock synchronization to IRIG standard 200-98, format B12x
Input impedance 6 kΩ at 1000 Hz
Modulation ratio: 3:1 to 6:1
Input signal, peak-peak: 200 mV to 20 V

5.5 IRIG-B 00X Interface (Un-modulated)

External clock synchronization to IRIG standard 200-98, format B00X.
Input signal TTL level
Input impedance at dc 10 kΩ

6 ENVIRONMENTAL CONDITIONS

6.1 Ambient Temperature Range

Per IEC 60255-6: 1988

Operating temperature range:	-25°C to +55°C (or -13°F to +131°F).
Storage and transit:	-25°C to +70°C (or -13°F to +158°F).
Tested as per IEC 60068-2-1: 2007	-25°C (-13°F) storage (96 hours) -40°C (-40°F) operation (96 hours)
IEC 60068-2-2: 2007	+85°C (+185°F) storage (96 hours)

6.2 Ambient Humidity Range

Per IEC 60068-2-3: 1969:
56 days at 93% relative humidity and +40°C

Per IEC 60068-2-30: 1980:
Damp heat cyclic, six (12 + 12) hour cycles, 93% RH, +25 to +55°C

7 TYPE TESTS

7.1 Insulation

As for IEC 60255-27: 2005 (incorporating corrigendum March 2007):
Insulation resistance > 100 MΩ at 500 Vdc
(Using only electronic/brushless insulation tester).

7.2 Creepage Distances and Clearances

Per EN 61010-1: 2001
Pollution degree 2, Overvoltage category III, Impulse test voltage 5 kV.

7.3 High Voltage (Dielectric) Withstand

EIA(RS)232 ports excepted.

Per IEC 60255-27: 2005, 2 kV rms AC, 1 minute:

Between all case terminals connected together, and the case earth.
Also, between all terminals of independent circuits.
1 kV rms AC for 1 minute, across open watchdog contacts.
1 kV rms AC for 1 minute, across open contacts of changeover output relays.

Per ANSI/IEEE C37.90-1989 (reaffirmed 1994):

1.5 kV rms AC for 1 minute, across open contacts of changeover output relays.

7.4 Impulse Voltage Withstand Test

Per IEC 60255-27: 2005
Front time: 1.2 μs, Time to half-value: 50 μs,
Peak value: 5 kV, 0.5 J
Between all terminals, and all terminals and case earth.

8 ELECTROMAGNETIC COMPATIBILITY (EMC)

8.1 1 MHz Burst High Frequency Disturbance Test

As for EN 60255-22-1: 2008, Class III,
Common-mode test voltage: 2.5 kV,
Differential test voltage: 1.0 kV,
Test duration: 2 s, Source impedance: 200 Ω
(EIA(RS)-232 ports excepted).

8.2 100 kHz Damped Oscillatory Test

EN 61000-4-18: 2007:	Level 3
Common mode test voltage:	2.5 kV
Differential mode test voltage:	1 kV

8.3 Immunity to Electrostatic Discharge

Per IEC 60255-22-2: 1997, Class 4,
15kV discharge in air to user interface, display, and exposed metalwork.
Per IEC 60255-22-2: 1997, Class 3,
8kV discharge in air to all communication ports.
6kV point contact discharge to any part of the front of the product.

8.4 Electrical Fast Transient or Burst Requirements

Per IEC 60255-22-4: 2002.

Test severity:	Class III and IV:
Amplitude:	2 kV, burst frequency 5 kHz (Class III),
Amplitude:	4 kV, burst frequency 2.5 kHz (Class IV).

Applied directly to auxiliary supply, and applied to all other inputs. EIA(RS)232 ports excepted.

8.5 Surge Withstand Capability

IEEE/ANSI C37.90.1:2002:
4 kV fast transient and 2.5 kV oscillatory applied common mode and differential mode to opto inputs (filtered), output relays, CTs, VTs, power supply, field voltage.
4 kV fast transient and 2.5 kV oscillatory applied common mode to communications, IRIG- B.

8.6 Surge Immunity Test

EIA(RS)232 ports excepted.
Per IEC 61000-4-5: 2005 Level 4,

Time to half-value:	1.2/50 µs,
Amplitude:	4 kV between all groups and case earth,
Amplitude:	2 kV between terminals of each group.

8.7 Immunity to Radiated Electromagnetic Energy

IEC 60255-22-3: 2000, Class III:

Test field strength, frequency band 80 to 1000 MHz:	10 V/m,
Test using AM:	1 kHz / 80%,
Spot tests at 80, 160, 450, 900 MHz	

IEEE/ANSI C37.90.2: 1995:

25 MHz to 1000 MHz, zero and 100% square wave modulated.
Field strength of 35 V/m.

8.8 Radiated Immunity from Digital Communications

EN61000-4-3: 2002, Level 4:
Test field strength, frequency band 800 to 960 MHz, and 1.4 to 2.0 GHz: 30 V/m,
Test using AM: 1 kHz / 80%.

8.9 Radiated Immunity from Digital Radio Telephones

ENV 50204: 1995 10 V/m, 900 MHz and 1.89 GHz.

8.10 Immunity to Conducted Disturbances Induced by Radio Frequency Fields

IEC 61000-4-6: 1996, Level 3, Disturbing test voltage: 10 V

8.11 Power Frequency Magnetic Field Immunity

IEC 61000-4-8: 1994, Level 5:	100 A/m applied continuously, 1000 A/m applied for 3 s.
IEC 61000-4-9: 1993, Level 5:	1000 A/m applied in all planes.
IEC 61000-4-10: 1993, Level 5:	

100 A/m applied in all planes at 100 kHz/1MHz with a burst duration of 2 s.

8.12 Conducted Emissions

EN 55022: 1998: Class A:

0.15 - 0.5 MHz, 79 dBμV (quasi peak) 66 dBμV (average)
0.5 – 30 MHz, 73 dBμV (quasi peak) 60 dBμV (average).

8.13 Radiated Emissions

EN 55022: 1998: Class A:

30 – 230 MHz, 40 dBμV/m at 10 m measurement distance
230 – 1 GHz, 47 dBμV/m at 10 m measurement distance.

9 EU DIRECTIVES

9.1 EMC Compliance

Per 89/336/EEC:

Compliance to the European Commission Directive on EMC is claimed via the Technical Construction File route. Product Specific Standards were used to establish conformity with EN50263: 2000

9.2 Product Safety

Per 2006/95/EC:

Compliance to the European Commission Low Voltage Directive. (LVD) is demonstrated using a Technical File. A product specific standard was used to establish conformity.

CE EN 60255-27: 2005 EN 60255-5:2001

9.3 R&TTE Compliance

Radio and Telecommunications Terminal Equipment (R&TTE) directive 99/5/EC.

Compliance demonstrated by compliance to both the EMC directive and the Low voltage directive, down to zero volts.

Applicable to rear communications ports.

9.4 ATEX Compliance

ATEX Potentially Explosive Atmospheres directive 94/9/EC, for equipment.
The equipment is compliant with Article 1(2) of European directive 94/9/EC.

It is approved for operation outside an ATEX hazardous area. It is however approved for connection to Increased Safety, “Ex e”, motors with rated ATEX protection, Equipment Category 2, to ensure their safe operation in gas Zones 1 and 2 hazardous areas.

II (2) G

Caution	**Equipment with this marking is not itself suitable for operation within a potentially explosive atmosphere.**

Compliance demonstrated by Notified Body certificates of compliance.

10 MECHANICAL ROBUSTNESS

10.1 Vibration Test

Per IEC 60255-21-1: 1996	Response Class 2 Endurance Class 2

10.2 Shock and Bump

Per IEC 60255-21-2: 1996	Shock response Class 2 Shock withstand Class 1 Bump Class 1

10.3 Seismic Test

Per IEC 60255-21-3: 1995	Class 2

11 P14X THIRD PARTY COMPLIANCES

11.1 Underwriters Laboratory (UL)

File Number: E202519
(Complies with Canadian and US requirements).

Issue Date 21-04-2005

11.2 Energy Network Association (ENA)

Certificate Number: 101 Issue 3
Assessment Date: 10-12-2004

Type(s): P141, P142, P143 & P145

12 PROTECTION FUNCTIONS

12.1 Three Phase Overcurrent Protection

Accuracy

Additional tolerance X/R ratios:	±5% over X/R 1…90
Overshoot:	<30 ms

12.2 Inverse Time Characteristic

Accuracy

DT Pick-up:	Setting ±5%
Minimum IDMT trip level:	1.05 x setting ±5%
Drop-off:	0.95 x setting ±5%
IDMT shape:	±5% or 40 ms whichever is greater
IEEE reset:	±5% or 50 ms whichever is greater
DT operation:	±2% or 50 ms, whichever is greater
DT reset:	±5%
Directional boundary (RCA ±90%):	±2% hysteresis 2^{o}
Characteristic:	UK curves IEC 60255-3 …1998
US curves:	IEEEC37.112…1996

12.3 Earth/Sensitive Fault Protection

12.3.1 Earth Fault 1

DT Pick-up:	Setting ±5%
Minimum IDMT trip level:	1.05 x Setting ±5%
Drop-off:	0.95 x Setting ±5%
IDMT shape:	±5% or 40 ms whichever is greater *
IEEE reset:	±5% or 50 ms whichever is greater
DT operation:	±2% or 50 ms whichever is greater
DT reset:	±5%
Repeatability:	2.5%

* Reference conditions TMS = 1, TD = 1 and IN> setting of 1 A operating range 2-20 In

12.3.2 Earth Fault 2

DT Pick-up:	Setting ±5%
Minimum IDMT Trip level:	1.05 x Setting ±5%
Drop-off:	0.95 x Setting ±5%
IDMT shape:	±5% or 40 ms whichever is greater *
IEEE reset:	±10% or 40 ms whichever is greater
DT operation:	±2% or 50 ms whichever is greater
DT reset:	±2% or 50 ms whichever is greater
Repeatability:	±5%

* Reference conditions TMS = 1, TD = 1 and IN > setting of 1A, operating range 2-20 In SEF

DT Pick-up:	Setting ±5%
Minimum IDMT Trip level:	1.05 x Setting ±5%
Drop-off:	0.95 x Setting ±5%
IDMT shape:	±5% or 40 ms whichever is greater *
IEEE reset:	±7.5% or 60 ms whichever is greater
DT operation:	±2% or 50 ms whichever is greater
DT reset:	±5%
Repeatability:	±5%

* Reference conditions TMS = 1, TD = 1 and IN > setting of 100 mA, operating range 2-0 In

12.3.3 REF

Pick-up:	Setting formula ±5%
Drop-off:	0.80 x setting formula ±5%
Operating time:	<60 ms
High pick up:	Setting ±5%
High operating time:	<30 ms
Repeatability:	<15%

12.3.4 Wattmetric SEF

Pick-up: For P=0W	ISEF> ±5% or P> ±5%
Drop off: For P>0W	(0.95 x ISEF>) ±5% or 0.9 x P> ±5%
Boundary accuracy:	±5% with 1^{o} hysteresis
Repeatability:	5%

12.3.5 SEF Cos(PHI)/

Pick-up:	Setting ±5% for angles RCA±60^{o}
Drop-off:	0.90 x Setting
IDMT shape:	±5% or 50ms whichever is greater *
IEEE reset:	±7.5% or 60ms whichever is greater
DT operation:	±2% or 50ms whichever is greater
DT reset:	±5%
Repeatability:	2%

* Reference conditions TMS = 1, TD = 1 and IN > setting of 100 mA, operating range 2-0 In

12.3.6 SEF Sin(PHI)

Pick-up:	Setting ±5% for angles from RCA±60^{o} to RCA±90^{o}
Drop-off:	0.90 x Setting
IDMT shape:	±5% or 50 ms whichever is greater *
IEEE reset:	±7.5% or 60 ms whichever is greater
DT operation:	±2% or 50 ms whichever is greater
DT reset:	±5%
Repeatability:	2%

Reference conditions TMS = 1, TD = 1 and IN > setting of 100 mA, operating range 2-0 In

12.3.7 Zero Polarizing

Operating pick-up:	±2%° of RCA ±90%
Hysteresis:	<3°
VN > Pick-up:	Setting ±10%
VN > Drop-off:	0.9 x Setting ±10%

12.3.8 Negative Polarizing

Operating Pick-up:	±2%° of RCA ±90%
Hysteresis:	<3°
VN 2 > Pick-up:	Setting ±10%
VN 2 > Drop-off:	0.9 x Setting ±10%
I2 > Pick up:	Setting ±10%
I2 > Drop-off:	0.9 x Setting ±10%

12.4 Negative Sequence Overcurrent

Accuracy

DT Pick-up:	Setting ±5%
Minimum IDMT trip level:	1.05 x Setting ±5%
Drop-off:	0.95 x Setting ±5%
IDMT shape:	±5% or 40 ms whichever is greater
IEEE reset:	±5% or 50 ms whichever is greater
DT operation:	±2% or 50 ms, whichever is greater
DT reset:	±5%
Directional boundary (RCA ±90%):	±2% hysteresis 2°
Characteristic:	UK curves IEC 60255-3 …1998
US curves:	IEEEC37.112…1996

12.5 Reverse/Low Forward/Overpower Protection

Accuracy

Pick-up: Setting	±10%
Reverse/Overpower drop off:	0.95 x Setting ±10%
Low forward Power drop off:	1.05 x Setting +10%
Angle variation pick-up:	Expected pick-up angle ±2 degree
Angle variation drop-off:	Expected drop-off angle ±2.5 degree
Operating time:	±2% or 50 ms whichever is greater
Repeatability:	<5%
Disengagement time:	<50 ms
tRESET:	±5%
Instantaneous operating time:	< 50 ms

12.6 Sensitive Reverse/Low Forward/Overpower (1 Phase)

Accuracy

Pick-up:	Setting ±10%
Reverse/Overpower Drop-off:	0.9 of setting ±10%
Low forward power Drop-off:	1.1 of Setting ±10%
Angle variation Pick-up:	Expected pick-up angle ±2 degree
Angle variation Drop-off:	Expected drop-off angle ±2.5% degree
Operating time:	±2% or 50 ms whichever is greater
Repeatability:	<5%
Disengagement time:	<50 ms
tRESET:	±5%
Instantaneous operating time:	<50 ms

12.7 Undervoltage Protection

Accuracy

DT Pick-up:	Setting ±5%
IDMT Pick-up:	Setting ±5%
Drop-off:	1.02 x Setting ±5%
IDMT shape:	±2% or 50 ms whichever is greater
DT operation:	±2% or 50 ms whichever is greater
Reset:	<75 ms
Repeatability:	<1%

12.8 Overvoltage Protection

Accuracy

DT Pick-up:	Setting ±5%
IDMT Pick-up:	Setting ±5%
Drop-off:	0.98 x Setting ±5%
IDMT shape:	±2% or 50 ms whichever is greater
DT operation:	±2% or 50 ms whichever is greater
Reset:	<75 ms
Repeatability:	<1%

12.9 Rate of Change of Voltage ‘dv/dt’ Protection

Accuracy for 110 V VT

Tolerance:	1% or 0.07, whichever is greater
Pick-up:	Setting ± tolerance
Drop-off:	(Setting - 0.07) ± tolerance for positive direction
Drop-off:	(Setting + 0.07) ± tolerance for negative direction
Operating time@50 Hz:	[(Avg.cycle*20)+60]ms
Reset time@50 Hz:	40 ms

12.10 Neutral Displacement/Residual Voltage

Accuracy

Pick-up:	Setting ±5% or 1.05 x Setting ±5%
Drop-off:	0.95 x Setting ±5%
IDMT shape:	±5% or 65 ms whichever is greater
DT operation:	±2% or 20 ms whichever is greater <55 ms
Reset:	<35 ms
Repeatability:	<10%

12.11 Underfrequency Protection

Accuracy

Pick-up:	Setting ±0.025 Hz
Drop-off:	1.05 x Setting ±0.025 Hz
DT operation:	±2% or 50 ms whichever is greater *

* The operating time will also include a time for the relay to frequency track (20 Hz/second)

12.12 Overfrequency Protection

Accuracy

Pick-up:	Setting ±0.025 Hz
Drop-off:	0.95 x Setting ±0.025 Hz
DT operation:	±2% or 50 ms whichever is greater *

* The operating will also include a time for the relay to frequency track (20 Hz/ second)

12.13 Advanced Over/Underfrequency ‘f+t’ Protection [81U/81O]

Accuracy

Pick-up:	Setting±10 mHz
Drop-off:	Setting +20mHz, ±10mHz (underfrequency) Setting -20mHz, ±10mHz (overfrequency)
Operating timer:	±2% or 50 ms whichever is greater

12.13.1 Operating & Reset Time

Operating time* (underfrequency):	<100 ms for Fs/Ff ratios less than 2 <160 ms for Fs/Ff ratios less than 6 <230 ms otherwise
Operating time* (overfrequency):	<125 ms for Fs/Ff ratios less than 2 <150 ms for Fs/Ff ratios less than 30 <200 ms otherwise
Reset time*:	<200 ms
* Reference conditions:	Tested using step changes in frequency with Freq.Av.Cycles setting = 0 and no intentional time delay.
Fs/Ff ratios as stated, where:	Fs = start frequency - frequency setting Ff = frequency setting - end frequency

12.14 Advanced Frequency Supervised Rate of Change of Frequency ‘f+df/dt’ Protection [81RF]

Accuracy

Pick-up: Setting±10 mHz (frequency threshold)
Setting ±3% or ±10 mHz/s, whichever is greater (df/dt threshold)

Drop-off (frequency threshold):
Setting +20 mHz, ±10 mHz (underfrequency)
Setting -20 mHz, ±10 mHz (overfrequency)

Drop-off (df/dt threshold, falling frequency):
Setting +0.005 Hz/s, ±10 mHz/s
(for settings between 0.01 Hz/s and 0.1Hz/s).
Setting +0.05 Hz/s, ±5% or ±55 mHz/s, whichever is greater
(for settings greater than 0.1 Hz/s).

Drop-off (df/dt threshold, rising frequency):
Setting -0.005 Hz/s, ±10 mHz/s
(for settings between 0.01Hz/s and 0.1 Hz/s).
Setting -0.05 Hz/s, ±5% or ±55 mHz/s, whichever is greater
(for settings greater than 0.1 Hz/s).

12.14.1 Operating & Reset Time

Instantaneous operating time: <125 ms for Freq.Av.Cycles setting = 0
Reset time: <400 ms for df/dt.Av.Cycles setting = 0

12.15 Advanced Independent Rate of Change of Frequency ‘df/dt+t’ Protection [81R]

Accuracy

Pick-up: Setting ±3% or ±10 mHz/s, whichever is greater

Drop-off (falling frequency): Setting +0.005 Hz/s, ±10 mHz/s (for settings between 0.01 Hz/s and 0.1Hz/s)
Setting +0.05 Hz/s, ±5% or ±55 mHz/s, whichever is greater (for settings greater than 0.1 Hz/s)

Drop-off (rising frequency): Setting -0.005 Hz/s, ±10 mHz/s (for settings between 0.01 Hz/s and 0.1Hz/s)
Setting -0.05 Hz/s, ±5% or ±55 mHz/s,
whichever is greater (for settings greater than 0.1 Hz/s)

Operating timer: ±2% or 50 ms whichever is greater

12.15.1 Operating & Reset Time

Operating time*: <200 ms for ramps 2x setting or greater
<300 ms for ramps 1.3x setting or greater

Reset time*: <250 ms

* Reference conditions: Tested with df/dt.Av.Cycles setting = 0, for df/dt settings greater than 0.1 Hz/s (positive or negative, as relevant) and no intentional time delay.

12.16 Advanced Average Rate of Change of Frequency ‘f+Df/Dt’ Protection [81RAV]

Accuracy

Accuracy

Pick-up:	Setting±10 mHz (frequency threshold) Setting ±0.1 Hz/s (Df/Dt threshold)*
Drop-off:	Setting +20 mHz, ±10mHz (falling frequency) Setting -20 mHz, ±10 mHz (rising frequency)
Operating timer:	±2% or 30 ms whichever is greater * Reference conditions: To maintain accuracy the minimum time delay setting, Dt, should be: Dt > 0.375 x Df + 0.23 (for Df setting < 1 Hz) Dt > 0.156 x Df + 0.47 (for Df setting ≥ 1 Hz)

12.16.1 Operating Time

Typically <125 ms with Freq.Av.Cycles = 0

12.17 Advanced Load Restoration

Accuracy

Pick-up:	Setting±10 mHz
Drop-off:	Setting -20 mHz, ±10 mHz
Restoration timer:	±2% or 50 ms whichever is greater
Holding timer:	±2% or 50 ms whichever is greater

12.18 Broken Conductor Logic

Accuracy

Pick-up:	Setting ±2.5%
Drop-off:	0.95 x Setting ±2.5%
DT operation:	±2% or 40 ms whichever is greater

12.19 Thermal Overload

Accuracy

Thermal alarm pick-up:	Calculated trip time ±10%
Thermal overload pick-up:	Calculated trip time ±10%
Cooling time accuracy:	±15% of theoretical
Repeatability:	<5%

* Operating time measured with applied current of 20% above thermal setting.

12.20 Voltage Dependent Overcurrent

Accuracy

VCO / VRO threshold Pick-up:	Setting ±5%
Overcurrent Pick-up:	(K factor x Setting) ±5%
VCO / VRO threshold Drop-off:	1.05 x Setting ±5%
Overcurrent Drop-off:	0.95 x (K factor x Setting) ±5%
Operating time:	±5% or 60 ms whichever is greater
Repeatability:	<5%

12.21 Cold Load Pick-up Setting

Accuracy

I> Pick-up:	Setting ±1.5%
I> Pick-up:	Setting ±2.5%
IN> Pick-up:	Setting ±1.5%
I> Drop-off:	0.95 x Setting ±1.5%
I> Drop-off:	0.95 x Setting ±2.5%
IN> Drop-off:	0.95 x Setting ±1.5%
DT operation:	±0.5% or 40 ms whichever is greater
Repeatability:	<1%

12.22 Negative Sequence Overvoltage Protection

Accuracy

Pick-up:	Setting ±5%
Drop-off:	0.95 x Setting ±5%
DT operation:	±2% or 50 ms whichever is greater
Repeatability:	<5%

12.23 Admittance, Conductance and Susceptance

Accuracy

YN, BN and BN measurements:	±5%
YN, BN, BN Pick-up:	Setting ±5%
YN, BN, BN Drop-off:	>0.85 x Setting
Operating time:	Start <100 ms Trip Setting ±2% or 50 ms
Operating boundary:	±2°
VN:	Setting ±5%

12.24 Selective Overcurrent Protection

Accuracy

Fast block operation:	<25 ms
Fast block reset:	<30 ms
Time delay:	Setting ±2% or 20 ms whichever is greater

13 SUPERVISION FUNCTIONS

13.1 Voltage Transformer Supervision (VTS)

Accuracy

Fast block operation: <25 ms
Fast block reset: <30 ms
Time delay: Setting ±2% or 20 ms whichever is greater

13.2 Current Transformer Supervision (CTS)

Accuracy

In> Pick-up:	Setting ±5%
VN< Pick-up:	Setting ±5%
In> Drop-off:	0.9 x Setting ±5%
VN< Drop-off:	(1.05 x Setting) ±5% or 1 V whichever is greater
Time delay operation:	Setting ±2% or 20 ms whichever is greater
CTS block operation:	<1 cycle
CTS reset:	<35 ms

13.3 CB Fail

Accuracy

I > Pick-up:	Setting ±5% or 20 mA whichever is greater
I > Drop-off:	100% of setting ±5% or 20 mA whichever is greater
Timers:	±2% or 50 ms whichever is greater
Reset time:	<25 ms without DC offset <35 ms with DC offset

14 PROGRAMMABLE SCHEME LOGIC

Output conditioner timer:	Setting ±2% or 50 ms whichever is greater
Dwell conditioner timer:	Setting ±2% or 50 ms whichever is greater
Pulse conditioner timer:	Setting ±2% or 50 ms whichever is greater

15 MEASUREMENTS AND RECORDING FACILITIES

15.1 Measurements

Current:	0.05… 3 In
Accuracy:	±1.0% of reading
Voltage:	0.05…2 Vn
Accuracy:	±1.0% of reading
Power (W):	0.2…2 Vn 0.05…3 In
Accuracy:	±5.0% of reading at unity power factor
Reactive Power (Vars):	0.2…2 Vn, 0.05…3 In
Accuracy:	±5.0% of reading at zero power factor
Apparent Power (VA):	0.2…2 Vn 0.05…3 In
Accuracy:	±5% of reading
Energy (Wh):	0.2…2 Vn 0.2…3 In
Accuracy:	±5% of reading at zero power factor
Energy (Varh):	0.2…2 Vn 0.2…3 In
Accuracy:	±5% of reading at zero power factor
Phase accuracy:	0°…360°
Accuracy:	±0.5%°
Frequency:	45…65 Hz
Accuracy:	±0.025 Hz

15.2 Performance

Year 2000:	Compliant
Real time clock accuracy:	<±2% seconds/day
Modulation ratio:	1/3 or 1/6
Input signal peak-peak amplitude:	200 mV…20 V
Input impedance at 1000 Hz:	6000 Ω
External clock synchronization:	Conforms to IRIG standard 200-98, format B

15.3 IRIG-B and Real Time Clock

Real time clock accuracy: < ±2 seconds/day

15.4 Disturbance Records

Accuracy

Magnitude and relative phases:	±5% of applied quantities
Duration:	±2%
Trigger position:	±2% (minimum Trigger 100 ms)
Line length:	0.01…1000 kn **
Line impedance (100/110 V):	0.1/In…250/In Ý
Line impedance (380/480 V):	0.4/In…1000/In Ý
Line angle:	20°…85°
KZN residual:	0…7.00
KZN res. angle:	-90°…+90°

15.5 Plant Supervision

Accuracy

Timers:	±2% or 20 ms whichever is greater
Broken current accuracy:	±5%

Timer Accuracy

Timers:	±2% or 40 ms whichever is greater
Reset time:	<30 ms

Undercurrent Accuracy

Pick-up:	±10% or 25 mA whichever is greater
Operating time:	<20 ms
Reset:	<25 ms

15.6 IEC 61850 Ethernet Data

15.6.1 100 Base FX Interface

15.6.1.1 Transmitter Optical Characteristics

Transmitter Optical Characteristics – 100 base FX interface
(T_A = 0°C to 70°C, V_{CC} = 4.75 V to 5.25 V)

Parameter	Sym	Min.	Typ.	Max	Unit
Output Optical Power BOL: 62.5/125 µm, NA = 0.275 Fiber EOL	P_{OUT}	–19 –20	–16.8	–14	dBm avg.
Output Optical Power BOL: 50/125 µm, NA = 0.20 Fiber EOL	P_{OUT}	–22.5 –23.5	–20.3	–14	dBm avg.
Optical Extinction Ratio				10 –10	% dB
Output Optical Power at Logic “0” State	P_{OUT} (“0”)			–45	dBm avg.
BOL – Beginning of life EOL – End of life					

Transmitter Optical Characteristics – 100 base FX interface

15.6.1.2 Receiver Optical Characteristics

Receiver Optical Characteristics – 100 base FX interface
(T_A = 0°C to 70°C, V_{CC} = 4.75 V to 5.25 V)

Parameter	Sym	Min.	Typ.	Max.	Unit
Input Optical Power Minimum at Window Edge	P_{IN} Min. (W)		–33.5	–31	dBm avg.
Input Optical Power Minimum at Eye Center	P_{IN} Min. (C)		–34.5	–31.8	dBm avg.
Input Optical Power Maximum	P_{IN} Max.	–14	–11.8		dBm avg.

Receiver Optical Characteristics – 100 base FX interface

Note	*The 10BaseFL connection will no longer be supported as IEC 61850 does not specify this interface*

16 SETTINGS, MEASUREMENTS AND RECORDS LIST

16.1 Settings List

Global Settings (System Data)

Language: English/French/German/Spanish
Frequency: 50/60 Hz

16.2 Circuit Breaker Control (CB Control)

CB Control by:	Disabled / Local / Remote / Local+Remote / Opto / Opto+local / Opto+Remote / Opto+Rem+local
Close Pulse Time:	0.10…50.00 s
Trip Pulse Time:	0.10…5.00 s
Man Close t max:	0.01…9999.00 s
Man Close Delay:	0.01…600.00 s
CB Healthy Time:	0.01…9999.00 s
Check Sync. Time:	0.01…9999.00 s
Reset Lockout by:	User Interface/CB Close
Man Close RstDly:	0.10…600.00 s
CB Status Input:	None / 52A / 52B / 52A & 52B

16.3 Date and Time

IRIG-B Sync:	Disabled/Enabled
Battery Status:	data
Battery Alarm:	Disabled/Enabled
LocalTime Enable:	Disabled/Fixed/Flexible
LocalTime Offset:	-720 min…720 min
DST Enable:	Disabled/Enabled
DST Offset:	30 min…60 min
DST Start:	First / Second / Third / Fourth / Last
DST Start Day:	Sun / Mon / Tues / Wed / Thurs / Fri / Sat
DST Start Month:	Jan / Feb / Mar / Apr / May / Jun / Jul / Aug / Sept / Oct / Nov / Dec
DST Start Mins:	0 min…1425 min
DST End:	First / Second / Third / Fourth / Last
DST End Day:	Sun / Mon / Tues / Wed / Thurs / Fri / Sat
DST End Month:	Jan / Feb / Mar / Apr / May / Jun / Jul / Aug / Sept / Oct / Nov / Dec
DST End Mins:	0 min…1425 min
RP1 Time Zone:	UTC/Local
RP2 Time Zone:	UTC/Local
Tunnel Time Zone:	UTC/Local

16.4 Configuration

Setting Group:	Select via Menu or Select via Opto
Active Settings:	Group 1/2/3/4
Setting Group 1:	Disabled/Enabled
Setting Group 2:	Disabled/Enabled
Setting Group 3:	Disabled/Enabled
Setting Group 4:	Disabled/Enabled

System Config:	Invisible/Visible
Overcurrent:	Disabled/Enabled
Negative Sequence O/C:	Disabled/Enabled
Broken Conductor:	Disabled/Enabled
Earth Fault 1:	Disabled/Enabled
Earth Fault 2:	Disabled/Enabled
SEF/REF1 Prot:	Disabled/Enabled
Residual O/V NVD:	Disabled/Enabled
Thermal Overload:	Disabled/Enabled
Neg. Sequence O/V:	Disabled/Enabled
Cold Load Pick-up:	Disabled/Enabled
Selective Logic:	Disabled/Enabled
Admit. Protection:	Disabled/Enabled
Power Protection:	Disabled/Enabled
Volt Protection:	Disabled/Enabled
Freq. Protection:	Disabled/Enabled
CB Fail:	Disabled/Enabled
Supervision:	Disabled/Enabled
Fault Locator:	Disabled/Enabled
System Checks2:	Disabled/Enabled
Auto-Reclose3:	Disabled/Enabled
Input Labels:	Invisible/Visible
Output Labels:	Invisible/Visible
Adv. Freq. Prot'n:	Disabled/Enabled
CT & VT Ratios:	Invisible/Visible

Record Control:	Invisible/Visible
Disturb Recorder:	Invisible/Visible
Measure't Setup:	Invisible/Visible
Comms Settings:	Invisible/Visible
Commission Tests:	Invisible/Visible
Setting Values:	Primary/Secondary
Control Inputs:	Invisible/Visible
Ctrl I/P Config:	Invisible/Visible
Ctrl I/P Labels:	Invisible/Visible
Direct Access:	Disabled/Enabled
InterMiCOM:	Disabled/Enabled
Function Key4:	Invisible/Visible
RP1 Read Only:	Disabled/Enabled
RP2 Read Only:	Disabled/Enabled
NIC Read Only:	Disabled/Enabled
LCD Contrast:	(Factory pre-set)

16.5 CT and VT Ratios

Main VT Primary:	100 V...1 MV
Main VT Sec'y:	80...140 V
C/S VT Primary2:	100 V...1 MV
C/S VT Secondary:	80...140 V
NVD VT Primary5:	100 V...1 MV
NVD VT Secondary:	80...140 V
Phase CT Primary:	1 A…30 kA
Phase CT Sec'y:	1 A/5 A
E/F CT Primary:	1 A…30 kA
E/F CT Sec'y:	1 A/5 A
SEF CT Primary:	1 A…30 kA
SEF CT Sec'y:	1 A/5 A
I Derived Phase5:	IA / IB / IC / None
C/S Input2:	A-N / B-N / C-N / A-B / B-C / C-A
Main VT Location2:	Line/Bus

16.6 Sequence of Event Recorder (Record Control)

Alarm Event:	Disabled/Enabled
Relay O/P Event:	Disabled/Enabled
Opto Input Event:	Disabled/Enabled
General Event:	Disabled/Enabled
Fault Rec. Event:	Disabled/Enabled
Maint. Rec. Event:	Disabled/Enabled
Protection Event:	Disabled/Enabled
DDB 31 - 0:(up to):	DDB 1279 - 1248:

Binary function link strings, selecting which DDB signals will be stored as events, and which will be filtered out

16.7 Oscillography (Disturbance Recorder)

Duration:	0.10…10.50 s
Trigger Position:	0.0…100.0%
Trigger Mode:	Single/Extended
Analog Channel 1:	(up to):
Analog Channel 8:	Disturbance channels selected from: VA/VB/VC/Vchecksync./IA/IB/IC/IN/IN Sensitive

Digital Input 1: (up to):
Digital Input 32:

Selected binary channel assignment from any DDB status point within the relay (opto input, output contact, alarms, starts, trips, controls, logic…).

Input 1 Trigger: (up to):
Input 32 Trigger: No Trigger Trigger L/H Trigger H/L

16.8 Measured Operating Data (Measure't. Setup)

Default Display: 3Ph + N Current / 3Ph Voltage / Power / Date and Time / Description / Plant Reference / Frequency

Access Level

Local Values:	Primary/Secondary
Remote Values:	Primary/Secondary
Measurement Ref:	VA/VB/VC/IA/IB/IC
Measurement Mode:	0/1/2/3
Fix Dem. Period:	1…99 mins
Roll Sub Period:	1…99 mins
Num. Sub Periods:	1…15
Distance Unit:	Miles/Kilometers
Fault Location:	Distance Ohms % of Line
Remote2 Values:	Primary/Secondary

16.9 Communications

RP1 Protocol:	Courier / IEC870-5-103 / DNP 3.0
RP1 Address: (Courier or IEC870-5-103):	0…255
RP1 Address: (DNP3.0):	0…65519
RP1 InactivTimer:	1…30 mins
RP1 Baud Rate: (IEC870-5-103):	9600 / 19200 bits/s
RP1 Baud Rate: (DNP3.0):	1200 / 2400 4800 / 9600 19200 / 38400 bits/s
RP1 Parity:	Odd/Even/None
RP1 Meas Period:	1…60 s
RP1 PhysicalLink:	Copper Fiber Optic (IEC870-5-103, DNP3.0, Courier, MODBUS) K-Bus (Courier only)
RP1 Time Sync:	Disabled/Enabled
DNP Need Time:	1…30 m
DNP App Fragment:	100…2048
DNP App Timeout:	1…120
DNP SBO Timeout:	1…10
DNP Link Timeout:	0…120
RP1 CS103 Blocking:	Disabled / Monitor Blocking / Command Blocking
RP1 Port Config. (Courier):	K Bus / EIA(RS)485
RP1 Comms. Mode:	IEC60870 FT1.2 Frame 10-Bit No Parity

16.10 Optional Additional Second Rear Communication (Rear Port2 (RP2))

RP2 Protocol:	Courier (fixed)
RP2 Port Config:	Courier over EIA(RS)232 / Courier over EIA(RS)485 / K-Bus
RP2 Comms. Mode:	IEC60870 FT1.2 Frame / 10-Bit NoParity
RP2 Address:	0…255
RP2 InactivTimer:	1…30 mins
RP2 Baud Rate:	9600 / 19200 / 38400 bits/s

16.11 Optional Ethernet Port

NIC Tunl Timeout:	1...30 mins
NIC Link Report:	Alarm/Event/None
NIC Link Timeout:	0.1...60 s

16.12 Commission Tests

Monitor bit 1: (up to): Monitor bit 8:	Binary function link strings, selecting which DDB signals have their status visible in the Commissioning menu, for test purposes
Test Mode:	Disabled Test Mode Blocked Contacts
Test Pattern:	Configuration of which output contacts are to be energized when the contact test is applied
Static Test Mode:	Disabled/Enabled

16.13 Circuit Breaker Condition Monitoring (CB Monitor Setup)

Broken I^:	1.0…2.0
I^ Maintenance:	Alarm Disabled/Enabled
I^ Maintenance:	1…25000
I^ Lockout:	Alarm Disabled/Enabled
I^ Lockout:	1…25000
No. CB Ops Maint:	Alarm Disabled/Enabled
No. CB Ops Maint:	1…10000
No. CB Ops Lock:	Alarm Disabled/Enabled
No. CB Ops Lock:	1…10000
CB Time Maint:	Alarm Disabled/Enabled
CB Time Maint:	0.005…0.500 s
CB Time Lockout:	Alarm Disabled/Enabled
CB Time Lockout:	0.005…0.500 s
Fault Freq. Lock:	Alarm Disabled/Enabled
Fault Freq. Count:	1…9999
Fault Freq. Time:	0…9999 s

16.14 Optocoupled Binary Inputs (Opto Config.)

Global Nominal V: 24 – 27 V / 30 – 34 V / 48 – 54 V / 110 – 125 V / 220 – 250 V

Custom Opto Input 1: (up to):

Opto Input #. (# = max. opto no. fitted):

Custom options allow independent thresholds to be set for each opto, from the same range as above.

Opto Filter Control: Binary function link string, selecting which optos have an extra 1/2 cycle noise filter, and which do not.

Characteristics: Standard 60% - 80% / 50% - 70%

Time stamping accuracy: + 1 msec

16.15 Control Inputs into PSL (Ctrl. I/P Config.)

Hotkey Enabled:	Binary function link string, selecting which of the control inputs are driven from Hotkeys.
Control Input 1: (up to): Control Input 32:	Latched/Pulsed
Ctrl Command 1: (up to): Ctrl Command 32:	ON/OFF / SET/RESET / IN/OUT / ENABLED/DISABLED

16.16 EIA(RS)232 Teleprotection (InterMiCOM Comms.)

Source Address:	1…10
Received Address:	1…10
Data Rate:	600 / 1200 / 2400 / 4800 / 9600 / 19200 baud
Loopback Mode:	Disabled/Internal/External
Test Pattern:	Configuration of which InterMiCOM signals are to be energized when the loopback test is applied.

16.17 InterMiCOM Conf.

IM Msg Alarm Lvl:	0…100.0%
IM1 Cmd Type:	(up to):
IM4 Cmd Type:	Disabled/Direct/Blocking
IM5 Cmd Type:	(up to):
IM8 Cmd Type:	Disabled/Permissive/Direct
IM1 FallBackMode:	(up to):
IM8 FallBackMode:	Default/Latched
IM1 DefaultValue:	(up to):
IM8 DefaultValue:	0/1
IM1 FrameSyncTim:	(up to):
IM8 FrameSyncTim:	10 ms…1.50 s

16.18 Function Keys

Fn. Key Status 1: (up to): Fn. Key Status 10	Disable / Lock / Unlock / Enable
Fn. Key 1 Mode: (up to): Fn. Key 10 Mode:	Toggled/Normal
Fn. Key 1 Label: (up to): Fn. Key 10 Label:	User defined text string to describe the function of the particular function key

16.19 IED CONFIGURATOR

Switch Conf. Bank:	No Action / Switch Banks

16.20 IEC61850 GOOSE

GoEna:	0x0000000000000000(bin)... 0xFFFFFFFFFFFFFFFF(bin)
Pub.Simul.Goose:	0x0000000000000000(bin)... 0xFFFFFFFFFFFFFFFF(bin)
Sub.Simon.Goose:	No/Yes

16.21 Control Input User Labels (Ctrl. I/P Labels)

Control Input 1: (up to): Control Input 32:	User defined text string to describe the function of the particular control input

17 SETTINGS IN MULTIPLE GROUPS

Note	*All settings here onwards apply for setting groups # = 1 to 4.*

18 PROTECTION FUNCTIONS (IN MULTIPLE GROUPS)

Note *All settings here onwards apply for setting groups # = 1 to 4.*

18.1 System Config.

Phase Sequence:	Standard ABC / Reverse ACB
2NDHARM BLOCKING:	Disabled / Enabled
2ndHarm Thresh:	5…70
I>lift 2H:	4…32

18.2 Phase Overcurrent (Overcurrent)

I>1 Function:	Disabled / DT / IEC S Inverse / IEC V Inverse / IEC E Inverse / UK LT Inverse / UK Rectifier / RI / IEEE M Inverse / IEEE V Inverse / IEEE E InverseUS Inverse / US ST Inverse / Def User Curve 1 / Def User Curve 2 / Def User Curve 3 / Def User Curve 4
I>1 Direction:	Non-Directional or Directional Fwd or Directional Rev
I>1 Current Set:	0.08…4.00 In
I>1 Time Delay:	0.00…100.00 s
I>1 TMS:	0.025…1.200
I>1 Time Dial:	0.01…100.00
I>1 K (RI):	0.10…10.00
I>1 DT Adder:	0.00…100.00
I>1 Reset Char.:	DT/Inverse
I>1 tRESET:	0.00…100.00 s
I>2 Status (up to):	
I>2 tRESET	All settings and options chosen from the same ranges as per the first stage overcurrent, I>1.

I>3 Status:	Disabled or Enabled
I>3 Direction:	Non-Directional or Directional Fwd or Directional Rev
I>3 Current Set:	0.08…32.00 In
I>3 Time Delay:	0.00…100.00 s

I>4 Status (up to):
I>4 Time Delay All settings and options chosen from the same ranges as per the third stage overcurrent, I>3.
I> Char Angle: -95…95º
I>5 Status (up to):
I>5 tRESET
All settings and options chosen from the same ranges as per the first stage overcurrent, I>1.
I>6 Status (up to):
I>6 Time Delay All settings and options chosen from the same ranges as per the third stage overcurrent, I>3.
I> Blocking:
Binary function link string, selecting which overcurrent elements (stages 1 to 4) will be blocked if VTS detection of fuse failure occurs.
Binary function link string, selecting which overcurrent elements (stages 1 to 4) will be blocked if 2nd Harmonic Block is enabled with an option of choosing 1PH block.

18.3 Voltage Dependent Overcurrent

V DEPENDANT O/C
V Dep OC Status
VCO Disabled
VCO I>1
VCO I>2
VCO I>1 & I>2
VCO I>5
VCO I>1 & I>2 & I>5
VCO I>1 & I>5
VC0 I>2 & I>5
VRO I>1
VRO I>2
VRO I>5
VRO I>1 & I>2
VRO I>1 & I>5
VRO I>2 & I>5
VRO I>1 & I>2 & I>5

V Dep OC V<1 Set
10…120 V (100/120 V)
40…480 V (380/440 V)

V Dep OC V<2 Set
10…120 V (100/120 V)
40…480 V (380/440 V)

18.4 Load Blinder

Blinder Status:	Disabled/Enabled
Blinder Function:	3Ph/1Ph
Blinder Mode:	Both/Forward/Reverse
FWD Z Impedance:	0.1…100 ohm
FWD Z Angle:	5…85 deg
REV Z Impedance:	0.1…100 ohm
REV Z Angle:	5…85 deg
Binder V<Block:	10…120 V
Binder I2>Block:	0.8…4 A
PU cycles:	0…50
DO cycles:	0…50

18.5 Negative Sequence Overcurrent

I2>1 Function: Disabled / DT / IEC S Inverse / IEC V Inverse / IEC E Inverse / UK LT Inverse / IEEE M Inverse / IEEE V Inverse / IEEE E Inverse / US Inverse / US ST Inverse

I2>1 Direction: Non-Directional or Directional Fwd or Directional Rev
I2>1 Current Set: 0.08…4.00 In
I2>1 Time Delay: 0.00…100.00 s
I2>1 TMS: 0.025…1.200
I2>1 Time Dial: 0.01…100.00
I2>1 DT Adder: 0.00…100.00
I2>1 Reset Char.: DT/Inverse
I2>1 tRESET: 0.00…100.00 s
I2>2 Status (up to): I2>2 tRESET

All settings and options chosen from the same ranges as per the first stage overcurrent, I2>1.

I2>3 Status: Disabled/Enabled
I2>3 Direction: Non-Directional or Directional Fwd or Directional Rev
I2>3 Current Set: 0.08…32.00 In
I2>3 Time Delay: 0.00…100.00 s
I2>4 Status (up to): I2>4 Time Delay
All settings and options chosen from the same ranges as per the third stage overcurrent, I2>3.
I2> VTS Blocking:
Binary function link string, selecting which Neg. Seq. O/C elements (stages 1 to 4) will be blocked if VTS detection of fuse failure occurs.
Binary function link string, selecting which Neg. Seq. O/C elements (stages 1 to 4) will be blocked if 2nd Harmonic Block is enabled.
I2> Char Angle: -95…95º
I2> V2pol Set: 0.5…25.0 (100 – 110 V):
2…100 (380 – 480 V):

18.6 Broken Conductor

Broken Conductor: Disabled/Enabled
I2/I1 Setting: 0.20…1.00
I2/I1 Time Delay: 0.0…100.0 s

18.7 Ground Overcurrent (Earth Fault 1 & 2)

IN1>1 Function	Disabled / DT / IEC S Inverse / IEC V Inverse / IEC E Inverse / UK LT Inverse / RI / IEEE M Inverse / IEEE V Inverse / IEEE E Inverse / US Inverse / US ST Inverse / IDG / Def User Curve 1 / Def User Curve 2 / Def User Curve 3 / Def User Curve 4
IN1>1 Directional	Non-Directional or Directional Fwd or Directional Rev
IN1>1 Current Set:	0.08…4.00 In
IN1>1 IDG Is:	1.0…4.0 In
IN1>1 Time Delay:	0.00…200.00 s
IN1>1 TMS:	0.025…1.200
IN1>1 Time Dial:	0.01…100.00
IN1>1 K(RI):	0.10..10.00
IN1>1 IDG Time:	1.00…2.00
IN1>1 DT Adder:	0.00…100.00
IN1>1 Reset Char.:	DT/Inverse
IN1>1 tRESET:	0.00…100.00 s
IN1>2 Status	(up to):
IN1>2 tRESET	

All settings and options chosen from the same ranges as per the first stage ground overcurrent, IN>1.

IN1>3 Status:	Disabled or Enabled
IN1>3 Directional:	Non-Directional or Directional Fwd or Directional Rev
IN1>3 Current Set:	0.08…32.00 In
IN1>3 Time Delay:	0.00…200.00 s
IN1>4 Status (up to):	IN1>4 Time Delay All settings and options chosen from the same ranges as per the third stage ground overcurrent, IN>3.
IN1> Blocking:	Binary function link string, selecting which ground overcurrent elements (stages 1 to 4) will be blocked if VTS detection of fuse failure occurs. Binary function link string, selecting which ground overcurrent elements (stages 1 to 4) will be blocked if 2nd Harmonic Block is enabled.
IN1> Char Angle:	-95…95º
IN1> Polarization:	Zero Sequence or Neg. Sequence
IN1> VNpol Set:	0.5…80.0 V (100 – 110 V) 2…320 V (380 – 480 V)
IN1> V2pol Set:	0.5…25.0 V (100 – 110 V) 2…100 V (380 – 480 V)
IN1> I2pol Set:	0.08…1.00 In

18.8 Sensitive Earth Fault Protection/ Restricted Earth Fault Protection

SEF/REF Options:	SEF / SEF cos (PHI) / SEF sin (PHI) / Wattmetric / Hi Z REF / Lo Z REF / Lo Z REF + SEF / Lo Z REF + Wattmetric
ISEF>1 Function:	Disabled / DT / IEC S Inverse / IEC V Inverse / IEC E Inverse / UK LT Inverse / RI / IEEE M Inverse
IEEE V Inverse:	IEEE E Inverse / US Inverse / US ST Inverse / IDG / Def User Curve 1 / Def User Curve 2 / Def User Curve 3 / Def User Curve 4
ISEF>1 Directional:	Non-Directional or Directional Fwd or Directional Rev.
ISEF>1 Current Set:	0.005…0.01 In
ISEF>1 IDG Is:	1.0…4.0 In
ISEF>1 Time Delay:	0.00…200.00 s
ISEF>1 TMS:	0.025…1.200
ISEF>1 Time Dial:	0.5…100.0
IN1>1 K(RI):	0.10..10.00
ISEF>1 IDG Time:	1.00..2.00
ISEF>1 DT Adder:	0.00…100.00
ISEF>1 Reset Char:	DT/Inverse
ISEF>1 tRESET:	0.00…100.00 s
ISEF>2 Status (up to):	ISEF>2 tRESET

All settings and options chosen from the same ranges as per the first stage ground overcurrent, IN>1.

ISEF>3 Status:	Disabled / Enabled
ISEF>3 Directional:	Non-Directional or Directional Fwd or Directional Rev
ISEF>3 Current Set:	0.005….2.000 In
ISEF>3 Time Delay:	0.00…200.00 s
ISEF>4 Status (up to):	
ISEF>4 Time Delay	All settings and options chosen from the same ranges as per the third stage ground overcurrent, IN>3.
ISEF> Blocking:	Binary function link string, selecting which ground overcurrent elements (stages 1 to 4) will be blocked if VTS detection of fuse failure occurs. Binary function link string, selecting which ground overcurrent elements (stages 1 to 4) will be blocked if 2nd Harmonic Block is enabled.
ISEF> Char. Angle:	-95…95º
ISEF> VNpol Set:	0.5…80.0V (100 – 110 V) or 2…320V (380 – 480 V)

18.8.1 WATTMETRIC SEF:

PN> Setting:	0…20 W (1A, 100/120 V)
PN> Setting:	0…100 W (5A, 100/120 V)
PN> Setting:	0 …80 W (1A, 380/440 V)
PN> Setting:	0…400 W (5A, 380/440 V)

18.8.1.1 Restricted Earth-Fault (Low Impedance)

IREF > K1:	0 …20%
IREF > K2:	0 …150%
IREF > Is1:	0.08…1.00 In
IREF > Is2:	0.1…1.50 In

18.8.1.2 Restricted Earth-Fault (High Impedance)

IREF > K1: 0.05…1.00 In

18.9 Neutral Voltage Displacement (Residual O/V NVD)

VN>1 Function:	Disabled / DT / IDMT
VN>1 Voltage Set:	1…50 V
VN>1 Time Delay:	0.00…100.00 s
VN>1 TMS:	0.5…100.0
VN>1 tReset:	0.00…100.00 s
VN>2 Status:	Disabled/Enabled
VN>2 Voltage Set:	1…80 V (100/110 V) 4…320 V (380/440 V)
VN>2 Time Delay:	0.00…100.00 s

18.10 Thermal Overload

Characteristic:	Disabled / Single / Dual
Thermal Trip:	0.08…4.00 In
Thermal Alarm:	50…100%
Time Constant 1:	1…200 mins
Time Constant 2:	1…200 mins

18.11 Negative Sequence Overvoltage Protection

V2> Status:	Disabled/Enabled
V2> Voltage Set:	1V…110 V (100/120 V) 4V – 440 V (380/440 V)
V2> Time Delay:	0.00…100.00 s

18.12 Cold Load Pick- up Setting

tcold Time Delay:	0…14 400 s
tclp Time Delay:	0…14 400 s

18.13 Overcurrent

I>1 Status: Block/Enabled
I>1 Current Set: 0.08…4.00 In
I>1 Time delay: 0.00…100.00 s
I>1 TMS: 0.025….2.000
I>1 Time Dial: 0.5…15.0
I>2 Status (up to):
I>2 Time Dial
All settings and options chosen from the same ranges as per the 1st stage.
I>3 Status: Block/Enabled
I>3 Current Set: 0.08…32.00 In
3 Time delay: 0.00…100.00 s
I>4 Status (up to):
I>4 Time Delay All settings & options chosen from the same ranges as the 1st stage.
E/F1
IN1>1 Status: Block/Enabled
IN1>1 Current Set: 0.08…4.00 In
IN1>1 IDG Is: 1.0…4.0 In
IN1>1 Time Delay: 0.00…200.00 s
IN1>1 TMS: 0.025….2.000
IN1>1 Time Dial: 0.5…15.0
IN1>1 K(RI): 0.10..10.00
IN1>2 Status (up to):
IN2> 1 K(RI)
All settings & options chosen from the same ranges as the E/F1 stage.
I>5 Status (up to):
I>5 Time Dial All settings & options chosen from the same ranges as the 1st stage.
I>6 Status (up to):
I>6 Time DelayAll settings & options chosen from the same ranges as the 3rd stage.

18.14 Selective Overcurrent Logic

Overcurrent
- I>3 Time Delay: 0.00…100.00 s
- I>4 Time Delay: 0.00…100.00 s

Earth Fault1
- IN1>3 Time Delay: 0.00…200.00 s
- IN1>4 Time Delay: 0.00…200.00 s

Earth Fault2
- IN2>3 Time Delay: 0.00…200.00 s
- IN2>4 Time Delay: 0.00…200.00 s

Sensitive E/F
- ISEF>3 Time Delay: 0.00…200.00 s
- ISEF>4 Time Delay: 0.00…200.00 s

Overcurrent
- I>6 Time Delay: 0.00…100.00 s

18.15 Neutral Admittance Protection

VN Threshold: 1…40 V (100/120 V) or 4…160 V (380/440 V)
CT Input Type: SEF CT / E/F CT
Correction angle: 30…30^{o}

18.15.1 Over Admittance

YN Status:	Disabled/Enabled
YN> Set (SEF):	0.1…10 mS (100/110 V) 0.025…2.5 mS (380/440 V)
YN> Set (EF):	1…100 mS (100/110 V) 0.25…25 mS (380/440 V)
YN> Time Delay:	0.05 s…100.00 s
YN> tRESET:	0.00…100.00 s

18.15.2 Over Conductance

GN Status:	Disabled/Enabled
GN>Direction	Non-Directional or Directional Fwd or Directional Rev.
GN> Set (SEF):	0.1…5 mS (100/110 V) or 0.25…1.25 mS (380/440 V)
GN> Set (E/F):	1…50 mS (100/110 V) or 0.25…12.5 mS (380/440 V)
GN> Time Delay:	0.05 s…100 s
GN>tRESET:	0 s…100 s

18.15.3 Over Susceptance

BN Status:	Disabled/Enabled
GN>Direction:	Non-Directional or Directional Fwd or Directional Rev
BN> Set (SEF):	0.1…5 mS (100/110 V) 0.025…1.25 mS (380/440 V)
BN> Set (E/F):	1…50 mS (100/110 V) 0.25…12.5 mS (380/440 V)
BN> Time Delay:	0.05…100 s
BN> tRESET:	0 s…100 s

18.16 Undervoltage Protection

V< Measur't. Mode:	Phase-Phase / Phase-Neutral
V< Operate Mode:	Any Phase / Three Phase
V<1 Function:	Disabled / DT / IDMT
V<1 Voltage Set:	10…120 V (100/110 V) 40…480 V (380/440 V)
V<1 Time Delay:	0.00…100.00 s
V<1 TMS:	0.5…100.0
V<1 Poledead Inh:	Disabled/Enabled
V<2 Status:	Disabled/Enabled
V<2 Voltage Set:	10…120 V (100/110 V) 40…480 V (380/440 V)
V<2 Time Delay:	0.00…100.00 s
V<2 Poledead Inh:	Disabled/Enabled

18.17 Overvoltage Protection

V> Measur't. Mode:	Phase-Phase or Phase-Neutral
V> Operate Mode:	Any Phase or Three Phase
V>1 Function:	Disabled / DT / IDMT
V>1 Voltage Set:	60…185 V (100/110 V) 240…740 V (380/440 V)
V>1 Time Delay:	0.00…100.00 s
V>1 TMS:	0.5…100.0
V>2 Status:	Disabled/Enabled
V>2 Voltage Set:	60…185 V (100/110 V) 240…740 V (380/440 V)
V>2 Time Delay:	0.00…100.00 s

18.18 dv/dt Protection

dv/dt Meas. Mode:	Phase-Phase / Phase-Neutral
dv/dt1 Function:	Disabled / Negative / Positive / Both
dv/dt1 Oper Mode:	Any Phase / Three Phase
dv/dt1 AvgCycles:	5…50
dv/dt1 Threshold:	0.5…200
dv/dt1 TimeDelay:	0…100 s
dv/dt1 tRESET:	0…100 s
dv/dt2 Function:	Disabled / Negative / Positive / Both
dv/dt2 Oper Mode:	Any Phase / Three Phase
dv/dt2 AvgCycles:	5…50
dv/dt2 Threshold:	0.5…200
dv/dt2 TimeDelay:	0…100 s
dv/dt2 tRESET:	0…100 s

18.19 Underfrequency Protection

F<1 Status:	Disabled/Enabled
F<1 Setting:	45.00…65.00 Hz
F<1 Time Delay:	0.00…100.00 s
F<2 Status (up to):	F<4 Time Delay

All settings and options chosen from the same ranges as per the 1st stage.

F> Blocking:	Binary function link string, selecting which frequency elements (stages 1 to 4) will be blocked by the pole-dead logic.

18.20 Overfrequency Protection

F>1 Status:	Disabled/Enabled
F>1 Setting:	45.00…65.00 Hz
F>1 Time Delay:	0.00…100.00 s
F<2 Status (up to):	F<2 Time Delay

All settings and options chosen from the same ranges as per the 1st stage.

18.21 Advanced Over/Underfrequency Protection (f+t [81U/81O])

Stage 1 f+t Status: Disabled / Enabled
1 (f+t) f: 40.10…69.90 Hz
1 (f+t) t: 0.00…100.00 s
Stage 2 f+t Status (up to): 9 (f+t)t
All settings and options chosen from the same ranges as per the first stage over/underfrequency, Stage 1 f+t.

18.22 Advanced Frequency Supervised Rate of Change of Frequency Protection (f+df/dt [81RF]

Stage 1 f+df/dt Status: Disabled / Enabled
1 (f+df/dt) f: 40.10…69.90 Hz
1 (f+df/dt) df/dt: 0.01…10.0 Hz/s
Stage 2 f+df/dt Status (up to): 9 (f+df/dt) df/dt
All settings and options chosen from the same ranges as per the first stage frequency supervized rate of change of frequency, Stage 1 f+df/dt.

18.23 Advanced Independent Rate of Change of Frequency Protection (df/dt+t [81R])

Stage 1 df/dt+t Status: Disabled / Negative / Positive
1 (df/dt+t) df/dt: 0.01…10.00 Hz/s
1 (df/dt+t) t: 0.00…100.00 s
Stage 2 df/dt+t Status (up to): 9 (df/dt+t) t
All settings and options chosen from the same ranges as per the first stage independent rate of change of frequency, Stage 1 df/dt+t.

18.24 Advanced Average Rate of Change of Frequency Protection (f+Df/Dt [81RAV])

Stage 1 f+Df/Dt Status: Disabled / Enabled
1 (f+Df/Dt) f: 40.10…69.90 Hz
1 (f+Df/Dt) Df: 0.2…10.0 Hz
1 (f+Df/Dt) Dt: 0.02…2.00 s
Stage 2 f+Df/Dt Status (up to): 9 (f+Df/Dt) Dt
All settings and options chosen from the same ranges as per the first stage average rate of change of frequency, Stage 1 f+Df/Dt.

18.25 Advanced Load Restoration

Restore1 Status: Disabled / Enabled
Restore1 Freq.: 40.10…69.90 Hz
Restore1 Time: 0…7200 s
Restore2 Status (up to): Restore9 Time
All settings and options chosen from the same ranges as per the first stage load restoration, Restore1.

18.26 Circuit Breaker Fail

CB Fail 1 Status:	Disabled/Enabled
CB Fail 1 Timer:	0.00…10.00 s
CB Fail 2 Status:	Disabled/Enabled
CB Fail 2 Timer:	0.00…10.00 s
Volt Prot. Reset:	I< Only or CB Open & I< or Prot. Reset & I<
Ext Prot. Reset:	I< Only or CB Open & I< or Prot. Reset & I<

18.27 Undercurrent

I< Current Set:	0.02…3.20 In
IN< Current Set:	0.02…3.20 In
ISEF< Current Set:	0.001…0.800 In

18.28 Blocked O/C

Remove I> Start:	Disabled/Enabled
Remove IN> Start:	Disabled/Enabled

18.29 Fuse Failure (VT Supervision)

VTS Status:	Blocking/Indication
VTS Reset Mode:	Manual/Auto
VTS Time Delay:	1.0…10.0 s
VTS I> Inhibit:	0.08…32.00 In
VTS I2> Inhibit:	0.05…0.50 In

18.30 CT Supervision

CTS Status:	Disabled/Enabled
CTS VN< Inhibit:	0.5…22.0 V (100/110 V) 2…88 V (380/440 V)
CTS IN> Set:	0.08…4.00 In
CTS Time Delay:	0…10 s
VTS PickupThresh:	20…120 V

18.31 Fault Locator

Line Length (km):	0.001…1000.000 km
Line Length (mi):	0.20…625.00 mi
Line Impedance:	0.10…250.00 Ω
Line Angle:	20…85°
KZN Residual:	0.00…7.00
KZN Res. Angle:	-90…90°

18.32 Bus-Line Synchronizm and Voltage Checks (System Checks)

Voltage Monitors

Live Voltage:	1.0…132.0 V (100/110 V) 22…528 V (380/440 V)
Dead Voltage:	1.0…132.0 V (100/110 V) 22…528 V (380/440 V)

18.33 Synchrocheck (Check Sync.)

CS1 Status:	Disabled/Enabled
CS1 Phase Angle:	5…90°
CS1 Slip Control:	None / Timer / Frequency / Both
CS1 Slip Freq.:	0.01…1.00 Hz
CS1 Slip Timer:	0.0…99.0 s
CS2 Status (up to):	CS2 Slip Timer

All settings and options chosen from the same ranges as per the first stage CS1 element.

CS Undervoltage:	10.0…132.0 V (100/110 V) 40…528 V (380/440 V)
CS Overvoltage:	40.0…185.0 V (100/110 V) 160…740 V (380/440 V)
CS Diff Voltage:	1.0…132.0 V (100/110 V) 4…528 V (380/440 V)
CS Voltage Block:	None / Undervoltage / Overvoltage / Differential / UV & OV / UV & DiffV / OV & DiffV / UV, OV & DiffV

18.34 System Split

SS Status:	Disabled/Enabled
SS Phase Angle:	90…175°
SS Under V Block:	Disabled/Enabled
SS Undervoltage:	10.0…132.0 V (100/110 V) 40…528 V (380/440 V)
SS Timer:	0.0…99.0 s
CB Close Time:	0.000…0.500 s

18.35 Auto-reclose

AR Mode Select:	Command Mode or Opto Set Mode or User Set Mode or Pulse Set Mode
Number of Shots:	1…4
Number of SEF Shots:	0…4
Sequence Co-ord.:	Disabled/Enabled
CS AR Immediate:	Disabled/Enabled
Dead Time 1:	0.01…300.00 s
Dead Time 2:	0.01…300.00 s
Dead Time 3:	0.01…9999.00 s
Dead Time 4:	0.01…9999.00 s
CB Healthy Time:	0.01 s…9999.00 s
Start Dead t on:	Protection Resets/CB Trips
tReclaim Extend:	No Operation/On Prot. Start

Reclaim Time 1:	1.00…600.00 s
Reclaim Time 2:	1.00…600.00 s
Reclaim Time 3:	1.00…600.00 s
Reclaim Time 4:	1.00…600.00 s
AR Inhibit Time:	0.01…600.00 s
AR Lockout:	No Block/Block Inst. Prot.
EFF Maint. Lock:	No Block/Block Inst. Prot.
AR Deselected:	No Block/Block Inst. Prot.
Manual close:	No Block/Block Inst. Prot.

Trip 1 Main:	No Block/Block Inst. Prot.
Trip 2 Main:	No Block/Block Inst. Prot.
Trip 3 Main:	No Block/Block Inst. Prot.
Trip 4 Main:	No Block/Block Inst. Prot.
Trip 5 Main:	No Block/Block Inst. Prot.
Trip 1 SEF:	No Block/Block Inst. Prot.
Trip 2 SEF:	No Block/Block Inst. Prot.
Trip 3 SEF:	No Block/Block Inst. Prot.
Trip 4 SEF:	No Block/Block Inst. Prot.
Trip 5 SEF:	No Block/Block Inst. Prot.
Man. Close on Flt:	No Lockout/Lockout
Trip AR Inactive:	No Lockout/Lockout
Reset Lockout by:	User Interface/Select Non-Auto
AR on Man. Close:	Enabled/Inhibited
Sys. Check Time:	0.01…9999.00 s
AR Skip Shot 1:	Enabled/disabled

18.35.1 AR INITIATION

I>1, I>2:	No Action/Initiate Main AR
I>3 and I>4:	No Action/Initiate Main AR/Block AR
IN1>1 and IN1>2:	No Action/Main AR
IN1>3 and IN1>4:	No Action/Initiate Main AR/Block AR
IN2>1, IN2>2:	No Action/Initiate Main AR
IN2>3 and IN2>4:	No Action/Initiate Main AR/Block AR
ISEF>1, ISEF>2, ISEF>3 and ISEF>4:	No Action/Initiate Main AR/Initiate SEF AR/Block AR
YN/GN/ BN>:	No Action/Initiate Main AR
Ext. Prot.:	No Action/Initiate Main AR

18.35.2 SYSTEM CHECKS

AR with ChkSync:	Disabled/Enabled
AR with SysSync:	Disabled/ Enabled
Live/Dead Ccts:	Disabled/Enabled
No System Checks:	Enabled/Disabled
SysChk on Shot 1:	Disabled/ Enabled
I>5:	No Action/Initiate Main AR
I>6:	No Action/Initiate Main AR/Block AR

18.36 Opto Input Labels

Opto Input 1: (up to): Opto Input 24:
User defined text string to describe the function of the particular opto input.

18.37 Output Labels

Relay 1: (up to): Relay 32:
User defined text string to describe the function of the particular relay output contact.

19 MEASUREMENTS LIST (IN MULTIPLE GROUPS)

Note	All settings here onwards apply for setting groups # = 1 to 4.

19.1 Measurements 1

Iφ Magnitude
Iφ Phase Angle
Per phase (φ = A, B, C) current measurements
IN Measured Mag.
IN Measured Ang.
IN Derived Mag.
IN Derived Angle
ISEF Magnitude
ISEF Angle
I1 Magnitude
I2 Magnitude
I0 Magnitude
Iφ RMS
Per phase (φ = A, B, C) RMS current measurements
Vφ-φ Magnitude
Vφ-φ Phase Angle
Vφ Magnitude
Vφ Phase Angle
All phase-phase and phase-neutral voltages (φ = A, B. C)
VN Derived Mag.
VN Derived Ang.
V1 Magnitude.
V2 Magnitude
V0 Magnitude
Vφ RMS
All phase-neutral voltages (φ = A, B, C)
Frequency
C/S Voltage Mag.
C/S Voltage Ang.
C/S Bus-line Ang.
Slip Frequency
IM Magnitude
IM Phase Angle
I1 Magnitude
I1 Phase Angle
I2 Magnitude
I2 Phase Angle
I0 Magnitude
I0 Phase Angle
V1 Magnitude
V1 Phase Angle
V2 Magnitude
V2 Phase Angle
V0 Magnitude
V0 Phase Angle

19.2 Measurements 2

φ Phase Watts
φ Phase VArs
φ Phase VA All phase segregated power measurements, real, reactive and apparent (φ = A, B, C)
3 Phase Watts
3 Phase VArs
3 Phase VA
Zero Seq. Power
3Ph Power Factor
φPh Power Factor
Independent power factor measurements for all three phases (φ = A, B, C).
3Ph WHours Fwd
3Ph WHours Rev.
3Ph VArHours Fwd
3Ph VArHours Rev.
3Ph W Fix Demand
3Ph VArs Fix Dem.
Iφ Fixed Demand Maximum demand currents measured on a per phase basis (φ = A, B, C).
3Ph W Roll Dem.
3Ph VArs Roll Dem.
Iφ Roll Demand
Maximum demand currents measured on a per phase basis (φ = A, B, C).
3Ph W Peak Dem.
3Ph VAr Peak Dem.
Iφ Peak Demand
Maximum demand currents measured on a per phase basis (φ = A, B, C).
Reset Demand: Yes/No

19.3 Measurements 3

Highest Phase I
Thermal State
Reset Thermal
IREF Diff.
IREF Bias
Admittance
Conductance
Susceptance
Admittance
Conductance
Susceptance
I2/I1 Ratio
SEF Power
IA 2nd Harmonic
IB 2nd Harmonic
IC 2nd Harmonic
APh Sen Watts
APh Sen Vars
APh Power Angle
Z1 Imp Mag
Z1 Imp Ang
Phase A Imp Mag
Phase A Imp Ang
Phase B Imp Mag
Phase B Imp Ang

Phase C Imp Mag
Phase C Imp Ang

19.4 Stage Statistics (Advanced)

StgX f+t Sta
StgX f+t Trip
StgX f+df/dt Trp
StgX df/dt+t Sta
StgX df/dt+t Trp
StgX f+Df/Dt Sta
StgX f+Df/Dt Trp
StgX Revn Date
(X = 1, 2, 3, 4, 5, 6, 7, 8, 9)

19.5 Circuit Breaker Monitoring Statistics

CB Operations
CB φ Operations
Circuit breaker operation counters on a per phase basis (φ = A, B, C).
Total Iφ Broken
Cumulative breaker interruption duty on a per phase basis (φ = A, B, C).
CB Operate Time
CB CONTROL
Total Re-closures

19.6 Fault Record Proforma

The following data is recorded for any relevant elements that operated during a fault, and can be viewed in each fault record.

Time & Date
Event Text
Event Value

Select Fault:	[0...n]
Started Phase:	A/B/C
Tripped Phase:	A/B/C
Overcurrent	Start I> 123456 or Trip I> 123456
Neg. Seq. O/C	Start I2> 1234 or Trip I2> 1234

19.6.1 Broken ConductorTrip

Earth Fault 1	Start IN1> 1234 or Trip IN1> 1234
Earth Fault 2	Start IN2> 1234 or Trip IN2> 1234
Sensitive E/F	Start ISEF> 1234 or Trip ISEF> 1234
Restricted E/F	Trip IREF>
Residual O/V NVD	Start VN> 1 2 or Trip VN> 1 2

Thermal Overload:	Alarm/Trip
Neg. Seq. O/V	V2> Start Trip
U/Voltage Start	V< 1 2 AB BC CA
U/Voltage Trip	V< 1 2 AB BC CA
O/Voltage Start	V> 1 2 AB BC CA
O/Voltage Trip	V> 1 2 AB BC CA
Underfrequency	Start F< 1234 or Trip F< 1234
Overfrequency	Start F> 1 2 or Trip F> 1 2
Overadmittance	YN> Start Trip
Overconductance	GN> Start Trip
Oversusceptance	BN> Start Trip
Breaker Fail:	CB Fail 1 2
Supervision	VTS/CTS/VCO/CLP
A/R State:	Trip 1/2/3/4/5
Advanced Freq. Protection	Start >123456789
Advanced Freq. Protection	Trip >123456789
Adv. F+df/dt Protection	Trip >123456789
Adv. df/dt Protection	Start >123456789
Adv. df/dt Protection	Trip >123456789
Adv. DelF/DelT Protection	Start >123456789
Adv. DelF/DelT Protection	Trip >123456789
Faulted Phase:	A/B/C

Start Elements:
Trip Elements: Binary data strings for fast polling of which protection elements started or tripped for the fault recorded.
Fault Alarms: Binary data strings for fast polling of alarms for the fault recorded.
Fault Time:
Active Group: 1/2/3/4
System Frequency: Hz
Fault Duration: s
CB Operate Time: s
Relay Trip Time: s
Fault Location: km/miles/Ω/%
The current magnitudes and phase angles stored before the fault inception.
$I\varphi$
$V\varphi$:
Per phase record of the current and voltage magnitudes during the fault.
IN Measured
IN Derived
IN Sensitive
IREF Diff.
IREF Bias
VAN
VBN
VCN
VN Derived
Admittance
Conductance
Susceptance

GETTING STARTED

CHAPTER NO 3

Date:	10/2014
Products covered by this chapter:	This chapter covers the specific versions of the MiCOM products listed below. This includes ***only*** the following combinations of Software Version and Hardware Suffix.
Hardware Suffix:	L (P141, P142 & P143) & M (P145)
Software Version:	A0 - P14x (P141, P142, P143 & P145)
Connection Diagrams:	10P141xx (xx = 01 to 07) 10P142xx (xx = 01 to 07) 10P143xx (xx = 01 to 07) 10P145xx (xx = 01 to 07)

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TABLES

FIGURES

1 INTRODUCTION TO THE RELAY

Warning	**Before carrying out any work on the equipment, you should be familiar with the contents of the Safety Information chapter/safety guide SFTY/4LM/C11 or later issue, the Technical Data chapter and the ratings on the equipment rating label.**

1.1 User Interfaces and Menu Structure

The settings and functions of the MiCOM protection relay can be accessed both from the front panel keypad and LCD, and via the front and rear communication ports. Information on each of these methods is given in this section to describe how to start using the relay.

1.2 Front Panel

The following figure shows the front panel of the relay; the hinged covers at the top and bottom of the front panel are shown open. An optional transparent front cover physically protects the front panel. With the cover in place, access to the user interface is read-only. Removing the cover allows access to the relay settings and does not compromise the protection of the product from the environment.

When editing relay settings, full access to the relay keypad is needed. To remove the front panel:

1. Open the top and bottom covers, then unclip and remove the transparent cover. If the lower cover is secured with a wire seal, remove the seal.
2. Using the side flanges of the transparent cover, pull the bottom edge away from the relay front panel until it is clear of the seal tab.
3. Move the cover vertically down to release the two fixing lugs from their recesses in the front panel.

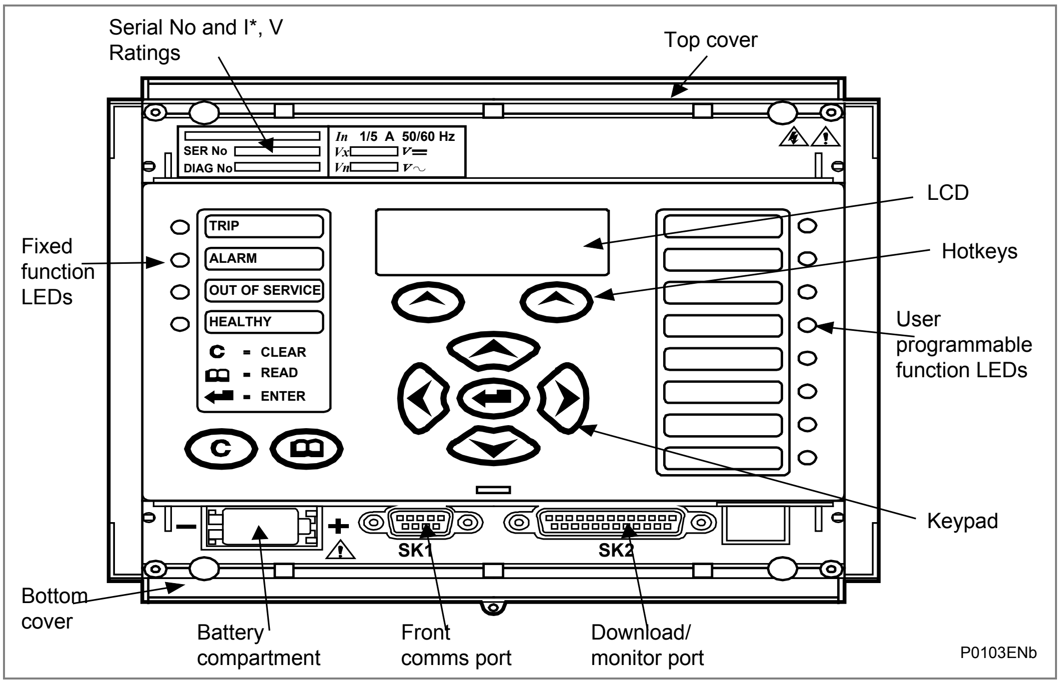

Figure 1 - Relay front view for P141/P142/P143 models

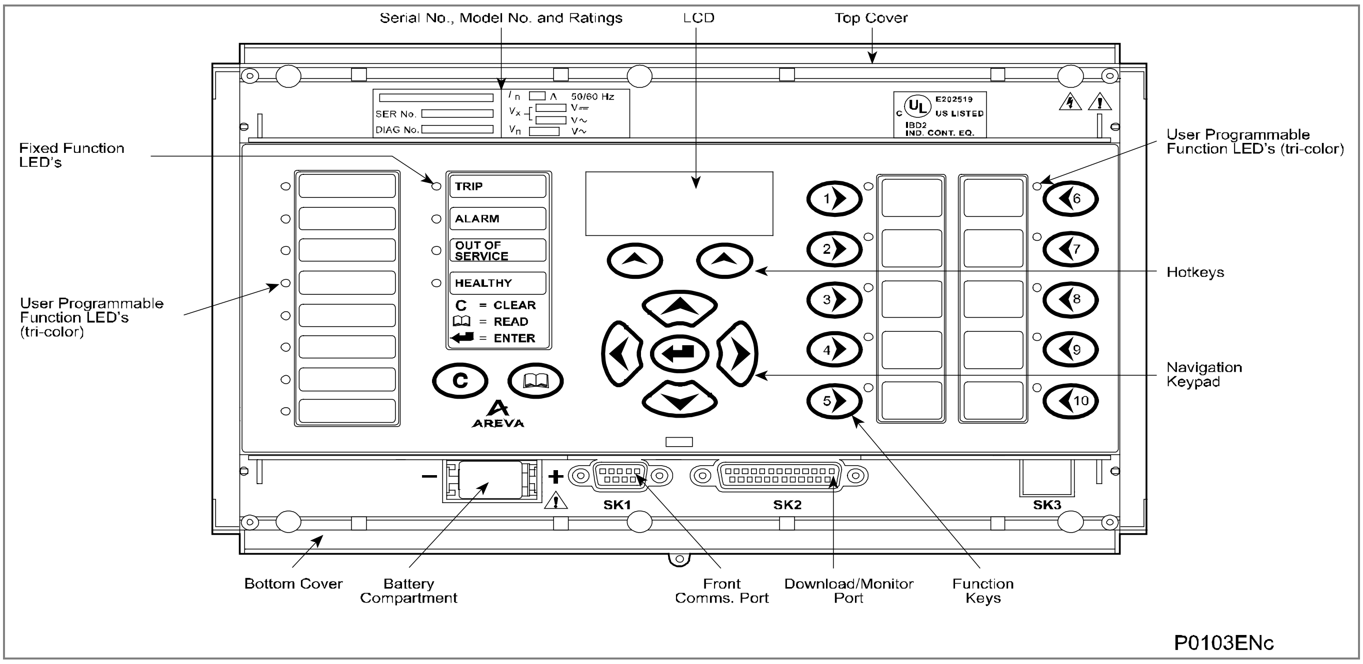

Figure 2 - Relay front view for P145 model

The front panel of the relay includes the following, as shown in the previous figure:

- a 16-character by 3-line alphanumeric Liquid Crystal Display (LCD)
- a 19-key keypad comprising:
    - 4 arrow keys (and), an enter key (), a clear key (), a read key (), 2 hot keys () and 10 (–) programmable function keys

Function key functionality (P145 model only):

- The relay front panel has control keys with programmable LEDs for local control. Factory default settings associate specific relay functions with these 10 direct-action keys and LEDs, e.g. Enable or Disable the auto-recloser function. Using programmable scheme logic, the user can change the default functions of the keys and LEDs to fit specific needs.
- Hotkey functionality:
  - **SCROLL** starts scrolling through the various default displays.
  - **STOP** stops scrolling the default display.

For control of setting groups, control inputs and circuit breaker operation

- P141/P142/P143 models: 12 LEDs; 4 fixed function LEDs on the left hand side of the front panel and 8 programmable function LEDs on the right hand side
- P145 model: 22 LEDs; 4 fixed function LEDs, 8 tri-color programmable function LEDs on the left hand side of the front panel and 10 tri-color programmable function LEDs on the right hand side associated with the function keys

Under the top hinged cover:

- The relay serial number, and the relay's current and voltage rating information

Under the bottom hinged cover:

- Battery compartment to hold the 1/2 AA size battery which is used for memory back-up for the real time clock, event, fault and disturbance records
- A 9-pin female D-type front port for communication with a PC locally to the relay (up to 15m distance) via an EIA(RS)232 serial data connection
- A 25-pin female D-type port providing internal signal monitoring and high speed local downloading of software and language text via a parallel data connection

1.2.1 LED Indications - Fixed Function

The Fixed Function LEDs on the left-hand side of the front panel show these conditions:

- **Trip** (Red) switches ON when the relay issues a trip signal. It is reset when the associated fault record is cleared from the front display. Also the trip LED can be configured as self-resetting.
- **Alarm** (Yellow) flashes when the relay registers an alarm. This may be triggered by a fault, event or maintenance record. The LED flashes until the alarms have been accepted (read), then changes to constantly ON. When the alarms are cleared, the LED switches OFF.
- **Out of Service** (Yellow) is ON when the relay's protection is unavailable.
- **Healthy** (Green) is ON when the relay is in correct working order, and should be ON at all times. It goes OFF if the relay's self-tests show there is an error in the relay's hardware or software. The state of the healthy LED is reflected by the watchdog contacts at the back of the relay.

To adjust the LCD contrast, from the **CONFIGURATION** column, select **LCD Contrast**. This is only needed in very hot or cold ambient temperatures.

1.2.2 Relay Rear Panel

Examples of the rear panel of the relay are shown in the following figure. All current and voltage signals, digital logic input signals and output contacts are connected at the rear of the relay. Also connected at the rear is the twisted pair wiring for the rear EIA(RS)485 communication port; the IRIG-B time synchronising input is optional, the Ethernet rear communication board with copper and fiber optic connections or the second communication are optional.

Refer to the wiring diagrams in the 'Connection Diagrams' chapter for further details.

Note	*The following diagrams show variants of the P145 relay.*
Note	*Figure 3 shows the optional optical fiber rear communication port with IRIG-B time synchronizing input.*
Note	*Figure 4 shows the relay with optional Ethernet rear communications port with copper and fiber optic connections.*

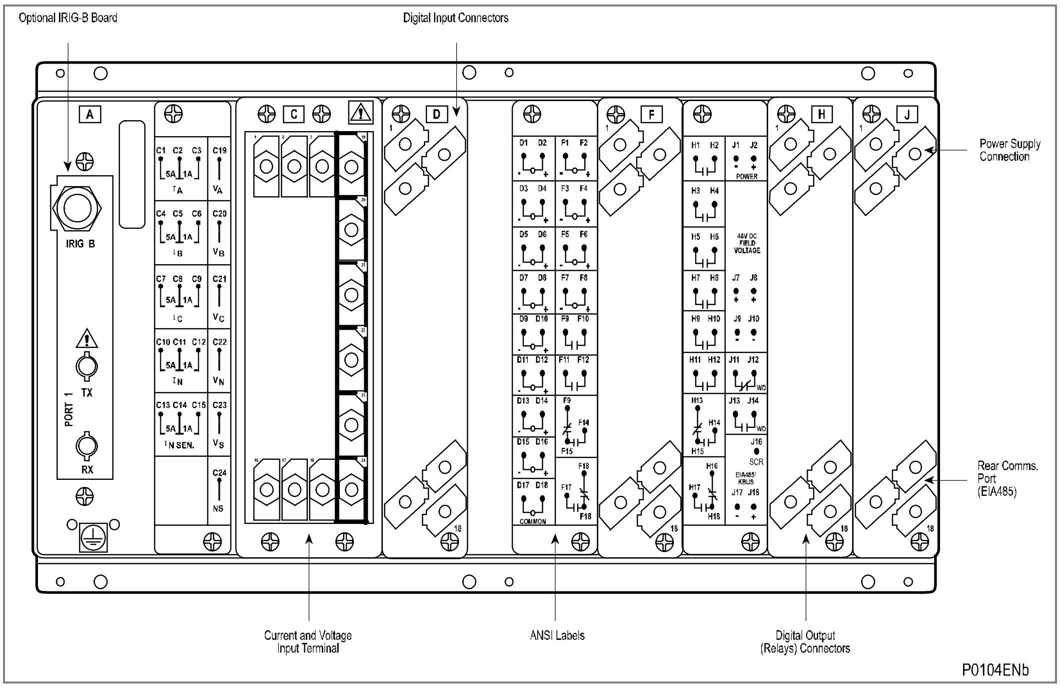

Figure 3 - Relay rear view for B-variant

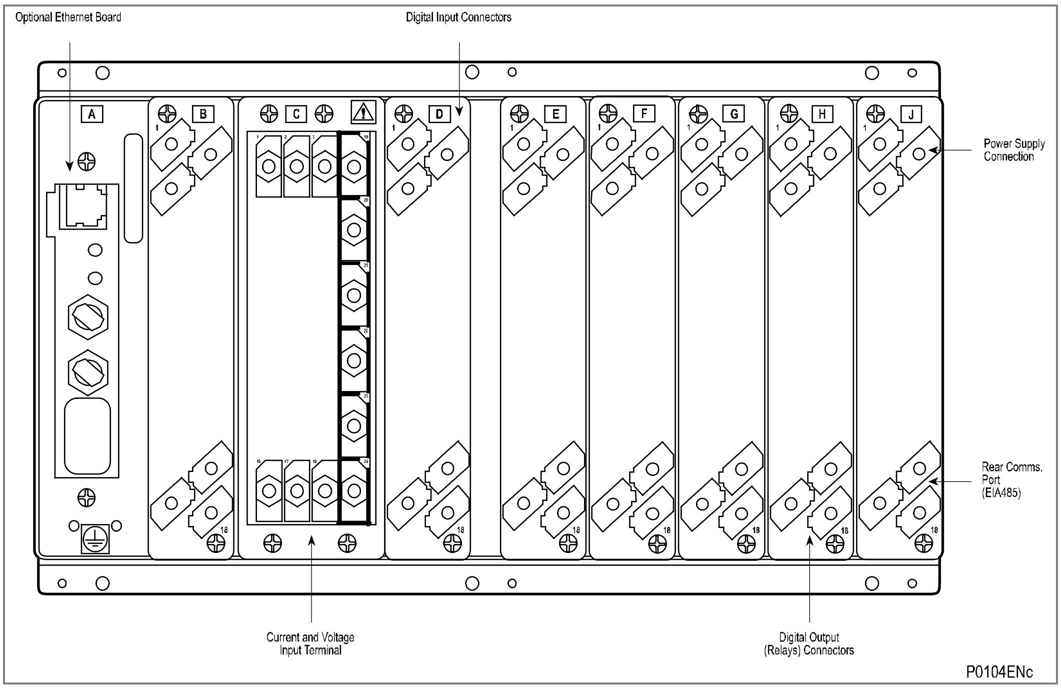

Figure 4 - Relay rear view for G-variant

2 RELAY CONNECTION AND POWER-UP

Before powering-up the relay, confirm that the relay power supply voltage and nominal ac signal magnitudes are appropriate for your application. The relay serial number, and the relay's current and voltage rating, power rating information can be viewed under the top hinged cover. The relay is available in the auxiliary voltage versions shown in this table:

Nominal Ranges		Operative dc Range	Operative ac Range
24 - 32V dc		19 to 65V	-
48 - 110V dc	-	37 to 150V	32 to 110V
110 - 250V dc	(100 - 240V ac rms) **	87 to 300V	80 to 265V
*** rated for ac or dc operation*			

Table 1 - Nominal ranges

Please note that the label does not specify the logic input ratings. These relays are fitted with universal opto isolated logic inputs that can be programmed for the nominal battery voltage of the circuit of which they are a part. See 'Universal Opto input' in the Product Design (Firmware) section for more information on logic input specifications.

Note	*The opto inputs have a maximum input voltage rating of 300V dc at any setting.*

Once the ratings have been verified for the application, connect external power capable of delivering the power requirements specified on the label to perform the relay familiarization procedures. Previous diagrams show the location of the power supply terminals - please refer to the Installation and Wiring Diagrams chapters for all the details, ensuring that the correct polarities are observed in the case of dc supply.

3 USER INTERFACES AND SETTINGS OPTIONS

The relay has these user interfaces:

- The front panel using the LCD and keypad.
- The front port which supports Courier communication.
- The rear port which supports one of these protocols:
  - Courier
  - MODBUS
  - IEC 60870-5-103
  - DNP3.0
- The optional Ethernet port supports IEC 61850-8-1 (and DNP3.0 for P14x products).
- A second optional rear port which supports Courier, KBUS or InterMiCOM communication.
- A third optional rear port(SK5) which supports InterMiCOM (for P14x products)

The protocol for the rear port must be specified when the relay is ordered.

The measurement information and relay settings that can be accessed from the different interfaces are shown in this table.

	Keypad or LCD	Courier	MODBUS	IEC870-5-103	DNP3.0	IEC61850-8-1
Display & modification of all settings	Yes	Yes	Yes			
Digital I/O signal status	Yes	Yes	Yes	Yes	Yes	Yes
Display/extraction of measurements	Yes	Yes	Yes	Yes	Yes	Yes
Display/extraction of fault records	Yes	Yes	Yes	Yes	Yes	Yes
Extraction of disturbance records		Yes	Yes	Yes		Yes
Programmable scheme logic settings		Yes				
Reset of fault & alarm records	Yes	Yes	Yes	Yes	Yes	
Clear event & fault records	Yes	Yes	Yes		Yes	
Time synchronization		Yes	Yes	Yes	Yes	Yes
Control commands	Yes	Yes	Yes	Yes	Yes	Yes

Table 2 - Measurement information and relay settings

4 MENU STRUCTURE

The relay's menu is arranged in a table. Each setting in the menu is referred to as a cell, and each cell in the menu may be accessed using a row and column address. The settings are arranged so that each column contains related settings, for example all the disturbance recorder settings are contained within the same column. As shown in the following diagram, the top row of each column contains the heading that describes the settings contained within that column. Movement between the columns of the menu can only be made at the column heading level.

A complete list of all of the menu settings is given in the Menu Content Map at the end of this section.

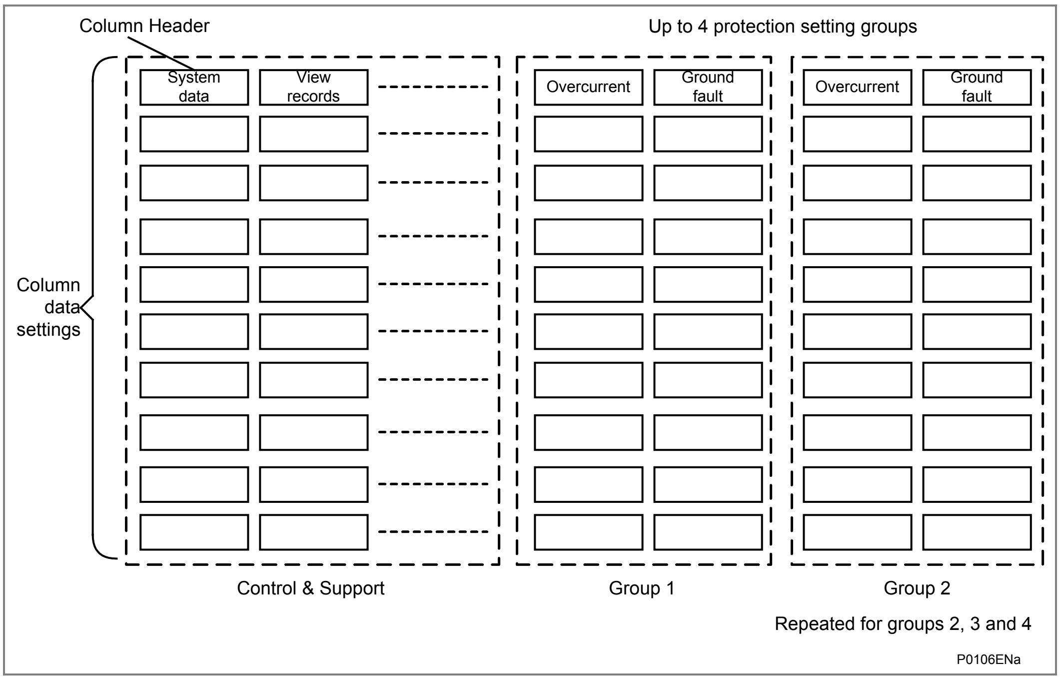

Figure 5 - Menu structure

The settings in the menu fall into one of these categories:

- Protection Settings
- Disturbance Recorder settings
- Control and Support (C&S) settings.

Different methods are used to change a setting depending on which category the setting falls into.

- C&S settings are stored and used by the relay immediately after they are entered.
- For either protection settings or disturbance recorder settings, the relay stores the new setting values in a temporary 'scratchpad'. It activates all the new settings together, but only after it has been confirmed that the new settings are to be adopted. This technique is employed to provide extra security, and so that several setting changes that are made within a group of protection settings will all take effect at the same time.

4.1 Protection Settings

The protection settings include the following items:

- Protection element settings
- Scheme logic settings
- Auto-reclose and check synchronization settings
- Fault locator settings

There are four groups of protection settings, with each group containing the same setting cells. One group of protection settings is selected as the active group, and is used by the protection elements.

4.2 Disturbance Recorder Settings

The disturbance recorder settings include the record duration and trigger position, selection of analogue and digital signals to record, and the signal sources that trigger the recording.

4.3 Control and Support Settings

The control and support settings include:

- Relay configuration settings
- Open/close circuit breaker (may vary according to relay type or model)
- CT & VT ratio settings
- Reset LEDs
- Active protection setting group
- Password & language settings
- Communications settings
- Measurement settings
- Event & fault record settings
- User interface settings
- Commissioning settings
- Circuit breaker control & monitoring settings

5 PASSWORD PROTECTION

5.1 Four-Level Access

The menu structure contains four levels of access three of which are password protected. These are summarized in Table 3.

Level	Meaning	Read Operation	Write Operation
0	Read Some Write Minimal	SYSTEM DATA column: Description Plant Reference Model Number Serial Number S/W Ref. Access Level Security Feature SECURITY CONFIG column: User Banner Attempts Remain Blk Time Remain Fallback PW level Security Code (UI only)	Password Entry LCD Contrast (UI only)
1	Read All Write Few	All data and settings are readable. Poll Measurements	All items writeable at level 0. Level 1 Password setting Select Event, Main and Fault (upload) Extract Events (e.g. via MiCOM S1 Studio)
2	Read All Write Some	All data and settings are readable. Poll Measurements	All items writeable at level 1. Setting Cells that change visibility (Visible/Invisible). Setting Values (Primary/Secondary) selector Commands: Reset Indication Reset Demand Reset Statistics Reset CB Data / counters Level 2 Password setting
3	Read All Write All	All data and settings are readable. Poll Measurements	All items writeable at level 2. Change all Setting cells Operations: Extract and download Setting file. Extract and download PSL Extract and download MCL61850 (IED Config - IEC61850) Extraction of Disturbance Recorder Courier/Modbus Accept Event (auto event extraction, e.g. via A2R) Commands: Change Active Group setting Close / Open CB Change Comms device address. Set Date & Time Switch MCL banks / Switch Conf. Bank in UI (IED Config - IEC61850) Enable / Disable Device ports (in SECURITY CONFIG column) Level 3 password setting

Table 3 - Password levels

Each of the two passwords are 4 characters of upper case text. The factory default for both passwords is AAAA. Each password is user-changeable once it has been correctly entered. Entry of the password is achieved either by a prompt when a setting change is attempted, or by moving to the '**Password**' cell in the '**System data**' column of the menu. The level of access is independently enabled for each interface, that is to say if level 2 access is enabled for the rear communication port, the front panel access will remain at level 0 unless the relevant password is entered at the front panel. The access level enabled by the password entry will time-out independently for each interface after a period of inactivity and revert to the default level. If the passwords are lost an emergency password can be supplied - contact Schneider Electric with the relay's serial number. The current level of access enabled for an interface can be determined by examining the '**Access level**' cell in the '**System data**' column, the access level for the front panel User Interface (UI), can also be found as one of the default display options.

The relay is supplied with a default access level of 2, such that no password is required to change any of the relay settings. It is also possible to set the default menu access level to either level 0 or level 1, preventing write access to the relay settings without the correct password. The default menu access level is set in the '**Password control**' cell which is found in the '**System data**' column of the menu.

Note	*This setting can only be changed when level 2 access is enabled).*

5.1.1 Default Password

Default passwords are blank for Level 1 and AAAA for Levels 2 and 3.

5.1.2 Password Rules

- Passwords may be any length between 0 and 8 characters long
- Passwords may or may not be NERC compliant
- Passwords may contain any ASCII character in the range ASCII code 33 (21 Hex) to ASCII code 122 (7A Hex) inclusive
- Only one password is required for all the IED interfaces

5.2 Password Strengthening

NERC compliant passwords result in a minimum level of complexity, and include these requirements:

- At least one upper-case alpha character
- At least one lower-case alpha character
- At least one numeric character
- At least one special character (%,$...)
- At least six characters long

5.3 Password Validation

The IED checks for NERC compliance. If the password is entered through the front panel then this is reflected on the panel Liquid Crystal Display (LCD) display.

If the entered password is NERC compliant, the following text is displayed

```
NERC COMPLIANT
P/WORD WAS SAVED
```

The IED does not enforce NERC compliance. It is the responsibility of the user to ensure that compliance is adhered to as and when necessary. In the case that the password entered is not NERC-compliant, the user is required to actively confirm this, in which case the non-compliance is logged.

If the entered password is not NERC compliant, the following text is displayed:

```
NERC COMPLIANCE
NOT MET CONFIRM?
```

On confirmation, the non-compliant password is stored and the following acknowledgement message is displayed for 2 seconds.

```
NON-NERC P/WORD
SAVED OK
```

If the action is cancelled, the password is rejected and the following message displayed for 2 seconds.

```
NON-NERC P/WORD
NOT SAVE
```

If the password is entered through a communications port using Courier or Modbus protocols the IED will store the password, irrespective of whether it is or isn't NERC-compliant, and then uses appropriate response codes to inform the client that the password was NERC-compliant or not. The client then can choose if he/she wishes to enter a new password that is NERC-compliant or leave the entered one in place.

5.3.1 Blank Passwords

A blank password is effectively a zero-length password. Through the front panel it is entered by confirming the password entry without actually entering any password characters. Through a communications port the Courier and Modbus protocols each have a means of writing a blank password to the IED. A blank password disables the need for a password at the level that this password applied.

Blank passwords have a slightly different validation procedure. If a blank password is entered through the front panel, the following text is displayed, after which the procedure is the same as already described:

```
BLANK PASSWORD
ENTERED CONFIRM
```

Blank Passwords cannot be configured if lower level password is not blank.

Blank Passwords affect fall back level after inactivity timeout or logout.

The 'fallback level' is the password level adopted by the IED after an inactivity timeout, or after the user logs out. This will be either the level of the highest level password that is blank, or level 0 if no passwords are blank.

5.4 Passwords Management

- Passwords may be any length between 0 and 8 characters long
- Passwords may or may not be NERC compliant
- Passwords may contain any ASCII character in the range ASCII code 33 (21 Hex) to ASCII code 122 (7A Hex) inclusive
- Only one password is required for all the IED interfaces

The user is locked out temporarily, after a defined number of failed password entry attempts. The number of password entry attempts, and the blocking periods are configurable. These settings are shown in Table 4.

Each invalid password entry attempt decrements the 'Attempts Remain' data cell by 1. When the maximum number of attempts has been reached, access is blocked. If the attempts timer expires, or the correct password is entered before the 'attempt count' reaches the maximum number, then the 'attempts count' is reset to 0.

An attempt is only counted if the attempted password uses only characters in the range defined in section 5.2 - Password Strengthening but the attempted password is not correct) does not match the corresponding password in the IED). Any attempt where one or more characters of the attempted password is not in the range will not be counted.

Once the password entry is blocked, a 'blocking timer' is initiated. Attempts to access the interface whilst the 'blocking timer' is running results in an error message, irrespective of whether the correct password is entered or not. Only after the 'blocking timer' has expired will access to the interface be unblocked, whereupon the attempts counter is reset to zero.

Attempts to write to the password entry whilst it is blocked results in the following message, which is displayed for 2 seconds.

```
NOT ACCEPTED
ENTRY IS BLOCKED
```

Appropriate responses achieve the same result if the password is written through a communications port.

The attempts count, attempts timer and blocking timer can be configured, as shown in Table 4 - .

Setting	Cell col row	Units	Default Setting	Available Setting
Attempts Limit	25 02		3	0 to 3 step 1
Attempts Timer	25 03	Minutes	2	1 to 3 step 1
Blocking Timer	25 04	Minutes	5	1 to 30 step 1

Table 4 - Password blocking configuration

5.5 Password Recovery

Password recovery is the means by which the passwords can be recovered on a device if the customer should mislay the configured passwords. To obtain the recovery password the customer must contact the Schneider Electric Contact Centre and supply two pieces of information from the IED – namely the Serial Number and its Security Code. The Contact Centre will use these items to generate a Recovery Password which is then provided to the customer.

The security code is a 16-character string of upper case characters. It is a read-only parameter. The IED generates its own security code randomly. A new code is generated under the following conditions:

- On power up
- Whenever settings are set back to default
- On expiry of validity timer (see below)
- When the recovery password is entered

As soon as the security code is displayed on the LCD display, a validity timer is started. This validity timer is set to 72 hours and is not configurable. This provides enough time for the contact centre to manually generate and send a recovery password. The Service Level Agreement (SLA) for recovery password generation is one working day, so 72 hours is sufficient time, even allowing for closure of the contact centre over weekends and bank holidays.

To prevent accidental reading of the IED security code the cell will initially display a warning message:

```
PRESS ENTER TO
READ SEC. CODE
```

The security code will be displayed on confirmation, whereupon the validity timer will be started. Note that the security code can only be read from the front panel.

5.5.1 Entry of the Recovery Password

The recovery password is intended for recovery only. It is not a replacement password that can be used continually. It can only be used once – for password recovery.

Entry of the recovery password causes the IED to reset all passwords back to default. This is all it is designed to do. After the passwords have been set back to default, it is up to the user to enter new passwords appropriate for the function for which they are intended, ensuring NERC compliance, if required.

On this action, the following message is displayed:

5.5.2 Password Encryption

The IED supports encryption for passwords entered remotely. The encryption key can be read from the IED through a specific cell available only through communication interfaces, not the front panel. Each time the key is read the IED generates a new key that is valid only for the next password encryption write. Once used, the key is invalidated and a new key must be read for the next encrypted password write. The encryption mechanism is otherwise transparent to the user.

```
PASSWORDS HAVE BEEN
SET TO DEFAULT
```

The recovery password can be applied through any interface, local or remote. It will achieve the same result irrespective of which interface it is applied through.

6 RELAY CONFIGURATION

The relay is a multi-function device that supports numerous different protection, control and communication features. To simplify the setting of the relay, there is a configuration settings column which can be used to enable or disable many of the functions of the relay. The settings associated with any function that is disabled are made invisible, i.e. they are not shown in the menu. To disable a function change the relevant cell in the '**Configuration'** column from '**Enabled'** to '**Disabled'**.

The configuration column controls which of the protection settings groups is selected as active through the '**Active settings**' cell. A protection setting group can also be disabled in the configuration column, provided it is not the present active group. Similarly, a disabled setting group cannot be set as the active group.

7 FRONT PANEL USER INTERFACE (KEYPAD AND LCD)

When the keypad is exposed it provides full access to the menu options of the relay, with the information displayed on the LCD.

The left, right, up and down keys which are used for menu navigation and setting value changes include an auto-repeat function that comes into operation if any of these keys are held continually pressed. This can speed up both setting value changes and menu navigation; the longer the key is held depressed, the faster the rate of change or movement becomes.

When the keypad is exposed it provides full access to the menu options of the relay, with the information displayed on the LCD.

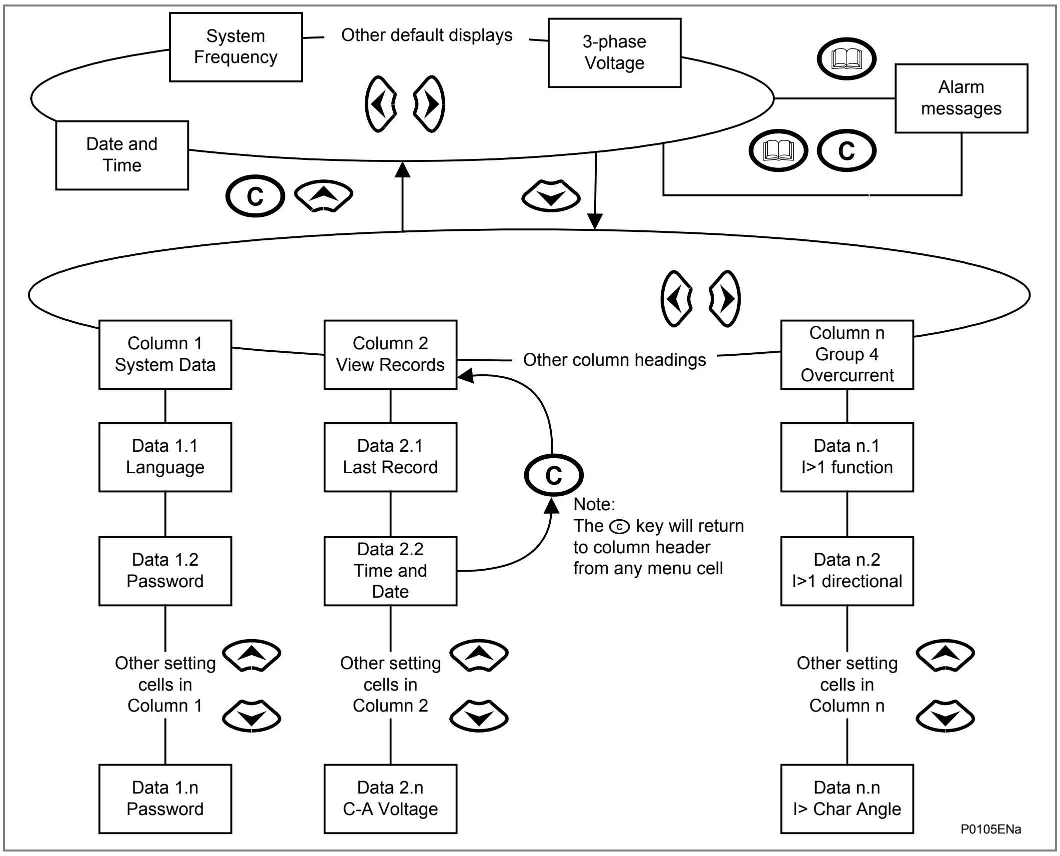

Figure 6 - Front panel user interface

7.1 Default Display and Menu Time-Out

The front panel menu has a default display. To change it, select **Measure't. setup** > **default display** and the following items can be selected:

- Date and time
- Relay description (user defined)
- Plant reference (user defined)
- System frequency
- 3-phase voltage
- 3-phase and neutral current
- Power
- Access permissions

From the default display you can view the other default display options using the and keys. If there is no keypad activity for 15 minutes, the default display reverts to the previous setting and the LCD backlight switches off. Any setting changes that have not been confirmed are lost and the original setting values are maintained.
Whenever the relay has an uncleared alarm (such as fault record, protection alarm, or control alarm) the default display is replaced by the following display.

```
Alarms/Faults
Present
```

Enter the menu structure of the relay from the default display, even if the display shows the **Alarms/Faults present** message.

7.2 Menu Navigation and Setting Browsing

Use the four arrow keys to browse the menu, following the menu structure shown above.

1. Starting at the default display, press the key to show the first column heading.
2. Use the and keys to select the required column heading.
3. Use the and keys to view the setting data in the column.
4. To return to the column header, either hold the key down or press the clear key C once. It is only possible to move across columns at the column heading level.
5. To return to the default display, press the key or the clear key C from any of the column headings. If you use the auto-repeat function of the key, you cannot go straight to the default display from one of the column cells because the auto-repeat stops at the column heading.
6. Press the key again to go to the default display.

7.3 Hotkey Menu Navigation

To access the hotkey menu from the default display:

1. Press the key directly below the **HOTKEY** text on the LCD.
2. Once in the hotkey menu, use the and keys to scroll between the available options, then use the hotkeys to control the function currently displayed.
   If neither the or keys are pressed within 20 seconds of entering a hotkey sub menu, the relay reverts to the default display.
3. Press the clear key to return to the default menu from any page of the hotkey menu.

The layout of a typical page of the hotkey menu is as follows:

- The top line shows the contents of the previous and next cells for easy menu navigation
- The center line shows the function
- The bottom line shows the options assigned to the direct access keys

The functions available in the hotkey menu are listed in the following sections.

7.3.1.1 Setting Group Selection

The user can either scroll using <<NXT GRP>> through the available setting groups or <<SELECT>> the setting group that is currently displayed.

When the SELECT button is pressed a screen confirming the current setting group is displayed for 2 seconds before the user is prompted with the <<NXT GRP>> or <<SELECT>> options again. The user can exit the sub menu by using the left and right arrow keys.

For more information on setting group selection refer to “Setting group selection” section in the Operation chapter.

7.3.1.2 Control Inputs - User Assignable Functions

The number of control inputs (user assignable functions – USR ASS) represented in the hotkey menu is user configurable in the “CTRL I/P CONFIG” column. The chosen inputs can be SET/RESET using the hotkey menu.

For more information refer to the “Control Inputs” section in the Operation chapter.

7.3.1.3 CB Control

The CB control functionality varies from one Px40 relay to another. For a detailed description of the CB control via the hotkey menu refer to the “**Circuit breaker control**” section of the Operation section.

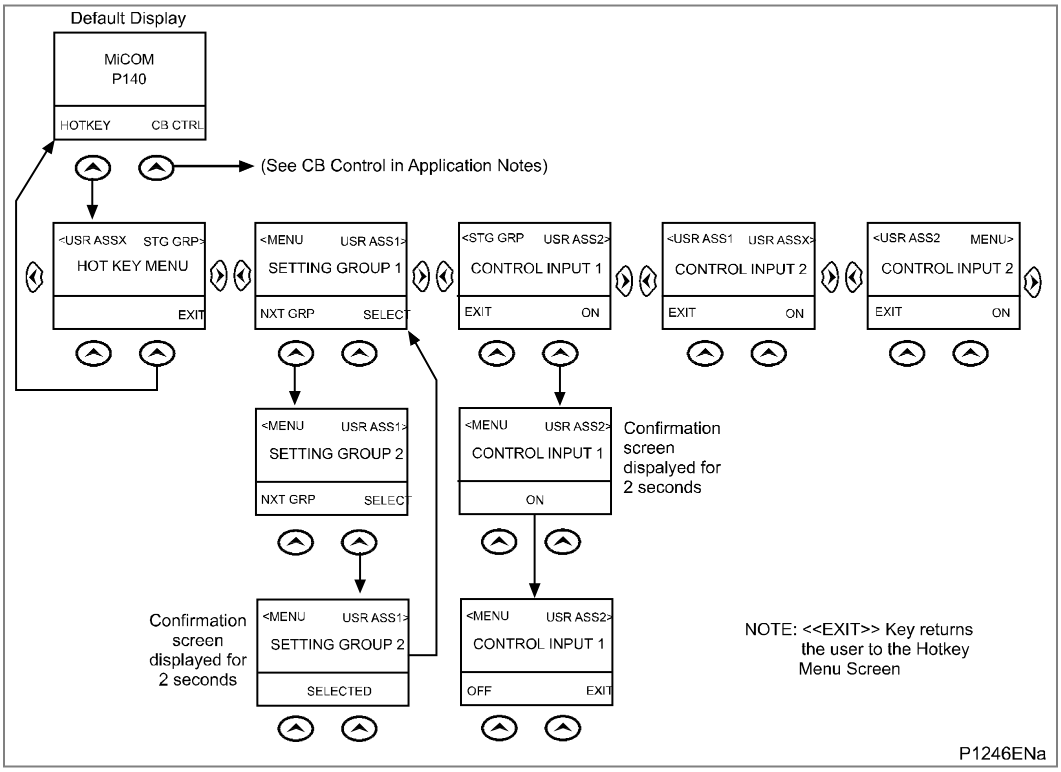

Figure 7 - Hotkey menu navigation

7.4 Password Entry

When entry of a password is required the following prompt will appear:

```
Enter password
**** Level 1
```

Note	*The password required to edit the setting is the prompt as shown above.*

A flashing cursor will indicate which character field of the password may be changed. Press the up and down keys to vary each character between A and Z. To move between the character fields of the password, use the left and right keys. The password is confirmed by pressing the enter key. The display will revert to '**Enter Password**' if an incorrect password is entered. At this point a message will be displayed indicating whether a correct password has been entered and if so what level of access has been unlocked. If this level is sufficient to edit the selected setting then the display will return to the setting page to allow the edit to continue. If the correct level of password has not been entered then the password prompt page will be returned to. To escape from this prompt press the clear key Ⓒ. Alternatively, the password can be entered using the '**Password**' cell of the '**System data**' column.

For the front panel user interface the password protected access will revert to the default access level after a keypad inactivity time-out of 15 minutes. It is possible to manually reset the password protection to the default level by moving to the '**Password**' menu cell in the '**System data**' column and pressing the clear key Ⓒ instead of entering a password.

7.5 Reading and Clearing of Alarm Messages and Fault Records

One or more alarm messages appear on the default display and the yellow alarm LED flashes. The alarm messages can either be self-resetting or latched, in which case they must be cleared manually.

1. To view the alarm messages, press the read key. When all alarms have been viewed but not cleared, the alarm LED change from flashing to constantly ON and the latest fault record appears (if there is one).
2. Scroll through the pages of the latest fault record, using the key. When all pages of the fault record have been viewed, the following prompt appears.

```
Press clear to
reset alarms
```

3. To clear all alarm messages, press ⓒ. To return to the display showing alarms or faults present, and leave the alarms uncleared, press.
4. Depending on the password configuration settings, you may need to enter a password before the alarm messages can be cleared. See the ***How to Access the IED/Relay*** section.
5. When all alarms are cleared, the yellow alarm LED switches OFF; also the red trip LED switches OFF if it was switched ON after a trip.
6. To speed up the procedure, enter the alarm viewer using the key, then press the ⓒ key. This goes straight to the fault record display. Press ⓒ again to move straight to the alarm reset prompt, then press ⓒ again to clear all alarms.

7.6 Setting Changes

1. To change the value of a setting, go to the relevant cell in the menu, then press the enter key to change the cell value. A flashing cursor on the LCD shows the value can be changed. If a password is required to edit the cell value, a password prompt appears.
2. To change the setting value, press the or keys. If the setting to be changed is a binary value or a text string, select the required bit or character to be changed using the and keys.
3. Press to confirm the new setting value or the clear key to discard it. The new setting is automatically discarded if it is not confirmed in 15 seconds.
4. For protection group settings and disturbance recorder settings, the changes must be confirmed before they are used by the relay.
5. To do this, when all required changes have been entered, return to the column heading level and press the key. Before returning to the default display, the following prompt appears.

```
Update settings?
Enter or clear
```

6. Press to accept the new settings or press to discard the new settings.

Note	*If the menu time-out occurs before the setting changes have been confirmed, the setting values are also discarded.*

Control and support settings are updated immediately after they are entered, without the **Update settings**? prompt.

8 FRONT COMMUNICATION PORT USER INTERFACE

The front communication port is provided by a 9-pin female D-type connector located under the bottom hinged cover. It provides EIA(RS)232 serial data communication and is intended for use with a PC locally to the relay (up to 15m distance) as shown in the following diagram. This port supports the Courier communication protocol only. Courier is the communication language developed by Schneider Electric to allow communication with its range of protection relays. The front port is particularly designed for use with the relay settings program MiCOM S1 Studio (Windows 2000, Windows XP or Windows Vista based software package).

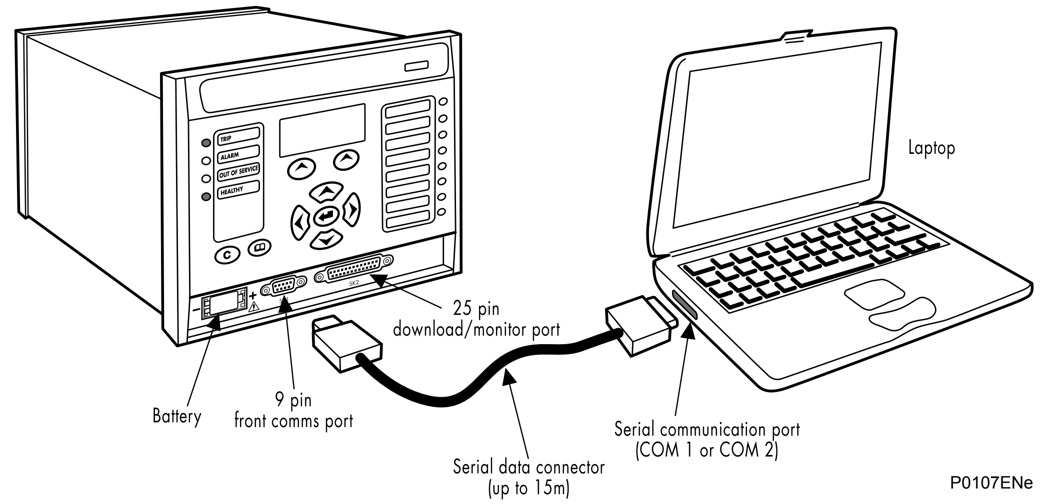

Figure 8 - Front port connection

The IED is a Data Communication Equipment (DCE) device. The pin connections of the 9-pin front port are as follows:

Pin no.	Description
2	Tx Transmit data
3	Rx Receive data
5	0V Zero volts common

Table 5 - 9-pin front port connections

None of the other pins are connected in the relay. The relay should be connected to the serial port of a PC, usually called COM1 or COM2. PCs are normally Data Terminal Equipment (DTE) devices which have a serial port pin connection as below (if in doubt check your PC manual):

Pin	25 Way	9 Way	Description
Pin no. 2	3	2	Rx Receive data
Pin no. 3	2	3	Tx Transmit data
Pin no. 5	7	5	0V Zero volts common

Table 6 - 25-way and 9-way serial pin connections

For successful data communication, the Tx pin on the relay must be connected to the Rx pin on the PC, and the Rx pin on the relay must be connected to the Tx pin on the PC, as shown in the diagram. Therefore, providing that the PC is a DTE with pin connections as given above, a 'straight through' serial connector is required, i.e. one that connects pin 2 to pin 2, pin 3 to pin 3, and pin 5 to pin 5.

Note	*A common cause of difficulty with serial data communication is connecting Tx to Tx and Rx to Rx. This could happen if a 'cross-over' serial connector is used, i.e. one that connects pin 2 to pin 3, and pin 3 to pin 2, or if the PC has the same pin configuration as the relay.*

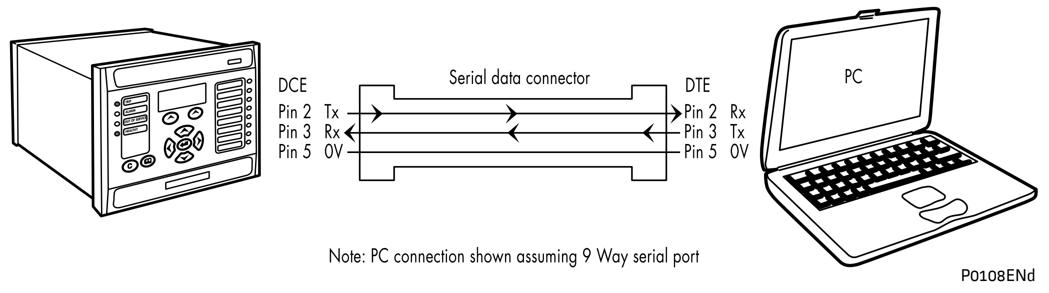

Figure 9 - PC - relay signal connection

Having made the physical connection from the relay to the PC, the PCs communication settings must be configured to match those of the relay. The relays communication settings for the front port are fixed as shown below:

Protocol	Baud rate	Courier address	Message format
Courier	19,200 bits/s	1	11 bit - 1 start bit, 8 data bits, 1 parity bit (even parity), 1 stop bit

Table 7 - Communication settings for front port

The inactivity timer for the front port is set at 15 minutes. This controls how long the relay will maintain its password access on the front port. If no messages are received on the front port for 15 minutes then any password access that has been enabled will be revoked.

8.1 Front Courier Port

The front EIA(RS)232 9-pin port supports the Courier protocol for one to one communication.

Note	*The front port is actually compliant to EIA(RS)574; the 9-pin version of EIA(RS)232, see www.tiaonline.org.*

The front port is designed for use during installation and commissioning/maintenance and is not suitable for permanent connection. Since this interface will not be used to link the relay to a substation communication system, some of the features of Courier are not implemented. These are as follows:

- Automatic Extraction of Event Records:
  - Courier Status byte does not support the Event flag
  - Send Event/Accept Event commands are not implemented
- Automatic Extraction of Disturbance Records:
  - Courier Status byte does not support the Disturbance flag
- Busy Response Layer: Courier Status byte does not support the Busy flag, the only response to a request will be the final data
- Fixed Address: The address of the front courier port is always 1, the Change Device address command is not supported.
- Fixed Baud Rate: 19200 bps

Note	*Although automatic extraction of event and disturbance records is not supported, this data can be manually accessed using the front port.*

9 MICOM S1 RELAY COMMUNICATIONS BASICS

The EIA(RS)232 front communication port is particularly designed for use with the relay settings program MiCOM S1 Studio. MiCOM S1 Studio is the universal MiCOM IED Support Software and provide users a direct and convenient access to all stored data in any MiCOM IED using the EIA(RS)232 front communication port.

MiCOM S1 Studio provides full access to MiCOM Px10, Px20, Px30, Px40, Modulex series, K series, L series relays and MiCOM Mx20 measurements units

9.1 PC Requirements

The minimum requirements for MiCOM S1 Studio software to properly work on a PC are:

- Minimum: 1 GHz Processor
256 MB RAM
Windows 2000
Screen resolution: 800 x 600 x 256 colours.
- Recommended: 2 GHz Processor
1 GB RAM
Windows XP
Screen resolution: 1024 x 768
- Microsoft Vista: 2 GHz Processor
2 GB RAM
5 GB free hard disk space
- MiCOM S1 Studio must be started with Administrator rights

9.2 Connecting to the Relay using MiCOM S1 Studio

This section is a quick start guide to using MiCOM S1 Studio and assumes this is installed on your PC. See the MiCOM S1 Studio program online help for more detailed information.

1. Make sure the EIA(RS)232 serial cable is properly connected between the port on the front panel of the relay and the PC.
2. To start MiCOM S1 Studio, select **Programs** > **Schneider Electric** > **MiCOM S1 Studio** > **MiCOM S1 Studio**.
3. Click the **Quick Connect** tab and select **Create a New System**.
4. Check the **Path to System file** is correct, then enter the name of the system in the **Name** field. To add a description of the system, use the **Comment** field.
5. Click **OK**.
6. Select the device type.
7. Select the communications port, and open a connection with the device.
8. Once connected, select the language for the settings file, the device name, then click **Finish**. The configuration is updated.
9. In the **Studio Explorer** window, select **Device** > **Supervise Device**… to control the relay directly.

9.3 Off-Line Use of MiCOM S1 Studio

MiCOM S1 Studio can also be used as an off-line tool to prepare settings, without access to the relay.

1. If creating a new system, in the Studio Explorer, select **create new** system. Then right-click the new system and select **New substation**.
2. Right-click the new substation and select **New voltage level**.
3. Then right-click the new voltage level and select **New bay**.
4. Then right-click the new bay and select **New device**.

   You can add a device at any level, whether it is a system, substation, voltage or bay.
5. Select a device type from the list, then enter the relay type. Click **Next**.
6. Enter the full model number and click **Next**.
7. Select the **Language** and **Model**, then click **Next**.
8. Enter a unique device name, then click **Finish**.
9. Right-click the **Settings** folder and select **New File**. A default file **000** is added.
10. Right-click file **000** and select click **Open**. You can then edit the settings. See the MiCOM S1 Studio program online help for more information.

10 USER PROGRAMMABLE CURVE TOOL (UPCT) OPTION

The User Programmable Curve Tool (UPCT) allows the creation of user defined curves and flexible download and upload of these curves into/from the MiCOM Px4x relays. This tool can be used to create user programmable over current operating and reset curves. For example, its user friendly Graphical User Interface (GUI) allows easy creation and visualization of curves either by inputting a formula or data points.

10.1.1 Supporting Software Versions

The UPCT is supported for the following products:

Relay Type	Product	Software Version
Feeder Management relays	P14x	46 onwards
Motor Protection relays	P24x	57 onwards

Table 8 – UPCT supported products

10.1.2 Application Advantages of User Programmable Curves

- Provide specific protection characteristics of Customer schemes
- Match more closely to the withstand characteristics for electrical equipment than standard curves.
- Provide compatibility with older relays and different manufacturers relays for retrofit / refurbishment.
- Data can be exported for protection grading and testing purposes.

10.1.3 Main Features and Overview of User Configurable Curve Tool

- Allows the user to create new configuration curve files or edit existing curve files
- Allows the user to enter a defined number of curve points (up to 256 points) or a user defined formula.
- Allows the user to create and save multiple formulae
- Allows the user defined curve to be associated with a predefined curve Px4x template.
- Allows interpolation between curve points
- Allows the user to save curve formulae in XML format and configured curve points in CSV format, suitable for download into the relay.
- Enables easy upload of the curve data from the relay.
- Allows the user to input formula constants with user defined values
- Allows the user to set a Definite Minimum Time (DMT) in the formula defined curves
- Graphically displays curves with zoom, pan User and point on curve facilities.
- Color coding of multiple curves enables effective comparison
- Allows the user to print curves or save curves in a range of standard image formats.

Please refer to the User Programmable Curve Tool Guide (Px4x/EN UPCT) for more information.

Notes:

MENU MAPS

CHAPTER NO 4

Date:	10/2014
Products covered by this chapter:	This chapter covers the specific versions of the MiCOM products listed below. This includes ***only*** the following combinations of Software Version and Hardware Suffix.
Hardware Suffix:	L (P141, P142 & P143) & M (P145)
Software Version:	A0 - P14x (P141, P142, P143 & P145)
Connection Diagrams:	10P141xx (xx = 01 to 07) 10P142xx (xx = 01 to 07) 10P143xx (xx = 01 to 07) 10P145xx (xx = 01 to 07)

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FIGURES

Notes:

1 RELAY MENU MAP (DEFAULT)

Note	*This menu map is annotated with the factory default settings.*

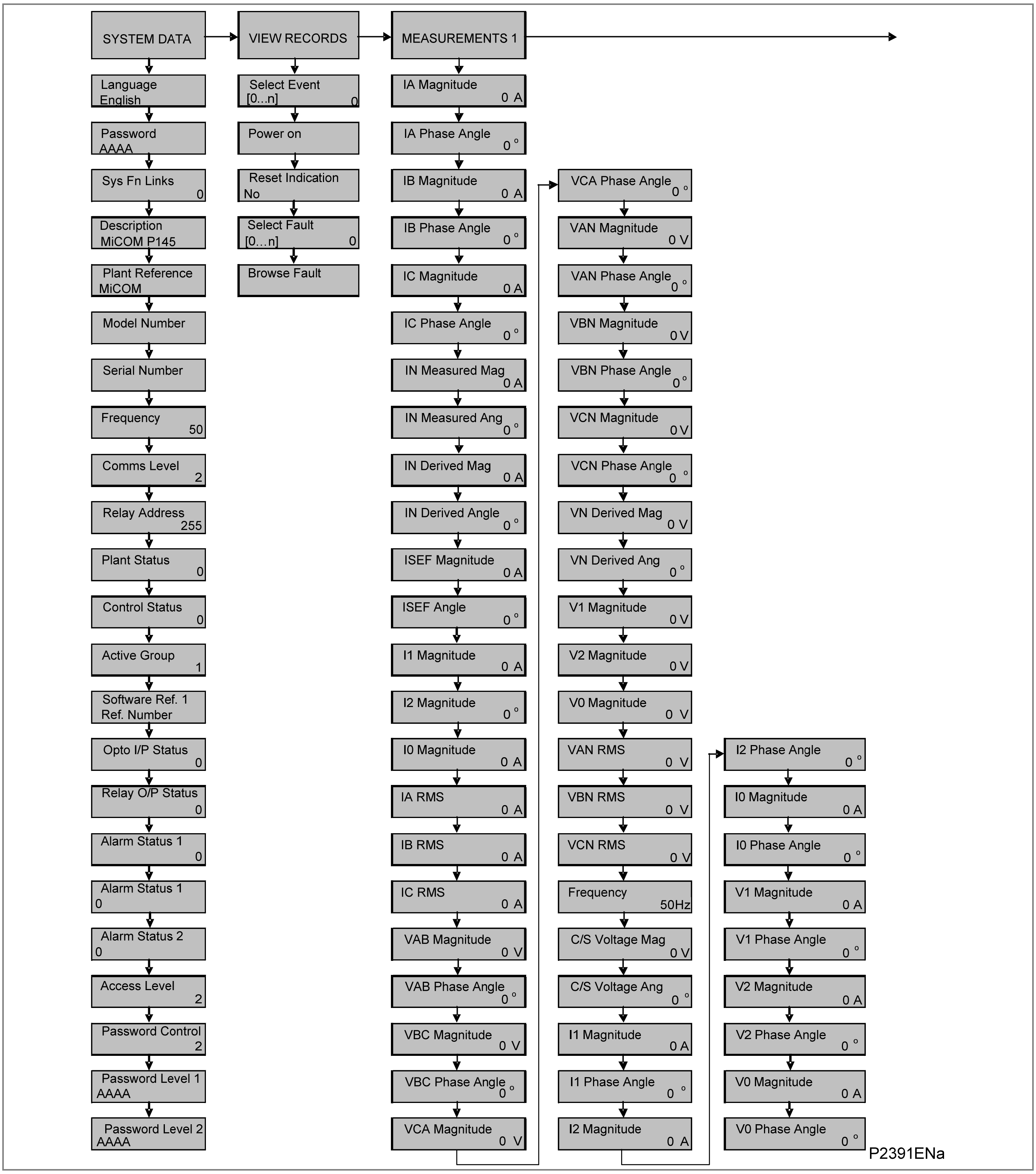


Figure 1 – System Data, View Records and Measurements 1

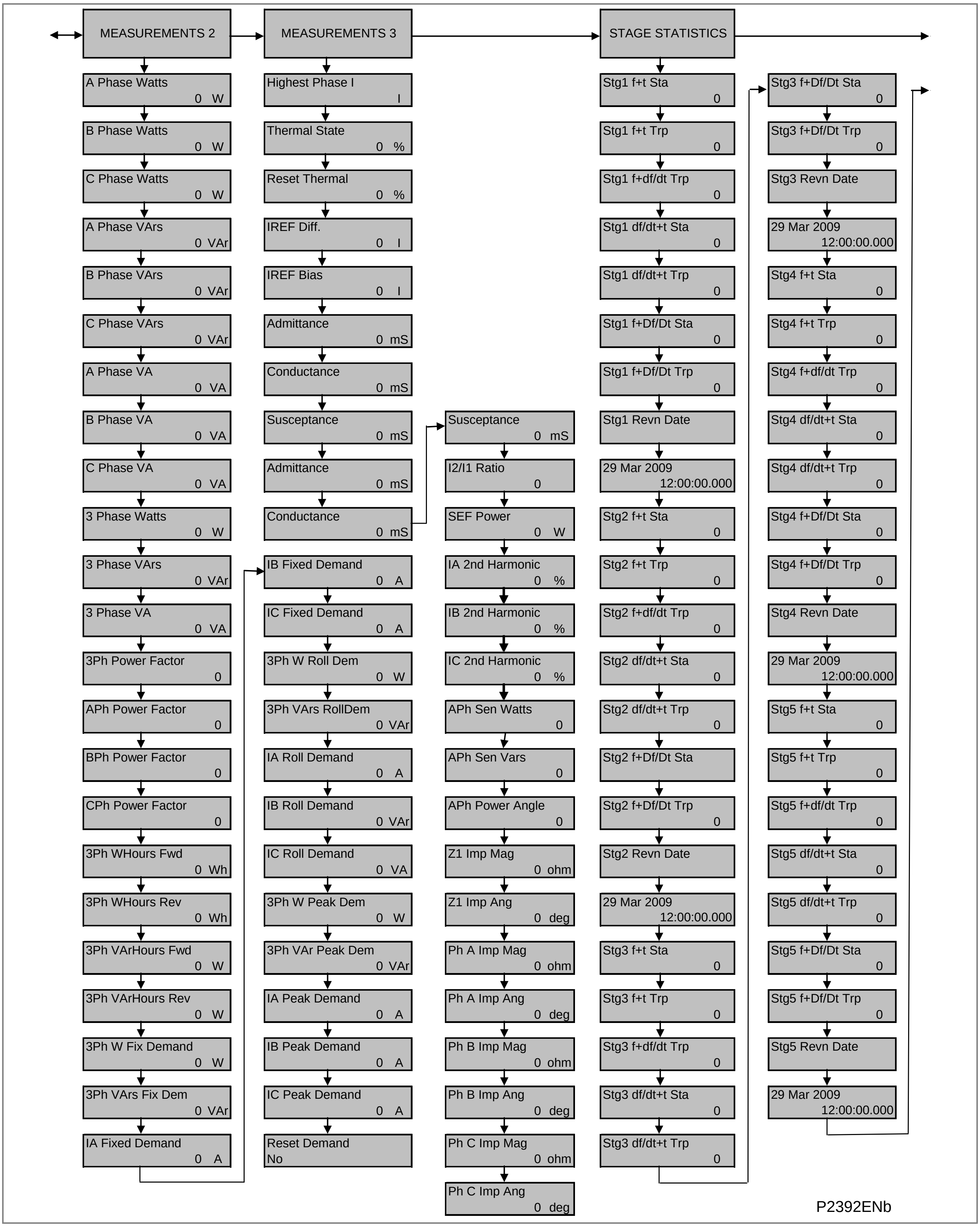


Figure 2 – Measurements 2 and 3 and Stage Statistics

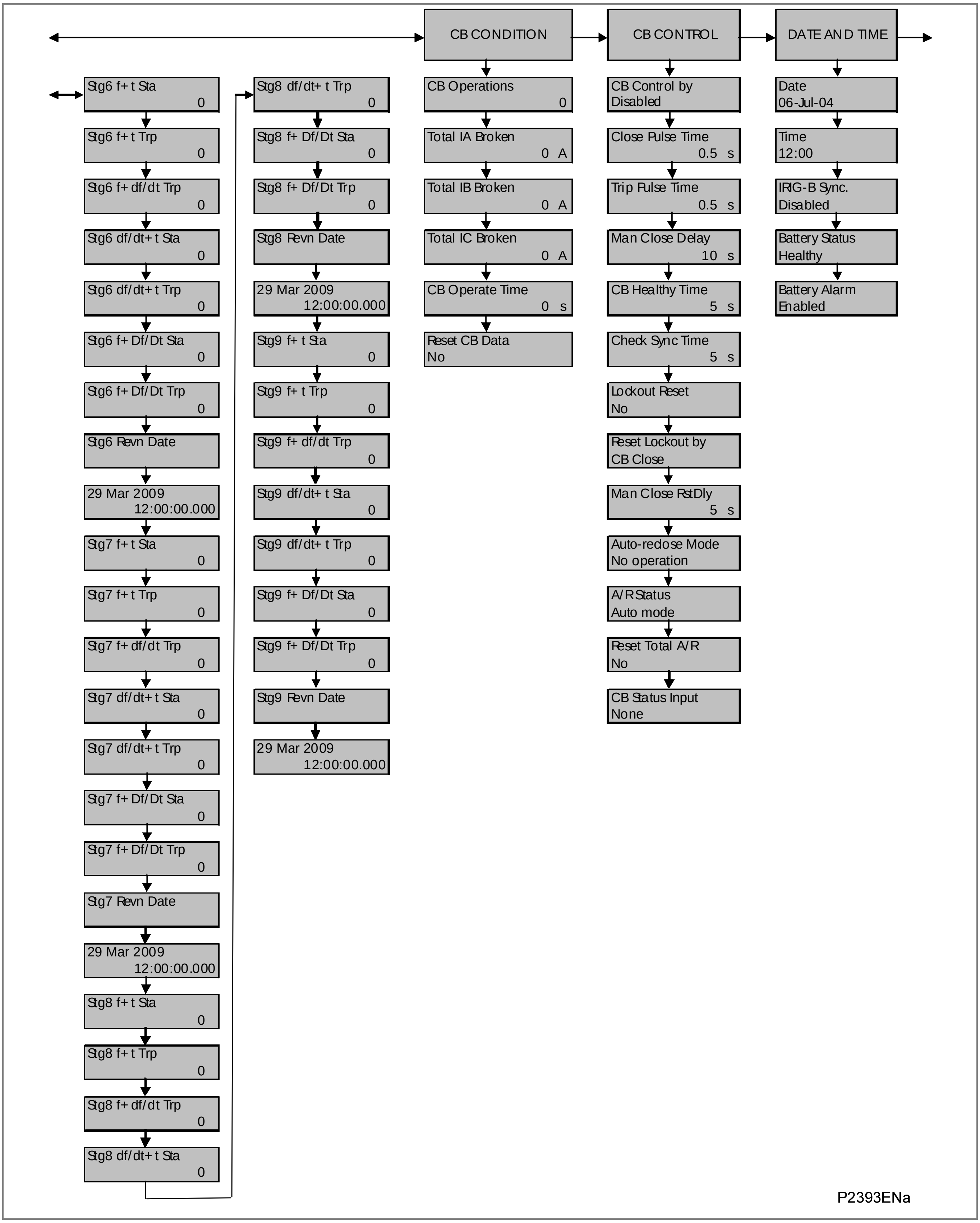


Figure 3 – CD Condition, CB Control and Date and Time

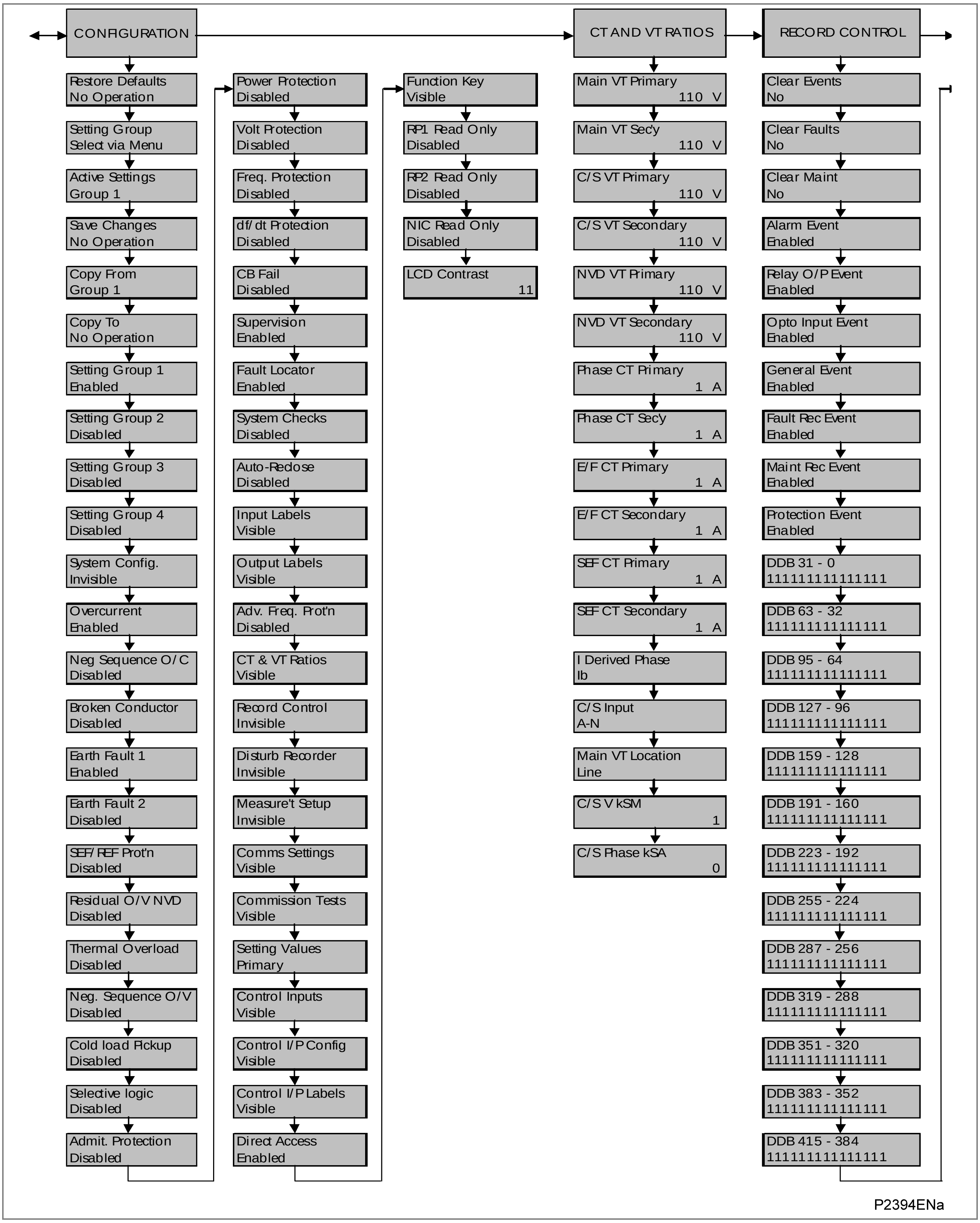


Figure 4 – Configuration, CT and VT Ratios and Record Control

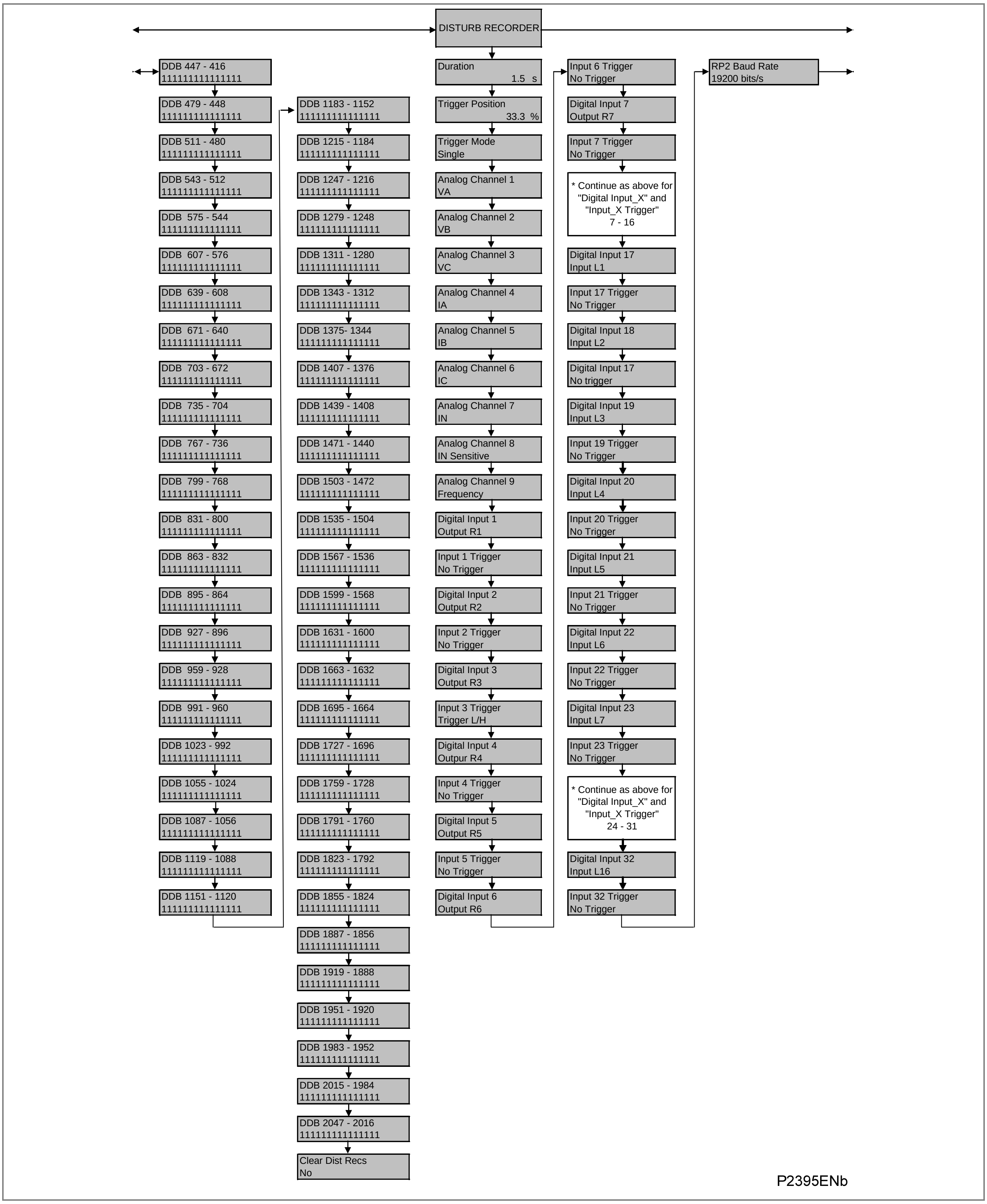


Figure 5 – Disturbance Recorder

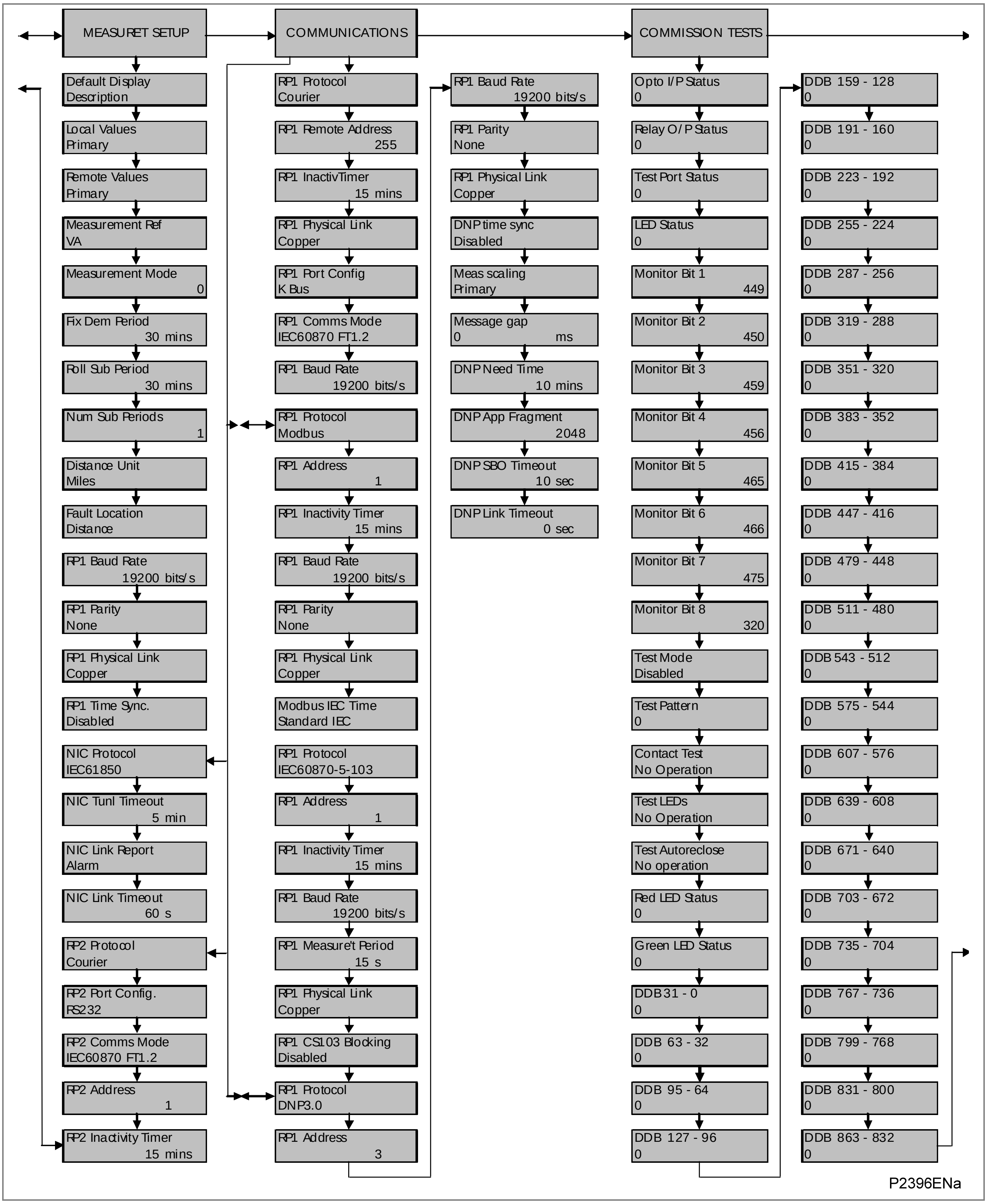


Figure 6 – Measurement Setup, Communications and Commission Tests

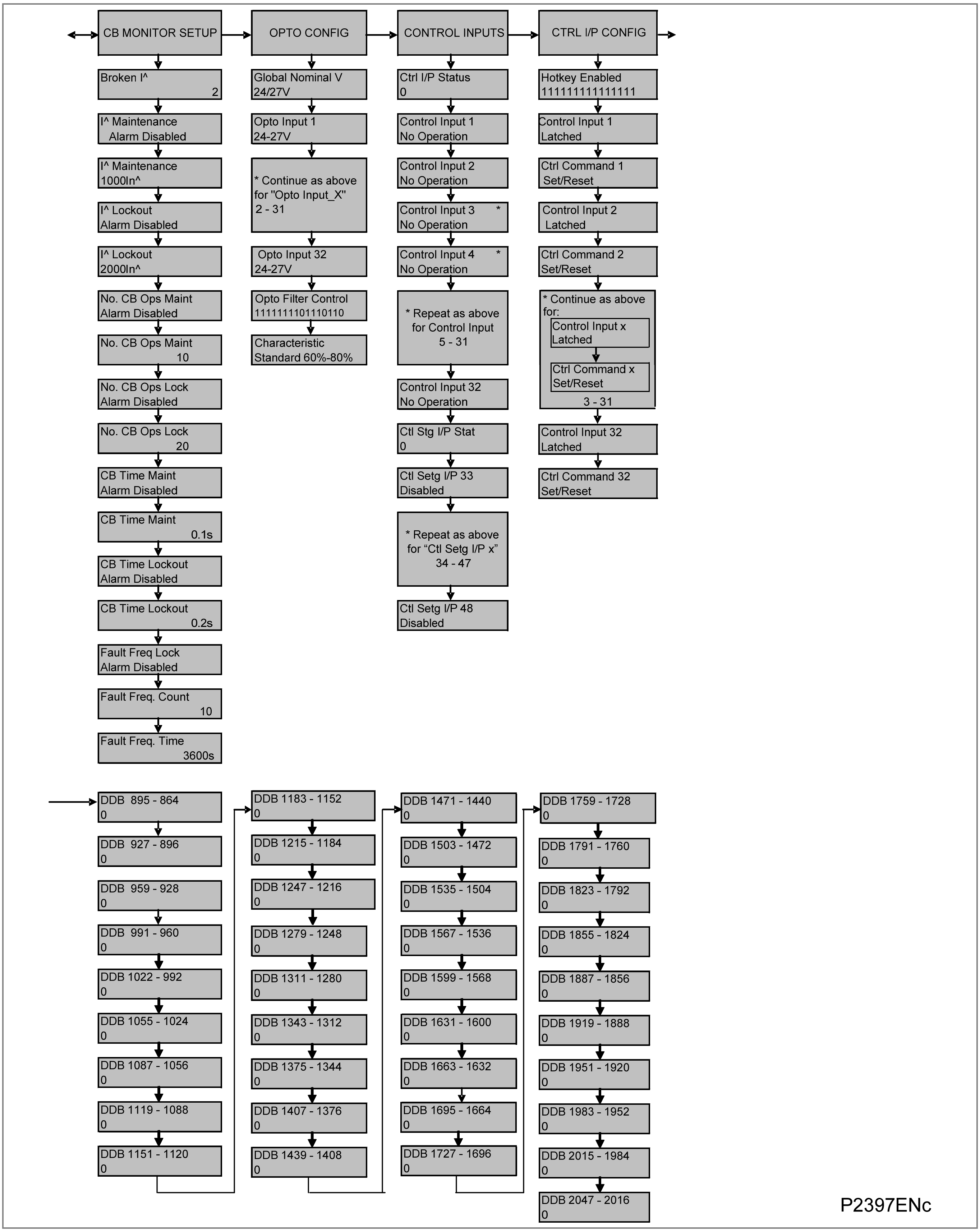


Figure 7 – CB Monitor Setup, Opto Config, Control Inputs and Control Input Config

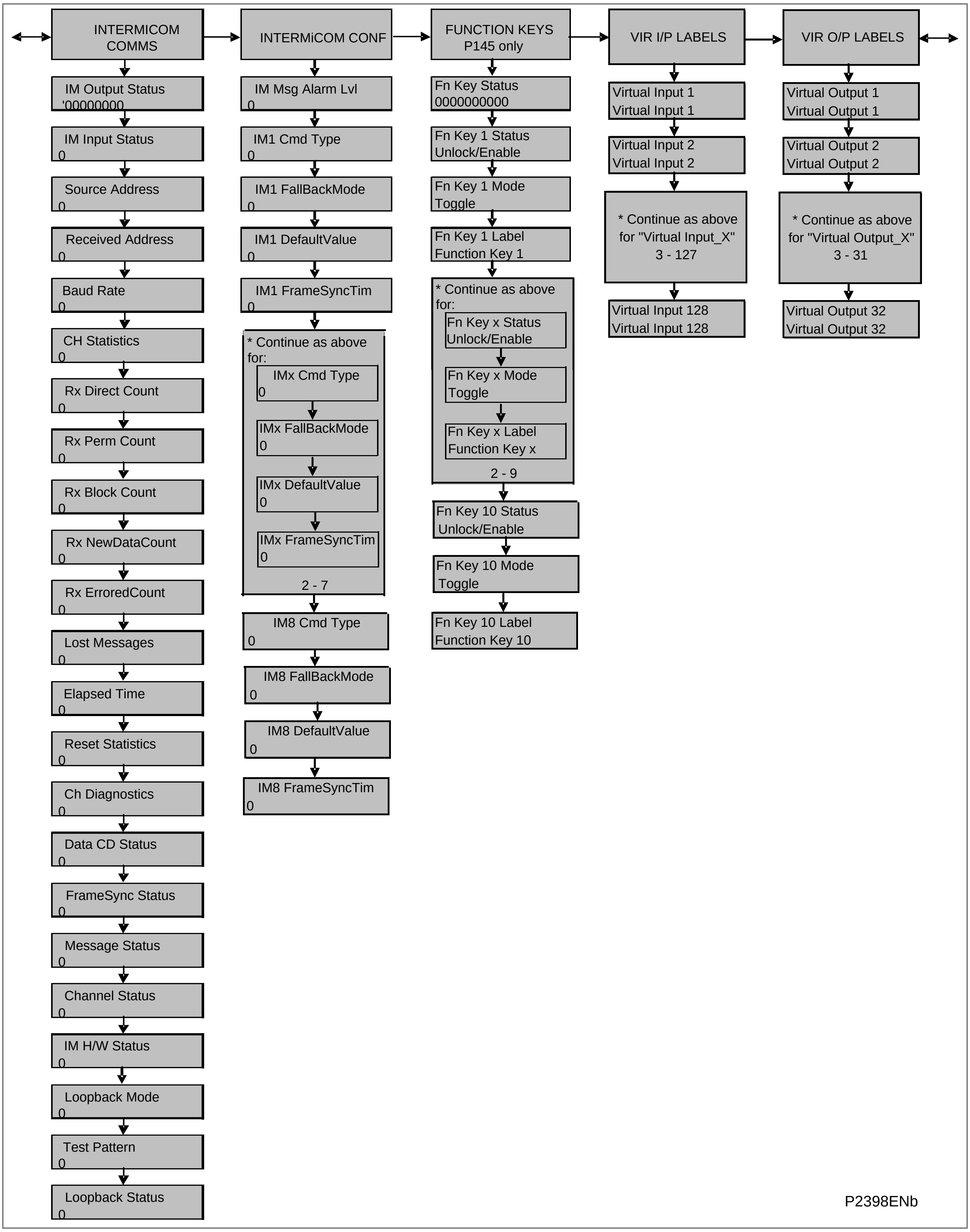


Figure 8 – InterMiCOM Communications, InterMiCOM Conf, Function Keys, VIR I/P and O/P Labels

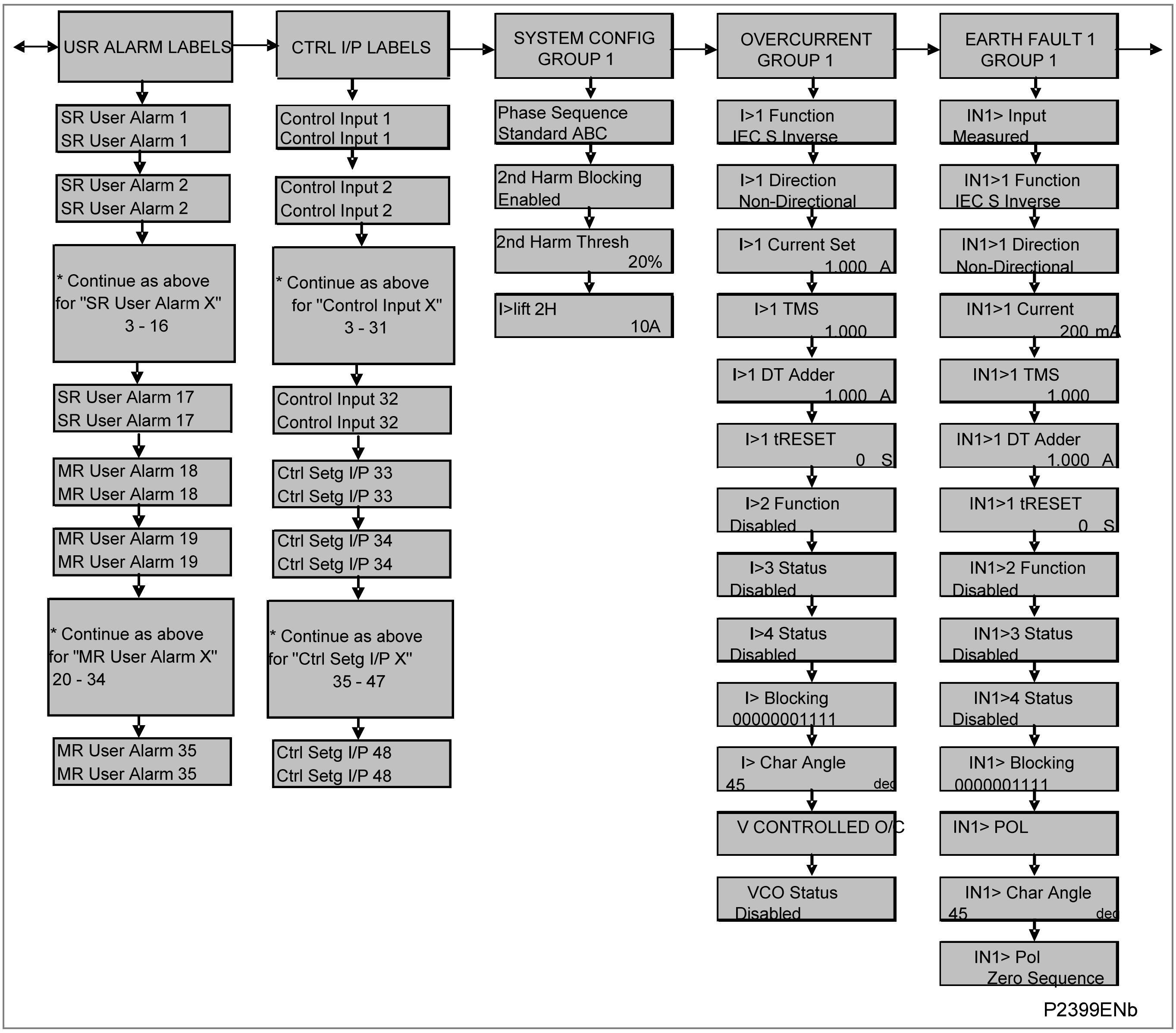


Figure 9 – USR Alarm Labels, Ctrl I/P Labels, System Config, Overcurrent and Earth Fault 1

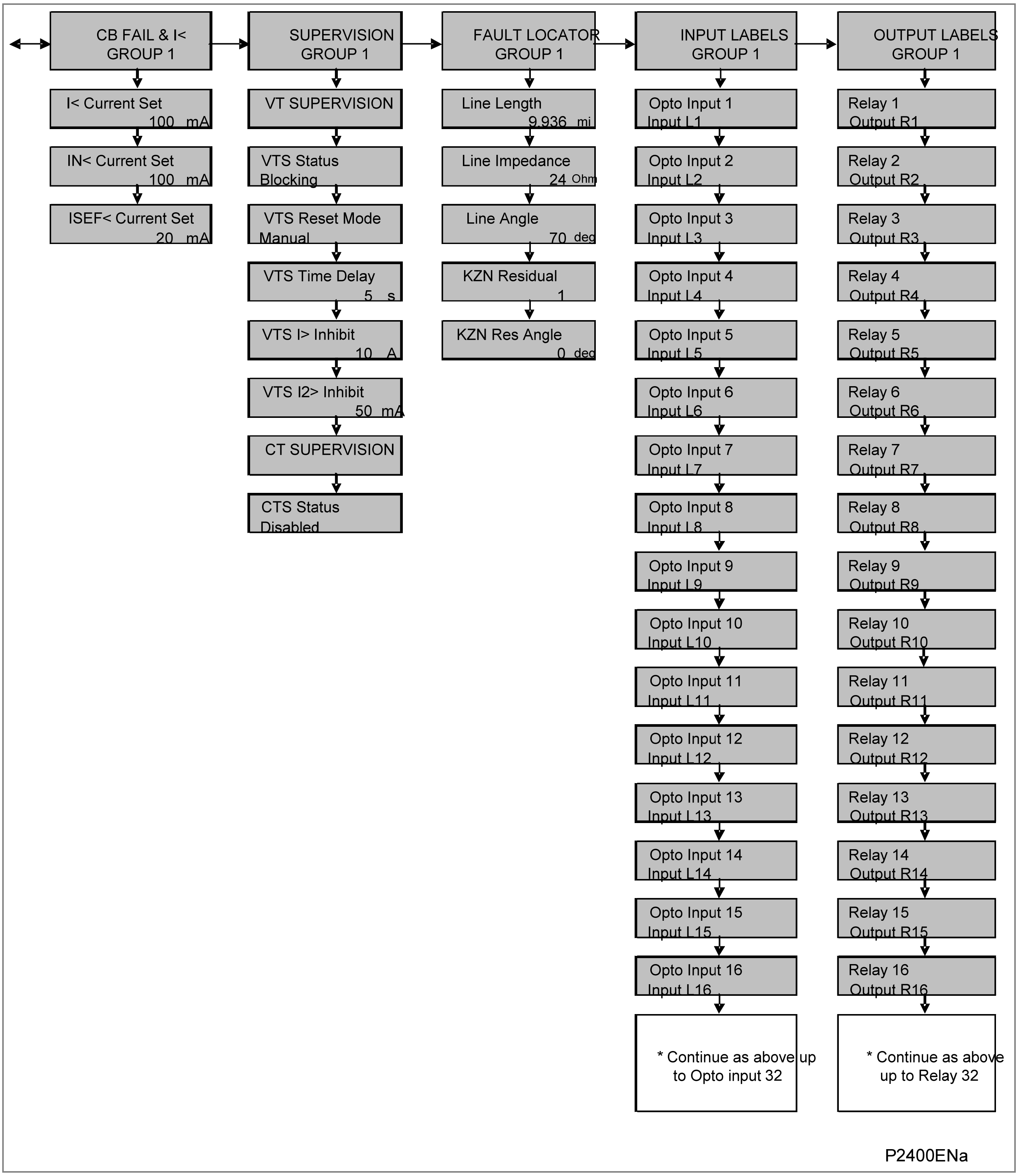


Figure 10 – CB Fail & I<, Supervision, Fault Locator, Input Labels and Output Labels

SETTINGS

CHAPTER NO 5

Date:	10/2014
Products covered by this chapter:	This chapter covers the specific versions of the MiCOM products listed below. This includes ***only*** the following combinations of Software Version and Hardware Suffix.
Hardware Suffix:	L (P141, P142 & P143) & M (P145)
Software Version:	A0 - P14x (P141, P142, P143 & P145)
Connection Diagrams:	10P141xx (xx = 01 to 07) 10P142xx (xx = 01 to 07) 10P143xx (xx = 01 to 07) 10P145xx (xx = 01 to 07)

CONTENTS

TABLES

Notes:

1 INTRODUCTION

The IED must be configured to the system and the application by means of appropriate settings.

The sequence in which the settings are listed and described in this chapter will be the protection setting, control and configuration settings and the disturbance recorder settings.

The IED is supplied with a factory-set configuration of default settings.

2 RELAY SETTINGS

The IED is a multi-function device that supports numerous different control and communication features. The settings associated with any function that is disabled are made invisible; i.e. they are not shown in the menu. To disable a function change the relevant cell in the '**Configuration'** column from '**Enabled'** to '**Disabled'**.

To simplify the setting of the IED, there is a configuration settings column, used to enable or disable many of the IED functions. The aim of the configuration column is to allow general configuration from a single point in the menu.

The configuration column controls which of the four settings groups is selected as active through the '**Active settings**' cell. A setting group can also be disabled in the configuration column, provided it is not the present active group. Similarly, a disabled setting group cannot be set as the active group.

The column also allows all of the setting values in one group of settings to be copied to another group.

To do this firstly set the '**Copy from**' cell to the setting group to be copied, then set the '**Copy to**' cell to the group where the copy is to be placed. The copied settings are initially placed in the temporary scratchpad, and will only be used by the IED following confirmation.

2.1 Restore Default Settings

To restore the default values to the settings in any protection settings group, set the 'restore defaults' cell to the relevant group number. Alternatively it is possible to set the 'restore defaults' cell to 'all settings' to restore the default values to all of the IEDs settings, not just the protection groups' settings. The default settings will initially be placed in the scratchpad and will only be used by the IED after they have been confirmed.

Note	*Restoring defaults to all settings includes the rear communication port settings, which may result in communication via the rear port being disrupted if the new (default) settings do not match those of the master station.*

3 CONFIGURATION MENU

Menu Text	Default Setting	Available Settings
Restore Defaults	No Operation	No Operation All Settings Setting Group 1 Setting Group 2 Setting Group 3 Setting Group 4
Setting to restore a setting group to factory default settings.		
Setting Group	Select via Menu	Select via Menu Select via Optos
Allows setting group changes to be initiated via Opto Input or via Menu.		
Active Settings	Group 1	Group 1, Group 2, Group 3, Group 4
Selects the active setting group.		
Save Changes	No Operation	No Operation, Save, Abort
Saves all relay settings.		
Copy from	Group 1	Group 1, 2, 3 or 4
Allows displayed settings to be copied from a selected setting group.		
Copy to	No Operation	No Operation Group 1, 2, 3 or 4
Allows displayed settings to be copied to a selected setting group.		
Setting Group 1	Enabled	Enabled or Disabled
If the setting group is disabled from the configuration, then all associated settings and signals are hidden, with the exception of this setting.		
Setting Group 2 (as above)	Disabled	Enabled or Disabled
Setting Group 3 (as above)	Disabled	Enabled or Disabled
Setting Group 4 (as above)	Disabled	Enabled or Disabled
System Config.	Invisible	Invisible or Visible
Sets the System Config. menu visible further on in the relay settings menu.		
Overcurrent	Enabled	Enabled or Disabled
To enable (activate) or disable (turn off) the Phase Overcurrent Protection function. I> stages: ANSI 50/51/67P.		
Neg. Sequence O/C	Disabled	Enabled or Disabled
To enable (activate) or disable (turn off) the Negative Sequence Overcurrent Protection function. I2> stages: ANSI 46/67.		
Broken Conductor	Disabled	Enabled or Disabled
To enable (activate) or disable (turn off) the Broken Conductor function. I2/I1> stage: ANSI 46BC.		
Earth Fault 1	Enabled	Enabled or Disabled
To enable (activate) or disable (turn off) the Earth Fault 1 Protection function. IN(measured)>stages: ANSI 50/51/67N.		
Earth Fault 2	Disabled	Enabled or Disabled
To enable (activate) or disable (turn off) the Earth Fault 2 Protection function. IN(derived)>stages: ANSI 50/51/67N.		
SEF/REF Prot.	Disabled	Enabled or Disabled
To enable (activate) or disable (turn off) the Sensitive Earth Fault/Restricted Earth Fault Protection function. ISEF>stages: ANSI 50.51/67N, IREF>stage: ANSI 64.		
Residual O/V NVD	Disabled	Enabled or Disabled
To enable (activate) or disable (turn off) the Residual Overvoltage Protection function. VN>stages: ANSI 59N		

Menu Text	Default Setting	Available Settings
Thermal Overload	Disabled	Enabled or Disabled
To enable (activate) or disable (turn off) the Thermal Overload Protection function. ANSI 49.		
Neg. Sequence O/V	Disabled	Enabled or Disabled
To enable (activate) or disable (turn off) the Negative Sequence Overvoltage Protection function. V2>stages: ANSI 47.		
Cold Load Pickup	Disabled	Enabled or Disabled
To enable (activate) or disable (turn off) the Cold Load Pick-up function.		
Selective Logic	Disabled	Enabled or Disabled
To enable (activate) or disable (turn off) the Selective Logic function.		
Admit. Protection	Disabled	Enabled or Disabled
To enable (activate) or disable (turn off) the Admittance Protection function. YN, GN, BN>stages.		
Power Protection	Disabled	Enabled or Disabled
To enable (activate) or disable (turn off) the Power Protection (over/under/sensitive) function. P>, P<, Sen P>, Sen P< stages.		
Volt Protection	Disabled	Enabled or Disabled
To enable (activate) or disable (turn off) the Voltage Protection (under/overvoltage) function. V<, V> stages: ANSI 27/59.		
Freq. Protection	Disabled	Enabled or Disabled
To enable (activate) or disable (turn off) the Frequency Protection (under/overfrequency) function. F<, F> stages: ANSI 81O/U.		
df/dt Protection	Disabled	Enabled or Disabled
To enable (activate) or disable (turn off) the Rate of Change of Frequency Protection function. df/dt>stages: ANSI 81R.		
CB Fail	Disabled	Enabled or Disabled
To enable (activate) or disable (turn off) the Circuit Breaker Fail Protection function. ANSI 50BF.		
Supervision	Enabled	Enabled or Disabled
To enable (activate) or disable (turn off) the Supervision (VTS&CTS) functions. ANSI VTS/CTS.		
Fault Locator	Enabled	Enabled or Disabled
To enable (activate) or disable (turn off) the Fault Locator function.		
System Checks (P143/5 only)	Disabled	Enabled or Disabled
To enable (activate) or disable (turn off) the System Checks (Check Sync. and Voltage Monitor) function. ANSI 25.		
Auto-reclose (P142/3/4/5 only)	Disabled	Enabled or Disabled
To enable (activate) or disable (turn off) the Auto-reclose function. ANSI 79.		
Input Labels	Visible	Invisible or Visible
Sets the Input Labels menu visible further on in the relay settings menu.		
Output Labels	Visible	Invisible or Visible
Sets the Output Labels menu visible further on in the relay settings menu.		
Adv. Frequency	Disabled	Enabled or Disabled
To enable (activate) or disable (turn off) the Advanced Frequency Protection function.		

Menu Text	Default Setting	Available Settings
CT & VT Ratios	Visible	Invisible or Visible
Sets the Current & Voltage Transformer Ratios menu visible further on in the relay settings menu.		
Record Control	Invisible	Invisible or Visible
Sets the Record Control menu visible further on in the relay settings menu.		
Disturb. Recorder	Invisible	Invisible or Visible
Sets the Disturbance Recorder menu visible further on in the relay settings menu.		
Measure't. Set-up	Invisible	Invisible or Visible
Sets the Measurement Setup menu visible further on in the relay settings menu.		
Comms. Settings	Visible	Invisible or Visible
Sets the Communications Settings menu visible further on in the relay settings menu. These are the settings associated with the 1st and 2nd rear communications ports.		
Commission Tests	Visible	Invisible or Visible
Sets the Commissioning Tests menu visible further on in the relay settings menu.		
Setting Values	Primary	Primary or Secondary
This affects all protection settings that are dependent upon CT and VT ratio’s.		
Control Inputs	Visible	Invisible or Visible
Activates the Control Input status and operation menu further on in the relay setting menu.		
Ctrl I/P Config.	Visible	Invisible or Visible
Sets the Control Input Configuration menu visible further on in the relay setting menu.		
Ctrl I/P Labels	Visible	Invisible or Visible
Sets the Control Input Labels menu visible further on in the relay setting menu.		
Direct Access	Enabled	Enabled/Disabled/Hotkey only/CB Cntrl. only
Defines what CB control direct access is allowed. Enabled implies control via menu, hotkeys etc.		
InterMiCOM	Disabled	Enabled or Disabled
To enable (activate) or disable (turn off) EIA(RS)232 InterMiCOM (integrated teleprotection).		
Function Key	Visible	Invisible or Visible
Sets the Function Key menu visible further on in the relay setting menu.		
RP1 Read Only	Disabled	Enabled or Disabled
To enable (activate) or disable (turn off) Read Only Mode of Rear Port 1.		
RP2 Read Only	Disabled	Enabled or Disabled
To enable (activate) or disable (turn off) Read Only Mode of Rear Port 2.		
NIC Read Only	Disabled	Enabled or Disabled
To enable (activate) or disable (turn off) Read Only Mode of Network Interface Card.		
LCD Contrast	11	0…31
Sets the LCD contrast.		

Table 1 - Relay Settings Configuration

4 PROTECTION SETTINGS

The grouped protection settings include all the following items that become active once enabled in the configuration column of the relay menu database:

- Protection element settings
- Programmable Scheme Logic (PSL) that also includes InterMiCOM signals mapping
- Protection Schemes
- Auto-reclose and check synchronization settings
- Fault locator settings.

There are four groups of protection settings, with each group containing the same setting cells. One group of protection settings is selected as the active group, and is used by the protection elements. Only the settings for group 1 are shown in this chapter. The settings are discussed in the same order in which they are displayed in the menu.

4.1 System Config (Group 1) Menu

A general system configuration menu is available which allows the phase rotation of the system to be specified, and the following column is available for each of the setting groups in the relay:

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
SYSTEM CONFIG. - GROUP 1				
Phase Sequence	Standards ABC	Standards ABC, Reverse ACB		
This setting allows the phase rotation to be set as a conventional rotation ABC or as a reverse phase rotation ACB. This will affect the positive and negative sequence quantities calculated by the relay and will also affect functions that are dependent on phase quantities. The table below indicates the calculation of the current and voltage sequence quantities, in particular positive and negative phase sequence, based on the phase rotation setting. Where a = 1∠120° rotation operator and a^2 = 1∠240°. Directional phase overcurrent protection, which incorporates cross polarization (for example IA is polarized by VBC, etc.), takes into account the phase reversal of the polarizing voltage caused by the reverse rotation setting quantities to ensure the forward and reverse directional operation is the same in both cases.				
Forward rotation - ABC		Reverse rotation - ACB		
$I_1 = (I_A + a.I_B + a^2.I_C)/3$		$I_1 = (I_A + a^2.I_B + a.I_C)/3$		
$I_2 = (I_A + a^2.I_B + a.I_C)/3$		$I_2 = (I_A + a.I_B + a^2.I_C)/3$		
$I_0 = (I_A + I_B + I_C)/3$		$I_0 = (I_A + I_B + I_C)/3$		
$V_1 = (V_A + a.V_B + a^2.V_C)/3$		$V_1 = (V_A + a^2.V_B + a.V_C)/3$		
$V_2 = (V_A + a^2.V_B + a.V_C)/3$		$V_2 = (V_A + a.V_B + a^2.V_C)/3$		
$V_0 = (V_A + V_B + V_C)/3$		$V_0 = (V_A + V_B + V_C)/3$		
2ND HARM BLOCKING				
2nd Harmonic	Disabled	Enabled or Disabled		
To enable (activate) or disable (turn off) the 2nd Harmonic Blocking of the overcurrent protection				
2nd Harm Thresh	20%	5%	70%	1%
If the level of second harmonic/fundamental in any phase current or neutral current exceeds the setting, the overcurrent protection will be blocked as selected.				

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
I> lift 2H	10 x In	4 x In	32 x In	0.01
The 2nd Harmonic blocking is applied only when the fundamental current is above 2nd Harm Thresh and below I> lift 2H setting. The reset levels are 95% of these thresholds.				

Table 2 - System Config - Group 1

4.2 Phase Overcurrent Protection

The overcurrent protection included in the relay provides six-stage non-directional/directional three-phase overcurrent protection with independent time delay characteristics. All overcurrent and directional settings apply to all three phases but are independent for each of the four stages.

The stages 1, 2 and 5 of overcurrent protection have time-delayed characteristics which are selectable between Inverse Definite Minimum Time (IDMT), or Definite Time (DT). The stages 3, 4 and 6 have DT characteristics only.

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
I>1 Function	IEC S Inverse	Disabled, DT, IEC S Inverse, IEC V Inverse, IEC E Inverse, UK LT Inverse, UK Rectifier, RI, IEEE M Inverse, IEEE V Inverse, IEEE E Inverse, US Inverse, US ST Inverse, Def User Curve 1, Def User Curve 2, Def User Curve 3, Def User Curve 4		
Setting for the tripping characteristic for the first stage overcurrent element.				
I>1 Direction	Non-directional	Non-directional Directional Fwd Directional Rev		
This setting determines the direction of measurement for first stage element.				
I>1 Current Set	1 x In	0.08 x In	4.0 x In	0.01 x In
Pick-up setting for first stage overcurrent element.				
I>1 Time Delay	1	0	100	0.01
Setting for the time-delay for the definite time setting if selected for first stage element.				
I>1 TMS	1	0.025	1.2	0.005
Setting for the time multiplier setting to adjust the operating time of the IEC IDMT characteristic.				
I>1 Time Dial	1	0.01	100	0.01
Setting for the time multiplier setting to adjust the operating time of the IEEE/US IDMT curves.				
I>1 K (RI)	1	0.1	10	0.05
Setting for the time multiplier to adjust the operating time for the RI curve.				
I>1 DT Adder	0	0	100	0.01
Setting to add an additional fixed time delay to the IDMT operate time characteristic.				
I>1 Reset Char.	DT	DT or Inverse		N/A
Setting to determine the type of reset/release characteristic of the IEEE/US curves.				
I>1 tRESET	0	0 s	100 s	0.01s
Setting that determines the reset/release time for definite time reset characteristic.				
I>2 Cells as for I>1 above				
Setting the same as for the first stage overcurrent element.				

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
I>3 Status	Disabled	Disabled or Enabled		N/A
Setting to enable or disable the third stage overcurrent element.				
I>3 Direction	Non-directional	Non-directional Directional Fwd Directional Rev		N/A
This setting determines the direction of measurement for the overcurrent element.				
I>3 Current Set	20 x In	0.08 x In	32 x In	0.01 x In
Pick-up setting for third stage overcurrent element.				
I>3 Time Delay	0	0 s	100 s	0.01 s
Setting for the operating time-delay for third stage overcurrent element.				
I>4 Cells as for I>3 Above				
Settings the same as the third stage overcurrent element.				
I> Char. Angle	45	–95°	+95°	1°
Setting for the relay characteristic angle used for the directional decision.				
I> Blocking	111 1111 111111	Bit 0 = VTS Blocks I>1, Bit 1 = VTS Blocks I>2, Bit 2 = VTS Blocks I>3, Bit 3 = VTS Blocks I>4, Bit 4 = VTS Blocks I>5, Bit 5 = VTS Blocks I>6, Bit 6 = A/R Blocks I>3, Bit 7 = A/R Blocks I>4, Bit 8 = A/R Blocks I>6, Bit 9 = 2H Blocks I>1, Bit 0A = 2H Blocks I>2, Bit 0B = 2H Blocks I>3, Bit 0C = 2H Blocks I>4, Bit 0D = 2H Blocks I>6, Bit 0E = 2H 1PH Block.		
Logic Settings that determine whether blocking signals from VT supervision, auto-reclose and 2^{nd} harmonic affect certain overcurrent stages. VTS Block - only affects directional overcurrent protection. With the relevant bit set to 1, operation of the Voltage Transformer Supervision (VTS), will block the stage. When set to 0, the stage will revert to Non-directional upon operation of the VTS. A/R Block - the auto-reclose logic can be set to selectively block instantaneous overcurrent elements for each shot in an auto-reclose sequence. This is set in the auto-reclose column. When a block instantaneous signal is generated then only those overcurrent stages selected to '1' in the I> Function link will be blocked. 2^{nd} Harmonic Block - 2^{nd} Harmonic Block logic can be set to selectively block phase overcurrent elements. This is set in the System Config column. When a block signal is generated then only those overcurrent stages selected to '1' in the I> Function link will be blocked.				
Voltage Dependent Overcurrent				
V Dep OC Status	Disabled	VCO Disabled, VCO I>1, VCO I>2, VCO I>1 & I>2, VCO I>5, VCO I>1 & I>2 & I>5, VCO I>1 & I>5, VC0 I>2 & I>5, VRO I>1, VRO I>2, VRO I>5, VRO I>1 & I>2, VRO I>1 & I>5, VRO I>2 & I>5, VRO I>1 & I>2 & I>5		N/A
Allows selection of whether voltage dependent over current should be applied to each of the first or second or fifth stage overcurrent elements.				

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
V Dep OC V<1 Set	80	10/120 V For 110/440 V respectively	40/480 V For 110/440 V respectively	¼ V For 110/440 V respectively
Undervoltage setting for voltage controlled and restrained over current characteristic				
V Dep OC k Setting	0.25	0.1	1	0.05
Setting to determine the overcurrent multiplier factor used to reduce the pick-up overcurrent setting.				
V Dep OC V<2 Set	60	10/40 V For 110/440 V respectively	120/480 V For 110/440 V respectively	¼ V For 110/440 V respectively
Undervoltage setting for voltage restrained over current characteristic				
I>5 Function	IEC S Inverse	Disabled, DT, IEC S Inverse, IEC V Inverse, IEC E Inverse, UK LT Inverse, UK Rectifier, RI, IEEE M Inverse, IEEE V Inverse, IEEE E Inverse, US Inverse, US ST Inverse.		
Setting for the tripping characteristic for the fifth stage overcurrent element.				
I>5 Direction	Non-directional	Non-directional Directional Fwd Directional Rev		
This setting determines the direction of measurement for fifth stage element.				
I>5 Current Set	1 x In	0.08 x In	4.0 x In	0.01 x In
Pick-up setting for fifth stage overcurrent element.				
I>5 Time Delay	1	0	100	0.01
Setting for the time-delay for the definite time setting if selected for fifth stage element.				
I>5 TMS	1	0.025	1.2	0.005
Setting for the time multiplier setting to adjust the operating time of the IEC IDMT characteristic.				
I>5 Time Dial	1	0.01	100	0.01
Setting for the time multiplier setting to adjust the operating time of the IEEE/US IDMT curves.				
I>5 K (RI)	1	0.1	10	0.05
Setting for the time multiplier to adjust the operating time for the RI curve.				
I>5 DT Adder	0	0	100	0.01
Setting to add an additional fixed time delay to the IDMT operate time characteristic.				
I>5 Reset Char.	DT	DT or Inverse		N/A
Setting to determine the type of reset/release characteristic of the IEEE/US curves.				
I>5 tRESET	0	0s	100s	0.01s
Setting that determines the reset/release time for definite time reset characteristic.				
I>6 Status	Disabled	Disabled or Enabled		N/A
Setting to enable or disable the sixth stage overcurrent element.				
I>6 Direction	Non-directional	Non-directional Directional Fwd Directional Rev		N/A
This setting determines the direction of measurement for the overcurrent element.				
I>6 Current Set	20 x In	0.08 x In	32 x In	0.01 x In
Pick-up setting for sixth stage overcurrent element.				
I>6 Time Delay	0	0 s	100 s	0.01 s
Setting for the operating time-delay for sixth stage overcurrent element.				

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
I> Blocking 2	0000	Bit 0 = Blinder Blk I>1, Bit 1 = Blinder Blk I>2, Bit 2 = Blinder Blk I>5, Bit 3 = Unused		
Setting for the operating time-delay for sixth stage overcurrent element.				
Blinder Status	Disabled	Disabled or Enabled		N/A
Setting used to activate (enable) or turn off (disable) the load blinder element.				
Blinder Function	3Ph	3Ph or 1Ph		N/A
Setting for measurement of impedance based on 3 phase or 1 phase.				
Blinder Mode	Both	Both or Forward or Reverse		N/A
Setting for the direction of blinder element.				
FWD Z Impedance	15	0.1 ohm	100 ohm	0.01
Setting for radius of under impedance circle in the forward direction.				
FWD Z Angle	30	5 deg	85 deg	1
Angle setting for the blinder line boundary with the gradient of the rise or fall with respect to the resistive axis in the forward direction.				
REV Z Impedance	15	0.1 ohm	100 ohm	0.01
Setting for radius of under impedance circle in the reverse direction.				
REV Z Angle	30	5 deg	85 deg	1
Angle setting for the blinder line boundary with the gradient of the rise or fall with respect to the resistive axis in the reverse direction.				
Blinder V< Block	15	10 V	120 V	1
Load blinder under voltage setting that over rides the blinder if the measured voltage in the affected phase falls below the setting.				
Blinder I2> Block	0.2	0.08 A	4 A	0.01
Setting to block blinder based on I2 when using 3 phase blinder.				
PU cycles	1	0	50	0.5
Setting to set the pickup cycles for stability.				
DO cycles	1	0	50	0.5
Setting to set the drop out cycles for stability.				

Table 3 - Phase Overcurrent Protection

4.3 Negative Sequence Overcurrent

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
I2>1 Status	Disabled	Disabled or Enabled		N/A
Setting to enable or disable the first stage negative sequence element.				
I2>1 Function	DT	Disabled, DT, IEC S Inverse, IEC V Inverse, IEC E Inverse, UK LT Inverse, IEEE M Inverse, IEEE V Inverse, IEEE E Inverse, US Inverse, US ST Inverse, Def User Curve 1, Def User Curve 2, Def User Curve 3, Def User Curve 4		
Setting for the tripping characteristic for the first stage negative sequence overcurrent element.				

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
I2>1Direction	Non-directional	Non-directional Directional Fwd Directional Rev		N/A
This setting determines the direction of measurement for this element.				
I2>1 Current Set	0.2 x In	0.08 In	4 In	0.01 In
Pick-up setting for the first stage negative sequence overcurrent element.				
I2>1 Time Delay	10	0 s	100 s	0.01 s
Setting for the operating time-delay for the first stage negative sequence overcurrent element.				
I2>1 TMS	1	0.025	1.2	0.005
Setting for the time multiplier setting to adjust the operating time of the IEC IDMT characteristic.				
I2>1 Time Dial	1	0.01	100	0.01
Setting for the time multiplier setting to adjust the operating time of the IEEE/US IDMT curves.				
I2>1 DT Adder	0	0	100	0.01
Setting to add an additional fixed time delay to the IDMT operate time characteristic.				
I2>1 Reset Char.	DT	DT or Inverse		N/A
Setting to determine the type of reset/release characteristic of the IEEE/US curves.				
I2>1 tRESET	0	0 s	100 s	0.01 s
Setting that determines the reset/release time for definite time reset characteristic.				
I2>2 Cells as for I2>3 Above				
I2>3 Status	Disabled	Disabled or Enabled		N/A
Setting to enable or disable the first stage negative sequence element.				
I2>3 Direction	Non-directional	Non-directional Directional Fwd Directional Rev		N/A
This setting determines the direction of measurement for this element.				
I2>3 Current Set	0.2 x In	0.08 In	4 In	0.01 In
Pick-up setting for the first stage negative sequence overcurrent element.				
I2>3 Time Delay	10	0 s	100 s	0.01 s
Setting for the operating time-delay for the first stage negative sequence overcurrent element.				
I2>4 Cells as for I>3 Above				
I2> Blocking	00001111	Bit 00 = VTS blocks I2>1 Bit 01 = VTS blocks I2>2 Bit 02 = VTS blocks I2>3 Bit 03 = VTS blocks I2>4 Bit 04 = 2H Blocks I2>1 Bit 05 = 2H Blocks I2>2 Bit 06 = 2H Blocks I2>3 Bit 07 = 2H Blocks I2>4		
Logic settings that determine whether VT supervision blocks selected negative sequence overcurrent stages. Setting ‘0’ will permit continued non-directional operation. 2^{nd} Harmonic Blocks – 2^{nd} Harmonic Blocks logic can be set to selectively block Negative sequence overcurrent elements stage 1. This is set in the System Config column. When a block signal is generated then only those Negative sequence overcurrent stages selected to '1' in the I> Function link will be blocked.				
I2> Char. Angle	–60°	–95°	+95°	1°
Setting for the relay characteristic angle used for the directional decision.				
I2> V2pol Set	5/20 V For 110/440 V respectively	0.5/2 V For 110/440 V respectively	25/100 V For 110/440 V respectively	0.5/2 V For 110/440 V respectively

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Setting determines the minimum negative sequence voltage threshold that must be present to determine directionality.				

Table 4 - Negative Sequence Overcurrent

4.4 Broken Conductor

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Broken Conductor	Disabled	Enabled/Disabled		N/A
Enables or disables the broken conductor function.				
I2/I1	0.2	0.2	1	0.01
Setting to determine the pick- up level of the negative to positive sequence current ratio.				
I2/I1 Time Delay	60s	0s	100s	1s
Setting for the function operating time delay.				

Table 5 - Broken Conductor

4.5 Earth Fault

The standard Earth Fault (EF) protection elements are duplicated within the relay and are referred to in the relay menu as “**Earth Fault 1**” (EF1) and “**Earth Fault 2**” (EF2). EF1 operates from earth fault current that is measured directly from the system; either by means of a separate CT located in a power system earth connection or via a residual connection of the three line CTs. The EF2 element operates from a residual current quantity that is derived internally from the summation of the three phase currents.

EF1 and EF2 are identical elements, each having four stages. The first and second stages have selectable IDMT or DT characteristics, whilst the third and fourth stages are DT only. Each stage is selectable to be either non-directional, directional forward or directional reverse. The timer hold facility, previously described for the overcurrent elements, is available on each of the first two stages.

The following table shows the relay menu for "**Earth Fault 1**" protection, including the available setting ranges and factory defaults. The menu for "**Earth Fault 2**" is identical to that for EF1 and so is not shown here.

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
IN1>1 Function	IEC S Inverse	Disabled, DT, IEC S Inverse, IEC V Inverse, IEC E Inverse, UK LT Inverse, RI, IEEE M Inverse, IEEE V Inverse, IEEE E Inverse, US Inverse, US ST Inverse, IDG, Def User Curve 1, Def User Curve 2, Def User Curve 3, Def User Curve 4		
Setting for the tripping characteristic for the first stage earth fault element.				
IN1>1 Direction	Non-directional	Non-directional Directional Fwd Directional Rev		N/A
This setting determines the direction of measurement for the first stage earth fault element.				
IN1>1 Current Set	0.2 x In	0.08 x In	4.0 x In	0.01 x In
Pick-up setting for the first stage earth fault element.				

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
IN1>1 IDG Is	1.5	1	4	0.1
This setting is set as a multiple of "IN>" setting for the IDG curve (Scandinavian) and determines the actual relay current threshold at which the element starts.				
IN1>1 Time Delay	1	0s	200s	0.01s
Time-delay setting for the first stage definite time element.				
IN1>1 TMS	1	0.025	1.2	0.005
Setting for the time multiplier setting to adjust the operating time of the IEC IDMT characteristic.				
IN1>1 Time Dial	1	0.01	100	0.1
Setting for the time multiplier setting to adjust the operating time of the IEEE/US IDMT curves.				
IN1>1 K (RI)	1	0.1	10	0.05
Setting for the time multiplier to adjust the operating time for the RI curve.				
IN1>1 IDG Time	1.2	1	2	0.01
Setting for the IDG curve used to set the minimum operating time at high levels of fault current.				
IN1>1 DT Adder	0	0	100	0.01
Setting to add an additional fixed time delay to the IDMT operate time characteristic.				
IN1>1 Reset Char.	DT	DT or Inverse N/A		
Setting to determine the type of reset/release characteristic of the IEEE/US curves.				
IN1>1 tRESET	0	0 s	100 s	0.01 s
Setting to determine the reset/release time for definite time reset characteristic.				
IN1>2 Cells as for IN1>1 Above				
IN1>3 Status	Disabled	Disabled or Enabled		N/A
Setting to enable or disable the third stage definite time element. If the function is disabled, then all associated settings with the exception of this setting, are hidden.				
IN1>3 Direction	Non-directional	Non-directional Directional Fwd Directional Rev		N/A
This setting determines the direction of measurement for the third stage earth fault element.				
IN1>3 Current	0.2 x In	0.08 x In	32 x In	0.01 x In
Pick-up setting for third stage earth fault element.				
IN1>3 Time Delay	0	0 s	200 s	0.01 s
Setting for the operating time delay for the third stage earth fault element.				
IN1>4 Cells as for IN1>3 Above				
IN1> Blocking	0000001111	Bit 0 = VTS Blocks IN>1, Bit 1 = VTS Blocks IN>2, Bit 2 = VTS Blocks IN>3, Bit 3 = VTS Blocks IN>4, Bit 4 = A/R Blocks IN>3, Bit 5 = A/R Blocks IN>4, Bits 6 = 2H Blocks IN>1, Bits 7 = 2H Blocks IN>2, Bits 8 = 2H Blocks IN>3, Bits 9 = 2H Blocks IN>4.		
Logic Settings that determine whether blocking signals from VT supervision, auto-reclose and 2^{nd} Harmonic blocks selected earth fault overcurrent stages. 2^{nd} Harmonic Blocks - 2^{nd} Harmonic Blocks logic can be set to selectively block earth fault overcurrent elements stage 1. This is set in the System Config column. When a block signal is generated then only those earth fault overcurrent stages selected to '1' in the I> Function link will be blocked.				
IN1> Char. Angle	–45°	–95°	+95°	1°
Setting for the relay characteristic angle used for the directional decision.				
IN1>Pol	Zero Sequence	Zero Sequence or Neg. Sequence		N/A

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Setting that determines whether the directional function uses zero sequence or negative sequence voltage polarizing.				
IN1>VNpol Set	5	0.5/2 V	80/320 V	0.5/2 V
Setting for the minimum zero sequence voltage polarizing quantity for directional decision				
IN1>V2pol Set	5	0.5/2 V	25/100 V	0.5/2 V
Setting for the minimum negative sequence voltage polarizing quantity for directional decision.				
IN1>I2pol Set	0.08	0.08 x In	1 x In	0.01In
Setting for the minimum negative sequence current polarizing quantity for directional decision.				

Table 6 - Earth Fault

4.6 Sensitive Earth Fault/Restricted Earth Fault

If a system is earthed through high impedance, or is subject to high ground fault resistance, the Earth Fault (EF) level will be severely limited. Consequently, the applied earth fault protection requires both an appropriate characteristic and a suitably sensitive setting range in order to be effective. A separate four-stage Sensitive Earth Fault (SEF) element is provided within the relay for this purpose, which has a dedicated input. This input may be configured to be used as a Restricted Earth Fault (REF) input. The REF protection in the relay may be configured to operate as either a high impedance or biased element.

Note	*The high impedance REF element of the relay shares the same CT input as the SEF protection. Hence, only one of these elements may be selected. However, the low impedance REF element does not use the SEF input and so may be selected at the same time.*

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
SEF/REF PROT'N. GROUP 1				
SEF/REF Options	SEF	SEF, SEF cos (PHI), SEF sin (PHI), Wattmetric, Hi Z REF, Lo Z REF, Lo Z REF + SEF, Lo Z REF + Wattmetric		
Setting to select the type of sensitive earth fault protection function and the type of high-impedance function to be used. If the function is not selected, then all associated settings and signals are hidden, with the exception of this setting.				
ISEF>1 Function	DT	Disabled, DT, IEC S Inverse, IEC V Inverse, IEC E inverse, UK LT Inverse, IEEE M Inverse, IEEE V Inverse, IEEE E Inverse, US Inverse, US ST Inverse, IDG, EPATR B, Def User Curve 1, Def User Curve 2, Def User Curve 3, Def User Curve 4		
Setting for the tripping characteristic for the first stage sensitive earth fault element.				
ISEF>1 Direction	Non-directional	Non-directional Direction Fwd Direction Rev		N/A
This setting determines the direction of measurement for the first stage sensitive earth fault element.				
ISEF>1 Current	0.05 x In	0.005 x In	0.1x In	0.00025 x In
Pick-up setting for the first stage sensitive earth fault element.				
ISEF>1 IDG Is	1.5	1	4	0.1
This setting is set as a multiple of “ISEF>” setting for the IDG curve (Scandinavian) and determines the actual relay current threshold at which the element starts.				
ISEF>1 Delay	1	0	200 s	0.01 s

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Setting for the time delay for the first stage definite time element.				
ISEF>1 TMS	1	0.025	1.2	0.005
Setting for the time multiplier to adjust the operating time of the IEC IDMT characteristic.				
ISEF>1 Time Dial	7	0.1	100	0.1
Setting for the time multiplier to adjust the operating time of the IEEE/US IDMT curves.				
ISEF>1 IDG Time	1.2	1	2	0.01
Setting for the IDG curve used to set the minimum operating time at high levels of fault current.				
ISEF>1 DT Adder	0	0	100	0.01
Setting to add an additional fixed time delay to the IDMT operate time characteristic.				
ISEF>1 Reset Char.	DT	DT or Inverse		N/A
Setting to determine the type of reset/release characteristic of the IEEE/US curves.				
ISEF>1 tRESET	0	0 s	100 s	0.01 s
Setting to determine the reset/release time for definite time reset characteristic.				
ISEF>2 Cells as for ISEF>1 Above				
ISEF>3 Status	Disabled	Disabled or Enabled		N/A
Setting to enable or disable the third stage definite time sensitive earth fault element.				
ISEF>3 Direction	Non-directional	Non-directional Directional Fwd Directional Rev		N/A
This setting determines the direction of measurement for the third stage element.				
ISEF>3 Current	0.2 x In	0.005 x In	2.0 x In	0.001 x In
Pick-up setting for the third stage sensitive earth fault element.				
ISEF>3 Time Delay	1	0 s	200 s	0.01 s
Setting for the operating time delay for third stage sensitive earth fault element.				
ISEF>4 Cells as for ISEF>3 Above				
ISEF> Blocking	0000001111	Bit 0 = VTS Blocks ISEF>1, Bit 1 = VTS Blocks ISEF>2, Bit 2 = VTS Blocks ISEF>3, Bit 3 = VTS Blocks ISEF>4, Bit 4 = A/R Blocks ISEF>3, Bit 5 = A/R Blocks ISEF>4. Bits 6 & 7 are not used. Bits 6 = 2H Blocks ISEF>1, Bits 7 = 2H Blocks ISEF>2, Bits 8 = 2H Blocks ISEF>3, Bits 9 = 2H Blocks ISEF>4		
Settings that determine whether VT supervision, auto-reclose and 2nd Harmonic logic signals blocks selected sensitive earth fault stages. 2nd Harmonic Blocks – 2nd Harmonic Blocks logic can be set to selectively block sensitive earth fault overcurrent elements stage 1. This is set in the System Config column. When a block signal is generated then only those sensitive earth fault overcurrent stages selected to '1' in the ISEF> Function link will be blocked				
ISEF POL	Sub-heading in menu			
ISEF> Char. Angle	–45°	–95°	+95°	1°
Setting for the relay characteristic angle used for the directional decision.				
ISEF>VNpol Set	5	0.5/2 V	80/320 V	0.5/2 V
Setting for the minimum zero sequence voltage polarizing quantity required for directional decision.				
WATTMETRIC SEF	Sub-heading in menu			
PN> Setting	9 In/36 In W	0 – 20 In/80 In W		0.05/ 0.2In W

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Setting for the threshold for the wattmetric component of zero sequence power. The power calculation is as follows: The PN> setting corresponds to: Vres x Ires x Cos (ϕ - ϕc) = 9 x Vo x Io x Cos (ϕ - ϕc) Where; ϕ = Angle between the Polarizing Voltage (-Vres) and the Residual Current ϕc = Relay Characteristic Angle (RCA) Setting (ISEF> Char Angle) Vres = Residual Voltage Ires = Residual Current Vo = Zero Sequence Voltage Io = Zero Sequence Current				
RESTRICTED E/F	Sub-heading in menu			
IREF>k1	20%	0.08x In	1.0 x In	0.01x In
Slope angle setting for the first slope of the low impedance biased characteristic.				
IREF>k2	150%	0%	150%	1%
Slope angle setting for the second slope of the low impedance biased characteristic.				
IREF>Is1	0.2	0.08 x In	1 x In	0.01 x In
Setting that determines the minimum differential operating current for the low impedance characteristics.				
IREF>Is2	1	0.1 x In	1.5 x In	0.01 x In
Setting that determines the bias current operating threshold for the second slope low impedance characteristics.				

Table 7 - Sensitive Earth Fault/Restricted Earth Fault

For the Hi Z REF option, the following settings are available:

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
RESTRICTED E/F	Sub-heading in menu			
IREF> Is	20%	0.05x In	1.0 x In	0.01x In
Setting that determines minimum differential operating current for the Hi-impedance element.				

Table 8 - Sensitive Earth Fault/Restricted Earth Fault (Hi Z Ref option)

4.7 Residual Overvoltage (Neutral Voltage Displacement)

The Neutral Voltage Displacement (NVD) element within the relay is of two-stage design, each stage having separate voltage and time delay settings. Stage 1 may be set to operate on either an IDMT or DT characteristic, whilst stage 2 may be set to DT only.

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
RESIDUAL O/V NVD GROUP 1				
VN>1 Function	DT	Disabled, DT, IDMT		N/A
Setting for the tripping characteristic of the first stage residual overvoltage element.				
VN>1 Voltage Set	5/20V For 110/440V respectively	1/4V For 110/440V respectively	80/320V For 110/440V respectively	1V
Pick-up setting for the first stage residual overvoltage characteristic.				
VN>1 Time Delay	5s	0	100	0.01s

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Operating time delay setting for the first stage definite time residual overvoltage element.				
VN>1 TMS	1	0.5	100	0.5
Setting for the time multiplier setting to adjust the operating time of the IDMT characteristic. The characteristic is defined as follows: t = K / (M – 1) Where: K = Time multiplier setting t = Operating time in seconds M = Derived residual voltage/relay setting voltage (VN> Voltage Set)				
VN>1 Reset	0	0	100	0.01
Setting to determine the reset/release definite time for the first stage characteristic				
VN>2 Status	Disabled	Disabled, Enabled		N/A
Setting to enable or disable the second stage definite time residual overvoltage element.				
VN>2 Voltage Set	10	1/4V (110/440V)	80/320V (110/440V)	1V
Pick-up setting for the second stage residual overvoltage element.				
VN>2 Time Delay	10s	0	100	0.01s
Operating time delay for the second stage residual overvoltage element.				

Table 9 - Residual Overvoltage (Neutral Voltage Displacement)

4.8 Thermal Overload

The thermal overload function within the relay is capable of being selected as a single time constant or dual time constant characteristic, dependent on the type of plant to be protected.

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
THERMAL OVERLOAD - GROUP 1				
Characteristic	Single	Disabled, Single, Dual		
Setting for the operating characteristic of the thermal overload element.				
Thermal Trip	1In	0.08In	4In	0.01In
Sets the maximum full load current allowed and the pick-up threshold of the thermal characteristic.				
Thermal Alarm	70%	50%	100%	1%
Setting for the thermal state threshold corresponding to a percentage of the trip threshold at which an alarm will be generated.				
Time Constant 1	10 minutes	1 minute	200 minutes	1 minute
Setting for the thermal time constant for a single time constant characteristic or the first time constant for the dual time constant characteristic.				
Time Constant 2	5 minutes	1 minute	200 minute	1 minute
Setting for the second thermal time constant for the dual time constant characteristic.				

Table 10 - Thermal Overload

4.9 Negative Sequence Overvoltage

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
NEG. SEQUENCE O/V - GROUP 1				
V2> status	Enabled	Enabled, Disabled		N/A
Setting to enable or disable the definite time negative sequence overvoltage element.				
V2> Voltage Set	15/60V For 110/440V respectively	1/4V For 110/440V respectively	110/440V For 110/440V respectively	1/4V For 110/440V respectively
Pick-up setting for the negative sequence overvoltage element.				
V2> Time Delay	5s	0	100	0.01
Operating time delay setting for the definite time stage element.				

Table 11 - Negative Sequence Overvoltage

4.10 Cold Load Pick-Up

The Cold Load Pick-Up (CLP) logic is included for each of the six overcurrent stages and the first stages of the measured (EF1) and derived (EF2) Earth Fault protection.

Note	*The CLP logic is enabled/disabled within the configuration column.*

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
COLD LOAD PICKUP - GROUP 1				
tcold Time Delay	7200s	0	14,400s	1s
This setting determines the time the load needs to be de-energized (dead time) before the new settings are applied.				
tclp Time Delay	7200s	0	14,400s	1s
This setting controls the period of time for which the relevant overcurrent and earth fault settings are altered or inhibited following circuit breaker closure.				
OVERCURRENT	Sub-heading			
I>1 Status	Enable	Block, Enable		N/A
As shown in the menu, the I>1 status cells have two setting options, "Enable" and "Block". Selection of "Enable" for a particular stage means that the current and time settings programmed in the following cells will be those that are adopted during the "tclp" time. Selection of "Block" simply blocks the relevant protection stage during the "tclp" time. It also removes the following current and time settings for that stage from the menu.				
I>1 Current set	1.5 x In	0.08 x In	4 x In	0.01 x In
This setting determines the new pick-up setting for first stage overcurrent element during the tclp time delay.				
I>1 Time Delay	1s	0	100s	0.01s
Setting for the new operating time delay for the first stage definite time overcurrent element during the tclp time.				
I>1 TMS	1	0.025	1.2	0.025
Setting for the new time multiplier setting for the first stage element to adjust the operating time of the IEC IDMT characteristic during the tclp time.				
I>1 Time Dial	7	0.5	15	0.1
Setting for the new time multiplier setting to adjust the operating time of the IEEE/US IDMT curves during the tclp time.				
I>2 Status as for I>1 Cells above	Enable	Block, Enable		N/A
I>3 Status	Block	Block, Enable		N/A

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
As shown in the menu the I>3 status cells have two setting options, "Enable" and "Block". Selection of "Enable" for a particular stage means that the current and time settings programmed in the following cells will be those that are adopted during the "tclp" time. Selection of "Block" simply blocks the relevant protection stage during the "tclp" time. It also removes the following current and time settings for that stage from the menu.				
I>3 Current Set	25 x In	0.08 x In	32 x In	0.01 x In
This setting determines the new pick-up setting for the third stage overcurrent function during the tclp time delay.				
I>3 Time Delay	0	0	100s	0.01s
Setting for the new operating time delay for the third stage definite time element during the tclp time.				
I>4 Status as for I>3 Cells above	Block	Block, Enable		N/A
STAGE 1 E/F 1	Sub-heading			
IN1>1 Status	Enable	Block, Enable		N/A
As shown in the menu the IN1>1 status cells have two setting options, "Enable" and "Block". Selection of "Enable" for a particular stage means that the current and time settings programmed in the following cells will be those that are adopted during the "tclp" time. Selection of "Block" simply blocks the relevant protection stage during the "tclp" time. It also removes the following current and time settings for that stage from the menu.				
IN1>1 Current	0.2 x In	0.08 x In	4 x In	0.01 x In
This setting determines the new pick-up setting for first stage earth fault element during the tclp time delay.				
IN1> IDG Is	1.5	1	4	0.1 x In
This setting is set as a multiple of “IN>” setting for the IDG curve (Scandinavian) and determines the new relay current threshold at which the element starts during the tclp time delay.				
IN1>1 Time Delay	1s	0	200s	0.01s
Setting for the new operating time delay for the first stage definite time element during the tclp time.				
IN1>1 TMS	1	0.025	1.2	0.025
Setting for the new time multiplier setting to adjust the operating time of the IEC IDMT characteristic during the tclp time.				
IN1>1 Time Dial	7	0.5	15	0.1
Setting for the new time multiplier setting to adjust the operating time of the IEEE/US IDMT curves during the tclp time.				
IN1>1 k (RI)	1.0	0.1	10	0.5
Setting for the new time multiplier to adjust the operating time for the RI curve during the tclp time.				
STAGE 1 E/F 2	Sub-heading			
IN2>1 Status as for IN1> Cells above	Enable	Block, Enable		N/A
I>5 Status	Enable	Block, Enable		N/A
As shown in the menu, the I>5 status cells have two setting options, "Enable" and "Block". Selection of "Enable" for a particular stage means that the current and time settings programmed in the following cells will be those that are adopted during the "tclp" time. Selection of "Block" simply blocks the relevant protection stage during the "tclp" time. It also removes the following current and time settings for that stage from the menu.				
I>5 Current set	1.5 x In	0.08 x In	4 x In	0.01 x In
This setting determines the new pick-up setting for fifth stage overcurrent element during the tclp time delay.				
I>5 Time Delay	1s	0	100s	0.01s
Setting for the new operating time delay for the fifth stage definite time overcurrent element during the tclp time.				
I>5 TMS	1	0.025	1.2	0.025
Setting for the new time multiplier setting for the fifth stage element to adjust the operating time of the IEC IDMT characteristic during the tclp time.				
I>5 Time Dial	7	0.5	15	0.1
Setting for the new time multiplier setting to adjust the operating time of the IEEE/US IDMT curves during the tclp time.				
I>6 Status	Block	Block, Enable		N/A

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
As shown in the menu the I>6 status cells have two setting options, "Enable" and "Block". Selection of "Enable" for a particular stage means that the current and time settings programmed in the following cells will be those that are adopted during the "tclp" time. Selection of "Block" simply blocks the relevant protection stage during the "tclp" time. It also removes the following current and time settings for that stage from the menu.				
I>6 Current Set	25 x In	0.08 x In	32 x In	0.01 x In
This setting determines the new pick-up setting for the sixth stage overcurrent function during the tclp time delay.				
I>6 Time Delay	0	0	100s	0.01s
Setting for the new operating time delay for the sixth stage definite time element during the tclp time.				

Table 12 - Cold Load Pick-Up

4.11 Selective Overcurrent Logic (SOL)

The Selective Overcurrent Logic (SOL) function provides the ability to temporarily increase the time delay settings of the third, fourth and the sixth stages of phase overcurrent, derived and measured earth fault and sensitive earth fault protection elements. This logic modifies the normal trip timer block functionality, to replace it with a second definite timer and is initiated by energization of the appropriate trip time opto-isolated input.

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
SELECTIVE LOGIC - GROUP 1				
OVERCURRENT	Sub-heading			
I>3 Time Delay	1s	0	100s	0.01s
Setting for the third stage definite time overcurrent element operating time when the selective logic is active.				
I>4 Time Delay	1s	0	100s	0.01s
Setting for the fourth stage definite time overcurrent element operating time when the selective logic is active.				
EARTH FAULT 1	Sub-heading			
IN1>3 Time Delay	2s	0	200s	0.01s
Setting for the third stage definite time earth fault (measured) element operating time when the selective logic is active.				
IN1>4 Time Delay	2s	0	200s	0.01s
Setting for the fourth stage definite time earth fault (measured) element operating time when the selective logic is active.				
EARTH FAULT 2	Sub-heading			
IN2>3 Time Delay	2s	0	200s	0.01s
Setting for the third stage definite time earth fault (derived) element operating time when the selective logic is active.				
IN2>4 Time Delay	2s	0	200s	0.01s
Setting for the fourth stage definite time earth fault (derived) element operating time when the selective logic is active.				
SENSITIVE E/F	Sub-heading			
ISEF>3 Delay	1s	0	200s	0.01s
Setting for the third stage definite time sensitive earth fault element operating time when the selective logic is active.				
ISEF>4 Delay	0.5s	0	200s	0.01s
Setting for the fourth stage definite time sensitive earth fault element operating time when the selective logic is active.				
I>6 Time Delay	1s	0	100s	0.01s
Setting for the sixth stage definite time overcurrent element operating time when the selective logic is active.				

Table 13 - Selective Overcurrent Logic

4.12 Neutral Admittance Protection

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
ADMIT. PROTECTION - GROUP 1				
VN Threshold	10/40V For 110/440V respectively	1/4V For 110/440V respectively	40/160V For 110/440V respectively	1/4V For 110/440V respectively
The overadmittance elements YN>, GN> and BN> will operate providing the neutral voltage remains above the set level for the set operating time of the element. They are blocked by operation of the fast VTS supervision output.				
CT Input Type	SEF CT	SEF CT/E/F CT		–
Setting determines which CT inputs are used for the admittance element calculations.				
Correction Angle	0 degree	–30 degree	30 degree	1 degree
This setting causes rotation of the directional boundary for conductance through the set correction angle.				
OVER ADMITTANCE				
YN> Status	Disabled	Disabled or Enabled		–
Setting to enable or disable the overadmittance stage. If the function disabled, then all associated settings with the exception of this setting, are hidden.				
YN> Set (SEF)	5mS/1.25mS For 110/440V respectively	0.1mS/ 0.025mS For 110/440V respectively	10mS/ 2.5mS For 110/440V respectively	0.1mS/ 0.025mS For 110/440V respectively
Sets the magnitude of the overadmittance threshold. If the measurement exceeds the set value and the magnitude of neutral voltage exceeds the set value threshold, the relay will operate.				
YN> Set (EF)	50mS/12.5mS For 110/440V respectively	1mS/ 0.25mS For 110/440V respectively	100mS/ 25mS For 110/440V respectively	1mS/ 0.25mS For 110/440V respectively
Sets the magnitude of the overadmittance threshold. If the measurement exceeds the set value and the magnitude of neutral voltage exceeds the set value threshold, the relay will operate.				
YN> Time Delay	1 s	0.05 s	100 s	0.01 s
Operating time delay setting for the overadmittance element.				
YN> tRESET	0 s	0 s	100 s	0.01 s
Sets the reset/release time for the definite time reset characteristic.				
OVER CONDUCTANCE				
GN> Status	Disabled	Disabled or Enabled		
Setting to enable or disable the overconductance stage. If the function is disabled, then all associated settings with the exception of this setting, are hidden.				
GN> Direction	Non-directional	Non-directional/ Directional Fwd/ Directional Rev		
This setting determines the direction of measurement for this element.				
GN> Set (SEF)	0.8mS/0.2mS For 110/440V respectively	0.1mS/ 0.025mS For 110/440V respectively	5mS/ 1.25mS For 110/440V respectively	0.1mS/ 0.025mS For 110/440V respectively
Sets the magnitude of the overconductance threshold. Provided the magnitude and the directional criteria are met for conductance and the magnitude of neutral voltage exceeds the set value VN Threshold, the relay will operate.				
GN> Set (EF)	2mS/0.5mS For 110/440V respectively	1mS/ 0.25mS For 110/440V respectively	50mS/ 2.5mS For 110/440V respectively	1mS/ 0.25mS For 110/440V respectively

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Sets the magnitude of the overconductance threshold. Provided the magnitude and the directional criteria are met for conductance and the magnitude of neutral voltage exceeds the set value VN Threshold, the relay will operate.				
GN> Time Delay	1 s	0.05 s	100 s	0.01 s
Sets the operating time delay for the overadmittance element.				
GN> tRESET	0 s	0 s	100 s	0.01 s
Sets the reset/release time for the definite time reset characteristic.				
OVER SUSCEPTANCE				
BN> Status	Disabled	Disabled or Enabled		
Setting to enable or disable the oversusceptance stage. If the function is disabled, then all associated settings with the exception of this setting, are hidden.				
BN> Direction	Non-directional	Non-directional/ Directional Fwd/ Directional Rev		
This setting determines the direction of measurement for this element.				
BN> Set (SEF)	0.8mS/0.2mS For 110/440V respectively	0.1mS/ 0.025mS For 110/440V respectively	5mS/ 1.25mS For 110/440V respectively	0.1mS/ 0.025mS For 110/440V respectively
Sets the magnitude of the oversusceptance threshold. Provided the magnitude and the directional criteria are met for conductance and the magnitude of neutral voltage exceeds the set value VN Threshold, the relay will operate.				
BN> Set (EF)	2mS/0.5mS For 110/440V respectively	1mS/ 0.25mS For 110/440V respectively	50mS/ 2.5mS For 110/440V respectively	1mS/ 0.25mS For 110/440V respectively
Sets the magnitude of the oversusceptance threshold. Provided the magnitude and the directional criteria are met for conductance and the magnitude of neutral voltage exceeds the set value VN Threshold, the relay will operate.				
BN> Time Delay	1 s	0.05 s	100 s	0.01 s
Setting for the operating time-delay for the oversusceptance element.				
BN> tRESET	0 s	0 s	100 s	0.01 s
Sets the reset/release time for the definite time reset characteristic.				

Table 14 - Neutral Admittance Protection

4.13 Power Protection

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
POWER PROTECTION - GROUP 1				
OVER POWER				
Power>1 Status	Disabled	Disabled/Enabled		
Setting to enable or disable the Power1 stage.				
Power>1 Direction	Forward	Forward/Reverse		
Setting for the direction of the Power>1 stage.				
Power>1 TimeDelay	1 s	0 s	100 s	0.01 s
Operating time delay setting for the first stage over power protection element.				
Power>1 tRESET	0 s	0 s	100 s	0.01 s
Resetting time delay setting for the first stage over power protection element.				
Power>1 1Ph Watt	40 W	1 W	325 W	1 W
Pickup setting of the 1 Phase 1 stage over power protection element - active mode.				

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Power>1 1Ph Var	24 Var	1 Var	325 Var	1 Var
Pickup setting of the 1 Phase 1 stage over power protection element - reactive mode.				
Power>1 3Ph Watt	120 W	1 W	325 W	1 W
Pickup setting of the 3 Phase 1 stage over power protection element - active mode.				
Power>1 3Ph Var	72 Var	1 Var	325 Var	1 Var
Pickup setting of the 3 Phase 1 stage over power protection element - reactive mode.				
Power>2 Status	Disabled	Disabled/Enabled		
Setting to enable or disable the Power2 stage.				
Power>2 Direction	Forward	Forward/Reverse		
Setting for the direction of the Power>2 stage.				
Power>2 Mode	Active	Active/Reactive		
Setting to select Active or Reactive mode.				
Power>2 TimeDelay	1 s	0 s	100 s	0.01 s
Operating time delay setting for the first stage over power protection element.				
Power>2 tRESET	0 s	0 s	100 s	0.01 s
Resetting time delay setting for the first stage over power protection element.				
Power>2 1Ph Watt	40 W	1 W	325 W	1 W
Pickup setting of the 1 Phase 2 stage over power protection element - active mode.				
Power>2 1Ph Var	24 Var	1 Var	325 Var	1 Var
Pickup setting of the 1 Phase 2 stage over power protection element - reactive mode.				
Power>1 3Ph Watt	120 W	1 W	325 W	1 W
Pickup setting of the 3 Phase 2 stage over power protection element - active mode.				
Power>1 3Ph Var	72 Var	1 Var	325 Var	1 Var
Pickup setting of the 3 Phase 2 stage over power protection element - reactive mode.				
UNDER POWER				
Power<1 Status	Disabled	Disabled/Enabled		
Setting to enable or disable the Power1 stage.				
Power<1 Direction	Forward	Forward/Reverse		
Setting for the direction of the Power<1 stage.				
Power<1 Mode	Active	Active/Reactive		
Setting to select Active or Reactive mode.				
Power<1 TimeDelay	1 s	0 s	100 s	0.01 s
Operating time delay setting for the first stage under power protection element.				
Power<1 tRESET	0 s	0 s	100 s	0.01 s
Operating time delay setting for the first stage under power protection element.				
Power<1 1Ph Watt	10 W	1 W	325 W	1 W
Pickup setting of the 1 Phase 1 stage under power protection element - active mode.				
Power<1 1Ph Var	6 Var	1 Var	325 Var	1 Var
Pickup setting of the 3 Phase 1 stage under power protection element - reactive mode.				
Power<1 3Ph Watt	30 W	1 W	325 W	1 W
Pickup setting of the 3 Phase 1 stage under power protection element - active mode.				
Power<1 3Ph Var	18 Var	1 Var	325 Var	1 Var
Pickup setting of the 1 Phase 2 stage under power protection element - reactive mode.				

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Power<2 Status	Disabled	Disabled/Enabled		
Setting to enable or disable the Power<2 stage.				
Power<2 Direction	Forward	Forward/Reverse		
Setting for the direction of the Power<2 stage.				
Power<2 Mode	Active	Active/Reactive		
Setting to select Active or Reactive mode.				
Power<2 TimeDelay	1 s	0 s	100 s	0.01 s
Operating time delay setting for the first stage under power protection element.				
Power<2 tRESET	0 s	0 s	100 s	0.01 s
Operating time delay setting for the first stage under power protection element.				
Power<2 1Ph Watt	10 W	1 W	325 W	1 W
Pickup setting of the 1 Phase 2 stage under power protection element - active mode.				
Power<2 1Ph Var	6 Var	1 Var	325 Var	1 Var
Pickup setting of the 3 Phase 2 stage under power protection element - reactive mode.				
Power<2 3Ph Watt	30 W	1 W	325 W	1 W
Pickup setting of the 3 Phase 2 stage under power protection element - active mode.				
Power<2 3Ph Var	18 Var	1 Var	325 Var	1 Var
Pickup setting of the 1 Phase 2 stage under power protection element - reactive mode.				
Power< Blocking	11	Bit 00 = Pole Dead Blocking disabled Stage 1 Bit 1 = Pole Dead Blocking disabled Stage 2		
Setting to enable or disable the Under Power Pole dead blocking.				
APh Sens Power	Disabled	Disabled/Enabled		
Setting to enable or disable the Sensitive Power.				
Comp Angle	0 degree	–5 degree	5 degree	0.1 degree
This setting for CT compensating angle.				
Sens P1 Function	Reverse	Disabled/Reverse/Low Forward/Over		
First stage sensitive power function operating mode.				
Sens –P>1 setting	0.5 x In W (Vn=100/120V) 2.0 x In W (Vn=400/440V)	0.3 x In W (Vn=100/120V) 1.2 x In W (Vn=400/440V)	15 x In W (Vn=100/120V) 60 x In W (Vn=400/440V)	0.1 x In W (Vn=100/120V) 0.4 x In W (Vn=400/440V)
Pickup setting of the first stage sensitive reverse power protection element.				
Sens P<1 setting	0.5 x In W (Vn=100/120V) 2.0 x In W (Vn=400/440V)	0.3 x In W (Vn=100/120V) 1.2 x In W (Vn=400/440V)	15 x In W (Vn=100/120V) 60 x In W (Vn=400/440V)	0.1 x In W (Vn=100/120V) 0.4 x In W (Vn=400/440V)
Pickup setting of the first stage sensitive low forward power protection element.				
Sens P>1 setting	50 x In W (Vn=100/120V) 200 x In W (Vn=400/440V)	0.3 x In W (Vn=100/120V) 1.2 x In W (Vn=400/440V)	100 x In W (Vn=100/120V) 400 x In W (Vn=400/440V)	0.1 x In W (Vn=100/120V) 0.4 x In W (Vn=400/440V)
Pickup setting of the first stage sensitive over power protection element.				
Sens P1 Delay	5 s	0 s	100 s	0.01 s
Operating time delay setting of the first stage sensitive power protection element.				
P1 tRESET	0 s	0 s	100 s	0.01 s
Drop off time delay setting of the first stage sensitive power protection element.				
P1 Poledead Inh	Enabled	Disabled/Enabled		

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Setting to enable or disable the Sensitive Power Stage 1 Pole dead inhibit.				
Sens P2 Function	Low Forward	Disabled/Reverse/Low Forward/Over		
Second stage sensitive power function operating mode.				
Sens –P>2 setting	0.5 x In W (Vn=100/120V) 2.0 x In W (Vn=400/440V)	0.3 x In W (Vn=100/120V) 1.2 x In W (Vn=400/440V)	15 x In W (Vn=100/120V) 60 x In W (Vn=400/440V)	0.1 x In W (Vn=100/120V) 0.4 x In W (Vn=400/440V)
Pickup setting of the second stage sensitive reverse power protection element.				
Sens P<2 setting	0.5 x In W (Vn=100/120V) 2.0 x In W (Vn=400/440V)	0.3 x In W (Vn=100/120V) 1.2 x In W (Vn=400/440V)	15 x In W (Vn=100/120V) 60 x In W (Vn=400/440V)	0.1 x In W (Vn=100/120V) 0.4 x In W (Vn=400/440V)
Pickup setting of the second stage sensitive low forward power protection element.				
Sens P>2 setting	50 x In W (Vn=100/120V) 200 x In W (Vn=400/440V)	0.3 x In W (Vn=100/120V) 1.2 x In W (Vn=400/440V)	100 x In W (Vn=100/120V) 400 x In W (Vn=400/440V)	0.1 x In W (Vn=100/120V) 0.4 x In W (Vn=400/440V)
Pickup setting of the second stage sensitive over power protection element.				
Sens P2 Delay	5 s	0 s	100 s	0.01 s
Operating time delay setting of the second stage sensitive power protection element.				
P2 tRESET	0 s	0 s	100 s	0.01 s
Drop off time delay setting of the second stage sensitive power protection element.				
P2 Poledead Inh	Enabled	Disabled/Enabled		
Setting to enable or disable the Sensitive Power Stage 2 Pole dead inhibit.				

Table 15 - Power Protection

4.14 Voltage Protection

The undervoltage protection included within the relay consists of two independent stages. These are configurable as either phase to phase or phase to neutral measuring by means of the "V<Measur't mode" cell.

Stage 1 may be selected as IDMT, DT or Disabled, within the "V<1 function" cell.

Stage 2 is DT only and is enabled/disabled in the "V<2 status" cell.

Two stages are included to provide both alarm and trip stages, where required.

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
VOLT PROTECTION - GROUP 1				
UNDERVOLTAGE	Sub-heading			
V< Measur't. Mode	Phase-Phase	Phase to Phase Phase to Neutral		N/A
Sets the measured input voltage that will be used for the undervoltage elements.				
V< Operate Mode	Any Phase	Any Phase Three Phase		N/A
Setting that determines whether any phase or all three phases has to satisfy the undervoltage criteria before a decision is made.				
V<1 Function	DT	Disabled DT IDMT		N/A

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Tripping characteristic for the first stage undervoltage function. The IDMT characteristic available on the first stage is defined by the following formula: t = K / (1 - M) Where: K = Time multiplier setting t = Operating time in seconds M = Measured voltage/relay setting voltage (V< Voltage Set)				
V<1 Voltage Set	80/320V For 110/440V respectively	10/40V For 110/440V respectively	120/480V For 110/440V respectively	1/4V For 110/440V respectively
Sets the pick-up setting for first stage undervoltage element.				
V<1 Time Delay	10s	0	100	0.01s
Setting for the operating time-delay for the first stage definite time undervoltage element.				
V<1 TMS	1	0.5	100	0.5
Setting for the time multiplier setting to adjust the operating time of the IEC IDMT characteristic.				
V<1 Poledead Inh	Enabled	Enabled, Disabled		N/A
If the cell is enabled, the relevant stage will become inhibited by the pole dead logic. This logic produces an output when it detects either an open circuit breaker via auxiliary contacts feeding the relay opto inputs or it detects a combination of both undercurrent and undervoltage on any one phase. It allows the undervoltage protection to reset when the circuit breaker opens to cater for line or bus side VT applications				
V<2 Status	Disabled	Enabled, Disabled		N/A
Setting to enable or disable the second stage undervoltage element.				
V<2 Voltage Set	60/240V For 110/440V respectively	10/40V For 110/440V respectively	120/480V For 110/440V respectively	1/4V For 110/440V respectively
This setting determines the pick-up setting for second stage undervoltage element.				
V<2 Time Delay	5s	0	100	0.01s
Setting for the operating time-delay for the second stage definite time undervoltage element.				
V<2 Poledead Inh	Enabled	Enabled Disabled		N/A
If the cell is enabled, the relevant stage will become inhibited by the pole dead logic. This logic produces an output when it detects either an open circuit breaker via auxiliary contacts feeding the relay opto inputs or it detects a combination of both undercurrent and undervoltage on any one phase. It allows the undervoltage protection to reset when the circuit breaker opens to cater for line or bus side VT applications				
OVERVOLTAGE	Sub-heading			
V> Measur't. Mode	Phase-Phase	Phase to Phase Phase to Neutral		N/A
Sets the measured input voltage that will be used for the overvoltage elements.				
V> Operate Mode	Any Phase	Any Phase Three Phase		N/A
Setting that determines whether any phase or all three phases has to satisfy the overvoltage criteria before a decision is made.				
V>1 Function	DT	Disabled DT IDMT		N/A
Tripping characteristic setting for the first stage overvoltage element. The IDMT characteristic available on the first stage is defined by the following formula: t = K / (M - 1) Where: K = Time multiplier setting t = Operating time in seconds M = Measured voltage/relay setting voltage (V<>Voltage Set)				

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
V>1 Voltage Set	130/520V For 110/440V respectively	40/240V For 110/440V respectively	160/740V For 110/440V respectively	1/4V For 110/440V respectively
Sets the pick-up setting for first stage overvoltage element.				
V>1 Time Delay	10s	0	100	0.01s
Setting for the operating time-delay for the first stage definite time overvoltage element.				
V>1 TMS	1	0.5	100	0.5
Setting for the time multiplier setting to adjust the operating time of the IEC IDMT characteristic.				
V>2 Status	Disabled	Enabled, Disabled		N/A
Setting to enable or disable the second stage overvoltage element.				
V>2 Voltage Set	150/600V For 110/440V respectively	40/240V For 110/440V respectively	160/740V For 110/440V respectively	1/4V For 110/440V respectively
This setting determines the pick-up setting for the second stage overvoltage element.				
V>2 Time Delay	5s	0	100	0.01s
Setting for the operating time-delay for the second stage definite time overvoltage element.				
dv/dt protection	Sub-heading			
dv/dt Meas Mode	Phase-Phase	Phase to Phase Phase to Neutral		N/A
Sets the measured input voltage that will be used for the dv/dt elements.				
dv/dt1 Function	Disabled	Disabled/Negative/Positive/Both		N/A
Setting to enable or disable the first stage rate of change of voltage element.				
dv/dt1 Oper Mode	Any Phase	Any Phase/Three Phase		
Setting that determines whether any phase or all three phases has to satisfy the rate of change of voltage criteria before a decision is made.				
dv/dt1 AvgCycles	10	5	50	1
Sets the number of power system cycles that are used to average the rate of change of voltage measurement.				
dv/dt1 Threshold	10 Volts/Sec	0.5 Volts/Sec	200 Volts/Sec	0.5 Volts/Sec
Rate of change of voltage threshold for the first stage.				
dv/dt1 TimeDelay	0.5 Sec	0 Sec	100 Sec	0.01 Sec
Operating time delay setting for the first stage rate of change of voltage protection element.				
dv/dt1 tRESET	0.03 Sec	0 Sec	100 Sec	0.01 Sec
Reset time delay setting for the first stage rate of change of voltage protection element.				
dv/dt2 Function	Disabled	Disabled/Negative/Positive/Both		N/A
Setting to enable or disable the second stage rate of change of voltage element.				
dv/dt2 Oper Mode	Any Phase	Any Phase/Three Phase		
Setting that determines whether any phase or all three phases has to satisfy the rate of change of voltage criteria before a decision is made.				
dv/dt2 AvgCycles	10	5	50	1
Sets the number of power system cycles that are used to average the rate of change of voltage measurement.				
dv/dt2 Threshold	10 Volts/Sec	0.5 Volts/Sec	200 Volts/Sec	0.5 Volts/Sec
Rate of change of voltage threshold for the second stage.				
dv/dt2 TimeDelay	0.5 Sec	0 Sec	100 Sec	0.01 Sec
Operating time delay setting for the second stage rate of change of voltage protection element.				
dv/dt2 tRESET	0.03 Sec	0 Sec	100 Sec	0.01 Sec
Reset time delay setting for the second stage rate of change of voltage protection element.				

Table 16 - Voltage Protection

4.15 Frequency Protection

The relay includes four stages of underfrequency and two stages of overfrequency protection to facilitate load shedding and subsequent restoration. The underfrequency stages may be optionally blocked by a pole dead (CB Open) condition.

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
FREQ. PROTECTION - GROUP 1				
UNDERFREQUENCY				
F<1 Status	Enabled	Enabled or Disabled		N/A
Setting to enable or disable the first stage underfrequency element.				
F<1 Setting	49.5 Hz	45Hz	65Hz	0.01Hz
Setting that determines the pick-up threshold for the first stage underfrequency element.				
F<1 Time Delay	4s	0s	100s	0.01s
Setting that determines the minimum operating time-delay for the first stage underfrequency element.				
F<2 Status (same as stage 1)	Disabled	Enabled or Disabled		N/A
F<3 Status (same as stage 1)	Disabled	Enabled or Disabled		N/A
F<4 Status (same as stage1)	Disabled	Enabled or Disabled		N/A
F< Function Link	0000			Bit 0 = F<1 Poledead Blk. Bit 1 = F<2 Poledead Blk. Bit 2 = F<3 Poledead Blk. Bit 3 = F<4 Poledead Blk.
Settings that determines whether pole dead logic signals blocks the underfrequency elements.				
OVERFREQUENCY				
F>1 Status	Enabled	Enabled or Disabled		N/A
Setting to enable or disable the first stage overfrequency element.				
F>1 Setting	50.5 Hz	45Hz	65Hz	0.01Hz
Setting that determines the pick-up threshold for the first stage overfrequency element.				
F>1 Time Delay	2s	0s	100s	0.01s
Setting that determines the minimum operating time-delay for the first stage overfrequency element.				
F>2 Status (same as stage1 above)	Disabled	Enabled or Disabled		N/A

Table 17 - Frequency Protection

4.16 Circuit Breaker Fail and Undercurrent Function

This function consists of a two-stage Circuit Breaker (CB) fail function that can be initiated by:

- Current-based or Voltage-based protection elements
- External protection elements.

For current-based protection, the reset condition is based on undercurrent operation to determine that the CB has opened. For the non-current based protection, the reset criteria may be selected by means of a setting for determining a CB Failure condition.

It is common practice to use low set undercurrent elements in protection relays to indicate that circuit breaker poles have interrupted the fault or load current, as required.

<table>
<tr><th>Menu Text</th><th>Default Setting</th><th colspan="2">Setting Range</th><th>Step Size</th></tr>
<tr><th></th><th></th><th>Min.</th><th>Max.</th><th></th></tr>
<tr><td colspan="5">CB FAIL & I< - GROUP 1</td></tr>
<tr><td>BREAKER FAIL</td><td colspan="4">Sub-heading</td></tr>
<tr><td>CB Fail 1 Status</td><td>Enabled</td><td colspan="3">Enabled or Disabled</td></tr>
<tr><td colspan="5">Setting to enable or disable the first stage of the circuit breaker function.</td></tr>
<tr><td>CB Fail 1 Timer</td><td>0.2s</td><td>0s</td><td>50s</td><td>0.01s</td></tr>
<tr><td colspan="5">Setting for the circuit breaker fail timer stage 1 for which the initiating condition must be valid.</td></tr>
<tr><td>CB Fail 2 Status</td><td>Enabled</td><td colspan="3">Enabled or Disabled</td></tr>
<tr><td colspan="5">Setting to enable or disable the second stage of the circuit breaker function.</td></tr>
<tr><td>CB Fail 2 Timer</td><td>0.2s</td><td>0s</td><td>50s</td><td>0.01s</td></tr>
<tr><td colspan="5">Setting for the circuit breaker fail timer stage 2 for which the initiating condition must be valid.</td></tr>
<tr><td>Volt Prot. Reset</td><td>CB Open & I< || Ext Rst CBF</td><td colspan="3">I< Only || Ext Rst CBF, CB Open & I< || Ext Rst CBF,
Prot. Reset & I< || Ext Rst CBF</td></tr>
<tr><td colspan="5">Setting which determines the elements that will reset the circuit breaker fail time for voltage protection function initiated circuit breaker fail conditions.</td></tr>
<tr><td>Ext. Prot. Reset</td><td>CB Open & I< || Ext Rst CBF</td><td colspan="3">I< Only || Ext Rst CBF, CB Open & I< || Ext Rst CBF,
Prot. Reset & I< || Ext Rst CBF</td></tr>
<tr><td colspan="5">Setting which determines the elements that will reset the circuit breaker fail time for external protection function initiated circuit breaker fail conditions.</td></tr>
<tr><td>UNDERCURRENT</td><td colspan="4">Sub-heading</td></tr>
<tr><td>I< Current Set</td><td>0.1In</td><td>0.02In</td><td>3.2In</td><td>0.01In</td></tr>
<tr><td colspan="5">Setting that determines the circuit breaker fail timer reset current for overcurrent based protection circuit breaker fail initiation.</td></tr>
<tr><td>IN< Current Set</td><td>0.1In</td><td>0.02In</td><td>3.2In</td><td>0.01In</td></tr>
<tr><td colspan="5">Setting that determines the circuit breaker fail timer reset current for earth fault current based protection circuit breaker fail initiation.</td></tr>
<tr><td>ISEF< Current</td><td>0.02In</td><td>0.001In</td><td>0.8In</td><td>0.0005In</td></tr>
<tr><td colspan="5">Setting that determines the circuit breaker fail timer reset current for sensitive earth fault current based circuit breaker fail initiation.</td></tr>
<tr><td>BLOCKED O/C</td><td colspan="4">Sub-heading</td></tr>
<tr><td>Remove I> Start</td><td>Disabled</td><td colspan="3">Enabled or Disabled</td></tr>
<tr><td colspan="5">The setting is used to remove starts issued from the overcurrent elements respectively following a breaker fail time out. The start is removed when the cell is set to enabled.</td></tr>
<tr><td>Remove IN> Start</td><td>Disabled</td><td colspan="3">Enabled or Disabled</td></tr>
</table>

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
This setting is used to remove starts issued from the earth elements following a breaker fail time out. The start is removed when the cell is set to enabled.				

Table 18 - Circuit Breaker Fail and Undercurrent Function

4.17 Supervision (VTS and CTS)

The VTS feature within the relay operates on detection of Negative Phase Sequence (NPS) voltage without the presence of NPS current.

The CT Supervision (CTS) feature operates on detection of derived zero sequence current, in the absence of corresponding derived zero sequence voltage that would normally accompany it.

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
SUPERVISION - GROUP 1				
VT SUPERVISION	Sub-heading			
VTS Status	Blocking	Blocking, Indication		
This setting determines whether the following operations will occur upon detection of VTS. VTS set to provide alarm indication only. Optional blocking of voltage dependent protection elements. Optional conversion of directional overcurrent elements to non-directional protection (available when set to blocking mode only). These settings are found in the function links cell of the relevant protection element columns in the menu.				
VTS Reset Mode	Manual	Manual, Auto		
The VTS block will be latched after a user settable time delay ‘VTS Time Delay’. Once the signal has latched then two methods of resetting are available. The first is manually via the front panel interface (or remote communications) and secondly, when in ‘Auto’ mode, provided the VTS condition has been removed and the 3 phase voltages have been restored above the phase level detector settings for more than 240ms.				
VTS Time Delay	5s	1s	10s	0.1s
Setting that determines the operating time-delay of the element upon detection of a voltage supervision condition.				
VTS I> Inhibit	10In	0.08In	32In	0.01In
The setting is used to override a voltage supervision block in the event of a phase fault occurring on the system that could trigger the voltage supervision logic.				
VTS I2> Inhibit	0.05In	0.05In	0.5In	0.01In
The setting is used to override a voltage supervision block in the event of a fault occurring on the system with negative sequence current above this setting which could trigger the voltage supervision logic.				
CT SUPERVISION	Sub-heading			
CTS Status	Disabled	Enabled or Disabled		N/A
Setting to enable or disable the current transformer supervision element.				
CTS VN< Inhibit	5/20V For 110/440V respectively	0.5/2V For 110/440V respectively	22/88V For 110/440V respectively	0.5/2V For 110/440V respectively
This setting is used to inhibit the current transformer supervision element should the zero sequence voltage exceed this setting.				
CTS IN> Set	0.1In	0.08 x In	4 x In	0.01 x In
This setting determines the level of zero sequence current that must be present for a valid current transformer supervision condition.				
CTS Time Delay	5	0s	10s	1s

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Setting that determines the operating time-delay of the element upon detection of a current transformer supervision condition.				
VTS PickupThresh	30V	20V	120V	1V
Setting that determines the pickup threshold of the voltage supervision.				

Table 19 - Supervision (VTS and CTS)

4.18 Fault Locator

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
FAULT LOCATOR - GROUP 1				
Line Length (miles)	10	0.005	621	0.005
Setting for the line length. Distance to fault is available in metres, miles, impedance or percentage of line length.				
Line Impedance	6	0.1	250	0.01
Setting for the positive sequence line impedance.				
Line Angle	70	20	85	1
Setting for the positive sequence line impedance angle.				
KZN Residual	1	0	7	0.01
Setting for the residual compensating factor. The residual impedance compensation magnitude and angle are calculated using the following formula: $KZn = \frac{ZL0 - ZL1}{3\ ZL1}$				
KZN Res. Angle	0	–90	90	1
Setting for the residual compensating factor angle.				

Table 20 - Fault Locator

4.19 System Checks (Check Sync. Function)

The P14x has a two stage Check Synchronization function that can be set independently.

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
SYSTEM CHECKS - GROUP 1				
VOLTAGE MONITORING	Sub-heading			
Live Voltage	32V	1/22V For 110/440V respectively	132/528V For 110/440V respectively	0.5/2V For 110/440V respectively
Sets the minimum voltage threshold above which a line or bus is to be recognized as being ‘Live’.				
Dead Voltage	13V	1/22V For 110/440V respectively	132/528V For 110/440V respectively	0.5/2V
Sets the voltage threshold below which a line or bus to be recognized as being ‘Dead’.				
CHECK SYNC.	Sub-heading			
Stage 1	Enabled	Enabled or Disabled		

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Setting to enable or disable the first stage check sync. element.				
CS1 Phase Angle	20.00°	5°	90°	1°
Sets the maximum phase angle difference between the line and bus voltage for the first stage check sync. element phase angle criteria to be satisfied.				
CS1 Slip Control	Frequency	Frequency/Both/Timer/None		
Setting that determines whether slip control is by slip frequency only, frequency + timer or timer only criteria to satisfy the first stage check sync. conditions. If slip control by timer or frequency + timer is selected, the combination of phase angle and timer settings determines an effective maximum slip frequency, calculated as: $\frac{2 \times A}{T \times 360}$ Hz. for Check Sync. 1, or Where A = Phase angle setting (°) T = Slip timer setting (seconds) For example, with Check Sync. 1 Phase Angle setting 30° and Timer setting 3.3 sec, the “slipping” vector has to remain within ±30° of the reference vector for at least 3.3 seconds. Therefore a synchro check output will not be given if the slip is greater than 2 x 30° in 3.3 seconds. Using the formula: 2 x 30 ÷ (3.3 x 360) = 0.0505 Hz (50.5 mHz). If Slip Control by Frequency + Timer is selected, for an output to be given, the slip frequency must be less than BOTH the set Slip Freq. value and the value determined by the Phase Angle and Timer settings. If Slip Control by Frequency, for an output to be given, the slip frequency must be less than the set Slip Freq. value setting only.				
CS1 Slip Freq.	50mHz	10mHz	1Hz	10mHz
Sets the maximum frequency difference between the line and bus voltage for the first stage check sync. element slip frequency to be satisfied.				
CS1 Slip Timer	1s	0s	99s	0.01s
Minimum operating time-delay setting for the first stage check sync. element.				
Stage 2	Enabled	Enabled or Disabled		
Setting to enable or disable the second stage check sync. element.				
CS2 Phase Angle	20.00°	5°	90°	1°
Sets the maximum phase angle difference between the line and bus voltage for the second stage check sync. element phase angle criteria to be satisfied.				
CS2 Slip Control	Frequency	Frequency/Freq. + Time/Freq. + Comp./Timer/None		
Setting that determines whether slip control is by slip frequency only, frequency + timer or timer only criteria to satisfy the CS1 conditions. If Slip Control by Timer or Frequency + Timer is selected, the combination of Phase Angle and Timer settings determines an effective maximum slip frequency, calculated as: $\frac{A}{T \times 360}$ Hz. for Check Sync. 2, or where A = Phase angle setting (°) T = Slip timer setting (seconds) For Check Sync. 2, with Phase Angle setting 10° and Timer setting 0.1 sec, the slipping vector has to remain within 10° of the reference vector, with the angle decreasing, for 0.1 sec. When the angle passes through zero and starts to increase, the synchro check output is blocked. Therefore an output will not be given if slip is greater than 10° in 0.1 second. Using the formula: 10 ÷ (0.1 x 360) = 0.278 Hz (278 mHz). If Slip Control by Frequency + Timer is selected, for an output to be given, the slip frequency must be less than BOTH the set Slip Freq. value and the value determined by the Phase Angle and Timer settings. If Slip Control by Frequency, for an output to be given, the slip frequency must be less than the set Slip Freq. value setting only. The “Freq. + Comp.” (Frequency + CB Time Compensation) setting modifies the Check Sync. 2 function to take account of the circuit breaker closing time. By measuring the slip frequency, and using the “CB Close Time” setting as a reference, the relay will issue the close command so that the circuit breaker closes at the instant the slip angle is equal to the “CS2 phase angle” setting. Unlike Check Sync. 1, Check Sync. 2 only permits closure for decreasing angles of slip, therefore the circuit breaker should always close within the limits defined by Check Sync. 2.				

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
CS2 Slip Freq.	50mHz	10mHz	1Hz	10mHz
Slip frequency setting for the second stage check sync. element.				
CS2 Slip Timer	1s	0s	99s	0.01s
Setting for the second stage Check Sync. slip timer.				
CS Undervoltage	54/216V For 110/440V respectively	10/40V For 110/440V respectively	132/528V For 110/440V respectively	0.5/2V For 110/440V respectively
Sets an undervoltage threshold above which the line and bus voltage must be to satisfy the Check Sync. condition if selected in the 'CS Voltage Block' cell.				
CS Overvoltage	130/520V For 110/440V respectively	40/240V For 110/440V respectively	160/740V For 110/440V respectively	0.5/2V For 110/440V respectively
Sets an overvoltage threshold above below which the line and bus voltage must be to satisfy the Check Sync. condition if selected in the 'CS Voltage Block' cell.				
CS Diff. Voltage	6.5/26V For 110/440V respectively	1/4V For 110/440V respectively	132/528V For 110/440V respectively	0.5/2V For 110/440V respectively
Sets the voltage magnitude threshold between the line and bus volts below that the line and bus voltage difference must be to satisfy the Check Sync. condition if selected in the 'CS Voltage Block' cell.				
CS Voltage Block	V<	V</V>/Vida.>/V< and V>/V< and Vida.>/V> and Vida.>/V< V> and Vida.>/None		
Selects whether an undervoltage, overvoltage and voltage difference thresholds for the line and bus voltages must be satisfied in order for the Check Sync. conditions to be satisfied.				
SYSTEM SPLIT	Sub-heading			
SS Status	Enabled	Enabled or Disabled		
Setting to enable or disable the system split function.				
SS Phase Angle	120°	90°	175°	1°
Sets the maximum phase angle difference between the line and bus voltage, which must be exceeded, for the System Split condition to be satisfied.				
SS Under V Block	Enabled	Enabled or Disabled		
Activates and undervoltage block criteria				
SS Undervoltage	54/216V For 110/440V respectively	10/40V For 110/440V respectively	132/528V For 110/440V respectively	0.5/2V For 110/440V respectively
Sets an undervoltage threshold above which the line and bus voltage must be to satisfy the System Split condition.				
SS Timer	1s	0s	99s	0.01s
The System Split output remains set for as long as the System Split criteria are true, or for a minimum period equal to the System Split Timer setting, whichever is longer.				
CB Close Time	50ms	0s	0.5s	1ms
Setting for the circuit breaker closing time to be used in the second stage Check Sync. criteria to compensate for the breaker closing time if selected.				

Table 21 - System Checks

4.20 Auto-Reclose (AR) Function (P142/P143/P145 Only)

The relay will initiate Auto-Reclose (AR) for fault clearances by the phase overcurrent, earth fault and SEF protections. It will block auto-reclose for fault clearances by other protections (voltage, frequency, thermal, etc.).

The following shows the relay settings for the auto-reclose function, which must be set in conjunction with the Circuit Breaker Control settings. The available setting ranges and factory defaults are shown below:

<table>
<tr><th rowspan="2">Menu Text</th><th rowspan="2">Default Setting</th><th colspan="2">Setting Range</th><th rowspan="2">Step Size</th></tr>
<tr><th>Min.</th><th>Max.</th></tr>
<tr><td colspan="5">AUTO-RECLOSE - GROUP 1</td></tr>
<tr><td>AR Mode Select</td><td>Command Mode</td><td colspan="3">Command Mode/Opto Set Mode/User Set Mode/Pulse Set Mode</td></tr>
<tr><td colspan="5">If the Live Line logic input is high, then auto-reclose is taken out of service and certain live-line specific settings applied as appropriate. Provided Live Line is low:
COMMAND MODE: Auto/Non-auto is selected by command cell “Auto-reclose Mode”.
OPTO SET MODE: Selects the Auto-reclose in service or out of service via an opto input linked to the appropriate Auto Mode input signal.
USER SET MODE: Selects the mode of the AR via the telecontrol input signal. If Telecontrol input is high, the CB Control Auto-reclose Mode command cell is used to select Auto or Non-auto operating mode. If Telecontrol input is low, behaves as OPTO SET setting (follows the status of the Auto Input signal).
PULSE SET MODE: Selects the mode of the AR via the telecontrol input signals. If Telecontrol input is high, the operating mode is toggled between Auto and Non-auto Mode on the falling edge of Auto Mode input pulses. The pulses are produced by SCADA system.
If the Telecontrol input is low, behaves as OPTO SET setting setting (follows the status of the Auto Input signal).
Note Auto Mode = AR in service and Non-auto = AR is out of service and instantaneous protection is blocked.</td></tr>
<tr><td>Number of Shots</td><td>1</td><td>1</td><td>4</td><td>1</td></tr>
<tr><td colspan="5">Sets the number of auto-reclose shots/cycles for overcurrent and earth fault trips.</td></tr>
<tr><td>Number of SEF Shots</td><td>0</td><td>0</td><td>4</td><td>1</td></tr>
<tr><td colspan="5">Sets the number of auto-reclose shots/cycles for sensitive earth fault trips.</td></tr>
<tr><td>Sequence Co-ord.</td><td>Disabled</td><td colspan="2">Enabled/Disabled</td><td>N/A</td></tr>
<tr><td colspan="5">Enables the sequence co-ordination function to ensure the correct protection grading between an upstream and downstream re-closing device. The main protection start or sensitive earth fault protection start signals indicate to the relay when fault current is present, advance the sequence count by one and start the dead time whether the breaker is open or closed. When the dead time is complete and the protection start inputs are off the reclaim timer will be initiated.</td></tr>
<tr><td>CS AR Immediate</td><td>Disabled</td><td colspan="2">Enabled/Disabled</td><td>N/A</td></tr>
<tr><td colspan="5">Setting “CS AR Immediate” Enabled allows immediate re-closure of the circuit breaker provided both sides of the circuit breaker are live and in synchronism at any time after the dead time has started. This allows for quicker load restoration, as it is not necessary to wait for the full dead time.
If “CS AR Immediate” is disabled, or Line and Bus volts are not both live, the dead timer will continue to run, assuming the “DDB#457: Dead Time Enabled” (mapped in Programmable Scheme Logic) is asserted high. The “Dead Time Enabled” function could be mapped to an opto input to indicate that the circuit breaker is healthy i.e. spring charged etc. Mapping the “Dead Time Enabled” function in PSL increases the flexibility by allowing it, if necessary, to be triggered by other conditions such as “Live Line/Dead Bus” for example. If “Dead Time Enabled” is not mapped in PSL, it defaults to high, so the dead time can run.</td></tr>
<tr><td>Dead Time 1</td><td>10s</td><td>0.01s</td><td>300s</td><td>0.01s</td></tr>
<tr><td colspan="5">Sets the dead time for the first auto-reclose cycle.</td></tr>
<tr><td>Dead Time 2</td><td>60s</td><td>0.01s</td><td>300s</td><td>0.01s</td></tr>
<tr><td colspan="5">Sets the dead time for the second auto-reclose cycle.</td></tr>
<tr><td>Dead Time 3</td><td>180s</td><td>0.01s</td><td>9999s</td><td>0.01s</td></tr>
</table>

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Sets the dead time for the third auto-reclose cycle.				
Dead Time 4	180s	0.01s	9999s	0.01s
Sets the dead time for the fourth auto-reclose cycle.				
CB Healthy Time	5s	0.01s	9999s	0.01s
If on completion of the dead time, the “CB Healthy" input is low, and remains low for a period given by the "CB Healthy Time" timer, lockout will result and the circuit breaker will remain open.				
Start Dead t On	Protection Resets	Protection Resets/CB Trips		N/A
Setting that determines whether the dead time is started when the circuit breaker trips or when the protection trip resets.				
tReclaim Extend	No Operation	No Operation/On Prot Start		
The setting allows the user to control whether the reclaim timer is suspended by the protection start contacts or not (i.e. whether the relay is permitted to reclaim if a fault condition is present and will be cleared in a long time-scale). When a setting of “No Operation” is used the Reclaim Timer will operate from the instant that the circuit breaker is closed and will continue until the timer expires. For certain applications it is advantageous to set “tReclaim Extend” to “On Prot. Start”. This facility allows the operation of the reclaim timer to be suspended after circuit breaker re-closure by a signal from the main protection start or sensitive earth fault protection start signals. The main protection start signal is initiated from the start of any protection which has been selected to "Initiate Main AR" (initiate auto-reclose) in the "AR Initiation" settings.				
Reclaim Time 1	180s	1s	600s	0.01s
Sets the auto-reclose reclaim time for the first auto-reclose cycle.				
Reclaim Time 2	180s	1s	600s	0.01s
Sets the auto-reclose reclaim time for the second auto-reclose cycle.				
Reclaim Time 3	180s	1s	600s	0.01s
Sets the auto-reclose reclaim time for the third auto-reclose cycle.				
Reclaim Time 4	180s	1s	600s	0.01s
Sets the auto-reclose reclaim time for the fourth auto-reclose cycle.				
AR Inhibit Time	5s	0.01s	600s	0.01s
With this setting, auto-reclose initiation is inhibited for a period equal to setting “A/R Inhibit Time” following a manual circuit breaker closure.				
AR Lockout	No Block	No Block/Block Inst. Prot.		N/A
Instantaneous protection can be blocked when the relay is locked out, using this setting.				
EFF Maint. Lock	No Block	No Block/Block Inst. Prot.		N/A
If this is set to "Block Inst. Prot." the instantaneous protection will be blocked for the last circuit breaker trip before lockout occurs. The instantaneous protection can be blocked to ensure that the last circuit breaker trip before lockout will be due to discriminative protection operation when the circuit breaker maintenance lockout counter or excessive fault frequency lockout has reached its penultimate value.				
AR Deselected	No Block	No Block/Block Inst. Prot.		N/A
This setting allows the instantaneous protection to be blocked when auto-reclose is in non-auto mode of operation.				
Manual Close	No Block	No Block/Block Inst. Prot.		N/A
This setting allows the instantaneous protection to be blocked when the circuit breaker is closed manually whilst there is no auto-reclose sequence in progress or auto-reclose is inhibited.				
Trip 1 Main	No Block	No Block/Block Inst. Prot.		N/A
These allow the instantaneous elements of phase, earth fault protection to be selectively blocked for a circuit breaker trip sequence. For example, if "Trip 1 Main" is set to "No Block" and "Trip 2 Main" is set to "Block Inst. Prot.", the instantaneous elements of the phase and earth fault protection will be available for the first trip but blocked afterwards for the second trip during the auto-reclose cycle.				
Trip 2 Main (as above)	Block Inst. Prot.	No Block/Block Inst. Prot.		N/A
Trip 3 Main (as above)	Block Inst. Prot.	No Block/Block Inst. Prot.		N/A
Trip 4 Main (as above)	Block Inst. Prot.	No Block/Block Inst. Prot.		N/A
Trip 5 Main (as above)	Block Inst. Prot.	No Block/Block Inst. Prot.		N/A

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Trip 1 SEF (as above)	Block Inst. Prot.	No Block/Block Inst. Prot.		N/A
These allow the instantaneous elements of sensitive earth fault protection to be selectively blocked for a circuit breaker trip sequence. For example, if "Trip 1 SEF" is set to "No Block" and "Trip 2 SEF" is set to "Block Inst. Prot.", the instantaneous elements of the sensitive protection will be available for the first trip but blocked afterwards for the second trip during the auto-reclose cycle.				
Trip 2 SEF (as above)	Block Inst. Prot.	No Block/Block Inst. Prot.		N/A
Trip 3 SEF (as above)	Block Inst. Prot.	No Block/Block Inst. Prot.		N/A
Trip 4 SEF (as above)	Block Inst. Prot.	No Block/Block Inst. Prot.		N/A
Trip 5 SEF (as above)	Block Inst. Prot.	No Block/Block Inst. Prot.		N/A
Man Close on Flt	Lockout	No Lockout/Lockout		N/A
An auto-reclose lockout is caused by a protection operation after manual closing during the "AR Inhibit Time" when the "Manual Close on Flt" setting is set to “Lockout”.				
Trip AR Inactive	No Lockout	No Lockout/Lockout		N/A
An auto-reclose lockout is caused by a protection operation when the relay is in the Live Line or Non-auto modes when "Trip AR Inactive" is set to "Lockout".				
Reset Lockout by	User interface	User Interface/ Select Non-auto		N/A
The setting is used to enable/disable the resetting of lockout when the relay is in the Non-auto operating mode.				
AR on Man Close	Inhibited	Enabled/Inhibited		N/A
If this is set to “Enabled”, auto-reclosing can be initiated immediately on circuit breaker closure, and settings “A/R Inhibit Time”, “Man Close on Flt” and “Manual Close” are irrelevant.				
Sys. Check Time	5	0.01	9999	0.01
AR INITIATION	Sub-heading			
AR Skip Shot 1	Disabled	Enabled or Disabled		N/A
When enabled this setting will allow the auto-reclose sequence counter to be incremented by one via a DDB input signal. This will therefore decrease the available re-close shots.				
I>1 I>2	Initiate Main AR	No Action/Initiate Main AR		N/A
Setting that determines if the first and second stage overcurrent initiates auto-reclose.				
I>3 I>4	Initiate Main AR	No Action/Initiate Main AR/ Block AR		N/A
Setting that determines if the third and fourth stage overcurrent initiates auto-reclose.				
IN1>1 IN1>2	Initiate Main AR	No Action/Initiate Main AR		N/A
Setting that determines if the first and second stage Earth Fault 1 function initiates auto-reclose.				
IN1>3 IN1>4	No Action	No Action/Initiate Main AR/ Block AR		N/A
Setting that determines if the third and fourth stage Earth Fault 1 function initiates auto-reclose.				
IN2>1 IN2>2	No Action	No Action/Initiate Main AR		N/A
Setting that determines if the first and second stage Earth Fault 2 function initiates auto-reclose.				
IN2>3 IN2>4	No Action	No Action/Initiate Main AR/ Block AR		N/A
Setting that determines if the third and fourth stage Earth Fault 2 function initiates auto-reclose.				
ISEF>1 ISEF>2	No Action	No Action/Initiate Main AR/ Initiate SEF AR/Block AR		N/A
Setting that determines if the first and second stage sensitive earth fault initiates auto-reclose.				
ISEF>3 ISEF>4	No Action	No Action/Initiate Main AR/ Initiate SEF AR/Block AR		N/A
Setting that determines if the third and fourth stage sensitive earth fault initiates auto-reclose.				
YN> GN> BN>	No Action	No Action/Initiate Main AR		N/A
Setting that determines if the admittance protection initiates auto-reclose.				
Ext. Prot.	No Action	No Action/Initiate Main AR		N/A

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Setting that determines if external protection inputs initiates auto-reclose. This must be mapped in programmable scheme logic.				
SYSTEM CHECKS				
AR with Chk. Sync.	Disabled	Enabled or Disabled		N/A
Enables auto-reclose with check synchronization. Only allows auto-reclose when the system satisfies the “Check Sync. Stage 1” settings.				
AR with Sys. Sync.	Disabled	Enabled or Disabled		N/A
Enables auto-reclose with check synchronization. Only allows auto-reclose when the system satisfies the “Check Sync. Stage 2” settings				
Live/Dead Ccts.	Disabled	Enabled or Disabled		N/A
When enabled, this setting will give an “AR Check Ok” signal when the “DDB#461 Circuits OK” is asserted high. This logic input DDB would normally be mapped in programmable scheme logic to appropriate combinations of Line Live, Line Dead, Bus Live and Bus Dead DDB signals. Auto-reclose can be initiated once DDB#461 is asserted high				
No System Checks	Disabled	Enabled or Disabled		N/A
When enabled this setting completely disables system checks thus allowing auto-reclose initiation.				
Sys. Chk. on Shot 1	Enabled	Enabled or Disabled		N/A
Can be used to disable system checks on first auto-reclose shot.				
I>5	Initiate Main AR	No Action/Initiate Main AR		N/A
Setting that determines if the fifth stage overcurrent initiates auto-reclose.				
I>6	Initiate Main AR	No Action/Initiate Main AR/ Block AR		N/A
Setting that determines if the sixth stage overcurrent initiates auto-reclose.				

Table 22 - Auto-Reclose Function (P142/P143/P145 Only)

4.21 Advanced Frequency Protection

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
ADV FREQUENCY PROTECTION - GROUP 1				
Freq Avg. Cycles	5	0	48	1
Sets the number of power system cycles that are used to average the frequency measurement.				
df/dt Avg. Cycles	5	0	48	1
Sets the number of power system cycles that are used to average the rate of change of frequency measurement.				
V<B Status	Disabled	Disabled/Enabled		
To enable (activate) or disable (turn off) the under voltage blocking of the frequency protection elements.				
V<B Voltage Set	25 V	10 V	120 V	1 V
Pick up setting for the under voltage blocking element. When operated, this will prevent any frequency based protection from operating.				
V<B Measur Mode	Phase-Phase	Phase-Phase/Phase-Neutral		
Sets the measured input voltage that will be used for the under voltage blocking.				
V<B Operate Mode	Three Phase	Three Phase/Any Phase		
Setting that determines whether any phase or all three phases has to satisfy the under voltage criteria before a decision is made.				
Stage 1	Disabled	Disabled/Enabled		
Setting to disable or enable first stage frequency protection.				

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Stg 1 f+t Status	Disabled	Disabled/Under/Over		
Setting to disable or to set as Under or Over frequency of the first stage frequency protection.				
Stg 1 f+t Freq	49 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the first stage frequency protection element.				
Stg 1 f+t Time	2 s	0 s	100 s	0.01 s
Setting for the operating time delay for the first stage frequency protection element.				
df/dt+t 1 Status	Disabled	Disabled/Negative/Positive/Both		
Setting to disable or set the ramp direction of the first stage df/dt protection.				
df/dt+t 1 Set	2 Hz/sec	0.01 Hz/sec	10 Hz/sec	0.01 Hz/sec
Rate of change of frequency threshold for the first stage.				
df/dt+t 1 Time	0.5 s	0 s	100 s	0.01 s
Setting for the operating time delay for the first stage rate of change of frequency protection element.				
Stg 1 f+t Status	Disabled	Disabled/Under/Over		
Setting to disable or to set as Under or Over frequency of the first stage frequency protection.				
f+df/dt 1 Status	Disabled	Disabled/Negative/Positive/Both		
Setting to disable or set the ramp direction of the first stage frequency supervised rate of change of frequency protection.				
f+df/dt 1 freq	49 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the first stage frequency supervised rate of change of frequency protection element.				
f+df/dt 1 df/dt	1 Hz/sec	0.01 Hz/sec	10 Hz/sec	0.01 Hz/sec
Frequency supervised rate of change of frequency threshold for the first stage.				
f+Df/Dt 1 Status	Disabled	Disabled/Under/Over		
Setting to disable or to set as Under or Over average rate of change of frequency of the first stage.				
f+Df/Dt 1 freq	49 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the first stage average rate of change of frequency protection element.				
f+Df/Dt 1 Dfreq	1 Hz	0.01 Hz	10 Hz	0.01 Hz
Change in frequency that must be measured in the set time for the first stage average rate of change of frequency protection element.				
f+Df/Dt 1 Dtime	0.5 s	0.02 s	100 s	0.01 s
The time period over which a change in frequency that in excess of the setting f+Df/Dt 1 Dfreq that must be measured for the first stage average rate of change of frequency protection element.				
Restore 1 Status	Disabled	Disabled/Enabled		
Setting to disable or Enable the first stage of load restoration.				
Restore 1 freq	49.5 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the first stage of load restoration, above which the associated load restoration time can start.				
Restore 1 time	240 s	0 s	7200 s	0.25 s
Time period for which the measured frequency must be higher than first stage restoration frequency setting to permit load restoration.				
Holding Timer 1	5 s	1 s	7200 s	1 s
Sets the holding time of the first stage load restoration function.				
Stg 1 UV Block	Disabled	Disabled/Enabled		
To enable (activate) or disable (turn off) the under voltage blocking of the stage 1 load restoration element.				
Stage 2	Disabled	Disabled/Enabled		
Setting to disable or enable second stage frequency protection.				
Stg 2 f+t Status	Disabled	Disabled/Under/Over		

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Setting to disable or to set as Under or Over frequency of the second stage frequency protection.				
Stg 2 f+t Freq	49 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the second stage frequency protection element.				
Stg 2 f+t Time	2 s	0 s	100 s	0.01 s
Setting for the operating time delay for the second stage frequency protection element.				
df/dt+t 2 Status	Disabled	Disabled/Negative/Positive/Both		
Setting to disable or set the ramp direction of the second stage df/dt protection.				
df/dt+t 2 Set	2 Hz/sec	0.01 Hz/sec	10 Hz/sec	0.01 Hz/sec
Rate of change of frequency threshold for the second stage.				
df/dt+t 2 Time	0.5 s	0 s	100 s	0.01 s
Setting for the operating time delay for the second stage rate of change of frequency protection element.				
f+df/dt 2 Status	Disabled	Disabled/Negative/Positive/Both		
Setting to disable or set the ramp direction of the second stage frequency supervised rate of change of frequency protection.				
f+df/dt 2 freq	49 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the second stage frequency supervised rate of change of frequency protection element.				
f+df/dt 2 df/dt	1 Hz/sec	0.01 Hz/sec	10 Hz/sec	0.01 Hz/sec
Frequency supervised rate of change of frequency threshold for the second stage.				
f+Df/Dt 2 Status	Disabled	Disabled/Under/Over		
Setting to disable or to set as Under or Over average rate of change of frequency of the second stage.				
f+Df/Dt 2 freq	49 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the second stage average rate of change of frequency protection element.				
f+Df/Dt 2 Dfreq	1 Hz	0.01 Hz	10 Hz	0.01 Hz
Change in frequency that must be measured in the set time for the second stage average rate of change of frequency protection element.				
f+Df/Dt 2 Dtime	0.5 s	0.02 s	100 s	0.01 s
The time period over which a change in frequency that in excess of the setting f+Df/Dt 2 Dfreq that must be measured for the second stage average rate of change of frequency protection element.				
Restore 2 Status	Disabled	Disabled/Enabled		
Setting to disable or Enable the second stage of load restoration.				
Restore 2 freq	49.5 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the second stage of load restoration, above which the associated load restoration time can start.				
Restore 2 time	240 s	0 s	7200 s	0.25 s
Time period for which the measured frequency must be higher than second stage restoration frequency setting to permit load restoration.				
Holding Timer 2	5 s	1 s	7200 s	1 s
Sets the holding time of the second stage load restoration function				
Stg 2 UV Block	Disabled	Disabled/Enabled		
To enable (activate) or disable (turn off) the under voltage blocking of the stage 2 load restoration element.				
Stage 3	Disabled	Disabled/Enabled		
Setting to disable or enable third stage frequency protection.				
Stg 3 f+t Status	Disabled	Disabled/Under/Over		
Setting to disable or to set as Under or Over frequency of the third stage frequency protection.				
Stg 3 f+t Freq	49 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the third stage frequency protection element.				

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Stg 3 f+t Time	2 s	0 s	100 s	0.01 s
Setting for the operating time delay for the third stage frequency protection element.				
df/dt+t 3 Status	Disabled	Disabled/Negative/Positive/Both		
Setting to disable or set the ramp direction of the third stage df/dt protection.				
df/dt+t 3 Set	2 Hz/sec	0.01 Hz/sec	10 Hz/sec	0.01 Hz/sec
Rate of change of frequency threshold for the third stage.				
df/dt+t 3 Time	0.5 s	0 s	100 s	0.01 s
Setting for the operating time delay for the third stage rate of change of frequency protection element.				
f+df/dt 3 Status	Disabled	Disabled/Negative/Positive/Both		
Setting to disable or set the ramp direction of the third stage frequency supervised rate of change of frequency protection.				
f+df/dt 3 freq	49 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the third stage frequency supervised rate of change of frequency protection element.				
f+df/dt 3 df/dt	1 Hz/sec	0.01 Hz/sec	10 Hz/sec	0.01 Hz/sec
Frequency supervised rate of change of frequency threshold for the third stage.				
f+Df/Dt 3 Status	Disabled	Disabled/Under/Over		
Setting to disable or to set as Under or Over average rate of change of frequency of the third stage.				
f+Df/Dt 3 freq	49 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the third stage average rate of change of frequency protection element.				
f+Df/Dt 3 Dfreq	1 Hz	0.01 Hz	10 Hz	0.01 Hz
Change in frequency that must be measured in the set time for the third stage average rate of change of frequency protection element.				
f+Df/Dt 3 Dtime	0.5 s	0.02 s	100 s	0.01 s
The time period over which a change in frequency that in excess of the setting f+Df/Dt 3 Dfreq that must be measured for the third stage average rate of change of frequency protection element.				
Restore 3 Status	Disabled	Disabled/Enabled		
Setting to disable or Enable the second stage of load restoration.				
Restore 3 freq	49.5 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the third stage of load restoration, above which the associated load restoration time can start.				
Restore 3 time	240 s	0 s	7200 s	0.25 s
Time period for which the measured frequency must be higher than third stage restoration frequency setting to permit load restoration.				
Holding Timer 3	5 s	1 s	7200 s	1 s
Sets the holding time of the third stage load restoration function.				
Stg 3 UV Block	Disabled	Disabled/Enabled		
To enable (activate) or disable (turn off) the under voltage blocking of the stage 3 load restoration element.				
Stage 4	Disabled	Disabled/Enabled		
Setting to disable or enable fourth stage frequency protection.				
Stg 4 f+t Status	Disabled	Disabled/Under/Over		
Setting to disable or to set as Under or Over frequency of the fourth stage frequency protection.				
Stg 4 f+t Freq	49 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the fourth stage frequency protection element.				
Stg 4 f+t Time	2 s	0 s	100 s	0.01 s
Setting for the operating time delay for the fourth stage frequency protection element.				
df/dt+t 4 Status	Disabled	Disabled/Negative/Positive/Both		

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Setting to disable or set the ramp direction of the fourth stage df/dt protection.				
df/dt+t 4 Set	2 Hz/sec	0.01 Hz/sec	10 Hz/sec	0.01 Hz/sec
Rate of change of frequency threshold for the fourth stage.				
df/dt+t 4 Time	0.5 s	0 s	100 s	0.01 s
Setting for the operating time delay for the fourth stage rate of change of frequency protection element.				
f+df/dt 4 Status	Disabled	Disabled/Negative/Positive/Both		
Setting to disable or set the ramp direction of the fourth stage frequency supervised rate of change of frequency protection.				
f+df/dt 4 freq	49 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the fourth stage frequency supervised rate of change of frequency protection element.				
f+df/dt 4 df/dt	1 Hz/sec	0.01 Hz/sec	10 Hz/sec	0.01 Hz/sec
Frequency supervised rate of change of frequency threshold for the fourth stage.				
f+Df/Dt 4 Status	Disabled	Disabled / Under / Over		
Setting to disable or to set as Under or Over average rate of change of frequency of the fourth stage.				
f+Df/Dt 4 freq	49 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the fourth stage average rate of change of frequency protection element.				
f+Df/Dt 4 Dfreq	1 Hz	0.01 Hz	10 Hz	0.01 Hz
Change in frequency that must be measured in the set time for the fourth stage average rate of change of frequency protection element.				
f+Df/Dt 4 Dtime	0.5 s	0.02 s	100 s	0.01 s
The time period over which a change in frequency that in excess of the setting f+Df/Dt 4 Dfreq that must be measured for the fourth stage average rate of change of frequency protection element.				
Restore 4 Status	Disabled	Disabled/Enabled		
Setting to disable or Enable the second stage of load restoration.				
Restore 4 freq	49.5 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the fourth stage of load restoration, above which the associated load restoration time can start.				
Restore 4 time	240 s	0 s	7200 s	0.25 s
Time period for which the measured frequency must be higher than fourth stage restoration frequency setting to permit load restoration.				
Holding Timer 4	5 s	1 s	7200 s	1 s
Sets the holding time of the fourth stage load restoration function.				
Stg 4 UV Block	Disabled	Disabled/Enabled		
To enable (activate) or disable (turn off) the under voltage blocking of the stage 4 load restoration element.				
Stage 5	Disabled	Disabled/Enabled		
Setting to disable or enable fifth stage frequency protection.				
Stg 5 f+t Status	Disabled	Disabled/Under/Over		
Setting to disable or to set as Under or Over frequency of the fifth stage frequency protection.				
Stg 5 f+t Freq	49 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the fifth stage frequency protection element.				
Stg 5 f+t Time	2 s	0 s	100 s	0.01 s
Setting for the operating time delay for the fifth stage frequency protection element.				
df/dt+t 5 Status	Disabled	Disabled/Negative/Positive/Both		
Setting to disable or set the ramp direction of the fifth stage df/dt protection.				
df/dt+t 5 Set	2 Hz/sec	0.01 Hz/sec	10 Hz/sec	0.01 Hz/sec
Rate of change of frequency threshold for the fifth stage.				

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
df/dt+t 5 Time	0.5 s	0 s	100 s	0.01 s
Setting for the operating time delay for the fifth stage rate of change of frequency protection element.				
f+df/dt 5 Status	Disabled	Disabled/Negative/Positive/Both		
Setting to disable or set the ramp direction of the fifth stage frequency supervised rate of change of frequency protection.				
f+df/dt 5 freq	49 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the fifth stage frequency supervised rate of change of frequency protection element.				
f+df/dt 5 df/dt	1 Hz/sec	0.01 Hz/sec	10 Hz/sec	0.01 Hz/sec
Frequency supervised rate of change of frequency threshold for the fifth stage.				
f+Df/Dt 5 Status	Disabled	Disabled/Under/Over		
Setting to disable or to set as Under or Over average rate of change of frequency of the fifth stage.				
f+Df/Dt 5 freq	49 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the fifth stage average rate of change of frequency protection element.				
f+Df/Dt 5 Dfreq	1 Hz	0.01 Hz	10 Hz	0.01 Hz
Change in frequency that must be measured in the set time for the fifth stage average rate of change of frequency protection element.				
f+Df/Dt 5 Dtime	0.5 s	0.02 s	100 s	0.01 s
The time period over which a change in frequency that in excess of the setting f+Df/Dt 5 Dfreq that must be measured for the fifth stage average rate of change of frequency protection element.				
Restore 5 Status	Disabled	Disabled/Enabled		
Setting to disable or Enable the fifth stage of load restoration.				
Restore 5 freq	49.5 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the fifth stage of load restoration, above which the associated load restoration time can start.				
Restore 5 time	240 s	0 s	7200 s	0.25 s
Time period for which the measured frequency must be higher than fifth stage restoration frequency setting to permit load restoration.				
Holding Timer 5	5 s	1 s	7200 s	1 s
Sets the holding time of the fifth stage load restoration function.				
Stg 5 UV Block	Disabled	Disabled/Enabled		
To enable (activate) or disable (turn off) the under voltage blocking of the stage 5 load restoration element.				
Stage 6	Disabled	Disabled/Enabled		
Setting to disable or enable sixth stage frequency protection.				
Stg 6 f+t Status	Disabled	Disabled/Under/Over		
Setting to disable or to set as Under or Over frequency of the sixth stage frequency protection.				
Stg 6 f+t Freq	49 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the sixth stage frequency protection element.				
Stg 6 f+t Time	2 s	0 s	100 s	0.01 s
Setting for the operating time delay for the sixth stage frequency protection element.				
df/dt+t 6 Status	Disabled	Disabled/Negative/Positive/Both		
Setting to disable or set the ramp direction of the sixth stage df/dt protection.				
df/dt+t 6 Set	2 Hz/sec	0.01 Hz/sec	10 Hz/sec	0.01 Hz/sec
Rate of change of frequency threshold for the sixth stage.				
df/dt+t 6 Time	0.5 s	0 s	100 s	0.01 s
Setting for the operating time delay for the sixth stage rate of change of frequency protection element.				
f+df/dt 6 Status	Disabled	Disabled/Negative/Positive/Both		

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Setting to disable or set the ramp direction of the sixth stage frequency supervised rate of change of frequency protection.				
f+df/dt 6 freq	49 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the sixth stage frequency supervised rate of change of frequency protection element.				
f+df/dt 6 df/dt	1 Hz/sec	0.01 Hz/sec	10 Hz/sec	0.01 Hz/sec
Frequency supervised rate of change of frequency threshold for the sixth stage.				
f+Df/Dt 6 Status	Disabled	Disabled/Under/Over		
Setting to disable or to set as Under or Over average rate of change of frequency of the sixth stage.				
f+Df/Dt 6 freq	49 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the sixth stage average rate of change of frequency protection element.				
f+Df/Dt 6 Dfreq	1 Hz	0.01 Hz	10 Hz	0.01 Hz
Change in frequency that must be measured in the set time for the sixth stage average rate of change of frequency protection element.				
f+Df/Dt 6 Dtime	0.5 s	0.02 s	100 s	0.01 s
The time period over which a change in frequency that in excess of the setting f+Df/Dt 6 Dfreq that must be measured for the sixth stage average rate of change of frequency protection element.				
Restore 6 Status	Disabled	Disabled/Enabled		
Setting to disable or Enable the sixth stage of load restoration.				
Restore 6 freq	49.5 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the sixth stage of load restoration, above which the associated load restoration time can start.				
Restore 6 time	240 s	0 s	7200 s	0.25 s
Time period for which the measured frequency must be higher than sixth stage restoration frequency setting to permit load restoration.				
Holding Timer 6	5 s	1 s	7200 s	1 s
Sets the holding time of the sixth stage load restoration function.				
Stg 6 UV Block	Disabled	Disabled/Enabled		
To enable (activate) or disable (turn off) the under voltage blocking of the stage 6 load restoration element.				
Stage 7	Disabled	Disabled/Enabled		
Setting to disable or enable seventh stage frequency protection.				
Stg 7 f+t Status	Disabled	Disabled/Under/Over		
Setting to disable or to set as Under or Over frequency of the seventh stage frequency protection.				
Stg 7 f+t Freq	49 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the seventh stage frequency protection element.				
Stg 7 f+t Time	2 s	0 s	100 s	0.01 s
Setting for the operating time delay for the seventh stage frequency protection element.				
df/dt+t 7 Status	Disabled	Disabled/Negative/Positive/Both		
Setting to disable or set the ramp direction of the seventh stage df/dt protection.				
df/dt+t 7 Set	2 Hz/sec	0.01 Hz/sec	10 Hz/sec	0.01 Hz/sec
Rate of change of frequency threshold for the seventh stage.				
df/dt+t 7 Time	0.5 s	0 s	100 s	0.01 s
Setting for the operating time delay for the seventh stage rate of change of frequency protection element.				
f+df/dt 7 Status	Disabled	Disabled/Negative/Positive/Both		
Setting to disable or set the ramp direction of the seventh stage frequency supervised rate of change of frequency protection.				
f+df/dt 7 freq	49 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the seventh stage frequency supervised rate of change of frequency protection element.				

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
f+df/dt 7 df/dt	1 Hz/sec	0.01 Hz/sec	10 Hz/sec	0.01 Hz/sec
Frequency supervised rate of change of frequency threshold for the seventh stage.				
f+Df/Dt 7 Status	Disabled	Disabled/Under/Over		
Setting to disable or to set as Under or Over average rate of change of frequency of the seventh stage.				
f+Df/Dt 7 freq	49 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the seventh stage average rate of change of frequency protection element.				
f+Df/Dt 7 Dfreq	1 Hz	0.01 Hz	10 Hz	0.01 Hz
Change in frequency that must be measured in the set time for the seventh stage average rate of change of frequency protection element.				
f+Df/Dt 7 Dtime	0.5 s	0.02 s	100 s	0.01 s
The time period over which a change in frequency that in excess of the setting f+Df/Dt 7 Dfreq that must be measured for the seventh stage average rate of change of frequency protection element.				
Restore 7 Status	Disabled	Disabled/Enabled		
Setting to disable or Enable the seventh stage of load restoration.				
Restore 7 freq	49.5 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the seventh stage of load restoration, above which the associated load restoration time can start.				
Restore 7 time	240 s	0 s	7200 s	0.25 s
Time period for which the measured frequency must be higher than seventh stage restoration frequency setting to permit load restoration.				
Holding Timer 7	5 s	1 s	7200 s	1 s
Sets the holding time of the seventh stage load restoration function				
Stg 7 UV Block	Disabled	Disabled/Enabled		
To enable (activate) or disable (turn off) the under voltage blocking of the stage 7 load restoration element.				
Stage 8	Disabled	Disabled/Enabled		
Setting to disable or enable eighth stage frequency protection.				
Stg 8 f+t Status	Disabled	Disabled/Under/Over		
Setting to disable or to set as Under or Over frequency of the eighth stage frequency protection.				
Stg 8 f+t Freq	49 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the eighth stage frequency protection element.				
Stg 8 f+t Time	2 s	0 s	100 s	0.01 s
Setting for the operating time delay for the eighth stage frequency protection element.				
df/dt+t 8 Status	Disabled	Disabled/Negative/Positive/Both		
Setting to disable or set the ramp direction of the eighth stage df/dt protection.				
df/dt+t 8 Set	2 Hz/sec	0.01 Hz/sec	10 Hz/sec	0.01 Hz/sec
Rate of change of frequency threshold for the eighth stage.				
df/dt+t 8 Time	0.5 s	0 s	100 s	0.01 s
Setting for the operating time delay for the eighth stage rate of change of frequency protection element.				
f+df/dt 8 Status	Disabled	Disabled/Negative/Positive/Both		
Setting to disable or set the ramp direction of the eighth stage frequency supervised rate of change of frequency protection.				
f+df/dt 8 freq	49 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the eighth stage frequency supervised rate of change of frequency protection element.				
f+df/dt 8 df/dt	1 Hz/sec	0.01 Hz/sec	10 Hz/sec	0.01 Hz/sec
Frequency supervised rate of change of frequency threshold for the eighth stage.				
f+Df/Dt 8 Status	Disabled	Disabled/Under/Over		

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Setting to disable or to set as Under or Over average rate of change of frequency of the eighth stage.				
f+Df/Dt 8 freq	49 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the eighth stage average rate of change of frequency protection element.				
f+Df/Dt 8 Dfreq	1 Hz	0.01 Hz	10 Hz	0.01 Hz
Change in frequency that must be measured in the set time for the eighth stage average rate of change of frequency protection element.				
f+Df/Dt 8 Dtime	0.5 s	0.02 s	100 s	0.01 s
The time period over which a change in frequency that in excess of the setting f+Df/Dt 8 Dfreq that must be measured for the eighth stage average rate of change of frequency protection element.				
Restore 8 Status	Disabled	Disabled/Enabled		
Setting to disable or Enable the eighth stage of load restoration.				
Restore 8 freq	49.5 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the eighth stage of load restoration, above which the associated load restoration time can start.				
Restore 8 time	240 s	0 s	7200 s	0.25 s
Time period for which the measured frequency must be higher than eighth stage restoration frequency setting to permit load restoration.				
Holding Timer 8	5 s	1 s	7200 s	1 s
Sets the holding time of the eighth stage load restoration function.				
Stg 8 UV Block	Disabled	Disabled/Enabled		
To enable (activate) or disable (turn off) the under voltage blocking of the stage 8 load restoration element.				
Stage 9	Disabled	Disabled/Enabled		
Setting to disable or enable ninth stage frequency protection.				
Stg 9 f+t Status	Disabled	Disabled/Under/Over		
Setting to disable or to set as Under or Over frequency of the ninth stage frequency protection.				
Stg 9 f+t Freq	49 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the eighth stage frequency protection element.				
Stg 9 f+t Time	2 s	0 s	100 s	0.01 s
Setting for the operating time delay for the ninth stage frequency protection element.				
df/dt+t 9 Status	Disabled	Disabled/Negative/Positive/Both		
Setting to disable or set the ramp direction of the ninth stage df/dt protection.				
df/dt+t 9 Set	2 Hz/sec	0.01 Hz/sec	10 Hz/sec	0.01 Hz/sec
Rate of change of frequency threshold for the ninth stage.				
df/dt+t 9 Time	0.5 s	0 s	100 s	0.01 s
Setting for the operating time delay for the ninth stage rate of change of frequency protection element.				
f+df/dt 9 Status	Disabled	Disabled/Negative/Positive/Both		
Setting to disable or set the ramp direction of the ninth stage frequency supervised rate of change of frequency protection.				
f+df/dt 9 freq	49 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the ninth stage frequency supervised rate of change of frequency protection element.				
f+df/dt 9 df/dt	1 Hz/sec	0.01 Hz/sec	10 Hz/sec	0.01 Hz/sec
Frequency supervised rate of change of frequency threshold for the ninth stage.				
f+Df/Dt 9 Status	Disabled	Disabled/Under/Over		
Setting to disable or to set as Under or Over average rate of change of frequency of the ninth stage.				
f+Df/Dt 9 freq	49 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the ninth stage average rate of change of frequency protection element.				

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
f+Df/Dt 9 Dfreq	1 Hz	0.01 Hz	10 Hz	0.01 Hz
Change in frequency that must be measured in the set time for the ninth stage average rate of change of frequency protection element.				
f+Df/Dt 9 Dtime	0.5 s	0.02 s	100 s	0.01 s
The time period over which a change in frequency that in excess of the setting f+Df/Dt 9 Dfreq that must be measured for the ninth stage average rate of change of frequency protection element.				
Restore 9 Status	Disabled	Disabled/Enabled		
Setting to disable or Enable the ninth stage of load restoration.				
Restore 9 freq	49.5 Hz	40.1 Hz	69.9 Hz	0.01 Hz
Pick up setting for the ninth stage of load restoration, above which the associated load restoration time can start.				
Restore 9 time	240 s	0 s	7200 s	0.25 s
Time period for which the measured frequency must be higher than ninth stage restoration frequency setting to permit load restoration.				
Holding Timer 9	5 s	1 s	7200 s	1 s
Sets the holding time of the ninth stage load restoration function.				
Stg 9 UV Block	Disabled	Disabled/Enabled		
To enable (activate) or disable (turn off) the under voltage blocking of the stage 9 load restoration element.				

Table 23 - Advanced Frequency Protection

5 INTEGRAL TELEPROTECTION SETTINGS

5.1 EIA(RS)232 InterMiCOM

'**InterMiCOM**' operates via an EIA(RS)232 physical output on the back of the 2nd rear communication board. It provides 8 independently settable digital signals that can be conveyed between line ends. The InterMiCOM teleprotection is restricted to 2 ends. InterMiCOM input and output mapping has to be done in the Programmable Scheme Logic (PSL).

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
INTERMiCOM COMMS				
IM Input Status	00000000			
Displays the status of each InterMiCOM input signal, with IM1 signal starting from the right. When loop back mode is set, all bits will display zero.				
IM Output Status	00000000			
Displays the status of each InterMiCOM output signal.				
Source Address	1	1	10	1
Setting for the unique relay address that is encoded in the InterMiCOM sent message.				
Receive Address	2	1	10	1
The aim of setting addresses is to establish pairs of relays which will only communicate with each other. Should an inadvertent channel misrouting or spurious loopback occur, an error will be logged, and the erroneous received data will be rejected. As an example, in a 2 ended scheme the following address setting would be correct: Local relay: Source Address = 1, Receive Address = 2 Remote relay: Source Address = 2, Receive Address = 1				
Baud Rate	9600	600, 1200, 2400, 4800, 9600, or 19200		
Setting of the signaling speed in terms of number of bits per second. The speed will match the capability of the MODEM or other characteristics of the channel provided.				
Ch Statistics	Visible	Invisible or Visible		
Settings that makes visible or invisible Channel Statistics on the LCD. The statistic is reset by either relay's powering down or using the 'Reset Statistics' cell.				
Rx Direct Count	0			
Displays the number of valid Direct Tripping messages since last counter reset.				
Rx Perm Count	0			
Displays the number of valid Permissive Tripping messages since last counter reset.				
Rx Block Count	0			
Displays the number of valid Blocking messages since last counter reset.				
Rx NewData Count	0			
Displays the number of different messages (change events) since last counter reset.				
Rx Errored Count	0			
Displays the number of invalid received messages since last counter reset.				
Lost Messages	0			
Displays the difference between the number of messages that were supposed to be received (based on set Baud Rate) and actual valid received messages since last reset.				
Elapsed Time	0			
Displays the time in seconds since last counter reset.				
Reset Statistics	No	Yes or No		

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Command that allows all Statistics and Channel Diagnostics to be reset.				
Ch Diagnostics	Visible	Invisible or Visible		
Setting that makes visible or invisible Channel Diagnostics on the LCD. The diagnostic is reset by either relay's powering down or using the 'Reset Statistics' cell.				
DATA CD Status	OK, FAIL, or Absent			
Indicates when the DCD line (pin 1 on EIA232 Connector) is energized. OK = DCD is energized FAIL = DCD is de-energized Absent = 2nd Rear port board is not fitted				
FrameSync Status	OK, FAIL, Absent or Unavailable			
Indicates when the message structure and synchronization is valid. OK = valid message structure and synchronization FAIL = synchronization has been lost Absent = 2^{nd} Rear port board is not fitted Unavailable = hardware error present				
Message Status	OK, FAIL, Absent or Unavailable			
Indicates when the percentage of received valid messages has fallen below the 'IM Msg Alarm Lvl' setting within the alarm time period. OK = acceptable ratio of lost messages FAIL = unacceptable ratio of lost messages Absent = 2^{nd} Rear port board is not fitted Unavailable = hardware error present				
Channel Status	OK, FAIL, Absent or Unavailable			
Indicates the state of the InterMiCOM communication channel. OK = channel healthy FAIL = channel failure Absent = 2^{nd} Rear port board is not fitted Unavailable = hardware error present				
IM H/W Status	OK, Read Error, Write Error, or Absent			
Indicates the state of InterMiCOM hardware . OK = InterMiCOM hardware healthy Read or Write Error = InterMiCOM failure Absent = 2^{nd} Rear port is not fitted or failed to initialize				
Loopback Mode	Disabled	Disabled, Internal or External		
Setting to allow testing of the InterMiCOM channel. When 'Internal' is selected, only the local InterMiCOM software functionality is tested, whereby the relay will receive its own sent data. 'External' setting allows a hardware and software check, with an external link required to jumper the sent data onto the receive channel. During normal service condition Loopback mode must be disabled.				
Test Pattern	11111111	00000000	11111111	-
Allows specific bit statuses to be inserted directly into the InterMiCOM message, to substitute real data. This is used for testing purposes.				
Loopback Status	OK, FAIL or Unavailable			
Indicates the status of the InterMiCOM loopback mode OK = loopback software (and hardware) is working correctly FAIL = loopback mode failure Unavailable = hardware error present				
INTERMiCOM CONF				
IM Msg Alarm Lvl	25%	0%	100%	0.1%
Setting that is used to alarm for poor channel quality. If during the fixed 1.6s window the ratio of invalid messages to the total number of messages that should be received (based upon the 'Baud Rate' setting) exceeds the above threshold, a 'Message Fail' alarm will be issued.				
IM1 Cmd Type	Blocking	Disabled, Direct or Blocking		

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Setting that defines the operative mode of the InterMiCOM_1 signal. Selecting the channel response for this bit to 'Blocking' allows fastest signaling, whereas setting to 'Direct' offers higher security at the expense of speed.				
IM1 FallBackMode	Default	Default or Latching		
Setting that defines the status of IM1 signal in case of heavy noise and message synchronization being lost. If set to 'Latching' the last valid IM1 status will be maintained until the new valid message is received. If set to 'Default', the IM1 status, pre-defined by the user in 'IM1 DefaultValue' cell will be set. A new valid message will replace 'IM1 DefaultValue', once the channel recovers.				
IM1 DefaultValue	1	0	1	1
Setting that defines the IM1 fallback status.				
IM1 FrameSyncTim	0.02s	0.01s	1.5s	0.01s
Time delay after which 'IM1 DefaultValue' is applied, providing that no valid message is received in the meantime.				
IM2 to IM4	Cells as for IM1 above			
IM5 Cmd Type	Direct	Disabled, Direct or Permissive		
Setting that defines the operative mode of the InterMiCOM_5 signal. Selecting the channel response for this bit to 'Permissive' offers higher dependability, whereas setting to 'Direct' offers higher security.				
IM5 FallBackMode	Default	Default or Latching		
As for IM1				
IM5 DefaultValue	0	0	1	1
Setting that defines the IM5 fallback status.				
IM5 FrameSyncTim	0.01s	0.01s	1.5s	0.01s
Time delay after which 'IM5 DefaultValue' is applied.				
IM6 to IM8	Cells as for IM5 above			

Table 24 - EIA(RS)232 InterMiCOM

6 CONTROL AND SUPPORT SETTINGS

The control and support settings are part of the main menu and are used to configure the global configuration for the relay. It includes submenu settings as shown here:

- Relay function configuration settings
- Open/close circuit breaker
- CT & VT ratio settings
- Reset LEDs
- Active protection setting group
- Password & language settings
- Circuit breaker control & monitoring settings
- Communications settings
- Measurement settings
- Event & fault record settings
- User interface settings
- Commissioning settings

6.1 System Data

This menu provides information for the device and general status of the relay.

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Language	English			
The default language used by the device. Selectable as English, French, German, Russian, Spanish.				
Password	****			
Device default password.				
Sys. Fn. Links	0			1
Setting to allow the fixed function trip LED to be self resetting.				
Description	MiCOM P145			
16 character relay description. Can be edited.				
Plant Reference	MiCOM			
Associated plant description and can be edited.				
Model Number	P145?11A??0460J			
Relay model number. This display cannot be altered.				
Serial Number	149188B			
Relay model number. This display cannot be altered.				
Frequency	50 Hz			10Hz
Relay set frequency. Settable between 50 and 60Hz				
Comms. Level 2				
Displays the conformance of the relay to the Courier Level 2 comms.				
Relay Address 1				
Sets the first rear port relay address.				
Plant Status	0000000000000000			

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Displays the circuit breaker plant status for up to 8 circuit breakers. The P14x relay supports only a single circuit breaker configuration.				
Control Status	0000000000000000			
Not used.				
Active Group	1			
Displays the active settings group.				
CB Trip/Close	No Operation			No Operation/ Trip/Close
Supports trip and close commands if enabled in the Circuit Breaker Control menu.				
Software Ref. 1	P145____4__460_A			
Software Ref. 2	P145____4__460_A			
Displays the relay software version including protocol and relay model. Software Ref. 2 is displayed for relay with IEC 61850 protocol only and this will display the software version of the Ethernet card.				
Opto I/P Status	0000000000000000			
Display the status of opto inputs fitted.				
Relay O/P Status	0000001000000000			
Displays the status of all output relays fitted.				
Alarm Status 1	00000000000000000000000000000000			
32 bit field gives status of first 32 alarms. Includes fixed and user settable alarms.				
Opto I/P Status	0000000000000000			
Duplicate. Displays the status of opto inputs.				
Relay O/P Status	0000001000000000			
Duplicate. Displays the status of output relays.				
Alarm Status 1	00000000000000000000000000000000			
Duplicate of Alarm Status 1 above.				
Alarm Status 2	00000000000000000000000000000000			
Next 32 alarm status defined.				
Alarm Status 3	00000000000000000000000000000000			
Next 32 alarm status defined. Assigned specifically for platform alarms.				
Access Level	2			
Displays the current access level.				
Level	**Summary**	**Details**		
Level 0	No password required	Read access to all settings, alarms, event records and fault records		
Level 1	Password 1 or 2 required	As level 0 plus: Control commands, e.g. circuit breaker open/close Reset of fault and alarm conditions, Reset LEDs Clearing of event and fault records		
Level 2	Password 2 required	As level 1 plus: All other settings		
Password Control	2	0	2	1
Sets the menu access level for the relay. This setting can only be changed when level 2 access is enabled.				
Password Level 1	****			
Allows user to change password level 1.				
Password Level 2	****			

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Allows user to change password level 2.				

Table 25 - System Data

6.2 Circuit Breaker (CB) Control

The IED/relay includes the following options for control of a single circuit breaker:

- Local tripping and closing, via the relay menu or hotkeys
- Local tripping and closing, via relay opto-isolated inputs
- Remote tripping and closing, using the relay communications

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
CB control by	Disabled	Disabled, Local, Remote, Local + Remote, Opto, Opto + Local, Opto + Remote, Opto + Remote + Local		
This Setting selects the type of circuit breaker control that be used in the logic				
Close Pulse Time	0.5s	0.01s	50s	0.01s
Defines the duration of the close pulse.				
Trip Pulse Time	0.5s	0.01s	5s	0.01s
Defines the duration of the trip pulse.				
Man Close Delay	10s	0.01s	600s	0.01s
This defines the delay time before the close pulse is executed.				
CB Healthy Time	5s	0.01s	9999s	0.01s
A settable time delay included for manual closure with this circuit breaker check. If the circuit breaker does not indicate a healthy condition in this time period following a close command then the relay will lockout and alarm.				
Check Sync. Time	5s	0.01s	9999s	0.01s
A user settable time delay is included for manual closure with check synchronizing. If the check sync. criteria are not satisfied in this time period following a close command the relay will lockout and alarm.				
Lockout Reset	No	No, Yes		
Displays if the Lockout condition has been reset.				
Reset Lockout By	CB Close	User Interface, CB Close		
Setting that determines if a lockout condition will be reset by a manual circuit breaker close command or via the user interface.				
Man Close RstDly	5s	0.01s	600s	0.01s
The manual close time, time delay, that is used to reset a lockout automatically from a manual close.				
Auto-reclose Mode	No Operation	No operation, auto, non-auto (refer to auto-reclose notes for further information)		
Visible if auto-reclose function is enabled. Works in conjunction with the auto-reclose mode selection and allows the auto-reclose to be switched in or out of service.				
A/R Status (Indication of current mode only	Auto Mode	Auto mode, non-auto mode, live line (refer to auto-reclose notes for further information)		
Displays the current status of the auto-reclose function.				
Total Reclosures	Data			
Displays the number of successful reclosures.				
Reset Total A/R	No	No, Yes		
Allows user to reset the auto-reclose counters.				

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
CB Status Input	None	None, 52A, 52B, Both 52A and 52B		
Setting to define the type of circuit breaker contacts that will be used for the circuit breaker control logic.				
1 Shot Clearance	Data			
Displays the number of successful first shot fault clearances.				
2 Shot Clearance	Data			
Displays the number of successful second shot fault clearances.				
3 Shot Clearance	Data			
Displays the number of successful third shot fault clearances.				
4 Shot Clearance	Data			
Displays the number of successful fourth shot fault clearances.				
Persistent Fault	Data			
Displays the number of unsuccessful fault clearances (caused lockout) by the auto-recloser.				

Table 26 - Circuit Breaker Control

6.3 Date and Time

Displays the date and time as well as the battery condition.

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Date/Time	Data			
Displays the relay's current date and time.				
IRIG-B Sync.	Disabled	Disabled or Enabled		
Enable IRIG-B time synchronization.				
IRIG-B Status	Data	Card not fitted/Card failed/ Signal healthy/ No signal		
Displays the status of IRIG-B.				
Battery Status	Data			
Displays whether the battery is healthy or not.				
Battery Alarm	Enabled	Disabled or Enabled		
Setting that determines whether an unhealthy relay battery condition is alarmed or not.				
SNTP Status	Data	Disabled, Trying server 1, Trying server 2, Server 1 OK, Server 2 OK, No response, No valid clock		
Displays information about the SNTP time synchronization status.				
LocalTime Enable	Disabled	Disabled/Fixed/Flexible		
Setting to turn on/off local time adjustments. Disabled - No local time zone will be maintained. Time synchronization from any interface will be used to directly set the master clock and all displayed (or read) times on all interfaces will be based on the master clock with no adjustment. Fixed - A local time zone adjustment can be defined using the LocalTime offset setting and all interfaces will use local time except SNTP time synchronization and IEC 61850 timestamps. Flexible - A local time zone adjustment can be defined using the LocalTime offset setting and each interface can be assigned to the UTC zone or local time zone with the exception of the local interfaces which will always be in the local time zone and IEC 61850/SNTP which will always be in the UTC zone.				
LocalTime Offset	0	-720	720	15

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Setting to specify an offset of -12 to +12 hrs in 15 minute intervals for local time zone. This adjustment is applied to the time based on the master clock which is UTC/GMT.				
DST Enable	Disabled	Disabled or Enabled		
Setting to turn on/off daylight saving time adjustment to local time.				
DST Offset	60 mins	30	60	30 mins
Setting to specify daylight saving offset which will be used for the time adjustment to local time.				
DST Start	Last	First, Second, Third, Fourth, Last		
Setting to specify the week of the month in which daylight saving time adjustment starts.				
DST Start Day	Sunday	Monday, Tuesday, Wednesday, Thursday, Friday, Saturday		
Setting to specify the day of the week in which daylight saving time adjustment starts.				
DST Start Month	March	January, February, March, April, May, June, July, August, September, October, November, December		
Setting to specify the month in which daylight saving time adjustment starts.				
DST Start Mins	60 mins	0	1425	15 mins
Setting to specify the time of day in which daylight saving time adjustment starts. This is set relative to 00:00 hrs on the selected day when time adjustment is to start.				
DST End	Last	First, Second, Third, Fourth, Last		
Setting to specify the week of the month in which daylight saving time adjustment ends.				
DST End Day	Sunday	Monday, Tuesday, Wednesday, Thursday, Friday, Saturday		
Setting to specify the day of the week in which daylight saving time adjustment ends.				
DST End Month	October	January, February, March, April, May, June, July, August, September, October, November, December		
Setting to specify the month in which daylight saving time adjustment ends.				
DST End Mins	60 mins	0	1425	15 mins
Setting to specify the time of day in which daylight saving time adjustment ends. This is set relative to 00:00 hrs on the selected day when time adjustment is to end.				
RP1 Time Zone	Local	UTC or Local		
Setting for the rear port 1 interface to specify if time synchronization received will be local or universal time co-ordinated.				
RP2 Time Zone	Local	UTC or Local		
Setting for the rear port 2 interface to specify if time synchronization received will be local or universal time co-ordinated.				
Tunnel Time Zone	Local	UTC or Local		
Setting to specify if time synchronization received will be local or universal time co-ordinate when ‘tunneling’ courier protocol over Ethernet.				

Table 27 - Date and Time

6.4 CT/VT Ratios

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Main VT Primary	110.0 V	100	1000 kV	1
Sets the main voltage transformer input primary voltage.				
Main VT Sec’y	110.0 V	80	140	0.2
Sets the main voltage transformer input secondary voltage.				

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Main VT Sec'y (for 440 VT module option)	440.0 V	196	560	0.8
Sets the main voltage transformer input secondary voltage for 440V VT module.				
C/S VT Primary (P143 & P145 Only)	110.0 V	100	1000 kV	1
Sets the check sync. voltage transformer input primary voltage.				
C/S VT Secondary (P143 & P145 Only)	110.0 V	80	140	0.2
Sets the check sync. voltage transformer input secondary voltage.				
C/S VT Secondary (P143 & P145 Only)	440.0 V	196	560	0.8
Sets the check sync. voltage transformer input secondary voltage for 440V VT module.				
Phase CT Primary	1.000A	1	30k	1
Sets the phase current transformer input primary current rating.				
Phase CT Sec'y	1.000A	1	5	4
Sets the phase current transformer input secondary current rating.				
E/F CT Primary	1.000A	1	30k	1
Sets the earth fault current transformer input primary current rating.				
E/F CT Secondary	1.000A	1	5	4
Sets the earth fault current transformer input secondary current rating.				
SEF CT Primary	1.000A	1	30k	1
Sets the sensitive earth fault current transformer input primary current rating.				
SEF CT Secondary	1.000A	1	5	4
Sets the sensitive earth fault current transformer input secondary current rating.				
C/S Input (P143 & P145 Only)	A-N	A-N, B-N, C-N, A-B, B-C, C-A		N/A
Selects the check sync. input voltage measurement.				
Main VT Location (P143 & P145 Only)	Line	Line, Bus		N/A
Selects the main voltage transformer location.				
C/S V kSM	1	0.1	3	0.001
Sets the voltage correction factor in case of different VT ratios.				
C/S Phase kSA	0	-150	180	30
Sets the phase angle correction factor.				

Table 28 - CT/VT Ratios

6.5 Record Control

It is possible to disable the reporting of events from all interfaces that support setting changes. The settings that control the various types of events are in the Record Control column. The effect of setting each to disabled is as follows:

Menu Text	Default Setting	Available settings
Clear Event	No	No or Yes

Menu Text	Default Setting	Available settings
Selecting "Yes" will cause the existing event log to be cleared and an event will be generated indicating that the events have been erased.		
Clear Faults	No	No or Yes
Selecting "Yes" will cause the existing fault records to be erased from the relay.		
Clear Maint.	No	No or Yes
Selecting "Yes" will cause the existing maintenance records to be erased from the relay.		
Alarm Event	Enabled	Enabled or Disabled
Disabling this setting means that all the occurrences that produce an alarm will result in no event being generated.		
Relay O/P Event	Enabled	Enabled or Disabled
Disabling this setting means that no event will be generated for any change in logic input state.		
Opto Input Event	Enabled	Enabled or Disabled
Disabling this setting means that no event will be generated for any change in logic input state.		
General Event	Enabled	Enabled or Disabled
Disabling this setting means that no General Events will be generated		
Fault Rec. Event	Enabled	Enabled or Disabled
Disabling this setting means that no event will be generated for any fault that produces a fault record		
Maint. Rec. Event	Enabled	Enabled or Disabled
Disabling this setting means that no event will be generated for any occurrence that produces a maintenance record.		
Protection Event	Enabled	Enabled or Disabled
Disabling this setting means that any operation of protection elements will not be logged as an event.		
DDB 31 - 0	11111111111111111111111111111111	
Chooses whether any individual DDBs should be deselected as a stored event, by setting the relevant bit to "0" (zero). Typically used for repetitive recurrent changes such as an Opto input assigned for Minute Pulse clock synchronizing.		
DDB 1279 - 1248	11111111111111111111111111111111	
As above, for all DDBs through to 1279.		

Table 29 - Record Control

6.6 Measurements

Menu Text	Default Settings	Available settings
MEASUREMENT SETUP		
Default Display	Description	Description/Plant Reference/ Frequency/Access Level/3Ph + N Current/3Ph Voltage/Power/Date and Time
This setting can be used to select the default display from a range of options. Note: It is also possible to view the other default displays whilst at the default level using the and keys. However once the 15 minute timeout elapses the default display will revert to that selected by this setting.		
Local Values	Primary	Primary/Secondary
This setting controls whether measured values via the front panel user interface and the front courier port are displayed as primary or secondary quantities.		
Remote Values	Primary	Primary/Secondary
This setting controls whether measured values via the rear communication port are displayed as primary or secondary quantities.		
Measurement Ref.	VA	VA/VB/VC/IA/IB/IC
Using this setting the phase reference for all angular measurements by the relay can be selected.		

Menu Text	Default Settings	Available settings
Measurement Mode	0	0 to 3 step 1
This setting is used to control the signing of the real and reactive power quantities; the signing convention used is defined in the Measurements and Recording section (P14x/EN MR).		
Fix Dem. Period	30 minutes	1 to 99 minutes step 1 minute
This setting defines the length of the fixed demand window.		
Roll Sub Period	30 minutes	1 to 99 minutes step 1 minute
These two settings are used to set the length of the window used for the calculation of rolling demand quantities.		
Num. Sub Periods	1	1 to 15 step 1
This setting is used to set the resolution of the rolling sub window.		
Distance Unit*	km	km/miles
This setting is used to select the unit of distance for fault location purposes. Note: The length of the line is preserved when converting from km to miles and vice versa.		
Fault Location*	Distance	Distance/Ohms/% of Line
The calculated fault location can be displayed using one of several options selected using this setting		

Table 30 - Measurement Setup

6.7 Communications

The communications settings apply to the rear communications ports only and will depend upon the particular protocol being used. Further details are given in the SCADA Communications chapter.

Depending on the values stored, the available settings may change too. The applicability of each setting is given in the description or available setting cell. These settings are available in the menu '**Communications'** column and are displayed.

These settings are available in the menu 'Communications' column and potentially cover a variety of different protocols and ports, including:

- Courier Protocol
- MODBUS Protocol
- IEC60870-5-103 Protocol
- DNP3.0 Protocol
- Ethernet Port - IEC 61850
- Ethernet Port - DNP3.0
- Rear Port 2 Settings

6.7.1 Courier Protocol

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
COMMUNICATIONS				
RP1 Protocol	Courier			
Indicates the communications protocol that will be used on the rear communications port.				

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
RP1 Remote Address	255	0	255	1
This cell sets the unique address for the relay such that only one relay is accessed by master station software.				
RP1 Inactivity Timer	15 mins.	1 mins.	30 mins.	1 min.
This cell controls how long the relay will wait without receiving any messages on the rear port before it reverts to its default state, including resetting any password access that was enabled.				
RP1 Physical Link	Copper	Copper, Fiber Optic or KBus		
This cell defines whether an electrical EIA(RS)485, fiber optic or KBus connection is being used for communication between the master station and relay. If 'Fiber Optic' is selected, the optional fiber optic communications board will be required.				
RP1 Port Config.	KBus	KBus or EIA(RS)485		
This cell defines whether an electrical KBus or EIA(RS)485 is being used for communication between the master station and relay.				
RP1 Comms. Mode	IEC60870 FT1.2 Frame	IEC60870 FT1.2 Frame or 10-Bit No Parity		
The choice is either IEC60870 FT1.2 for normal operation with 11-bit modems, or 10-bit no parity.				
RP1 Baud Rate	19200 bits/s	9600 bits/s, 19200 bits/s or 38400 bits/s		
This cell controls the communication speed between relay and master station. It is important that both relay and master station are set at the same speed setting.				

Table 31 - Courier Protocol Communications

6.7.2 MODBUS Protocol

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
COMMUNICATIONS				
RP1 Protocol	MODBUS			
Indicates the communications protocol that will be used on the rear communications port.				
RP1 Address	1	1	247	1
This cell sets the unique address for the relay such that only one relay is accessed by master station software.				
RP1 Inactivity Timer	15 mins.	1 mins.	30 mins.	1 min.
This cell controls how long the relay will wait without receiving any messages on the rear port before it reverts to its default state, including resetting any password access that was enabled.				
RP1 Baud Rate	19200 bits/s	9600 bits/s, 19200 bits/s or 38400 bits/s		
This cell controls the communication speed between relay and master station. It is important that both relay and master station are set at the same speed setting.				
RP1 Parity	None	Odd, Even or None		
This cell controls the parity format used in the data frames. It is important that both relay and master station are set with the same parity setting.				
RP1 Physical Link	Copper	Copper or Fiber Optic		
This cell defines whether an electrical EIA(RS) 485 or fiber optic connection is being used for communication between the master station and relay. If 'Fiber Optic' is selected, the optional fiber optic communications board will be required.				
MODBUS IEC Time	Standard IEC	Standard IEC or Reverse		
When 'Standard IEC' is selected the time format complies with IEC60870-5-4 requirements such that byte 1 of the information is transmitted first, followed by bytes 2 through to 7. If 'Reverse' is selected the transmission of information is reversed.				

Table 32 - MODBUS Protocol Communications

6.7.3 IEC60870-5-103 Protocol

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
COMMUNICATIONS				
RP1 Protocol	IEC60870-5-103			
Indicates the communications protocol that will be used on the rear communications port.				
RP1 Address	1	0	247	1
This cell sets the unique address for the relay such that only one relay is accessed by master station software.				
RP1 Inactivity Timer	15 mins.	1 mins.	30 mins.	1 min.
This cell controls how long the relay will wait without receiving any messages on the rear port before it reverts to its default state, including resetting any password access that was enabled.				
RP1 Baud Rate	19200 bits/s	9600 bits/s or 19200 bits/s		
This cell controls the communication speed between relay and master station. It is important that both relay and master station are set at the same speed setting.				
RP1 Measure't. Period	15s	1s	60s	1s
This cell controls the time interval that the relay will use between sending measurement data to the master station.				
RP1 Physical Link	Copper	Copper or Fiber Optic		
RP1 CS103 Blocking	Disabled	Disabled, Monitor Blocking or Command Blocking		
There are three settings associated with this cell: Disabled No blocking selected. Monitor Blocking - When the monitor blocking DDB Signal is active high, either by energizing an opto input or control input, reading of the status information and disturbance records is not permitted. When in this mode the relay returns a "termination of general interrogation" message to the master station. Command Blocking When the command blocking DDB signal is active high, either by energizing an opto input or control input, all remote commands will be ignored (i.e. CB Trip/Close, change setting group etc.). When in this mode the relay returns a "negative acknowledgement of command" message to the master station.				

Table 33 - IEC60870-5-103 Protocol Communications

6.7.4 DNP3.0 Protocol

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
COMMUNICATIONS				
RP1 Protocol	DNP 3.0			
Indicates the communications protocol that will be used on the rear communications port.				
RP1 Address	1	0	65519	1
This cell sets the unique address for the relay such that only one relay is accessed by master station software.				
RP1 Baud Rate	19200 bits/s	1200 bits/s, 2400 bits/s, 4800 bits/s, 9600 bits/s, 19200 bits/s or 38400 bits/s		
This cell controls the communication speed between relay and master station. It is important that both relay and master station are set at the same speed setting.				
RP1 Parity	None	Odd, Even or None		
This cell controls the parity format used in the data frames. It is important that both relay and master station are set with the same parity setting.				
RP1 Physical Link	Copper	Copper or Fiber Optic		
This cell defines whether an electrical EIA(RS) 485 or fiber optic connection is being used for communication between the master station and relay. If 'Fiber Optic' is selected, the optional fiber optic communications board will be required.				

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
DNP Time Sync.	Disabled	Disabled or Enabled		
If set to ‘Enabled’ the DNP3.0 master station can be used to sychronize the time on the relay. If set to ‘Disabled’ either the internal free running clock, or IRIG-B input are used.				
Meas Scaling	Primary	Primary, Secondary or Normalized		
Setting to report analog values in terms of primary, secondary or normalized (with respect to the CT/VT ratio setting) values.				
Message Gap (ms)	0	0	50	1
This setting allows the master station to have an interframe gap.				
DNP Need Time (minutes)	10	1	30	1
This cell sets the time delay before the next time synchronisation is required.				
DNP App Fragment	2048	100	2048	1
Value to set the maximum size of the relay message response.				
DNP App Timeout (seconds)	2	1	120	1
DNP App Timeout is the timeout period following the sending of any part of a multi-fragment message to receiving an application confirmation from the master station. If timeout occurs the request will be cancelled by the relay				
DNP SBO Timeout (seconds)	10	1	10	1
DNP SBO Timeout is the timeout period following selection and awaiting the operating command from the master station.				
DNP Link Timeout (seconds)	0	0	120	1
DNP Link Timeout (DNP3 Serial only) is the timeout period following link layer confirmation by the relay.				

Table 34 - DNP3.0 Protocol Communications

6.7.5 Ethernet Port - IEC 61850

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
NIC Protocol	IEC 61850			
Indicates that IEC 61850 will be used on the rear Ethernet port.				
NIC MAC Address	Ethernet MAC Address			
Indicates the MAC address of the rear Ethernet port.				
NIC Tunl Timeout	5 mins	1 min	30 mins	1 min
Duration of time waited before an inactive tunnel to MiCOM S1 is reset.				
NIC Link Report	Alarm	Alarm, Event, None		
Configures how a failed/unfitted network link (copper or fiber) is reported: Alarm - An alarm is raised for a failed link Event - An event is logged for a failed link None - Nothing reported for a failed link				

Table 35 - Ethernet Port - IEC 61850 Protocol Communications

6.7.6 Ethernet Port - DNP3.0

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
NIC Protocol	DNP 3.0			
Indicates that DNP3.0 will be used on the rear Ethernet port.				

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
IP Address	0.0.0.0			
Indicates the IP address of the relay.				
Subnet Mask	0.0.0.0			
Indicates the Subnet address.				
NIC MAC Address	*Ethernet MAC Address*			
Indicates the MAC address of the rear Ethernet port.				
Gateway				
Indicates the Gateway address.				
DNP Time Sync.	Disabled	Disabled or Enabled		
If set to 'Enabled' the DNP3.0 master station can be used to synchronize the time on the relay. If set to 'Disabled' either the internal free running clock, or IRIG-B input are used.				
Meas Scaling	Primary	Primary, Secondary or Normalized		
Setting to report analog values in terms of primary, secondary or normalized (with respect to the CT/VT ratio setting) values.				
NIC Tunl Timeout	5 mins	1 min	30 mins	1 min
Duration of time waited before an inactive tunnel to MiCOM S1 is reset.				
Meas Scaling	Primary	Primary, Secondary or Normalized		
Setting to report analog values in terms of primary, secondary or normalized (with respect to the CT/VT ratio setting) values.				
NIC Link Report	Alarm	Alarm, Event, None		
Configures how a failed/unfitted network link (copper or fiber) is reported: Alarm - An alarm is raised for a failed link Event - An event is logged for a failed link None - Nothing reported for a failed link				
NIC Link Timeout	60s	0.1s	60s	0.1s
Duration of time waited, after failed network link is detected, before communication by the alternative media interface is attempted.				
SNTP PARAMETERS				
SNTP Server 1	SNTP Server 1 address			
Indicates the SNTP Server 1 address.				
SNTP Server 2	SNTP Server 1 address			
Indicates the SNTP Server 2 address.				
SNTP Poll Rate	64s	64s	1024s	1s
Duration of SNTP poll rate in seconds.				
DNP3.0 Need Time	10 mins	1 min	30 mins	1 min
The duration of time waited before requesting another time sync from the master.				
DNP App Fragment	2048	100	2048	1
The maximum message length (application fragment size) transmitted by the relay.				
DNP App Timeout	2s	1s	120s	1s
Duration of time waited, after sending a message fragment and awaiting a confirmation from the master.				
DNP SBO Timeout	10s	1s	10s	1s
Duration of time waited, after receiving a select command and awaiting an operate confirmation from the master.				

Table 36 - Ethernet Port - DNP3.0 Protocol Communications

6.7.7 Rear Port 2 Settings

The settings shown are those configurable for the second rear port which is only available with the Courier protocol.

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
COMMUNICATIONS				
RP2 Protocol	Courier			
Indicates the communications protocol that will be used on the rear communications port.				
RP2 Port Config.	RS232	EIA(RS)232, EIA(RS)485 or KBus		
This cell defines whether an electrical EIA(RS)232, EIA(RS)485 or KBus is being used for communication.				
RP2 Comms. Mode	IEC60870 FT1.2 Frame	IEC60870 FT1.2 Frame or 10-Bit No Parity		
The choice is either IEC60870 FT1.2 for normal operation with 11-bit modems, or 10-bit no parity.				
RP2 Address	255	0	255	1
This cell sets the unique address for the relay such that only one relay is accessed by master station software.				
RP2 Inactivity Timer	15 mins.	1 mins.	30 mins.	1 min.
This cell controls how long the relay will wait without receiving any messages on the rear port before it reverts to its default state, including resetting any password access that was enabled.				
RP2 Baud Rate	19200 bits/s	9600 bits/s, 19200 bits/s or 38400 bits/s		
This cell controls the communication speed between relay and master station. It is important that both relay and master station are set at the same speed setting.				

Table 37 - Rear Port 2 Settings

6.8 Commissioning Tests

To help minimising the time required to test MiCOM relays the relay provides several test facilities under the ‘COMMISSION TESTS’ menu heading.

There are menu cells which allow the status of the opto-isolated inputs, output relay contacts, internal Digital Data Bus (DDB) signals and user-programmable LEDs to be monitored. Additionally there are cells to test the operation of the output contacts, user-programmable LEDs.

This column is visible when the “Commission tests” setting (“Configuration” column) = “visible”.

Menu Text	Default Setting	Available settings
COMMISSION TESTS		
Opto I/P Status	0000000000000000	
This menu cell displays the status of the relay’s opto-isolated inputs as a binary string, a ‘1’ indicating an energized opto-isolated input and a ‘0’ a de-energized one		
Relay O/P Status	0000000000000000	
This menu cell displays the status of the digital data bus (DDB) signals that result in energization of the output relays as a binary string, a ‘1’ indicating an operated state and ‘0’ a non-operated state. When the ‘Test Mode’ cell is set to ‘Enabled’ the ‘Relay O/P Status’ cell does not show the current status of the output relays and hence can not be used to confirm operation of the output relays. Therefore it will be necessary to monitor the state of each contact in turn.		
Test Port Status	00000000	
This menu cell displays the status of the eight digital data bus (DDB) signals that have been allocated in the ‘Monitor Bit’ cells.		
Monitor Bit 1	64 (LED 1)	0 to 511 See PSL section for details of digital data bus signals

Menu Text	Default Setting	Available settings
The eight 'Monitor Bit' cells allow the user to select the status of which digital data bus signals can be observed in the 'Test Port Status' cell or via the monitor/download port.		
Monitor Bit 8	71 (LED 8)	0 to 511
The eight 'Monitor Bit' cells allow the user to select the status of which digital data bus signals can be observed in the 'Test Port Status' cell or via the monitor/download port.		
Test Mode	Disabled	Disabled, Test Mode, Contacts Blocked
The Test Mode menu cell is used to allow secondary injection testing to be performed on the relay without operation of the trip contacts. It also enables a facility to directly test the output contacts by applying menu controlled test signals. To select test mode the Test Mode menu cell should be set to 'Test Mode', which takes the relay out of service and blocks operation of output contacts and maintenance, counters. It also causes an alarm condition to be recorded and the yellow 'Out of Service' LED to illuminate and an alarm message 'Prot'n. Disabled' is given. This also freezes any information stored in the Circuit Breaker Condition column and in IEC60870-5-103 builds changes the Cause of Transmission, COT, to Test Mode. To enable testing of output contacts the Test Mode cell should be set to Contacts Blocked. This blocks the protection from operating the contacts and enables the test pattern and contact test functions which can be used to manually operate the output contacts. Once testing is complete the cell must be set back to 'Disabled' to restore the relay back to service.		
Test Pattern	00000000000000000000000000000000	0 = Not Operated 1 = Operated
This cell is used to select the output relay contacts that will be tested when the 'Contact Test' cell is set to 'Apply Test'.		
Contact Test	No Operation	No Operation, Apply Test, Remove Test
When the 'Apply Test' command in this cell is issued the contacts set for operation (set to '1') in the 'Test Pattern' cell change state. After the test has been applied the command text on the LCD will change to 'No Operation' and the contacts will remain in the Test State until reset issuing the 'Remove Test' command. The command text on the LCD will again revert to 'No Operation' after the 'Remove Test' command has been issued. Note: When the 'Test Mode' cell is set to 'Enabled' the 'Relay O/P Status' cell does not show the current status of the output relays and hence can not be used to confirm operation of the output relays. Therefore it will be necessary to monitor the state of each contact in turn.		
Test LEDs	No Operation	No Operation Apply Test
When the 'Apply Test' command in this cell is issued the eighteen user-programmable LEDs will illuminate for approximately 2 seconds before they extinguish and the command text on the LCD reverts to 'No Operation'.		
Test Auto-reclose	No Operation	No Operation 3 Pole Test
Where the relay provides an auto-reclose function, this cell will be available for testing the sequence of circuit breaker trip and auto-reclose cycles with the settings applied. Issuing the command '3 Pole Trip' will cause the relay to perform the first three phase trip/re-close cycle so that associated output contacts can be checked for operation at the correct times during the cycle. Once the trip output has operated the command text will revert to 'No Operation' whilst the rest of the auto-reclose cycle is performed. To test subsequent three phase auto-reclose cycles repeat the '3 Pole Trip' command. *Note* *The factory settings for the relay's programmable scheme logic has the 'AR Trip Test' signal mapped to relay 3. If the programmable scheme logic has been changed, it is essential that this signal remains mapped to relay 3 for the 'Test Auto-reclose' facility to work.*		
Red LED Status	000000000000000000	
This cell is an eighteen bit binary string that indicates which of the user-programmable LEDs on the relay are illuminated with the Red LED input active when accessing the relay from a remote location, a '1' indicating a particular LED is lit and a '0' not lit.		
Green LED Status	000000000000000000	
This cell is an eighteen bit binary string that indicates which of the user-programmable LEDs on the relay are illuminated with the Green LED input active when accessing the relay from a remote location, a '1' indicating a particular LED is lit and a '0' not lit.		
DDB 31 - 0	00000000000000000000001000000000	
Displays the status of DDB signals 0-31.		
DDB 1022 - 992	00000000000000000000000000000000	
Displays the status of DDB signals 1022 – 992.		

Table 38 - Commissioning Tests

6.9 Circuit Breaker Condition Monitor Setup

The following table, detailing the options available for the Circuit Breaker condition monitoring, is taken from the relay menu. It includes the setup of the current broken facility and those features that can be set to raise an alarm or Circuit Breaker lockout.

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
CB MONITOR SETUP				
Broken I^	2	1	2	0.1
This sets the factor to be used for the cumulative I^ counter calculation that monitors the cumulative severity of the duty placed on the interrupter. This factor is set according to the type of Circuit Breaker used.				
I^ Maintenance	Alarm Disabled	Alarm Disabled, Alarm Enabled		
Setting which determines if an alarm will be raised or not when the cumulative I^ maintenance counter threshold is exceeded.				
I^ Maintenance	1000In^	1In^	25000In^	1In^
Setting that determines the threshold for the cumulative I^ maintenance counter monitors.				
I^ Lockout	Alarm Disabled	Alarm Disabled, Alarm Enabled		
Setting which determines if an alarm will be raised or not when the cumulative I^lockout counter threshold is exceeded.				
I^ Lockout	2000In^	1In^	25000In^	1In^
Setting that determines the threshold for the cumulative I^ lockout counter monitor. Set that should maintenance not be carried out, the relay can be set to lockout the auto-reclose function on reaching a second operations threshold.				
No CB Ops. Maint.	Alarm Disabled	Alarm Disabled, Alarm Enabled		
Setting to activate the number of circuit breaker operations maintenance alarm.				
No CB Ops. Maint.	10	1	10000	1
Sets the threshold for number of circuit breaker operations maintenance alarm, indicating when preventative maintenance is due.				
No CB Ops. Lock	Alarm Disabled	Alarm Disabled, Alarm Enabled		
Setting to activate the number of circuit breaker operations lockout alarm.				
No CB Ops. Lock	20	1	10000	1
Sets the threshold for number of circuit breaker operations lockout. The relay can be set to lockout the auto-reclose function on reaching a second operations threshold.				
CB Time Maint.	Alarm Disabled	Alarm Disabled, Alarm Enabled		
Setting to activate the circuit breaker operating time maintenance alarm.				
CB Time Maint.	0.1s	0.005s	0.5s	0.001s
Setting for the circuit operating time threshold which is set in relation to the specified interrupting time of the circuit breaker.				
CB Time Lockout	Alarm Disabled	Alarm Disabled, Alarm Enabled		
Setting to activate the circuit breaker operating time lockout alarm.				
CB Time Lockout	0.2s	0.005s	0.5s	0.001s
Setting for the circuit breaker operating time threshold which is set in relation to the specified interrupting time of the circuit breaker. The relay can be set to lockout the auto-reclose function on reaching a second operations threshold.				
Fault Freq. Lock	Alarm Disabled	Alarm Disabled, Alarm Enabled		
Enables the fault frequency counter alarm.				
Fault Freq. Count	10	1	9999	1
Sets a circuit breaker frequent operations counter that monitors the number of operations over a set time period.				
Fault Freq. Time	3600s	0	9999s	1s

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Sets the time period over which the circuit breaker frequent operations are to be monitored.				

Table 39 - Circuit Breaker Condition Monitor Setup

6.10 Opto Configuration

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
OPTO CONFIG.				
Global Nominal V	24 - 27	24 - 27, 30 - 34, 48 - 54, 110 - 125, 220 - 250, Custom		
Sets the nominal battery voltage for all opto inputs by selecting one of the five standard ratings in the Global Nominal V settings. If Custom is selected then each opto input can individually be set to a nominal voltage value.				
Opto Input 1	24 - 27	24 - 27, 30 - 34, 48 - 54, 110 - 125, 220 - 250		
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting.				
Opto Input 2 - 32	24 - 27	24 - 27, 30 - 34, 48 - 54, 110 - 125, 220 - 250		
Each opto input can individually be set to a nominal voltage value if custom is selected for the global setting.				
Opto Filter Cntl.	1111111111111111			
Selects each input with a pre-set filter of ½ cycle that renders the input immune to induced noise on the wiring.				
Characteristics	Standard 60% - 80%	Standard 60% - 80%, 50% - 70%		
Selects the pick-up and drop-off characteristics of the optos. Selecting the standard setting means they nominally provide a Logic 1 or On value for Voltages ≥80% of the set lower nominal voltage and a Logic 0 or Off value for the voltages ≤60% of the set higher nominal voltage.				

Table 40 - Opto Configuration

6.11 Control Inputs

Each custom input can be set or reset from a Bit Field or separate enable/disable selection.

Menu Text	Default Setting	Setting Range	Step Size
CONTROL INPUTS			
Ctl Stg I/P Stat	0000000000000000		
Set or reset each custom input from a Bit Field			
Ctrl Setg I/P 33	Disabled	Disabled, Enabled	
Set or reset each custom input from separate enable/disable selection			
Ctrl Setg I/P 34 to 48	Disabled	Disabled, Enabled	
Set or reset each custom input from separate enable/disable selection			

Table 41 - Control Inputs

6.12 Control Input Configuration

The control inputs function as software switches that can be set or reset either locally or remotely. These inputs can be used to trigger any function that they are connected to as part of the PSL.

This column is visible when the "Control I/P Config" setting ("Configuration" column) = "visible".

Menu Text	Default Setting	Setting Range	Step Size
CTRL I/P CONFIG.			
Hotkey Enabled	11111111111111111111111111111111		
Setting to allow the control inputs to be individually assigned to the “Hotkey” menu by setting ‘1’ in the appropriate bit in the “Hotkey Enabled” cell. The hotkey menu allows the control inputs to be set, reset or pulsed without the need to enter the “CONTROL INPUTS” column.			
Control Input 1	Latched	Latched, Pulsed	
Configures the control inputs as either ‘latched’ or ‘pulsed’. A latched control input will remain in the set state until a reset command is given, either by the menu or the serial communications. A pulsed control input, however, will remain energized for 10ms after the set command is given and will then reset automatically (i.e. no reset command required) .			
Ctrl Command 1	Set/Reset	Set/Reset, In/Out, Enabled/Disabled, On/Off	
Allows the SET/RESET text, displayed in the hotkey menu, to be changed to something more suitable for the application of an individual control input, such as “ON/OFF”, “IN/OUT” etc.			
Control Input 2 to 32	Latched	Latched, Pulsed	
Configures the control inputs as either ‘latched’ or ‘pulsed’.			
Ctrl Command 2 to 32	Set/Reset	Set/Reset, In/Out, Enabled/Disabled, On/Off	
Allows the SET/RESET text, displayed in the hotkey menu, to be changed to something more suitable for the application of an individual control input, such as “ON/OFF”, “IN/OUT” etc.			

Table 42 - Control Input Configuration

6.13 Function Keys (P145 Model Only)

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
FUNCTION KEYS				
Fn. Key Status	0000000000			
Displays the status of each function key.				
Fn. Key 1 Status	Unlock/Enable	Disable, Lock, Unlock/Enable		
Setting to activate function key. The ‘Lock’ setting allows a function key output that is set to toggle mode to be locked in its current active state.				
Fn. Key 1 Mode	Toggle	Toggle, Normal		
Sets the function key in toggle or normal mode. In ‘Toggle’ mode, a single key press will set/latch the function key output as ‘high’ or ‘low’ in programmable scheme logic. This feature can be used to enable/disable relay functions. In the ‘Normal’ mode the function key output will remain ‘high’ as long as key is pressed.				
Fn. Key 1 Label	Function Key 1			
Allows the text of the function key to be changed to something more suitable for the application.				
Fn. Key 2 to 10 Status	Unlock/Enable	Disable, Lock, Unlock/Enable		
Setting to activate function key. The ‘Lock’ setting allows a function key output that is set to toggle mode to be locked in its current active position.				
Fn. Key 2 to 10 Mode	Toggle	Toggle, Normal		
Sets the function key in toggle or normal mode. In ‘Toggle’ mode, a single key press will set/latch the function key output as ‘high’ or ‘low’ in programmable scheme logic. This feature can be used to enable/disable relay functions. In the ‘Normal’ mode the function key output will remain ‘high’ as long as key is pressed.				
Fn. Key 2 to 10 Label	Function Key 2 to 10			
Allows the text of the function key to be changed to something more suitable for the application.				

Table 43 - Function Keys (P145 Model Only)

6.14 IED Configurator (for IEC 61850 Configuration)

The contents of the IED CONFIGURATOR column (for IEC 61850 configuration) are mostly data cells, displayed for information but not editable. To edit the configuration, you need to use the IED (Intelligent Electronic Device) configurator tool within the Schneider Electric MiCOM S1 Studio software.

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
IED CONFIGURATOR				
Switch Conf.Bank	No Action	No Action, Switch Banks		
Setting which allows the user to switch between the current configuration, held in the Active Memory Bank (and partly displayed below), to the configuration sent to and held in the Inactive Memory Bank.				
Restore MCL	No Action	No Action, Restore		
Setting which allows the user to restore MCL or no action.				
Active Conf.Name	Data			
The name of the configuration in the Active Memory Bank, usually taken from the SCL file.				
Active Conf.Rev	Data			
Configuration revision number of the Active Memory Bank, used for version management.				
Inact.Conf.Name	Data			
The name of the configuration in the Inactive Memory Bank, usually taken from the SCL file.				
Inact.Conf.Rev	Data			
Configuration revision number of the Inactive Memory Bank, used for version management.				
IP PARAMETERS				
IP Address	Data			
Displays the unique network IP address that identifies the relay.				
Subnet Mask	Data			
Displays the sub-network that the relay is connected to.				
Gateway	Data			
Displays the IP address of the gateway (proxy) that the relay is connected to.				
SNTP PARAMETERS				
SNTP Server 1	Data			
Displays the IP address of the primary SNTP server.				
SNTP Server 2	Data			
Displays the IP address of the secondary SNTP server.				
IEC 61850 SCL.				
IED Name	Data			
8 character IED name, which is the unique name on the IEC 61850 network for the IED, usually taken from the SCL file.				
IEC 61850 GOOSE				
GoEna	0x00000000	0x00000000	0x11111111	1
Setting to enable GOOSE publisher settings.				
Test Mode	0x00000000	0x00000000	0x11111111	1
The Test Mode cell allows the test pattern to be sent in the GOOSE message, for example for testing or commissioning.				
Ignore Test Flag	No	No, Yes		
When set to ‘Yes’, the test flag in the subscribed GOOSE message is ignored and the data treated as normal.				

Table 44 - IED Configurator (for IEC 61850 Configuration)

6.15 Control Input Labels

Menu Text	Default Setting	Setting Range	Step Size
CTRL I/P LABELS			
Control Input 1	Control Input 1	16 Character Text	
Setting to change the text associated with each individual control input. This text will be displayed when a control input is accessed by the hotkey menu, or it can be displayed in the programmable scheme logic.			
Control Input 2 to 32	Control Input 2 to 32	16 Character Text	
Setting to change the text associated with each individual control input. This text will be displayed when a control input is accessed by the hotkey menu, or it can be displayed in the programmable scheme logic.			
Ctrl Setg I/P 33 to 48	Ctrl Setg I/P 33 to 48	16 Character Text	
Setting to change the text associated with each individual custom input.			

Table 45 - Control Input Labels

6.16 Virtual Input Labels

Menu Text	Default Setting	Setting Range	Step Size
VIR I/P LABELS			
Virtual Input 1	Virtual Input 1	16 Character Text	
Setting to change the text associated with each individual virtual input.			
Virtual Input 2 to 128	Virtual Input 2 to 128	16 Character Text	
Setting to change the text associated with each individual virtual input.			

Table 46 - Virtual Input Labels

6.17 Virtual Output Labels

Menu Text	Default Setting	Setting Range	Step Size
VIR O/P LABELS			
Virtual Output 1	Virtual Output 1	16 Character Text	
Setting to change the text associated with each individual virtual output.			
Virtual Output 2 to 32	Virtual Output 2 to 32	16 Character Text	
Setting to change the text associated with each individual virtual output.			

Table 47 - Virtual Output Labels

6.18 User Alarm Labels

Menu Text	Default Setting	Setting Range	Step Size
USR ALARM LABELS			
SR User Alarm 1	SR User Alarm 1	16 Character Text	
Setting to change the text associated with each individual user definable self reset alarm.			
SR User Alarm 2 to 17	SR User Alarm 2 to 17	16 Character Text	
Setting to change the text associated with each individual user definable self reset alarm.			
MR User Alarm 18	MR User Alarm 18	16 Character Text	
Setting to change the text associated with each individual user definable manual reset alarm.			
MR User Alarm 19 to 35	SR User Alarm 19 to 35	16 Character Text	
Setting to change the text associated with each individual user definable manual reset alarm.			

Table 48 – User Alarm Labels

6.19 Disturbance Recorder Settings

The disturbance recorder settings include the record duration and trigger position, selection of analog and digital signals to record, and the signal sources that trigger the recording.

The precise event recorder column ("Disturb. Recorder" menu) is visible when the "Disturb recorder" setting ("Configuration" column) = "visible".

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
DISTURB. RECORDER				
Duration	XCPU2 (3s) XCPU3 (1.5s)	0.1s	**XCPU2 (3s)** **XCPU3 (10.5s)**??	0.01s
This sets the overall recording time.				
Trigger Position	XCPU2 (16.7%) XCPU3 (33.3%)	0	**XCPU2 (16.7%)** XCPU3 (100%)??	0.1%
This sets the trigger point as a percentage of the duration. For example, the default settings show that the overall recording time is set to 1.5s with the trigger point being at 33.3% of this, giving 0.5s pre-fault and 1s post fault recording times.				
Trigger Mode	Single	Single or Extended		
If set to single mode, if a further trigger occurs whilst a recording is taking place, the recorder will ignore the trigger. However, if this has been set to "Extended", the post trigger timer will be reset to zero, thereby extending the recording time.				
Analog. Channel 1	VA	VA, VB, VC, VCHECKSYNC., IA, IB, IC, IN, IN Sensitive		
Selects any available analog input to be assigned to this channel.				
Analog. Channel 2	VB	As above		
Analog. Channel 3	VC	As above		
Analog. Channel 4	IA	As above		
Analog. Channel 5	IB	As above		
Analog. Channel 6	IC	As above		
Analog. Channel 7	IN	As above		
Analog. Channel 8	IN Sensitive	As above		
Analog. Channel 9	Frequency	As above		
Digital Inputs 1 to 32	Relays 1 to 12 and Opto's 1 to 12	Any of 12 O/P Contacts or Any of 12 Opto Inputs or Internal Digital Signals		
The digital channels may be mapped to any of the opto isolated inputs or output contacts, in addition to a number of internal relay digital signals, such as protection starts, LEDs etc.				
Inputs 1 to 32 Trigger	No Trigger except Dedicated Trip Relay O/P's which are set to Trigger L/H	No Trigger, Trigger L/H, Trigger H/L		
Any of the digital channels may be selected to trigger the disturbance recorder on either a low to high or a high to low transition.				
Digital Inputs 33 to 128	Unused	Any of 12 O/P Contacts or Any of 12 Opto Inputs or Internal Digital Signals		
The digital channels may be mapped to any of the opto isolated inputs or output contacts, in addition to a number of internal relay digital signals, such as protection starts, LEDs etc.				

Table 49 - Disturbance Recorder Settings

Notes:

OPERATION

CHAPTER NO 6

Date:	10/2014
Products covered by this chapter:	This chapter covers the specific versions of the MiCOM products listed below. This includes ***only*** the following combinations of Software Version and Hardware Suffix.
Hardware Suffix:	L (P141, P142 & P143) & M (P145)
Software Version:	A0 - P14x (P141, P142, P143 & P145)
Connection Diagrams:	10P141xx (xx = 01 to 07) 10P142xx (xx = 01 to 07) 10P143xx (xx = 01 to 07) 10P145xx (xx = 01 to 07)

CONTENTS

TABLES

FIGURES

1 OPERATION OF INDIVIDUAL PROTECTION FUNCTIONS

The following sections detail the individual protection functions.

1.1 Overcurrent Protection

The overcurrent protection included in the P14x relays provides four-stage non-directional/ directional three-phase overcurrent protection with independent time delay characteristics. All overcurrent and directional settings apply to all three phases but are independent for each of the four stages. .

The first two stages of overcurrent protection have time-delayed characteristics which are selectable between Inverse Definite Minimum Time (IDMT), or Definite Time (DT). The third and fourth stages have definite time characteristics only.

Various methods are available to achieve correct relay co-ordination on a system; by means of time alone, current alone or a combination of both time and current. Grading by means of current is only possible where there is an appreciable difference in fault level between the two relay locations. Grading by time is used by some utilities but can often lead to excessive fault clearance times at or near source substations where the fault level is highest. For these reasons the most commonly applied characteristic in co-ordinating overcurrent relays is the IDMT type.

The inverse time delayed characteristics indicated above, comply with the following formula:

IEC curves

$$t = Tx \left(\frac{\beta}{(M^{\alpha} - 1)} + L \right) + C$$

or

IEEE curves

$$t = \text{TD x} \left(\frac{\beta}{M^{\alpha} - 1} + L \right) + C$$

where:

t	=	Operation time
β	=	Constant
M	=	I/Is
K	=	Constant
I	=	Measured current
Is	=	Current threshold setting
α	=	Constant
L	=	ANSI/IEEE constant (zero for IEC curves)
T	=	Time multiplier setting for IEC curves
TD	=	Time dial setting for IEEE curves
C	=	Definite time adder (zero for standard curves)

Curve Description	Standard	β Constant	α Constant	L Constant
Standard Inverse	IEC	0.14	0.02	0
Very Inverse	IEC	13.5	1	0
Extremely Inverse	IEC	80	2	0
Long Time Inverse	UK	120	1	0
Rectifier	UK	45900	5.6	0
Moderately Inverse	IEEE	0.0515	0.02	0.114
Very Inverse	IEEE	19.61	2	0.491
Extremely Inverse	IEEE	28.2	2	0.1217
Inverse	US	5.95	2	0.18
Short Time Inverse	US	0.16758	0.02	0.11858

Note *The IEEE and US curves are set differently to the IEC/UK curves, with regard to the time setting. A time multiplier setting (TMS) is used to adjust the operating time of the IEC curves, whereas a time dial setting is employed for the IEEE/US curves. The menu is arranged such that if an IEC/UK curve is selected, the "**I> Time Dial**" cell is not visible and vice versa for the TMS setting. For both IEC and IEEE/US type curves, a definite time adder setting is available that will effectively increase the operating time of the curves by the set value.*

Table 1 - Curve descriptions, standards and constants

The IEC/UK inverse characteristics can be used with a definite time reset characteristic, however, the IEEE/US curves may have an inverse or definite time reset characteristic. The following equation can used to calculate the inverse reset time for IEEE/US curves:

$$tRESET = \frac{TD \text{ x } S}{(1 - M^2)} \text{ in seconds}$$

Where:
TD = Time dial setting for IEEE curves
S = Constant
M = I/Is

Curve Description	Standard	S Constant
Moderately Inverse	IEEE	4.85
Very Inverse	IEEE	21.6
Extremely Inverse	IEEE	29.1
Inverse	US	5.95
Short Time Inverse	US	2.261

Table 2 - Curve descriptions, standards and constants

1.1.1 RI Curve

The RI curve (electromechanical) has been included in the first and second stage characteristic setting options for phase overcurrent and both earth fault 1 and earth fault 2 protections. The curve is represented by the following equation.

$$t = K \times \left(\frac{1}{0.339 - \left({}^{0.236}/_{M} \right)} \right) \text{ in seconds}$$

With K adjustable from 0.1 to 10 in steps of 0.05

1.1.2 Timer Hold Facility

The first two stages of overcurrent protection in the P14x relay are provided with a timer hold facility, which may either be set to zero or to a definite time value. Setting of the timer to zero means that the overcurrent timer for that stage will reset instantaneously once the current falls below 95% of the current setting. Setting of the hold timer to a value other than zero, delays the resetting of the protection element timers for this period. When the reset time of the overcurrent relay is instantaneous, the relay will be repeatedly reset and not be able to trip until the fault becomes permanent. By using the Timer Hold facility the relay will integrate the fault current pulses, thereby reducing fault clearance time.

The timer hold facility can be found for the first and second overcurrent stages as settings "**I>1 tRESET**" and "**I>2 tRESET**", respectively. Note that this cell is not visible for the IEEE/US curves if an inverse time reset characteristic has been selected, as the reset time is then determined by the programmed time dial setting.

The functional logic diagram for non-directional overcurrent is shown in Figure 1. The overcurrent block is a level detector that detects that the current magnitude is above the threshold. It provides a start and also initiates the IDMT/DT characteristic depending on the setting.

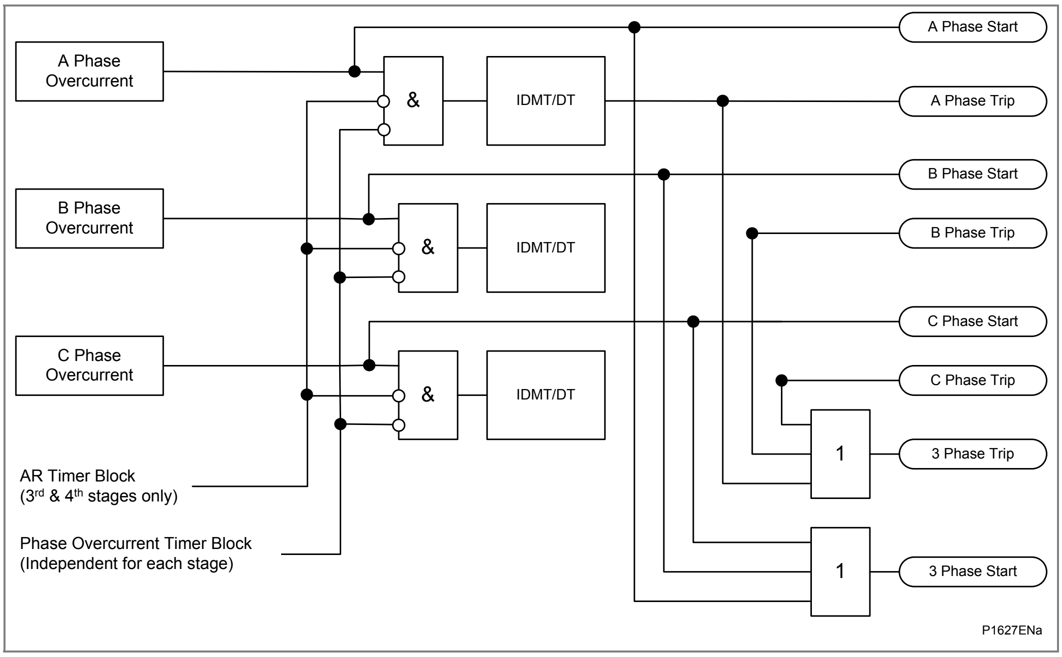


Figure 1 - Non-directional overcurrent logic diagram

A timer block input is available for each stage which will reset the overcurrent timers of all three phases if energized, taking account of the reset time delay if selected for the “**I>1**” and “**I>2**” stages.

The auto-reclose logic (A/R Block) can be set to block instantaneous overcurrent elements after a prescribed number of shots. This is set in the auto-reclose column. When a block instantaneous signal is generated then only those overcurrent stages i.e. “**I>3**” and “**I>4**” selected to '**1**' in the “**I> Blocking**” link will be blocked.

1.2 Directional Overcurrent Protection

The phase fault elements of the P14x relays are internally polarized by the quadrature phase-phase voltages, as shown in Table 3

Phase of Protection	Operate Current	Polarizing Voltage
A Phase	IA	VBC
B Phase	IB	VCA
C Phase	IC	VAB

Table 3 - Phase, Operating Current and Polarizing Voltages

Under system fault conditions, the fault current vector will lag its nominal phase voltage by an angle dependent upon the system X/R ratio. It is therefore a requirement that the relay operates with maximum sensitivity for currents lying in this region. This is achieved by means of the relay characteristic angle (RCA) setting; this defines the angle by which the current applied to the relay must be displaced from the voltage applied to the relay to obtain maximum relay sensitivity. This is set in cell "**I>Char Angle**" in the overcurrent menu. On the P14x relays, it is possible to set characteristic angles anywhere in the range –95° to +95°.

The functional logic block diagram for directional overcurrent is shown in Figure 2.

The overcurrent block is a level detector that detects that the current magnitude is above the threshold and together with the respective polarizing voltage, a directional check is performed based on the following criteria:

Directional forward

$$-90° < (\text{angle}(I) - \text{angle}(V) - RCA) < 90°$$

Directional reverse

$$-90° > (\text{angle}(I) - \text{angle}(V) - RCA) > 90°$$

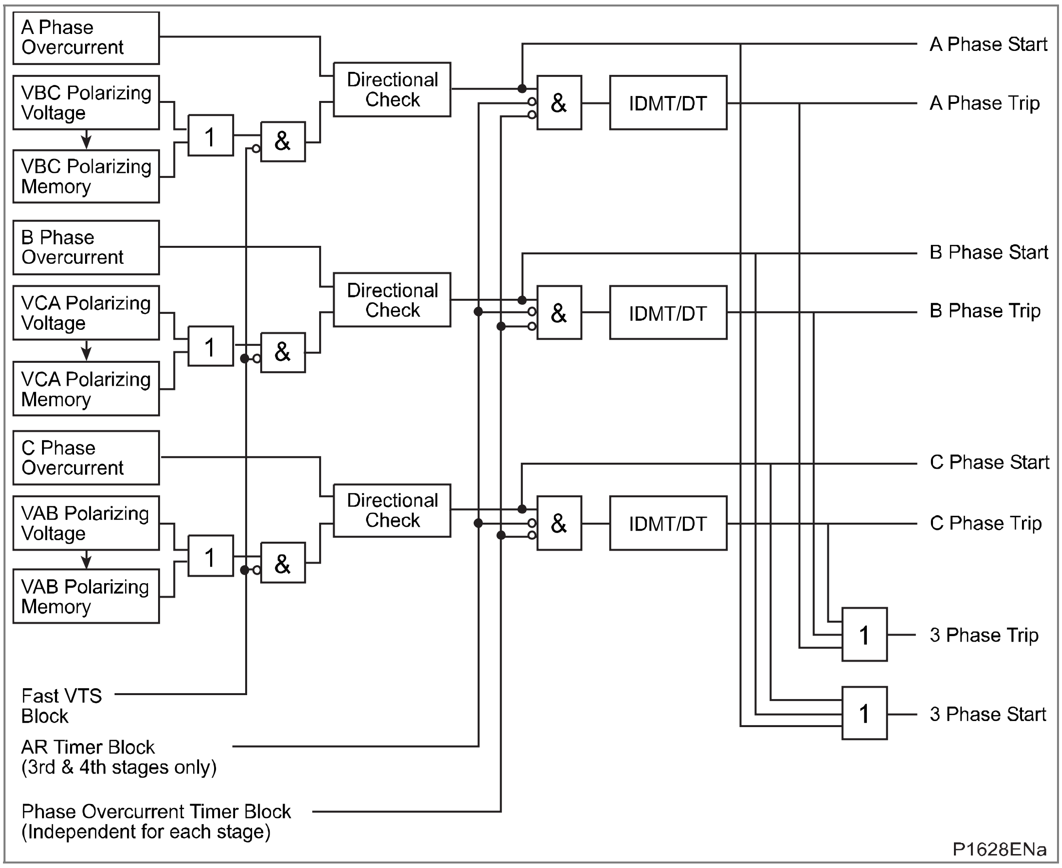


Figure 2 - Directional overcurrent logic

Any of the four overcurrent stages may be configured to be directional noting that IDMT characteristics are only selectable on the first two stages. When the element is selected as directional, a Voltage Transformer Supervision (VTS) Block option is available. When the relevant bit is set to 1, operation of the VTS, will block the stage if directionalized. When set to 0, the stage will revert to non-directional upon operation of the VTS.

1.2.1 Synchronous Polarization

For a close up three-phase fault, all three voltages will collapse to zero and no healthy phase voltages will be present. For this reason, the P14x relays include a synchronous polarization feature that stores the pre-fault voltage information and continues to apply it to the directional overcurrent elements for a time period of 3.2 seconds. This ensures that either instantaneous or time delayed directional overcurrent elements will be allowed to operate, even with a three-phase voltage collapse.

1.3 Thermal Overload Protection

The relay incorporates a current based thermal replica, using rms load current to model heating and cooling of the protected plant. The element can be set with both alarm and trip stages.

The heat generated within an item of plant, such as a cable or a transformer, is the resistive loss ($I^2R \times t$). Thus, heating is directly proportional to current squared. The thermal time characteristic used in the relay is therefore based on current squared, integrated over time. The relay automatically uses the largest phase current for input to the thermal model.

Equipment is designed to operate continuously at a temperature corresponding to its full load rating, where heat generated is balanced with heat dissipated by radiation etc. Over-temperature conditions therefore occur when currents in excess of rating are allowed to flow for a period of time. It can be shown that temperatures during heating follow exponential time constants and a similar exponential decrease of temperature occurs during cooling.

The relay provides two characteristics that may be selected according to the application.

1.3.1 Single Time Constant Characteristic

This characteristic is used to protect cables, dry type transformers (e.g. type AN), and capacitor banks.

The thermal time characteristic is given by:

$$t = -\tau \log_e \left(\frac{I^2 - (K.I_{FLC})^2}{(I^2 - Ip^2)} \right)$$

Where:

t	=	Time to trip, following application of the overload current, I;
τ	=	Heating and cooling time constant of the protected plant;
I	=	Largest phase current;
I_{FLC}	=	Full load current rating (relay setting '**Thermal Trip**');
k	=	1.05 constant, allows continuous operation up to <1.05 I_{FLC};
I_P	=	Steady state pre-loading before application of the overload.

The time to trip varies depending on the load current carried before application of the overload, i.e. whether the overload was applied from '**hot**" or "**cold**".

The thermal time constant characteristic may be rewritten as:

$$e^{(-t/\tau)} = \left(\frac{\theta - \theta p}{\theta - 1} \right)$$

Where:

$, = I^2/k^2\ I_{FLC}^2$

and

$\theta p = Ip^2/k^2\ I_{FLC}^2$

Where θ is the thermal state and is θ_p the pre-fault thermal state.

Note	*A current of 105%Is (kI_{FLC}) has to be applied for several time constants to cause a thermal state measurement of 100%*

1.3.2 Dual Time Constant Characteristic

This characteristic is used to protect oil-filled transformers with natural air cooling (e.g. type ONAN). The thermal model is similar to that with the single time constant, except that two timer constants must be set.

For marginal overloading, heat will flow from the windings into the bulk of the insulating oil. Thus, at low current, the replica curve is dominated by the long time constant for the oil. This provides protection against a general rise in oil temperature.

For severe overloading, heat accumulates in the transformer windings, with little opportunity for dissipation into the surrounding insulating oil. Thus, at high current, the replica curve is dominated by the short time constant for the windings. This provides protection against hot spots developing within the transformer windings.

Overall, the dual time constant characteristic provided within the relay serves to protect the winding insulation from ageing, and to minimize gas production by overheated oil. Note, however, that the thermal model does not compensate for the effects of ambient temperature change.

The thermal curve is defined as:

$$0.4e^{(-t/\tau)} + 0.6e^{(-t/\tau)} = \frac{I^2 - (k.I FLC)^2}{I^2 - Ip^2}$$

Where:

$\tau 1$ = Heating and cooling time constant of the transformer windings

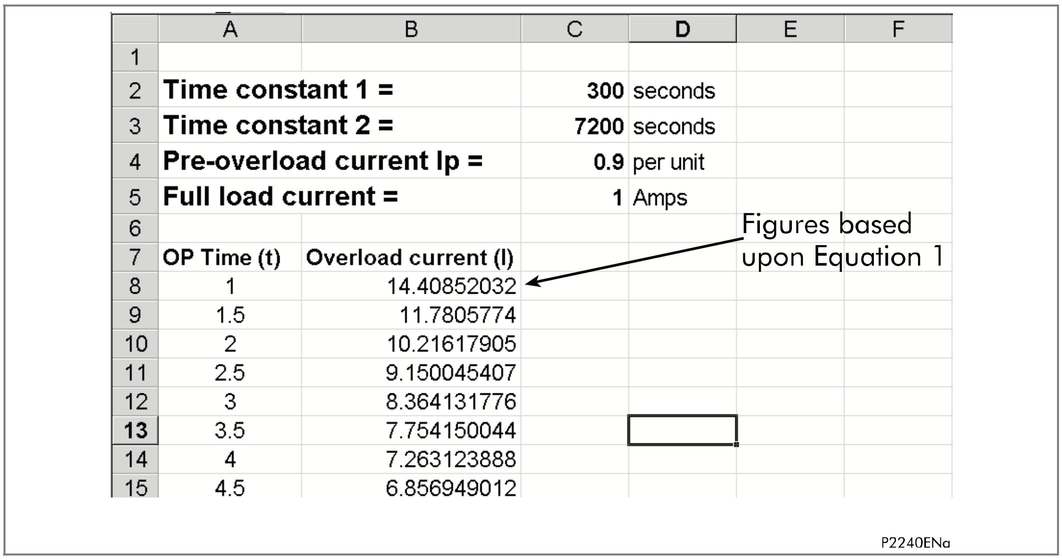
τ_2 = Heating and cooling time constant for the insulating oil

In practice, it is difficult to solve this equation to give the operating time (t), therefore a graphical solution, using a spreadsheet package, is recommended. The spreadsheet can be arranged to calculate the current that will give a chosen operating time. The equation to calculate the current is defined as:

Equation 1:

$$I = \sqrt{\frac{0.4 Ip^2.e^{(-t/\tau 1)} + 0.6 Ip^2.e^{(-t/\tau 2)} - k^2.I_{FLC}^2}{0.4\ e^{(-t/\tau 1)} + 0.6\ e^{(-t/\tau 2)} - 1}}$$

Figure 3 shows how this equation can be used within a spreadsheet to calculate the relay operating time.



	A	B	C	D	E	F
1						
2	**Time constant 1 =**		**300**	seconds		
3	**Time constant 2 =**		**7200**	seconds		
4	**Pre-overload current Ip =**		**0.9**	per unit		
5	**Full load current =**		**1**	Amps		
6						
7	**OP Time (t)**	**Overload current (I)**				
8	1	14.40852032				
9	1.5	11.7805774				
10	2	10.21617905				
11	2.5	9.150045407				
12	3	8.364131776				
13	3.5	7.754150044				
14	4	7.263123888				
15	4.5	6.856949012				

Figure 3 - Spreadsheet calculation for dual time constant thermal characteristic

The results from the spreadsheet can be plotted in a graph of current against time as shown in Figure 4.

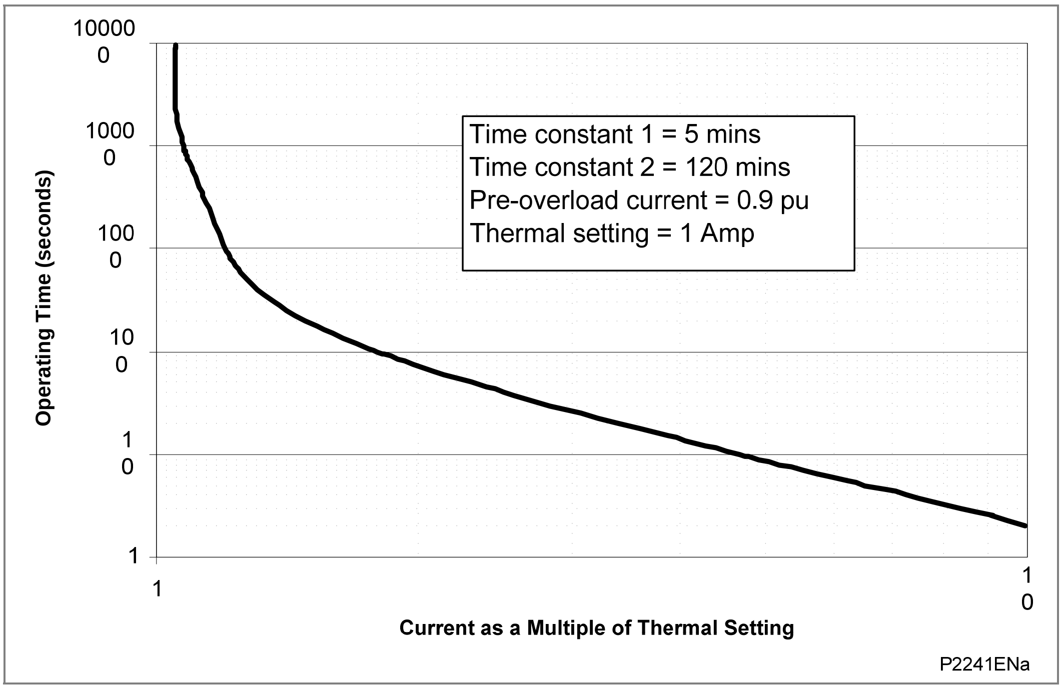


Figure 4 - Dual time constant thermal characteristic

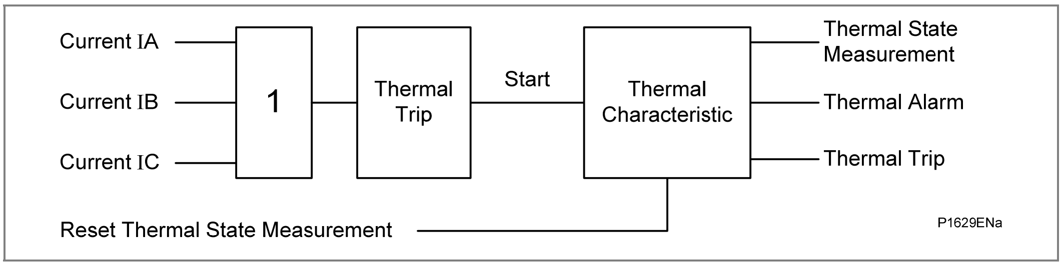


Figure 5 - Thermal overload protection logic diagram

The functional block diagram for the thermal overload protection is shown in Figure 5.

The magnitudes of the three phase input currents are compared and the largest magnitude taken as the input to the thermal overload function. If this current exceeds the thermal trip threshold setting a start condition is asserted.

The thermal protection also provides an indication of the thermal state in the '**MEASUREMENTS 3**' column of the relay. The thermal state can be reset by either an opto input (if assigned to this function using the programmable scheme logic) or the relay menu. The reset function in the menu is also found in the '**MEASUREMENTS 3**' column with the thermal state.

1.4 Earth Fault (EF) Protection

The P14x relays have a total of five input current transformers; one for each of the phase current inputs and two for supplying the Earth Fault (EF) protection elements. With this flexible input arrangement, various combinations of standard, Sensitive Earth Fault (SEF) and Restricted Earth Fault (REF) protection may be configured within the relay.

It should be noted that in order to achieve the sensitive setting range that is available in the P14x relays for SEF protection, the input CT is designed specifically to operate at low current magnitudes. This input is common to both the SEF and high impedance REF protection, so these features are treated as mutually exclusive within the relay menu.

1.4.1 Standard Earth Fault Protection Elements

The standard earth fault protection elements are duplicated within the P14x relays and are referred to in the relay menu as "Earth Fault 1" (EF1) and "Earth Fault 2" (EF2). EF1 operates from earth fault current which is measured directly from the system; either by means of a separate CT located in a power system earth connection or via a residual connection of the three line CTs. The EF2 element operates from a residual current quantity which is derived internally from the summation of the three-phase currents.

EF1 and EF2 are identical elements, each having four stages. The first and second stages have selectable IDMT or DT characteristics, whilst the third and fourth stages are DT only. Each stage is selectable to be either non-directional, directional forward or directional reverse. The Timer Hold facility, previously described for the overcurrent elements, is available on each of the first two stages.

The logic diagram for non-directional earth fault overcurrent is shown in Figure 6.

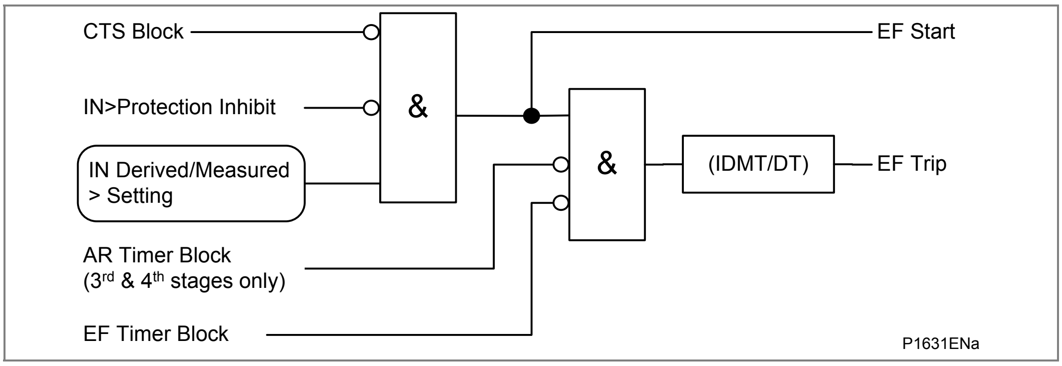


Figure 6 - Non-directional EF logic (single stage)

The earth fault protection can be set IN/OUT of service using the appropriate DDB inhibit signal that can be operated from an opto input or control command.

The auto-reclose logic (A/R Block) can be set to block instantaneous earth fault elements after a prescribed number of shots. This is set in the auto-reclose column. When a block instantaneous signal is generated then only those earth fault stages selected to '**1**' in the "**IN1> Function**" or "**IN2> Function**" link will be blocked.

For inverse time delayed characteristics refer to the phase overcurrent elements, section 1.1.

1.4.1.1 P144 - Reconstruction of the Missing Phase Current

The P144 relay is designed to function with inputs from only 2 phase CTs and one Core Balance CT (CBCT). Since only two phases are presented to the relay, the relay must derive the missing phase current using the available phase and earth current. The missing phase current is selectable in the CT and VT RATIO column in the cell name "**I**

Derived Phase". In this cell it is possible to select, either IA, IB or IC, with IB being the default setting.

The missing phase is calculated using one of the following equations:

$$\text{Current IA} = \left(\frac{\text{ISEF x ISEF CT Ratio}}{\text{Phase CT Ratio}} \right) - (\text{IB} + \text{IC})$$

$$\text{Current IB} = \left(\frac{\text{ISEF x ISEF CT Ratio}}{\text{Phase CT Ratio}} \right) - (\text{IA} + \text{IC})$$

input (see

$$\text{Current IC} = \left(\frac{\text{ISEF x ISEF CT Ratio}}{\text{Phase CT Ratio}} \right) - (\text{IA} + \text{IB})$$

The dynamic range of SEF current input is limited to 2In in order to give greater accuracy for small earth fault currents. However, in the event of a cross country fault the earth fault current may exceed 2In, which may limit the effectiveness of the earth fault protection. To improve the relays dynamic range, it is recommended that the standard earth fault input (EF1) be wired in series with the SEF section of P14x/EN AP/B74). The dynamic range of the EF1 input is limited to 64In. This then allows the EF1 protection to provide the high set protection instead of the SEF input.

Although the equations above indicate that the missing phase current is derived from the ISEF input, the relay actually selects the highest of either ISEF or EF1. In the event of a cross country fault, the ISEF input is likely to saturate, thus the highest current will be EF1. In order for this technique to function correctly it is essential that the E/F and SEF CT ratios are set the same.

1.4.1.2 IDG Curve

The IDG curve is commonly used for time delayed earth fault protection in the Swedish market. This curve is available in stages 1 and 2 of Earth Fault 1, Earth Fault 2 and Sensitive Earth Fault protections.

The IDG curve is represented by the following equation:

$$t = 5.8 - 1.35 \log_e \left(\frac{I}{\text{IN > Setting}} \right) \text{ in seconds}$$

Where:

I = Measured current

IN>Setting = An adjustable setting which defines the start point of the characteristic

Although the start point of the characteristic is defined by the "**IN>**" setting, the actual relay current threshold is a different setting called "**IDG Is**". The "**IDG Is**" setting is set as a multiple of "**IN>**".

An additional setting "**IDG Time**" is also used to set the minimum operating time at high levels of fault current.

Figure 7 illustrates how the IDG characteristic is implemented.

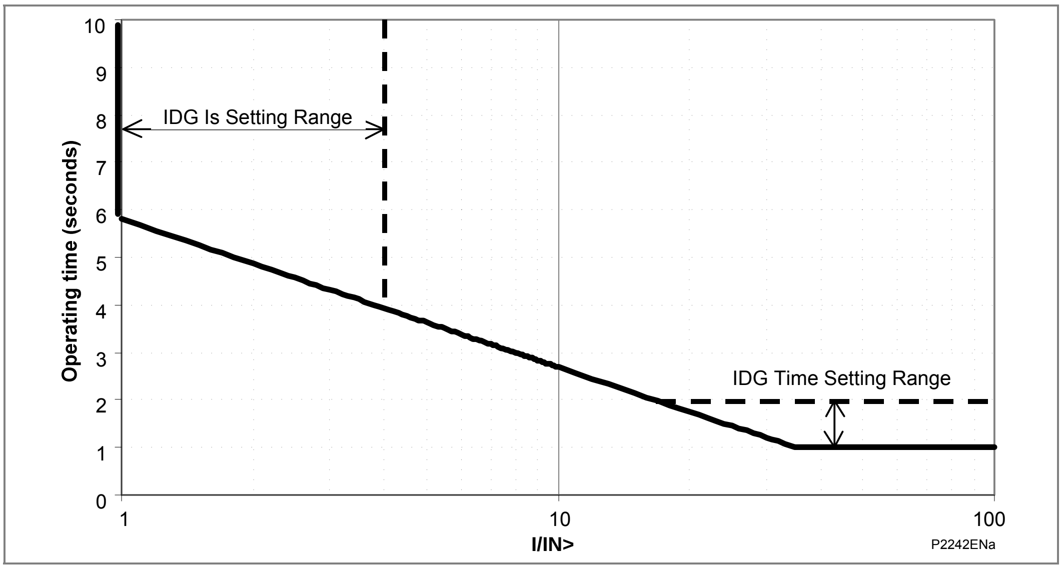


Figure 7 - IDG characteristic

1.4.2 Sensitive Earth Fault (SEF) Protection Element

A separate four-stage SEF element is provided within the P14x relay for this purpose, which has a dedicated input. The functionality of the SEF is the same as that illustrated in Figure 6 for EF1/2, bearing in mind that a separate input is used. The SEF protection can be set IN/OUT of service using the DDB 442 '**Inhibit SEF**' input signal that can be operated from an opto input or control command. This DDB signal blocks the starts and trips of all four stages of SEF protection. DDBs 216 - 219 '**ISEF>1/2/3/4 Timer Blk.**' can be used to block the four trip stages of SEF protection individually, however, these signals do not block the starts.

For the range of available inverse time delayed characteristics, refer to those of the phase overcurrent elements, section 1.1.

From the settings menu, the "**SEF/REF options**" cell has a number of setting options. To enable standard, four stage SEF protection, the SEF option should be selected, which is the default setting. However, if wattmetric, restricted earth fault (not applicable to P144) or a combination of both protections are required, then one of the remaining options should be selected. These are described in more detail in sections 1.5 and 1.6. The "**Wattmetric**" and "**Restricted E/F**" (not applicable to P144) cells will only appear in the menu if the functions have been selected in the option cell.

Each SEF stage is selectable to be either non-directional, directional forward or directional reverse in the "**ISEF>Direction**" cell. The timer hold facility, previously described for the overcurrent elements in section 1.1 is available on each of the first two stages and is set in the same manner.

1.4.2.1 EPATR B Curve

The EPATR B curve is commonly used for time delayed sensitive earth fault protection in certain markets. This curve is only available in the Sensitive Earth Fault protection stages 1 and 2.

The EPATR_B curve is based on primary current settings, employing a SEF CT Ratio of 100:1 A.

The EPATR_B curve has 3 separate segments defined in terms of the primary current and using the 100:1 fixed CT ratio and is defined as follows:

Segment	Primary Current Range Based on 100A:1A CT Ratio	Current/Time Characteristic
1	ISEF = 0.5A to 6.0A	t = 432 x TMS/ISEF $^{0.655}$ secs
2	ISEF = 6.0A to 200A	t = 800 x TMS/ISEF secs
3	ISEF above 200A	t = 4 x TMS secs

Where TMS (time multiplier setting) is 0.025 - 1.2 in steps of 0.025.

Figure 8 illustrates how the EPATR B characteristic is implemented.

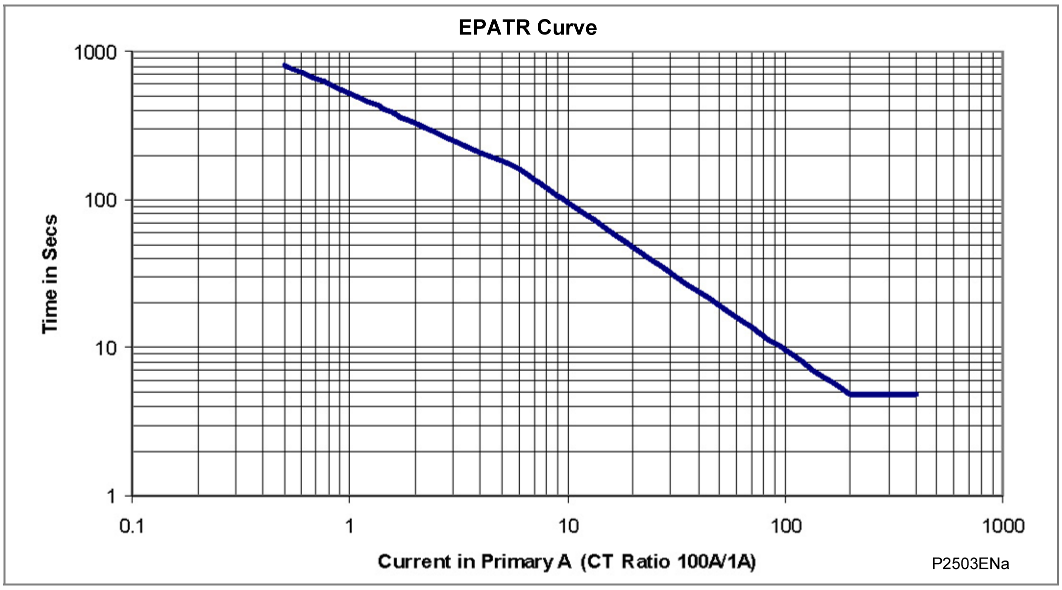


Figure 8 - EPATR B characteristic shown for TMS = 1.0

1.5 Directional Earth Fault (DEF) Protection

As stated in the previous sections, each of the four stages of EF1, EF2 and SEF protection may be set to be directional if required. Consequently, as with the application of directional overcurrent protection, a suitable voltage supply is required by the relay to provide the necessary polarization.

With the standard earth fault protection element in the P14x relay, two options are available for polarization; Residual Voltage or Negative Sequence. The Sensitive Earth Fault (SEF) protection element is available with only residual voltage polarization.

1.5.1 Residual Voltage Polarization

With earth fault protection, the polarizing signal requires to be representative of the earth fault condition. As residual voltage is generated during earth fault conditions, this quantity is commonly used to polarize DEF elements. The P141/P142/P143/P145 relay internally derives this voltage from the 3-phase voltage input that must be supplied from either a 5-limb or three single-phase VTs. The P144 relay on the other hand, measures this voltage from the residual voltage input which must be supplied from a suitable broken delta VT. These types of VT design allow the passage of residual flux and consequently permit the relay to derive the required residual voltage. In addition, the primary star point of the VT must be earthed. A three limb VT has no path for residual flux and is therefore unsuitable to supply the relay.

It is possible that small levels of residual voltage will be present under normal system conditions due to system imbalances, VT inaccuracies, relay tolerances etc. Hence, the P14x relay includes a user settable threshold (IN>VNPol set) which must be exceeded in order for the DEF function to be operational. The residual voltage measurement provided in the “**Measurements 1**” column of the menu may assist in determining the required threshold setting during the commissioning stage, as this will indicate the level of standing residual voltage present.

Note	*Residual voltage is nominally 180° out of phase with residual current. Consequently, the DEF elements are polarized from the "**-Vres**" quantity. This 180° phase shift is automatically introduced within the P14x relay.*

The logic diagram for directional earth fault overcurrent with neutral voltage polarization is shown in Figure 9.

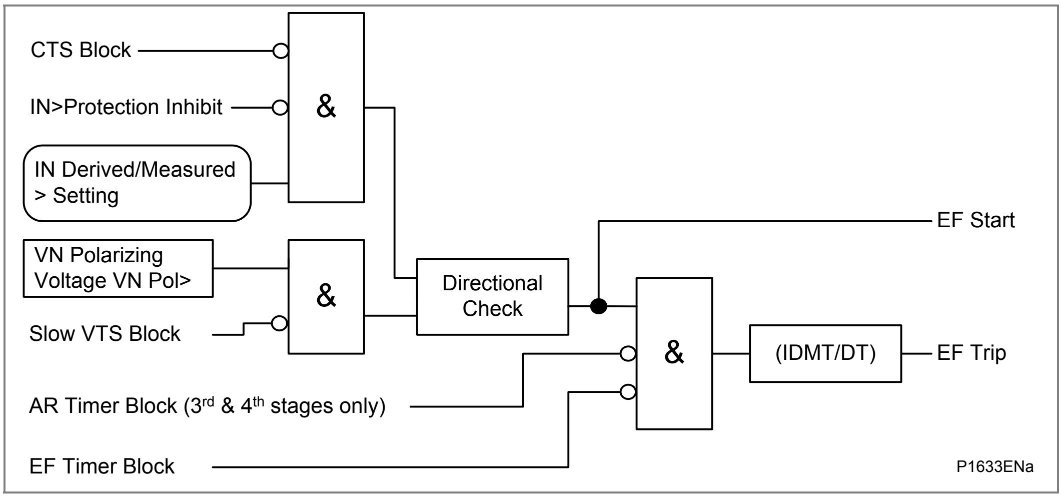


Figure 9 - Directional EF with neutral voltage polarization (single state)

VT Supervision (VTS) selectively blocks the directional protection or causes it to revert to non-directional operation. When selected to block the directional protection, VTS blocking is applied to the directional checking which effectively blocks the start outputs as well.

1.5.2 Negative Sequence Polarization

In certain applications, the use of residual voltage polarization of DEF may either be not possible to achieve, or problematic. An example of the former case would be where a suitable type of VT was unavailable, for example if only a three limb VT was fitted. An example of the latter case would be an HV/EHV parallel line application where problems with zero sequence mutual coupling may exist.

In either of these situations, the problem may be solved by the use of Negative Phase Sequence (NPS) quantities for polarization. This method determines the fault direction by comparison of NPS voltage with NPS current. The operate quantity, however, is still residual current.

This is available for selection on both the derived and measured standard earth fault elements (EF1 and EF2) but not on the SEF protection. It requires a suitable voltage and current threshold to be set in cells "**IN>V2pol set**" and "**IN>I2pol set**", respectively.

Negative sequence polarizing is not recommended for impedance earthed systems regardless of the type of VT feeding the relay. This is due to the reduced earth fault current limiting the voltage drop across the negative sequence source impedance (V2pol) to negligible levels. If this voltage is less than 0.5 volts the relay will cease to provide DEF.

The logic diagram for directional earth fault overcurrent with negative sequence polarization is shown in Figure 10.

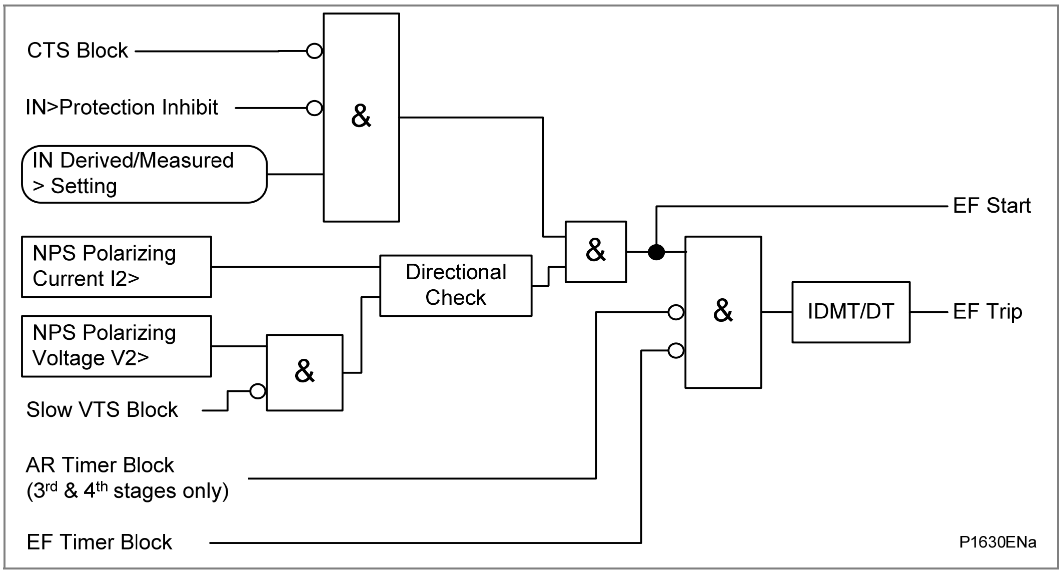


Figure 10 - Directional EF with negative sequence polarization (single stage)

The directional criteria with negative sequence polarization is given below:

Directional forward	-90° < (angle(I2) - angle(V2 + 180°) - RCA) < 90°
Directional reverse	-90° > (angle(I2) - angle(V2 + 180°) - RCA) > 90°

1.5.3 Operation of Sensitive Earth Fault (SEF) Element

The SEF element is designed to be applied to resistively earthed, insulated and compensated networks and have distinct functions to cater for these different requirements.

The logic diagram for sensitive directional earth fault overcurrent with neutral voltage polarization is shown in Figure 11.

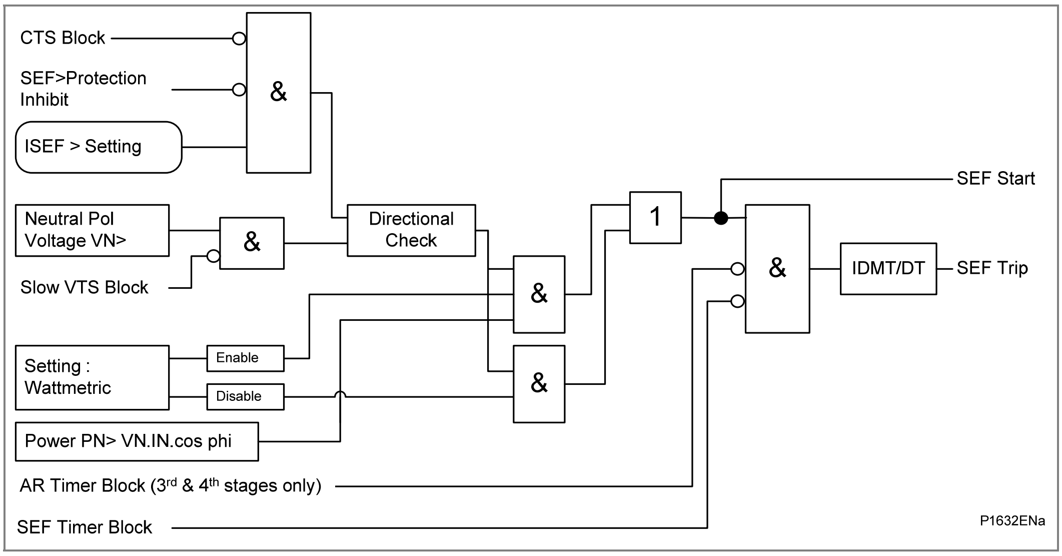


Figure 11 - Directional SEF with VN polarization (single stage)

The Sensitive Earth Fault (SEF) protection can be set IN/OUT of service using the appropriate DDB inhibit signal that can be operated from an opto input or control command. VT Supervision (VTS) selectively blocks the directional protection or causes it to revert to non-directional operation. When selected to block the directional protection, VTS blocking is applied to the directional checking which effectively blocks the start outputs as well.

The directional check criteria are given below for the standard directional sensitive earth fault element:

Directional forward $-90° < (\text{angle}(I_N) - \text{angle}(V_N + 180°) - \text{RCA}) < 90°$

Directional reverse $-90° > (\text{angle}(I_N) - \text{angle}(V_N + 180°) - \text{RCA}) > 90°$

Three possibilities exist for the type of protection element that may be applied for earth fault detection:

1. A suitably sensitive directional earth fault relay having a Relay Characteristic Angle setting (RCA) of zero degrees, with the possibility of fine adjustment about this threshold.
2. A sensitive directional zero sequence wattmetric relay having similar requirements to 1. Above with respect to the required RCA settings.
3. A sensitive directional earth fault relay having $I\cos\phi$ and $I\sin\phi$ characteristics.

All stages of the sensitive earth fault element of the P14x relay are settable down to 0.5% of rated current and would therefore fulfill the requirements of the first method listed above and could therefore be applied successfully. However, many utilities (particularly in central Europe) have standardized on the wattmetric method of earth fault detection, which is described in the following section.

Zero sequence power measurement, as a derivative of Vo and Io, offers improved relay security against false operation with any spurious core balance CT output for non earth fault conditions. This is also the case for a sensitive directional earth fault relay having an adjustable Vo polarizing threshold.

1.5.4 Wattmetric Characteristic

Analysis has shown (see Application Notes, section 2.5.4) that a small angular difference exists between the spill current on the healthy and faulted feeders for earth faults on compensated networks. Taking into account the efforts of coil and feeder resistance, it can be seen that this angular difference gives rise to active components of current which are in anti-phase to one another. This is shown in Figure 12.

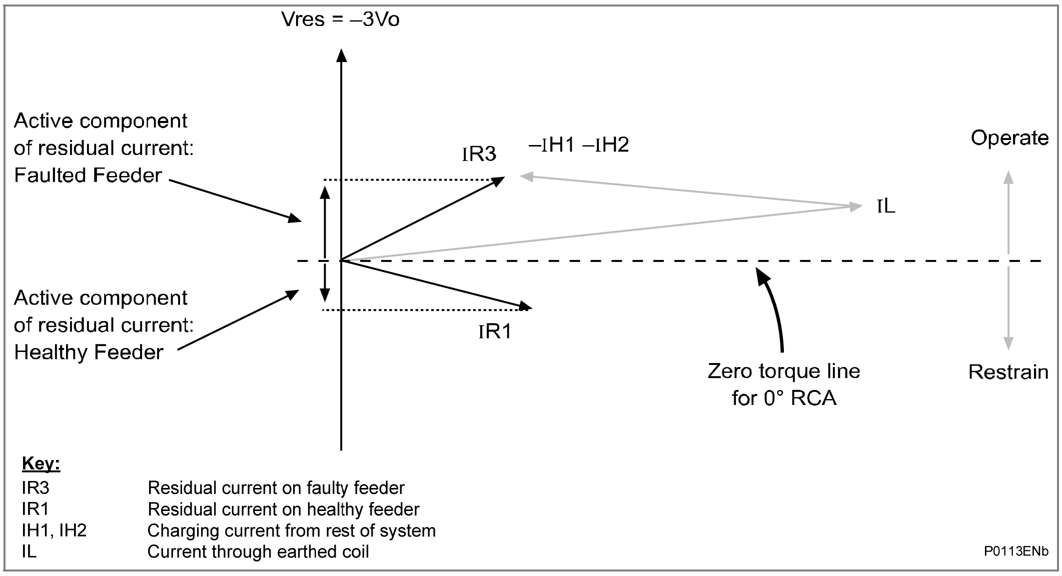


Figure 12 - Resistive components of spill current

Consequently, the active components of zero sequence power will also lie in similar planes and so a relay capable of detecting active power would be able to make a discriminatory decision. i.e. if the wattmetric component of zero sequence power was detected in the forward direction, then this would be indicative of a fault on that feeder; if power was detected in the reverse direction, then the fault must be present on an adjacent feeder or at the source

For operation of the directional earth fault element within the P14x relays, all three of the settable thresholds on the relay must be exceeded; namely the current "**ISEF>**", the voltage "**ISEF>VNpol Set**" and the power "**PN> Setting**".

As can be seen from the following formula, the power setting within the relay menu is called PN> and is therefore calculated using residual rather than zero sequence quantities. Residual quantities are three times their respective zero sequence values and so the complete formula for operation is as shown below:

The PN> setting corresponds to:

$$\text{Vres} \times \text{Ires} \times \text{Cos}(\phi - \phi c) = 9 \times \text{Vo} \times \text{Io} \times \text{Cos}(\phi - \phi c)$$

Where:

ϕ	=	Angle between the Polarizing Voltage (-Vres) and the Residual Current
ϕc	=	Relay Characteristic Angle (RCA) Setting (ISEF> Char. Angle)
Vres	=	Residual Voltage
Ires	=	Residual Current
Vo	=	Zero Sequence Voltage
Io	=	Zero Sequence Current

The action of setting the PN> threshold to zero would effectively disable the wattmetric function and the relay would operate as a basic, sensitive directional earth fault element. However, if this is required, then the '**SEF**' option can be selected from the '**Sens. E/F Options**' cell in the menu.

Note	*The residual power setting, PN>, is scaled by the programmed CT and VT ratios in the relay.*

A further point to note is that when a power threshold other than zero is selected, a slight alteration is made to the angular boundaries of the directional characteristic. Rather than being ±90° from the RCA, they are made slightly narrower at ±85°.

The directional check criteria is as follows:

Directional Forward -85° < (angle(I_N) - angle(V_N + 180°) - RCA) < 85°

Directional Reverse -85° > (angle(I_N) - angle(V_N + 180°) - RCA) > 85°

1.5.5 Icosϕ/Isinϕ Characteristic

In some applications, the residual current on the healthy feeder can lie just inside the operating boundary following a fault condition. The residual current for the faulted feeder lies close to the operating boundary.

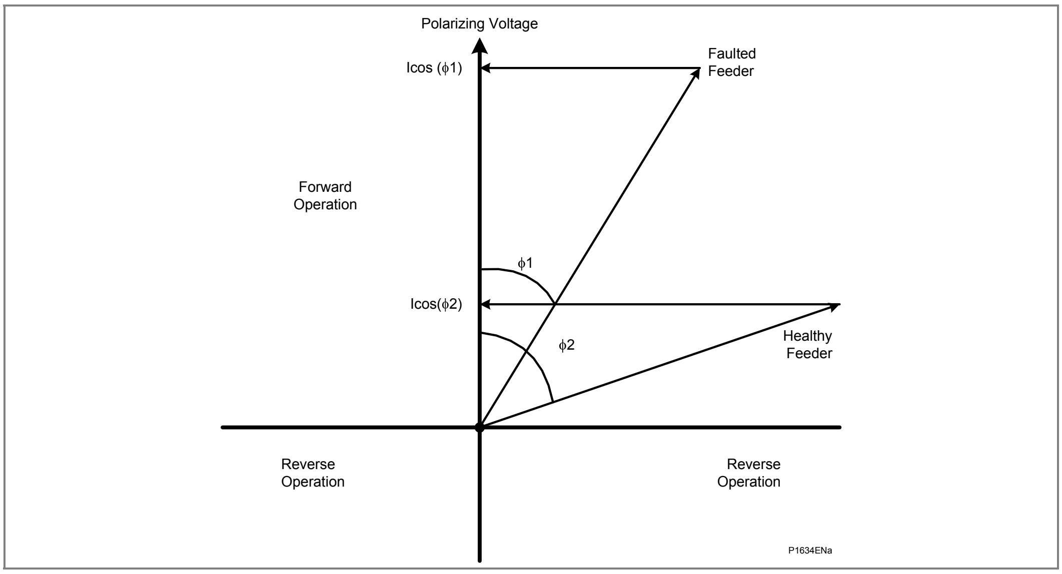


Figure 13 - Operating characteristic for Icosϕ

Figure 13 shows the method of discrimination when the real (cosϕ) component is considered, since faults close to the polarizing voltage will have a higher magnitude than those close to the operating boundary. In the diagram, it is assumed that the actual magnitude of current is I in both the faulted and non-faulted feeders.

Active component Icosϕ

The criterion for operation is: I (cosϕ) > Isef

Reactive component Isinϕ

The criterion for operation is: I (sinϕ) > Isef

Where Isef is the relay stage sensitive earth fault current setting.

If any stage is set non-directional, the element reverts back to normal operation based on current magnitude I with no directional decision.

In this case, correct discrimination is achieved by means of an Icosϕ characteristic as the faulted feeder will have a large active component of residual current, whilst the healthy feeder will have a small value.

For insulated earth applications, it is common to use the Isinϕ characteristic.

All of the relevant settings can be found under the SENSITIVE E/F column within the relay menu. Within the Sens. E/F Options cell, there are two possibilities for selecting wattmetric earth fault protection; either on its own or in conjunction with low impedance REF protection, which is described in section 1.6.1. The SEF cosϕ and SEF sinϕ options are not available with low impedance REF protection.

1.6 Restricted Earth Fault (REF) Protection (Not Applicable to P144)

The Restricted Earth Fault (REF) protection in the P14x relays may be configured to operate as either a high impedance or low impedance element and the following sections describe the application of the relay in each mode.

The high impedance REF element of the relay shares the same CT input as the SEF protection hence, only one of these elements may be selected. However, the low impedance REF element does not use the SEF input and so may be selected at the same time.

1.6.1 Biased Differential Protection

In a biased differential relay, the through current is measured and used to increase the setting of the differential element. For heavy through faults, one CT in the scheme can be expected to become more saturated than the other and hence differential current can be produced. However, biasing will increase the relay setting such that the resulting differential current is insufficient to cause operation of the relay.

Figure 14 and Figure 15 show the operating characteristic for the P14x relay applied for biased REF protection.

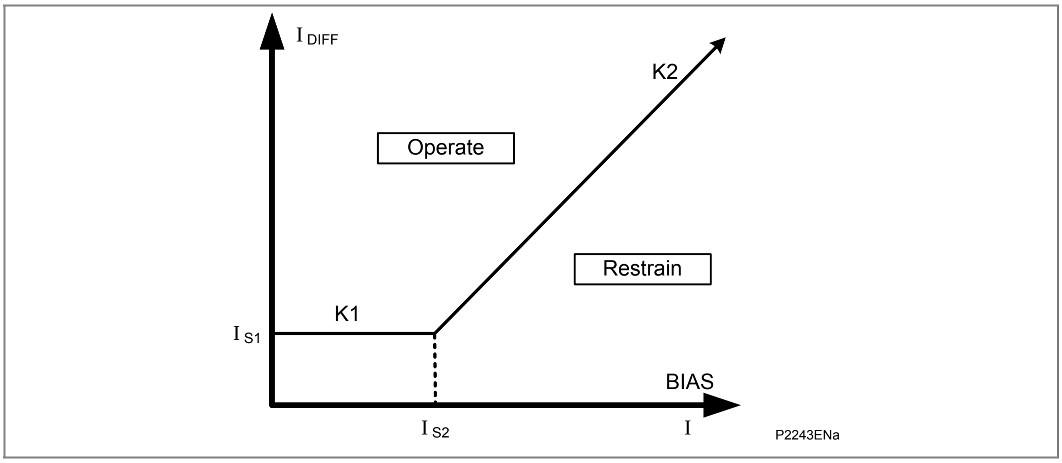


Figure 14 - REF bias characteristic

The actual operating characteristic of the element is shown in Figure 14.

The formulae used by the relay to calculate the required bias quantity is therefore as follows:

Ibias = {(Highest of Ia, Ib or Ic) + (Ineutral x Scaling Factor)}/2

The reason for the scaling factor included on the neutral current is explained by referring to Figure 15.

For IBIAS < IS2

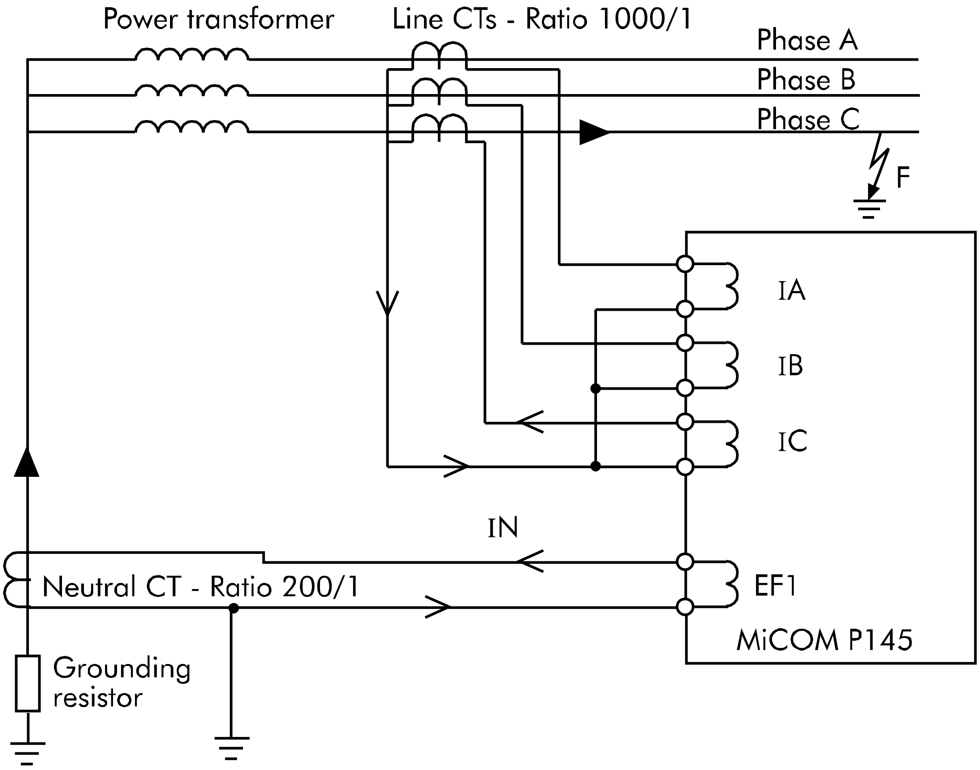
Operate when IDIFF > IS1 + K1.IBIAS

For IBIAS = IS2

Operate when IDIFF > IS1 + K1.IS2

For IBIAS > IS2

Operate when IDIFF > IS1 + K1.IS2 + K2.(IBIAS-IS2)



$$I\text{Bias} = \frac{(\text{Highest of } I_A,\ I_B \text{ or } I_C) + (I_N \times \text{Scaling factor})}{2}$$

$$\text{Where scaling factor} = \frac{\text{Neutral CT ratio}}{\text{Line CT ratio}} \quad \left(= \frac{200}{1000} = 0.2 \text{ in this case} \right)$$

$$I\text{Diff} = \overline{I_A} + \overline{I_B} + \overline{I_C} + (\text{Scaling factor} \times \overline{I_N})$$

P0114ENb

Figure 15 - REF bias principle

Where it is required that the neutral CT also drives the EF1 protection element to provide standby earth fault protection, it may be a requirement that the neutral CT has a lower ratio than the line CTs in order to provide better earth fault sensitivity. If this were not accounted for in the REF protection, the neutral current value used would be incorrect. For this reason, the relay automatically scales the level of neutral current used in the bias calculation by a factor equal to the ratio of the neutral to line CT primary ratings. The use of this scaling factor is shown in Figure 15, where the formulae for bias and differential currents are given.

1.6.2 High Impedance Restricted Earth Protection

The high impedance principle is best explained by considering a differential scheme where one CT is saturated for an external fault, as shown in Figure 16.

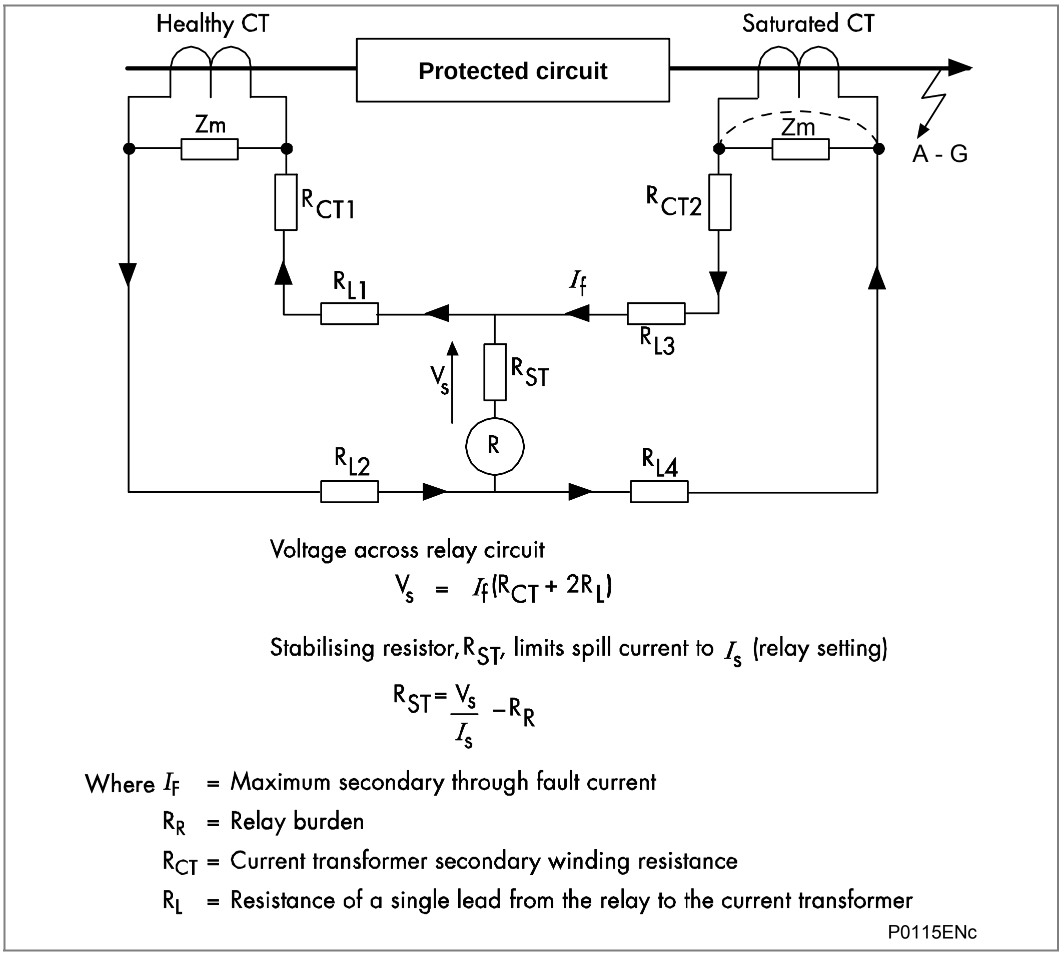


Figure 16 - High impedance principle

If the relay circuit is considered to be a very high impedance, the secondary current produced by the healthy CT will flow through the saturated CT. If CT magnetizing impedance of the saturated CT is considered to be negligible, the maximum voltage across the relay circuit will be equal to the secondary fault current multiplied by the connected impedance, (R_{L3} + R_{L4} + R_{CT2}).

The relay can be made stable for this maximum applied voltage by increasing the overall impedance of the relay circuit, such that the resulting current through the relay is less than its current setting. As the impedance of the relay input alone is relatively low, a series connected external resistor is required. The value of this resistor, R_{ST}, is calculated by the formula shown in Figure 16 An additional non-linear, metrosil, may be required to limit the peak secondary circuit voltage during internal fault conditions.

To ensure that the protection will operate quickly during an internal fault, the CT's used to operate the protection must have a kneepoint voltage of at least 4Vs.

The necessary relay connections for high impedance REF are shown in Figure 17.

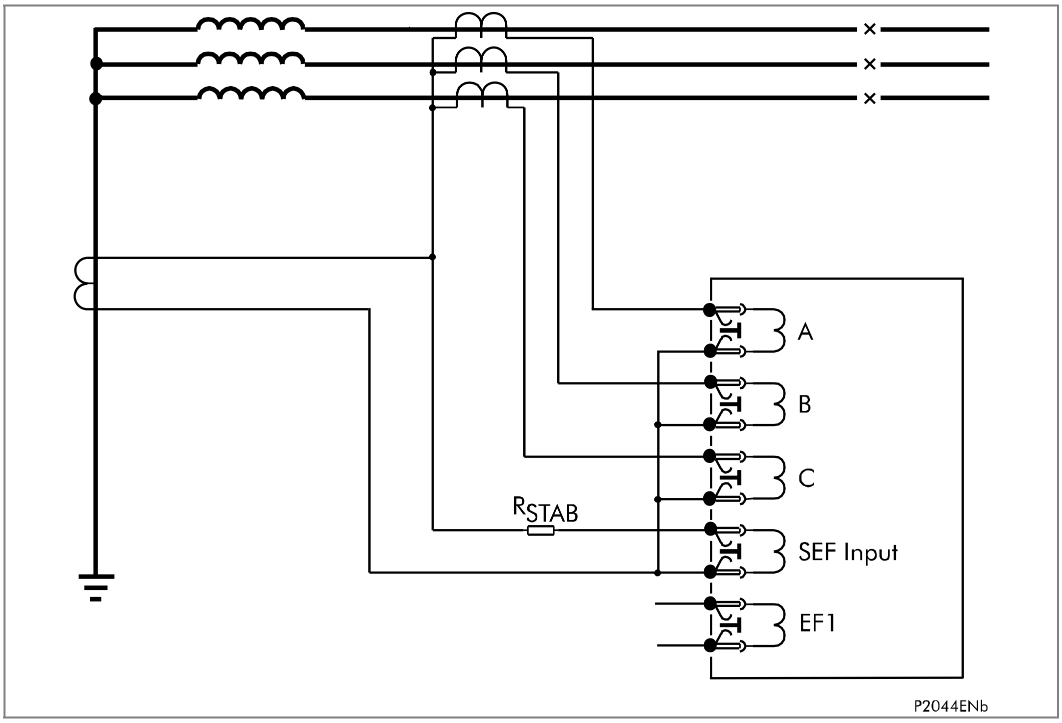


Figure 17 - High impedance REF relay/CT connections

1.7 Residual Overvoltage (Neutral Displacement) Protection

On a healthy three-phase power system, the addition of each of the three-phase to earth voltages is nominally zero, as it is the vector addition of three balanced vectors at 120° to one another. However, when an earth fault occurs on the primary system this balance is upset and a '**residual**' voltage is produced. This could be measured, for example, at the secondary terminals of a voltage transformer having a "**broken delta**" secondary connection. Hence, a residual voltage-measuring relay can be used to offer earth fault protection on such a system. Note that this condition causes a rise in the neutral voltage with respect to earth that is commonly referred to as "**neutral voltage displacement**" or NVD.

The detection of a residual overvoltage condition is an alternative means of earth fault detection, which does not require any measurement of current. This may be particularly advantageous in high impedance earthed or insulated systems, where the provision of core balance CT's on each feeder may be either impractical, or uneconomic.

The P14x relay internally derives this residual voltage from the three-phase voltage input that must be supplied from either a 5-limb or three single-phase VTs. The NVD element within the P14x relays is of two-stage design, each stage having separate voltage and time delay settings. Stage 1 may be set to operate on either an IDMT or DT characteristic, whilst stage 2 may be set to DT only.

The IDMT characteristic available on the first stage is defined by the following formula:

$$t = K/(M - 1)$$

Where:

K	=	Time multiplier setting
t	=	Operating time in seconds
M	=	Derived residual voltage/relay setting voltage (VN> Voltage Set)

Two stages are included for the NVD protection to account for applications that require both alarm and trip stages, for example, an insulated system. It is common in such a case for the system to have been designed to withstand the associated healthy phase overvoltages for a number of hours following an earth fault. In such applications, an alarm is generated soon after the condition is detected, which serves to indicate the presence of an earth fault on the system. This gives time for system operators to locate and isolate the fault. The second stage of the protection can issue a trip signal if the fault condition persists.

The functional block diagram of the first stage residual overvoltage is shown in Figure 18:

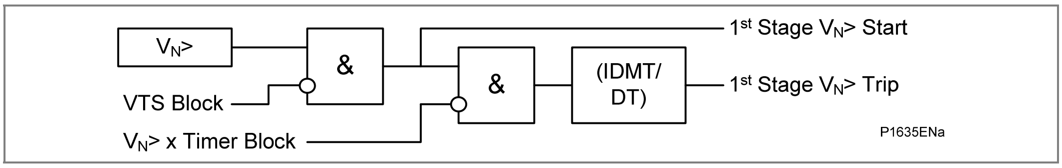


Figure 18 - Residual overvoltage logic (single stage)

VTS blocking when asserted, effectively blocks the start outputs.

When enabled, the following signals are set by the residual overvoltage logic according to the status of the monitored function:

VN>1 Start	(DDB 327)	1st Stage Residual Overvoltage Start
VN>2 Start	(DDB 328)	2nd Stage Residual Overvoltage Start
VN>1 Timer Blk.	(DDB 220)	Block Residual Overvoltage Stage 1 Time Delay
VN>2 Timer Blk.	(DDB 221)	Block Residual Overvoltage Stage 2 Time Delay
VN>1 Trip	(DDB 274)	1st Stage Residual Overvoltage Trip
VN>2 Trip	(DDB 275)	2nd Stage Residual Overvoltage Trip

1.8 Undervoltage Protection

Both the under and overvoltage protection functions can be found in the relay menu "**Volt Protection**". The undervoltage protection included within the P14x relays consists of two independent stages. These are configurable as either phase to phase or phase to neutral measuring within the "**V<Measur't mode**" cell.

Stage 1 may be selected as IDMT, DT or Disabled, within the "**V<1 Function**" cell. Stage 2 is DT only and is enabled/disabled in the "**V<2 status**" cell.

The IDMT characteristic available on the first stage is defined by the following formula:

$t = K/(1 - M)$

Where:
K = Time multiplier setting
t = Operating time in seconds
M = Measured voltage/relay setting voltage (V< Voltage Set)

Two stages are included to provide both alarm and trip stages, where required. Alternatively, different time settings may be required depending upon the severity of the voltage dip, i.e. motor loads will be able to withstand a small voltage depression for a longer time than if a major voltage excursion were to occur.

Outputs are available for single or three-phase conditions via the "**V<Operate Mode**" cell.

The logic diagram of the first stage undervoltage function is shown in Figure 19.

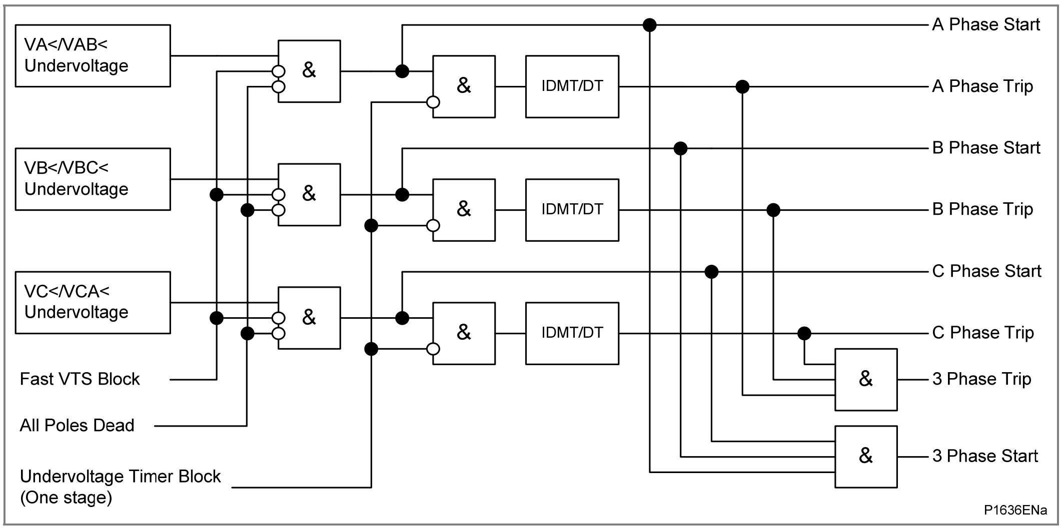


Figure 19 - Undervoltage - single and three phase tripping mode (single stage)

When the protected feeder is de-energized, or the circuit breaker is opened, an undervoltage condition would be detected. Therefore, the "**V<Poledead Inh**" cell is included for each of the two stages to block the undervoltage protection from operating for this condition. If the cell is enabled, the relevant stage will become inhibited by the in-built pole dead logic within the relay. This logic produces an output when it detects either an open circuit breaker via auxiliary contacts feeding the relay opto inputs or it detects a combination of both undercurrent and undervoltage on any one phase.

Note	*When the setting "**oper mode**" set to '**Any Phase**', the stage DDB will be from an OR gate output of the three individual phases start/trip and when it is set to '**Three Phase**', the stage DDB will be from an AND gate output of the three individual phases signal. This is applicable for over voltage and rate of change of voltage protection.*

1.9 Overvoltage Protection

Both the under and overvoltage protection functions can be found in the relay menu "**Volt Protection**". The overvoltage protection included within the P14x relays consists of two independent stages. These are configurable as either phase to phase or phase to neutral measuring within the "**V>Measur't mode**" cell.

Stage 1 may be selected as IDMT, DT or Disabled, within the "**V>1 Function**" cell. Stage 2 is DT only and is enabled/disabled in the "**V>2 status**" cell.

The IDMT characteristic available on the first stage is defined by the following formula:

$t = K/(M - 1)$

Where:
K = Time multiplier setting
t = Operating time in seconds
M = Measured voltage / relay setting voltage (V> Voltage Set)

The logic diagram of the first stage overvoltage function is shown in Figure 20.

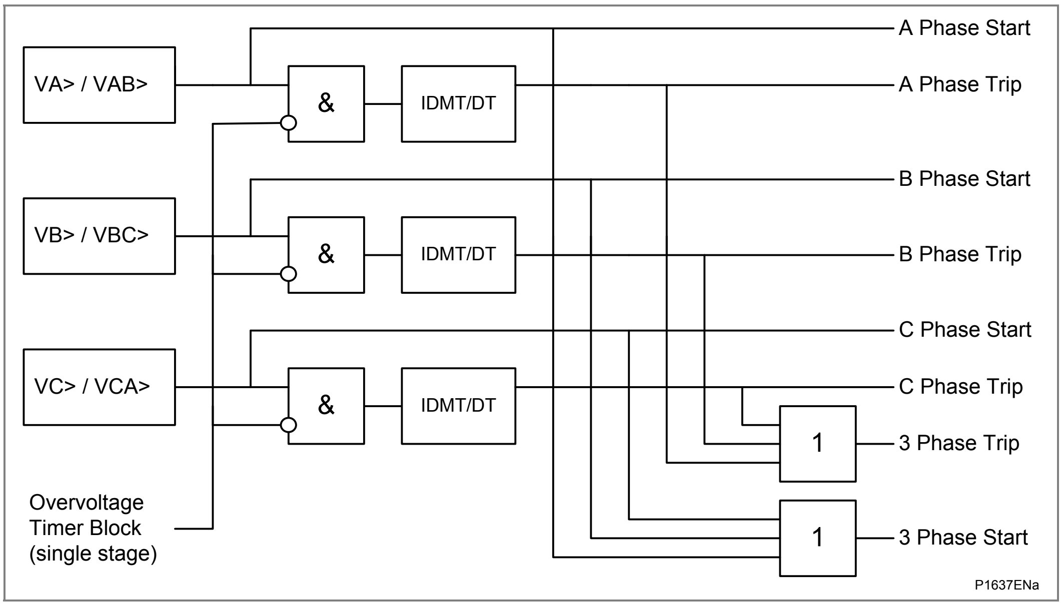


Figure 20 - Overvoltage - single and three phase tripping mode (single stage)

1.10 Negative Sequence Overvoltage Protection

The P14x relay includes a negative phase sequence overvoltage element. This element monitors the input voltage rotation and magnitude (normally from a bus connected voltage transformer) and may be interlocked with the motor contactor or circuit breaker to prevent the motor from being energized whilst incorrect phase rotation exists.

This single stage is selectable as definite time only and is enabled within the "**V2>status**" cell.

The logic diagram for the negative sequence overcurrent protection is shown in Figure 21:

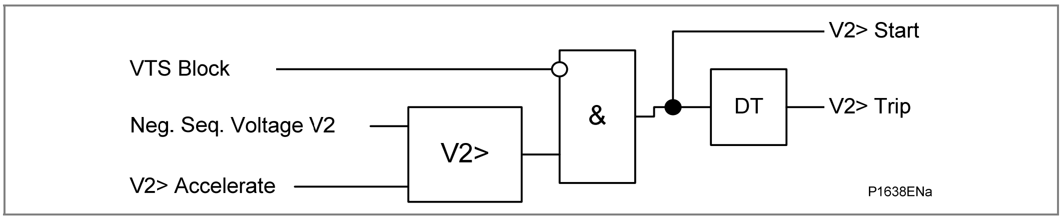


Figure 21 - Negative sequence overvoltage element logic

When enabled, the following signals are set by the negative sequence overvoltage logic according to the status of the monitored function.

V2> Accelerate	(DDB 517)	Accelerate the operating time of the function from typically 80msec. to 40msec. when set to instantaneous
V2> Start	(DDB 330)	Stage started when high
V2> Trip	(DDB 277)	Stage tripped when high

1.11 Negative Phase Sequence (NPS) Overcurrent Protection

The relay provides four independent stages of Negative Phase Sequence (NPS) overcurrent protection.

The negative phase sequence overcurrent protection included in the P14x relays provides four-stage non-directional/directional overcurrent protection with independent time delay characteristics. The first two stages of overcurrent protection have time-delayed characteristics which are selectable between Inverse Definite Minimum Time (IDMT), or Definite Time (DT). The third and fourth stages have definite time characteristics only. The inverse time delayed characteristics support both IEC and IEEE curves and please refer to section 1.1 for a detailed description. The user may choose to directionalize operation of the elements, for either forward or reverse fault protection for which a suitable relay characteristic angle may be set. Alternatively, the elements may be set as non-directional.

For the negative phase sequence directional elements to operate, the relay must detect a polarizing voltage above a minimum threshold, "**I2> V2pol Set**". When the element is selected as directional, a VTS Block option is available. When the relevant bit is set to 1, operation of the Voltage Transformer Supervision (VTS), will block the stage if directionalized. When set to 0, the stage will revert to non-directional upon operation of the VTS.

When enabled, the following signals are set by the negative sequence O/C logic according to the status of the monitored function.

I2> Inhibit	(DDB 504)	Inhibit all 4 stages when high
I2>1 Tmr. Block	(DDB 505)	Block timer on 1st stage when high
I2>2 Tmr. Block	(DDB 506)	Block timer on 1st stage when high
I2>3 Tmr. Block	(DDB 507)	Block timer on 1st stage when high
I2>4 Tmr. Block	(DDB 508)	Block timer on 1st stage when high
I2>1 Start	(DDB 509)	1st stage started when high
I2>2 Start	(DDB 510)	2nd stage started when high
I2>3 Start	(DDB 511)	3rd stage started when high
I2>4 Start	(DDB 512)	4th stage started when high
I2>1 Trip	(DDB 513)	1st stage tripped when high
I2>2 Trip	(DDB 514)	2nd stage tripped when high
I3>3 Trip	(DDB 515)	3rd stage tripped when high
I4>4 Trip	(DDB 516)	4th stage tripped when high

All the above signals are available as DDB signals for mapping in Programmable Scheme Logic (PSL). In addition the negative sequence overcurrent protection trips 1/2/3/4 are mapped internally to the block auto-reclose logic.

Negative sequence overcurrent protection starts 1/2/3/4 are mapped internally to the ANY START DDB signal - DDB 294.

The non-directional and directional operation is shown in Figure 22 and Figure 23:

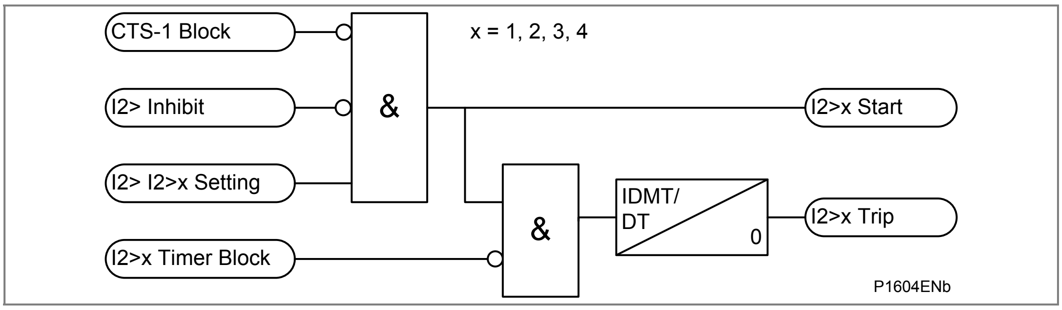


Figure 22 - Negative sequence overcurrent non-directional operation

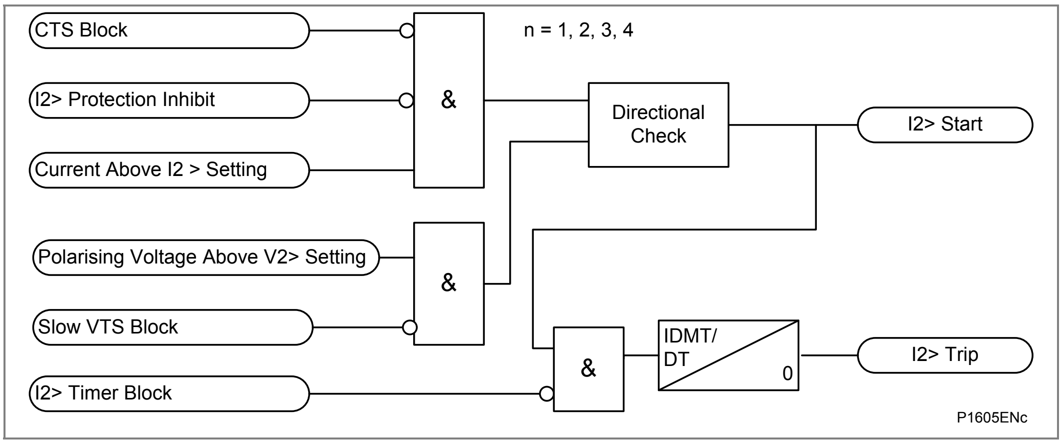


Figure 23 - Directionalizing the negative phase sequence overcurrent element

Directionality is achieved by comparison of the angle between the negative phase sequence voltage and the negative phase sequence current and the element may be selected to operate in either the forward or reverse direction. A suitable relay characteristic angle setting (I2> Char Angle) is chosen to provide optimum performance. This setting should be set equal to the phase angle of the negative sequence current with respect to the inverted negative sequence voltage (–V2), in order to be at the center of the directional characteristic.

For the negative phase sequence directional elements to operate, the relay must detect a polarizing voltage above a minimum threshold, "**I2> V2pol Set**". This must be set in excess of any steady state negative phase sequence voltage. This may be determined during the commissioning stage by viewing the negative phase sequence measurements in the relay.

1.12 Voltage Dependent Overcurrent

A protection element linked to over current that can be configured as either voltage controlled or voltage restrained over current protection. The operation of the same is detailed in the following sections:

- 1.13 - Voltage Controlled Overcurrent (VCO) Protection (51V)
- 1.14 - Voltage Restrained Overcurrent Protection

1.13 Voltage Controlled Overcurrent (VCO) Protection (51V)

If the current seen by a local relay for a remote fault condition is below its overcurrent setting, a Voltage Controlled Overcurrent (VCO) element may be used to increase the relay sensitivity to such faults. In this case, a reduction in system voltage will occur; this may then be used to reduce the pick up level of the overcurrent protection.

The VCO function can be selectively enabled on the first two stages of the main overcurrent element, which was described in section 1.1. When VCO is enabled, the overcurrent setting is modified by the multiplier k when the voltage falls below a threshold as shown in the following table:

Element	Phase to Phase Voltage for Control	Element Pick Up when Control Voltage > Setting	Element Pick Up when Control Voltage < Setting
Ia>	Vab	I>1, I>2, I>5	k.I>
Ib>	Vbc	I>1, I>2, I>5	k.I>
Ic>	Vca	I>1, I>2, I>5	k.I>

Table 4 - Voltage Controlled Overcurrent settings

Note *Voltage dependent overcurrent relays are more often applied in generator protection applications in order to give adequate overcurrent relay sensitivity for close up fault conditions. The fault characteristic of this protection must then co-ordinate with any of the downstream overcurrent relays that are responsive to the current decrement condition. It therefore follows that if the P14x relay is to be applied on an outgoing feeder from a generator station, the use of voltage controlled overcurrent protection in the feeder relay may allow better co-ordination with the VCO relay on the generator.*

1.14 Voltage Restrained Overcurrent Protection

In voltage restrained mode the effective operating current of the protection element is continuously variable as the applied voltage varies between two voltage thresholds, “V Dep. OC V<1 Set” and “V Dep. OC V<2 Set”, as shown in the figure below. In this mode, it is quite difficult to determine the behavior of the protection function during a fault. This protection mode is, however, considered to be better suited to applications where the generator is connected to the system via a generator transformer.

With indirect connection of the generator, a solid phase-phase fault on the local busbar will result in only a partial phase-phase voltage collapse at the generator terminals.

The P14x voltage-restrained current setting is related to measured voltage as follows:

For V > V<1: Current setting (I_s) = I>
For V<2 < V < V<1: Current setting (I_s) = K.I> + (I > - K. I>) {V – V<2 / V<1 – V<2}
For V < V<2: Current setting (I_s) = K.I>

Where:
I> = Over current stage setting
I_s = Current setting at voltage V
V = Voltage applied to relay element
V<1 = “V Dep. OC V<1 Set”
V<2 = “V Dep. OC V<2 Set”

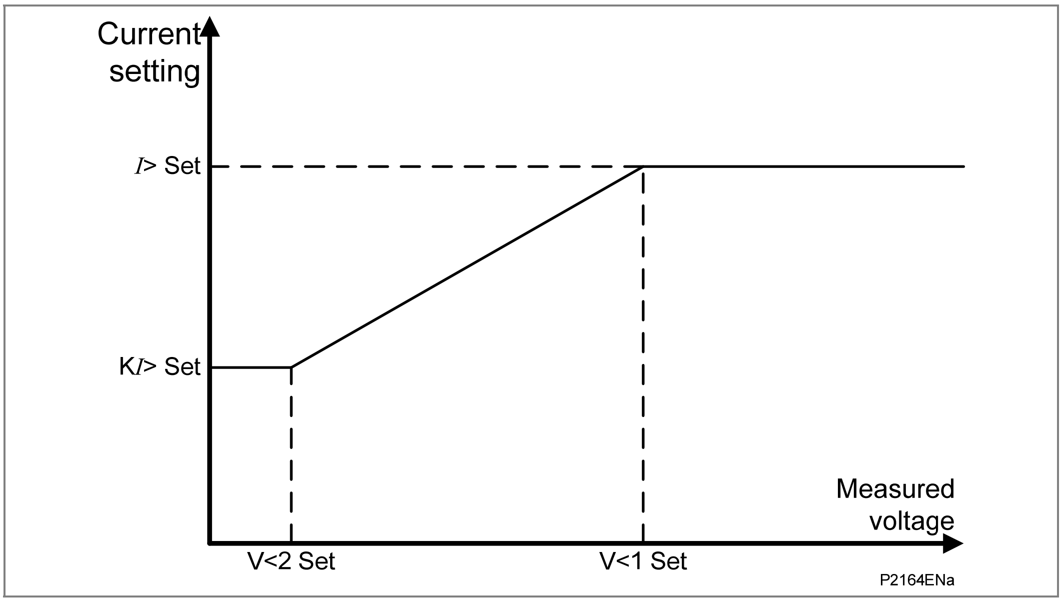


Figure 24 - Modification of current pickup level for voltage restrained overcurrent protection

1.15 Load Blinders

Load blinders are provided for phase fault elements to prevent maloperation / maltripping for heavy load flow. The purpose is to configure a blinder envelope which surrounds the expected worst case load limits, and to block tripping for any impedance measured within the blinder region. Only fault impedance which is outside the load area will be allowed to cause a trip. The phase overcurrent elements are settable independent of the load. Facility is provided to allow the load blinder to be bypassed any time the measured voltage for the phase in question falls below an undervoltage setting.
The load encroachment applies a characteristic as shown in the figure below:

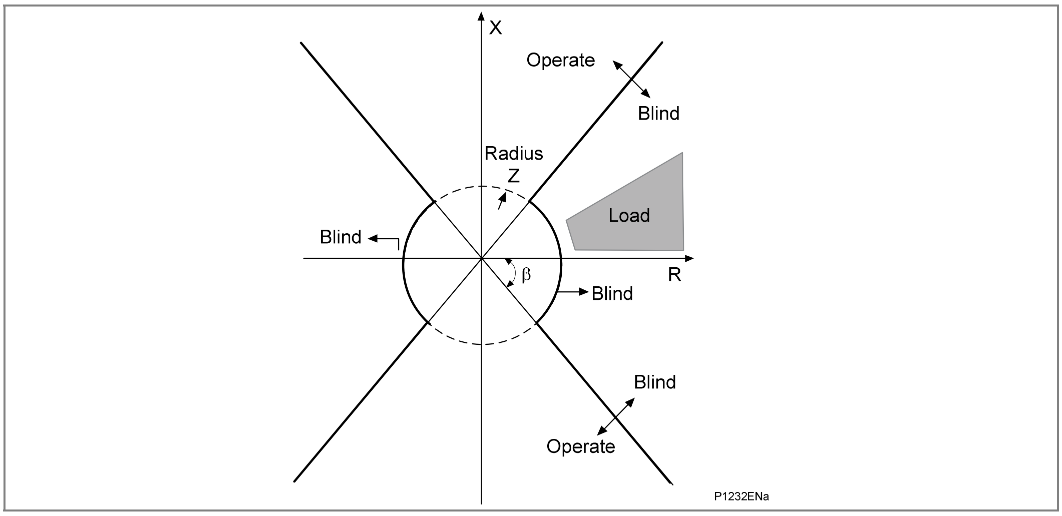


Figure 26 - Load blinder and angle

It is possible to set the impedance and angle setting independently for the forward and reverse regions in the Z plane.

There are two modes of operation, three phase mode and single phase mode. The three phase mode uses positive sequence impedance (Z1) and the single phase mode uses the normal impedance (Z) of each phase. The three phase mode uses I2> blocking in addition to under voltage. When single phase mode is selected, the over current blocking will be phase segregated.

1.16 Circuit Breaker Fail (CBF) Protection

The Circuit Breaker Failure (CBF) protection incorporates two timers, "CB Fail 1 Timer" and "CB Fail 2 Timer", allowing configuration for these scenarios:

- Simple CBF, where only "CB Fail 1 Timer" is enabled. For any protection trip, the "CB Fail 1 Timer" is started, and normally reset when the circuit breaker opens to isolate the fault. If breaker opening is not detected, "CB Fail 1 Timer" times out and closes an output contact assigned to breaker fail (using the programmable scheme logic). This contact is used to backtrip upstream switchgear, generally tripping all infeeds connected to the same busbar section
- A re-tripping scheme, plus delayed backtripping. Here, "CB Fail 1 Timer" is used to route a trip to a second trip circuit of the same circuit breaker. This requires duplicated circuit breaker trip coils, and is known as re-tripping. Should re-tripping fail to open the circuit breaker, a backtrip may be issued following an additional time delay. The backtrip uses "CB Fail 2 Timer", which is also started at the instant of the initial protection element trip.
- A DDB ‘CBF Inhibit’ has been added to enable / disable CB fail functionality.

The complete breaker fail logic is shown in Figure 25.

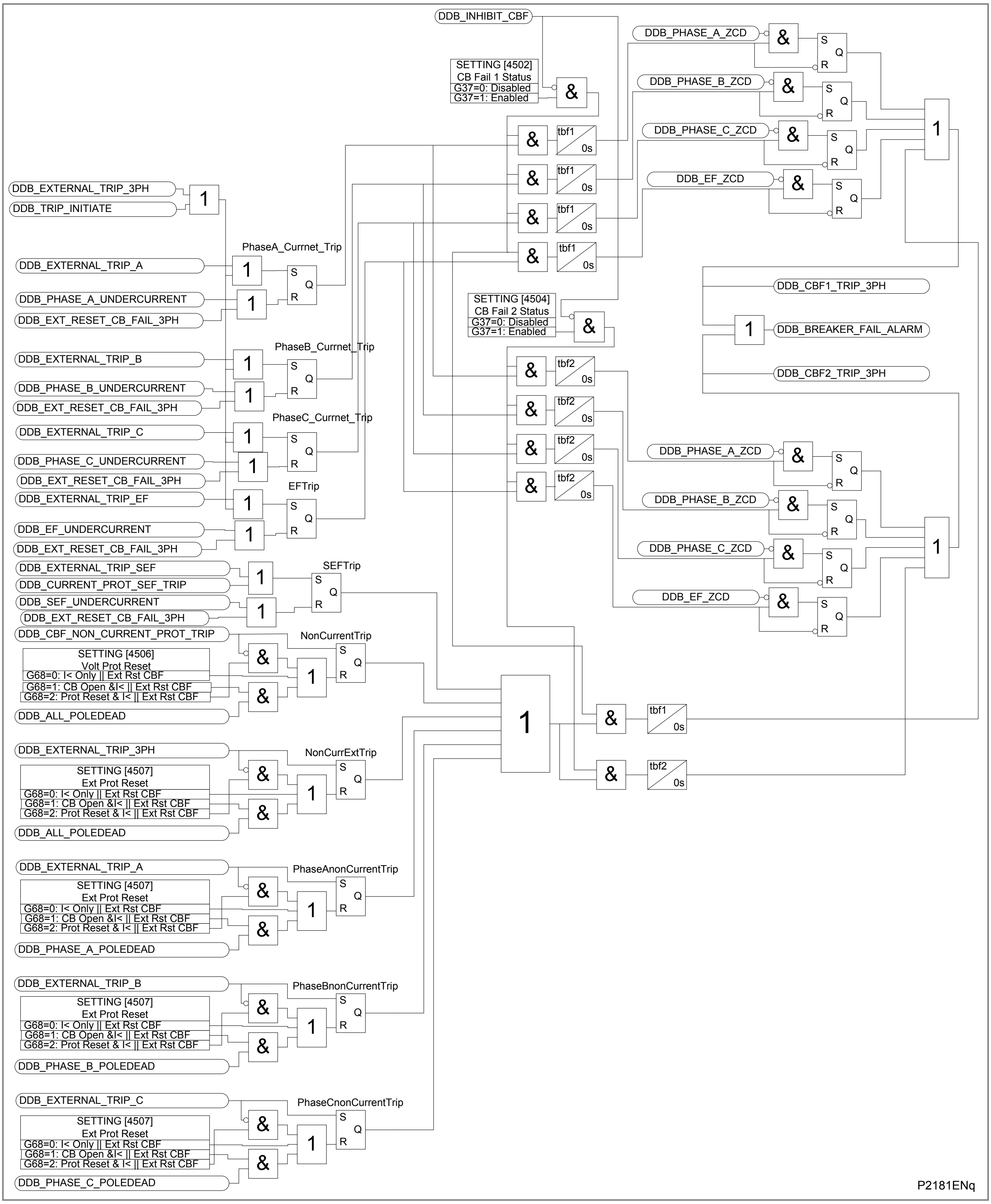


Figure 25 - CB fail logic

CBF elements "**CB Fail 1 Timer**" and "**CB Fail 2 Timer**" can be configured to operate for trips triggered by protection elements within the relay or via an external protection trip.

The latter is achieved by allocating one of the relay opto-isolated inputs to "**External Trip**" using the programmable scheme logic.

Resetting of the CBF is possible from:

- DDB 1192 is set;
- A breaker open indication (from the relay's pole dead logic) and the undercurrent elements have reset;
- A protection reset and the undercurrent elements have reset

The resetting options are summarized in the following table:

Initiation (Menu Selectable)	CB Fail Timer Reset Mechanism
Current based protection	Two options are available. (e.g. 50/51/46/21/87..) [IA< operates] & [IB< operates] & [IC< operates] & [IN< operates] AND [DDB_EXT_RESET_CB_FAIL_3PH (1192) is set]
Sensitive earth fault element	Two options are available. [ISEF< Operates] AND [DDB_EXT_RESET_CB_FAIL_3PH (1192) is set]
Non-current based protection (e.g. 27/59/81/32L..)	Four options are available. The user can select from the following options. [All I< and IN< elements operate] [Protection element reset] AND [All I< and IN< elements operate] CB open (all 3 poles) AND [All I< and IN< elements operate] AND [DDB_EXT_RESET_CB_FAIL_3PH (1192) is set]
External protection	Four options are available. The user can select any or all of the options. [All I< and IN< elements operate] [External trip reset] AND [All I< and IN< elements operate] CB open (all 3 poles) AND [All I< and IN< elements operate] AND [DDB_EXT_RESET_CB_FAIL_3PH (1192) is set]

Table 5 - CB fail timer reset mechanism

The "**Remove I> Start**" and "**Remove IN> Start**" settings are available in the settings menu and used to remove starts issued from the overcurrent and earth elements respectively following a breaker fail time out. The start is removed when the cell is set to Enabled.

1.17 CB Fail External Reset

The CB Fail external reset functionality has been added to the relay.

New DDB signals have been added for these reasons:

- To reset individual phase failure logic triggers
- To trigger 3-phase signals for all phases
- For Sensitive Earth Fault (SEF) conditions

Four extra signals have also been added for the second circuit breaker for any relays which use two circuit breakers.

The DDB database now includes an Extra DDB signal and an Ext Rst CBF (DDB 1192) entry. To achieve the desired functionality, the 3 phase CBF external reset signal is connected via an OR gate together with the corresponding phase undercurrent signal at each stage of the logic in the CB failure logic. After modification, the resultant CB failure logic looks like that shown in Figure 25.

1.18 Broken Conductor Detection

The relay incorporates an element which measures the ratio of negative to positive phase sequence current (I_2/I_1). This will be affected to a lesser extent than the measurement of negative sequence current alone, since the ratio is approximately constant with variations in load current. Hence, a more sensitive setting may be achieved.

The logic diagram is as shown below. The ratio of I2/I1 is calculated and is compared with the threshold and if the threshold is exceeded then the delay timer is initiated. The CTS block signal is used to block the operation of the delay timer.

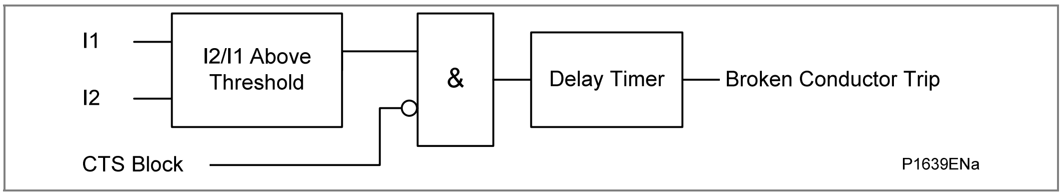


Figure 26 - Broken conductor logic

1.19 Frequency Protection

The Feeder relay includes 4 stages of underfrequency and 2 stages of overfrequency protection to facilitate load shedding and subsequent restoration. The underfrequency stages may be optionally blocked by a pole dead (CB Open) condition. All the stages may be enabled/disabled in the "**F<n Status**" or "**F>n Status**" cell depending on which element is selected.

The logic diagram for the underfrequency logic is as shown in Figure 27. Only a single stage is shown. The other 3 stages are identical in functionality.

If the frequency is below the setting and not blocked the DT timer is started. Blocking may come from the All_Poledead signal (selectively enabled for each stage) or the underfrequency timer block.

If the frequency cannot be determined, the function is also blocked.

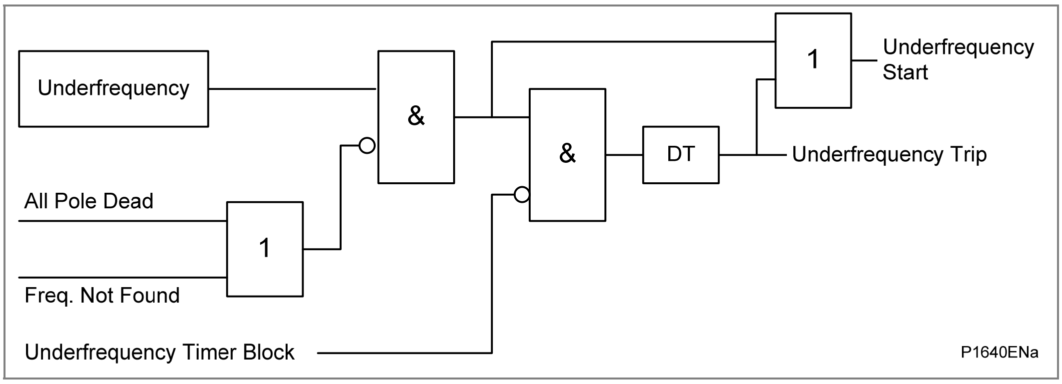


Figure 27 - Underfrequency logic (single stage)

The functional logic diagram is for the overfrequency function as shown in Figure 28. Only a single stage is shown as the other stages are identical in functionality. If the frequency is above the setting and not blocked the DT timer is started and after this has timed out the trip is produced. Blocking may come from the All_Poledead signal (selectively enabled for each stage) or the overfrequency timer block.

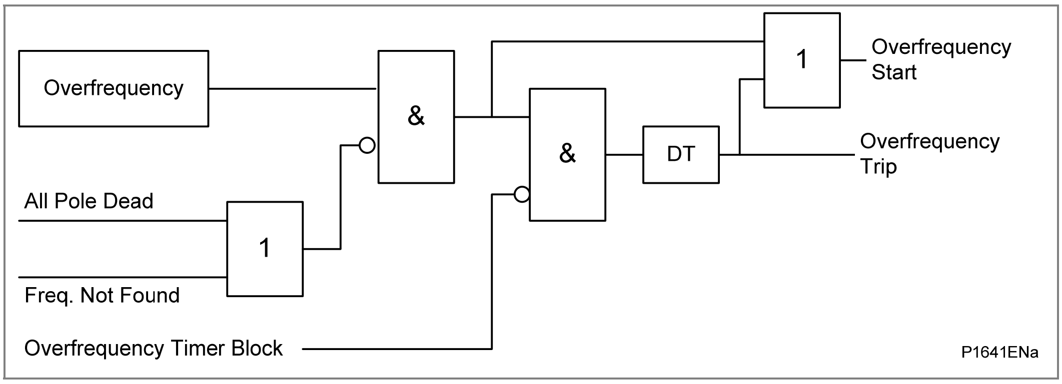


Figure 28 - Overfrequency logic (single stage)

When enabled, the following signals are set by the under/overfrequency logic according to the status of the monitored functions.

Freq. Not Found	(DDB 411)	Frequency Not Found by the frequency tracking
F<1 Timer Block	(DDB 412)	Block Underfrequency Stage 1 Timer
F<2 Timer Block	(DDB 413)	Block Underfrequency Stage 2 Timer
F<3 Timer Block	(DDB 414)	Block Underfrequency Stage 3 Timer
F<4 Timer Block	(DDB 415)	Block Underfrequency Stage 4 Timer
F>1 Timer Block	(DDB 416)	Block Overfrequency Stage 1 Timer
F>2 Timer Block	(DDB 417)	Block Overfrequency Stage 2 Timer
F<1 Start	(DDB 418)	Underfrequency Stage 1 Start
F<2 Start	(DDB 419)	Underfrequency Stage 2 Start
F<3 Start	(DDB 420)	Underfrequency Stage 3 Start
F<4 Start	(DDB 421)	Underfrequency Stage 4 Start
F>1 Start	(DDB 422)	Overfrequency Stage 1 Start
F>2 Start	(DDB 423)	Overfrequency Stage 2 Start
F<1 Trip	(DDB 424)	Underfrequency Stage 1 Trip
F<2 Trip	(DDB 425)	Underfrequency Stage 2 Trip
F<3 Trip	(DDB 426)	Underfrequency Stage 3 Trip
F<4 Trip	(DDB 427)	Underfrequency Stage 4 Trip
F>1 Trip	(DDB 428)	Overfrequency Stage 1 Trip
F>2 Trip	(DDB 429)	Overfrequency Stage 2 Trip

1.20 Advanced Under/Over Frequency Protection

This feature is available only when advanced frequency protection option “**Adv. Freq. Prot’n**” is enabled in the configuration and “**Freq Protection**” is disabled.

The Feeder relay includes 9 stages of underfrequency and 9 stages of overfrequency protection to facilitate load shedding and subsequent restoration. The underfrequency stages may be optionally blocked by a pole dead (CB Open) condition. All the stages may be enabled/disabled in the "**F<n Status**" or "**F>n Status**" cell depending on which element is selected.

The logic diagram for the underfrequency logic is as shown in Figure 29. Only a single stage is shown. The other 8 stages are identical in functionality.

If the frequency is below the setting and not blocked the DT timer is started. Blocking may come from the All_Poledead signal (selectively enabled for each stage) or the underfrequency timer block.

If the frequency cannot be determined, the function is also blocked.

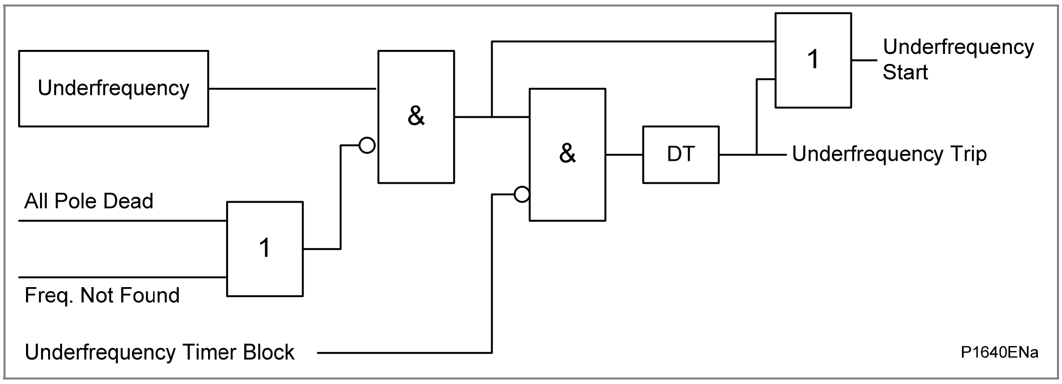


Figure 29 - Advanced underfrequency logic (single stage)

The functional logic diagram is for the overfrequency function as shown in Figure 30. Only a single stage is shown as the other stages are identical in functionality. If the frequency is above the setting and not blocked the DT timer is started and after this has timed out the trip is produced. Blocking may come from the All_Poledead signal (selectively enabled for each stage) or the overfrequency timer block.

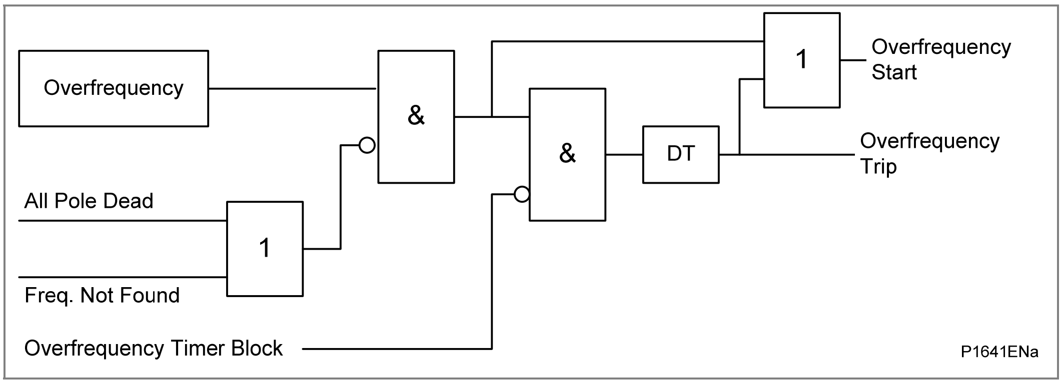


Figure 30 - Advanced overfrequency logic (single stage)

The P140 provides nine independent definite time delayed stages of frequency protection (f+t). Depending upon whether the threshold is set above or below the system nominal frequency, each stage can respond to either under or over frequency conditions. The relay will also indicate that an incorrect setting has been applied if the frequency threshold is set to the nominal system frequency. Although the elements are described as definite time delayed, by setting the time delay to zero, the element will operate instantaneously.

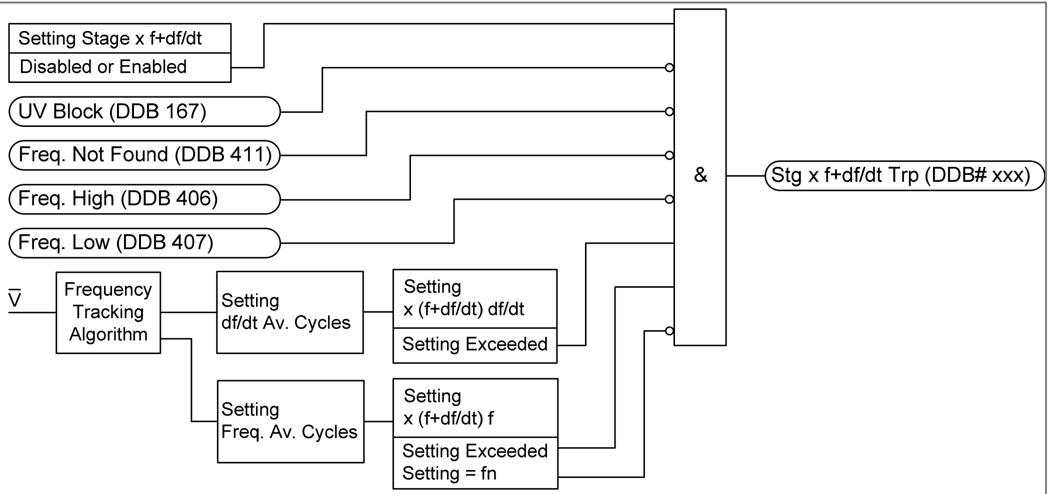
Within the Programmable Scheme Logic (PSL), signals are available to indicate the start and trip of each frequency stage (Starts: DDB 1281, DDB 1295, DDB 1309, DDB 1323, DDB 1337, DDB 1351, DDB 1365, DDB 1379 and DDB 1393; Trips: DDB 1282, DDB 1296, DDB 1310, DDB 1324, DDB 1338, DDB 1352, DDB 1366, DDB 1380 and DDB 1394). The state of the DDB signals can be programmed to be viewed in the “**Monitor Bit x**” cells of the “**COMMISSION TESTS**” column in the relay.

Note	*The "**Advanced Frequency Protection**" ported from P940 (firmware version 43) has IEC 61850 logical nodes only for df/dt. The frequency logical nodes (over and under frequency) remains as it is in P140 earlier (version 42). There is a 9 stage frequency protection in the Adv. Freq. prot ported from P940. However, as this is a non standard IEC 61850 logical node, the earlier available P140 feature for frequency protection shall be used for IEC 61850.*

1.21 Advanced Frequency Supervised Rate of Change of Frequency Protection ‘f+df/dt’ [81RF]

The P140 provides nine independent stages of frequency supervised rate of change of frequency protection (f+df/dt). Depending upon whether the frequency threshold is set above or below the system nominal frequency, each stage can respond to either rising or falling frequency conditions. For example, if the frequency threshold is set above nominal frequency, the df/dt setting is considered as positive and the element will operate for rising frequency conditions. If the frequency threshold is set below nominal frequency, the df/dt setting is considered as negative and the element will operate for falling frequency conditions. The relay will also indicate that an incorrect setting has been applied if the frequency threshold is set to the nominal system frequency. There is no intentional time delay associated with this element although using the Programmable Scheme Logic (PSL), time delays could be applied if required.

Within the PSL, signals are available to indicate the trip of each frequency supervised rate of change of frequency stage (DDB 1283, DDB 1297, DDB 1311, DDB 1325, DDB 1339, DDB 1353, DDB 1367, DDB 1381 and DDB 1395). The state of the DDB signals can be programmed to be viewed in the “**Monitor Bit x**” cells of the “**COMMISSION TESTS**” column in the relay.



Stage x f+df/dt	DDB# xxx Stg x f+df/dt Trp
Stage 1 f+df/dt	Stg 1 f+df/dt Trp (DDB 1283)
Stage 2 f+df/dt	Stg 2 f+df/dt Trp (DDB 1297)
Stage 3 f+df/dt	Stg 3 f+df/dt Trp (DDB 1311)
Stage 4 f+df/dt	Stg 4 f+df/dt Trp (DDB 1325)
Stage 5 f+df/dt	Stg 5 f+df/dt Trp (DDB 1339)
Stage 6 f+df/dt	Stg 6 f+df/dt Trp (DDB 1353)
Stage 7 f+df/dt	Stg 7 f+df/dt Trp (DDB 1367)
Stage 8 f+df/dt	Stg 8 f+df/dt Trp (DDB 1381)
Stage 9 f+df/dt	Stg 9 f+df/dt Trp (DDB 1395)

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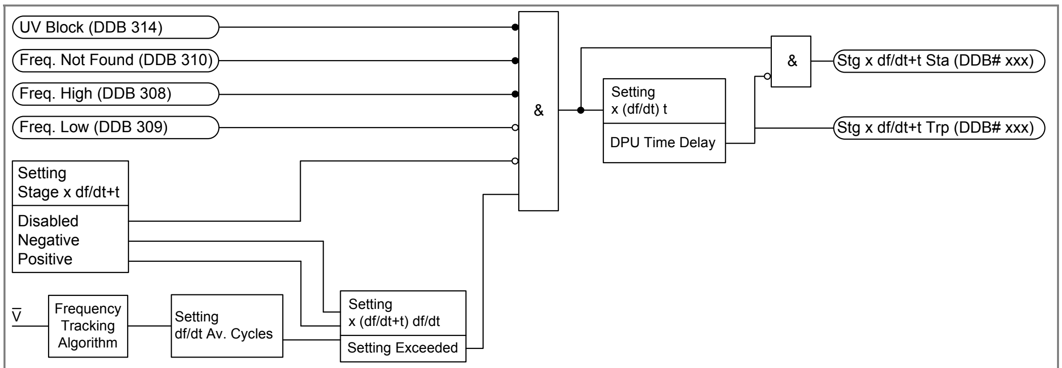
Figure 31 - Advanced frequency supervised rate of change of frequency logic (single stage shown)

1.22 Advanced Independent Rate of Change of Frequency Protection ‘df/dt+t’ [81R]

This feature is available only when advanced frequency protection option “**Adv. Freq. Prot’n**” is enabled in the configuration and “**df/dt Protection**” is disabled.

The P140 provides nine independent stages of rate of change of frequency protection (df/dt+t). The “**Stage X df/dt+t**” setting will define whether the stage is disabled, operates for rising frequency conditions (set to “**Positive”**) or operates for falling frequency conditions (set to “**Negative**”). The output of the element would normally be given a user-selectable time delay, although it is possible to set this to zero and create an instantaneous element.

Within the Programmable Scheme Logic (PSL), signals are available to indicate the start and trip of each rate of change of frequency stage. (Starts: DDB 1284, DDB 1298, DDB 1312, DDB 1326, DDB 1340, DDB 1354, DDB 1368, DDB 1382 & DDB 1396; Trips: DDB 1285, DDB 1299, DDB 1313, DDB 1327, DDB 1341, DDB 1355, DDB 1369, DDB 1383 & DDB 1397). The state of the DDB signals can be programmed to be viewed in the “**Monitor Bit x**” cells of the “**COMMISSION TESTS**” column in the relay.



Stage x df/dt+t	Stg x df/dt+t Sta	Stg x df/dt+t Trp
Stage 1 df/dt+t	Stg 1 df/dt+t Sta (DDB 148)	Stg 1 df/dt+t Trp (DDB 149)
Stage 2 df/dt+t	Stg 2 df/dt+t Sta (DDB 157)	Stg 2 df/dt+t Trp (DDB 158)
Stage 3 df/dt+t	Stg 3 df/dt+t Sta (DDB 166)	Stg 3 df/dt+t Trp (DDB 167)
Stage 4 df/dt+t	Stg 4 df/dt+t Sta (DDB 175)	Stg 4 df/dt+t Trp (DDB 176)
Stage 5 df/dt+t	Stg 5 df/dt+t Sta (DDB 184)	Stg 5 df/dt+t Trp (DDB 185)
Stage 6 df/dt+t	Stg 6 df/dt+t Sta (DDB 193)	Stg 6 df/dt+t Trp (DDB 194)

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Figure 32 - Advanced independent rate of change of frequency logic (single stage shown)

1.23 Advanced Average Rate of Change of Frequency Protection ‘f+Df/Dt’ [81RAV]

The rate of change of frequency elements described in earlier use an “**instantaneous**” measurement of “**df/dt**” based upon a 3 cycle, filtered “**rolling**” average technique. Due to the oscillatory nature of frequency excursions, this instantaneous value can sometimes be misleading, either causing unexpected operation or excessive stability. For this reason, the P140 relays also provide an element for monitoring the longer term frequency trend, thereby reducing the effects of non-linearities in the system and providing increased security to the rate of change of frequency decision.

Using the average rate of change of frequency element “**f+Df/Dt**”, when the measured frequency crosses the supervising frequency threshold a timer is initiated. At the end of this time period, Δt, the frequency difference, Δf, is evaluated and if this exceeds the setting, a trip output is given.

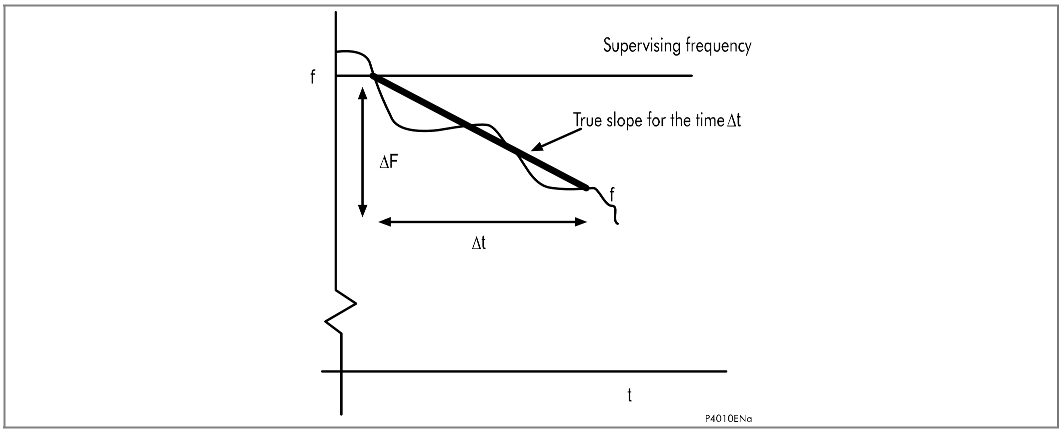
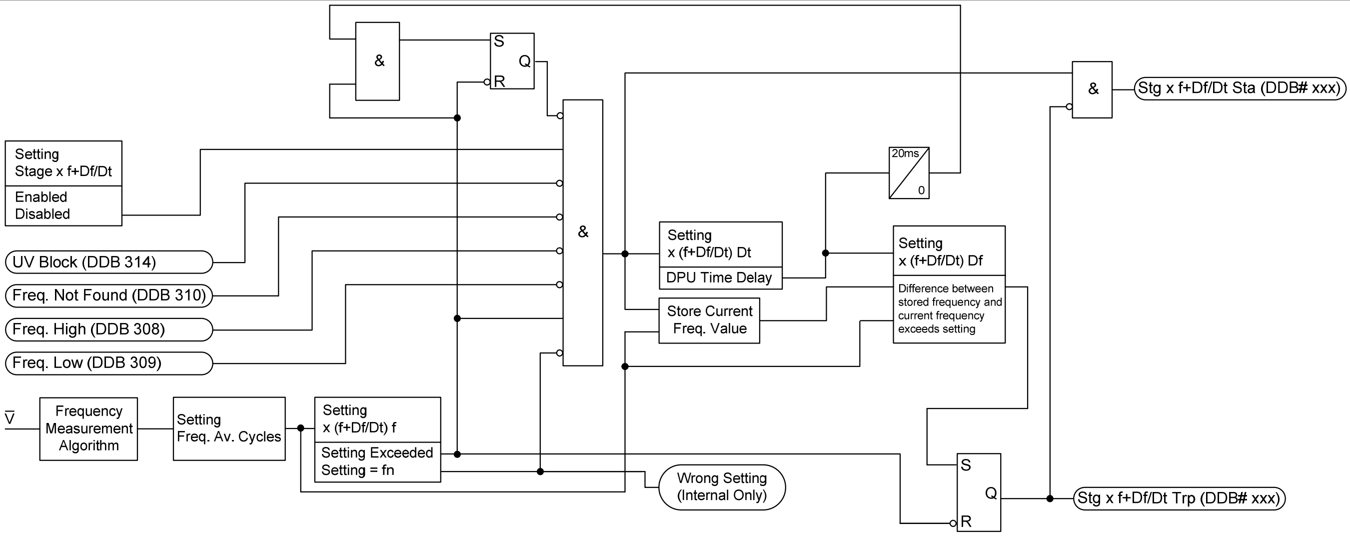


Figure 33 - Advanced average rate of change of frequency protection

After time Δt, regardless of the outcome of the comparison, the element is blocked from further operation until the frequency recovers to a value above the supervising frequency threshold (or below in the case where the element is configured for overfrequency operation). If the element has operated, the trip DDB signal will be on until the frequency recovers to a value above the supervising frequency threshold.

The P140 provides nine stages of average rate of change of frequency protection (f+Df/Dt). Depending upon whether the frequency threshold is set above or below the system nominal frequency, each stage can respond to either rising or falling frequency conditions. For example, if the frequency threshold is set above nominal frequency, the element will operate for rising frequency conditions. The average rate of change of frequency is then measured based upon the frequency difference, Df over the settable time period, Dt.

Within the Programmable Scheme Logic (PSL), signals are available to indicate the start and trip of each average rate of change of frequency stage. (Starts DDB 1286, DDB 1300, DDB 1314, DDB 1328, DDB 1342, DDB 1356, DDB 1370, DDB 1384 & DDB 1398; Trips: DDB 1287, DDB 1301, DDB 1315, DDB 1329, DDB 1343, DDB 1357, DDB 1371, DDB 1385 & DDB 1399). The state of the DDB signals can be programmed to be viewed in the “**Monitor Bit x**” cells of the “**COMMISSION TESTS**” column in the relay.



Stage x f+Df/Dt	Stg x f+Df/Dt Sta	Stg x f+Df/Dt Trp	Wrong Setting
Stage 1 f+Df/Dt	Stg 1 f+Df/Dt Sta (DDB 150)	Stg 1 f+Df/Dt Trp (DDB 151)	Wrong Setting 19 (DDB 290)
Stage 2 f+Df/Dt	Stg 2 f+Df/Dt Sta (DDB 159)	Stg 2 f+Df/Dt Trp (DDB 160)	Wrong Setting 20 (DDB 291)
Stage 3 f+Df/Dt	Stg 3 f+Df/Dt Sta (DDB 168)	Stg 3 f+Df/Dt Trp (DDB 169)	Wrong Setting 21 (DDB 292)
Stage 4 f+Df/Dt	Stg 4 f+Df/Dt Sta (DDB 177)	Stg 4 f+Df/Dt Trp (DDB 178)	Wrong Setting 22 (DDB 293)
Stage 5 f+Df/Dt	Stg 5 f+Df/Dt Sta (DDB 186)	Stg 5 f+Df/Dt Trp (DDB 187)	Wrong Setting 23 (DDB 294)
Stage 6 f+Df/Dt	Stg 6 f+Df/Dt Sta (DDB 195)	Stg 6 f+Df/Dt Trp (DDB 196)	Wrong Setting 24 (DDB 295)

Figure 34 - Advanced average rate of change of frequency logic (single stage shown)

1.24 Advanced Load Restoration

The P140 uses the measurement of system frequency as its main criteria for load restoration. For each stage of restoration, it is necessary that the same stage of load shedding has occurred previously and that no elements within that stage are configured for overfrequency or rising frequency conditions. If load shedding has not occurred based upon the frequency protection elements, the load restoration for that stage is inactive.

Load restoration for a given stage begins when the system frequency rises above the "**RestoreX Freq.**" setting for that stage and the stage restoration timer "**RestoreX Time**" is initiated. If the system frequency remains above the frequency setting for the set time delay, load restoration of that stage will be triggered. Unfortunately, frequency recovery profiles are highly non-linear and it would be reasonably common for the system frequency to transiently fall below the restoration frequency threshold. If the restoration timer immediately reset whenever a frequency dip occurred, it is likely that load restoration would never be successful and for this reason a "**holding band**" is also implemented on the relay. The holding band is a region defined by the restoration frequency and the highest frequency setting used in the load shedding elements for that stage. The difference between these two settings must always be greater than 0.02Hz, otherwise a "**Wrong Setting**" alarm will be generated. Whenever the system frequency dips into the holding band, operation of the stage restoration timer is suspended until the frequency rises above the restoration frequency setting, at which point timing will continue. If the system frequency dip is sufficiently large to cause any frequency element to start or trip in this stage i.e. if the frequency falls below the lower limit of the holding band, the restoration timer will immediately be reset.

Figure 35 illustrates the operation of the load restoration facility and holding band.

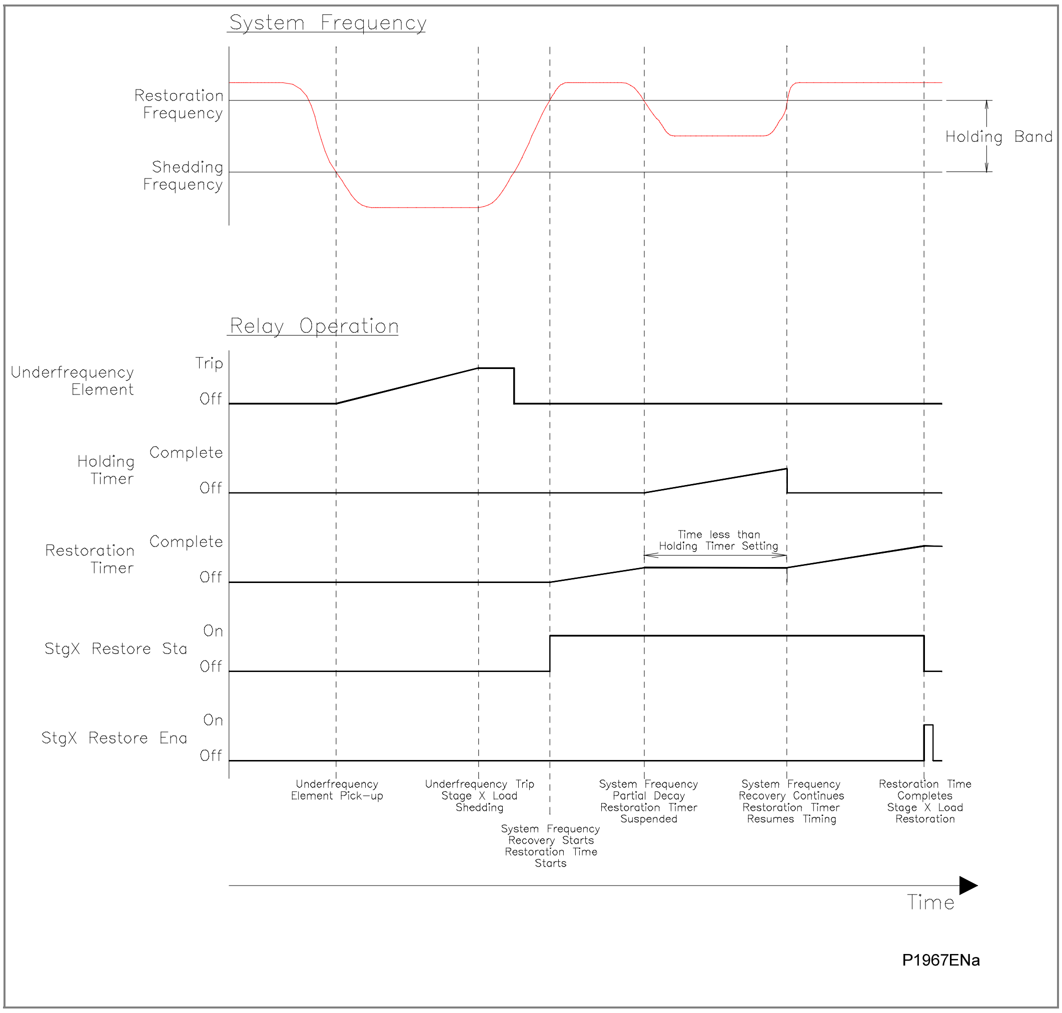


Figure 35 - Advanced load restoration with short deviation into holding band

If the system frequency remains in the holding band for too long it is likely that other system frequency problems are occurring and it would be prudent to reset the restoration timer for that stage. For this reason, as soon as the system frequency is measured to be within the holding band, the "**Holding Timer**" is initiated. If the system frequency doesn't leave the holding band before the holding timer setting has been exceeded, the load restoration time delay for that stage is immediately reset. It should be noted that the holding timer has a common setting for all stages of load restoration.

An example of the case when the time in the holding band is excessive is shown in Figure 36.

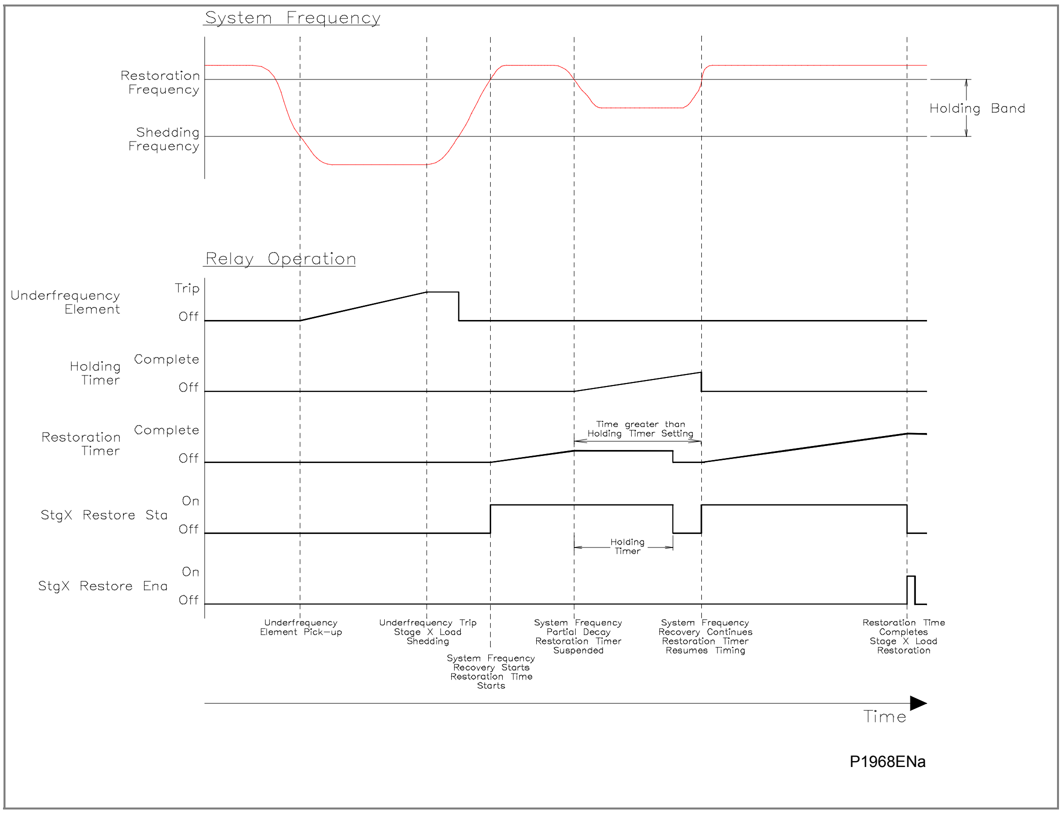
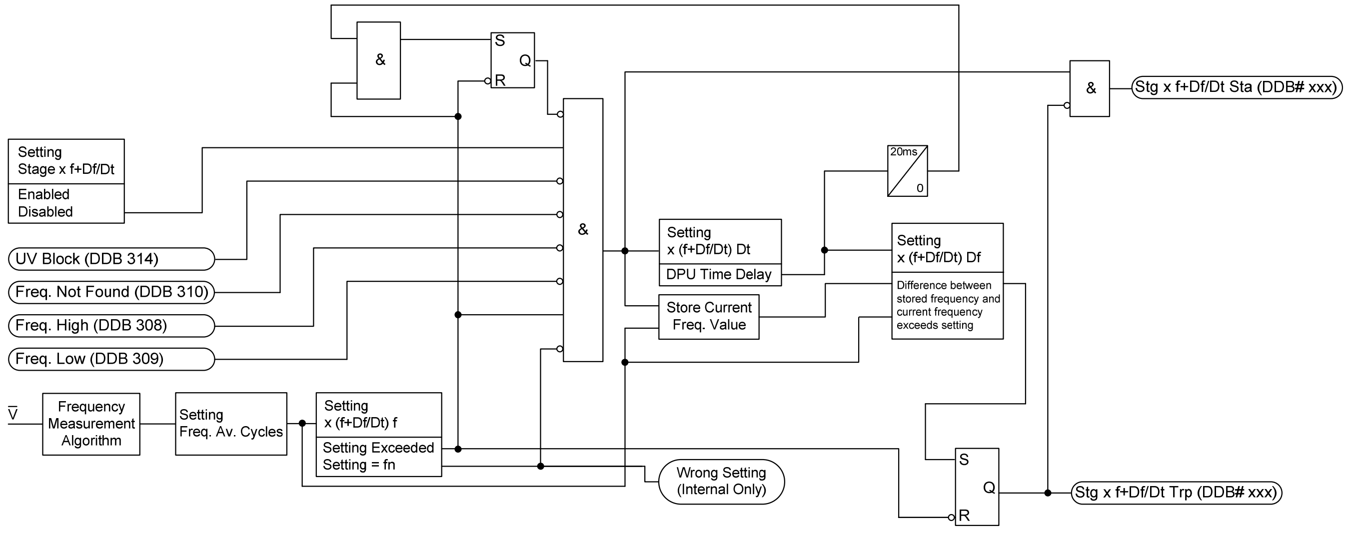


Figure 36 - Advanced load restoration with long deviation into holding band

The P140 provides up to nine stages of load restoration with individual restoration frequency and time delays. Each stage of load restoration can be enabled or disabled but operation is also linked to the number of load shedding stages that have been configured using the frequency protection elements. Within a stage, if any frequency protection element is set for overfrequency operation or has a positive rate of change of frequency setting, the load restoration for that stage is automatically inhibited and a wrong setting alarm will be raised. For example, if stage 5 frequency protection “**f+t**” was set above nominal frequency, it would not be possible to use the stage 5 load restoration facility, even if other stage 5 frequency protection elements were set for load shedding. This means that the number of load restoration stages is always less than or equal to the number of load shedding stages. In addition, the stage load restoration can only occur if that stage of load shedding has been tripped from any of the frequency protection elements. For example, for stage 5 load restoration to occur, a stage 5 frequency protection element must have previously operated to shed load. Although the load restoration on the P140 is based upon frequency measurement, it is possible to use the Programmable Scheme Logic (PSL) of the relay to interlock with other plant items.

Within the Programmable Scheme Logic (PSL), signals are available to indicate when the stage load restoration frequency has been reached (start) and when the restoration timer for that stage has completed thereby enabling a close command to be given (enable). (Starts: DDB 1291, DDB 1305, DDB 1319, DDB 1333, DDB 1347, DDB 1361, DDB 1375, DDB 1389, DDB 1403; Enable: DDB 1292, DDB 1306, DDB 1320, DDB 1334, DDB 1348, DDB 1362, DDB 1376, DDB 1390, DDB 1404. The state of the DDB signals can be programmed to be viewed in the “**Monitor Bit x**” cells of the “**COMMISSION TESTS**” column in the relay.



Stage x f+Df/Dt	Stg x f+Df/Dt Sta	Stg x f+Df/Dt Trp	Wrong Setting
Stage 1 f+Df/Dt	Stg 1 f+Df/Dt Sta (DDB 150)	Stg 1 f+Df/Dt Trp (DDB 151)	Wrong Setting 19 (DDB 290)
Stage 2 f+Df/Dt	Stg 2 f+Df/Dt Sta (DDB 159)	Stg 2 f+Df/Dt Trp (DDB 160)	Wrong Setting 20 (DDB 291)
Stage 3 f+Df/Dt	Stg 3 f+Df/Dt Sta (DDB 168)	Stg 3 f+Df/Dt Trp (DDB 169)	Wrong Setting 21 (DDB 292)
Stage 4 f+Df/Dt	Stg 4 f+Df/Dt Sta (DDB 177)	Stg 4 f+Df/Dt Trp (DDB 178)	Wrong Setting 22 (DDB 293)
Stage 5 f+Df/Dt	Stg 5 f+Df/Dt Sta (DDB 186)	Stg 5 f+Df/Dt Trp (DDB 187)	Wrong Setting 23 (DDB 294)
Stage 6 f+Df/Dt	Stg 6 f+Df/Dt Sta (DDB 195)	Stg 6 f+Df/Dt Trp (DDB 196)	Wrong Setting 24 (DDB 295)

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Figure 37 - Advanced load restoration logic

1.25 Cold Load Pick-Up (CLP) Logic

The Cold Load Pick-Up (CLP) logic included within the P14x relays serves to either inhibit one or more stages of the overcurrent protection for a set duration or, alternatively, to raise the settings of selected stages. This, therefore, allows the protection settings to be set closer to the load profile by automatically increasing them following circuit energization. The CLP logic thus provides stability, whilst maintaining protection during starting. Note that any of the overcurrent stages that have been disabled in the main relay menu will not appear in the CLP menu.

This function acts upon the following protection functions:

- Non-Directional/Directional phase overcurrent (1st, 2nd, 3rd and 4th stages)
- Non-Directional/Directional earth fault - 1 (1st stage)
- Non-Directional/Directional earth fault - 2 (1st stage)

The functional logic diagram for the cold load pick-up function is shown in Figure 38, together with the example of its effect on phase A of the first stage overcurrent function. The principle of operation is identical for the 3-phase overcurrent function stages 1, 2, 3 and 4 and EF-1 stage 1 and directional EF-2 stage 1.

Cold load pick up operation occurs when the circuit breaker remains open for a time greater than tcold and is subsequently closed. CLP operation is applied after tcold and remains for a set time delay of tclp following closure of the circuit breaker. The status of the circuit breaker is provided either by means of the CB auxiliary contacts or by means of an external device via logic inputs. Whilst CLP operation is in force, the CLP settings are enabled for all the 3- phase overcurrent function stages 1, 2, 3 and 4 and associated time delayed elements, EF-1 function stage 1 and EF-2 stage 1. (Note that one setting option is the ability to disable (or block) a given overcurrent stage). After the time delay tclp has elapsed, the normal overcurrent settings are applied.

The impact of VCO is considered in the diagram since this function can also affect the 3 individual phase overcurrent settings for stages 1 and 2.

In the quiescent state, the protection operates from the normal phase overcurrent and time delay settings. However, if a VCO undervoltage condition arises, the relay will operate from the normal settings multiplied by the VCO “**K**” factor. Where there is a simultaneous VCO undervoltage and CLP condition, the relay will operate from the normal settings multiplied by the VCO “**K**” factor. If the CLP condition prevails and the VCO function resets, the relay will operate using the CLP settings.

Time delayed elements are reset to zero if they are disabled during the transitions between normal settings and CLP settings.

It should be noted that in the event of a conflict between Selective Logic and CLP on the 3rd and 4th stages of the 3-phase directional overcurrent, EF and SEF protection functions, Selective Logic has greater priority.

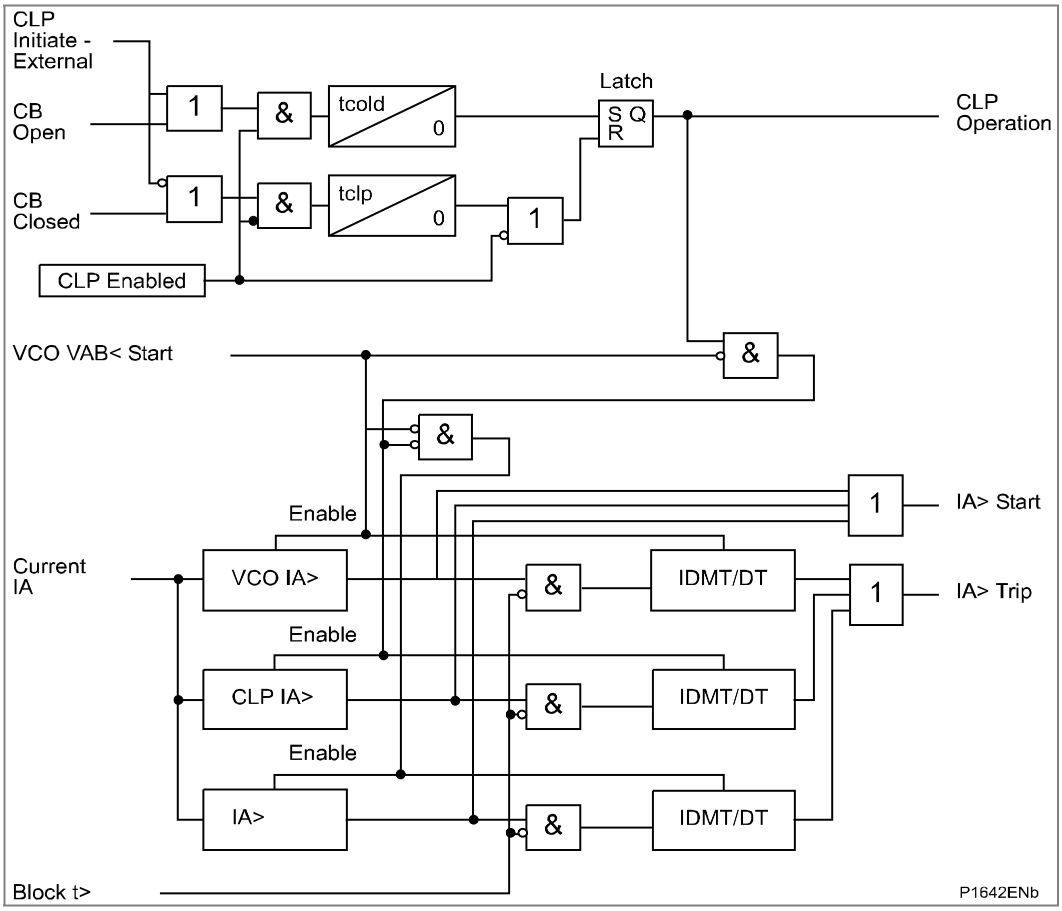

Figure 38 - Cold load pick-up logic

The normal settings will be applied to the directional phase overcurrent, standby earth fault and sensitive earth fault protection functions when the CLP element resets.

When enabled, the following signals are set by the CLP logic according to the status of the monitored function.

CLP Initiate	(DDB 226)	Initiate Cold load pick-up
CLP Operation	(DDB 347)	Indicates the Cold load pick-up logic is in operation

"**tcold**" and "**tclp**" are initiated via the CB open and CB closed signals generated within the relay. Connecting auxiliary contacts from the circuit breaker or starting device to the relay opto-inputs produces these signals. It is important to note that if both an open and closed contact are unavailable, the relay can be configured to be driven from either a single 52a, or 52b contact, as the relay will simply invert one signal to provide the other. This option is available in the "**CB control column**" in the "**CB status input**" cell and can be programmed as either "**None**", 52a, 52b or both 52a and 52b.

1.26 Selective Overcurrent Logic

Section 1.23 describes the use of non-cascade protection schemes that make use of start contacts from downstream relays connected to block operation of upstream relays. In the case of Selective Overcurrent Logic (SOL), the start contacts are used to raise the time delays of upstream relays, instead of blocking. This provides an alternative approach to achieving non-cascade types of overcurrent scheme. This may be more familiar to some utilities than the blocked overcurrent arrangement.

The SOL function provides the ability to temporarily increase the time delay settings of the third and fourth stages of phase overcurrent, derived and measured earth fault and sensitive earth fault protection elements. This logic is initiated by energization of the appropriate opto-isolated input.

To allow time for a start contact to initiate a change of setting, the time settings of the third and fourth stages should include a nominal delay.

This function acts upon the following protection functions:

- Non-Directional/Directional phase overcurrent (3rd and 4th stages)
- Non-Directional/Directional earth fault - 1 (3rd and 4th stages)
- Non-Directional/Directional earth fault - 2 (3rd and 4th stages)
- Non-Directional/Directional sensitive earth fault (3rd and 4th stages)

The logic diagram for the selective overcurrent function is shown for phase A of the third stage overcurrent function. The principle of operation is identical for the 3-phase phase overcurrent function stages 3 and 4, earth fault function -1 stages 3 and 4, earth fault function -2 stages 3 and 4 and the sensitive earth fault function stages 3 and 4.

When the selective logic function is enabled, the action of the blocking input is as follows:

1. No block applied

   In the event of a fault condition that continuously asserts the start output, the function will assert a trip signal after the normal time delay t>3 has elapsed.

2. Logic input block applied

   In the event of a fault condition that continuously asserts the start output, the function will assert a trip signal after the selective logic time delay t>3 sel has elapsed.

3. Auto-reclose input block applied

   In the event of a fault condition that continuously asserts the start output, when an auto-reclose block is applied the function will not trip. The auto-reclose block also overrides the logic input block and will block the t>3 sel timer.

   It is noted that the Auto-reclose function outputs two signals that block protection, namely; AR Block Maint. Protection and AR Block SEF Protection.

   > AR Block Maint. Protection is common to the 3-phase overcurrent function stages 3 & 4, earth fault function -1 stages 3 & 4, and earth fault function -2 stages 3 & 4.

   > AR Block SEF Protection is common to the sensitive earth fault function stages 3 & 4.

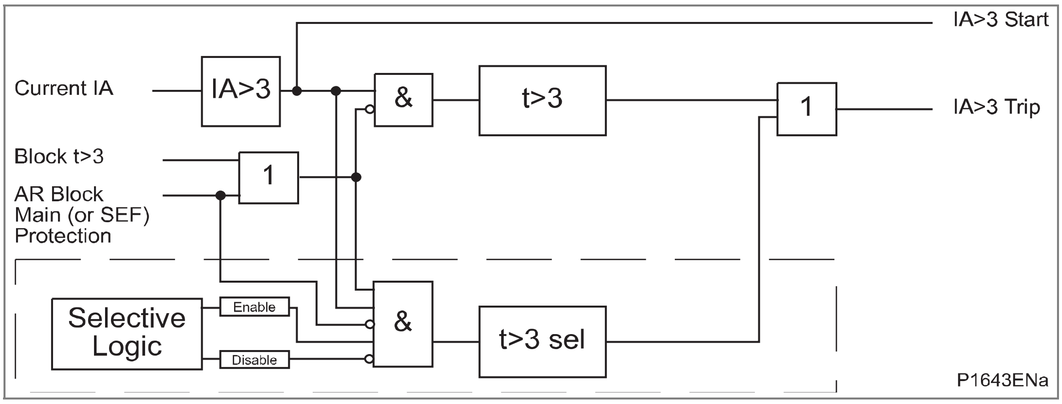

Figure 39 - Selective overcurrent logic

1.27 Blocked Overcurrent Scheme Logic

The P14x relay has start outputs available from each stage of the overcurrent and earth fault elements, including the sensitive earth fault element. These start signals may then be routed to output contacts by programming accordingly. Each stage is also capable of being blocked by being programmed to the relevant opto-isolated input.

To facilitate the implementation of a blocked overcurrent scheme the following logic is implemented to provide the "**I> Blocked O/C Start (DDB 348)**" signal.

The I> Blocked O/C Start is derived from the logical "**OR**" of the phase overcurrent start outputs.

The logical "**OR**" output is then gated with the signal BF Alarm (Block AR) and the setting {I> Start Blocked By CB Fail} as shown in the diagram below:

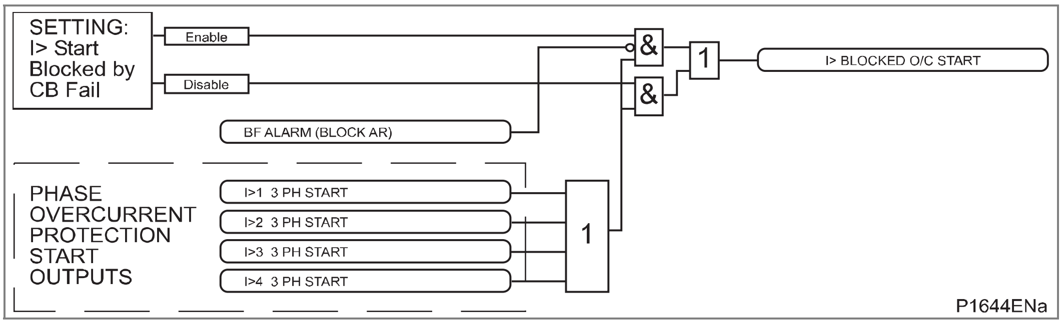

Figure 40 - Overcurrent blocked operation

For the earth fault and sensitive earth fault element, the following logic is implemented to provide the "**IN>/ISEF> Blocked O/C Start (DDB 349)**" signal.

The IN>/ISEF> Blocked O/C Start is derived from the logical "**OR**" of the earth fault and sensitive earth fault signals protection start outputs.

The logical "**OR**" output is then gated with the signal BF Alarm (Block AR) and the setting {IN>/ISEF> Start Blocked By CB Fail} as shown in Figure 41.

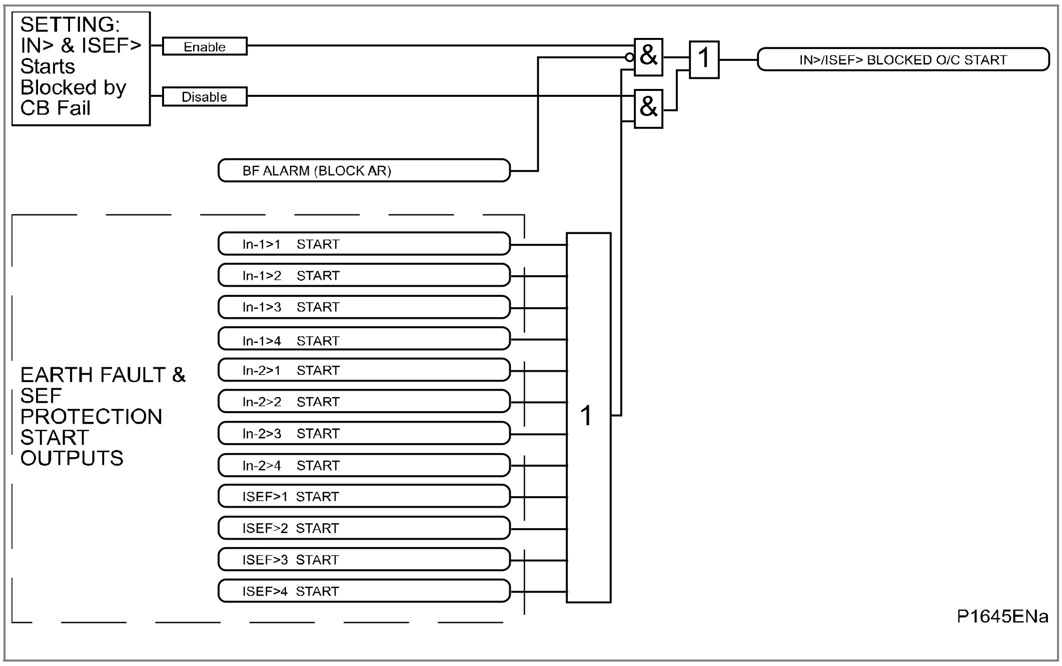

Figure 41 - Earth fault blocked operation

1.28 Neutral Admittance Protection

Neutral admittance protection is mandatory for the Polish market, deriving its neutral current input from either the E/F CT or the SEF CT by means of a setting. The neutral voltage is based on the internally derived quantity VN.

Three single stage elements are provided:

- Overadmittance YN> that is non-directional, providing both start and time delayed trip outputs. The trip may be blocked by a logic input
- Overconductance GN> that is non-directional/directional, providing both start and time delayed trip outputs. The trip may be blocked by a logic input
- Oversusceptance BN> that is non-directional/directional, providing both start and time delayed trip outputs. The trip may be blocked by a logic input

The overadmittance elements YN>, GN> and BN> will operate providing the neutral voltage remains above the set level for the set operating time of the element. They are blocked by operation of the fast VTS supervision output.

The overadmittance elements provide measurements of admittance, conductance and susceptance that also appear in the fault record, providing the protection is enabled.

The overadmittance elements are capable of initiating auto-reclose, similarly to the earth fault protection, by means of YN>, GN> and BN> settings in the AUTO-RECLOSE menu column.

1.28.1 Operation of Admittance Protection

The admittance protection is non-directional. Hence, provided the magnitude of admittance exceeds the set value YN> Set and the magnitude of neutral voltage exceeds the set value VN Threshold, the relay will operate.

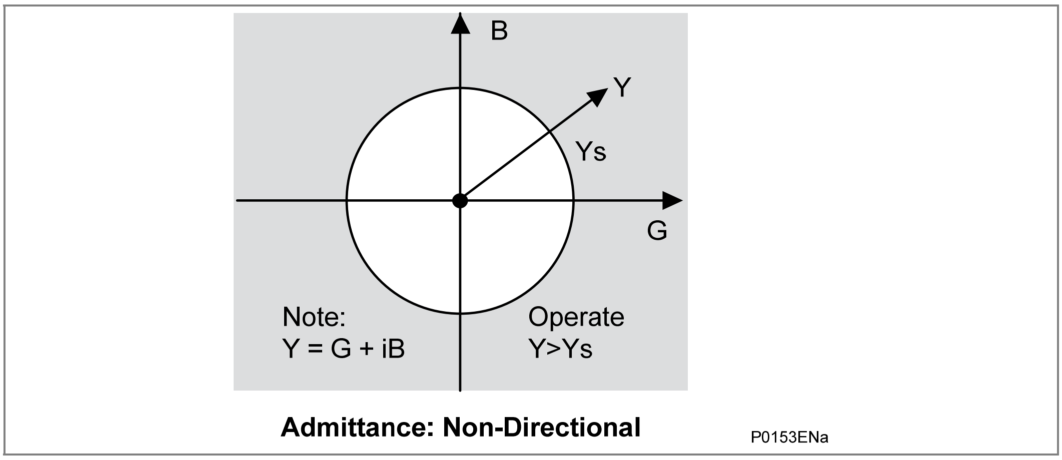

Figure 42 - Non-directional admittance

1.28.2 Operation of Conductance Protection

The conductance protection may be set non-directional, directional forward or directional reverse. Hence, provided the magnitude and the directional criteria are met for conductance and the magnitude of neutral voltage exceeds the set value VN Threshold, the relay will operate. The correction angle causes rotation of the directional boundary for conductance through the set correction angle.

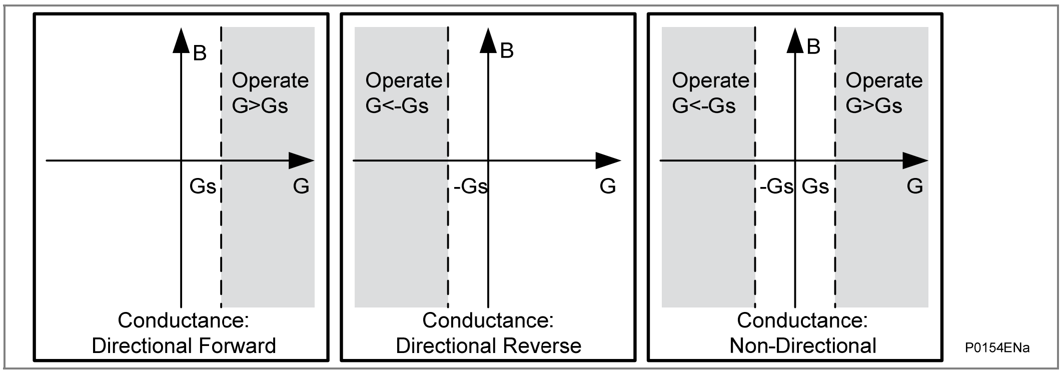

Figure 43 - Operation of Conductance Protection

Note the following:

Forward operation: Center of characteristic occurs when IN is in phase with VN.

If the correction angle is set to +30°, this rotates the boundary from 90° - 270° to 60° - 240°. It is assumed that the direction of the G axis indicates 0°.

1.28.3 Operation of Susceptance Protection

The susceptance protection may be set non-directional, directional forward or directional reverse. Hence, provided the magnitude and the directional criteria are met for susceptance and the magnitude of neutral voltage exceeds the set value VN Threshold, the relay will operate. The correction angle causes rotation of the directional boundary for susceptance through the set correction angle.

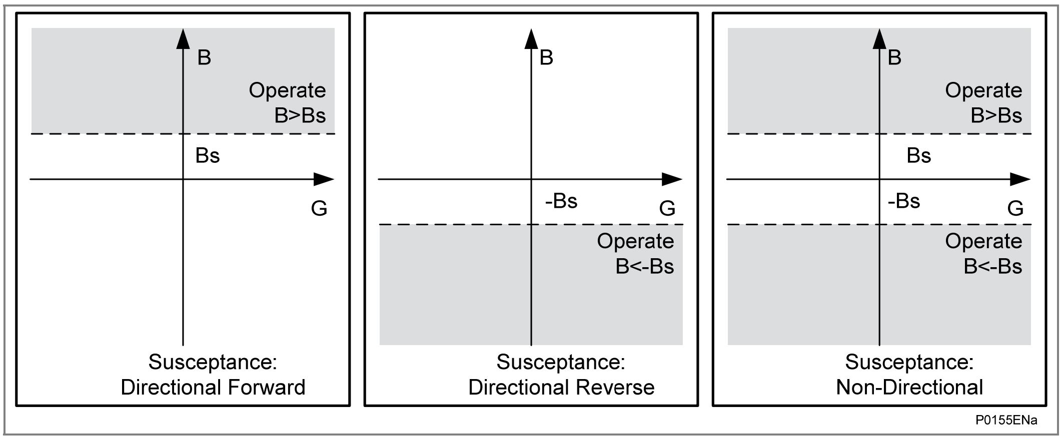

Figure 44 - Operation of Susceptance Protection

Note the following:

Forward operation: Center of characteristic occurs when IN leads VN by 90°.

If the correction angle is set to +30°, this rotates the boundary from 0° - 180° to 330° - 150°. It is assumed that the direction of the G axis indicates 0°.

1.29 2nd Harmonic Blocking

The 2nd Harmonic Blocking detects high inrush current flows that occur when transformers or machines are connected. The function will then block the following functions:

- Phase overcurrent stages 1,2,3,4 (selectable cross block/phase segregated block) - See Note *
- Earth Fault measured stages 1,2,3,4 cross block only
- Earth Fault derived stages 1,2,3,4 cross block only
- Sensitive Earth Fault stages 1,2,3,4 cross block only
- Negative Sequence overcurrent stages 1,2,3,4 cross block only

*Note **	*The cross block/phase segregated block shall apply to all 4 stages for Phase overcurrent*

The 2nd Harmonic Blocking function identifies an inrush current by evaluating the ratio of the second harmonic current components to the fundamental wave. If this ratio exceeds the set thresholds, then the inrush stabilization function operates. Another settable current trigger blocks **(I> lift 2H)** 2nd Harmonic Blocking, if the current exceeds this trigger. By selecting the I> Blocking operating mode, the user determines whether 2nd Harmonic Blocking will operate phase selectively or across all phases.

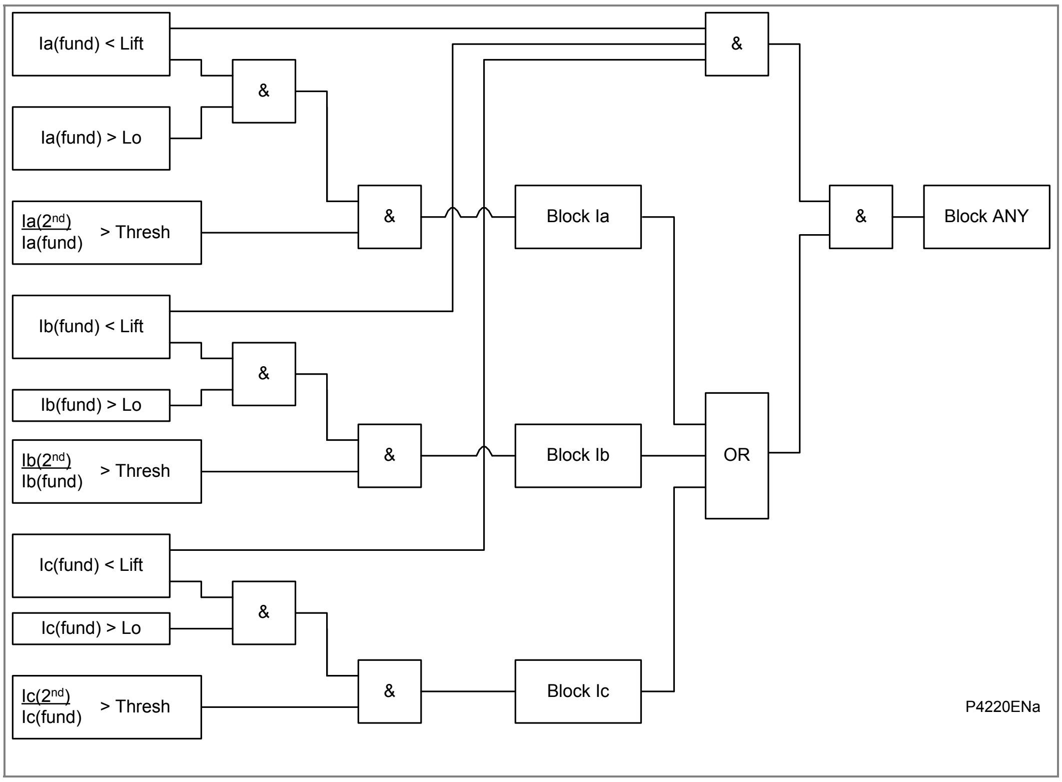

Figure 45 - 2nd Harmonic blocking

1.30 InterMiCOM Teleprotection Introduction

The InterMiCOM application is an effective replacement to the traditional hardwired logic scheme presently used by the P140 range protection relays when applied in 2-relay blocking, direct or permissive type scheme applications.

8 binary input DDB signals and 8 binary output DDB signals, which may be mapped in PSL, are provided at each relay end and the InterMiCOM application provides a means of transferring data between two protection relays using a dedicated full-duplex communications channel.

It is possible to customize the individual signals for blocking, permissive or direct tripping applications which have different requirements for security, speed and dependability.

The loss of communications for a time greater than a set frame synchronization period will cause the signals to fall back to previous or set default values.

Communications statistics and a loopback mode are available for commissioning purposes.

1.30.1 Definition of Teleprotection Commands

The decision to send a command is made by a local protective relay operation, and three generic types of InterMiCOM signal are available:

<u>Intertripping</u>	In intertripping (direct or transfer tripping applications), the command is not supervised at the receiving end by any protection relay and simply causes CB operation. Since no checking of the received signal by another protection device is performed, it is absolutely essential that any noise on the signaling channel isn't seen as being a valid signal. In other words, an intertripping channel must be very secure.
<u>Permissive</u>	In permissive applications, tripping is only permitted when the command coincides with a protection operation at the receiving end. Since this applies a second, independent check before tripping, the signaling channel for permissive schemes do not have to be as secure as for intertripping channels.
<u>Blocking</u>	In blocking applications, tripping is only permitted when no signal is received but a protection operation has occurred. In other words, when a command is transmitted, the receiving end device is blocked from operating even if a protection operation occurs. Since the signal is used to prevent tripping, it is imperative that a signal is received whenever possible and as quickly as possible. In other words, a blocking channel must be fast and dependable.

The requirements for the three channel types are shown in Figure 46.

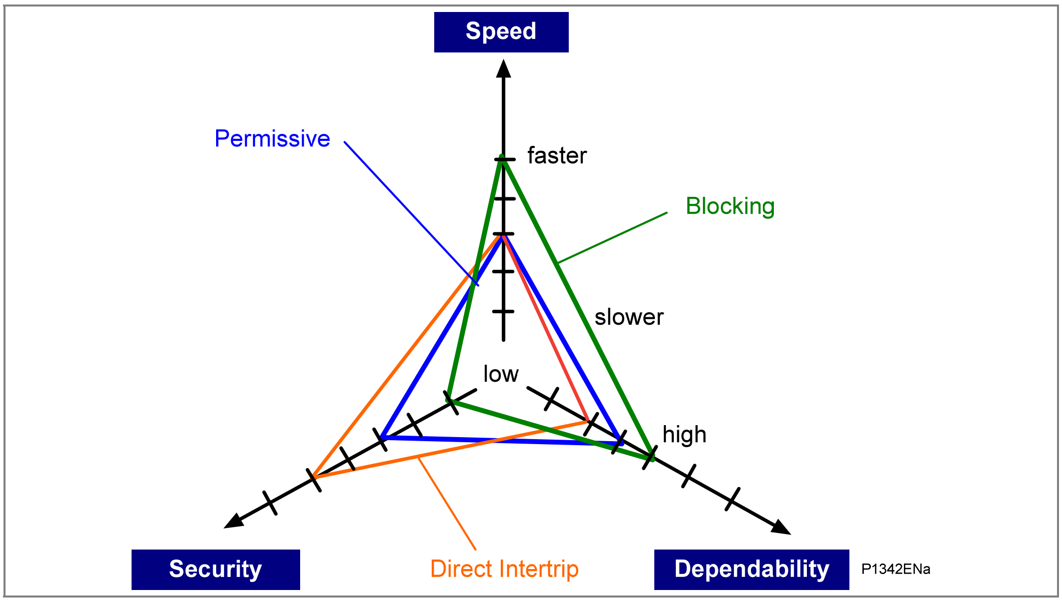

Figure 46 - Pictorial comparison of operating modes

This diagram shows that a blocking signal should be fast and dependable; a direct intertrip signal should be very secure and a permissive signal is an intermediate compromise of speed, security and dependability. In MODEM applications, all three modes can be applied to selected signaling bits within each message.

1.31 EIA(RS)232 InterMiCOM

1.31.1 Communications Media

InterMiCOM is capable of transferring up to 8 commands over one communication channel. Due to recent expansions in communication networks, most signaling channels are now digital schemes utilizing multiplexed fiber optics and for this reason, InterMiCOM provides a standard EIA(RS)232 output using digital signaling techniques. This digital signal can then be converted using suitable devices to any communications media as required. The EIA(RS)232 output may alternatively be connected to a MODEM link.

Regardless of whether analogue or digital systems are being used, all the requirements of teleprotection commands are governed by an international standard IEC60834-1:1999 and InterMiCOM is compliant with the essential requirements of this standard. This standard governs the speed requirements of the commands as well as the probability of unwanted commands being received (security) and the probability of missing commands (dependability).

1.31.2 General Features and Implementation

InterMiCOM provides 8 commands over a single communications link, with the mode of operation of each command being individually selectable within the “**IM# Cmd Type**” cell. “**Blocking**” mode provides the fastest signaling speed (available on commands 1 - 4), “**Direct Intertrip**” mode provides the most secure signaling (available on commands 1 - 8) and “**Permissive**” mode provides the most dependable signaling (available on commands 5 - 8). Each command can also be disabled so that it has no effect in the logic of the relay.

Since many applications will involve the commands being sent over a multiplexed communications channel, it is necessary to ensure that only data from the correct relay is used. Both relays in the scheme must be programmed with a unique pair of addresses that correspond with each other in the “**Source Address**” and “**Receive Address**” cells. For example, at the local end relay if we set the “**Source Address**” to 1, the “**Receive Address**” at the remote end relay must also be set to 1. Similarly, if the remote end relay has a “**Source Address**” set to 2, the “**Receive Address**” at the local end must also be set to 2. All four addresses must not be set identical in any given relay scheme if the possibility of incorrect signaling is to be avoided.

It must be ensured that the presence of noise in the communications channel isn’t interpreted as valid messages by the relay. For this reason, InterMiCOM uses a combination of unique pair addressing described above, basic signal format checking and for “**Direct Intertrip**” commands an 8-bit Cyclic Redundancy Check (CRC) is also performed. This CRC calculation is performed at both the sending and receiving end relay for each message and then compared in order to maximize the security of the “**Direct Intertrip**” commands.

Most of the time the communications will perform adequately and the presence of the various checking algorithms in the message structure will ensure that InterMiCOM signals are processed correctly. However, careful consideration is also required for the periods of extreme noise pollution or the unlikely situation of total communications failure and how the relay should react. During periods of extreme noise, it is possible that the synchronization of the message structure will be lost and it may become impossible to decode the full message accurately. During this noisy period, the last good command can be maintained until a new valid message is received by setting the “**IM# FallBackMode**” cell to “**Latched**”. Alternatively, if the synchronization is lost for a period of time, a known fallback state can be assigned to the command by setting the “**IM# FallBackMode**” cell to “**Default**”. In this latter case, the time period will need to be set in the “**IM# FrameSynTim**” cell and the default value will need to be set in “**IM# DefaultValue**” cell. As soon as a full valid message is seen by the relay all the timer periods are reset and the new valid command states are used. An alarm is provided if the noise on the channel becomes excessive.

When there is a total communications failure, the relay will use the fallback (failsafe) strategy as described above. Total failure of the channel is considered when no message data is received for four power system cycles or if there is a loss of the DCD line.

1.31.3 EIA(RS)232 Physical Connections

InterMiCOM on the Px40 relays is implemented using a 9-pin '**D**' type female connector (labeled SK5) located at the bottom of the 2nd Rear communication board. This connector on the Px40 relay is wired in DTE (Data Terminating Equipment) mode, as indicated below:

Pin	Acronym	InterMiCOM Usage
1	DCD	"Data Carrier Detect" is only used when connecting to modems otherwise this should be tied high by connecting to terminal 4.
2	RxD	"Receive Data"
3	TxD	"Transmit Data"
4	DTR	"Data Terminal Ready" is permanently tied high by the hardware since InterMiCOM requires a permanently open communication channel.
5	GND	"Signal Ground"
6	Not used	-
7	RTS	"Ready To Send" is permanently tied high by the hardware since InterMiCOM requires a permanently open communication channel.
8	Not used	-
9	Not used	-

Table 6 - EIA(RS)232 Physical Connections

Depending upon whether a direct or modem connection between the two relays in the scheme is being used, the required pin connections are described below.

1.31.4 Direct Connection

The EIA(RS)232 protocol only allows for short transmission distances due to the signaling levels used and therefore the connection shown below is limited to less than 15m. However, this may be extended by introducing suitable EIA(RS)232 to fiber optic converters, such as the Schneider Electric CILI203. Depending upon the type of converter and fiber used, direct communication over a few kilometers can easily be achieved.

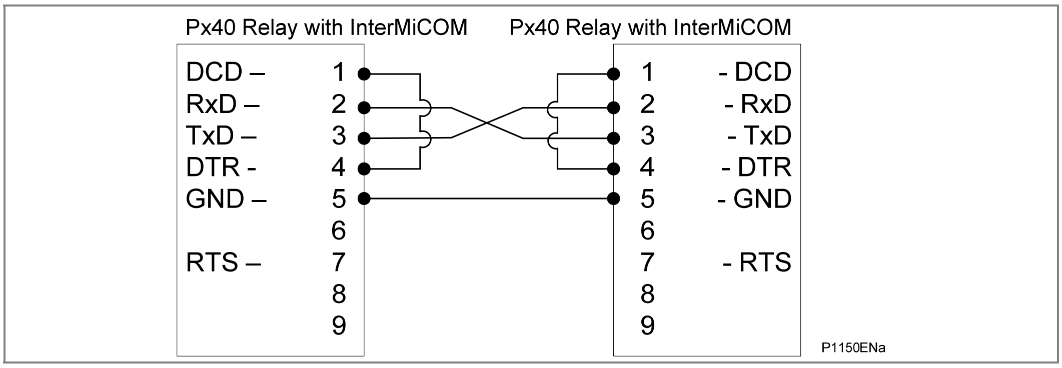

Figure 47 - Direct connection within the local substation

This type of connection should also be used when connecting to multiplexers that have no ability to control the DCD line.

1.31.5 Modem Connection

For long distance communication, modems may be used in which the case the following connections should be made.

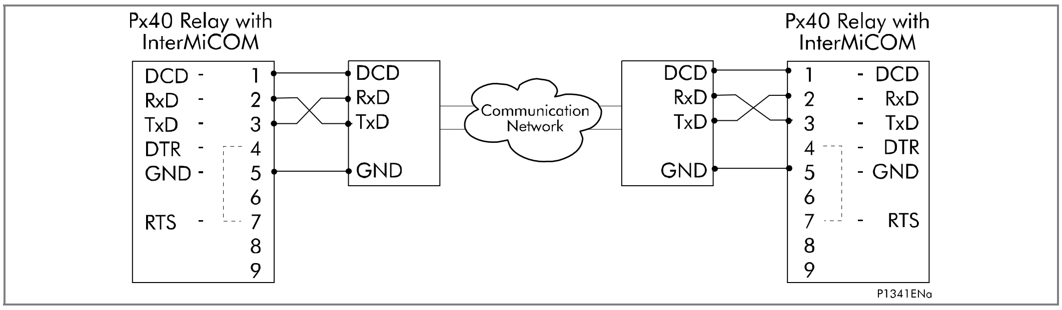

Figure 48 - InterMiCOM teleprotection via a MODEM link

This type of connection should also be used when connecting to multiplexers that have the ability to control the DCD line. With this type of connection it should be noted that the maximum distance between the Px40 relay and the modem should be 15m, and that a baud rate suitable for the communications path used should be selected.

1.31.6 RS422 Connection

RS232 to RS422 converter such as Schneider Electric CK212 may also be used for a longer distance application; it can be formed as in Figure 49:

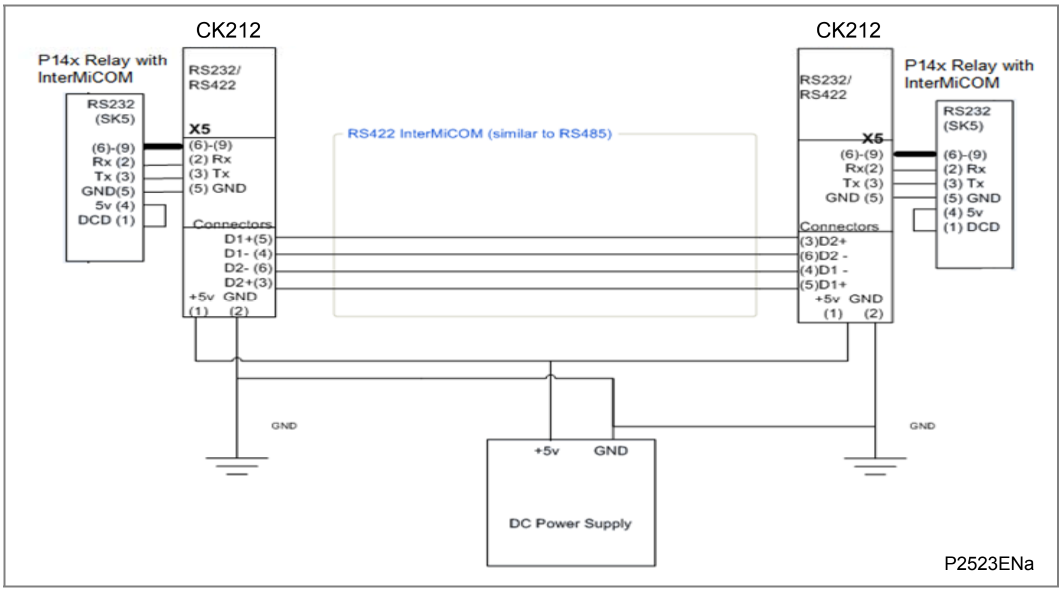

Figure 49 - InterMiCOM teleprotection via a RS422 protocol

With this type of connection, the maximum distance between the Px40 relay and the converter should be 15m.

Up to 1.2km length can be achieved with this type of protocol, depending on the converter performance.

1.31.7 Fiber Optic Connection

For long distance communication, fiber optic converter may be used in which the case the following connections should be made:

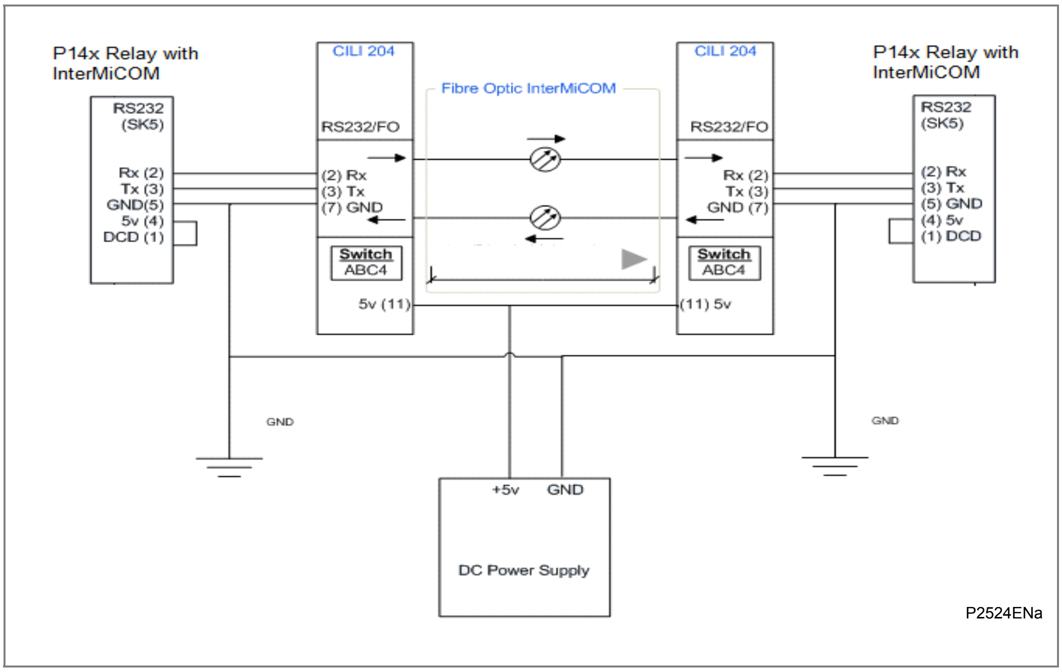

Figure 50 - InterMiCOM teleprotection via fiber optic

With this type of connection, the maximum distance between the Px40 relay and the converter should be 15m.

The length that can be achieved is depending on the converter performance.

1.31.8 Functional Assignment

Even though settings are made on the relay to control the mode of the intertrip signals, it is necessary to assign InterMiCOM input and output signals in the relay Programmable Scheme Logic (PSL) if InterMiCOM is to be successfully implemented. Two icons are provided on the PSL editor of MiCOM S1 for "**Integral tripping In**" and "**Integral tripping out**" which can be used to assign the 8 intertripping commands. The example shown below in Figure 51 shows a "**Control Input_1**" connected to the "**Intertrip O/P1**" signal which would then be transmitted to the remote end. At the remote end, the "**Intertrip I/P1**" signal could then be assigned within the PSL. In this example, we can see that when intertrip signal 1 is received from the remote relay, the local end relay would operate an output contact, R1.

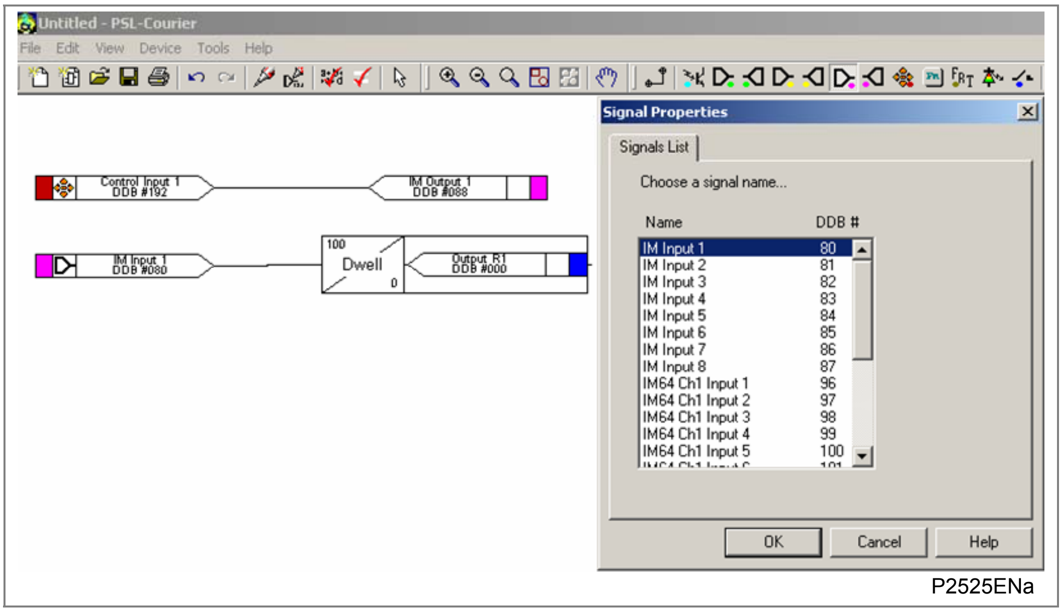

Figure 51 - Example assignment of signals within the PSL

It should be noted that when an InterMiCOM signal is sent from the local relay, only the remote end relay will react to this command. The local end relay will only react to InterMiCOM commands initiated at the remote end. InterMiCOM is thus suitable for teleprotection schemes requiring Duplex signaling.

1.32 InterMiCOM Statistics and Diagnostics

It is possible to hide the channel diagnostics and statistics from view by setting the "**Ch Statistics**" and/or "**Ch Diagnostics**" cells to "**Invisible**". All channel statistics are reset when the relay is powered up, or by user selection using the "**Reset Statistics**" cell.

1.33 Sensitive Power Protection

Two stages of sensitive power protection are provided, these can be independently selected as reverse power, over power, low forward power or disabled, and operation in each mode is described in the following sections.

It is assumed that when the sensitive power function is used, the SEF CT is connected to Phase A current therefore the measured power is ISEF x VA.

1.33.1 A phase Sensitive Power Calculation

Input Quantities:

Sensitive power will be calculated from VA Ph-N voltage and I sensitive current input (which is assumed to be connected to phase A).

The calculation for active power with the correction angle is shown in the equation below, where VA is A-phase voltage, IAS is A-phase sensitive current, ϕ is the angle of IAS with respect to VA and θC is the CT correction angle.

Equation 2:

$$P(Aph.) = I_{AS} V_A \cos(\phi - \theta_C)$$

Calculations within the relay are based upon quadrature components obtained from the Fourier analysis of the input signals. The quadrature values for VA and IAS available from the ADB will be used for the sensitive power calculation as shown:

$\overline{V}_A = V_{AR} + jV_{Ai}$

$\overline{I}_{AS} = I_{ASr} + jI_{ASi}$

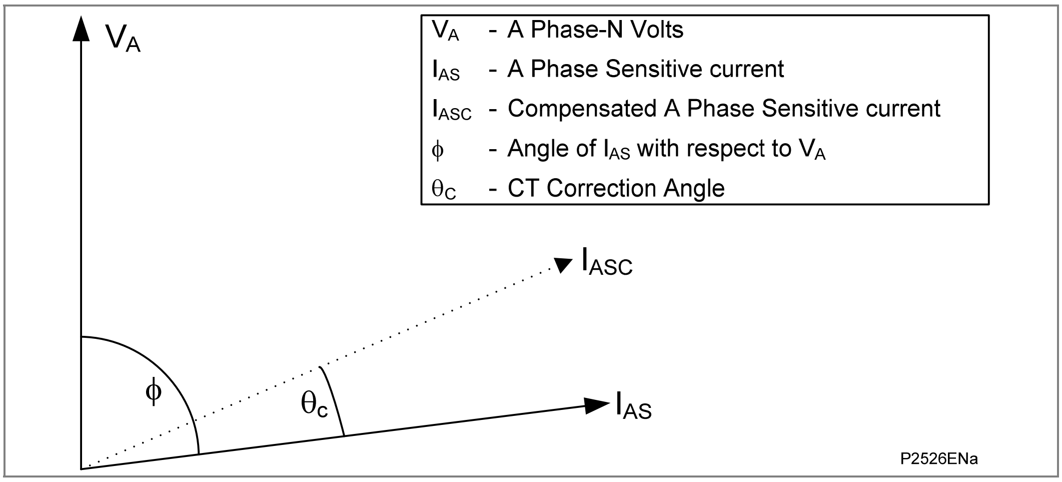

Figure 52 - Sensitive power input vectors

CT Correction:

The CT correction will rotate the I_{AS} vector by the correction angle, as shown in Figure 52. This correction is performed before the power calculation and can be achieved with the use of a rotation matrix.

$$\overline{I}_{AS} = \begin{bmatrix} I_{ASr} \\ I_{ASi} \end{bmatrix}$$ Using rotation matrix - $$\begin{bmatrix} \cos\theta_C & -\sin\theta_C \\ \sin\theta_C & \cos\theta_C \end{bmatrix}$$

The corrected phase A sensitive current I_{ASC} is calculated as follows:

$$\bar{I}_{ASC} = \begin{bmatrix} I_{ASCr} \\ I_{ASCi} \end{bmatrix} \qquad = \begin{bmatrix} I_{ASr} \\ I_{ASi} \end{bmatrix} \begin{bmatrix} \cos\theta_C & -\sin\theta_C \\ \sin\theta_C & \cos\theta_C \end{bmatrix}$$

$$= \begin{bmatrix} I_{ASr}\cos\theta_C - I_{ASi}\sin\theta_C \\ I_{ASr}\sin\theta_C + I_{ASi}\cos\theta_C \end{bmatrix}$$

therefore:

Equation 3:

$$I_{ASCr} = I_{ASr}\cos\theta_C - I_{ASi}\sin\theta_C$$

And

Equation 4:

$$I_{ASCi} = I_{ASr}\sin\theta_C + I_{ASi}\cos\theta_C$$

The $\sin\theta_c$ and $\cos\theta_c$ values will be stored and only calculated when the compensation angle setting is changed. The stored values can then be used to calculate I_{ASC} and I_{ASC}.

Active Power Calculation:

The corrected A-phase sensitive current vector can now be used to calculate the sensitive A-Phase active power P_{AS}.

Using the equation: $P_{AS} = \mathrm{Re}\,\bar{V}_A \bar{I}^*_{ASC}$

Therefore:

$$P_{AS} = \mathrm{Re}\left((V_{Ar} + jV_{Ai})(I_{ASCr} + jI_{ASCi})^*\right)$$

$$P_{AS} = \mathrm{Re}\left((V_{Ar} + jV_{Ai})(I_{ASCr} - jI_{ASCi})\right)$$

Equation 5:

$$P_{AS} = \mathrm{Re}\left((V_{Ar}I_{ASCr} + V_{Ai}I_{ASCi}) + j(V_{Ai}I_{ASCr} - V_{Ar}I_{ASCi})\right)$$

$$P_{AS} = V_{Ar}I_{ASCr} + V_{Ai}I_{ASCi}$$

1.33.2 Sensitive Power Measurements

Three sensitive power related measurements are added to the Measurements column, the visibility of which will depend on the protection configuration.

- A-Phase Sensitive Active Power (Watts)
- A-Phase Sensitive Re-active Power (VArs)
- A-Phase Sensitive Power Angle

1.34 Phase Segregated Power Protection

The power protection element provides 2 stages of directional underpower and 2 stages of directional overpower for both active and reactive power. The directional element shall be configurable as forward or reverse to set 3 phase and single phase trip.

The basis of operation is that the elements use three phase power/single phase power, based on Fourier measurement, as the energising quantity. For overpower, a start condition occurs when two consecutive measurements exceed the setting threshold in the absence of an inhibit condition from VTS slow block and pole dead (if selected). A trip condition occurs if the start condition is present for the set trip time.

The start (and trip if operated) and the trip timer shall reset if the power falls below the drop-off level or if an inhibit condition occurs. The reset mechanism shall be similar to the overcurrent functionality for a pecking fault condition, where the amount of travel for the operate timer is memorised for a set reset time delay. If the start condition returns before the reset timer has timed out, the operate time initialises from the memorised travel value. Otherwise the memorised value is reset to zero after the reset time times out.

For underpower, the operation occurs when the energising quantity goes below setting.

The logic diagram for any phase (or for the three phase) is shown in Figure 53:

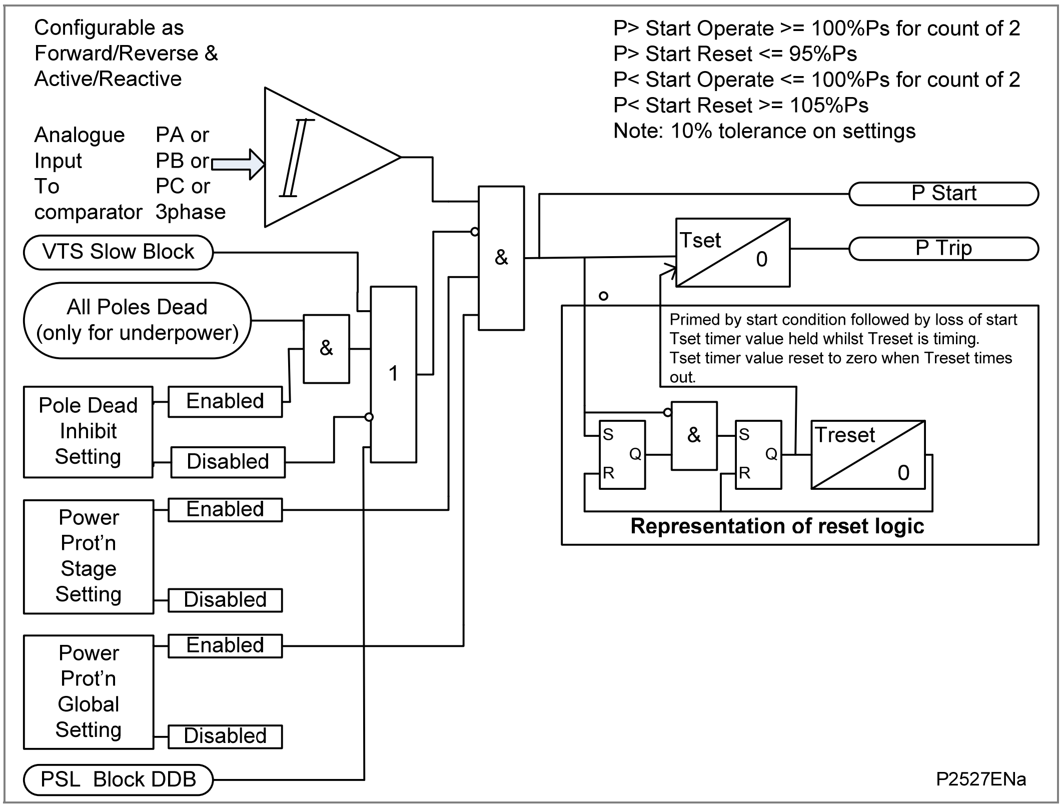

Figure 53 - Under/Over Power Protection Stage

The overall functionality of the power protection is summarised as follows:

Starting: The Start DDB will be raised if the power is above setting (100%) and drops off at 95% of setting.

Tripping: The Trip DDB will be raised if the Start DDB is on for more than the TimeDelay setting (Trip Timer timeout).

The Trip will reset when the Start is reset.

tRESET:	The Trip Timer will get reset if the Start is off for more than the tRESET setting.
Blocking:	VTS: VTS Slow Block is hardcoded into the protection and will block the start condition provided no trip condition is present.
Poledead:	If (DDB_ALL_POLEDEAD) is on and the Poledead is set, the protection will be reset and blocked.
PSL:	If the PSL block DDB is on, the protection will be reset and blocked.

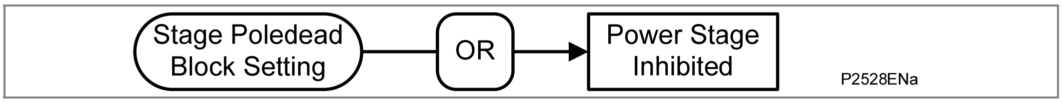

Figure 54 - Stage Poledead Block Settings or Power Stage Inhibited

1.35 Rate of Change of Voltage (dv/dt) Protection

Instantaneous dv/dt:

- The P140 samples the 3 voltages (ph-N) 24 samples per cycle and the frequency tracking secure that sampling by tracking on a certain channel frequency. Every PCON (every 12 samples in P140) the sampling buffer (24 samples length) get updated with last new 12 samples therefore the Fourier fundamental magnitude will be updated. The Instant dv/dt will then be based on the VoltageNow - VoltageLastCycle (stored in a length of 2 buffer) as shown in this graph:

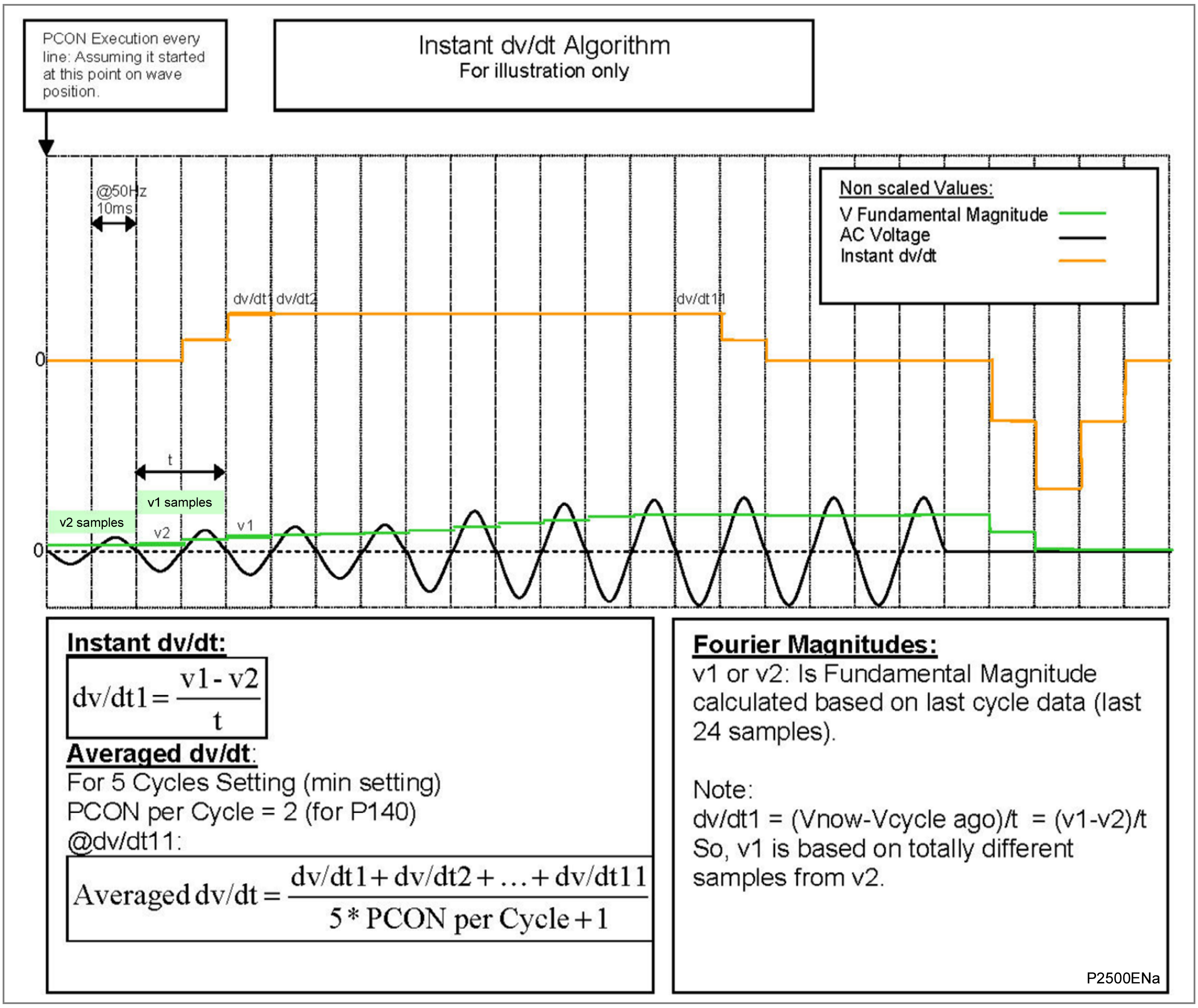

Figure 55 - Instant dv/dt Algorithm

The buffers of the dv/dt protection will be reset and a "**buffers not full**" flag will be raised (which then gives no dv/dt response until the buffers are full again after about 1.04s):

- In case of "**Frequency Not Found**" is raised from the frequency Tracking algorithm.
- When "**dv/dt Meas Mode**" setting changes.

Setting	Action
Phase - Phase	Phase - Phase voltages used
Phase - Neutral	Phase - Neutral voltages used

- Relay Power up.
- Both dv/dt Stages are disabled.

1.35.1 Averaged dv/dt

The averaging will consist of averaging the rate of change over a set number of cycles (rolling window) similar to the advanced frequency df/dt+t. Each stage will have its own "**dv/dt? AvgCycles**".

The instant dv/dt (mentioned previously) will be stored in a 101 length buffer to cover the MAX setting of 50 cycles averaging. Therefore both stages will access the same buffer but with the capability of having different Averaging Cycles Setting. Dependent on the averaging cycles, the averaged dv/dt will be based on the instant dv/dt now and the previous ones as shown in the figure above.

All the above operations will be blocked (and buffers reset) in case of "**Frequency Not Found**" is raised from the frequency Tracking algorithm.

The buffer resets also when "**dv/dt Meas Mode**" setting changes.

If the buffer resets (for any of the above reasons) or the relay just powered up, the dv/dt will wait until the 101 buffer is filled again (about 1s).

1.35.2 Start DDBs

A start will be raised if the averaged dv/dt is above setting two times consecutively (2 PCON, which is maximum delay of 20ms@50Hz) and then will not drop off unless averaged dv/dt is below (setting-Hyst) for four times consecutively (4 PCON, which is maximum delay of 40ms@50Hz).

Hyst = 0.07 @110 VT rating and 0.28 @440 VT (derived from ripple in dv/dt reading while having no dv/dt at 11v and 5 Cycles averaging).

1.35.3 Trip DDBs

Trip will be raised if:

- The start is raised continuously for more than TimeDelay setting.
  or
- If start goes off for less than the tRESET setting and the overall time is above TimeDelay setting.

1.35.4 Blocking DDBs

For each stage there is a PSL blocking signal "**dv/dt? Blocking**" which will reset the whole stage (timers and DDBs).

1.35.5 Generic DDB

For each stage there is a generic Start and Trip DDB ("**dv/dt? Start**" and "**dv/dt? Trip**") controlled by setting "**dv/dt? Oper Mode**". For Any-Phase setting this DDB will be the logical OR of the 3 phases DDBs and for Three-Phase setting this DDB will be the logical AND of the 3 phases DDBs.

1.35.6 dv/dt Start Operating Times

Here is a V/s graph for a sudden dv/dt.

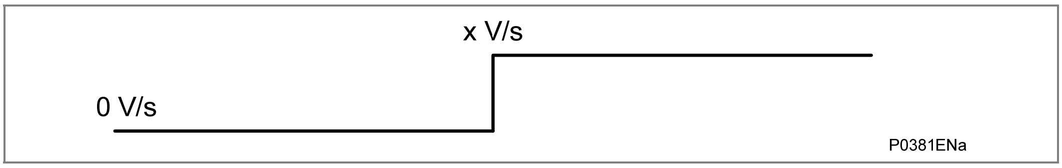

Figure 56 – V/s graph

When applying a sudden dv/dt:

@50Hz,
Operating times for any start signal = No of Averaging Cycles x 2x10ms + 5x10ms ±10ms

(1) (2) (3)

@60Hz the 10ms becomes 8.33ms

1. It is controlled by no. of averaging cycles setting
2. It is a combination of:

   2 cycles (40ms which is the time required to see a change in the Inst dv/dt due to having the dv from Voltage now - Voltage cycle ago, see the above figure)

   10ms for 2 counts strategies till the start is raised
3. Tolerance

2 OPERATION OF NON PROTECTION FUNCTIONS

2.1 Three-Phase Auto-Reclosing

The P14x will initiate auto-reclose for fault clearances by the phase overcurrent, earth fault and SEF protections.

In addition to these settings, function links in the "**OVERCURRENT**", "**EARTH FAULT1**", "**EARTH FAULT2**" and "**SEF/REF PROT'N**" columns are also required to fully integrate the auto-reclose logic in the relay.

The auto-reclose function provides multi-shot three-phase auto-reclose control. It can be adjusted to perform a single shot, two shot, three shot or four shot cycle, selectable via "**Number of Shots**". There is also the option to initiate a separate auto-reclose cycle with a different number of shots, "**Number of SEF Shots**", for the SEF protection. Dead times for all shots (re-close attempts) are independently adjustable.

An auto-reclose cycle can be internally initiated by operation of a protection element or externally by a separate protection device, provided the circuit breaker is closed until the instant of protection operation. The dead time "**Dead Time 1**", "**Dead Time 2**", "**Dead Time 3**", "**Dead Time 4**" starts when the circuit breaker has tripped and optionally when the protection has reset, selectable via "**Start Dead t On**". At the end of the relevant dead time, a CB close signal is given, provided system conditions are suitable. The system conditions to be met for closing are that the system voltages are in synchronism or dead line/live bus or live line/dead bus conditions exist, indicated by the internal check synchronizing element and that the circuit breaker closing spring, or other energy source, is fully charged indicated from the "**DDB 230: CB Healthy**" input. The CB close signal is cut-off when the circuit breaker closes.

When the CB has closed the reclaim time "**Reclaim Time**" starts. If the circuit breaker does not trip again, the auto-reclose function resets at the end of the reclaim time. If the protection operates during the reclaim time the relay either advances to the next shot in the programmed auto-reclose cycle, or, if all programmed re-close attempts have been made, goes to lockout.

CB Status signals must also be available within the relay, i.e. the default setting for "**CB Status Input**" should be modified accordingly for the application. The default PSL requires 52A, 52B and CB Healthy logic inputs, so a setting of "**Both 52A and 52B**" is required for the CB Status Input.

2.1.1 Logic Functions

2.1.1.1 Logic Inputs

The auto-reclose function has several Digital Data Bus (DDB) logic inputs, which can be mapped in PSL to any of the opto-isolated inputs on the relay or to one or more of the DDB signals generated by the relay logic. The function of these inputs is described below, identified by their signal text.

CB Healthy

The majority of circuit breakers are only capable of providing one trip-close-trip cycle. Following this, it is necessary to re-establish if there is sufficient energy in the circuit breaker (spring charged, gas pressure healthy, etc.) before the CB can be re-closed. The "**DDB 230: CB Healthy**" input is used to ensure that there is sufficient energy available to close and trip the CB before initiating a CB close command. If on completion of the dead time, the "**DDB 230: CB Healthy**" input is low, and remains low for a period given by the "**CB Healthy Time**" timer, lockout will result and the CB will remain open

This check can be disabled by not allocating an opto input for "**DDB 230: CB Healthy**". The signal defaults to high if no logic is mapped to DDB 230 within the PSL in the relay

BAR

The "**DDB 239: Block AR**" input will block auto-reclose and cause a lockout if auto-reclose is in progress. It can be used when protection operation without auto-reclose is required. A typical example is on a transformer feeder, where auto-reclosing may be initiated from the feeder protection but blocked from the transformer protection.

Reset Lockout

The "**DDB 237: Reset Lockout**" input can be used to reset the auto-reclose function following lockout and reset any auto-reclose alarms, provided that the signals which initiated the lockout have been removed.

Auto Mode

The "**DDB 241: Auto Mode**" input is used to select the Auto operating mode; auto-reclose in service. When the "**DDB 241: Auto Mode**", "**DDB 240: Live Line Mode**" and "**DDB 242: Telecontrol**" inputs are off the "**Non Auto Mode**" of operation is selected; auto-reclose out of service.

Live Line Mode

The "**DDB 240: Live Line Mode**" input is used to select the Live Line operating mode where auto-reclose is out of service and all blocking of instantaneous protection by auto-reclose is disabled. This operating mode takes precedence over all other operating modes for safety reasons, as it indicates that utility personnel are working near live equipment.

Telecontrol Mode

The "**DDB 242: Telecontrol**" input is used to select the Telecontrol operating mode whereby the Auto and Non Auto modes of operation can be selected remotely.

Live/Dead Ccts OK

DDB 461: “**Live/Dead Ccts** OK” is an input to the auto-reclose logic. When AR is enabled with one or both sides of the CB dead (AUTO-RECLOSE GROUP 1 - SYSTEM CHECKS setting [49 43] - Live/Dead Ccts: Enabled), DDB 461 should be mapped in PSL to appropriate combinations of Live Line, Dead Line, Live Bus and Dead Bus signals from the system check logic (DDB 443, 444, 445 & 446), as required for the specific application. If setting 49 43 is Disabled, DDB 461 mapping is irrelevant.

AR SysChecks OK

DDB 403: “**AR Sys. Checks OK**” can be mapped in PSL from system checks output DDB 449: “**Sys. Chks. Inactive**”, to enable auto-reclosing without any system checks, if the system check function is disabled (CONFIGURATION setting 09 23 - System Checks: Disabled). This mapping is not essential, because AUTO-RECLOSE GROUP 1 - SYSTEM CHECKS setting [49 44] - No System Checks can be set to Enabled to achieve the same effect.

DDB 403 can also be mapped to an opto input, to enable the P14x to receive a signal from an external system monitoring relay to indicate that system conditions are suitable for CB closing. This should not normally be necessary, since the P14x has comprehensive built in system check functionality.

Ext. AR Prot. trip/start

DDB 439: “**Ext. AR Prot. Trip**” and/or DDB 440: “**Ext. AR Prot. Start**” allow initiation of auto-reclosing by a separate protection relay. Please refer to section 2.1.2.2 - Auto-Reclose Initiation.

DAR Complete

At least one major utility, which uses delayed auto-reclosing (DAR) on most of its transmission network, requires a "**DAR in Progress**" signal from AR initiation up to the application of the CB Close command, but not during the reclaim time following CB re-closure. DDB 453: "**DAR Complete**" can, if required, be mapped in PSL to be activated for a short pulse when a CB Close command is given at the end of the dead time. If DDB 453: "**DAR Complete**" is activated during an auto-reclose cycle, output DDB 456: "**AR in Progress 1**" resets, even though the reclaim time may still be running and DDB 360: "**AR in Progress**" remains set until the end of the reclaim time. For most applications, DDB 453 can be ignored, i.e. not mapped in PSL; in such cases, output DDB 456: AR in Progress 1 operates and resets in parallel with DDB 360: AR in Progress.

CB In Service

One of the interlocks in the auto-reclose initiation logic is DDB 454: "**CB in Service**". This input must be high until the instant of protection operation for an auto-reclose cycle to be initiated. For most applications, this DDB can be mapped simply from the "**CB Closed**" DDB 379. More complex PSL mapping can be programmed if required, e.g. where it is necessary to confirm not only that the CB is closed but also that the line and/or bus VT is actually live up to the instant of protection operation.

AR Restart

In a very small number of applications, it is sometimes necessary to initiate an auto-reclose cycle via an external signal to an opto input when the normal interlock conditions are not all satisfied, i.e. the CB is open and the associated feeder is dead. If input DDB 455: "**AR Restart**" is mapped to an opto input, activation of that opto input will initiate an auto-reclose cycle irrespective of the status of the "**CB in Service**" input, provided the other interlock conditions, such as AR enabled, are still satisfied.

DT OK to Start

This is an optional extra interlock in the dead time initiation logic. In addition to the CB being open and the protection reset, DDB 458: "**DT OK to Start**" has to be high to enable the dead time function to be "**primed**" after an AR cycle has started. Once the dead time function is primed, DDB 458 has no further effect – the dead time function stays primed even if DDB 458 subsequently goes low. A typical PSL mapping for this input is from a "**Dead Line**" signal (DDB 444) from the system check logic, to enable dead time priming only when the feeder has gone dead after CB tripping. If this extra dead time priming interlock is not required, DDB 458 can be left unmapped, and will then default to high.

Dead Time Enabled

This is another optional interlock in the dead time logic. In addition to the CB open, protection reset and "**dead time primed**" signals, DDB 457: "**Dead Time Enabled**" has to be high to allow the dead time to run. If DDB 457 goes low, the dead time stops and resets, but stays primed, and will restart from zero when DDB 457 goes high again. A typical PSL mapping for DDB 457 is from the CB Healthy input DDB 230, or from selected Live Bus, Dead Line etc. signals from the system check logic. It could also be mapped to an opto input to provide a "**hold off**" function for the follower CB in a "**master/follower**" application with 2 CBs. If this optional interlock is not required, DDB 457 can be left unmapped, and will then default to high.

AR Init. Trip Test

If DDB 464: "**AR Init. Trip Test**" is mapped to an opto input, and that input is activated momentarily, the relay logic generates a CB trip output via DDB 372, mapped in default PSL to output R3, and initiates an auto-reclose cycle.

AR skip shot 1

If DDB 530: "**AR Skip Shot 1**" is mapped to an opto input, and that input is activated momentarily, the relay logic will cause the auto-reclose sequence counter to increment by

1. This will therefore decrease the available re-close shots and will lockout the re-closer should the re-closer be on its maximum re-close attempt e.g. if the re-closer is set to two re-close shots, initiation of the DDB 530 will cause the re-close counter to 1, thus the re-closer only has one re-close cycle before it locks out.

Inhibit Reclaim Time

If DDB 532: "**Inh Reclaim Time**" is mapped to an opto input, and that input is active at the start of the reclaim time, the relay logic will cause the reclaim timers to be blocked.

2.1.1.2 Auto-Reclose Logic Outputs

The following DDB signals can be assigned to a relay contact in the PSL or assigned to a Monitor Bit in "**Commissioning Tests**", to provide information about the status of the auto-reclose cycle. They can also be applied to other PSL logic as required. The logic output DDBs are described below, identified by their DDB signal text.

AR In Progress

The "**DDB 360: AR in Progress**" signal is present during the complete re-close cycle from protection initiation to the end of the reclaim time or lockout. DDB 456: "**AR in Progress 1**" operates with DDB 360 at auto-reclose initiation, and, if DDB 453: "**DAR Complete**" does not operate, remains operated until DDB 360 resets at the end of the cycle. If DDB 453 goes high during the auto-reclose cycle, DDB 456 resets (see notes on logic input "**DAR Complete**" above).

Sequence Counter Status

During each auto-reclose cycle, a "**Sequence Counter**" increments by 1 after each fault trip, and resets to zero at the end of the cycle.

- DDB 362: "**Seq. Counter = 0**" is set when the counter is at zero;
- DDB 363: "**Seq. Counter = 1**" is set when the counter is at 1;
- DDB 364: "**Seq. Counter = 2**" is set when the counter is at 2;
- DDB 365: "**Seq. Counter = 3**" is set when the counter is at 3; and
- DDB 366: "**Seq. Counter = 4**" is set when the counter is at 4.

Successful Close

The "**DDB 367: Successful Close**" output indicates that an auto-reclose cycle has been successfully completed. A successful auto-reclose signal is given after the CB has tripped from the protection and re-closed whereupon the fault has been cleared and the reclaim time has expired resetting the auto-reclose cycle. The successful auto-reclose output is reset at the next CB trip or from one of the reset lockout methods; see section 2.1.2.8.1 - Reset from Lockout.

AR In Service

The "**DDB 361: AR in service**" output indicates whether the auto-reclose is in or out of service. Auto-reclose is in service when the relay is in Auto mode and out of service when in the Non Auto and Live Line modes.

Block Main Prot.

The "**DDB 358: Block Main Prot.**" output indicates that the instantaneous protection "**I>3**", "**I>4**", "**IN1>3**", "**IN1>4**", "**IN2>3**", "**IN2>4**" is being blocked by the auto-reclose logic during the auto-reclose cycle. Blocking of the instantaneous stages for each trip of the auto-reclose cycle is programmed using the Overcurrent and Earth Fault 1/2 function link settings, "**I> Function Link**", "**IN1> Func. Link**", "**IN2> Func. Link**", and the "**Trip 1/2/3/4/5 Main**" settings; see section 2.1.2.3 - Blocking Instantaneous Protection during an AR Cycle.

Block SEF Prot.

The "**DDB 359: Block SEF Prot.**" output indicates that the instantaneous SEF protection "**ISEF>3, ISEF>4**" is being blocked by the auto-reclose logic during the auto-reclose cycle. Blocking of the instantaneous SEF stages for each trip of the auto-reclose cycle is programmed using the SEF/REF Prot'n. function link setting, "**ISEF> Func. Link**", and the "**Trip 1/2/3/4/5 SEF**" settings; see section **Error! Reference source not found.** '**Blocking instantaneous protection during an auto-reclose cycle**'.

Re-Close Checks

DDB 460: "**Re-close Checks**" operates when the dead time function is "**primed**" (see notes on logic input "**DT OK to Start**", above).

Dead T in Prog.

The "**DDB 368: Dead T in Prog.**" output indicates that the dead time is in progress. This signal is set when DDB 460: "**Re-close Checks**" is set AND input DDB 457: "**Dead Time Enabled**" is high, and may be useful during relay commissioning to check the operation of the auto-reclose cycle.

DT Complete

DDB 459: "**DT Complete**" operates at the end of the set dead time, and remains operated until either the scheme resets at the end of the reclaim time or a further protection operation/AR initiation occurs. It can be applied purely as an indication, or included in PSL mapping to logic input DDB 453: "**DAR Complete**" if required (see logic input notes).

System Checks Indication

DDB 462: "**AR Sync. Check**" operates when either of the synchro check modules, if selected for auto-reclosing, confirms an "**in synchronism**" condition.

DDB 463: "**AR Sys. Checks OK**" operates when any selected system check condition (synchro check, live bus/dead line etc.) is confirmed.

Auto-Close

The "**DDB 371: Auto Close**" output indicates that the auto-reclose logic has issued a close signal to the CB. This output feeds a signal to the control close pulse timer and remains on until the CB has closed. This signal may be useful during relay commissioning to check the operation of the auto-reclose cycle.

"Trip when AR Blocked" Indication

DDB 369: "**Protection Lockt.**" operates if AR lockout is triggered by protection operation either during the inhibit period following a manual CB close (see section 2.1.2.7 - Auto-Reclose Inhibit following Manual Close or when the relay is in Non Auto or Live Line mode (see section 2.1.2.8 - AR Lockout).

Reset Lockout Indication

DDB 370: "**Reset Lckout Alm.**" operates when the relay is in Non Auto mode, if setting 49 22 - "**Reset Lockout by**" - is set to "**Select Non Auto**". See section 2.1.2.8.1 - Reset from Lockout.

Reclaim In Progress

The "**DDB 533: Reclaim in Prog**" output indicates that a reclaim timer is in progress and will drop-off once the reclaim timer resets.

Reclaim complete

The "**DDB 534: Reclaim Complete**" operates at the end of the set reclaim time and is a fast reset. To maintain the output indication a dwell timer will have to be implemented in PSL.

2.1.1.3 Auto-Reclose Alarms

The following DDB signals will produce a relay alarm. These are described below, identified by their DDB signal text.

AR no checksync. (latched)

The "**DDB 165: AR No Check Sync.**" alarm indicates that the system voltages were not suitable for auto-reclosing at the end of the check sync. window time (Sys. Check Time), leading to a lockout condition. This alarm can be reset using one of the reset lockout methods; see section 2.1.2.8.1 - Reset from Lockout.

AR CB unhealthy (latched)

The "**DDB 164: AR CB Unhealthy**" alarm indicates that the "**DDB 230: CB Healthy**" input was not energized at the end of the "**CB Healthy Time**", leading to a lockout condition. The "**DDB 230: CB Healthy**" input is used to indicate that there is sufficient energy in the CB operating mechanism to close and trip the CB at the end of the dead time. This alarm can be reset using one of the reset lockout methods; see section 2.1.2.8.1 - Reset from Lockout.

AR lockout (self reset)

The "**DDB 163: AR Lockout**" alarm indicates that the relay is in a lockout status and that further re-close attempts will not be made; see section 2.1.2.8 - AR Lockout for more details. This alarm can be reset using one of the reset lockout methods; see section 2.1.2.8.1 - Reset from Lockout.

2.1.2 Main Operating Features

2.1.2.1 Operation Modes

The auto-reclosing function has three operating modes:

- AUTO MODE — Auto-reclose in service
- NON AUTO MODE — Auto-reclose out of service - selected protection functions are blocked if setting “**AR Deselected**” [4914] = Block Inst. Prot.
- LIVE LINE MODE — Auto-reclose out of service - protection functions are NOT blocked, even if setting “**AR Deselected**” [4914] = Block Inst. Prot. LIVE LINE MODE is a functional requirement by some utilities, for maximum safety during live line working on the protected feeder.

For any operating mode to be selected, CONFIGURATION menu setting “**Auto-reclose**” [0924] must first be set to “**Enabled**”. The required operating mode can then be selected by different methods, to suit specific application requirements. The basic method of mode selection is determined by AUTO-RECLOSE Group n menu setting “**AR Mode Select**” [4091], as summarized in the following table:

A/R Mode Select Setting	Description
COMMAND MODE	Auto/Non Auto is selected by command cell “Auto-reclose Mode”.
OPTO SET MODE	If DDB 241: Auto Mode input is high Auto operating mode is selected (Auto-reclose is in service). If DDB 241: Auto Mode input is low Non Auto operating mode is selected (Auto-reclose is out of service and instantaneous protection is blocked).
USER SET MODE	If DDB 242: Telecontrol input is high, the CB Control Auto-reclose Mode is used to select Auto or Non Auto operating mode. If DDB 242: Telecontrol input is low, behaves as OPTO SET setting.

A/R Mode Select Setting	Description
PULSE SET MODE	If DDB 242: Telecontrol input is high, the operating mode is toggled between Auto and Non Auto Mode on the falling edge of DDB 241: Auto Mode input pulses. The pulses are produced by SCADA system. If DDB 242: Telecontrol input is low, behaves as OPTO SET setting.

Note *If "**Live Line Mode**" input DDB 240 is active, the scheme is forced into LIVE LINE MODE, irrespective of the AR Mode Select setting and Auto Mode and Telecontrol input DDBs.*

Table 7 - A/R Mode Select Setting and description

Live Line Mode input DDB 240 and Telecontrol input DDB 242 are provided to meet the requirements of some utilities who apply a four position selector switch to select AUTO, NON AUTO or LIVE Line operating modes, as shown in Figure 57.

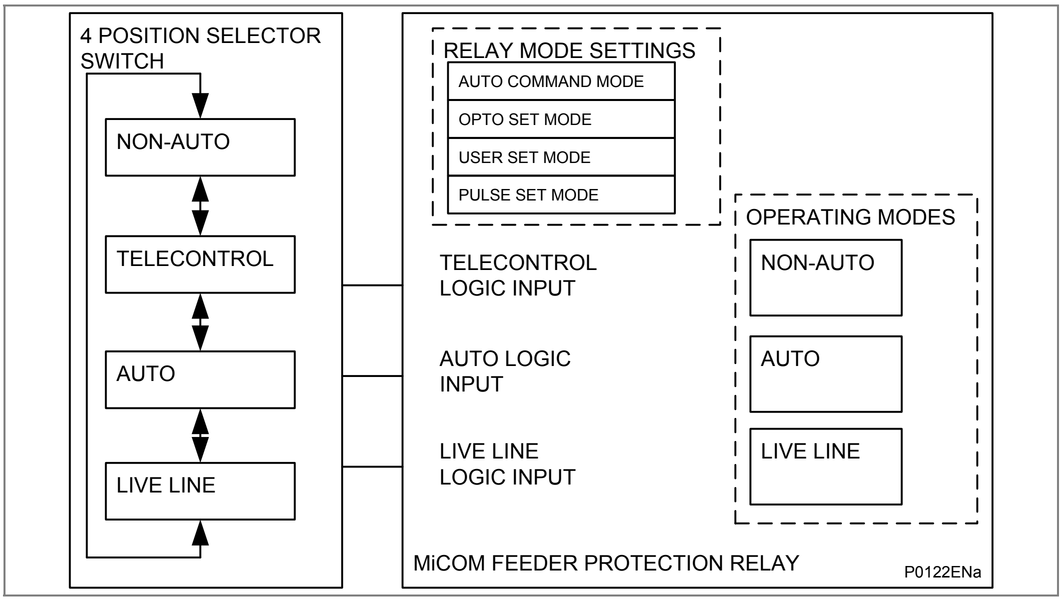

Figure 57 - Operating modes

For this application, the four position switch is arranged to activate relay inputs as shown in the table below:

Switch	Input Logic Signals		
Position	Auto	Telecontrol	Live Line
Non Auto	0	0	0
Telecontrol	0 or SCADA Pulse	1	0
Auto	1	0	0
Live Line	0	0	1

Table 8 - Switches and input logic signals

Operating mode selection logic is shown in Figure 58.

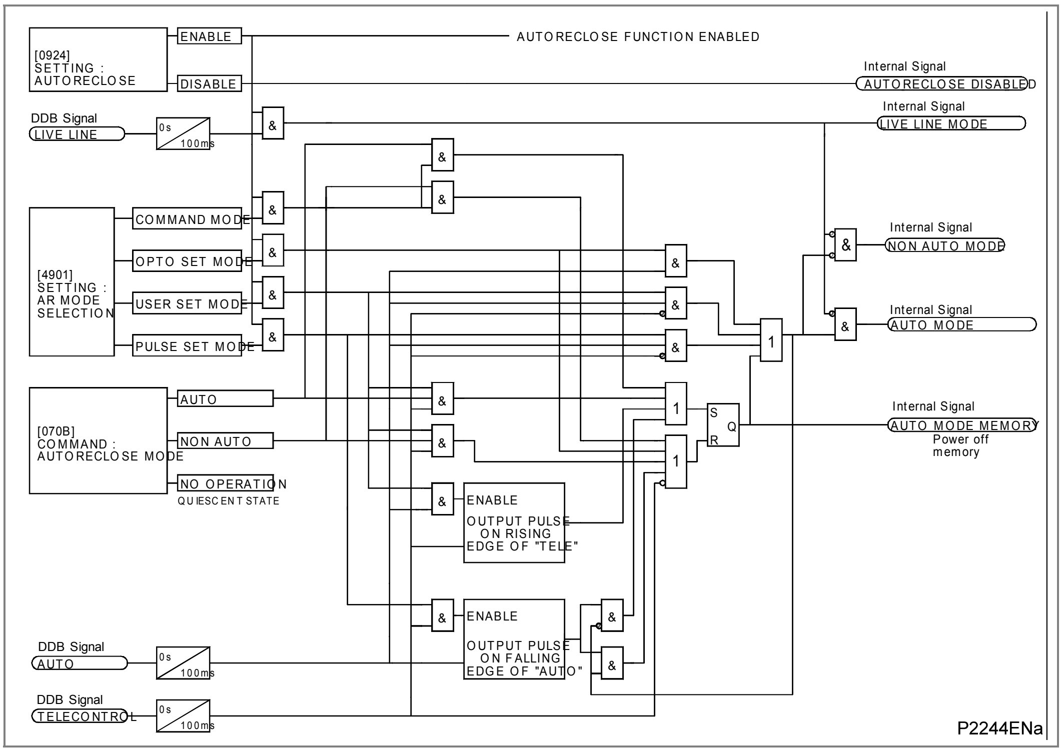

Figure 58 - Mode select functional diagram

The mode selection logic includes a 100ms delayed drop off on Auto Mode, Telecontrol and Live Line Mode logic inputs, to ensure a predictable change of operating modes even if the four position switch does not have make-before-break contacts. The logic also ensures that when the switch is moved from Auto or Non Auto position to Telecontrol, the scheme remains in the previously selected mode (Auto or Non Auto) until a different mode is selected by remote control.

The status of the AUTO MODE MEMORY signal is stored in non volatile memory to ensure that the selected operating mode is restored following an auxiliary power interruption.

For applications where live line operating mode and remote selection of Auto/Non-auto modes are not required, a simple two position switch can be arranged to activate Auto Mode input DDB 241, with DDB 240 and DDB 242 being unused.

2.1.2.2 Auto-Reclose Initiation

Auto-reclose is usually initiated from the internal protection of the relay. The stages of overcurrent and earth fault protection can be programmed to initiate auto-reclose, "**Initiate Main AR**", not initiate auto-reclose, "**No Action**", or block auto-reclose, "**Block AR**". High set instantaneous protection may be used to indicate a transformer fault on a transformer feeder and so be set to "**Block AR**". The stages of sensitive earth fault protection can be programmed to initiate auto-reclose, "**Initiate Main AR**", initiate SEF auto-reclose, "**Initiate SEF AR**", not initiate auto-reclose, "**No Action**", or block auto-reclose, "**Block AR**". Normally, SEF protection operation is due to a permanent fault and is set for "**No Action**". These settings are found under the "**AR INITIATION**" settings. For example if "**I>1**" is set to "**Initiate Main AR**", operation of the "**I>1**" protection stage will initiate auto-reclose; if ISEF>1 is set to "**No Action**", operation of the ISEF>1 protection stage will lead to a CB trip but no re-close.

A selection must be made for each protection stage that is enabled.

A separate protection device may also externally initiate auto-reclose. In this case, the following DDB signals should be mapped to logic inputs:

DDB 439: Ext. AR Prot. Trip

DDB 440: Ext. AR Prot. Start (if appropriate)

The setting EXT. PROT. should be set to "**Initiate Main AR**".

The auto-reclose can be initiated from a protection start, when sequence co-ordination is required, and from a protection trip.

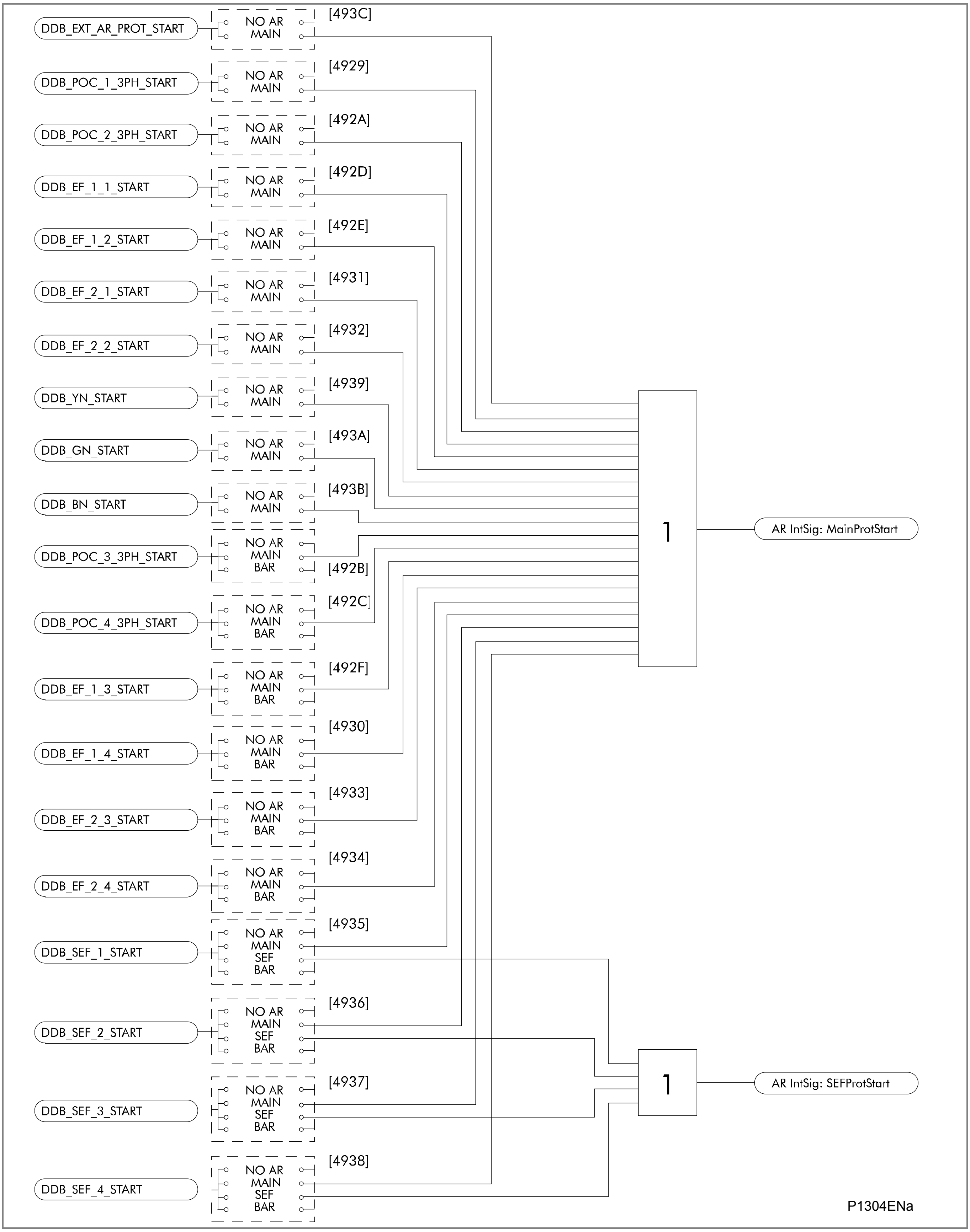

Figure 59 - “Protection start” signals

- Figure 59 illustrates how the start signal is generated and Figure 60, demonstrates how the protection trip signal is produced. Figure 60 also shows how the block auto-reclose is performed together with external AR initiation. Auto-reclose blocking is discussed in detail in section 2.1.2.8 - AR Lockout.

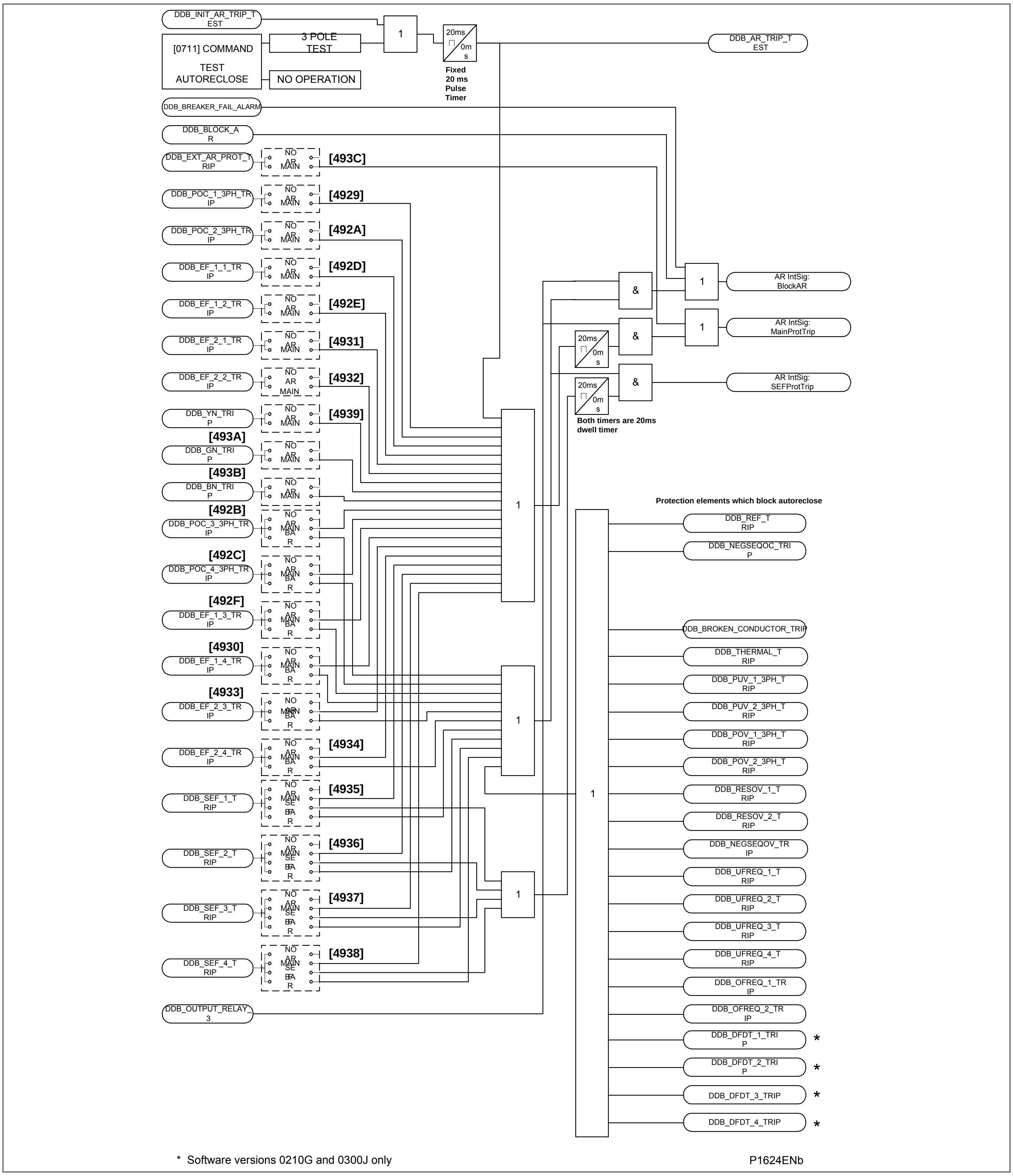

Figure 60 - Auto-reclose blocking logic

Although a protection start and a protection trip can initiate an AR cycle, several checks still have to be performed before the initiate signal is given. Some of the checks are listed below:

- Auto mode has been selected (AR in service)
- Live line mode is disabled
- The number of main protection and SEF shots have not been reached ("**Man High Shots**" and SEF "**High Shots**" Signals see Figure 61)
- Sequence co-ordination enabled (required only for protection start to initiate AR; not necessary for protection trip)
- CB lockout not set
- CB "**In Service**" (DDB 454 is high)

Note	*For auto reclose cycle to commence, the protection trip (e.g., I>1 trip, DDB # 243) needs to be mapped to a DDB (trip command In DDB # 536). This is applicable for Firmware releases 40 and later versions. It shall be noted that in Firmware versions 39 and lower ones, the any trip DDB signal was dependent on R3.*

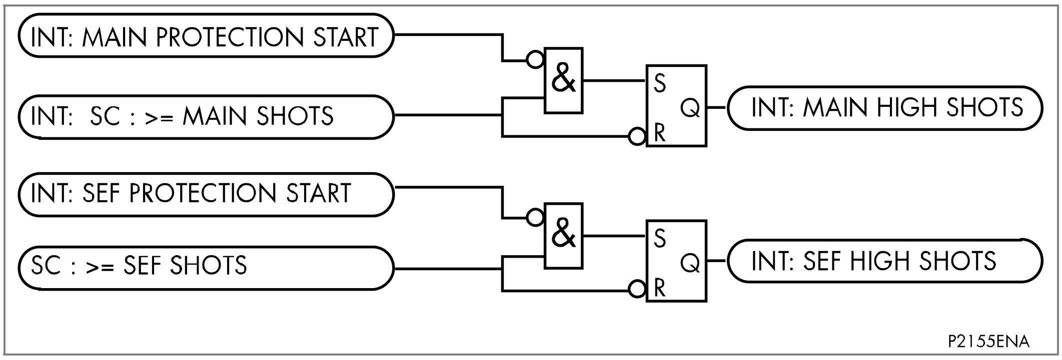

Figure 61 - Shots exceeded logic

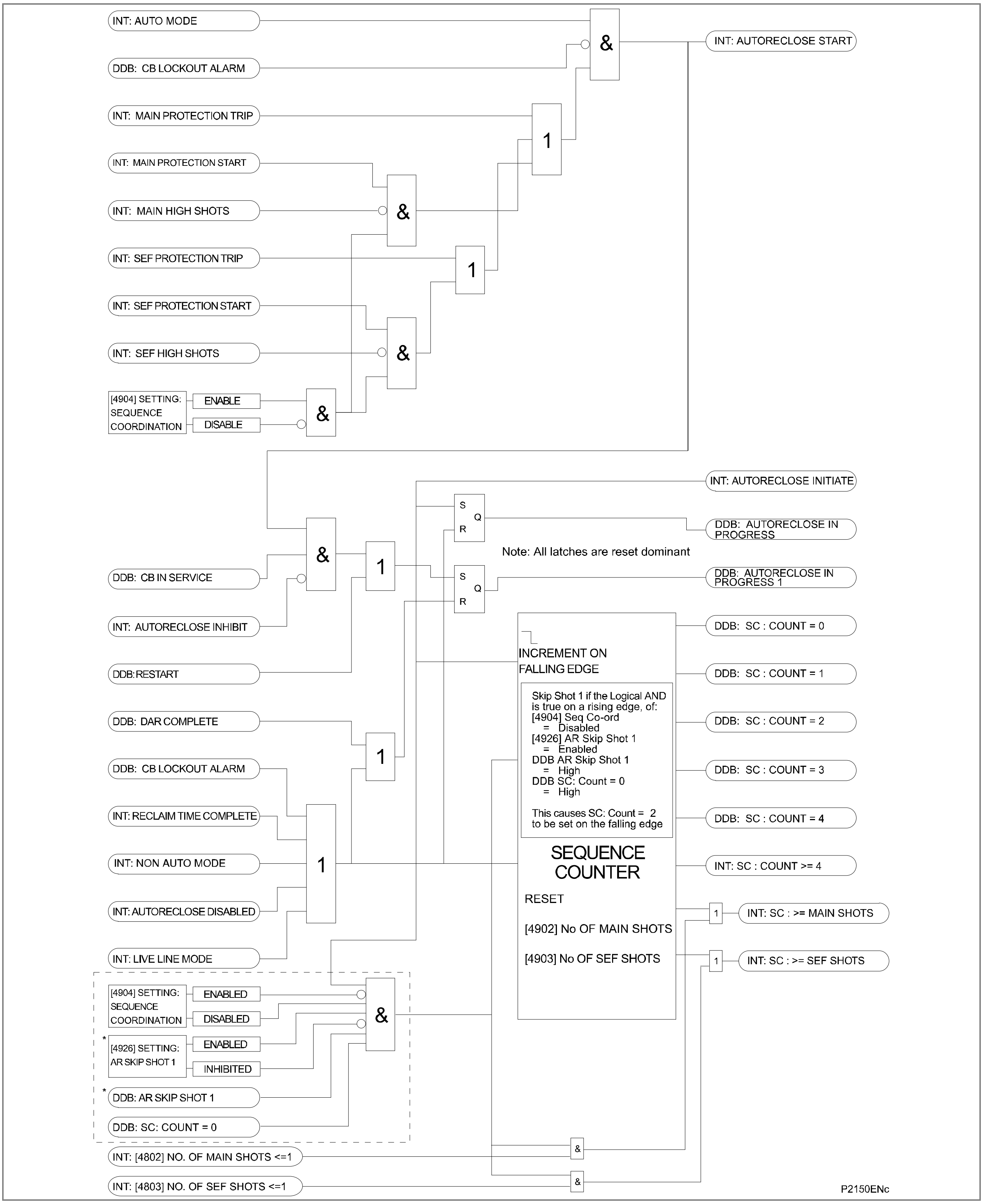

Figure 62 - AR initiation and sequence counter

Figure 62 illustrates how the auto-reclose is initiated.

2.1.2.3 Blocking Instantaneous Protection during an AR Cycle

Instantaneous protection may be blocked or not blocked for each trip in an auto-reclose cycle. This is selected using the "**Trip 1/2/3/4/5 Main**" and "**Trip 1/2/3/4/5 SEF**" settings. These allow the instantaneous elements of phase, earth fault and SEF protection to be selectively blocked for a CB trip sequence. For example, if "**Trip 1 Main**" is set to "**No Block**" and "**Trip 2 Main**" is set to "**Block Inst. Prot.**", the instantaneous elements of the phase and earth fault protection will be available for the first trip but blocked afterwards for the second trip during the auto-reclose cycle. This is clearly illustrated in Figure 63.

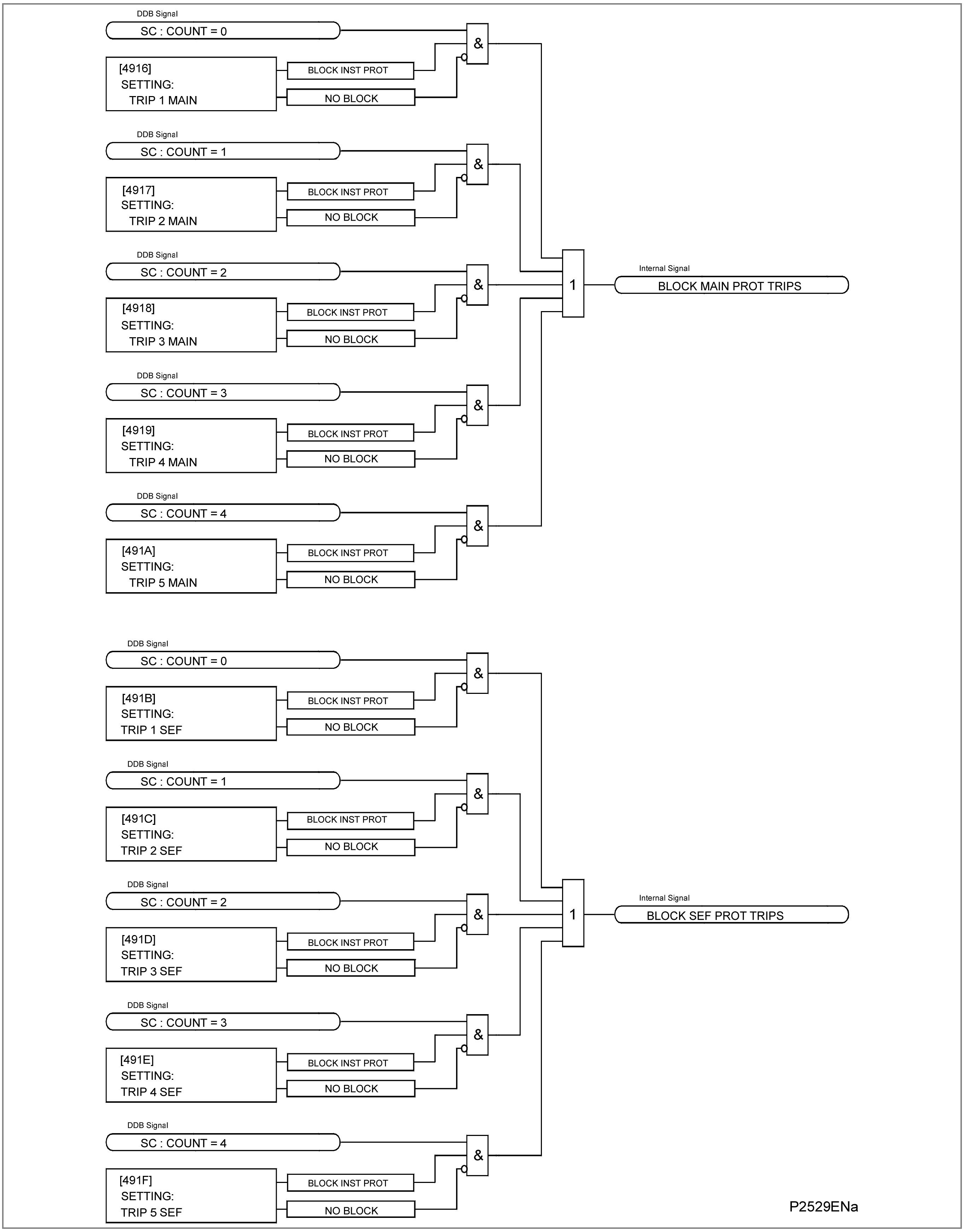

Figure 63 - "Block instantaneous protection" for selected trips

Instantaneous protection can also be blocked when the CB maintenance lockout counter or excessive fault frequency lockout has reached its penultimate value. For example, if "**No CB Ops. Lock**" is set to 100 and the "**CB Operations = 99**", the instantaneous protection can be blocked to ensure that the last CB trip before lockout will be due to discriminative protection operation.

This is controlled using the "**EFF Maint. Lock**" setting, if this is set to "**Block Inst. Prot.**" the instantaneous protection will be blocked for the last CB Trip before lockout occurs.

Instantaneous protection can also be blocked when the relay is locked out, using the "**A/R Lockout**" setting, "**No Block/Block Inst. Prot.**". It can also be blocked after a manual close using the "**Manual Close**" setting, "**No Block/Block Inst. Prot.**" or when the relay is in the Non Auto mode using the "**A/R Deselected**" setting "**No Block/Block Inst. Prot.**". The logic for these features is shown in Figure 64.

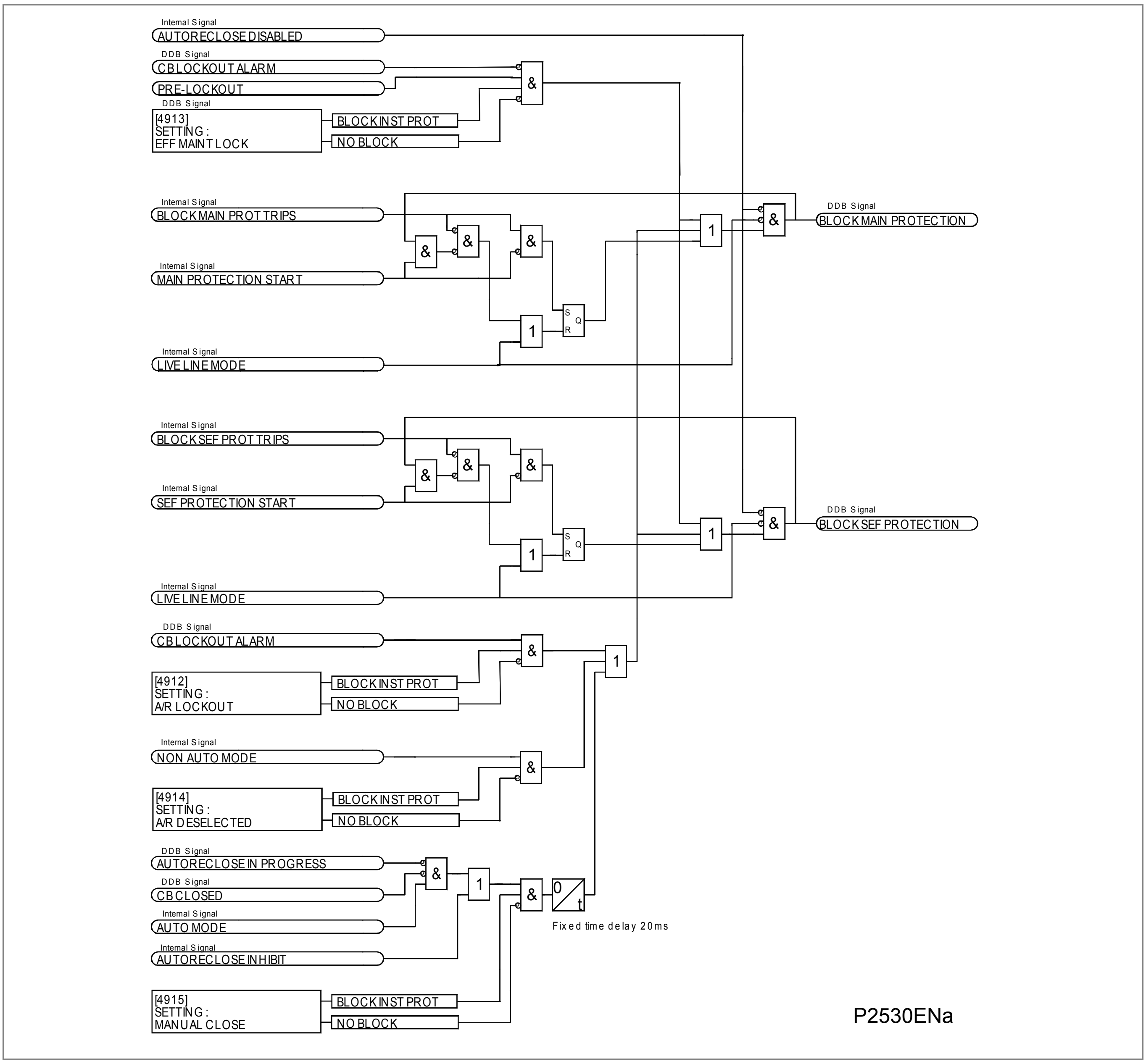

Figure 64 - “Block instantaneous protection” for AR unavailable or maintenance/EFF lockout

Note	*The instantaneous protection stages must be identified in the Overcurrent, Earth Fault1, Earth Fault2 and SEF/REF Prot'n. function link settings, "**I> Blocking**", "**IN1> Blocking**", "**IN2> Blocking**" and "**ISEF> Blocking**" respectively.*

External protection may be blocked by mapping DDB 358 "**Block Main Prot.**" Or DDB 359 "**Block SEF Prot.**" to appropriate output relay contacts.

2.1.2.4 Dead Time Control

Dead time is "**primed**" (DDB 460 - Re-close Checks - set) when:

- the CB has tripped, and
- (optionally via setting "**Start Dead t On**"), the protection has reset, and
- DDB 458 - DT OK to Start - goes high

Dead time remains "**primed**" until the protection re-operates, or the scheme resets at the end of the auto-reclose cycle.

Once primed, the dead timer starts to run when DDB 457 - Dead Time Enabled is high.

Setting "**CS AR Immediate**" Enabled allows immediate re-closure of the circuit breaker provided both sides of the circuit breaker are live and in synchronism at any time after the dead time has started. This allows for quicker load restoration, as it is not necessary to wait for the full dead time.

If "**CS AR Immediate**" is disabled, or Line and Bus volts are not both live, the dead timer will continue to run, assuming the "**DDB 457: Dead Time Enabled**" (mapped in PSL) is asserted high. The "**Dead Time Enabled**" function could be mapped to an opto input to indicate that the circuit breaker is healthy i.e. spring charged etc. Mapping the "**Dead Time Enabled**" function in PSL increases the flexibility by allowing it, if necessary, to be triggered by other conditions such as "**Live Line/Dead Bus**" for example. If "**Dead Time Enabled**" is not mapped in PSL, it defaults to high, so the dead time can run.

The dead time control logic is shown in Figure 65.

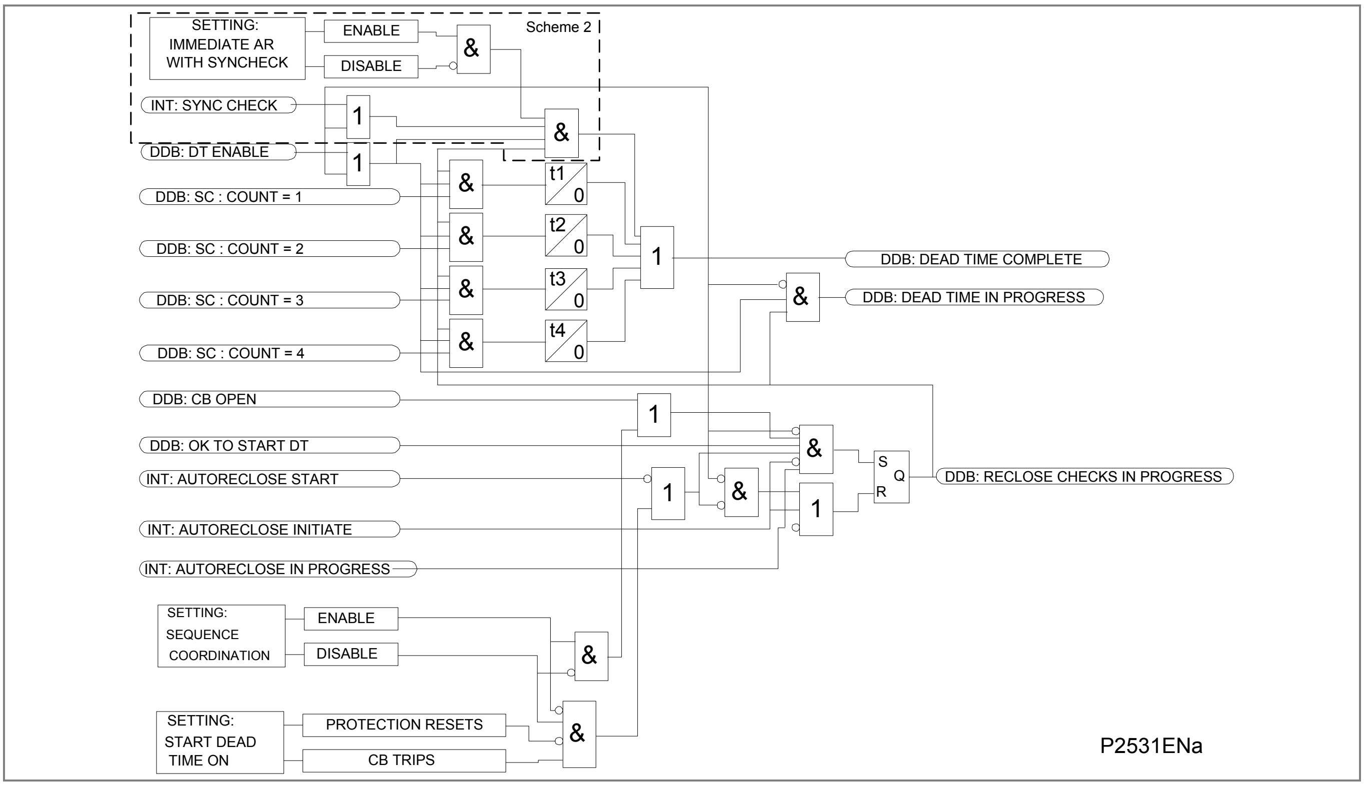

Figure 65 - Dead time control

Once the dead time is completed or a synchronism check is confirmed, the “**Auto-close**” signal is given, provided both the “**CB Healthy**” and the “**System Checks**” are satisfied. (See Figure 67 ”). The “**Auto-close**” signal triggers a “**CB Close**” command via the CB Control functionality (see section 2.10 - Circuit Breaker Control).

The “**AR CB Close Control**” Logic is shown in Figure 66.

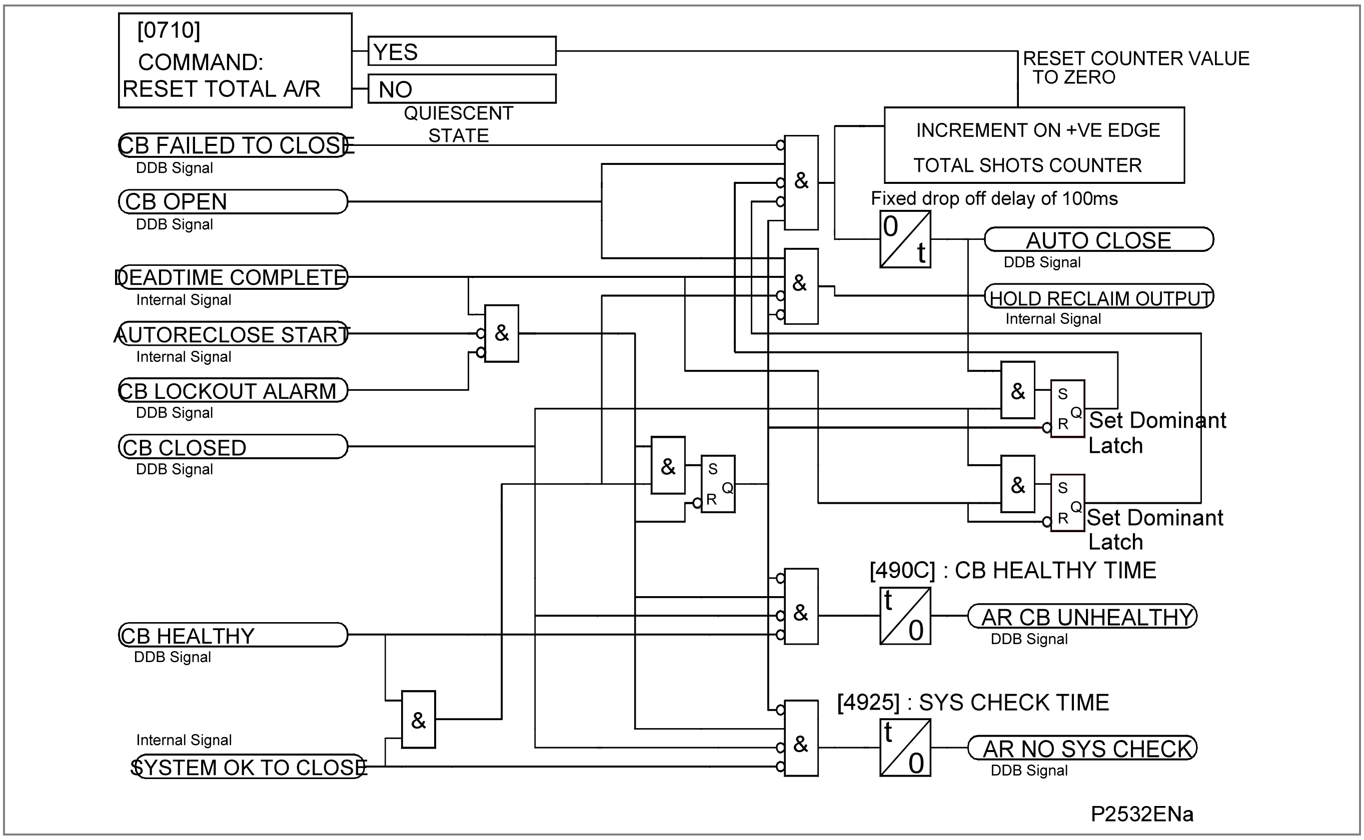

Figure 66 - AR CB close control

2.1.2.5 System Checks

The permission to initiate an auto-reclose depends upon the following System Check settings:

- **Live/Dead Ccts** When enabled this setting will give an “**AR Check Ok**” signal when the “**DDB 461 Circuits OK**” is asserted high. This logic input DDB would normally be mapped in PSL to appropriate combinations of Line Live, Line Dead, Bus Live and Bus Dead DDB signals. Auto-reclose can be initiated once DDB 461 is asserted high
- **No System Checks** When enabled this setting completely disables system checks thus allowing auto-reclose initiation
- **Sys. Chk. on Shot 1** Can be used to disable system checks on first AR shot
- **AR with Chk. Sync.** Only allows auto-reclose when the system satisfies the “**Check Sync. Stage 1**” settings (SYSTEM CHECKS menu)
- **AR with Sys. Sync.** Only allows auto-reclose when the system satisfies the “**Check Sync. Stage 2**” settings (SYSTEM CHECKS menu)

The “**SYSTEM CHECKS**” logic can be found in REF _Ref401100419 \h Figure 67.

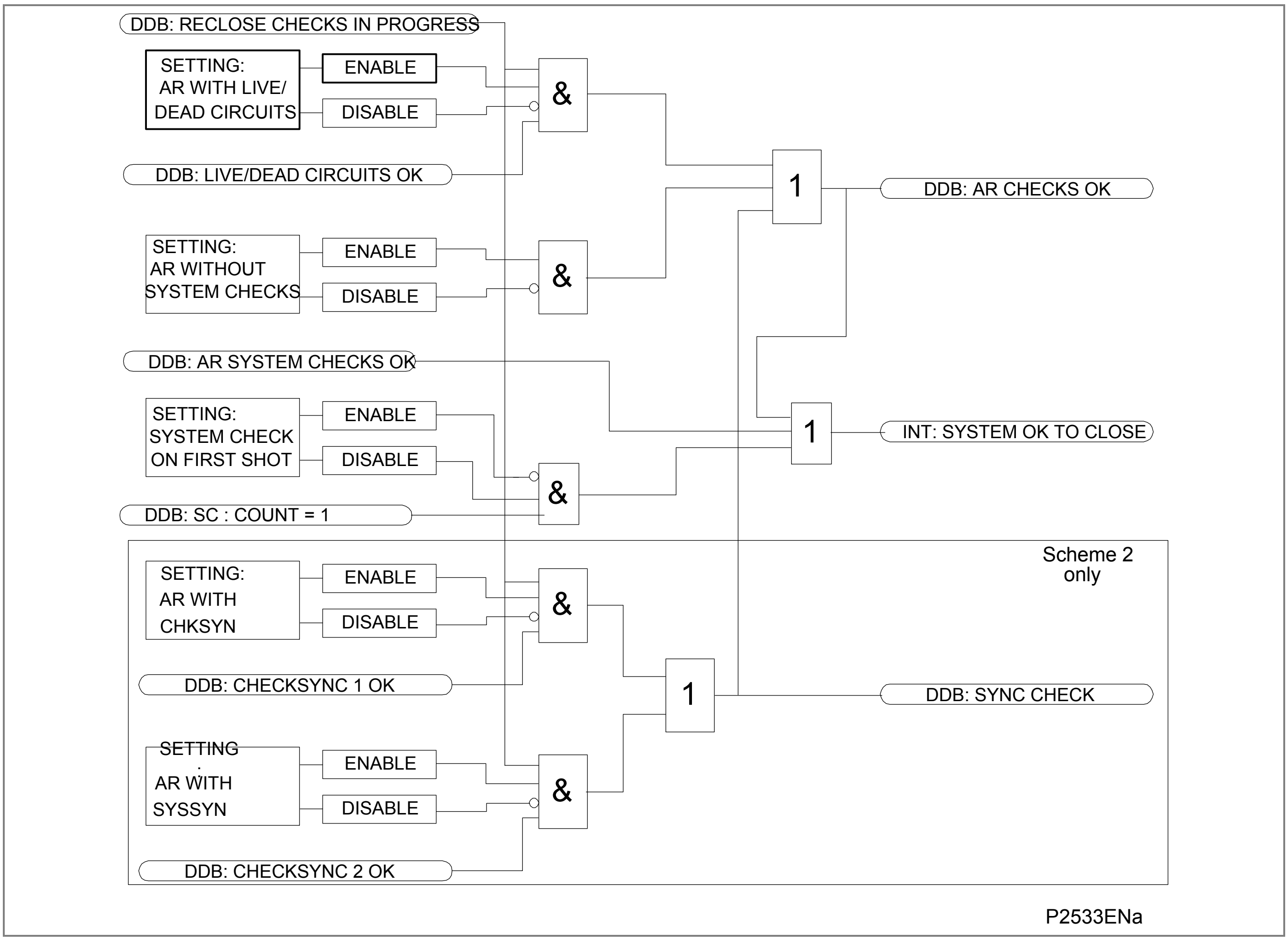

Figure 67 - System checks

2.1.2.6 Reclaim Timer Initiation

The “**tReclaim Extend**” setting allows the user to control whether the timer is suspended from the protection start contacts or not. When a setting of “**No Operation**” is used the Reclaim Timer will operate from the instant that the CB is closed and will continue until the timer expires. The "**Reclaim Time**" must, therefore, be set in excess of the time delayed protection operating time to ensure that the protection can operate before the auto-reclose function is reset. If the auto-reclose function resets before the time delayed protection has operated instantaneous protection could be re-enabled and discriminating tripping lost.

For certain applications it is advantageous to set “**tReclaim Extend**” to “**On Prot. Start**”. This facility allows the operation of the reclaim timer to be suspended after CB re-closure by a signal from the main protection start or SEF protection start signals. The main protection start signal is initiated from the start of any protection which has been selected to "**Initiate Main AR**" (initiate auto-reclose) in the "**AR Initiation**" settings. The SEF protection start signal is initiated from the start of any SEF protection that has been selected to "**Initiate SEF AR**" (initiate SEF auto-reclose) in the "**AR Initiation**" settings. This feature ensures that the reclaim time cannot time out and reset the auto-reclose before the time delayed protection has operated. Since the Reclaim Timer will be suspended, it is unnecessary to use a timer setting in excess of the protection operating time, therefore a short reclaim time can be used. Short reclaim time settings can help to prevent unnecessary lockout for a succession of transient faults in a short period, for example during a thunderstorm. For more information, please refer to the Reclaim Timer logic in Figure 68.

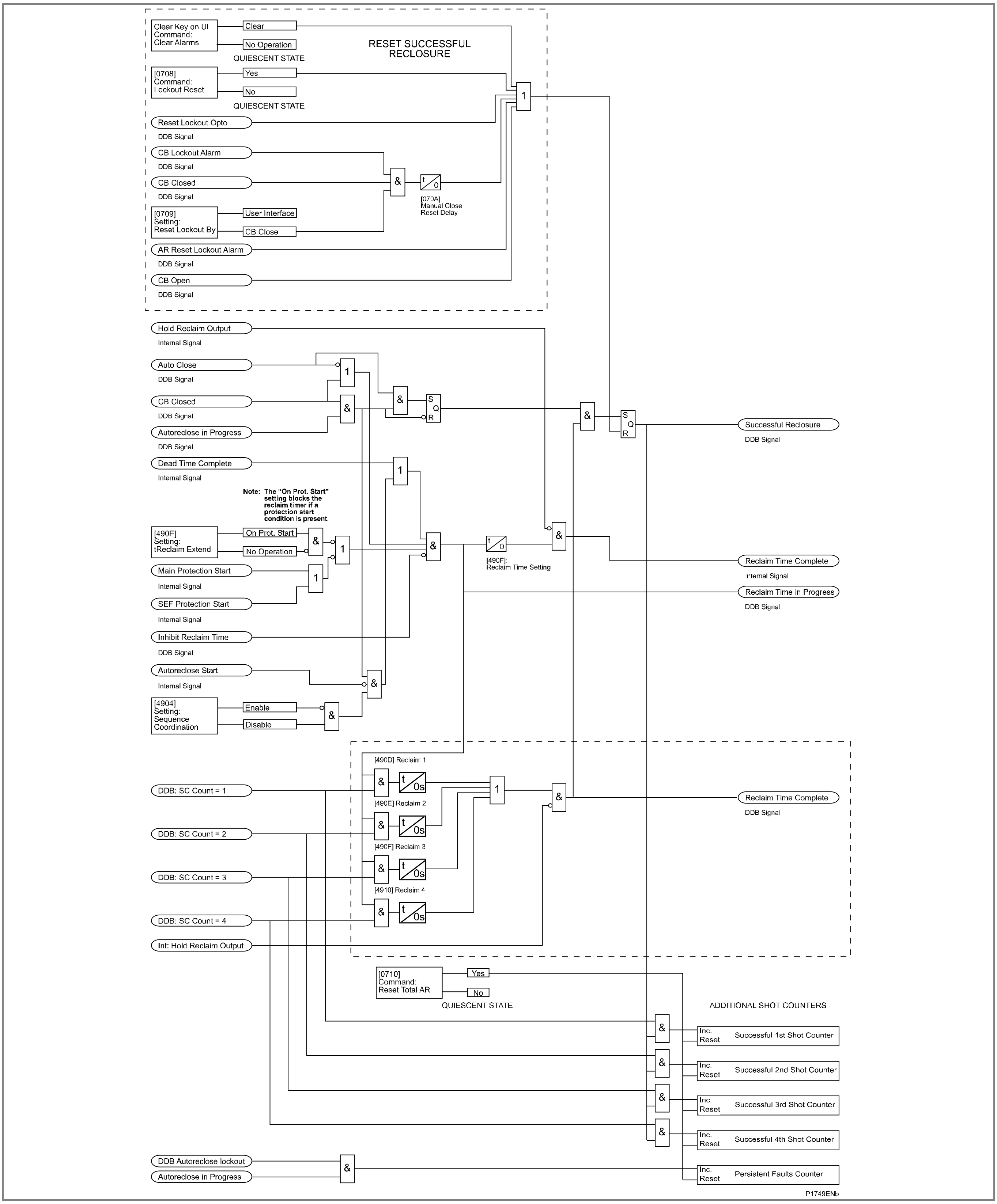

Figure 68 - Reclaim time/AR successful logic

2.1.2.7 Auto-Reclose Inhibit following Manual Close

To ensure that auto-reclosing is not initiated for a manual CB closure on to a pre-existing fault (switch on to fault), AUTO-RECLOSE menu setting “**A/R on Man Close**” can be set to “**Inhibited**”. With this setting, auto-reclose initiation is inhibited for a period equal to setting “**A/R Inhibit Time**” following a manual CB closure. The logic for A/R Inhibit is shown in Figure 69.

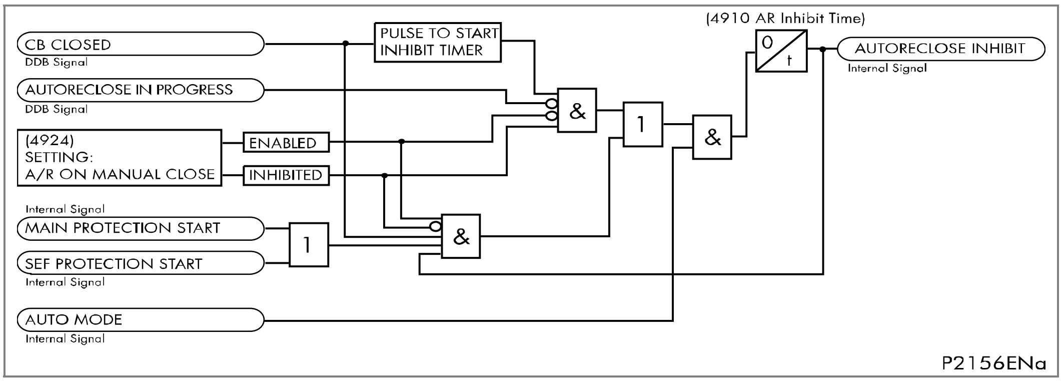

Figure 69 - AR initiation inhibit

If a protection operation occurs during the inhibit period, auto-reclosing is not initiated. A further option is provided by setting “**Man Close on Flt**”; if this is set to “**Lockout**”, auto-reclose is locked out (DDB 163: AR Lockout) for a fault during the inhibit period following manual CB closure. If “**Man Close on Flt**” is set to “**No Lockout**”, the CB trips without re-closure, but auto-reclose is not locked out.

If it is required to block selected fast non-discriminating protection to obtain fully discriminative tripping during the AR initiation inhibit period following CB manual close, setting “**Manual Close**” can be set to “**Block Inst. Prot.**”. A “**No Block**” setting will enable all protection elements immediately on CB closure.

If setting “**A/R on Man Clo**se” is set to “**Enabled**”, auto-reclosing can be initiated immediately on CB closure, and settings “**A/R Inhibit Time**”, “**Man Close on Flt**” and “**Manual Close**” are irrelevant.

Settings “**A/R on Man Close**”, “**A/R Inhibit Time**”, “**Man Close on Flt**” and “**Manual Close**” are all in the AUTO-RECLOSE menu.

2.1.2.8 AR Lockout

If protection operates during the reclaim time, following the final reclose attempt, the relay will be driven to lockout and the auto-reclose function will be disabled until the lockout condition is reset. This will produce an alarm, "**DDB 163: AR Lockout**". The "**DDB 239: Block AR**" input will block auto-reclose and cause a lockout if auto-reclose is in progress.

Auto-reclose lockout can also be caused by the CB failing to close because the CB springs are not charged/low gas pressure or there is no synchronism between the system voltages indicated by the "**DDB 164: AR CB Unhealthy**" and "**DDB 165: AR No Check Sync.**" alarms. The functionality, described above, is shown in the AR Lockout logic diagram in Figure 70.

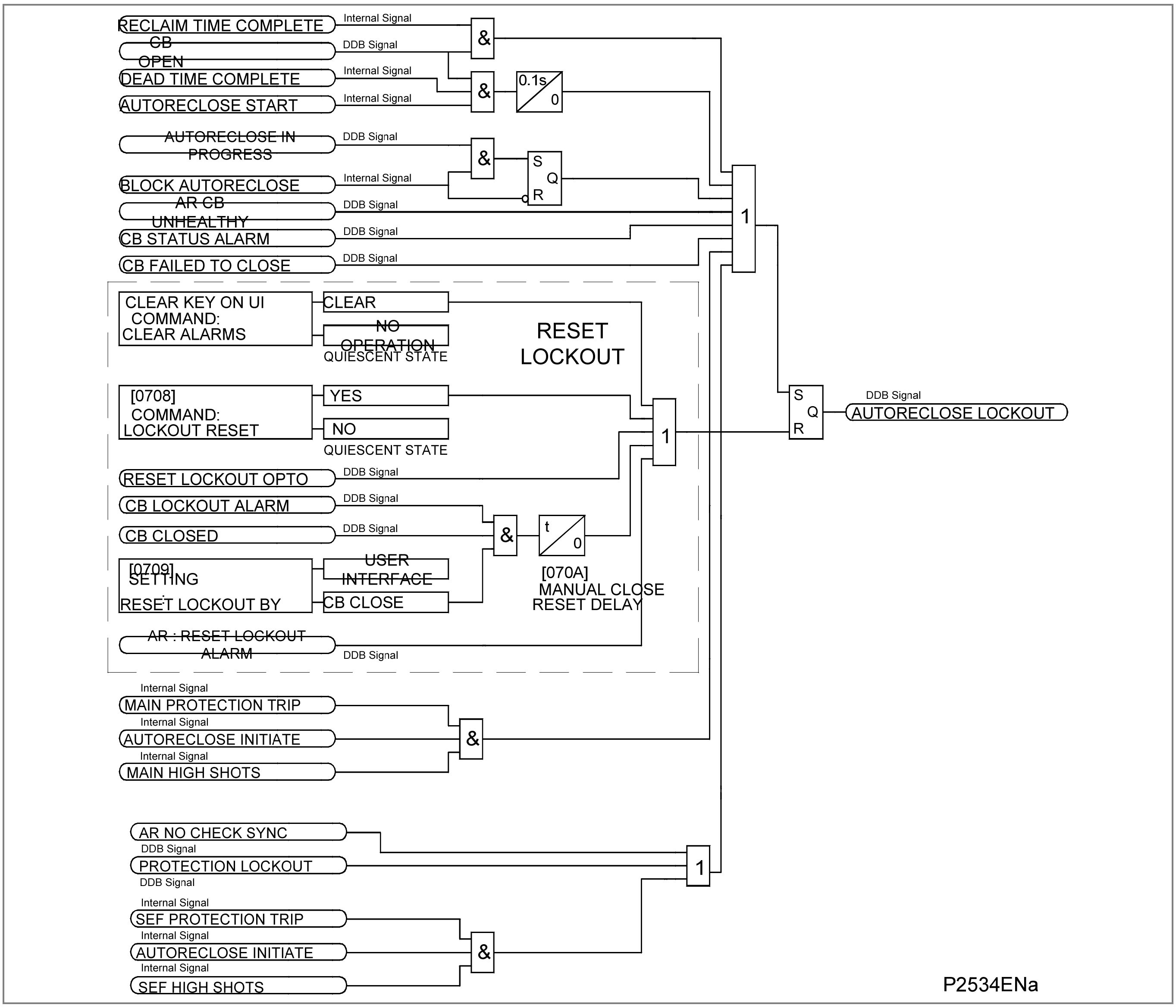

Figure 70 - Overall AR lockout logic

AR lockout may also be due to a protection operation when the relay is in the Live Line or Non Auto modes when "**Trip AR Inactive**" is set to "**Lockout**". Auto-reclose lockout can also be caused by a protection operation after manual closing during the "**AR Inhibit Time**" when the "**Manual Close on Flt.**" setting is set to Lockout.

Figure 71 shows the logic associated with these functions.

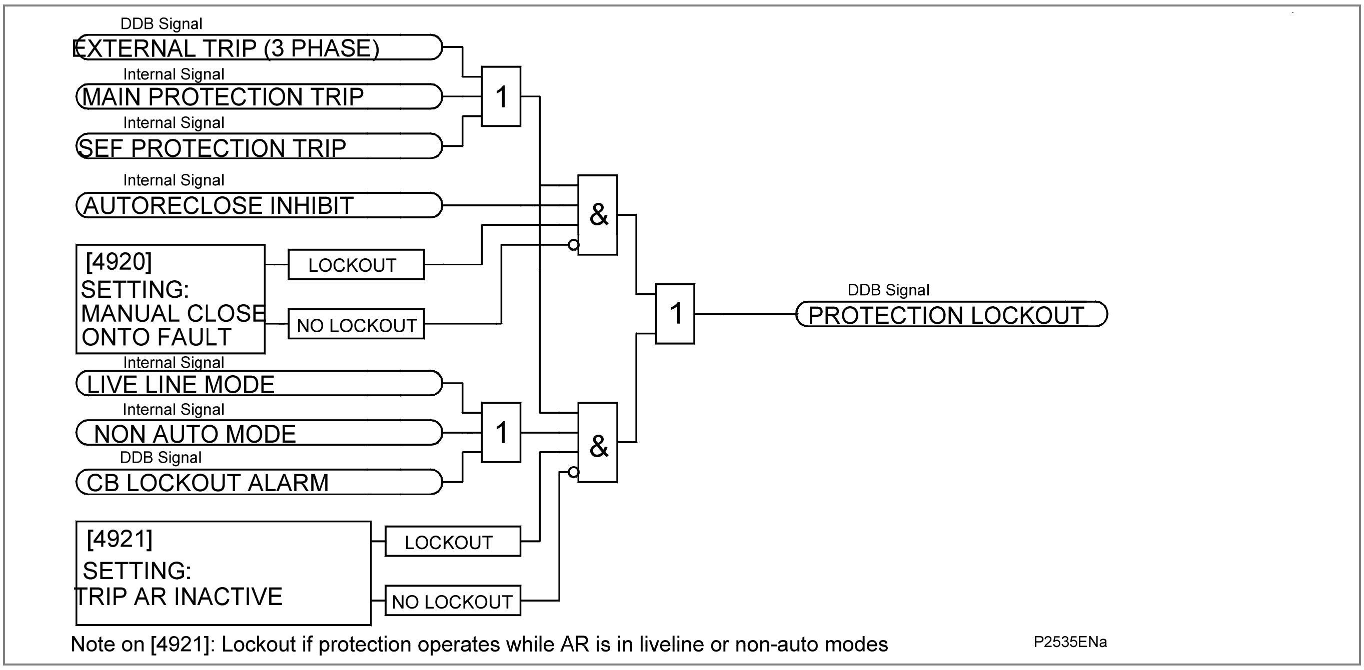

Figure 71 - Lockout for protection trip when AR not available

Note	*Lockout can also be caused by the CB condition monitoring functions, maintenance lockout, excessive fault frequency lockout, broken current lockout, CB failed to trip, CB failed to close, manual close no check synchronism and CB unhealthy.*

2.1.2.8.1 Reset from Lockout

The "**DDB 237: Reset Lockout**" input can be used to reset the auto-reclose function following lockout and reset any auto-reclose alarms, provided that the signals which initiated the lockout have been removed. Lockout can also be reset from the clear key or the "**CB CONTROL**" command "**Lockout Reset**".

The "**Reset Lockout by**" setting, "**CB Close/User interface**" in "**CB CONTROL**" (0709) is used to enable/disable reset of lockout automatically from a manual close after the manual close time "**Man. Close Rst. Dly.**". The "**Reset Lockout by**" setting, "**Select Non Auto/User interface**" in "**AUTO-RECLOSE**" (4922) is used to enable/disable the resetting of lockout when the relay is in the Non Auto operating mode. The reset lockout methods are summarized in the following table:

Reset Lockout Method	When Available?
User Interface via the “Clear” key. *Note* *This will also reset all other protection flags*	Always
User interface via “CB Control” Command “Lockout Reset	Always
Via opto input “Reset lockout”	Always
Following a successful manual close if “Reset Lockout by” (CB CONTROL menu) is set to “CB Close” after “Man. Close Rst. Dly.” time	Only when set
By selecting “Non Auto” mode, provided “Reset Lockout by” (AUTO-RECLOSE menu) is set to “Select Non Auto”	Only when set

Table 9 - Reset lockout method availability

2.1.2.9 Sequence Co-Ordination

The auto-reclose setting "**Sequence Co-ord.**" can be used to enable the selection of sequence co-ordination with other protection devices, such as downstream pole mounted

re-closers. The main protection start or SEF protection start signals indicate to the relay when fault current is present, advance the sequence count by one and start the dead time whether the breaker is open or closed. When the dead time is complete and the protection start inputs are off the reclaim timer will be initiated. This is shown in Figure 72.

Both the upstream and downstream auto-reclose relay should be programmed with the same number of shots to lockout and number of instantaneous trips before instantaneous protection is blocked. Thus, for a persistent downstream fault using sequence co-ordination both auto-reclose relays will be on the same sequence count and will be blocking instantaneous protection at the same time and so correct discrimination can be obtained. When sequence co-ordination is disabled, the breaker has to be tripped to start the dead time and advance the sequence count by one.

For some applications with downstream pole mounted re-closers when using sequence co-ordination it may be desirable to re-enable instantaneous protection when the re-closer has locked out. When the downstream re-closer has locked out there is no need for discrimination. This allows the user to have instantaneous then IDMT and then instantaneous trips again during an auto-reclose cycle. Instantaneous protection may be blocked or not blocked for each trip in an auto-reclose cycle using the "**Trip 1/2/3/4/5 Main**" and "**Trip 1/2/3/4/5 SEF**" settings, "**Block Inst. Prot./No Block**".

2.1.2.10 Check Synchronizing for first Re-close

The “**Sys. Chk. on Shot 1**”, (within SYSTEM CHECKS sub menu of AUTO-RECLOSE) setting is used to "**Enable/Disable**" system checks for the first re-close in an auto-reclose cycle. This may be preferred when high speed auto-reclose is applied to avoid the extra time for a synchronism check. Subsequent re-close attempts in a multi-shot cycle will still require a synchronism check.

2.2 Trip LED Logic

The trip LED can be reset when the flags for the last fault are displayed. The flags are displayed automatically after a trip occurs, or can be selected in the fault record menu. The reset of trip LED and the fault records is performed by pressing the ⓒ key once the fault record has been read.

Setting “**Sys. Fn. Links**” (SYSTEM DATA Column) to logic “**1**” sets the trip LED to automatic reset. Resetting will occur when the circuit is re-closed and the “**Any Pole Dead**” signal (DDB 380) has been reset for three seconds. Resetting, however, will be prevented if the “**Any start**” signal is active after the breaker closes. This function is particularly useful when used in conjunction with the auto-reclose logic, as it will prevent unwanted trip flags being displayed after a successful re-closure of the breaker.

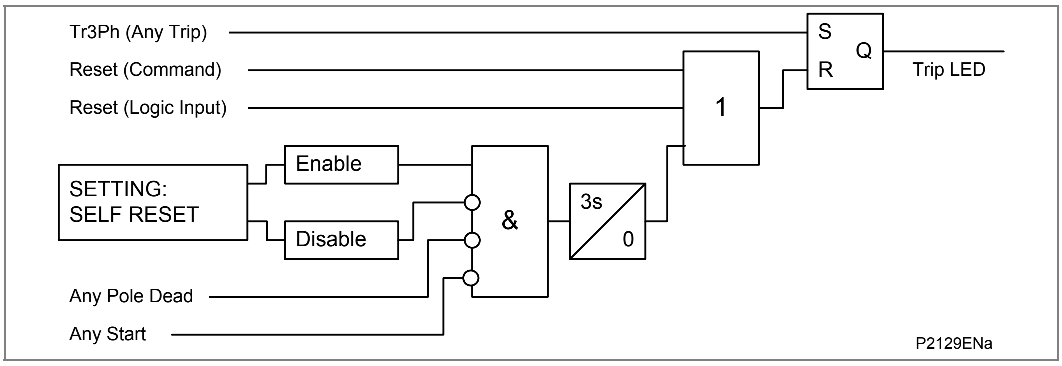

Figure 72 - Trip LED logic diagram

2.3 Check Synchronism (P143 and P145 only)

2.3.1 Overview

In some situations it is possible for both "**bus**" and "**line**" sides of a circuit breaker to be live when the circuit breaker is open, for example at the ends of a feeder which has a power source at each end. Therefore, when closing the circuit breaker, it is normally necessary to check that the network conditions on both sides are suitable, before giving a CB Close command. This applies to both manual circuit breaker closing and auto-reclosure. If a circuit breaker is closed when the line and bus voltages are both live, with a large phase angle, frequency or magnitude difference between them, the system could be subjected to an unacceptable shock, resulting in loss of stability, and possible damage to connected machines.

System checks involve monitoring the voltages on both sides of a circuit breaker, and, if both sides are live, performing a synchronism check to determine whether the phase angle, frequency and voltage magnitude differences between the voltage vectors, are within permitted limits.

The pre-closing system conditions for a given circuit breaker depend on the system configuration and, for auto-reclosing, on the selected auto-reclose program. For example, on a feeder with delayed auto-reclosing, the circuit breakers at the two line ends are normally arranged to close at different times. The first line end to close usually has a live bus and a dead line immediately before reclosing, and charges the line (dead line charge) when the circuit breaker closes. The second line end circuit breaker sees live bus and live line after the first circuit breaker has re-closed. If there is a parallel connection between the ends of the tripped feeder, they are unlikely to go out of synchronism, i.e. the frequencies will be the same, but the increased impedance could cause the phase angle between the two voltages to increase. Therefore the second circuit breaker to close might need a synchronism check, to ensure that the phase angle has not increased to a level that would cause unacceptable shock to the system when the circuit breaker closes.

If there are no parallel interconnections between the ends of the tripped feeder, the two systems could lose synchronism, and the frequency at one end could "**slip**" relative to the other end. In this situation, the second line end would require a synchronism check comprising both phase angle and slip frequency checks.

If the second line end busbar has no power source other than the feeder that has tripped; the circuit breaker will see a live line and dead bus assuming the first circuit breaker has re-closed. When the second line end circuit breaker closes the bus will charge from the live line (dead bus charge).

2.3.2 VT Selection

The P14x has a three-phase "**Main VT**" input and a single-phase "**Check Sync. VT**" input. Depending on the primary system arrangement, the main three-phase VT for the relay may be located on either the busbar side or the line side of the circuit breaker, with the check sync. VT being located on the other side. Hence, the relay has to be programmed with the location of the main VT. This is done via the "**Main VT Location**" setting in the CT & VT RATIOS menu.

The Check Sync. VT may be connected to either a phase to phase or phase to neutral voltage, and for correct synchronism check operation, the relay has to be programmed with the required connection. The "**C/S Input**" setting in the CT & VT RATIOS menu should be set to A-N, B-N, C-N, A-B, B-C or C-A as appropriate.

2.3.3 Basic Functionality

System check logic is collectively enabled or disabled as required, by setting “**System Checks**” in the CONFIGURATION menu. The associated settings are available in SYSTEM CHECKS, sub-menus VOLTAGE MONITORS, CHECK SYNC. and SYSTEM SPLIT. If “**System Checks**” is selected to Disabled, the associated SYSTEM CHECKS menu becomes invisible, and a **Sys. checks inactive** DDB signal is set.

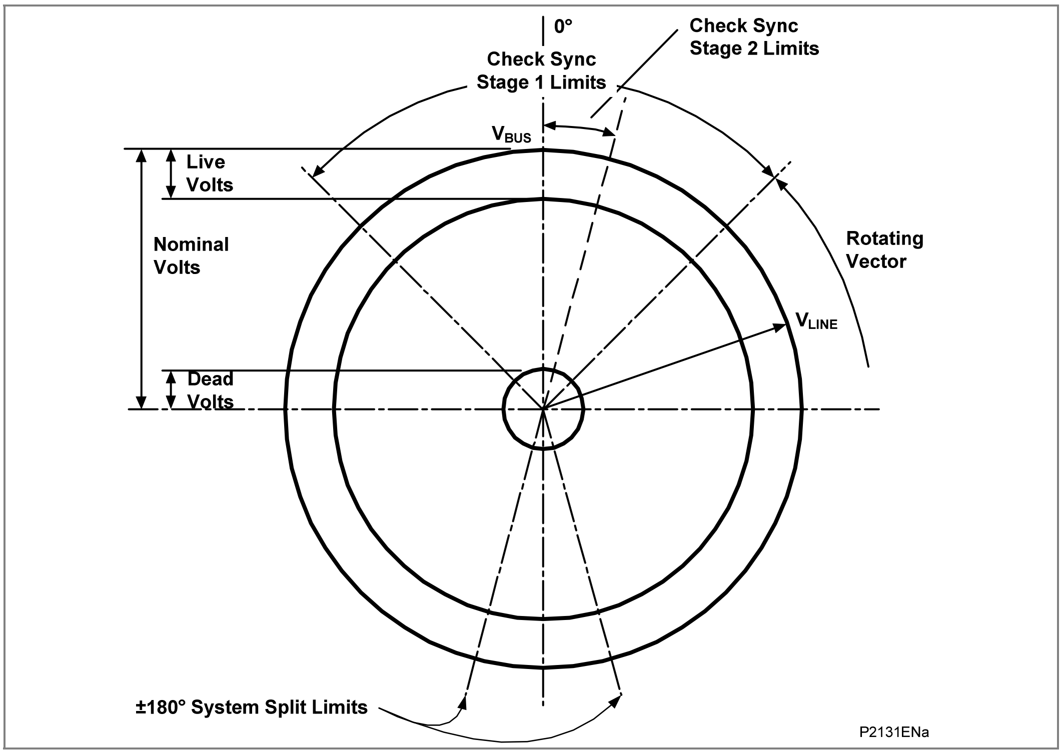

Figure 73 - Synchro check and synchro split functionality

The overall “**Check Sync.**” and “**System Split**” functionality is shown in Figure 73.

In most situations where synchronism check is required, the Check Sync. 1 function alone will provide the necessary functionality, and the Check Sync. 2 and System Split signals can be ignored.

2.3.3.1 Synchronism Check

Check Sync. 1 and Check Sync. 2 are two synchro check logic modules with similar functionality, but independent settings (see Figure 73).

For either module to function:

> the System Checks setting must be Enabled
>
> AND
>
> the individual Check Sync. 1(2) Status setting must be Enabled
>
> AND
>
> the module must be individually “**enabled**”, by activation of DDB signal Check Sync. 1(2) Enabled, mapped in PSL.

When enabled, each logic module sets its output signal when:

> Line volts and bus volts are both live (Line Live and Bus Live signals both set)
>
> AND

measured phase angle is < Check Sync. 1(2) Phase Angle setting

AND

(for Check Sync. 2 only), the phase angle magnitude is decreasing (Check Sync. 1 can operate with increasing or decreasing phase angle provided other conditions are satisfied)

AND

if Check Sync. 1(2) Slip Control is set to Frequency or Frequency + Timer, the measured slip frequency is < Check Sync. 1(2) Slip Freq. Setting

AND

if Check Sync. Voltage Blocking is set to OV, UV + OV, OV + DiffV or UV + OV + DiffV, both line volts and bus volts magnitudes are < Check Sync. Overvoltage setting

AND

if Check Sync. Voltage Blocking is set to UV, UV + OV, UV + DiffV or UV + OV + DiffV, both line volts and bus volts magnitudes are > Check Sync. Undervoltage setting

AND

if Check Sync. Voltage Blocking is set to DiffV, UV + DiffV, OV + DiffV or UV + OV + DiffV, the voltage magnitude difference between line volts and bus volts is < Check Sync. Diff. Voltage setting

AND

if Check Sync. 1(2) Slip Control is set to Timer or Frequency + Timer, the above conditions have been true for a time > or = Check Sync. 1(2) Slip Timer setting

Note	*Live Line/Dead Bus and Dead Bus/Line functionality is provided as part of the default PSL (see Figure 73).*

2.3.3.2 Slip Control by Timer

If Slip Control by Timer or Frequency + Timer is selected, the combination of Phase Angle and Timer settings determines an effective maximum slip frequency, calculated as:

$$\frac{2 \times A}{T \times 360} \text{ Hz. for Check Sync 1}$$

or

$$\frac{A}{T \times 360} \text{ Hz. for Check Sync 2}$$

A = Phase Angle setting (°)
T = Slip Timer setting (seconds)

For example, with Check Sync. 1 Phase Angle setting 30° and Timer setting 3.3 sec., the "**slipping**" vector has to remain within ±30° of the reference vector for at least 3.3 seconds. Therefore a synchro check output will not be given if the slip is greater than 2 x 30° in 3.3 seconds. Using the formula: 2 x 30 ÷ (3.3 x 360) = 0.0505 Hz (50.5 mHz).

For Check Sync. 2, with Phase Angle setting 10° and Timer setting 0.1 sec., the slipping vector has to remain within 10° of the reference vector, with the angle decreasing, for 0.1 sec. When the angle passes through zero and starts to increase, the synchro check output is blocked. Therefore an output will not be given if slip is greater than 10° in 0.1 second. Using the formula: 10 ÷ (0.1 x 360) = 0.278 Hz (278 mHz).

Slip control by Timer is not practical for “**large slip/small phase angle**” applications, because the timer settings required are very small, sometimes < 0.1s. For these situations, slip control by frequency is recommended.

If Slip Control by Frequency + Timer is selected, for an output to be given, the slip frequency must be less than BOTH the set Slip Freq. value and the value determined by the Phase Angle and Timer settings.

2.3.4 Check Sync. 2 and System Split

Check sync. 2 and system split functions are included for situations where the maximum permitted slip frequency and phase angle for synchro check can change according to actual system conditions. A typical application is on a closely interconnected system, where synchronism is normally retained when a given feeder is tripped, but under some circumstances, with parallel interconnections out of service, the feeder ends can drift out of synchronism when the feeder is tripped. Depending on the system and machine characteristics, the conditions for safe circuit breaker closing could be, for example:

Condition 1: For synchronized systems, with zero or very small slip:

Slip ≦50 mHz; phase angle <30°

Condition 2: For unsynchronized systems, with significant slip:

Slip ≦250 mHz; phase angle <10° and decreasing

By enabling both Check Sync. 1, set for condition 1, and Check Sync. 2, set for condition 2, the P14x can be configured to allow CB closure if either of the two conditions is detected.

For manual circuit breaker closing with synchro check, some utilities might prefer to arrange the logic to check initially for condition 1 only. However, if a System Split is detected before the condition 1 parameters are satisfied, the relay will switch to checking for condition 2 parameters instead, based upon the assumption that a significant degree of slip must be present when system split conditions are detected. This can be arranged by suitable PSL logic, using the system check DDB signals.

2.3.4.1 Predictive Closure of Circuit Breaker

The “**Freq.+Comp.**” (Frequency + CB Time Compensation) setting modifies the Check Sync. 2 function to take account of the circuit breaker closing time. When set to provide CB Close Time compensation, a predictive approach is used to close the circuit breaker ensuring that closing occurs at close to 0º thus minimising the impact to the power system. The actual closing angle is subject to the constraints of the existing product architecture, i.e. the protection task runs twice per power system cycle, based on frequency tracking over the frequency range of 40Hz to 70Hz.

2.3.4.2 System Split

For the System Split module to function (see Figure 73):

The System Checks setting must be Enabled

AND

the SS Status setting must be Enabled

AND

the module must be individually “**enabled**”, by activation of DDB signal System Split Enabled, mapped in PSL.

When enabled, the System Split module sets its output signal when:

Line volts and bus volts are both live (Line Live and Bus Live signals both set)

AND

measured phase angle is > SS Phase Angle setting

AND

if SS Volt Blocking is set to Undervoltage, both line volts and bus volts magnitudes are > SS Undervoltage setting

The System Split output remains set for as long as the above conditions are true, or for a minimum period equal to the SS Timer setting, whichever is longer.

The overall system checks functionality and default PSL for the function is shown in Figure 74 and Figure 75 respectively.

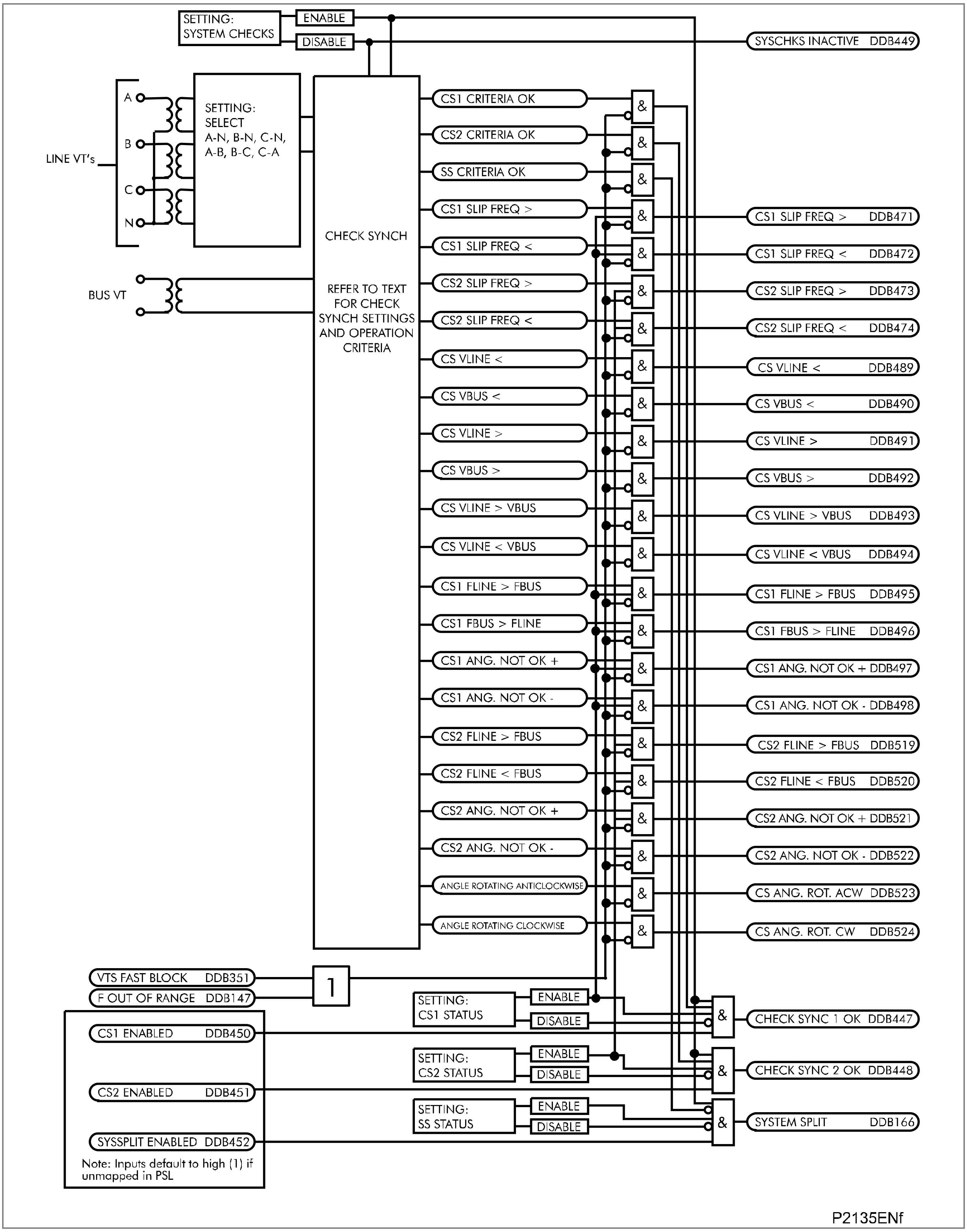

Figure 74 - System checks functional logic diagram

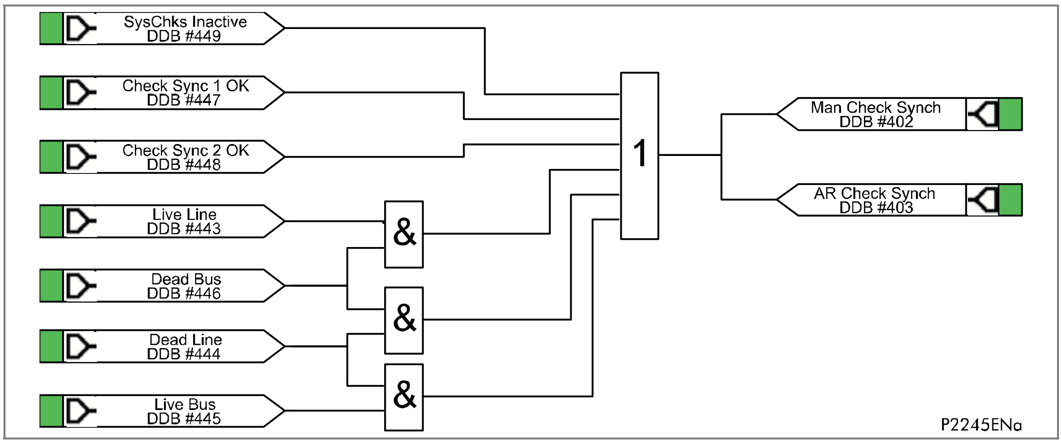

Figure 75 - Check sync. default PSL

2.3.4.3 Voltage and Phase Angle Correction

This feature involves the Check Synchronizing function with different VT ratios. The relay needs to convert the measured secondary voltages into primary voltage, which in turn shall be used for check synchronizing function. This is used in applications where the VTs are having different ratios on bus/line sides of the circuit breaker. Likewise, the transformer may be of any vector group (say Dy11, Yd5, etc.), in which case an angular correction factor is required in case the VTs mounted on different sides are used for synchronizing.

There are some applications where the main VT is in the HV side of a transformer and the check sync VT is in the LV side or vice-versa. Due to the group index of the transformer, if this is different from "**0**", both voltages are not "**in phase**", so the Check Synchronizing feature must have a '**k**' factor (correction factor) in order to give this vectorial correction.

kSM, setting ranges from 0.1 to 3, in steps of 0.001, where kSM is the voltage correction factor.

kSA, setting ranges from -150 to 180º, in steps of 30º, where kSA is the angle correction factor.

After adding 'k' factors:

For the check synch the following will be used:

For matching magnitudes, assuming C/S input setting [0A0F] is A-N:

If:

$V_{cs(\sec)} \times kSM = V_{a(\sec)}$ then line and bus voltages magnitudes are matched

For matching angles:

If:

$$\angle V_{cs(\sec)}{}^{\circ} + kSA^{\circ} = \angle V_{a(\sec)}{}^{\circ}$$

then line and bus voltage angles are matched

Where kSM is [0A14] C/S V kSM
and kSA is [0A15] C/S Phase kSA

Important	Setting the right VT ratios will not adjust the k factors and will have no impact on the check synch functionality, check synch will only take into account the k factors setting. The VT ratios have impacts on the presentation of the related measurements or settings in terms of primary or secondary values. The CS voltage settings in system check column are all referenced by the Main VT ratios. The Bus-Line Ang [0230] measurement takes into account the C/S Phase kSA setting.

Following are various possible application scenarios, wherein voltage correction factor and angular correction factors are applied to match different VT ratios:

Scenario	Physical Ratio's (ph-N Values)				Relay Setting Ratio's				CS Correction Factors	
	Main VT Ratio		CS VT Ratio		Main VT Ratio (ph-ph) Always		CS VT Ratio		kSM [0A14]	kSA [0A15]
	Pri (kV)	Sec (V)	Pri (kV)	Sec (V)	[0A01]Pri (kV)	[0A02]Sec (V)	[0A03]Pri (kV)	[0A04]Sec (V)		
1	220/√3	110/√3	132/√3	100/√3	220	110	132	100	1.1	30º
2	220/√3	110/√3	220/√3	110	220	110	127	110	0.577	0º
3	220/√3	110/√3	220/√3	110/3	220	110	381	110	1.732	0º

Table 10 - Physical and Relay Setting Ratios and Correction Factors

In the above examples, the CS VT ratio settings in the relay are so adjusted to a value such that they are within the acceptable range of the relay inputs and by multiplying a voltage correction factor, kSA, they are corrected and made equal to the physical ratios. This does not directly match the physical ratios. It can be phase - phase, phase - neutral or any ratio which can match the physical VT ratio.

2.4 Function Keys (P145 only)

The P145 relay offers users 10 function keys for programming any operator control functionality such as auto-reclose ON/OFF, earth fault1 ON/OFF etc. via PSL. Each function key has an associated programmable tri-color LED that can be programmed to give the desired indication on function key activation.

These function keys can be used to trigger any function that they are connected to as part of the PSL. The function key commands can be found in the '**Function Keys**' menu (see Settings section, P14x/EN ST). In the '**Fn. Key Status**' menu cell there is a 10 bit word which represent the 10 function key commands and their status can be read from this 10 bit word.

In the programmable scheme logic editor 10 function key signals, DDB 712 - 721, which can be set to a logic 1 or On state, as described above, are available to perform control functions defined by the user.

The "**Function Keys**" column has '**Fn. Key n Mode**' cell which allows the user to configure the function key as either '**Toggled**' or '**Normal**'. In the '**Toggle**' mode the function key DDB signal output will remain in the set state until a reset command is given, by activating the function key on the next key press. In the '**Normal**' mode, the function key DDB signal will remain energized for as long as the function key is pressed and will then reset automatically. A minimum pulse duration can be programmed for a function key by adding a minimum pulse timer to the function key DDB output signal.

The "**Fn. Key n Status**" cell is used to enable/unlock or disable the function key signals in PSL. The '**Lock**' setting has been specifically provided to allow the locking of a function key thus preventing further activation of the key on consequent key presses. This allows function keys that are set to '**Toggled**' mode and their DDB signal active '**high**', to be locked in their active state thus preventing any further key presses from deactivating the associated function. Locking a function key that is set to the "**Normal**" mode causes the associated DDB signals to be permanently off. This safety feature prevents any inadvertent function key presses from activating or deactivating critical relay functions.

The "**Fn. Key Labels**" cell makes it possible to change the text associated with each individual function key. This text will be displayed when a function key is accessed in the function key menu, or it can be displayed in the PSL.

The status of the function keys is stored in battery backed memory. In the event that the auxiliary supply is interrupted the status of all the function keys will be recorded. Following the restoration of the auxiliary supply the status of the function keys, prior to supply failure, will be reinstated. If the battery is missing or flat the function key DDB signals will set to logic 0 once the auxiliary supply is restored. Please also note the relay will only recognize a single function key press at a time and that a minimum key press duration of approximately 200msec. is required before the key press is recognized in PSL. This deglitching feature avoids accidental double presses.

2.5 Voltage Transformer Supervision (VTS)

The Voltage Transformer Supervision (VTS) feature is used to detect failure of the ac voltage inputs to the relay. In the case of the P144, supervision of the residual voltage input is not provided, as there will be no reliable voltage to measure under healthy system conditions. This may be caused by internal voltage transformer faults, overloading, or faults on the interconnecting wiring to relays. This usually results in one or more VT fuses blowing. Following a failure of the ac voltage input there would be a misrepresentation of the phase voltages on the power system, as measured by the relay, which may result in mal-operation.

The VTS logic in the relay is designed to detect the voltage failure, and automatically adjust the configuration of protection elements whose stability would otherwise be compromised. A time-delayed alarm output is also available.

There are three main aspects to consider regarding the failure of the VT supply. These are defined below:

- Loss of one or two-phase voltages
- Loss of all three-phase voltages under load conditions
- Absence of three-phase voltages upon line energization

The VTS feature within the relay operates on detection of negative phase sequence (nps) voltage without the presence of negative phase sequence current. This gives operation for the loss of one or two-phase voltages. Stability of the VTS function is assured during system fault conditions, by the presence of nps current. The use of negative sequence quantities ensures correct operation even where three-limb or '**V**' connected VT's are used.

Negative Sequence VTS Element:

> The negative sequence thresholds used by the element are V_2 = 10V (or 40V on a 380/440V rated relay), and I_2 = 0.05 to 0.5In settable (defaulted to 0.05In).

2.5.1 Loss of all 3-Phase Voltages under Load Conditions

Under the loss of all three-phase voltages to the relay, there will be no negative phase sequence quantities present to operate the VTS function. However, under such circumstances, a collapse of the three-phase voltages will occur. If this is detected without a corresponding change in any of the phase current signals (which would be indicative of a fault), then a VTS condition will be raised. In practice, the relay detects the presence of superimposed current signals, which are changes in the current applied to the relay. These signals are generated by comparison of the present value of the current with that exactly one cycle previously. Under normal load conditions, the value of superimposed current should therefore be zero. Under a fault condition a superimposed current signal will be generated which will prevent operation of the VTS.

The phase voltage level detectors are fixed and will drop off at 10V (40V on 380/440V relays) and pickup at 30V (120V on 380/440V relays).

The sensitivity of the superimposed current elements is fixed at 0.1In.

2.5.2 Absence of 3-Phase Voltages on Line Energization

If a VT were inadvertently left isolated prior to line energization, incorrect operation of voltage dependent elements could result. The previous VTS element detected three-phase VT failure by absence of all 3-phase voltages with no corresponding change in current. On line energization there will, however, be a change in current (as a result of load or line charging current for example). An alternative method of detecting three-phase VT failure is therefore required on line energization.

The absence of measured voltage on all three phases on line energization can be as a result of 2 conditions. The first is a three-phase VT failure and the second is a close up three-phase fault. The first condition would require blocking of the voltage dependent function and the second would require tripping. To differentiate between these 2 conditions an overcurrent level detector (VTS I> Inhibit) is used which will prevent a VTS block from being issued if it operates. This element should be set in excess of any non-fault based currents on line energization (load, line charging current, transformer inrush current if applicable) but below the level of current produced by a close up three-phase fault. If the line is now closed where a three-phase VT failure is present the overcurrent detector will not operate and a VTS block will be applied. Closing onto a three-phase fault will result in operation of the overcurrent detector and prevent a VTS block being applied.

This logic will only be enabled during a live line condition (as indicated by the relays pole dead logic) to prevent operation under dead system conditions i.e. where no voltage will be present and the VTS I> Inhibit overcurrent element will not be picked up.

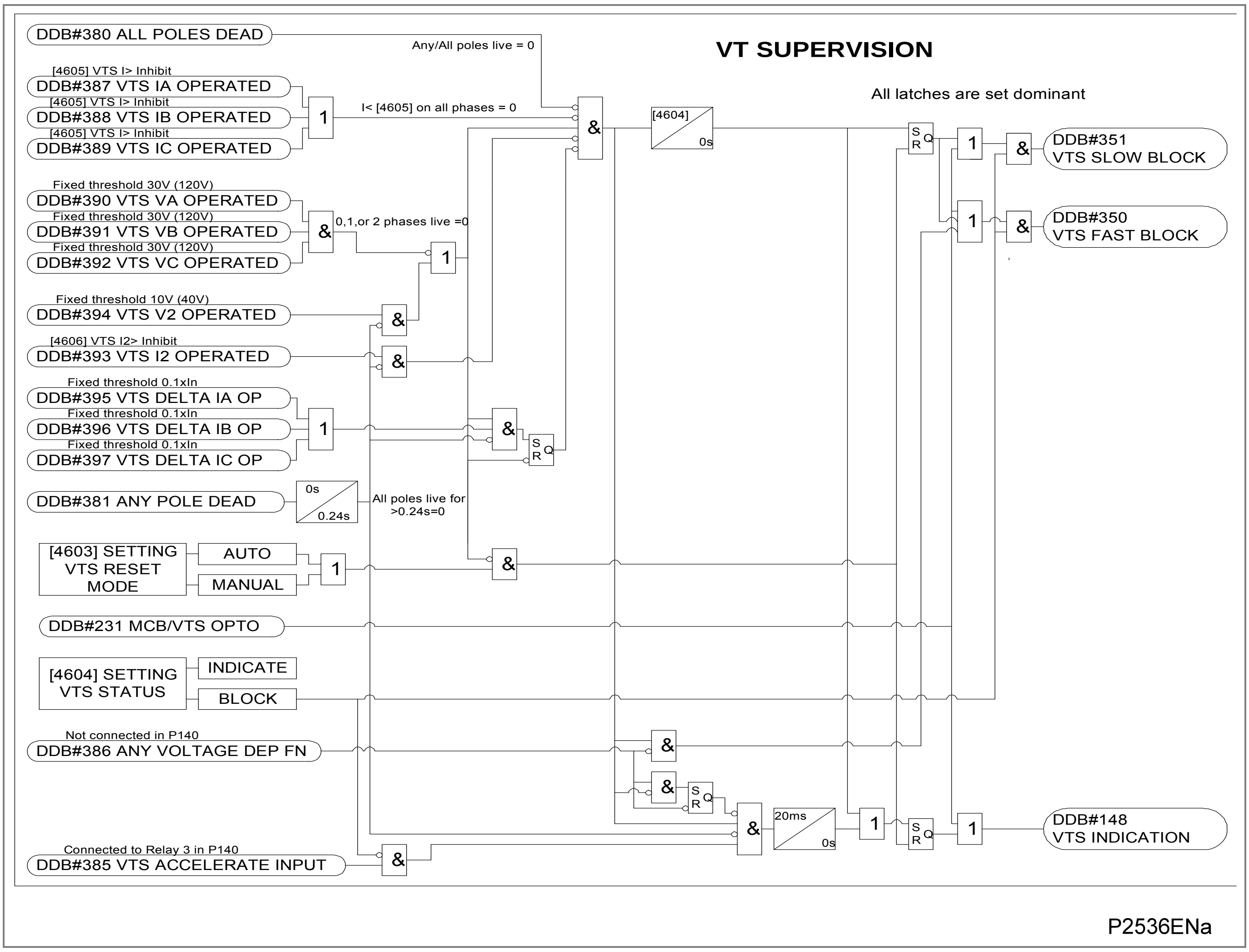

Figure 76 - VTS Logic

POLE DEAD = CB OPEN OR (I<0.05xIn AND V<10V AND VTS SLOW BLOCK=0)

i.e. Pole live = CB CLOSED AND (I>0.055xIn OR V>30V OR VTS SLOW BLOCK =1)

Required to drive the VTS logic are a number of dedicated level detectors as follows:

- IA>, IB>, IC> these level detectors operate in less than 20ms and their settings should be greater than load current. This setting is specified as VTS current threshold
- I2> this level detector operates on negative sequence current and has a user setting
- ∆IA>, ∆IB>, ∆IC> these are level detectors operating on superimposed phase currents and have a fixed setting of 10% of nominal
- VA>, VB>, VC> these are level detectors operating on phase voltages and have a fixed setting Pickup level 30V (Vn 100/120V), 120V (Vn 380/440V), Drop Off level 10V (Vn 100/120V), 40V (Vn 380/440V)
- V2> this level detector operates on negative sequence voltage, it has a fixed setting of 10V/40V depending on VT ratio (100/120 or 380/440)

2.5.2.1 Outputs

Signal Name	Description
VTS Fast Block	Used to block voltage dependent functions
VTS Slow block	Used to block the Any Pole dead signal
VTS Indication	Signal used to indicate a VTS operation

Table 11 - Signal name outputs

2.6 Current Transformer Supervision (CTS)

The CT supervision feature operates on detection of derived zero sequence current, in the absence of corresponding derived zero sequence voltage that would normally accompany it. The CTS logic is shown in Figure 77.

The voltage transformer connection used must be able to refer zero sequence voltages from the primary to the secondary side. Thus, this element should only be enabled where the VT is of five limb construction, or comprises three single-phase units, and has the primary star point earthed.

Operation of the element will produce a time-delayed alarm visible on the LCD and event record (plus DDB 149: CT Fail Alarm), with an instantaneous block (DDB 352: CTS Block) for inhibition of protection elements. Protection elements operating from derived quantities (Broken Conductor, Earth Fault2, Neg. Seq. O/C) are always blocked on operation of the CT supervision element; other protections can be selectively blocked by customizing the PSL, integrating DDB 352: CTS Block with the protection function logic.

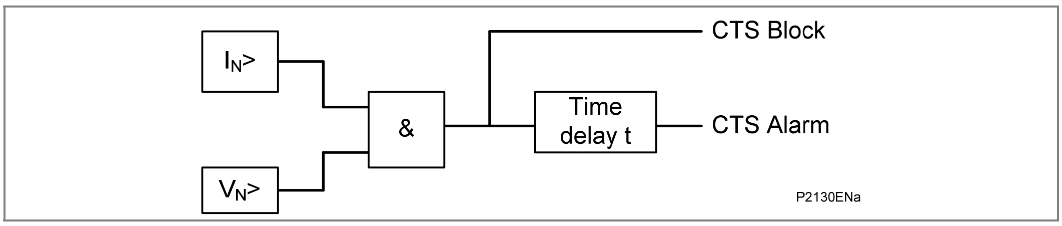

Figure 77 - CT supervision logic diagram

2.7 Circuit Breaker State Monitoring

The relay incorporates circuit breaker state monitoring, giving an indication of the position of the circuit breaker, or, if the state is unknown, an alarm is raised.

2.7.1 Circuit Breaker State Monitoring Features

MiCOM relays can be set to monitor normally open (52a) and normally closed (52b) auxiliary contacts of the circuit breaker. Under healthy conditions, these contacts will be in opposite states. Should both sets of contacts be open, this would indicate one of the following conditions:

- Auxiliary contacts/wiring defective
- Circuit Breaker (CB) is defective
- CB is in isolated position

Should both sets of contacts be closed, only one of the following two conditions would apply:

- Auxiliary contacts/wiring defective
- Circuit Breaker (CB) is defective

If any of the above conditions exist, an alarm will be issued after a 5s time delay. A normally open/normally closed output contact can be assigned to this function via the Programmable Scheme Logic (PSL). The time delay is set to avoid unwanted operation during normal switching duties.

In the CB CONTROL column of the relay menu there is a setting called '**CB Status Input**'. This cell can be set at one of the following four options:

- None
- 52A
- 52B
- Both 52A and 52B

Where '**None**' is selected no CB status will be available. This will directly affect any function within the relay that requires this signal, for example CB control, auto-reclose, etc. Where only 52A is used on its own then the relay will assume a 52B signal from the absence of the 52A signal. Circuit breaker status information will be available in this case but no discrepancy alarm will be available. The above is also true where only a 52B is used. If both 52A and 52B are used then status information will be available and in addition a discrepancy alarm will be possible, according to the following table. 52A and 52B inputs are assigned to relay opto-isolated inputs via the PSL. The CB State Monitoring logic is shown in Figure 78.

Auxiliary Contact Position		CB State Detected	Action
52A	**52B**		
Open	Closed	Breaker open	Circuit breaker healthy
Closed	Open	Breaker closed	Circuit breaker healthy
Closed	Closed	CB failure	Alarm raised if the condition persists for greater than 5s
Open	Open	State unknown	Alarm raised if the condition persists for greater than 5s

Table 12 - CB state monitoring logic

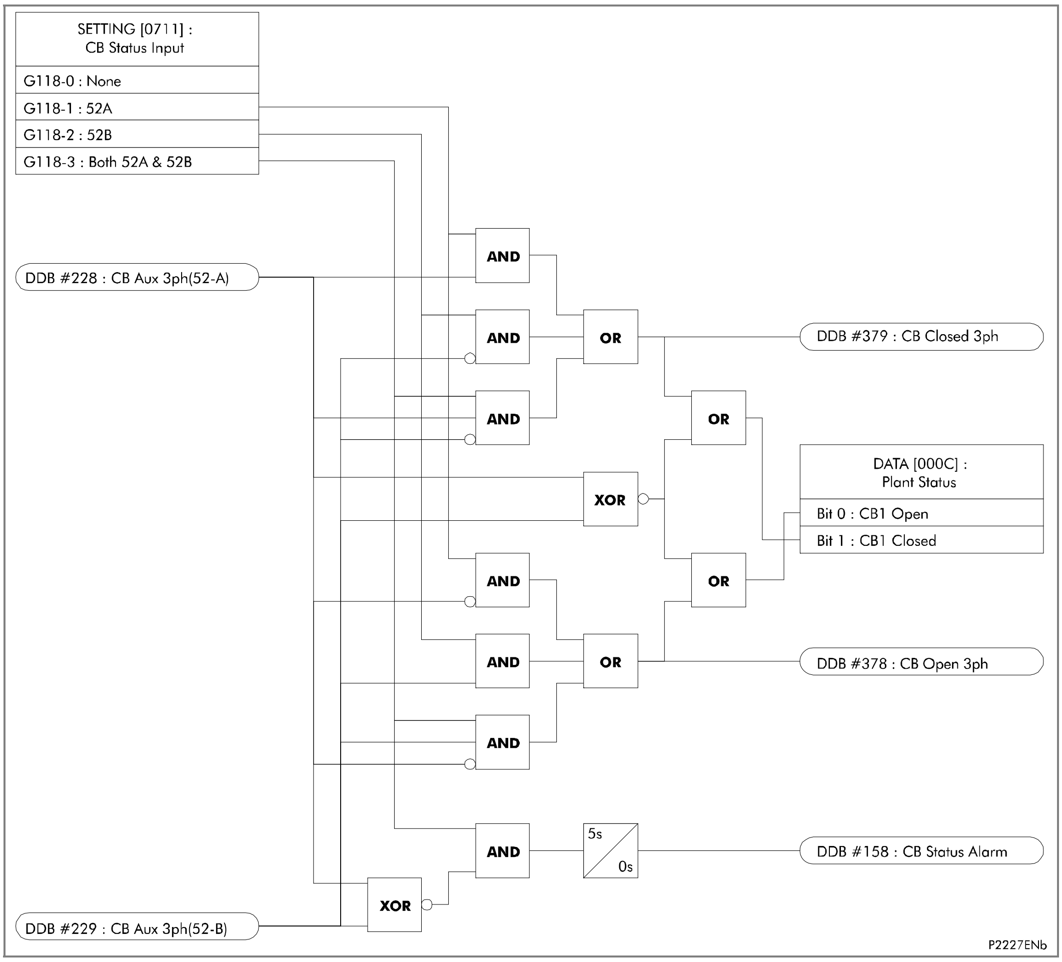

Figure 78 - CB state monitoring

2.8 Pole Dead Logic

The Pole Dead Logic can be used to give an indication if one or more phases of the line are dead. It can also be used to selectively block operation of both the under frequency and under voltage elements. The under voltage protection will be blocked by a pole dead condition provided the "**Pole Dead Inhibit**" setting is enabled. Any of the four under frequency elements can be blocked by setting the relevant "**F< function links**".

A pole dead condition is determined by either monitoring the status of the circuit breaker auxiliary contacts or by measuring the line currents and voltages. The status of the circuit breaker is provided by the "**CB State Monitoring**" logic. If a "**CB Open**" signal (DDB 378) is given the relay will automatically initiate a pole dead condition regardless of the current and voltage measurement. Similarly if both the line current and voltage fall below a pre-set threshold the relay will also initiate a pole dead condition. This is necessary so that a pole dead indication is still given even when an upstream breaker is opened. The under voltage (V<) and under current (I<) thresholds have the following, fixed, pickup and drop-off levels:

Settings	Range	Step Size
V< Pick-up and drop off	10V and 30V (100/120V) 40V and 120V (380/440V)	Fixed
I< Pick-up and drop off	0.05 In and 0.055In	Fixed

Table 13 - Settings, range and step size

If one or more poles are dead the relay will indicate which phase is dead and will also assert the ANY POLE DEAD DDB signal (DDB 384). If all phases were dead the ANY POLE DEAD signal would be accompanied by the ALL POLE DEAD DDB signal (DDB 380).

In the event that the VT fails a signal is taken from the VTS logic (DDB 351 - Slow Block) to block the pole dead indications that would be generated by the under voltage and undercurrent thresholds. However, the VTS logic will not block the pole dead indications if they are initiated by a "**CB Open**" signal (DDB 378).

The pole dead logic diagram is shown in Figure 79.

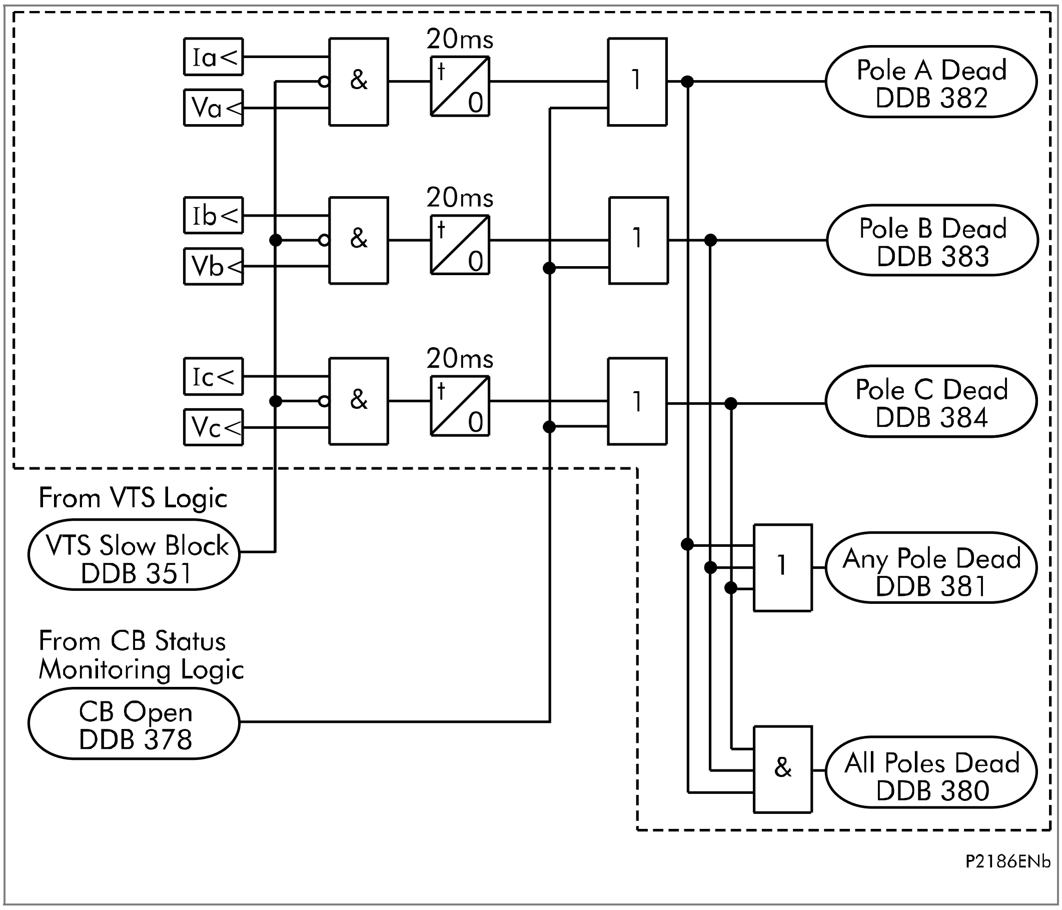

Figure 79 - Pole dead logic

2.9 Circuit Breaker Condition Monitoring

The P14x relays record various statistics related to each circuit breaker trip operation, allowing a more accurate assessment of the circuit breaker condition to be determined. These monitoring features are discussed in the following section.

2.9.1 Circuit Breaker Condition Monitoring Features

For each circuit breaker trip operation the relay records statistics as shown in the following table taken from the relay menu. The menu cells shown are counter values only. The Min./Max. values in this case show the range of the counter values. These cells can not be set.

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
CB Operations {3 pole tripping}	0	0	10000	1
Displays the total number of 3 pole trips issued by the relay.				
Total IA Broken	0	0	25000In^	1
Displays the total fault current interrupted by the relay for the A phase.				
Total IB Broken	0	0	25000In^	1
Displays the total fault current interrupted by the relay for the A phase.				
Total IC Broken	0	0	25000In^	1In^
Displays the total fault current interrupted by the relay for the A phase.				
CB Operate Time	0	0	0.5s	0.001
Displays the calculated CB operating time.				
Reset CB Data	No		Yes, No	
Setting to reset the CB condition counters.				

Table 14 - CB Settings

The above counters may be reset to zero, for example, following a maintenance inspection and overhaul. The circuit breaker condition monitoring counters will be updated every time the relay issues a trip command. In cases where the breaker is tripped by an external protection device it is also possible to update the CB condition monitoring. This is achieved by allocating one of the relays opto-isolated inputs (via the programmable scheme logic) to accept a trigger from an external device. The signal that is mapped to the opto is called ‘**External Trip**’.

Note	*When in Commissioning test mode the CB condition monitoring counters will not be updated.*

2.10 Circuit Breaker Control

The relay includes the following options for control of a single circuit breaker:

- Local tripping and closing, via the relay menu, hotkeys or function keys
- Local tripping and closing, via relay opto-isolated inputs
- Remote tripping and closing, using the relay communications

It is recommended that separate relay output contacts are allocated for remote circuit breaker control and protection tripping. This enables the control outputs to be selected via a local/remote selector switch as shown in Figure 80. Where this feature is not required the same output contact(s) can be used for both protection and remote tripping.

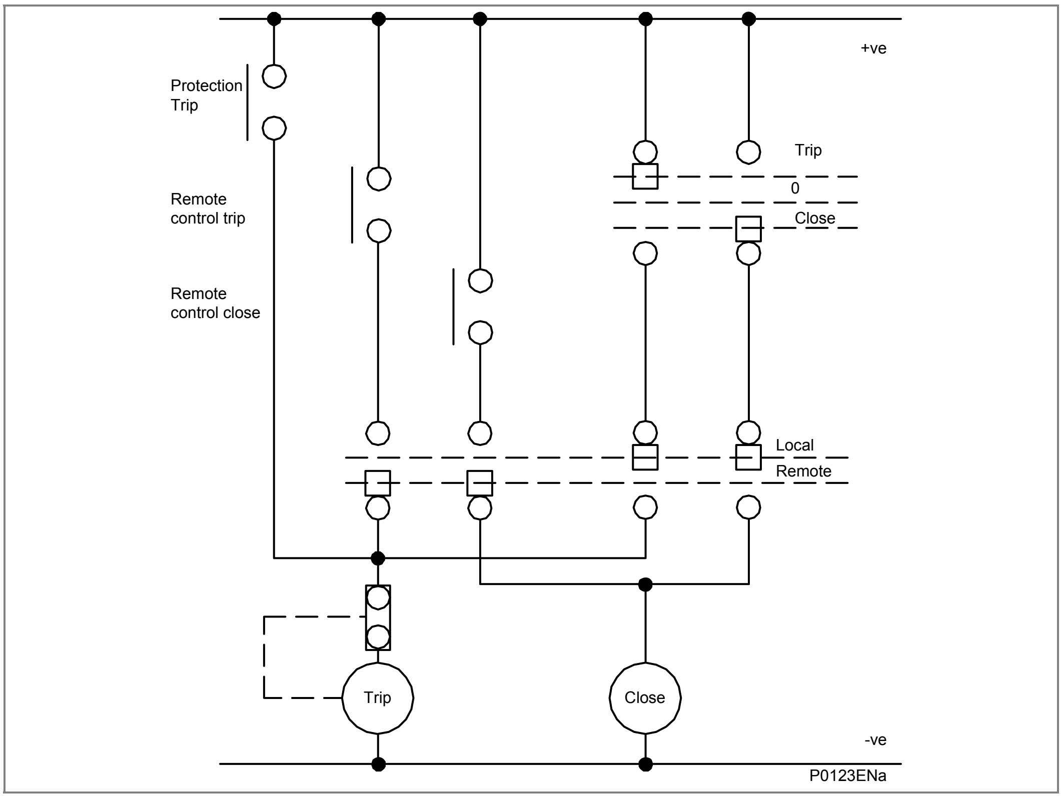

Figure 80 - Remote control of circuit breaker

A manual trip will be permitted provided that the circuit breaker is initially closed. Likewise, a close command can only be issued if the CB is initially open. To confirm these states it will be necessary to use the breaker 52A and/or 52B contacts (the different selection options are given from the ‘**CB Status Input**’). If no CB auxiliary contacts are available then this cell should be set to None. Under these circumstances no CB control (manual or auto) will be possible.

Once a CB Close command is initiated the output contact can be set to operate following a user defined time delay (‘**Man. Close Delay**’). This would give personnel time to move safely away from the circuit breaker following the close command. This time delay will apply to all manual CB Close commands.

The length of the trip or close control pulse can be set via the ‘**Trip Pulse Time**’ and ‘**Close Pulse Time**’ settings respectively. These should be set long enough to ensure the breaker has completed its open or close cycle before the pulse has elapsed.

Note	*The manual trip and close commands are found in the SYSTEM DATA column and the hotkey menu.*

If an attempt to close the breaker is being made, and a protection trip signal is generated, the protection trip command overrides the close command.

Where the check synchronism function is set, this can be enabled to supervise manual circuit breaker close commands. A circuit breaker close output will only be issued if the check synchronism criteria are satisfied. A user settable time delay is included (‘**C/S Window**’) for manual closure with check synchronizing. If the check sync. criteria are not satisfied in this time period following a close command the relay will lockout and alarm.

In addition to a synchronism check before manual re-closure there is also a CB Healthy check if required. This facility accepts an input to one of the relays opto-isolators to indicate that the breaker is capable of closing (circuit breaker energy for example). A user settable time delay is included "**CB Healthy Time**" for manual closure with this check. If the CB does not indicate a healthy condition in this time period following a close command then the relay will lockout and alarm.

The "**Reset Lockout by**" setting, "**CB Close/User interface**" in "**CB CONTROL**" (0709) is used to enable/disable reset of lockout automatically from a manual close after the manual close time "**Man. Close Rst. Dly.**".

If the CB fails to respond to the control command (indicated by no change in the state of CB Status inputs) a "**CB Failed to Trip**" or "**CB Failed to Close**" alarm will be generated after the relevant trip or close pulses have expired. These alarms can be viewed on the relay LCD display, remotely via the relay communications, or can be assigned to operate output contacts for annunciation using the relays programmable scheme logic (PSL).

Note	*The "**CB Healthy Time**" timer and "**Check Sync. Time**" timer set under this menu section are applicable to manual circuit breaker operations only. These settings are duplicated in the auto-reclose menu for auto-reclose applications.*

The "**Lockout Reset**" and "**Reset Lockout by**" setting cells in the menu are applicable to CB Lockouts associated with manual circuit breaker closure, CB Condition monitoring (Number of circuit breaker operations, for example) and auto-reclose lockouts.

The CB Control logic is shown in Figure 81.

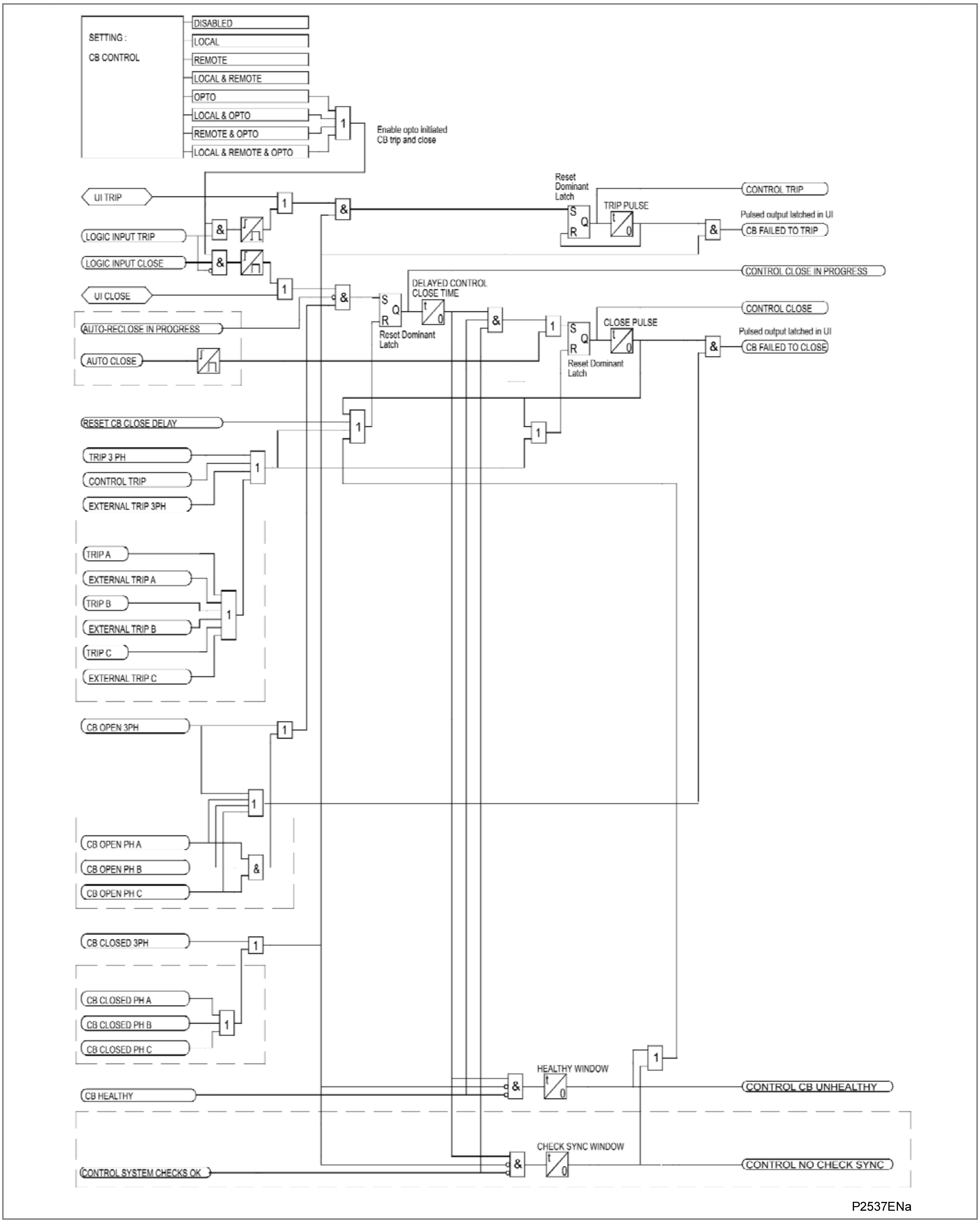

Figure 81 - Circuit breaker control

2.10.1 CB Control using Hotkeys

The hotkeys allow direct access to the manual trip and close commands without the need to enter the SYSTEM DATA column. Hotkeys supplement the direct access possible via the function keys described in section 2.4. Red or green color coding can be applied when used in CB control applications.

IF <<TRIP>> or <<CLOSE>> is selected the user is prompted to confirm the execution of the relevant command. If a trip is executed a screen with the CB status will be displayed once the command has been completed. If a close is executed a screen with a timing bar will appear while the command is being executed. This screen has the option to cancel or restart the close procedure. The timer used is taken from the manual close delay timer setting in the CB Control menu. When the command has been executed, a screen confirming the present status of the circuit breaker is displayed. The user is then prompted to select the next appropriate command or exit - this will return to the default relay screen.

If no keys are pressed for a period of 25 seconds while waiting for the command confirmation, the relay will revert to showing the CB Status. If no key presses are made for a period of 25 seconds while displaying the CB status screen, the relay will revert to the default relay screen. Figure 82 shows the hotkey menu associated with CB control functionality.

To avoid accidental operation of the trip and close functionality, the hotkey CB control commands will be disabled for 10 seconds after exiting the hotkey menu.

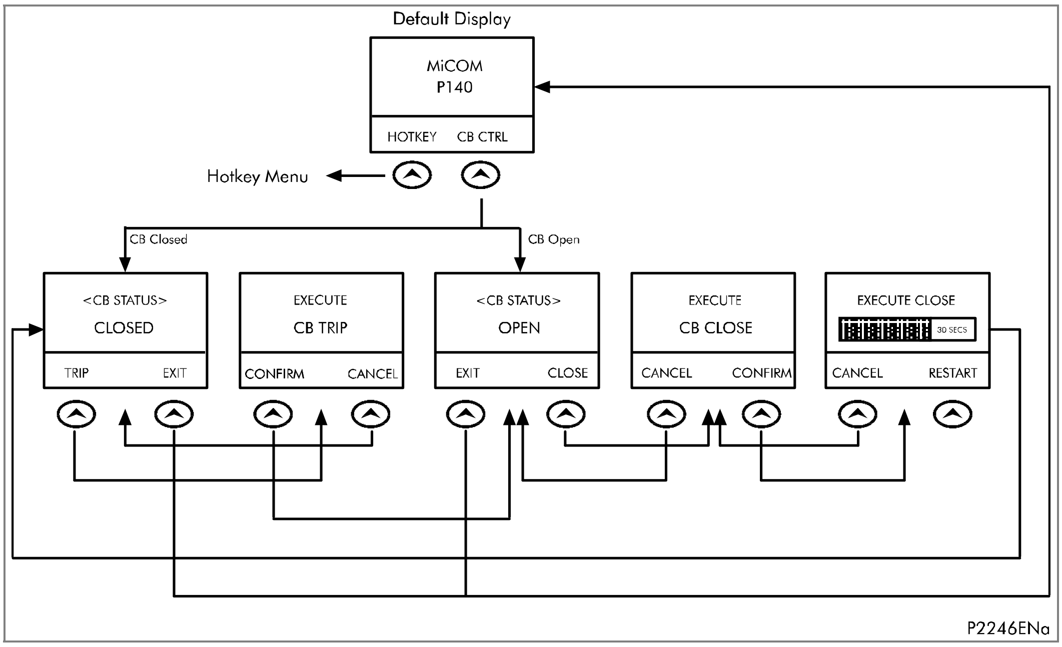

Figure 82 - CB control hotkey menu

2.10.2 CB Control using Function Keys

The function keys allow direct control of the circuit breaker if programmed to do this in PSL. local tripping and closing, via relay opto-isolated inputs must be set in the “**CB Control**” menu ‘**CB control by**’ cell to enable this functionality. All CB manual control settings and conditions will apply for manual tripping and closing via function keys.

The following default logic can be programmed to activate this feature:

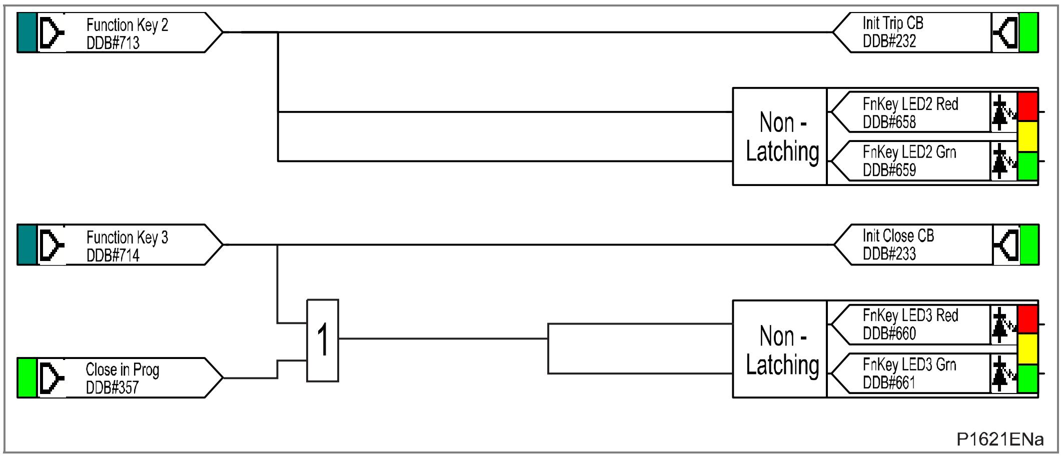

Figure 83 - CB control via function keys default PSL

Function key 2 and function key 3 are both enabled and set to '**Normal**' Mode and the associated DDB signals '**DDB 713**' and '**DDB 714**' will be active high '**1**' on key press.

The following DDB signal must be mapped to the relevant function key:

Init. Trip CB	(DDB 232)	Initiate manual circuit breaker trip
Init. Close CB	(DDB 233)	Initiate manual circuit breaker close

The programmable function key LED's have been mapped such that the LED's will indicate yellow whilst the keys are activated.

2.11 Setting Groups Selection

The setting groups can be changed either via opto inputs, via a menu selection, via the hotkey menu or via function keys (P145 model only). In the Configuration column if **'Setting Group - select via optos**' is selected then any opto input or function key can be programmed in PSL to select the setting group as shown in the table below. If **'Setting Group - select via menu**' is selected then in the Configuration column the **'Active Settings - Group1/2/3/4**' can be used to select the setting group.

The setting group can be changed via the hotkey menu providing '**Setting Group select via menu**' is chosen.

Two DDB signals are available in PSL for selecting a setting group via an opto input or function key selection (see default PSL in the Programmable Scheme Logic section, P14x/EN PL). The following table illustrates the setting group that is active on activation of the relevant DDB signals.

DDB 527 SG Select 1X	DDB 526 SG Select X1	Selected Setting Group
0	0	1
0	1	2
1	0	3
1	1	4

Note *Each setting group has its own PSL. Once a PSL has been designed it can be sent to any one of 4 setting groups within the relay. When downloading a PSL to the relay the user will be prompted to enter the desired setting group to which it will be sent. This is also the case when extracting a PSL from the relay.*

Table 15 - DDB setting groups

2.12 Control Inputs

The control inputs function as software switches that can be set or reset either locally or remotely. These inputs can be used to trigger any function that they are connected to as part of the PSL. There are three setting columns associated with the control inputs that are: "**CONTROL INPUTS**", "**CTRL. I/P CONFIG.**" and "**CTRL. I/P LABELS**". The function of these columns is described below:

Menu Text	Default Setting	Setting Range	Step Size
CONTROL INPUTS			
Ctrl I/P Status	00000000000000000000000000000000		
Control Input 1	No Operation	No Operation, Set, Reset	
Control Input 2 to 32	No Operation	No Operation, Set, Reset	

Table 16 - Control Inputs

The Control Input commands can be found in the '**Control Input**' menu. In the '**Ctrl. I/P status**' menu cell there is a 32 bit word which represent the 32 control input commands. The status of the 32 control inputs can be read from this 32-bit word. The 32 control inputs can also be set and reset from this cell by setting a 1 to set or 0 to reset a particular control input. Alternatively, each of the 32 Control Inputs can be set and reset using the individual menu setting cells '**Control Input 1, 2, 3**' etc. The Control Inputs are available through the relay menu as described above and also via the rear communications.

In the programmable scheme logic editor 32 Control Input signals, DDB 800 - 831, which can be set to a logic 1 or On state, as described above, are available to perform control functions defined by the user.

Menu Text	Default Setting	Setting Range	Step Size
CTRL. I/P CONFIG.			
Hotkey Enabled	11111111111111111111111111111111		
Control Input 1	Latched	Latched, Pulsed	
Ctrl Command 1	SET/RESET	SET/RESET, IN/OUT, ENABLED/DISABLED, ON/OFF	
Control Input 2 to 32	Latched	Latched, Pulsed	
Ctrl Command 2 to 32	SET/RESET	SET/RESET, IN/OUT, ENABLED/DISABLED, ON/OFF	

Table 17 - Ctrl. I/P Config.

Menu Text	Default Setting	Setting Range	Step Size
CTRL. I/P LABELS			
Control Input 1	Control Input 1	16 character text	
Control Input 2 to 32	Control Input 2 to 32	16 character text	

Table 18 - Ctrl. I/P Labels

The "**CTRL. I/P CONFIG.**" column has several functions one of which allows the user to configure the control inputs as either '**latched**' or '**pulsed**'. A latched control input will remain in the set state until a reset command is given, either by the menu or the serial communications. A pulsed control input, however, will remain energized for 10ms after the set command is given and will then reset automatically (i.e. no reset command required).

In addition to the latched/pulsed option this column also allows the control inputs to be individually assigned to the "**Hotkey**" menu by setting '**1'** in the appropriate bit in the "**Hotkey Enabled**" cell. The hotkey menu allows the control inputs to be set, reset or pulsed without the need to enter the "**CONTROL INPUTS**" column. The "**Ctrl.**

Command" cell also allows the SET/RESET text, displayed in the hotkey menu, to be changed to something more suitable for the application of an individual control input, such as "**ON/OFF", "IN/OUT**" etc.

The "**CTRL. I/P LABELS**" column makes it possible to change the text associated with each individual control input. This text will be displayed when a control input is accessed by the hotkey menu, or it can be displayed in the PSL.

Note	*The status of the control inputs is stored in (non - volatile) FLASH memory.*

2.13 Custom Inputs

The custom inputs will be similar to the control inputs but the value will be a setting stored in flash, and will produce events. There are two setting columns associated with the custom inputs that are: "**CONTROL INPUTS**" and "**CTRL. I/P LABELS**". The function of these columns is described below:

Menu Text	Default Setting	Setting Range	Step Size
CONTROL INPUTS			
Ctl Stg I/P Stat	0000000000000000		
Ctrl Setg I/P 33	Disabled	Disabled, Enabled	
Ctrl Setg I/P 34 to 48	Disabled	Disabled, Enabled	

Table 19 – Ctrl Setg I/P Inputs

The Custom Input commands can be found in the '**Control Input**' menu. In the '**Ctl Stg I/P Stat**' menu cell there is a 16 bit word which represent the 16 custom input commands. The status of the 16 custom inputs can be read from this 16-bit word. The 16 custom inputs can also be set and reset from this cell by setting a 1 to set or 0 to reset a particular custom input. Alternatively, each of the 16 Custom Inputs can be set and reset using the individual menu setting cells 'Ctrl Setg I/P **33, 34, 35**' etc. Each of the custom inputs needs to be adjustable from Courier, CS103 and the User Interface.

In the programmable scheme logic editor 16 Custom Input signals, DDB 1197 - 1212, which can be set to a logic 1 or On state.

Menu Text	Default Setting	Setting Range	Step Size
CTRL I/P LABELS			
Ctrl Setg I/P 33	Ctrl Setg I/P 33	16 character text	
Ctrl Setg I/P 34 to 48	Ctrl Setg I/P 34 to 48	16 character text	

Table 20 – Ctrl Setg I/P Labels

The "**CTRL. I/P LABELS**" column makes it possible to change the text associated with each individual custom input.

Note	*The status of the custom inputs is stored in FLASH memory and will produce events*

2.14 User Alarms

2.14.1 User Alarms

The User Alarms have settable labels (these are similar to input / output labels). These are provided for customized labels such as binary inputs, output relays and control inputs.

The relay now includes a new "USER ALARM COLUMN LABELS" column to store the labels for each User Alarm.

Note	*The relay provides 32 USER ALARMS from 1 to 32.*

The User Alarm labels are used in the PSL configuration as for the binary inputs, output relays and control inputs.

2.14.2 Virtual IO User Alarms

The user can edit these labels to have customizable relays. This is useful where user alarm DDBs and GOOSE DDBs can have different names according to the customer requirements. Changes can be applied via the HMI or by using a setting file. The user needs to make sure that these changes are reflected in the PSL, in HMI and in the setting file.

Customers can change their usage of the IEC61850-DNP3 protocol. This may be useful if they are more familiar with or prefer to use DNP3 over other options.

The relay now includes new “VIRTUAL INPUT COLUMN LABELS” and “VIRTUAL OUTPUT COLUMN LABELS” columns.

2.14.3 Custom Input

The user inputs are similar to the control inputs but the value is a setting stored in flash memory. Each custom input has an individual customizable label. The inputs are adjustable from a Bit Field or separate enable/disable selection. Each of the inputs can be adjusted from Courier, CS103 and the User Interface.

2.15 Real Time Clock Synchronization via Opto-Inputs

In modern protective schemes it is often desirable to synchronize the relays real time clock so that events from different relays can be placed in chronological order. This can be done using the IRIG-B input, via the communication interface connected to the substation control system. DDB 610 (IRIG-B Signal Valid) will be true if IRIG-B signal is present and IRIG-B Sync. is Enabled. In addition to these methods the P14x range offers the facility to synchronize via an opto-input by routing it in PSL to DDB 475 (Time Sync.). Pulsing this input will result in the real time clock snapping to the nearest minute. The recommended pulse duration is 20ms to be repeated no more than once per minute. An example of the time sync. function is shown.

Time of “Sync. Pulse”	Corrected Time
19:47:00 to 19:47:29	19:47:00
19:47:30 to 19:47:59	19:48:00
Note *The above assumes a time format of hh:mm:ss*	

Table 21 - Time of “Sync. Pulse” and corrected time

To avoid the event buffer from being filled with unnecessary time sync. events, it is possible to ignore any event that is generated by the time sync. opto input. This can be done by applying the following settings:

Menu Text	Value
RECORD CONTROL	
Opto Input Event	Enabled
Protection Event	Enabled
DDB 63 – 32 (Opto Inputs)	Set “Time Sync.” associated opto to 0

Table 22 - Record control

To improve the recognition time of the time sync. opto input by approximately 10ms, the opto input filtering could be disabled. This is achieved by setting the appropriate bit to 0 in the "**Opto Filter Cntl.**" cell (OPTO CONFIG. column). Disabling the filtering may make the opto input more susceptible to induced noise. Fortunately, the effects of induced noise can be minimized by using the methods described in the Product Design chapter.

The relay now has some new DDB signals. These have been added to validate the existence of IRIG-B card signals. IRIG-B signals are validated when the IRIG-B card signal setting which is enabled occurs at the same time as when the IRIG-B signal status setting is present. This logic is shown in Figure 84 below.

This is useful because it allows a customer to map an additional DDB in the PSL to indicate the IRIG-B status. This means that the customer can then monitor the validation of the IRIG-B signals. For example, they could then assign it to an output relay and send it (via the relevant protocol) using a SCADA communications system.

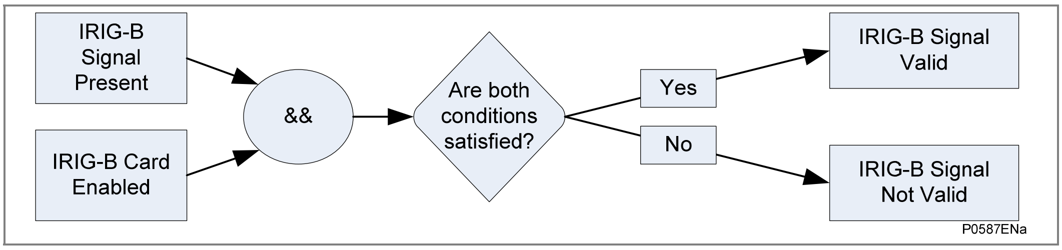

Figure 84 – IRIG-B signals validation chart

2.16 Enhanced Opto Time Stamping

Each opto-input sample will be time stamped within a tolerance of ±1ms with respect to the relay's Real Time Clock. These time stamps shall be utilized for the opto event logs and for the disturbance recording. The relay needs to be synchronized accurately to an external clock source such as the GPS clock and the synchronization shall consist of IRIG-B and SNTP through Ethernet communication. The P14x time synchronization accuracy will be 1ms through IRIG-B (both modulated and de-modulated) and SNTP. The total time stamping accuracy, with reference to an external clock source, also takes the time synchronization accuracy into consideration.

For both the filtered and unfiltered opto inputs, the time stamp of an opto change event will be the sampling time at which the opto change of state has occurred. If a mixture of filtered and unfiltered optos changes state at the same sampling interval, these state changes will be reported as a single event. The enhanced opto event time stamping is consistent across all the implemented protocols. The GOOSE messages will be published in a timely manner and will not be delayed by any event filtering mechanisms that is used to align the event time stamps.

2.17 Read Only Mode

With IEC61850 and Ethernet/Internet communication capabilities, security has become a pressing issue. The Px40 relay provides a facility to allow the user to enable or disable the change in configuration remotely. This feature is available only in relays with Courier, Courier with IEC 60870-5-103, Courier with IEC 61850 and Courier with IEC 60870-5-103 and IEC 61850 protocol options. It has to be noted that in IEC 60870-5-103 protocol, Read Only Mode function is different from the existing Command block feature.

2.17.1 Protocol/Port Implementation

2.17.1.1 IEC 60870-5-103 Protocol on Rear Port 1

The protocol does not support settings but the indications, measurands and disturbance records commands are available at the interface.

Allowed:

Poll Class 1 (read spontaneous events)

Poll Class 2 (read measurands)

GI sequence (ASDU7 **'Start GI'**, Poll Class 1)

Transmission of Disturbance Records sequence (ASDU24, ASDU25, Poll Class 1)

Time Synchronization (ASDU6)

General Commands (ASDU20), namely:

- INF23 activate characteristic 1
- INF24 activate characteristic 2
- INF25 activate characteristic 3
- INF26 activate characteristic 4

Blocked:
Write parameter (=change setting) (private ASDUs)

- General Commands (ASDU20), namely:
- INF16 auto-recloser on/off

- INF19 LED reset
- Private INFs (e.g. CB open/close, control inputs)

2.17.1.2 Courier Protocol on Rear Port 1/2 and Ethernet

Allowed:
Read settings, statuses, measurands

Read records (event, fault, disturbance)

Time Synchronization

Change active setting group

Blocked:
Write settings

All controls, including:

Reset Indication (Trip LED)

Operate control inputs

CB operations

Auto-reclose operations

Reset demands

Clear event/fault/maintenance/disturbance records

Test LEDs & contacts

2.17.1.3 IEC 61850

Allowed:
Read statuses, measurands

Generate reports

Extract disturbance records

Time synchronization

Change active setting group

Blocked:
All controls, including:

Enable/disable protection

Operate control inputs

CB operations (Close/Trip, Lock)

Reset LEDs

2.17.2 Courier Database Support

Three new settings, one for each remote communications port at the back of the relay are created to support the enabling and disabling of the read only mode at each port.

The ‘**NIC Read Only**’ setting will apply to all the communications protocols (including the Tunnelled Courier) that are transmitted via the Ethernet Port. Their default values are ‘**Disabled**’.

The MODBUS and DNP3 communications interfaces that do not support the feature will ignore these settings.

2.17.3 New DDB Signals

The remote read only mode is also available in the PSL via three dedicated DDB signals:

- RP1 Read Only
- RP2 Read Only
- NIC Read Only

Through careful scheme logic design, the activations of these read only signals can be facilitated via Opto Inputs, Control Inputs and Function Keys.

These DDBs are available in every build, however they are effective only in Courier, IEC 60870-5-103 build and in latest IEC 61850 (firmware version 42 onwards). The setting cells are not available in MODBUS and DNP3.0.

Notes:

APPLICATION NOTES

CHAPTER NO 7

Date:	10/2014
Products covered by this chapter:	This chapter covers the specific versions of the MiCOM products listed below. This includes ***only*** the following combinations of Software Version and Hardware Suffix.
Hardware Suffix:	L (P141, P142 & P143) & M (P145)
Software Version:	A0 - P14x (P141, P142, P143 & P145)
Connection Diagrams:	10P141xx (xx = 01 to 07) 10P142xx (xx = 01 to 07) 10P143xx (xx = 01 to 07) 10P145xx (xx = 01 to 07)

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EQUATIONS

1 INTRODUCTION

1.1 Frequency Protection

Generation and utilization need to be well balanced in any industrial, distribution or transmission network. As load increases, the generation needs to be stepped up to maintain frequency of the supply because there are many frequency sensitive electrical apparatus that can be damaged when network frequency departs from the allowed band for safe operation. At times, when sudden overloads occur, the frequency drops at a rate decided by the system inertia constant, magnitude of overload, system damping constant and various other parameters. Unless corrective measures are taken at the appropriate time, frequency decay can go beyond the point of no return and cause widespread network collapse. In a wider scenario, this can result in “Blackouts”. To put the network back in healthy condition, considerable amount of time and effort is required to re-synchronize and re-energize.

Protective relays that can detect a low frequency condition are generally used in such cases to disconnect unimportant loads in order to save the network, by re-establishing the “generation-load equation”. However, with such devices, the action is initiated only after the event and while some salvaging of the situation can be achieved, this form of corrective action may not be effective enough and cannot cope with sudden load increases, causing large frequency decays in very short times. In such cases a device that can anticipate the severity of frequency decay and act to disconnect loads before the frequency actually reaches dangerously low levels, can become very effective in containing damage.

During severe disturbances, the frequency of the system oscillates as various generators try to synchronize on to a common frequency. The measurement of instantaneous rate of change of frequency can be misleading during such a disturbance. The frequency decay needs to be monitored over a longer period of time to make the correct decision for load shedding.

Normally, generators are rated for a lifetime operation in a particular band of frequency and operation outside this band can cause mechanical damage to the turbine blades. Protection against such contingencies is required when frequency does not improve even after load shedding steps have been taken and can be used for operator alarms or turbine trips in case of severe frequency decay.

Whilst load shedding leads to an improvement in the system frequency, the disconnected loads need to be reconnected after the system is stable again. Loads should only be restored if the frequency remains stable for some period of time, but minor frequency excursions can be ignored during this time period. The number of load restoration steps are normally less than the load shedding steps to reduce repeated disturbances while restoring load.

This 9 stage advance frequency protection is available in P14x relays only when this feature “Adv. Freq. Prot’n” is enabled in the configuration menu and disabling the 4 stage Under/Over/Rate of Change frequency protection.

2 APPLICATION OF INDIVIDUAL PROTECTION FUNCTIONS

The following sections detail the individual protection functions in addition to where and how they may be applied. Worked examples are provided, to show how the settings are applied to the IED.

2.1 Overcurrent Protection

Overcurrent relays are the most commonly used protective devices in any industrial or distribution power system. They provide main protection to both feeders and busbars when unit protection is not used. They are also commonly applied to provide back-up protection when unit systems, such as pilot wire schemes, are used.

There are a few application considerations to make when applying overcurrent relays.

2.1.1 Transformer Magnetizing Inrush

When applying overcurrent protection to the HV side of a power transformer it is usual to apply a high set instantaneous overcurrent element in addition to the time delayed low-set, to reduce fault clearance times for HV fault conditions. Typically, this will be set to approximately 1.3 times the LV fault level, such that it will only operate for HV faults. A 30% safety margin is sufficient due to the low transient overreach of the third and fourth overcurrent stages. Transient overreach defines the response of a relay to DC components of fault current and is quoted as a percentage.

The second requirement for this element is that it should remain inoperative during transformer energization, when a large primary current flows for a transient period. In most applications, the requirement to set the relay above the LV fault level will automatically result in settings that will be above the level of magnetizing inrush current.

As an alternative, inrush blocking can be applied.

In applications where the sensitivity of overcurrent thresholds need to be set below the prospective peak inrush current, the inrush block function can be used to block the overcurrent, earth fault and negative sequence overcurrent stages.

During transformer inrush conditions, the second harmonic component of the inrush current may be as high as 70%. In practice, the second harmonic level may not be the same for all phases during inrush and therefore the relay will provide an Inrush Blocking signal for any phase above the set threshold. In general, a setting of 15% to 20% for the Inrush H2 ratio can be applied in most cases taking care that setting it too high, inrush blocking may not operate for low levels of second harmonic current which may result in the O/C element tripping during transformer energization. Similarly applying a too low a setting, inrush blocking may prevent tripping during some internal transformer faults with significant second harmonic current.

2.1.2 Application of Timer Hold Facility

This feature may be useful in certain applications, for example when grading with upstream electromechanical overcurrent relays, which have inherent reset time delays. Setting of the hold timer to a value other than zero, delays the resetting of the protection element timers for this period thus allowing the element to behave similar to an electromechanical relay.

Another possible situation where the timer hold facility may be used to reduce fault clearance times is where intermittent faults may be experienced. An example of this may occur in a plastic insulated cable. In this application it is possible that the fault energy melts and reseals the cable insulation, thereby extinguishing the fault. This process repeats to give a succession of fault current pulses, each of increasing duration with reducing intervals between the pulses, until the fault becomes permanent.

When the reset time of the overcurrent relay is instantaneous, the relay will be repeatedly reset and not be able to trip until the fault becomes permanent. By using the Timer Hold facility the relay will integrate the fault current pulses, thereby reducing fault clearance time.

2.1.3 Setting Guidelines

When applying the overcurrent protection provided in the P145 relays, standard principles should be applied in calculating the necessary current and time settings for co-ordination The Network Protection and Automation Guide (NPAG) textbook offers further assistance. The example detailed below shows a typical setting calculation and describes how the settings are applied to the relay.

Assume the following parameters for a relay feeding an LV switchboard:

CT Ratio = 500/1

Full load current of circuit = 450A

Slowest downstream protection = 100A Fuse

The current setting employed on the P145 relay must account for both the maximum load current and the reset ratio of the relay itself:

I> must be greater than: 450/0.95 = 474A

The P145 relay allows the current settings to be applied to the relay in either primary or secondary quantities. This is done by programming the "Setting Values" cell of the "CONFIGURATION" column to either primary or secondary. When this cell is set to primary, all phase overcurrent setting values are scaled by the programmed CT ratio. This is found in the "VT & CT Ratios" column of the relay menu, where cells "Phase CT Primary" and "Phase CT Secondary" can be programmed with the primary and secondary CT ratings, respectively.

In this example, assuming primary currents are to be used, the ratio should be programmed as 500/1.

The required setting is therefore 0.95A in terms of secondary current or 475A in terms of primary.

A suitable time delayed characteristic will now need to be chosen. When co-ordinating with downstream fuses, the applied relay characteristic should be closely matched to the fuse characteristic. Therefore, assuming IDMT co-ordination is to be used, an Extremely Inverse (EI) characteristic would normally be chosen. As previously described, this is found under "I>1 Function" and should therefore be programmed as "IEC E Inverse".

Finally, a suitable time multiplier setting (TMS) must be calculated and entered in cell "I>1 TMS".

Also note that the final 4 cells in the overcurrent menu refer to the voltage controlled overcurrent (VCO) protection which is separately described in section 2.12.

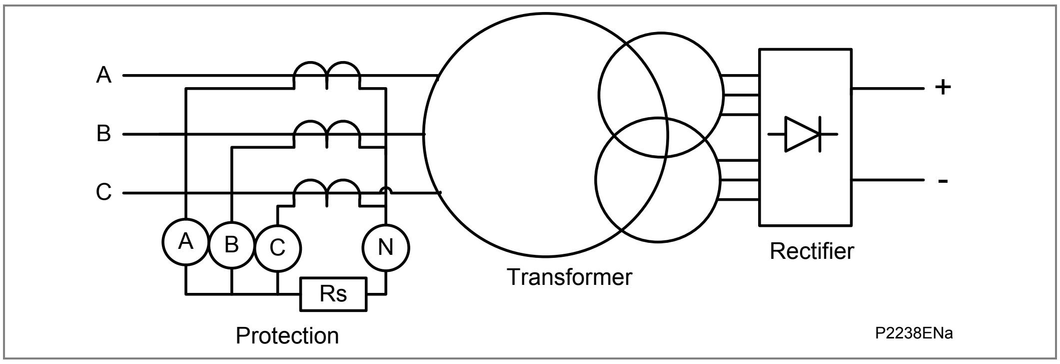


Figure 1 - Protection for silicon rectifiers

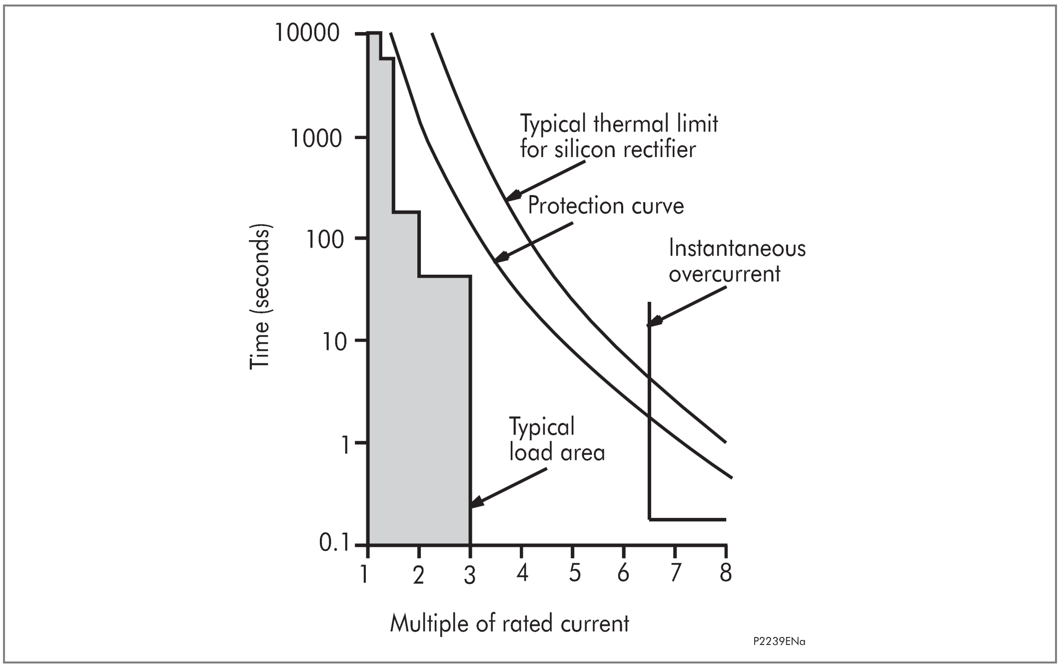


Figure 2 - Matching curve to load and thermal limit of rectifier

The rectifier protection feature has been based upon the inverse time/current characteristic as used in the MCTD 01 (Silicon Rectifier Protection Relay) and the above diagram show a typical application.

The protection of a rectifier differs from the more traditional overcurrent applications in that many rectifiers can withstand relatively long overload periods without damage, typically 150% for 2 hours and 300% for 1 min.

The I> setting should be set to typically 110% of the maximum allowable continuous load of the rectifier. The relay gives start indications when the I> setting has been exceeded, but this is of no consequence, as this function is not used in this application. The rectifier curve should be chosen for the inverse curve as it allows for relatively long overloads even with a 110% I> setting.

Typical settings for the TMS are:

Light industrial service	TMS	=	0.025
Medium duty service	TMS	=	0.1
Heavy duty traction	TMS	=	0.8

The high set is typically set at 8 times rated current as this ensures HV AC protection will discriminate with faults covered by the LV protection. However, it has been known for the high set to be set to 4, or 5 times where there is more confidence in the AC protection.

Use of the thermal element to provide protection between 70% and 160% of rated current could enhance the protection. It is also common practice to provide restricted earth fault protection for the transformer feeding the rectifier. See the appropriate section dealing with restricted earth fault protection.

2.2 Directional Overcurrent Protection

If fault current can flow in both directions through a relay location, it is necessary to add directionality to the overcurrent relays in order to obtain correct co-ordination. Typical systems that require such protection are parallel feeders (both plain and transformer) and ring main systems, each of which are relatively common in distribution networks.

Two common applications, which require the use of directional relays, are considered in the following sections.

2.2.1 Parallel Feeders

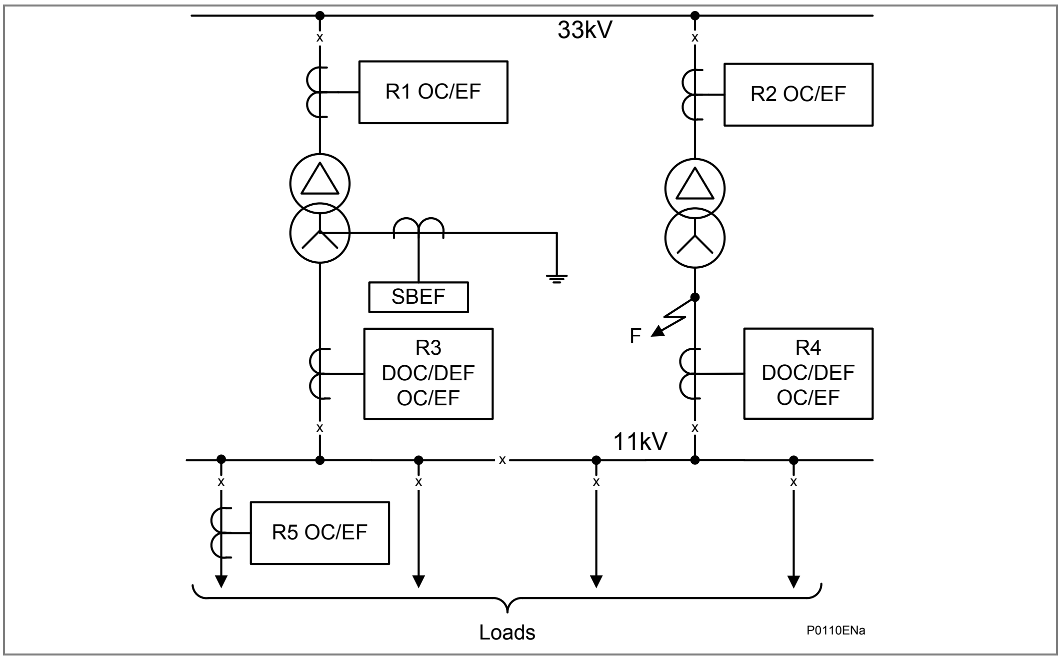


Figure 3 - Typical distribution system using parallel transformers

Figure 3 shows a typical distribution system utilizing parallel power transformers. In such an application, a fault at ‘F’ could result in the operation of both R3 and R4 relays and the subsequent loss of supply to the 11kV busbar. Hence, with this system configuration, it is necessary to apply directional relays at these locations set to 'look into' their respective transformers. These relays should co-ordinate with the non-directional relays, R1 and R2; hence ensuring discriminative relay operation during such fault conditions.

In such an application, relays R3 and R4 may commonly require non-directional overcurrent protection elements to provide protection to the 11kV busbar, in addition to providing a back-up function to the overcurrent relays on the outgoing feeders (R5).

When applying the P145 relays in the above application, stage 1 of the overcurrent protection of relays R3 and R4 would be set non-directional and time graded with R5, using an appropriate time delay characteristic. Stage 2 could then be set directional, looking back into the transformer, also having a characteristic which provided correct co-ordination with R1 and R2 IDMT or DT characteristics are selectable for both stages 1 and 2 and directionality of each of the overcurrent stages is set in cell "I> Direction".

Note	*The principles previously outlined for the parallel transformer application are equally applicable for plain feeders that are operating in parallel.*

2.2.2 Ring Main Arrangements

A typical ring main with associated overcurrent protection is shown in Figure 4.

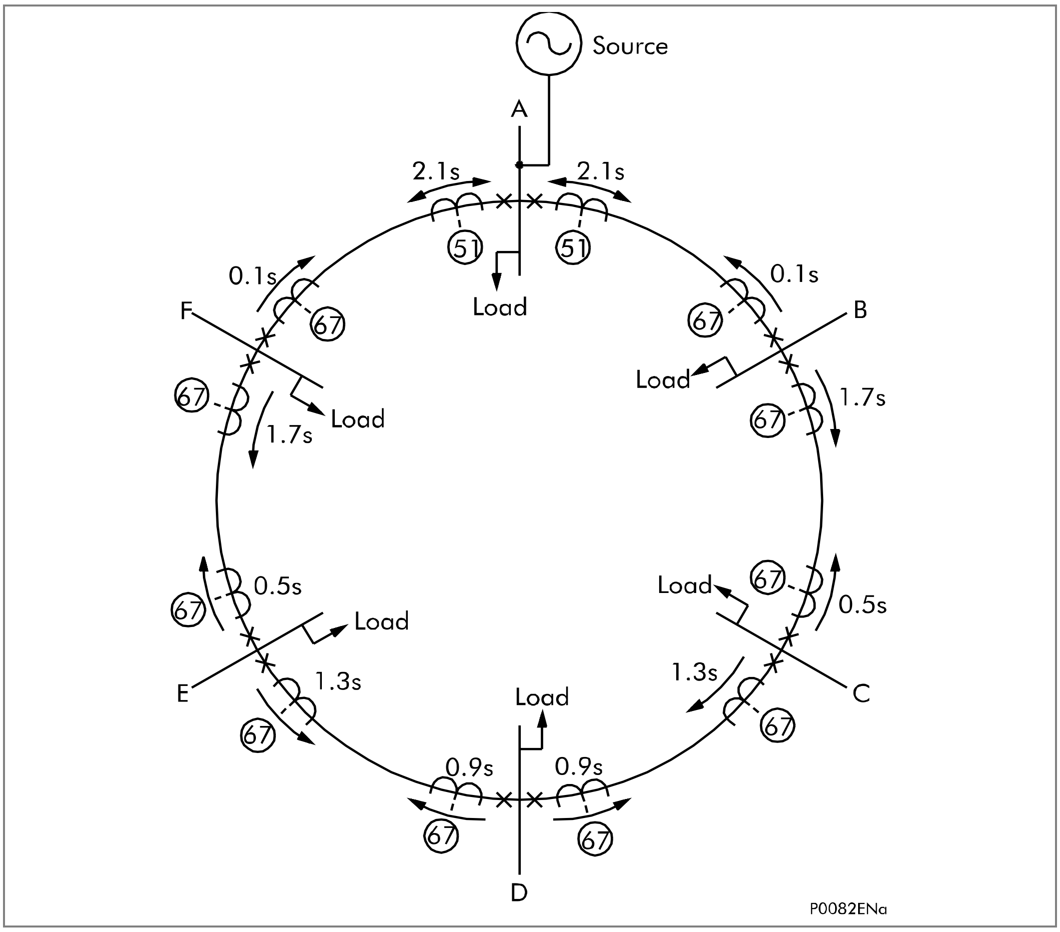


Figure 4 - Typical ring main with associated overcurrent protection

As with the previously described parallel feeder arrangement, it can be seen that current may flow in either direction through the various relay locations. Therefore, directional overcurrent relays are again required in order to provide a discriminative protection system.

The normal grading procedure for overcurrent relays protecting a ring main circuit is to open the ring at the supply point and to grade the relays first clockwise and then anti-clockwise. The arrows shown at the various relay locations in Figure 4 depict the direction for forward operation of the respective relays, i.e. in the same way as for parallel feeders, the directional relays are set to look into the feeder that they are protecting. Figure 4 shows typical relay time settings (if definite time co-ordination was employed), from which it can be seen that any faults on the inter-connectors between stations are cleared discriminatively by the relays at each end of the feeder.

Again, any of the four overcurrent stages may be configured to be directional and co-ordinated as per the previously outlined grading procedure, noting that IDMT characteristics are only selectable on the first two stages.

2.2.3 Setting Guidelines

The applied current settings for directional overcurrent relays are dependent upon the application in question. In a parallel feeder arrangement, load current is always flowing in the non-operate direction. Hence, the relay current setting may be less than the full load rating of the circuit; typically 50% of In.

Note	*The minimum setting that may be applied has to take into account the thermal rating of the relay. Some electro-mechanical directional overcurrent relays have continuous withstand ratings of only twice the applied current setting and hence 50% of rating was the minimum setting that could be applied. With the P145, the continuous current rating is 4 x rated current and so it is possible to apply much more sensitive settings if required. However, there are minimum safe current setting constraints to be observed when applying directional overcurrent protection at the receiving-ends of parallel feeders. The minimum safe settings to ensure that there is no possibility of an unwanted trip during clearance of a source fault are as follows for linear system load:*

Parallel plain feeders:

Set>50% Prefault load current

Parallel transformer feeders:

Set>87% Prefault load current

When the above setting constraints are infringed, independent-time protection is more likely to issue an unwanted trip during clearance of a source fault than dependent-time protection.

Where the above setting constraints are unavoidably infringed, secure phase fault protection can be provided with relays which have 2-out-of-3 directional protection tripping logic.

In a ring main application, it is possible for load current to flow in either direction through the relaying point. Hence, the current setting must be above the maximum load current, as in a standard non-directional application.

The required characteristic angle settings for directional relays will differ depending on the exact application in which they are used. Recommended characteristic angle settings are as follows:

- Plain feeders, or applications with an earthing point (zero sequence source) behind the relay location, should utilize a +30° RCA setting
- Transformer feeders, or applications with a zero sequence source in front of the relay location, should utilize a +45° RCA setting

Whilst it is possible to set the RCA to exactly match the system fault angle, it is recommended that the above guidelines are adhered to, as these settings have been shown to provide satisfactory performance and stability under a wide range of system conditions.

2.3 Thermal Overload Protection

Thermal overload protection can be used to prevent electrical plant from operating at temperatures in excess of the designed maximum withstand. Prolonged overloading causes excessive heating, which may result in premature ageing of the insulation, or in extreme cases, insulation failure.

The relay incorporates a current based thermal replica, using rms load current to model heating and cooling of the protected plant. The element can be set with both alarm and trip stages.

The heat generated within an item of plant, such as a cable or a transformer, is the resistive loss (I2R x t). Thus, heating is directly proportional to current squared. The thermal time characteristic used in the relay is therefore based on current squared, integrated over time. The relay automatically uses the largest phase current for input to the thermal model.

Equipment is designed to operate continuously at a temperature corresponding to its full load rating, where heat generated is balanced with heat dissipated by radiation etc. Over-temperature conditions therefore occur when currents in excess of rating are allowed to flow for a period of time. It can be shown that temperatures during heating follow exponential time constants and a similar exponential decrease of temperature occurs during cooling.

2.3.1 Setting Guidelines

2.3.1.1 Single Time Constant Characteristic

The current setting is calculated as:

Thermal Trip = Permissible continuous loading of the plant item/CT ratio.

Typical time constant values are given in in the following tables. The relay setting, "Time Constant τ", is in minutes.

Paper insulated lead sheathed cables or polyethylene insulated cables, laid above ground or in conduits:

CSA mm^2	6 - 11 kV	22 kV	33 kV	66 kV
25 – 50	10	15	40	–
70 – 120	15	25	40	60
150	25	40	40	60
185	25	40	60	60
240	40	40	60	60
300	40	60	60	90

Typical time constant values

Other plant items:

The following table shows it in minutes, for different cable rated voltages and conductor cross-sectional areas:

	Time Constant τ (Minutes)	Limits
Dry-type Transformers	40 60 - 90	Rating <400 kVA Rating 400 - 800 kVA
Air-core Reactors	40	
Capacitor Banks	10	
Overhead Lines	10	Cross section ≥100 mm2 Cu or 150mm2 Al
Busbars	60	

Typical time constant values

An alarm can be raised on reaching a thermal state corresponding to a percentage of the trip threshold. A typical setting might be "Thermal Alarm" = 70% of thermal capacity.

2.3.1.2 Dual Time Constant Characteristic

The current setting is calculated as:

Thermal Trip = Permissible continuous loading of the transformer / CT ratio.

Typical time constant values are shown in the following table:

An alarm can be raised on reaching a thermal state corresponding to a percentage of the trip threshold. A typical setting might be ‘Thermal Alarm’ = 70% of thermal capacity.

Note	*The thermal time constants given in the above tables are typical only. Reference should always be made to the plant manufacturer for accurate information.*

	τ1 (minutes)	τ2 (minutes)	Limits
Oil-filled transformer	5	120	Rating 400 - 1600 kVA

2.4 Earth Fault (EF) Protection

The fact that both EF1 and EF2 elements may be enabled in the relay at the same time leads to a number of applications advantages. For example, the parallel transformer application previously shown in 0 requires directional earth fault protection at locations R3 and R4, to provide discriminative protection. However, in order to provide back-up protection for the transformer, busbar and other downstream earth fault devices, Standby Earth Fault (SBEF) protection is also commonly applied. This function has traditionally been fulfilled by a separate earth fault relay, fed from a single CT in the transformer earth connection. The EF1 and EF2 elements of the P145 relay may be used to provide both the Directional Earth Fault (DEF) and SBEF functions, respectively.

Where a Neutral Earthing Resistor (NER) is used to limit the earth fault level to a particular value, it is possible that an earth fault condition could cause a flashover of the NER and hence a dramatic increase in the earth fault current. For this reason, it may be appropriate to apply two stage SBEF protection. The first stage should have suitable current and time characteristics which co-ordinate with downstream earth fault protection. The second stage may then be set with a higher current setting but with zero time delay; hence providing fast clearance of an earth fault which gives rise to an NER flashover.

The remaining two stages are available for customer specific applications.

The previous examples relating to transformer feeders utilize both EF1 and EF2 elements. In a standard feeder application requiring three-phase overcurrent and earth fault protection, only one of the earth fault elements would need to be applied. If EF1 were to be used, the connection would be a standard arrangement of the three-phase currents feeding into the phase inputs, with the EF1 input connected into the residual path (this is shown in Figure 5). In this application, EF2 should be disabled in the menu. Alternatively, where the EF2 element is used, no residual connection of the CT’s will be required.

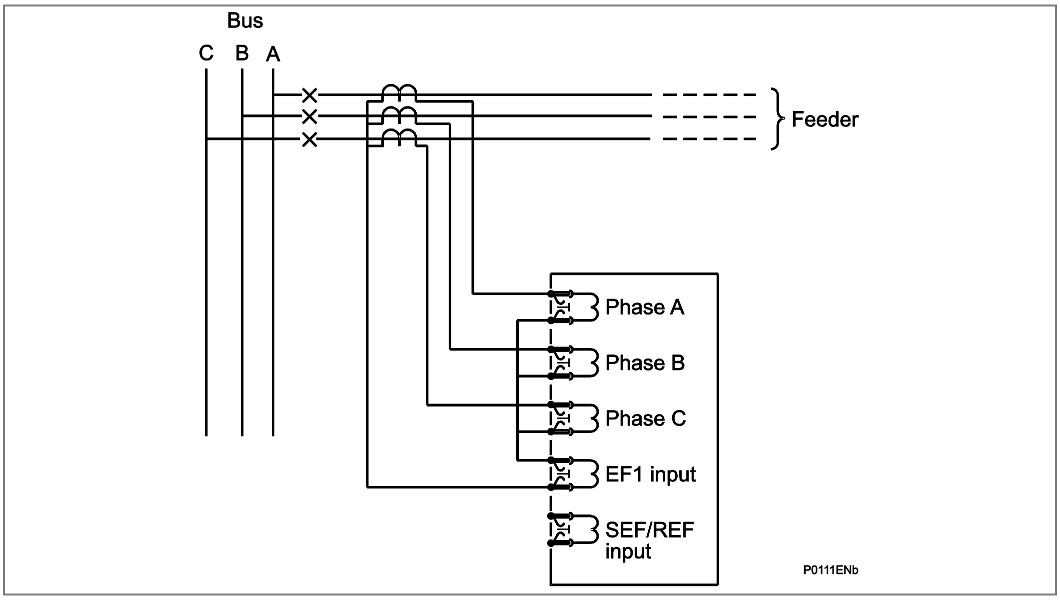


Figure 5 - P141/P142/P143/P145 - three-phase overcurrent & residually connected earth fault protection

2.4.1 Sensitive Earth Fault (SEF) Protection Element

Sensitive Earth Fault (SEF) would normally be fed from a Core Balance Current Transformer (CBCT) mounted around the three phases of the feeder cable. However, care must be taken in the positioning of the CT with respect to the earthing of the cable sheath. See below.

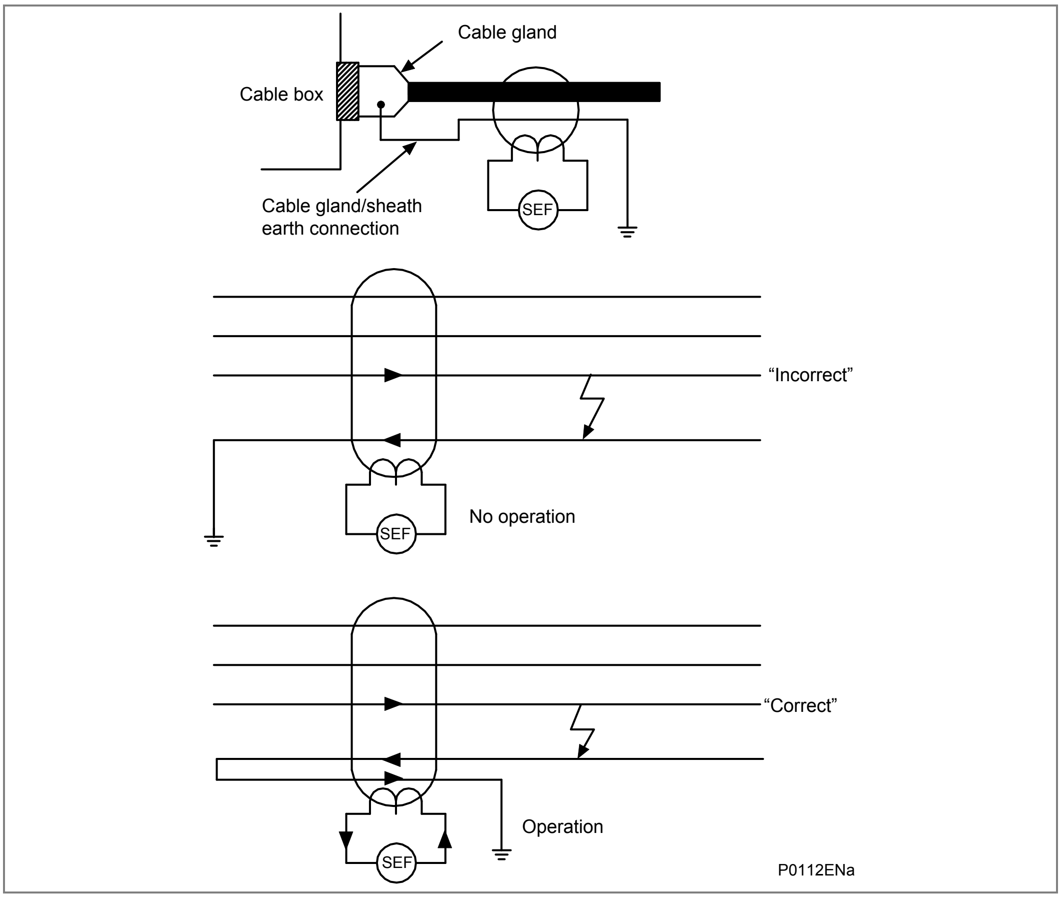


Figure 6 - Positioning of core balance current transformers

As can be seen from the above illustration, if the cable sheath is terminated at the cable gland and earthed directly at that point, a cable fault (from phase to sheath) will not result in any unbalance current in the core balance CT. Hence, prior to earthing, the connection must be brought back through the CBCT and earthed on the feeder side. This then ensures correct relay operation during earth fault conditions.

2.5 Directional Earth Fault (DEF) Protection

As stated in the previous sections, each of the four stages of EF1, EF2 and SEF protection may be set to be directional if required. Consequently, as with the application of directional overcurrent protection, a suitable voltage supply is required by the relay to provide the necessary polarization.

2.5.1 General Setting Guidelines for DEF Applied to Earthed Systems

When setting the Relay Characteristic Angle (RCA) for the directional overcurrent element, a positive angle setting was specified. With DEF, the residual current under fault conditions lies at an angle lagging the polarizing voltage. Hence, negative RCA settings are required for DEF applications. This is set in cell "I>Char Angle" in the relevant earth fault menu.

The following angle settings are recommended for a residual voltage polarized relay:

Resistance earthed systems	=	0°
Distribution systems (solidly earthed)	=	–45°
Transmission systems (solidly earthed)	=	–60°

For negative sequence polarization, the RCA settings must be based on the angle of the nps source impedance, much the same as for residual polarizing. Typical settings would be:

Distribution systems	–45°
Transmission systems	–60°

2.5.2 Application to Insulated Systems

Operational advantages may be gained by the use of insulated systems. However, it is still vital that detection of the fault is achieved. This is not possible by means of standard current operated earth fault protection. One possibility for fault detection is by means of a residual overvoltage device. This functionality is included within the P145 relays and is detailed in section 2.7. However, fully discriminative earth fault protection on this type of system can only be achieved by the application of a sensitive earth fault element. This type of relay is set to detect the resultant imbalance in the system charging currents that occurs under earth fault conditions. It is therefore essential that a core balance CT be used for this application.

This eliminates the possibility of spill current that may arise from slight mismatches between residually connected line CTs. It also enables a much lower CT ratio to be applied, thereby allowing the required protection sensitivity to be more easily achieved.

When considering the fault distribution on an insulated system for a C phase fault, from 0, it can be seen that the relays on the healthy feeders see the unbalance in the charging currents for their own feeder. The relay on the faulted feeder, however, sees the charging current from the rest of the system (IH1 and IH2 in this case), with it's own feeders charging current (IH3) becoming cancelled out. The phasor diagrams shown in Figure 8 further illustrate this.

Referring to the phasor diagram, it can be seen that the C phase to earth fault causes the voltages on the healthy phases to rise by a factor of √3. The A phase charging current (Ia1), is then shown to be leading the resultant A phase voltage by 90°. Likewise, the B phase charging current leads the resultant Vb by 90°.

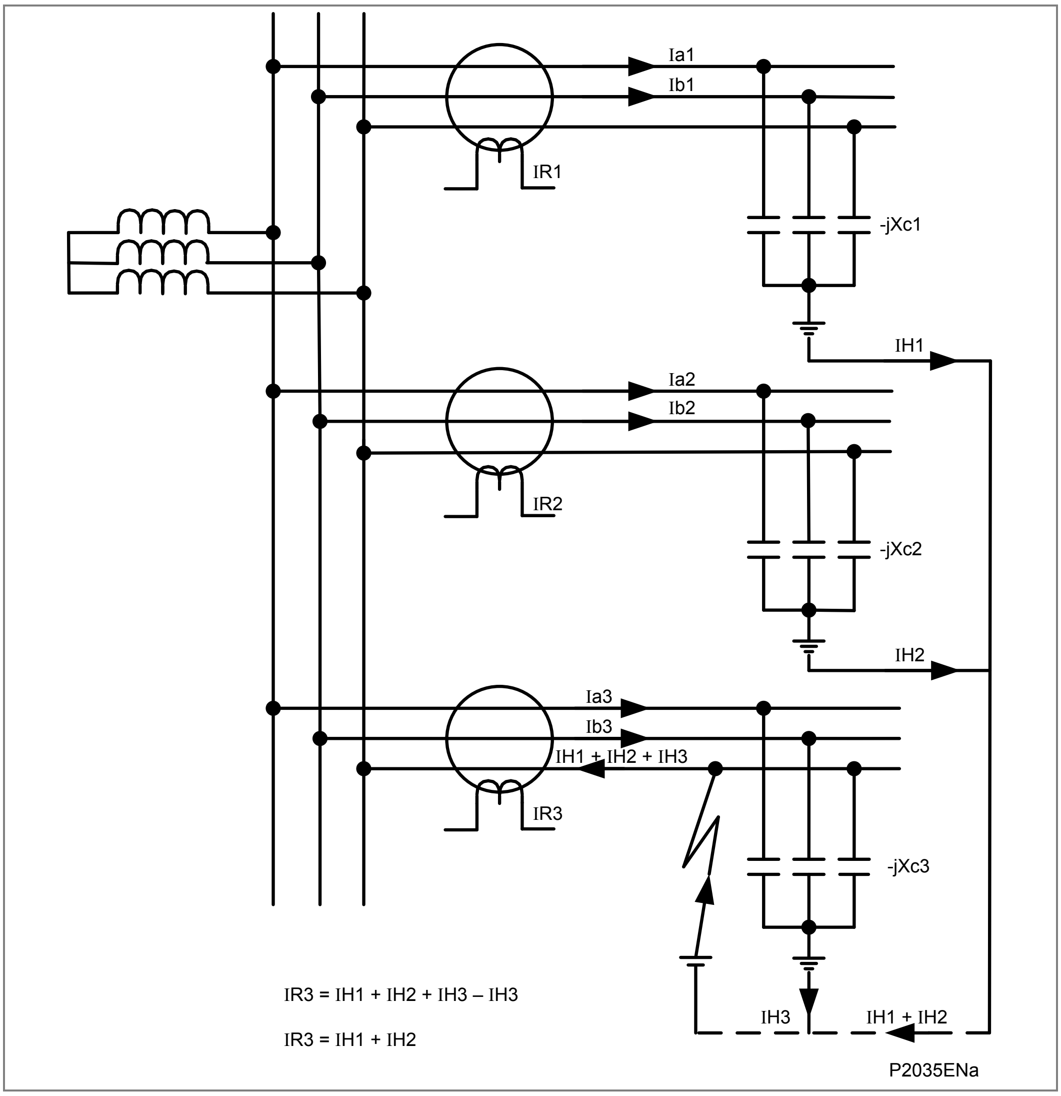


Figure 7 - Current distribution in an insulated system with C phase fault

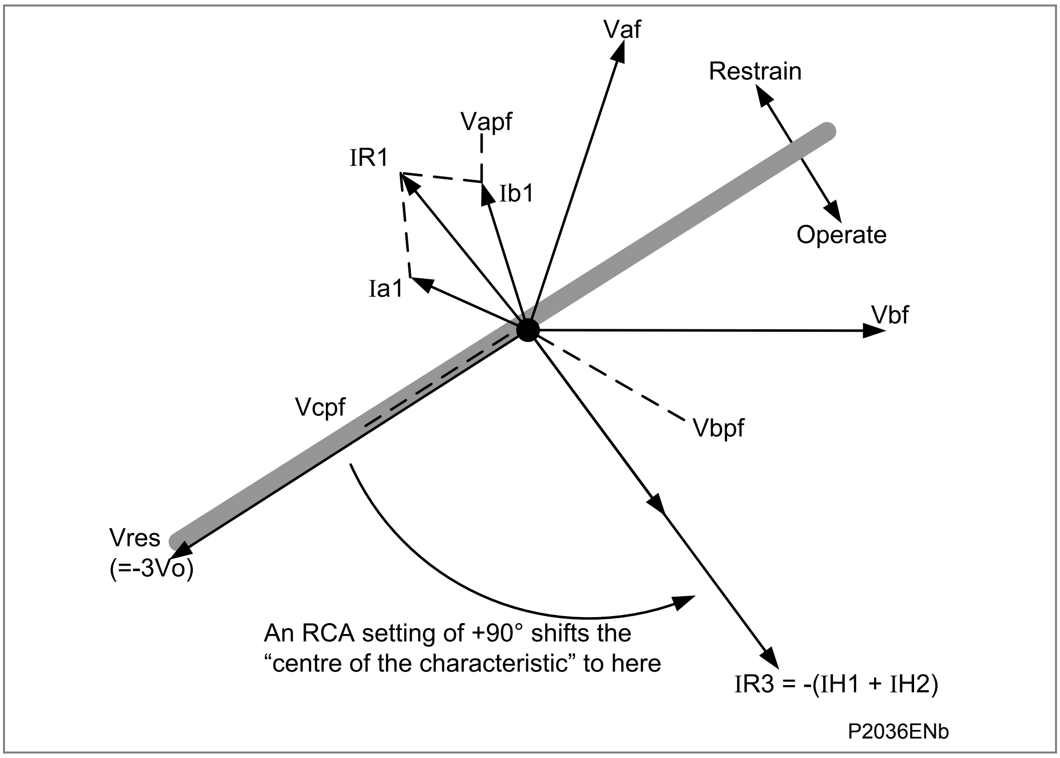


Figure 8 - Phasor diagrams for insulated system with C phase fault

The unbalance current detected by a core balance current transformer on the healthy feeders can be seen to be the vector addition of Ia1 and Ib1, giving a residual current which lies at exactly 90° lagging the polarizing voltage (–3Vo). As the healthy phase voltages have risen by a factor of √3, the charging currents on these phases will also be √3 times larger than their steady state values. Therefore, the magnitude of residual current, IR1, is equal to 3 x the steady state per phase charging current.

The phasor diagrams indicate that the residual currents on the healthy and faulted feeders, IR1 and IR3 respectively, are in anti-phase. A directional element could therefore be used to provide discriminative earth fault protection.

If the polarizing voltage of this element, equal to –3Vo, is shifted through +90°, the residual current seen by the relay on the faulted feeder will lie within the operate region of the directional characteristic and the current on the healthy feeders will fall within the restrain region.

As previously stated, the required characteristic angle setting for the SEF element when applied to insulated systems, is +90°. It should be noted though, that this recommended setting corresponds to the relay being connected such that it's direction of current flow for operation is from the source busbar towards the feeder, as would be the convention for a relay on an earthed system. However, if the forward direction for operation were set as being from the feeder into the busbar, (which some utilities may standardize on), then a –90° RCA would be required. The correct relay connections to give a defined direction for operation are shown on the relay connection diagram.

Note	*Discrimination can be provided without the need for directional control. This can only be achieved if it is possible to set the relay in excess of the charging current of the protected feeder and below the charging current for the rest of the system.*

2.5.3 Setting Guidelines - Insulated Systems

As has been previously shown, the residual current detected by the relay on the faulted feeder is equal to the sum of the charging currents flowing from the rest of the system. Further, the addition of the two healthy phase charging currents on each feeder gives a total charging current which has a magnitude of three times the per phase value. Therefore, the total unbalance current detected by the relay is equal to three times the per phase charging current of the rest of the system. A typical relay setting may therefore be in the order of 30% of this value, i.e. equal to the per phase charging current of the remaining system. Practically though, the required setting may well be determined on site, where suitable settings can be adopted based upon practically obtained results. The use of the P145 relays' comprehensive measurement and fault recording facilities may prove useful in this respect.

2.5.4 Application to Petersen Coil Earthed Systems

Power systems are usually earthed in order to limit transient overvoltages during arcing faults and also to assist with detection and clearance of earth faults. Impedance earthing has the advantage of limiting damage incurred by plant during earth fault conditions and also limits the risk of explosive failure of switchgear, which is a danger to personnel. In addition, it limits touch and step potentials at a substation or in the vicinity of an earth fault.

If a high impedance device is used for earthing the system, or the system is unearthed, the earth fault current will be reduced but the steady state and transient overvoltages on the sound phases can be very high. Consequently, it is generally the case that high impedance earthing will only be used in low/medium voltage networks in which it does not prove too costly to provide the necessary insulation against such overvoltages. Higher system voltages would normally be solidly earthed or earthed via a low impedance.

A special case of high impedance earthing via a reactor occurs when the inductive earthing reactance is made equal to the total system capacitive reactance to earth at system frequency. This practice is widely referred to as Petersen (or resonant) Coil Earthing. With a correctly tuned system, the steady state earth fault current will be zero, so that arcing earth faults become self-extinguishing. Such a system can, if designed to do so, be run with one phase earthed for a long period until the cause of the fault is identified and rectified.

Figure 9 shows a source of generation earthed through a Petersen Coil, with an earth fault applied on the A Phase. Under this situation, it can be seen that the A phase shunt capacitance becomes short-circuited by the fault. Consequently, the calculations show that if the reactance of the earthing coil is set correctly, the resulting steady state earth fault current will be zero.

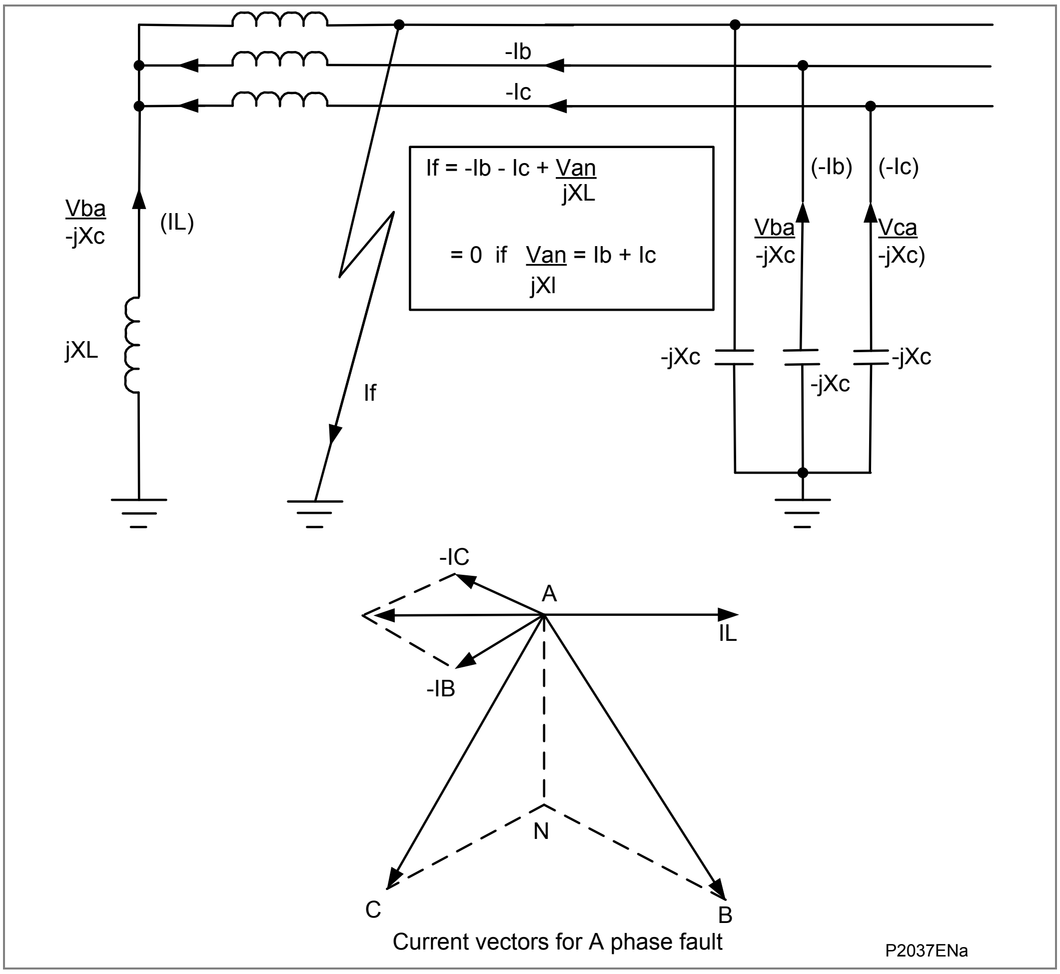


Figure 9 - Current distribution in Petersen Coil earthed system

Figure 9 shows a radial distribution system having a source that is earthed via a Petersen Coil. Three outgoing feeders are present, the lower of which has a phase to earth fault applied on the C phase.

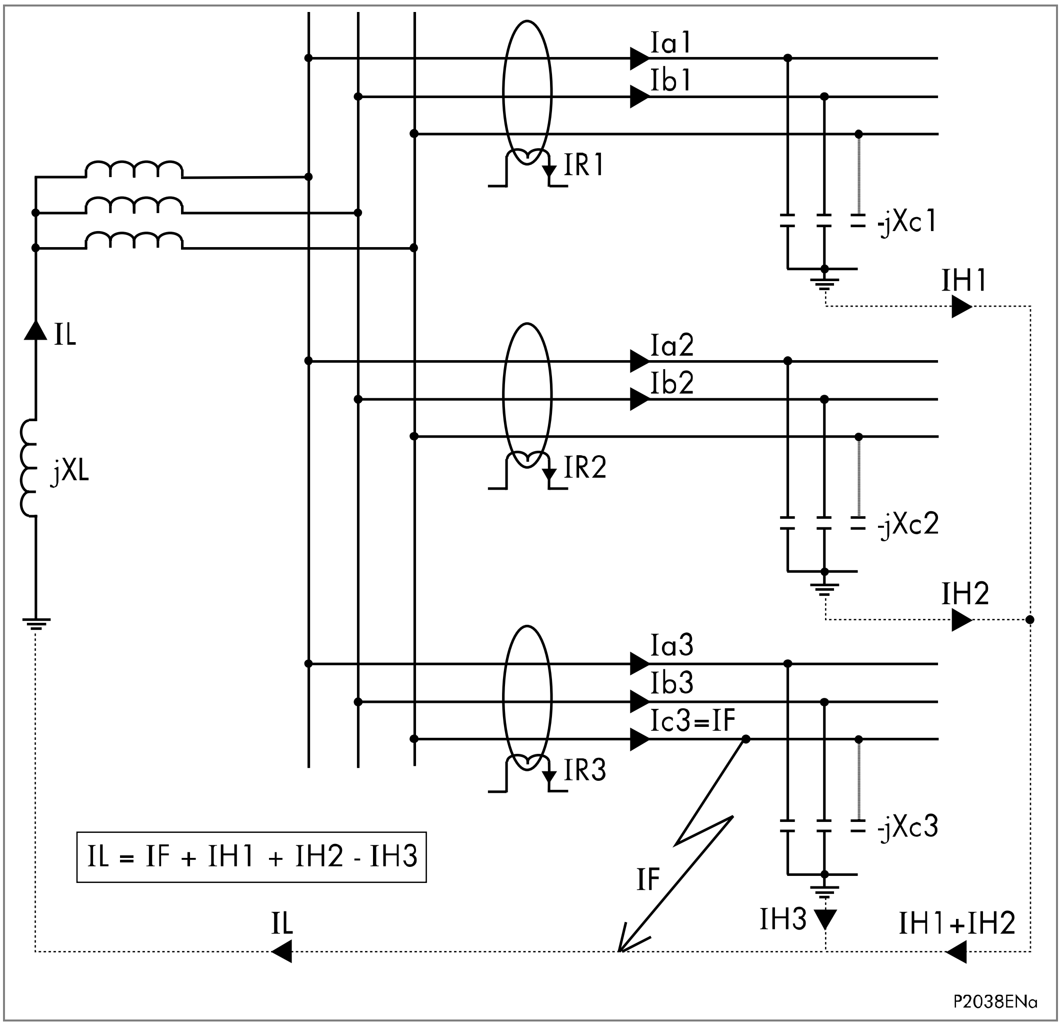


Figure 10 - Distribution of currents during a C phase to earth fault

Figure 11 (a, b and c) show vector diagrams for the previous system, assuming that it is fully compensated (i.e. coil reactance fully tuned to system capacitance), in addition to assuming a theoretical situation where no resistance is present either in the earthing coil or in the feeder cables.

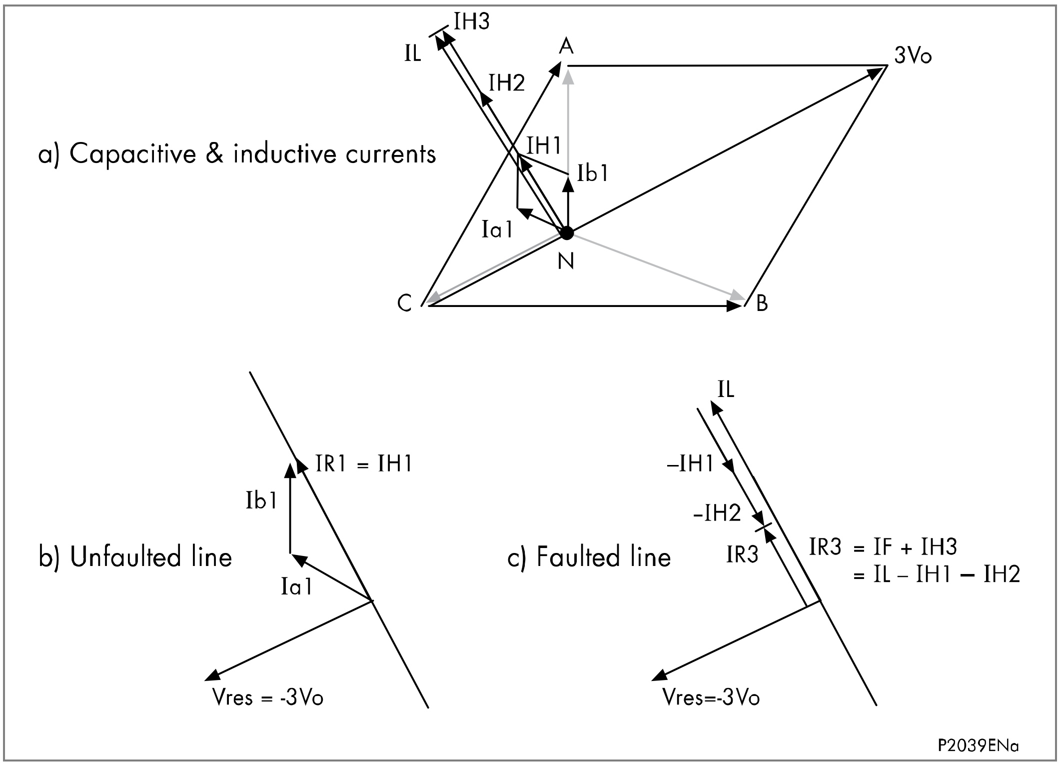


Figure 11 - Theoretical case - no resistance present in XL or XC

Referring to the vector diagram illustrated in Figure 11a, it can be seen that the C phase to earth fault causes the voltages on the healthy phases to rise by a factor of √3. The A phase charging currents (Ia1, Ia2 and Ia3), are then shown to be leading the resultant A phase voltage by 90° and likewise for the B phase charging currents with respect to the resultant Vb.

The unbalance current detected by a core balance current transformer on the healthy feeders can be seen to be a simple vector addition of Ia1 and Ib1, giving a residual current which lies at exactly 90° lagging the residual voltage (Figure 11b). Clearly, as the healthy phase voltages have risen by a factor of √3, the charging currents on these phases will also be √3 times larger than their steady state values. Therefore, the magnitude of residual current, IR1, is equal to 3 x the steady state per phase charging current.

Note	*The actual residual voltage used as a reference signal for directional earth fault relays is phase shifted by 180° and is therefore shown as –3Vo in the vector diagrams. This phase shift is automatically introduced within the P145 relays.* *On the faulted feeder, the residual current is the addition of the charging current on the healthy phases (IH3) plus the fault current (IF). The net unbalance is therefore equal to IL-IH1-IH2, as shown in Figure 11c.* *This situation may be more readily observed by considering the zero sequence network for this fault condition. This is depicted in Figure 12.*

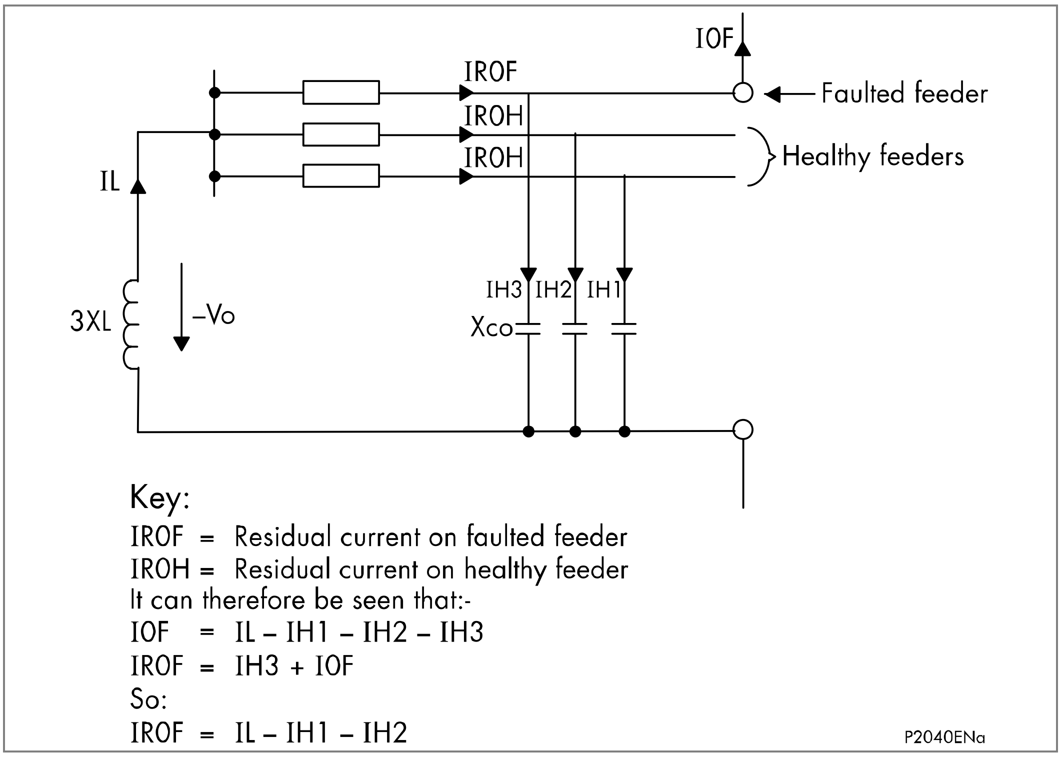


Figure 12 - Zero sequence network showing residual currents

In comparing the residual currents occurring on the healthy and on the faulted feeders (Figure 11b and Figure 11c), it can be seen that the currents would be similar in both magnitude and phase; hence it would not be possible to apply a relay which could provide discrimination.

However, as previously stated, the scenario of no resistance being present in the coil or feeder cables is purely theoretical. Further consideration therefore needs to be given to a practical application in which the resistive component is no longer ignored - consider Figure 13.

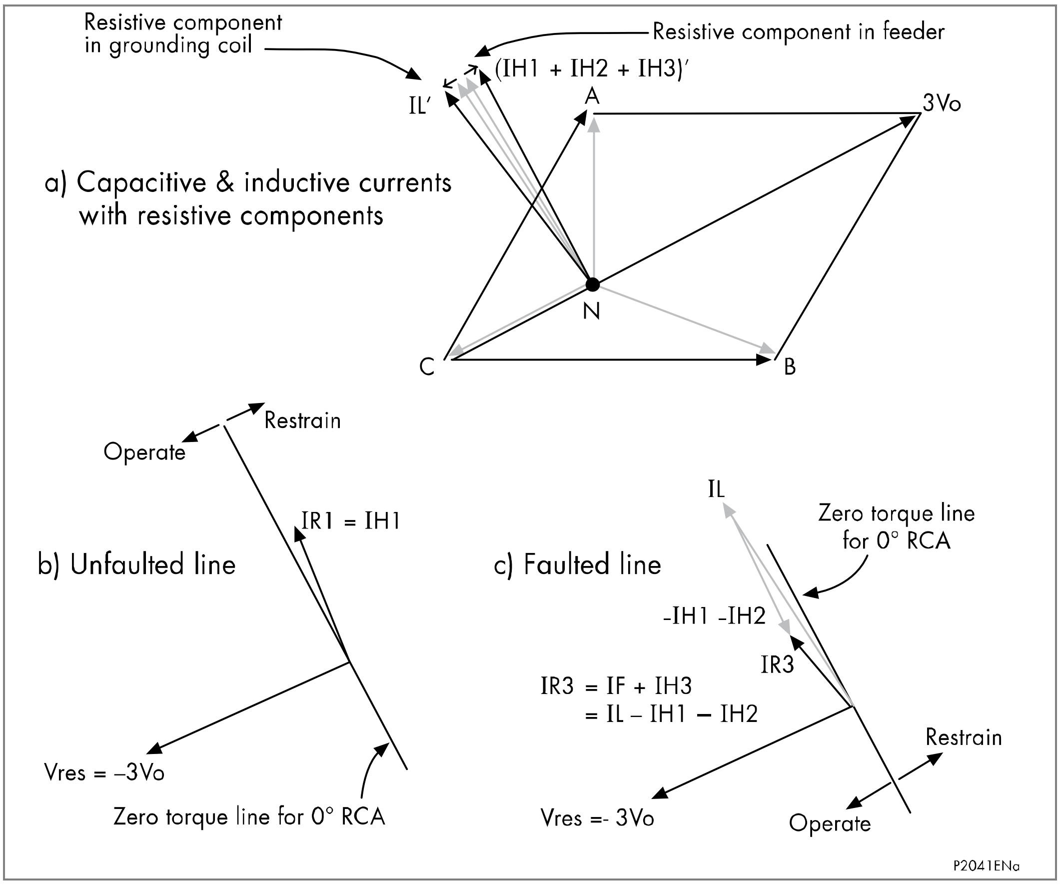


Figure 13 - Practical case - resistance present in XL and Xc

Figure 13a again shows the relationship between the capacitive currents, coil current and residual voltage. It can now be seen that due to the presence of resistance in the feeders, the healthy phase charging currents are now leading their respective phase voltages by less than 90°. In a similar manner, the resistance present in the earthing coil has the effect of shifting the current, IL, to an angle less than 90° lagging. The result of these slight shifts in angles can be seen in Figure 13b and Figure 13c.

The residual current now appears at an angle in excess of 90° from the polarizing voltage for the unfaulted feeder and less than 90° on the faulted feeder. Hence, a directional relay having a characteristic angle setting of 0° (with respect to the polarizing signal of -3Vo) could be applied to provide discrimination. i.e. the healthy feeder residual current would appear within the restrain section of the characteristic but the residual current on the faulted feeder would lie within the operate region - as shown in Figure 12b and Figure 12c.

In practical systems, it may be found that a value of resistance is purposely inserted in parallel with the earthing coil. This serves two purposes; one is to actually increase the level of earth fault current to a more practically detectable level and the second is to increase the angular difference between the residual signals; again to aid in the application of discriminating protection.

2.5.5 Applications to Compensated Networks

2.5.5.1 Required Relay Current and Voltage Connections

Referring to the relevant application diagram for the P145 Relay, it should be applied such that it’s direction for forward operation is looking down into the protected feeder (away from the busbar), with a 0° RCA setting.

2.5.5.2 Calculation of Required Relay Settings

As has been previously shown, for a fully compensated system, the residual current detected by the relay on the faulted feeder is equal to the coil current minus the sum of the charging currents flowing from the rest of the system. Further, as stated in the previous section, the addition of the two healthy phase charging currents on each feeder gives a total charging current which has a magnitude of three times the steady state per phase value. Therefore, for a fully compensated system, the total unbalance current detected by the relay is equal to three times the per phase charging current of the faulted circuit. A typical relay setting may therefore be in the order of 30% of this value, i.e. equal to the per phase charging current of the faulted circuit. Practically though, the required setting may well be determined on site, where system faults can be applied and suitable settings can be adopted based upon practically obtained results.

It should be noted that in most situations, the system will not be fully compensated and consequently a small level of steady state fault current will be allowed to flow. The residual current seen by the relay on the faulted feeder may thus be a larger value, which further emphasizes the fact that relay settings should be based upon practical current levels, wherever possible.

The above also holds true regarding the required Relay Characteristic Angle (RCA) setting. As has been shown earlier, a nominal RCA setting of 0º is required. However, fine-tuning of this setting will require to be carried out on site in order to obtain the optimum setting in accordance with the levels of coil and feeder resistances present. The loading and performance of the CT will also have an effect in this regard. The effect of CT magnetizing current will be to create phase lead of current. Whilst this would assist with operation of faulted feeder relays it would reduce the stability margin of healthy feeder relays. A compromise can therefore be reached through fine adjustment of the RCA. This is adjustable in 1° steps on the P145 relays.

2.6 Restricted Earth Fault (REF) Protection

Earth faults occurring on a transformer winding or terminal may be of limited magnitude, either due to the impedance present in the earth path or by the percentage of transformer winding that is involved in the fault. It is common to apply standby earth fault protection fed from a single CT in the transformer earth connection - this provides time-delayed protection for a transformer winding or terminal fault. In general, particularly as the size of the transformer increases, it becomes unacceptable to rely on time delayed protection to clear winding or terminal faults as this would lead to an increased amount of damage to the transformer. A common requirement is therefore to provide instantaneous phase and earth fault protection. Applying differential protection across the transformer may fulfill these requirements. However, an earth fault occurring on the LV winding, particularly if it is of a limited level, may not be detected by the differential relay, as it is only measuring the corresponding HV current. Therefore, instantaneous protection that is restricted to operating for transformer earth faults only is applied. This is referred to as Restricted Earth Fault (REF) Protection.

It can also be referred to as Restricted, or Balanced, Earth Fault (REF or BEF) Protection. The BEF terminology is usually used when the protection is applied to a delta winding.

When applying differential protection such as REF, some suitable means must be employed to give the protection stability under external fault conditions, therefore ensuring that relay operation only occurs for faults on the transformer winding / connections.

Two methods are commonly used; bias or high impedance. The biasing technique operates by measuring the level of through current flowing and altering the relay sensitivity accordingly. The high impedance technique ensures that the relay circuit is of sufficiently high impedance such that the differential voltage that may occur under external fault conditions is less than that required to drive setting current through the relay.

The REF protection in the relays can be configured to operate as high impedance element. Following sections describe the application of the relay for high impedance element.

Note	*The high impedance REF element of the relay shares the same CT input as the SEF protection. Hence, only one of these elements may be selected.*

Note	*The low impedance REF element does not use the SEF input and so may be selected at the same time.*
Note	*CT requirements for REF protection are included in the Current Transformer (CT) Requirements section.*

2.6.1 Biased Differential Protection

Figure 14 shows the appropriate relay connections for the P145 relay applied for biased REF protection.

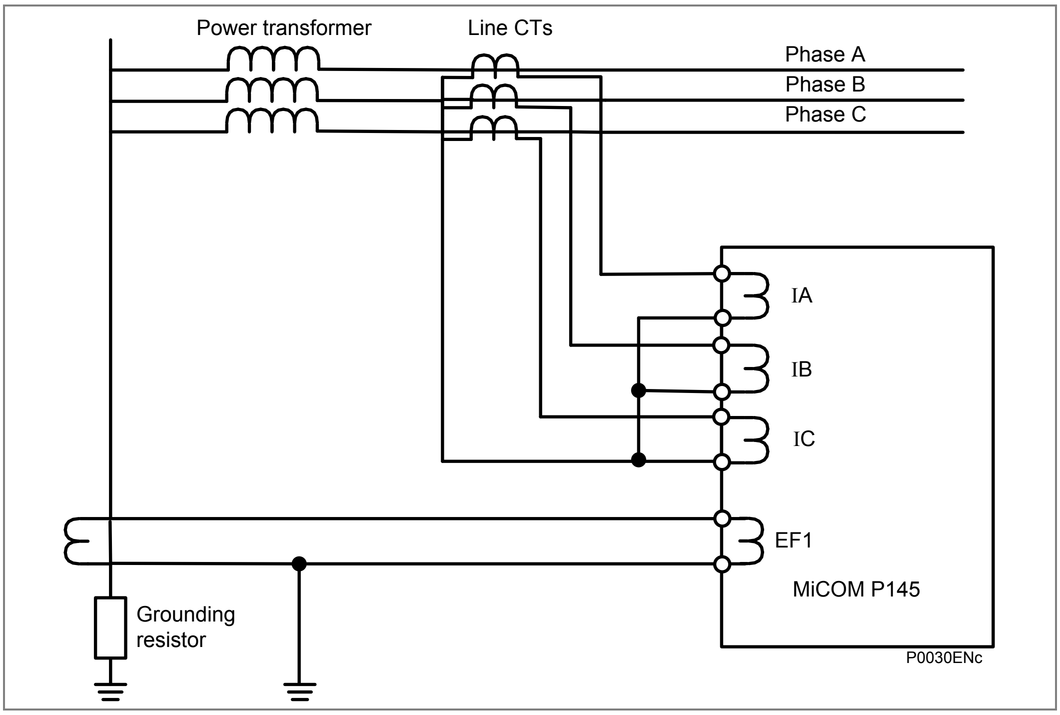


Figure 14 - Relay connections for biased REF protection

As can be seen in Figure 14, the three line CTs are connected to the three-phase CTs in the normal manner. The neutral CT is then connected to the EF1 CT input. These currents are then used internally to derive both a bias and a differential current quantity for use by the low impedance REF protection. The advantage of this mode of connection is that the line and neutral CT's are not differentially connected and so the neutral CT can also be used to drive the EF1 protection to provide Standby Earth Fault Protection. Also, no external equipment such as stabilizing resistors or metrosils is required, as is the case with high impedance protection.

2.6.2 Setting Guidelines for Biased REF Protection

As can be seen from Figure 13 in the Operation section (P14x/EN OP), two bias settings are provided in the REF characteristic of the P145. The k1 level of bias is applied up to through currents of Is2, which is normally set to the rated current of the transformer. k1 should normally be set to 0% to give optimum sensitivity for internal faults. However, if any CT mismatch is present under normal conditions, then k1 may be increased accordingly, to compensate.

k2 bias is applied for through currents above Is2 and would typically be set to 150%.

2.6.3 Setting Guidelines for High Impedance REF

From the **SEF/REF options** cell, **Hi Z REF** must be selected to enable this protection. The only setting cell then visible is **IREF>Is**, which may be programmed with the required differential current setting. This would typically be set to give a primary operating current of either 30% of the minimum earth fault level for a resistance earthed system or between 10 and 60% of rated current for a solidly earthed system.

The primary operating current (Iop) will be a function of the current transformer ratio, the relay operating current (IREF>Is1), the number of current transformers in parallel with a relay element (n) and the magnetizing current of each current transformer (Ie) at the stability voltage (Vs). This relationship can be expressed in three ways:

1. To determine the maximum current transformer magnetizing current to achieve a specific primary operating current with a particular relay operating current:

$$I_e < \frac{1}{n} \times \left(\frac{I_{op}}{\text{CT ratio}} - I\ REF > I_s \right)$$

2. To determine the minimum relay current setting to achieve a specific primary operating current with a given current transformer magnetizing current.

$$[\ I\ REF > I_s\ ] < \left(\frac{I_{op}}{\text{CT ratio}} - nI_e \right)$$

3. To express the protection primary operating current for a particular relay operating current and with a particular level of magnetizing current.

$$I_{op} = (\text{CT ratio}) \times (IREF > Is + nI_c)$$

In order to achieve the required primary operating current with the current transformers that are used, a current setting (IREF>Is) must be selected for the high impedance element, as detailed in expression (ii) above. The setting of the Stabilizing Resistor (RST) must be calculated in the following manner, where the setting is a function of the required stability voltage setting (Vs) and the relay current setting (IREF>Is).

$$R_{st} = \frac{V_s}{I_{REF} > I_s} = \frac{I_F\ (R_{CT} + 2_{RL})}{I_{REF} > I_s}$$

Note	*The above formula assumes negligible relay burden.*

The stabilizing resistor that can be supplied is continuously adjustable up to its maximum declared resistance.

2.6.4 Use of METROSIL Non-Linear Resistors

Metrosils are used to limit the peak voltage developed by the current transformers under internal fault conditions, to a value below the insulation level of the current transformers, relay and interconnecting leads, which are normally able to withstand 3000 V peak.

The following formulae should be used to estimate the peak transient voltage that can be produced for an internal fault. The peak voltage produced during an internal fault will be a function of the current transformer kneepoint voltage and the prospective voltage that would be produced for an internal fault if current transformer saturation did not occur.

$$Vp = 2\sqrt{2V_k\,(V_f - V_k)}$$

V_f = $I'f\,(R_{ct} + 2R_L + R_{ST})$

Where:

V_p = Peak voltage developed by the CT under internal fault conditions
V_k = Current transformer kneepoint voltage
V_f = Maximum voltage that would be produced if CT saturation did not occur
I'_f = Maximum internal secondary fault current
R_{ct} = Current transformer secondary winding resistance
R_L = Maximum lead burden from current transformer to relay
R_{ST} = Relay stabilizing resistor

When the value given by the formulae is greater than 3000 V peak, metrosils should be applied. They are connected across the relay circuit and serve the purpose of shunting the secondary current output of the current transformer from the relay in order to prevent very high secondary voltages.

Metrosils are externally mounted and take the form of annular discs. Their operating characteristics follow the expression:

V = $CI^{0.25}$

Where:

V = Instantaneous voltage applied to the non-linear resistor (metrosil)
C = Constant of the non-linear resistor (metrosil)
I = Instantaneous current through the non-linear resistor (metrosil)

With a sinusoidal voltage applied across the metrosil, the RMS current would be approximately 0.52 x the peak current. This current value can be calculated as follows:

$$I(rms) = 0.52\left(\frac{Vs\,(rms) \times \sqrt{2}}{C}\right)^4$$

Where:
Vs(rms) = rms value of the sinusoidal voltage applied across the metrosil.

This is due to the fact that the current waveform through the metrosil is not sinusoidal but appreciably distorted.

For satisfactory application of a non-linear resistor (metrosil), it's characteristic should be such that it complies with the following requirements:

1. At the relay voltage setting, the non-linear resistor (metrosil) current should be as low as possible, but no greater than approximately 30 mA rms for 1 A current transformers and approximately 100 mA rms for 5 A current transformers.
2. At the maximum secondary current, the non-linear resistor (metrosil) should limit the voltage to 1500 V rms or 2120 V peak for 0.25 second. At higher relay voltage settings, it is not always possible to limit the fault voltage to 1500V rms, so higher fault voltages may have to be tolerated.

The following tables show the typical Metrosil types that will be required, depending on relay current rating, REF voltage setting etc.

2.6.4.1 Metrosil Units for Relays with a 1 Amp CT

The Metrosil units with 1 Amp CTs have been designed to comply with the following restrictions:

- At the relay voltage setting, the Metrosil current should be less than 30mA rms.
- At the maximum secondary internal fault current the Metrosil unit should limit the voltage to 1500V rms if possible.

The Metrosil units normally recommended for use with 1Amp CT's are as shown below:

Relay voltage setting	Nominal characteristic		Recommended Metrosil type	
	C	β	Single pole relay	Triple pole relay
Up to 125 V rms 125 to 300 V rms	450 900	0.25 0.25	600 A/S1/S256 600 A/S1/S1088	600 A/S3/1/S802 600 A/S3/1/S1195

Note *Single pole Metrosil units are normally supplied without mounting brackets unless otherwise specified by the customer.*

2.6.4.2 Metrosil Units for Relays with a 5 Amp CT

Metrosil units for relays with a 5 amp CT

These Metrosil units have been designed to comply with the following requirements:

1. At the relay voltage setting, the Metrosil current should be less than 100 mA rms (the actual maximum currents passed by the units shown below their type description.
2. At the maximum secondary internal fault current the Metrosil unit should limit the voltage to 1500 V rms for 0.25 secs. At the higher relay settings, it is not possible to limit the fault voltage to 1500 V rms hence higher fault voltages have to be tolerated (indicated by *, **, ***).
3. The Metrosil units normally recommended for use with 5 Amp CTs and single pole relays are as shown in the following table:

Secondary internal fault current	Recommended Metrosil type			
	Relay voltage setting			
Amps rms	Up to 200 V rms	250 V rms	275 V rms	300 V rms
50 A	600 A/S1/S1213 C = 540/640 35 mA rms	600 A/S1/S1214 C = 670/800 40 mA rms	600 A/S1/S1214 C =670/800 50 mA rms	600 A/S1/S1223 C = 740/870* 50 mA rms
100 A	600 A/S2/P/S1217 C = 470/540 70 mA rms	600 A/S2/P/S1215 C = 570/670 75 mA rms	600 A/S2/P/S1215 C =570/670 100 mA rms	600 A/S2/P/S1196 C =620/740* 100 mA rms
150 A	600 A/S3/P/S1219 C = 430/500 100 mA rms	600 A/S3/P/S1220 C = 520/620 100 mA rms	600 A/S3/P/S1221C = 570/670** 100 mA rms	600 A/S3/P/S1222C =620/740*** 100 mA rm
	Note:	*2400 V peak	**2200 V peak	***2600 V peak

In some situations single disc assemblies may be acceptable, contact Schneider Electric for detailed applications.

Note 1	*The Metrosil units recommended for use with 5 Amp CTs can also be applied for use with triple pole relays and consist of three single pole units mounted on the same central stud but electrically insulated from each other. To order these units please specify "Triple pole Metrosil type", followed by the single pole type reference.*
Note 2	*Metrosil units for higher relay voltage settings and fault currents can be supplied if required.*

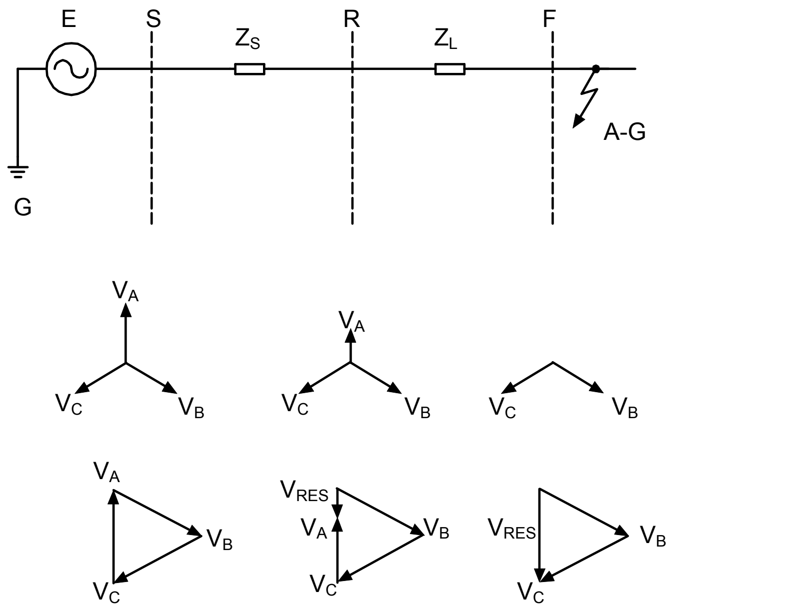
2.7 Residual Overvoltage (Neutral Displacement) Protection

On a healthy three-phase power system, the addition of each of the three-phase to earth voltages is nominally zero, as it is the vector addition of three balanced vectors at 120° to one another. However, when an earth fault occurs on the primary system this balance is upset and a ‘residual’ voltage is produced. This could be measured, for example, at the secondary terminals of a voltage transformer having a “broken delta” secondary connection. Hence, a residual voltage-measuring relay can be used to offer earth fault protection on such a system.

Note	*This condition causes a rise in the neutral voltage with respect to earth that is commonly referred to as “neutral voltage displacement” or NVD.*

The following figure shows the residual voltages that are produced during earth fault conditions occurring on a solid earthed power system.

As shown in below the residual voltage measured by a relay for an earth fault on a solidly earthed system is solely dependent upon the ratio of source impedance behind the relay to line impedance in front of the relay, up to the point of fault. For a remote fault, the Zs/Zl ratio will be small, resulting in a correspondingly small residual voltage. As such, depending upon the relay setting, such a relay would only operate for faults up to a certain distance along the system. The value of residual voltage generated for an earth fault condition is given by the general formula shown.



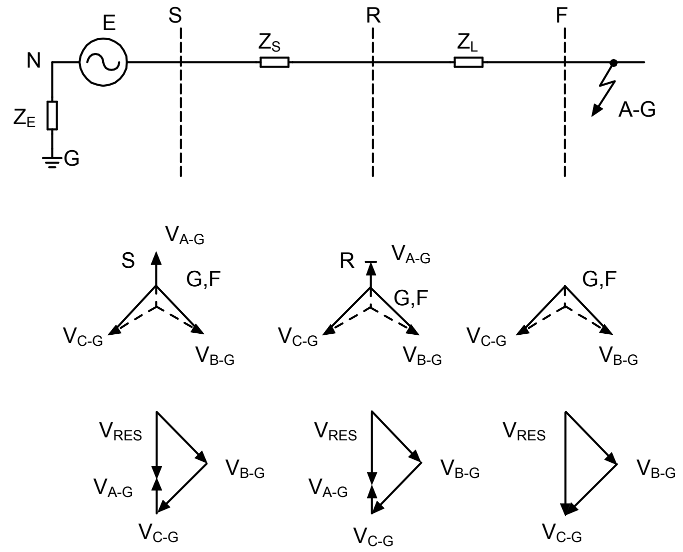
Residual voltage at R (relay point) is dependant upon Z_S/Z_L ratio.

$$V_{RES} = \frac{Z_{S0}}{2Z_{S1} + Z_{S0} + 2Z_{L1} + Z_{L0}} \text{ X } 3 \text{ E}$$

Figure 15 - Residual voltage, solidly earthed system

The following figure shows the residual voltages that are produced during earth fault conditions occurring on an impedance earthed power system.

This shows that a resistance earthed system will always generate a relatively large degree of residual voltage, as the zero sequence source impedance now includes the earthing impedance. It follows then, that the residual voltage generated by an earth fault on an insulated system will be the highest possible value (3 x phase-neutral voltage), as the zero sequence source impedance is infinite.



$$V_{RES} = \frac{Z_{S0} + 3Z_E}{2Z_{S1} + Z_{S0} + 2Z_{L1} + Z_{L0} + 3Z_E} \text{ X 3 E}$$

Figure 16 - Residual voltage, resistance earthed system

The detection of a residual overvoltage condition is an alternative means of earth fault detection, which does not require any measurement of current. This may be particularly advantageous in high impedance earthed or insulated systems, where the provision of core balance CT's on each feeder may be either impractical, or uneconomic.

It must be noted that where residual overvoltage protection is applied, such a voltage will be generated for a fault occurring anywhere on that section of the system and hence the NVD protection must co-ordinate with other earth fault protections.

The P145 relay internally derives this voltage from the three-phase voltage input that must be supplied from either a 5-limb or three single-phase VT's. These types of VT design allow the passage of residual flux and consequently permit the relay to derive the required residual voltage. In addition, the primary star point of the VT must be earthed. A three limb VT has no path for residual flux and is therefore unsuitable to supply the relay.

2.7.1 Setting Guidelines

The voltage setting applied to the elements depends on the magnitude of residual voltage that is expected to occur during the earth fault condition. This in turn is dependent on the method of system earthing employed and may be calculated by using the formulae previously given in the previous diagrams. It must also be ensured that the relay is set above any standing level of residual voltage that is present on the system.

Note	*IDMT characteristics are selectable on the first stage of NVD so that elements located at various points on the system may be time graded with one another.*

2.8 Undervoltage Protection

Undervoltage conditions may occur on a power system for a variety of reasons, some of which are outlined below:

- Increased system loading. Generally, some corrective action would be taken by voltage regulating equipment such as AVRs or On Load Tap Changers, in order to bring the system voltage back to it's nominal value. If the regulating equipment is unsuccessful in restoring healthy system voltage, then tripping by means of an undervoltage relay will be required following a suitable time delay.
- Faults occurring on the power system result in a reduction in voltage of the phases involved in the fault. The proportion by which the voltage decreases is directly dependent upon the type of fault, method of system earthing and it's location with respect to the relaying point. Consequently, co-ordination with other voltage and current-based protection devices is essential in order to achieve correct discrimination.
- Complete loss of busbar voltage. This may occur due to fault conditions present on the incomer or busbar itself, resulting in total isolation of the incoming power supply. For this condition, it may be a requirement for each of the outgoing circuits to be isolated, such that when supply voltage is restored, the load is not connected. Hence, the automatic tripping of a feeder upon detection of complete loss of voltage may be required. This may be achieved by a three-phase undervoltage element.
- Where outgoing feeders from a busbar are supplying induction motor loads, excessive dips in the supply may cause the connected motors to stall, and should be tripped for voltage reductions which last longer than a pre-determined time.

Both the under and overvoltage protection functions can be found in the relay menu "Volt Protection". The following table shows the undervoltage section of this menu along with the available setting ranges and factory defaults.

2.8.1 Setting Guidelines

In the majority of applications, undervoltage protection is not required to operate during system earth fault conditions. If this is the case, the element should be selected in the menu to operate from a phase to phase voltage measurement, as this quantity is less affected by single-phase voltage depressions due to earth faults.

The voltage threshold setting for the undervoltage protection should be set at some value below the voltage excursions that may be expected under normal system operating conditions. This threshold is dependent upon the system in question but typical healthy system voltage excursions may be in the order of -10% of nominal value.

Similar comments apply with regard to a time setting for this element, i.e. the required time delay is dependent upon the time for which the system is able to withstand a depressed voltage. As mentioned earlier, if motor loads are connected, then a typical time setting may be in the order of 0.5 seconds.

2.9 Overvoltage Protection

As previously discussed, undervoltage conditions are relatively common, as they are related to fault conditions etc. However, overvoltage conditions are also a possibility and are generally related to loss of load conditions as described below:

Under conditions of load rejection, the supply voltage will increase in magnitude. This situation would normally be rectified by voltage regulating equipment such as AVR's or on-load tap changers. However, failure of this equipment to bring the system voltage back within prescribed limits leaves the system with an overvoltage condition which must be cleared in order to preserve the life of the system insulation. Hence, overvoltage protection that is suitably time-delayed to allow for normal regulator action, may be applied.

During earth fault conditions on a power system there may be an increase in the healthy phase voltages. Ideally, the system should be designed to withstand such overvoltages for a defined period of time.

2.9.1 Setting Guidelines

The inclusion of the two stages and their respective operating characteristics allows for a number of possible applications:

- Use of the IDMT characteristic gives the option of a longer time delay if the overvoltage condition is only slight but results in a fast trip for a severe overvoltage. As the voltage settings for both of the stages are independent, the second stage could then be set lower than the first to provide a time delayed alarm stage if required .
- Alternatively, if preferred, both stages could be set to definite time and configured to provide the required alarm and trip stages.
- If only one stage of overvoltage protection is required, or if the element is required to provide an alarm only, the remaining stage may be disabled within the relay menu.

This type of protection must be co-ordinated with any other overvoltage relays at other locations on the system. This should be carried out in a similar manner to that used for grading current operated devices.

2.10 Negative Phase Sequence (NPS) Overvoltage Protection

Where an incoming feeder is supplying a switchboard which is feeding rotating plant (e.g. induction motors), correct phasing and balance of the ac supply is essential. Incorrect phase rotation will result in any connected motors rotating in the wrong direction. For directionally sensitive applications, such as elevators and conveyor belts, it may be unacceptable to allow this to happen.

Any unbalanced condition occurring on the incoming supply will result in the presence of Negative Phase Sequence (NPS) components of voltage. In the event of incorrect phase rotation, the supply voltage would effectively consist of 100% NPS voltage only.

2.10.1 Setting Guidelines

As the primary concern is normally the detection of incorrect phase rotation (rather than small unbalances), a sensitive setting is not required. In addition, it must be ensured that the setting is above any standing nps voltage that may be present due to imbalances in the measuring VT, relay tolerances etc. A setting of approximately 15% of rated voltage may be typical.

Note:	*Standing levels of nps voltage (V2) will be displayed in the "Measurements 1" column of the relay menu, labeled "V2 Magnitude". Hence, if more sensitive settings are required, they may be determined during the commissioning stage by viewing the actual level that is present.*

The operation time of the element will be highly dependent on the application. A typical setting would be in the region of 5s.

2.11 Negative Phase Sequence (NPS) Overcurrent Protection

When applying traditional phase overcurrent protection, the overcurrent elements must be set higher than maximum load current, thereby limiting the element’s sensitivity. Most protection schemes also use an earth fault element operating from residual current, which improves sensitivity for earth faults. However, certain faults may arise which can remain undetected by such schemes.

Any unbalanced fault condition will produce negative sequence current of some magnitude. Thus, a Negative Phase Sequence (NPS) overcurrent element can operate for both phase-to-phase and phase-to-earth faults.

- NPS overcurrent elements give greater sensitivity to resistive phase-to-phase faults, where phase overcurrent elements may not operate
- In certain applications, residual current may not be detected by an earth fault relay due to the system configuration. For example, an earth fault relay applied on the delta side of a delta-star transformer is unable to detect earth faults on the star side. However, negative sequence current will be present on both sides of the transformer for any fault condition, irrespective of the transformer configuration. Therefore, a NPS overcurrent element may be employed to provide time-delayed back-up protection for any uncleared asymmetrical faults downstream
- Where rotating machines are protected by fuses, loss of a fuse produces a large amount of negative sequence current. This is a dangerous condition for the machine due to the heating effects of NPS current and hence an upstream NPS overcurrent element may be applied to provide back-up protection for dedicated motor protection relays
- It may be required to simply alarm for the presence of NPS currents on the system. Operators may then investigate the cause of the unbalance

2.11.1 Setting Guidelines

2.11.1.1 Negative Phase Sequence Current Threshold, 'I2> Current Set'

The current pick-up threshold must be set higher than the NPS current due to the maximum normal load unbalance on the system. This can be set practically at the commissioning stage, making use of the relay measurement function to display the standing NPS current, and setting at least 20% above this figure.

Where the NPS element is required to operate for specific uncleared asymmetric faults, a precise threshold setting would have to be based upon an individual fault analysis for that particular system due to the complexities involved. However, to ensure operation of the protection, the current pick-up setting must be set approximately 20% below the lowest calculated NPS fault current contribution to a specific remote fault condition.

2.11.1.2 Time delay for the Negative Phase Sequence Overcurrent Element, 'I2> Time Delay'

As stated above, correct setting of the time delay for this function is vital. It should also be noted that this element is applied primarily to provide back-up protection to other protective devices or to provide an alarm. Hence, in practice, it would be associated with a long time delay.

It must be ensured that the time delay is set greater than the operating time of any other protective device (at minimum fault level) on the system which may respond to unbalanced faults.

- Phase overcurrent elements
- Earth fault elements
- Broken conductor elements
- Negative phase sequence influenced thermal elements

2.11.1.3 Directionalizing the Negative Phase Sequence Overcurrent Element

Where negative phase sequence current may flow in either direction through a relay location, such as parallel lines, directional control of the element should be employed. Directionality is achieved by comparison of the angle between the negative phase sequence voltage and the negative phase sequence current and the element may be selected to operate in either the forward or reverse direction. A suitable relay characteristic angle setting (I2> Char Angle) is chosen to provide optimum performance. This setting should be set equal to the phase angle of the negative sequence current with respect to the inverted negative sequence voltage (– V2), in order to be at the center of the directional characteristic.

The angle that occurs between V2 and I2 under fault conditions is directly dependent upon the negative sequence source impedance of the system. However, typical settings for the element are as follows;

- For a transmission system the RCA should be set equal to -60°
- For a distribution system the RCA should be set equal to -45°

For the negative phase sequence directional elements to operate, the relay must detect a polarizing voltage above a minimum threshold, **I2> V2pol Set**. This must be set in excess of any steady state negative phase sequence voltage. This may be determined during the commissioning stage by viewing the negative phase sequence measurements in the relay.

2.12 Voltage Controlled Overcurrent (VCO) Protection (51V)

As described in section 2.1, overcurrent relays are co-ordinated throughout a system such that cascade operation is achieved. This means that the failure of a downstream circuit breaker to trip for a fault condition, whether due to the failure of a protective device, or of the breaker itself, should result in time graded tripping of the next upstream circuit breaker.

However, where long feeders are protected by overcurrent relays, the detection of remote phase-to-phase faults may prove difficult. This is due to the fact that the current pick up of phase overcurrent elements must be set above the maximum load current, thereby limiting the elements minimum sensitivity. If the current seen by a local relay for a remote fault condition is below it's overcurrent setting, a Voltage Controlled Overcurrent (VCO) element may be used to increase the relay sensitivity to such faults. In this case, a reduction in system voltage will occur; this may then be used to reduce the pick up level of the overcurrent protection.

Note	*Voltage dependent overcurrent relays are more often applied in generator protection applications in order to give adequate overcurrent relay sensitivity for close up fault conditions. The fault characteristic of this protection must then co-ordinate with any of the downstream overcurrent relays that are responsive to the current decrement condition. It therefore follows that if the P145 relay is to be applied on an outgoing feeder from a generator station, the use of voltage controlled overcurrent protection in the feeder relay may allow better co-ordination with the VCO relay on the generator. The settings in such an application will be directly dependent upon those employed for the generator relay.*

2.12.1 Setting Guidelines

The "VCO k Setting" should be set low enough to allow operation for remote phase to phase faults, typically:

$$k = \frac{I_F}{I > \times 1.2}$$

Where:

If = Minimum fault current expected for the remote fault

I> = Phase current setting for the element to have VCO control

e.g. If the overcurrent relay has a setting of 160% In, but the minimum fault current for the remote fault condition is only 80% In, then the required k factor is given by:

$$k = \frac{0.8}{1.6 \times 1.2} = 0.42$$

The voltage threshold, "VCO V< Setting", would be set below the lowest system voltage that may occur under normal system operating conditions, whilst ensuring correct detection of the remote fault.

2.13 Circuit Breaker Fail (CBF) Protection

Following inception of a fault one or more main protection devices will operate and issue a trip output to the circuit breaker(s) associated with the faulted circuit. Operation of the circuit breaker is essential to isolate the fault, and prevent damage / further damage to the power system. For transmission/sub-transmission systems, slow fault clearance can also threaten system stability. It is therefore common practice to install Circuit Breaker Failure (CBF) protection, which monitors that the circuit breaker has opened within a reasonable time. If the fault current has not been interrupted following a set time delay from circuit breaker trip initiation, CBF protection will operate.

CBF operation can be used to backtrip upstream circuit breakers to ensure that the fault is isolated correctly. CBF operation can also reset all start output contacts, ensuring that any blocks asserted on upstream protection are removed.

2.13.1 Reset Mechanisms for Breaker Fail Timers

It is common practice to use low set undercurrent elements in protection relays to indicate that circuit breaker poles have interrupted the fault or load current, as required. This covers the following situations:

- Where circuit breaker auxiliary contacts are defective, or cannot be relied upon to definitely indicate that the breaker has tripped
- Where a circuit breaker has started to open but has become jammed. This may result in continued arcing at the primary contacts, with an additional arcing resistance in the fault current path. Should this resistance severely limit fault current, the initiating protection element may reset. Thus, reset of the element may not give a reliable indication that the circuit breaker has opened fully

For any protection function requiring current to operate, the relay uses operation of undercurrent elements (I<) to detect that the necessary circuit breaker poles have tripped and reset the CB fail timers. However, the undercurrent elements may not be reliable methods of resetting CBF in all applications. For example:

- Where non-current operated protection, such as under/overvoltage or under/overfrequency, derives measurements from a line connected voltage transformer. Here, I< only gives a reliable reset method if the protected circuit would always have load current flowing. Detecting drop-off of the initiating protection element might be a more reliable method
- Where non-current operated protection, such as under/overvoltage or under/overfrequency, derives measurements from a busbar connected voltage transformer. Again using I< would rely upon the feeder normally being loaded. Also, tripping the circuit breaker may not remove the initiating condition from the busbar, and hence drop-off of the protection element may not occur. In such cases, the position of the circuit breaker auxiliary contacts may give the best reset method

CBF protection monitors whether the circuit breaker has opened in reasonable amount of time when protection devices issues trip command in fault situation. This should happen to prevent further damage in power system and isolate the fault in transmission or sub-transmission systems. If a false short pulse energized to opto input connected in PSL to DDB227 “External Trip 3ph” which may not enough for normal trip but because of CB failure logic this signal goes to SET-RESET gate and causes protection trip after 200ms.

2.13.2 Typical Settings

2.13.2.1 Breaker Fail Timer Settings

Typical timer settings to use are as follows:

CB fail reset mechanism	tBF time delay	Typical delay for 2 ½ cycle circuit breaker
Initiating element reset	CB interrupting time + element reset time (max.) + error in tBF timer + safety margin	50 + 45 + 10 + 50 = 155 ms
CB open	CB auxiliary contacts opening/closing time (max.) + error in tBF timer + safety margin	50 + 10 + 50 = 110 ms
Undercurrent elements	CB interrupting time + undercurrent element (max.) + safety margin	50 + 25 + 50 = 125 ms

Note *All CB Fail resetting involves the operation of the undercurrent elements. Where element reset or CB open resetting is used the undercurrent time setting should still be used if this proves to be the worst case.*

The examples above consider direct tripping of a 2½ cycle circuit breaker.

Note *Where auxiliary tripping relays are used, an additional 10-15 ms must be added to allow for trip relay operation.*

2.13.2.2 Breaker Fail Undercurrent Settings

The phase undercurrent settings (I<) must be set less than load current, to ensure that I< operation indicates that the circuit breaker pole is open. A typical setting for overhead line or cable circuits is 20% In, reduced to 10% or 5% where the infeed has a high SIR ratio (e.g. at a spur terminal with embedded generation infeed).

The sensitive earth fault protection (SEF) undercurrent element must be set less than the respective trip setting, typically as follows:

ISEF< = (ISEF> trip) / 2

IN< = (IN> trip)/2

2.14 Broken Conductor Detection

The majority of faults on a power system occur between one phase and ground or two phases and ground. These are known as shunt faults and arise from lightning discharges and other overvoltages which initiate flashovers. Alternatively, they may arise from other causes such as birds on overhead lines or mechanical damage to cables etc. Such faults result in an appreciable increase in current and hence in the majority of applications are easily detectable.

Another type of unbalanced fault that can occur on the system is the series or open circuit fault. These can arise from broken conductors, maloperation of single phase switchgear, or single-phasing of fuses. Series faults will not cause an increase in phase current on the system and hence are not readily detectable by standard protection. However, they will produce an unbalance and a resultant level of negative phase sequence current, which can be detected.

It is possible to apply a negative phase sequence overcurrent relay to detect the above condition. However, on a lightly loaded line, the negative sequence current resulting from a series fault condition may be very close to, or less than, the full load steady state unbalance arising from CT errors, load unbalance etc. A negative sequence element therefore would not operate at low load levels.

2.14.1 Setting Guidelines

For a broken conductor affecting a single point earthed power system, there will be little zero sequence current flow and the ratio of I2/I1 that flows in the protected circuit will approach 100%. In the case of a multiple earthed power system (assuming equal impedance's in each sequence network), the ratio I2/I1 will be 50%.

In practice, the levels of standing negative phase sequence current present on the system govern this minimum setting. This can be determined from a system study, or by making use of the relay measurement facilities at the commissioning stage. If the latter method is adopted, it is important to take the measurements during maximum system load conditions, to ensure that all single-phase loads are accounted for.

Note	*A minimum value of 8% negative phase sequence current is required for successful relay operation.*

Since sensitive settings have been employed, it can be expected that the element will operate for any unbalance condition occurring on the system (for example, during a single pole auto-reclose cycle). Hence, a long time delay is necessary to ensure co-ordination with other protective devices. A 60 second time delay setting may be typical.

The example following information was recorded by the relay during commissioning;

Ifull load	=	500 A
I2	=	50 A

therefore the quiescent I2/I1 ratio is given by;

I2/I1	=	50/500 = 0.1

To allow for tolerances and load variations a setting of 20% of this value may be typical: Therefore set I2/I1 = 0.2

In a double circuit (parallel line) application, using a 40% setting will ensure that the broken conductor protection will operate only for the circuit that is affected. Setting 0.4 results in no pick-up for the parallel healthy circuit.

Set I2/I1 Time Delay = 60 s to allow adequate time for short circuit fault clearance by time delayed protections.

2.15 Cold-Load Pick-Up (CLP) Logic

When a feeder circuit breaker is closed in order to energize a load, the current levels that flow for a period of time following energization may differ greatly from the normal load levels. Consequently, overcurrent settings that have been applied to give short circuit protection may not be suitable during the period of energization, as they may give incorrect operation.

The Cold Load Pick-Up (CLP) logic included within the P145 relays serves to either inhibit one or more stages of the overcurrent protection for a set duration or, alternatively, to raise the settings of selected stages. This, therefore, allows the protection settings to be set closer to the load profile by automatically increasing them following circuit energization. The CLP logic thus provides stability, whilst maintaining protection during starting.

2.15.1 Air Conditioning/Resistive Heating Loads

Where a feeder is being used to supply air conditioning or resistive heating loads there may be a conflict between the ‘steady state’ overcurrent settings and those required following energization. This is due to the temporary increase in load current that may arise during this period. The CLP logic can be used to alter the applied settings during this time.

In this situation, “Enable” should be selected (from the "I> status" option) and the temporary current and time settings can then be programmed. These settings would be chosen in accordance with the expected load profile. Where it is not necessary to alter the setting of a particular stage, the CLP settings should be set to the required overcurrent settings.

It may not be necessary to alter the protection settings following a short supply interruption. In this case a suitable tcold timer setting can be used.

It should be noted that it is not possible to alter any of the directional settings in the CLP logic.

2.15.2 Motor Feeders

In general, a dedicated motor protection device from the MiCOM range would protect feeders supplying motor loads. However, if no specific protection has been applied (possibly due to economic reasons) then the CLP logic in the P145 may be used to modify the overcurrent settings accordingly during starting.

Depending upon the magnitude and duration of the motor starting current, it may be sufficient to simply block operation of instantaneous elements or, if the start duration is long, the time delayed protection settings may also need to be raised. Hence, a combination of both blocking and raising of settings of the relevant overcurrent stages may be adopted. The CLP overcurrent settings in this case must be chosen with regard to the motor starting characteristic.

As previously described, the CLP logic includes the option of either blocking or raising the settings of the first stage of the standard earth fault protection. This may be useful where instantaneous earth fault protection is required to be applied to the motor. During conditions of motor starting, it is likely that incorrect operation of the earth fault element would occur due to asymmetric CT saturation. This is a result of the high level of starting current causing saturation of one or more of the line CT’s feeding the overcurrent/earth fault protection. The resultant transient imbalance in the secondary line current quantities is thus detected by the residually connected earth fault element. For this reason, it is normal to either apply a nominal time delay to the element, or to utilize a series stabilizing resistor.

The CLP logic may be utilized to allow reduced operating times or current settings to be applied to the earth fault element under normal running conditions. These settings could then be raised prior to motor starting, via the logic.

2.15.3 Switch Onto Fault Protection (SOTF)

In some feeder applications, fast tripping may be required if a fault is present on the feeder when it is energized. Such faults may be due to a fault condition not having been removed from the feeder, or due to earthing clamps having been left on following maintenance. In either case, it may be desirable to clear the fault condition in an accelerated time, rather than waiting for the time delay associated with IDMT overcurrent protection.

The above situation may be catered for by the CLP logic. Selected overcurrent/earth fault stages could be set to instantaneous operation for a defined period following circuit breaker closure (typically 200ms). Hence, instantaneous fault clearance would be achieved for a SOTF condition.

2.16 Blocked Overcurrent Protection

Blocked overcurrent protection involves the use of start contacts from downstream relays wired onto blocking inputs of upstream relays. This allows identical current and time settings to be employed on each of the relays involved in the scheme, as the relay nearest to the fault does not receive a blocking signal and hence trips discriminatively. This type of scheme therefore reduces the amount of required grading stages and consequently fault clearance times.

The principle of blocked overcurrent protection may be extended by setting fast acting overcurrent elements on the incoming feeders to a substation which are then arranged to be blocked by start contacts from the relays protecting the outgoing feeders. The fast acting element is thus allowed to trip for a fault condition on the busbar but is stable for external feeder faults by means of the blocking signal. This type of scheme therefore provides much reduced fault clearance times for busbar faults than would be the case with conventional time graded overcurrent protection. The availability of multiple overcurrent and earth fault stages means that back-up time graded overcurrent protection is also provided. This is shown in Figure 17 and Figure 18.

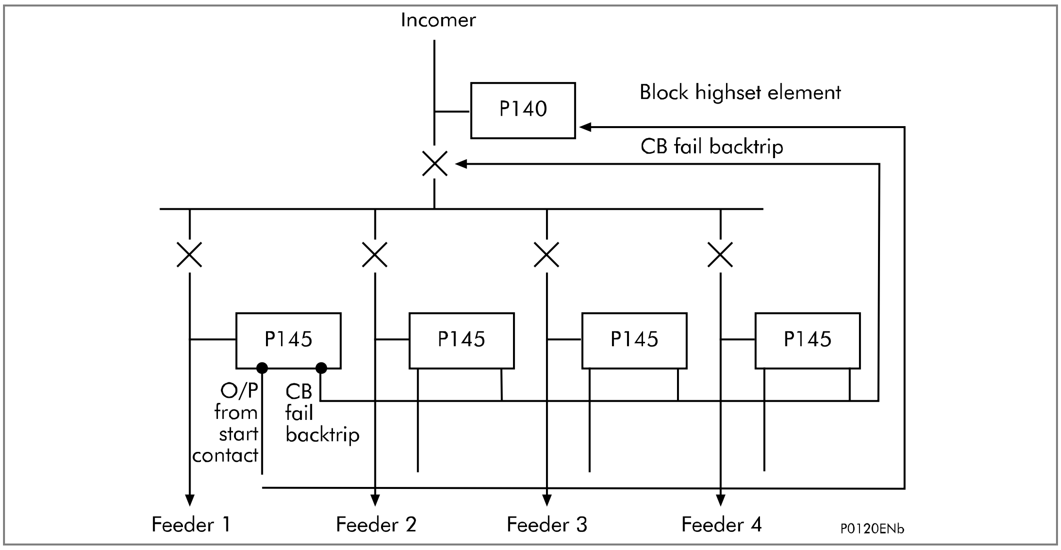


Figure 17 - Simple busbar blocking scheme (single incomer)

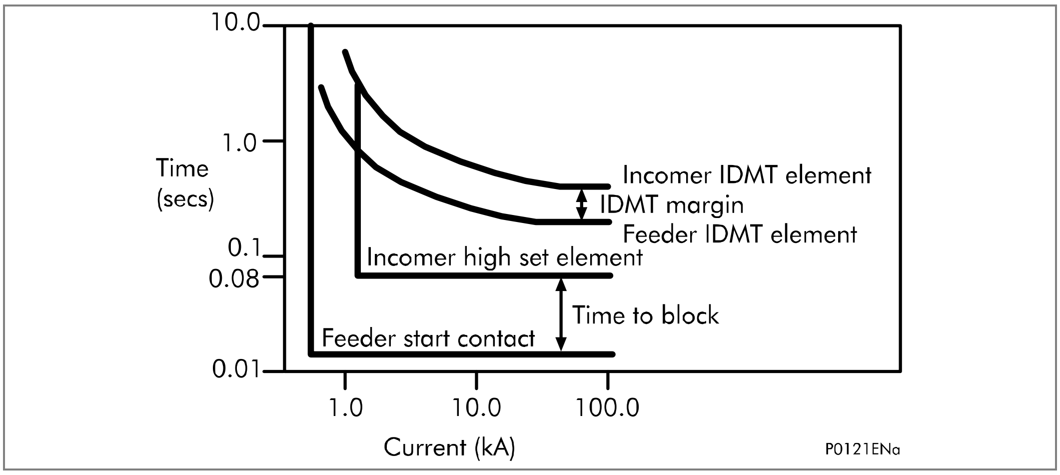


Figure 18 - Simple busbar blocking scheme (single incomer)

For further guidance on the use of blocked overcurrent schemes refer to Schneider Electric.

2.17 Advanced Underfrequency Protection ‘f+t’ [81U]

Frequency variations on a power system are an indication that the power balance between generation and load has been lost. In particular, under-frequency implies that the net load is in excess of the available generation. Such a condition can arise, when an interconnected system splits, and the load left connected to one of the subsystems is in excess of the capacity of the generators in that particular subsystem. Industrial plants that are dependent on utilities to supply part of their loads will experience under-frequency conditions when the incoming lines are lost.

An underfrequency condition at nominal voltage can result in over-fluxing of generators and transformers and many types of industrial loads have limited tolerances on the operating frequency and running speeds e.g. synchronous motors. Sustained underfrequency has implications on the stability of the system, whereby any subsequent disturbance may lead to damage to frequency sensitive equipment and even blackouts, if the underfrequency condition is not corrected sufficiently fast.

The underfrequency protection settings are found in the “f+t [81U/81O]” relay menu column.

2.17.1 Setting Guidelines

In order to minimize the effects of underfrequency on a system, a multi stage load shedding scheme may be used with the plant loads prioritized and grouped. During an underfrequency condition, the load groups are disconnected sequentially depending on the level of underfrequency, with the highest priority group being the last one to be disconnected.

The effectiveness of each stage of load shedding depends on what proportion of the power deficiency it represents. If the load shedding stage is too small compared to the prevailing generation deficiency, then the improvement in frequency may be non-existent. This aspect should be taken into account when forming the load groups.

Time delays should be sufficient to override any transient dips in frequency, as well as to provide time for the frequency controls in the system to respond. This should be balanced against the system survival requirement since excessive time delays may jeopardize system stability. Time delay settings of 5 - 20s are typical.

An example of a four-stage load shedding scheme for 50Hz systems is shown below:

Stage	Element	Frequency Setting (Hz)	Time Setting (Sec)
1	Stage 1(f+t)	49.0	20s
2	Stage 2(f+t)	48.6	20s
3	Stage 3(f+t)	48.2	10s
4	Stage 4(f+t)	47.8	10s

Table 1 - Four-stage load shedding scheme example

The relatively long time delays are intended to provide time for the system controls to respond and will work well in a situation where the decline of system frequency is slow. For situations where rapid decline of frequency is expected, the load shedding scheme above should be supplemented by rate of change of frequency protection elements.

It may be noted that the protection package for generators at site may include underfrequency relays. The settings made on the P140 should be co-ordinated with the generator protection frequency relays.

2.18 Advanced Overfrequency Protection ‘f+t’ [81O]

Over frequency running of a generator arises when the mechanical power input to the machine exceeds the electrical output. This could happen, for instance, when there is a sudden loss of load due to tripping of an outgoing feeder from the plant to a load center. Under such over speed conditions, the governor should respond quickly so as to obtain a balance between the mechanical input and electrical output, thereby restoring normal frequency. Over frequency protection is required as a back-up to cater for slow response of frequency control equipment.

The overfrequency protection settings are found in the “f+t [81U/81O]” relay menu column.

2.18.1 Setting Guidelines

Following faults on the network, or other operational requirements, it is possible that various subsystems will be formed within the power network and it is likely that each of these subsystems will suffer from a generation to load imbalance. The “islands” where generation exceeds the existing load will be subject to over frequency conditions, the level of frequency being a function of the percentage of excess generation. Severe over frequency conditions may be unacceptable to many industrial loads, since running speeds of motors will be affected. The “f+t” element of the MiCOM P140 can be suitably set to sense this contingency.

An example of two-stage over frequency protection is shown below using stages 5 and 6 of the “f+t” element. However, it should be considered that settings for a real system will depend upon the maximum frequency that equipment can tolerate for a given period of time.

Stage	Element	Frequency Setting (Hz)	Time Setting (Sec.)
1	Stage 5(f+t)	50.5	30
2	Stage 6(f+t)	51.0	20

Table 2 - Two-stage over frequency protection

The relatively long time delays are intended to provide time for the system controls to respond and will work well in a situation where the increase of system frequency is slow.

For situations where rapid increase of frequency is expected, the protection scheme above could be supplemented by rate of change of frequency protection elements, possibly utilized to split the system further. For example, in the system shown in Figure 19 the generation in the MV bus is sized according to the loads on that bus, whereas the generators linked to the HV bus produce energy for export to utility. If the links to the grid are lost, the IPP generation will cause the system frequency to rise. This rate of rise can be used to isolate the MV bus from the HV system, if operationally acceptable.

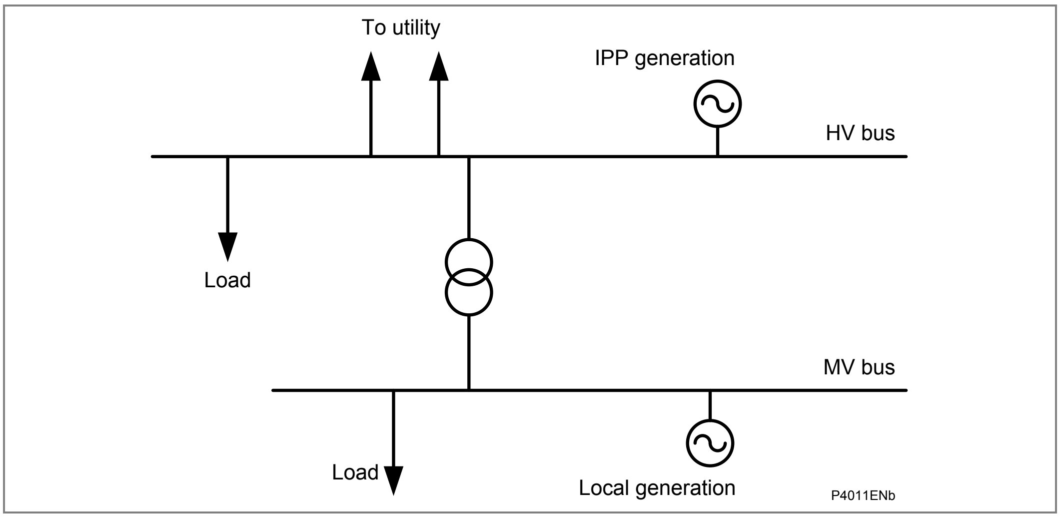


Figure 19 - Power system segregation based upon frequency measurements

Table 3, Table 4 and Table 5 give possible settings that could be used to speed up the process of segregating the system as outlined above, in conjunction with the overfrequency element:

Stage	Frequency "f+t [81U/81O]" Elements		Frequency Supervised Rate of Change of Frequency "f+df/dt dt [81RF]" Elements	
	Frequency Setting (Hz)	Time Setting (Sec.)	Frequency Setting (Hz)	Rate of Change of Frequency Setting (Hz/Sec)
1	50.5	30	50.5	1.0
2	51	20	51	1.0

Table 3 - Typical settings for over frequency with frequency supervised rate of change of frequency

Stage	Frequency "f+t [81U/81O]" Elements		Average Rate of Change of Frequency "f+Df/Dt [81RAV]" Elements		
	Frequency Setting (Hz)	Time Setting (Sec.)	Frequency Setting (Hz)	Frequency Difference Setting, Df (Hz)	Time Period, Dt (Sec.)
1	50.5	30	50.5	0.5	0.5
2	51	20	51	0.5	0.5

Table 4 - Overfrequency protection with average rate of change of frequency

Stage	Frequency "f+t [81U/81O]" Elements		Rate of Change of Frequency "df/dt+t [81R]" Elements	
	Frequency Setting (Hz)	Time Setting (Sec.)	Rate of Change of Frequency Setting (Hz/Sec.)	Time Setting (Sec.)
1	50.5	30	3.0	0.5
2	51	20	2.0	0.5

Table 5 - Overfrequency protection with independent rate of change of frequency

It may be noted that the protection package for generators at site may include overfrequency relays. The settings made on the P140 should be co-ordinated with the generator protection frequency relays.

2.19 Advanced Frequency Supervised Rate of Change of Frequency Protection ‘f+df/dt’ [81RF]

Conditions may arise in an electrical network where the load to generation imbalance is considerable and this may result in relatively rapid changes of the system frequency. In such a case, maintaining the system stability is an onerous task, and calls for quick corrective action.

High speed load shedding cannot be achieved by monitoring the system frequency alone and the rate of change of system frequency becomes an equally critical parameter to use.

In the load shedding scheme below, it is assumed under falling frequency conditions that by shedding a stage of load, the system can be stabilized at frequency f2. For slow rates of decay, this can be achieved using the underfrequency protection element set at frequency f1 with a suitable time delay. However, if the generation deficit is substantial, the frequency will rapidly decrease and it is possible that the time delay imposed by the underfrequency protection will not allow for frequency stabilization. In this case, the chance of system recovery will be enhanced by disconnecting the load stage based upon a measurement of rate of change of frequency and bypassing the time delay.

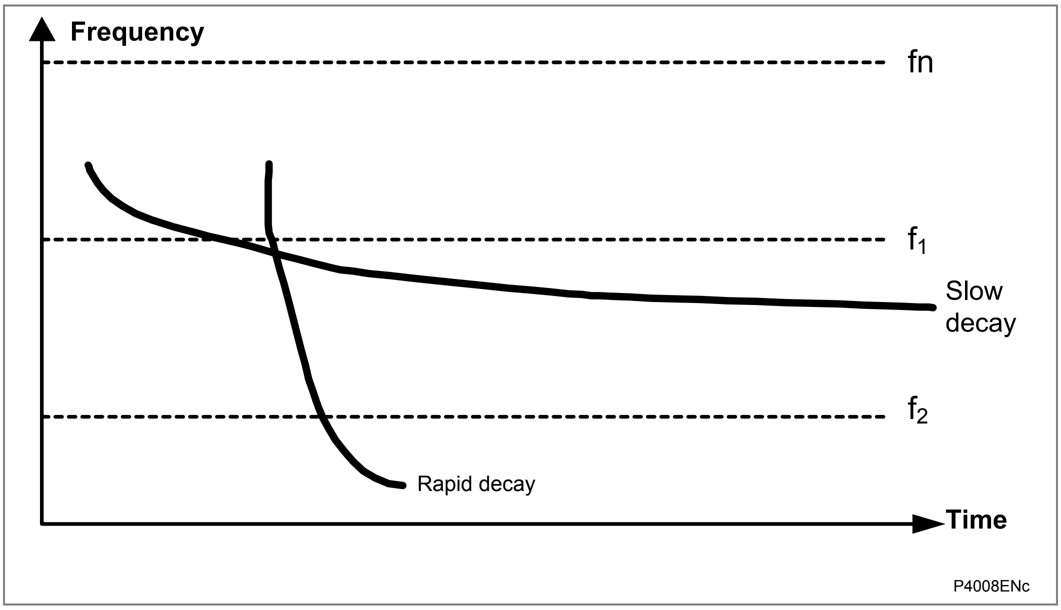


Figure 20 - Advanced frequency supervised rate of change of frequency protection

With the frequency supervised rate of change of frequency element, the basic rate of change of frequency measurement is supervised by an additional frequency measurement. As such, the rate of change of frequency AND the frequency must exceed the set thresholds before an output can be given.

The frequency supervised rate of change of frequency protection settings may be found in the “f+df/dt [81RF]” relay menu column.

2.19.1 Setting Guidelines

It is recommended that the frequency supervised rate of change of frequency protection (f+df/dt) element be used in conjunction with the time delayed frequency protection (f+t) elements.

A four stage high speed load shedding scheme may be configured as shown in Table 6 and Table 7, noting that in each stage, both the "f+t" and the "f+df/dt" elements are enabled.

Stage	Frequency "f+t [81U/81O]" Elements		Frequency Supervised Rate of Change of Frequency "f+df/dt [81RF]" Elements	
	Frequency Setting (Hz)	Time Setting (Sec.)	Frequency Setting (Hz)	Rate of Change of Frequency Setting (Hz/sec.)
1	49	20	49	1.0
2	48.6	20	48.6	1.0
3	48.2	10	48.2	1.0
4	47.8	10	47.8	1.0

Table 6 - Four-stage high-speed load shedding scheme

It may be possible to further improve the speed of load shedding in critical cases by changing the frequency setting on the frequency supervised rate of change of frequency element. In the settings shown in Table 7, the frequency settings for the "f+df/dt" element have been set slightly higher than the frequency settings for the "f+t" element. This difference will allow for the measuring time of the relay, assuming the set rate of frequency change and default frequency averaging cycles, and will result in the tripping of the two elements at approximately the same frequency value. Thus, with this scheme, the slow frequency decline and fast frequency decline scenarios are independently monitored and optimized without sacrificing system security.

Stage	Frequency "f+t [81U/81O]" Elements		Frequency Supervised Rate of Change of Frequency "f+df/dt [81RF]" Elements	
	Frequency Setting (Hz)	Time Setting (Sec.)	Frequency Setting (Hz)	Rate of Change of Frequency Setting (Hz/sec.)
1	49	20	49.2	1.0
2	48.6	20	48.8	1.0
3	48.2	10	48.4	1.0
4	47.8	10	48.0	1.0

Table 7 - Improved four-stage high-speed load shedding scheme

2.20 Advanced Independent Rate of Change of Frequency Protection 'df/dt+t' [81R]

This element is a plain rate of change of frequency monitoring element, and is not supervised by a frequency setting as per the "f+df/dt" element. However, a timer is included to provide a time delayed operation. The element can be utilized to provide extra flexibility to a load shedding scheme in dealing with severe load to generation imbalances.

As mentioned in other sections, conditions involving very large load - generation imbalances may occur, accompanied by rapid decline in system frequency. Shedding of one or two stages of load is unlikely to stop the decline in frequency, if the discrepancy is still large. In such a situation, it is advantageous to have an element that identifies the high rate of decline of frequency, and adapts the load shedding scheme accordingly.

Since the rate of change monitoring is independent of frequency, the element can identify frequency variations occurring close to nominal frequency and thus provide early warning to the operator on a developing frequency problem. Additionally, the element could also be used as an alarm to warn operators of unusually high system frequency variations.

The rate of change of frequency protection settings may be found in the "df/dt+t [81R]" relay menu column.

2.20.1 Setting Guidelines

Considerable care should be taken when setting this element because it is not supervised by a frequency setting. Setting of the time delay or increasing the number of df/dt averaging cycles will lead to a more stable element but this should be considered against the loss of fast tripping capability as the tripping time is extended.

It is likely that this element would be used in conjunction with other frequency based protection elements to provide a scheme that accounts for severe frequency fluctuations. An example scheme is shown in Table 8:

Stage	Frequency “f+t [81U/81O]” Elements		Frequency Supervised Rate of Change of Frequency “f+df/dt [81RF]” Elements	
	Frequency Setting (Hz)	Time Setting (Sec.)	Frequency Setting (Hz)	Rate of Change of Frequency Setting (Hz/Sec.)
1	49	20	49.2	1.0
2	48.6	20	48.8	1.0
3	48.2	10	48.4	1.0
4	47.8	10	48.0	1.0
5	-	-	-	-

Stage	Rate of Change of Frequency “df/dt+t [81R]” Elements	
	Rate of Change of Frequency Setting (Hz/Sec.)	Time Setting (Sec.)
1	-	-
2	-	-
3	-3.0	0.5
4	-3.0	0.5
5	-3.0	0.1

Table 8 - Improved setting guidelines

In the above scheme, tripping of the last two stages is accelerated by using the independent rate of change of frequency element. If the frequency starts falling at a high rate (> 3Hz/s in this example), then stages 3 & 4 are shed at around 48.5Hz, with the objective of a better chance of system stability. Stage 5 serves as an alarm and gives operators advance warning that the situation is critical and if it persists, there is the likelihood for all stages of load being shed.

2.21 Advanced Average Rate of Change of Frequency Protection ‘f+Df/Dt’ [81RAV]

Owing to the complex dynamics of power systems, variations in frequency during times of generation - load imbalance do not follow any regular patterns and are highly non-linear. Oscillations will occur as the system seeks to address the imbalance, resulting in frequency oscillations typically in the order of 0.1Hz to 1Hz, in addition to the basic change in frequency.

The rate of change of frequency elements discussed in section 2.3 and section 2.4 both use an “instantaneous” measurement of “df/dt” based upon a 3 cycle, filtered, “rolling” average technique. Due to the oscillatory nature of frequency excursions, this instantaneous value can sometimes be misleading, either causing unexpected operation or excessive stability. For this reason, the P140 relays also provide an element for monitoring the longer term frequency trend, thereby reducing the effects of non-linearity’s in the system and providing increased security to the rate of change of frequency decision.

Using the average rate of change of frequency element “f+Df/Dt”, when the measured frequency crosses the supervising frequency threshold a timer is initiated. At the end of this time period, Δt, the frequency difference, Δf, is evaluated and if this exceeds the setting, a trip output is given.

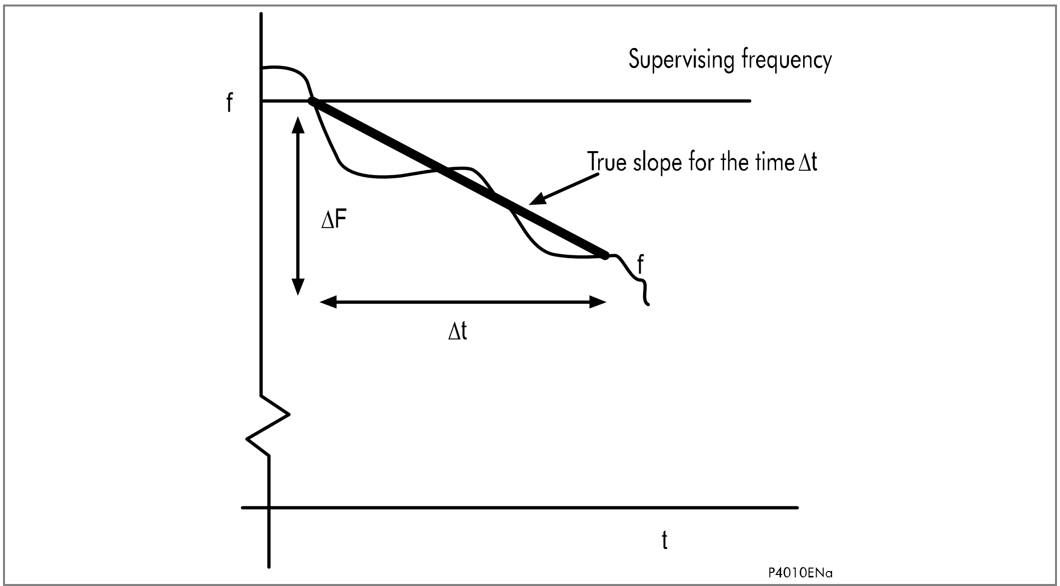


Figure 21 - Advanced average rate of change of frequency protection

After time Δt, regardless of the outcome of the comparison, the element is blocked from further operation until the frequency recovers to a value above the supervising frequency threshold (or below in the case where the element is configured for overfrequency operation).

The average rate of change of frequency protection settings may be found in the “f+Df/Dt [81RAV]” relay menu column.

2.21.1 Setting Guidelines

As for the other rate of change of frequency elements, it is recommended that the “f+Df/Dt” element be used in conjunction with the “f+t” element. The average rate of change of frequency element can be set to measure the rate of change over a short period as low as 20ms (1 cycle @ 50Hz) or a relatively long period up to 2s (100 cycles @ 50Hz). With a time setting, Dt, towards the lower end of this range, the element becomes similar to the frequency supervised rate of change function, “f+df/dt”. With high Dt settings, the element acts as a frequency trend monitor.

Although the element has a wide range of setting possibilities, it is recommended that the Dt setting is set greater than 100ms to ensure the accuracy of the element as described in P14x/EN TD.

A possible four stage load shedding scheme using the average rate of change frequency element is shown in Table 9:

Stage	Frequency “f+t [81U/81O]” Elements		Average Rate of Change of Frequency “f+Df/Dt [81RAV]” Elements		
	(f+t) f Frequency Setting (Hz)	(f+t) t Time Setting (Sec.)	(f+Df/Dt) f Frequency Setting (Hz)	(f+Df/Dt) Df Frequency Diff Setting, (Hz)	(f+Df/Dt) Dt Time Period, (Sec.)
1	49	20	49	0.5	0.5
2	48.6	20	48.6	0.5	0.5
3	48.2	10	48.2	0.5	0.5

Stage	Frequency “f+t [81U/81O]” Elements		Average Rate of Change of Frequency “f+Df/Dt [81RAV]” Elements		
	(f+t) f Frequency Setting (Hz)	(f+t) t Time Setting (Sec.)	(f+Df/Dt) f Frequency Setting (Hz)	(f+Df/Dt) Df Frequency Diff Setting, (Hz)	(f+Df/Dt) Dt Time Period, (Sec.)
4	47.8	10	47.8	0.5	0.5

Table 9 - Four-stage load shedding scheme (average rate of change of frequency)

In the above scheme, the faster load shed decisions are made by monitoring the frequency change over 500ms. Hence tripping takes place slower than in schemes employing the frequency supervised rate of change element (f+df/dt [81RF]), but the difference is not very much at this setting. If the delay is unacceptable for system stability, then the scheme can be improved by increasing the independent “f” setting of the element. Depending upon how much this value is increased, the frequency at which the “f+Df/Dt” element will trip also increases and hence reduces the time delay to load shedding under more severe frequency fluctuations. For example, with the settings shown in Table 10 and assuming the set average rate of frequency decline, the first stage of load shedding would be tripped approximately 300msecs after 49.0Hz had been reached and at a frequency of approximately 48.7Hz.

Stage	Frequency “f+t [81U/81O]” Elements		Average Rate of Change of Frequency “f+Df/Dt [81RAV]” Elements		
	(f+t) f Frequency Setting (Hz)	(f+t) t Time Setting (Sec)	(f+Df/Dt) f Frequency Setting (Hz)	(f+Df/Dt) Df Frequency Diff Setting (Hz)	(f+Df/Dt) Dt Time Period, (Sec.)
1	49	20	49.2	0.5	0.5 s
2	48.6	20	48.8	0.5	0.5 s
3	48.2	10	48.4	0.5	0.5 s
4	47.8	10	48.0	0.5	0.5 s

Table 10 - Improved four-stage load shedding system

2.22 Advanced Load Restoration

It is the goal of load shedding to stabilize the frequency on a system and to re-establish the load to generation imbalance that initially caused the frequency to decline. As the system stabilizes and the generation capability improves, the system frequency will recover to near normal levels and after some time delay it is possible to consider the restoration of load onto the healthy system. However, load restoration needs to be performed carefully and systematically so that system stability is not jeopardized again. A careful balance needs to be sought to minimize the length of time that the loads are disconnected but at the same time, not re-connect loads that will cause the problem to immediately re-occur.

In the case of industrial plants with captive generation, restoration should be linked to the available generation since connecting additional load when the generation is still inadequate, will only result in declining frequency and consequent load shedding. If the in-plant generation is insufficient to meet the load requirements, then load restoration should be interlocked with recovery of the utility supply.

The load restoration settings may be found in the “Load Restoration” relay menu column.

2.22.1 Setting Guidelines

A four stage, single frequency load restoration scheme is shown in Table 11. The frequency setting has been chosen such that there is sufficient separation between the highest load shed frequency (49.0 Hz from the underfrequency protection elements - see section 2.1.1) and the restoration frequency to prevent any possible hunting. A restoration frequency setting closer to nominal frequency may be chosen if an operating frequency of 49.3 Hz is unacceptable.

Stage	Restoration Frequency Setting (Hz)	Restoration Time Delay (secs)	Holding Time Delay (secs)
1	49.3Hz	240 sec	20 sec
2	49.3Hz	180 sec	20 sec
3	49.3Hz	120 sec	20 sec
4	49.3Hz	60 sec	20 sec

Table 11 - Restoration guidelines

In this scheme, the time delays ensure that the most critical loads are reconnected first assuming that the higher stages refer to more important loads. By sequentially restoring the load, it is also hoped that system stability is maintained and that the frequency problems are not re-instated. These time settings are system dependent; higher or lower settings may be required depending on the particular application.

It is possible to set up restoration schemes involving multiple frequencies. This allows faster restoration of loads, but the possibility of continuous system operation at frequencies far removed from the nominal must be considered in this case. A typical scheme using two frequencies is shown in Table 12:

Stage	Restore Freq. Restoration Frequency Setting (Hz)	Restore Delay Restoration Time Delay (S)	Holding Time Delay (S)
1	49.5Hz	120 sec	20 sec
2	49.5Hz	60 sec	20 sec
3	49.0Hz	120 sec	20 sec
4	49.0Hz	60 sec	20 sec

Table 12 - Typical scheme using two frequencies

Staggered time settings may be used in this scheme as well, but the time separation among the restoration of stages will be a function of the frequency recovery pattern. Time co-ordinated restoration can only be guaranteed for those stages with a common restoration frequency setting.

2.23 EIA(RS)232 InterMiCOM (“MODEM InterMiCOM”)

The settings needed for the implementation of MODEM InterMiCOM are stored in two columns of the menu structure. The first column entitled **INTERMICOM COMMS** contains all the information to configure the communication channel and also contains the channel statistics and diagnostic facilities. The second column entitled **INTERMICOM CONF** selects the format of each signal and its fallback operation mode.

The settings needed for the InterMiCOM signaling are largely dependant on whether a direct or indirect (modem/multiplexed) connection between the scheme ends is used.

Direct connections will either be short metallic or dedicated fiber optic based (by means of suitable EIA(RS)232 to optical fiber converters) and hence can be set to have the highest signaling speed of 19200b/s. Due to this high signaling rate, the difference in operating speed between the direct, permissive and blocking type signals is so small that the most secure signaling (direct intertrip) can be selected without any significant loss of speed. In turn, since the direct intertrip signaling requires the full checking of the message frame structure and CRC checks, it would seem prudent that the **IM# Fallback Mode** be set to Default with a minimal intentional delay by setting **IM# FrameSyncTim** to 10 msecs. In other words, whenever two consecutive messages have an invalid structure, the relay will immediately revert to the default value until a new valid message is received.

For indirect connections, the settings that can be applied will become more application and communication media dependent. As for the direct connections, consider only the fastest baud rate but this will usually increase the cost of the necessary modem/multiplexer. In addition, devices operating at these high baud rates may suffer from **data jams** during periods of interference and in the event of communication interruptions, may require longer re-synchronization periods. Both of these factors will reduce the effective communication speed thereby leading to a recommended baud rate setting of 9.6 kbit/s. As the baud rate decreases, the communications will become more robust with fewer interruptions, but the overall signaling times will increase.

Since it is likely that slower baud rates will be selected, the choice of signaling mode becomes significant. However, once the signaling mode has been chosen it is necessary to consider what should happen during periods of noise when message structure and content can be lost. If **Blocking** mode is selected, only a small amount of the total message is actually used to provide the signal, which means that in a noisy environment there is still a good likelihood of receiving a valid message. In this case, it is recommended that the **IM# Fallback Mode** is set to **Default** with a reasonably long **IM# FrameSyncTim**. A typical default selection of Default = 1 (blocking received substitute) would generally apply as the failsafe assignment for blocking schemes.

If **Direct Intertrip** mode is selected, the whole message structure must be valid and checked to provide the signal, which means that in a very noisy environment the chances of receiving a valid message are quite small. In this case, it is recommended that the **IM# Fallback Mode** is set to **Default** with a minimum **IM# FrameSyncTim** setting i.e. whenever a non-valid message is received, InterMiCOM will use the set default value. A typical default selection of Default = 0 (intertrip NOT received substitute) would generally apply as the failsafe assignment for intertripping schemes.

If **Permissive** mode is selected, the chances of receiving a valid message is between that of the **Blocking** and **Direct Intertrip** modes. In this case, it is possible that the **IM# Fallback Mode** is set to **Latched**. The table below highlights the recommended **IM# FrameSyncTim** settings for the different signaling modes and baud rates:

<table>
<tr><th rowspan="2">Baud rate</th><th colspan="2">Minimum recommended
“IM# FrameSyncTim” Setting</th><th rowspan="2">Minimum setting (ms)</th><th rowspan="2">Maximum setting (ms)</th></tr>
<tr><th>Direct intertrip mode</th><th>Blocking mode</th></tr>
<tr><td>600</td><td>100</td><td>250</td><td>100</td><td>1500</td></tr>
<tr><td>1200</td><td>50</td><td>130</td><td>50</td><td>1500</td></tr>
<tr><td>2400</td><td>30</td><td>70</td><td>30</td><td>1500</td></tr>
<tr><td>4800</td><td>20</td><td>40</td><td>20</td><td>1500</td></tr>
<tr><td>9600</td><td>10</td><td>20</td><td>10</td><td>1500</td></tr>
<tr><td>19200</td><td>10</td><td>10</td><td>10</td><td>1500</td></tr>
<tr><td colspan="5">Note No recommended setting is given for the Permissive mode since it is anticipated that Latched operation will be selected. However, if Default mode is selected, the IM# FrameSyncTim setting should be set greater than the minimum settings listed above. If the IM# FrameSyncTim setting is set lower than the minimum setting listed above, there is a danger that the relay will monitor a correct change in message as a corrupted message.</td></tr>
<tr><td colspan="5">A setting of 25% is recommended for the communications failure alarm.</td></tr>
</table>

Table 13 - Recommended IM# FrameSyncTim settings

A setting of 25% is recommended for the communications failure alarm.

2.24 Sensitive Power Protection

The Sensitive Power is a single phase power element using A phase current and voltage. This protection provides all the required functionality - Low Forward Power, Reverse Power and Over Power with timer and pole-dead inhibit.

For both reverse and low forward power protection function settings greater than 3% Pn, the phase angle errors of suitable protection class current transformers will not result in any risk of mal-operation or failure to operate. However, for the sensitive power protection if settings less than 3% are used, it is recommended that the current input is driven by a correctly loaded metering class current transformer.

The sensitive power protection has a minimum setting accuracy of 0.5% Pn using the In sensitive CT to calculate single phase active power. It also provides phase compensation to remove errors introduced by the primary input transformers.

2.25 Phase Segregated Power Protection

2.25.1 Low Forward Power Protection

When the machine is generating and the CB connecting the generator to the system is tripped, the electrical load on the generator is cut. This could lead to generator over-speed if the mechanical input power is not reduced quickly. Turbo-alternators with low-inertia rotor designs, do not have a high over speed tolerance. Trapped steam in the turbine, downstream of a valve that has just closed, can rapidly lead to over speed. To reduce the risk of over speed damage to such sets, it is sometimes chosen to interlock non-urgent tripping of the generator breaker and the excitation system with a low forward power check. This ensures that the generator set circuit breaker is opened only when the output power is sufficiently low that over speeding is unlikely. The delay in electrical tripping, until prime mover input power has been removed, may be deemed acceptable for 'non-urgent' protection trips. For 'urgent' trips, the low forward power interlock should not be used. With the low probability of 'urgent' trips, the risk of over speed and possible consequences must be accepted.

The low forward power protection can be arranged to interlock 'non-urgent' protection tripping using the relay scheme logic. It can also be arranged to provide a contact for external interlocking of manual tripping, if desired. To prevent unwanted relay alarms and flags, a low forward power protection element can be disabled when the circuit breaker is opened via 'poledead' logic. The low forward power protection can also be used to provide loss of load protection when a machine is motoring. It can be used for example to protect a machine which is pumping from becoming unprimed or to stop a motor in the event of a failure in the mechanical transmission. A typical application would be for pump storage generators operating in the motoring mode, where there is a need to prevent the machine becoming unprimed which can cause blade and runner cavitation.

2.25.2 Reverse Power Protection

A generator is expected to supply power to the connected system in normal operation. If the generator prime mover fails, a generator that is connected in parallel with another source of electrical supply will begin to 'motor'. This reversal of power flow due to loss of prime mover can be detected by the reverse power element. The consequences of generator motoring and the level of power drawn from the power system will be dependent on the type of prime mover.

In some applications, the level of reverse power in the case of prime mover failure may fluctuate. This may be the case for a failed diesel engine. To prevent cyclic initiation and reset of the main trip timer, and consequent failure to trip, an adjustable reset time delay is provided. This delay would need to be set longer than the period for which the reverse power could fall below the power setting. This setting needs to be taken into account when setting the main trip time delay. It should also be noted that a delay on reset in excess of half the period of any system power swings could result in operation of the reverse power protection during swings. Reverse power protection may also be used to interlock the opening of the generator set circuit breaker for 'non-urgent' tripping. Reverse power interlocks are preferred over low forward power interlocks by some utilities.

2.25.3 Over Power Protection

The overpower protection can be used as overload indication, as a back-up protection for failure of governor and control equipment, and would be set above the maximum power rating of the machine.

3 APPLICATION OF NON PROTECTION FUNCTIONS

3.1 Three-Phase Auto-Reclosing

An analysis of faults on any overhead line network has shown that 80 - 90% are transient in nature.

A transient fault, such as an insulator flashover, is a self-clearing ‘non-damage’ fault. This type of fault can be cleared by the immediate tripping of one or more circuit breakers to isolate the fault, and does not recur when the line is re-energized. Lightning is the most common cause of transient faults, other possible causes being clashing conductors and wind blown debris. The remaining 10 - 20% of faults are either semi-permanent or permanent.

A small tree branch falling on the line could cause a semi-permanent fault. Here the cause of the fault would not be removed by the immediate tripping of the circuit, but could be burnt away during a time-delayed trip.

Permanent faults could be broken conductors, transformer faults, cable faults or machine faults that must be located and repaired before the supply can be restored.

In the majority of fault incidents, if the faulty line is immediately tripped out, and time is allowed for the fault arc to de-ionize, re-closure of the circuit breakers will result in the line being successfully re-energized. Auto-reclose schemes are employed to automatically re-close a switching device a set time after it has been opened due to operation of protection where transient and semi-permanent faults are prevalent.

On HV/MV distribution networks, auto-reclosing is applied mainly to radial feeders where system stability problems do not generally arise. The main advantages to be derived from using auto-reclose can be summarized as follows:

- Minimizes interruptions in supply to the consumer
- Reduces operating costs - less man-hours in repairing fault damage and the possibility of running substations unattended. With auto-reclose instantaneous protection can be used which means shorter fault duration’s which gives rise to less fault damage and fewer permanent faults

The introduction of auto-reclosing gives an important benefit on circuits using time graded protection, in that it allows the use of instantaneous protection to give a high speed first trip. With fast tripping, the duration of the power arc resulting from an overhead line fault is reduced to a minimum, thus lessening the chance of damage to the line, which might otherwise cause a transient fault to develop into a permanent fault. Using instantaneous protection also prevents blowing of fuses in teed circuits and reduces circuit breaker maintenance by eliminating pre-arc heating when clearing transient faults.

It should be noted that when instantaneous protection is used with auto-reclosing, the scheme is normally arranged to block the instantaneous protection after the first trip. Therefore, if the fault persists after re-closure, the time graded protection will give discriminative tripping with fuses or other protection devices, resulting in the isolation of the faulted section. However, for certain applications, where the majority of the faults are likely to be transient, it is not uncommon to allow more than one instantaneous trip before the instantaneous protection is blocked.

Some schemes allow a number of re-closures and time graded trips after the first instantaneous trip, which may result in the burning out and clearance of semi-permanent faults. Such a scheme may also be used to allow fuses to operate in teed feeders where the fault current is low.

When considering feeders that are partly overhead line and partly underground cable, any decision to install auto-reclosing would be influenced by any data known on the frequency of transient faults. When a significant proportion of the faults are permanent, the advantages of auto-reclosing are small, particularly since re-closing on to a faulty cable is likely to aggravate the damage.

3.1.1 Setting Guidelines

3.1.1.1 Number of Shots

There are no clear-cut rules for defining the number of shots for a particular application. Generally medium voltage systems utilize only two or three shot auto-reclose schemes. However, in certain countries, for specific applications, four shots is not uncommon. Four shots have the advantage that the final dead time can be set sufficiently long to allow any thunderstorms to pass before re-closing for the final time. This arrangement will prevent unnecessary lockout for consecutive transient faults.

Typically, the first trip, and sometimes the second, will result from instantaneous protection - since 80% of faults are transient, the subsequent trips will be time delayed, all with increasing dead times to clear semi-permanent faults.

In order to determine the required number of shots the following factors must be taken into account:

- An important consideration is the ability of the circuit breaker to perform several trip-close operations in quick succession and the effect of these operations on the maintenance period.
- On EHV transmission circuits with high fault levels, only one re-closure is normally applied, because of the damage that could be caused by multiple re-closures if the fault is permanent.

3.1.1.2 Dead Timer Setting

The choice of dead time is, very much, system dependent. The main factors that can influence the choice of dead time are:

- Stability and synchronism requirements
- Operational convenience
- Load
- The type of circuit breaker
- Fault de-ionizing time
- The protection reset time

3.1.1.3 Stability and Synchronism Requirements

If the power transfer level on a specific feeder is such that the systems at either end of the feeder could quickly fall out of synchronism if the feeder is opened, it is usually required to re-close the feeder as quickly as possible, to prevent loss of synchronism. This is called High Speed Auto-Reclosing (HSAR). In this situation, the dead time setting should be adjusted to the minimum time necessary to allow complete de-ionization of the fault path and restoration of the full voltage withstand level, and comply with the “minimum dead time” limitations imposed by the circuit breaker and protection (see below). Typical HSAR dead time values are between 0.3 and 0.5 seconds.

On a closely interconnected transmission system, where alternative power transfer paths usually hold the overall system in synchronism even when a specific feeder opens, or on a radial supply system where there are no stability implications, it is often preferred to leave a feeder open for a few seconds after fault clearance. This allows the system to stabilize, and reduces the shock to the system on re-closure. This is called slow or

Delayed Auto-Reclosing (DAR). The dead time setting for DAR is usually selected for operational convenience (see below).

3.1.1.3.1 Operational Convenience

When HSAR is not required, the dead time chosen for the first re-closure (shot) following a fault trip is not critical. It should be long enough to allow any transients resulting from the fault and trip to decay, but not so long as to cause major inconvenience to consumers who are affected by the loss of the feeder. The setting chosen often depends on service experience with the specific feeder.

Typical first shot dead time settings on 11 kV distribution systems are 5 to 10 seconds. In situations where two parallel circuits from one substation are carried on the same towers, it is often arranged for the dead times on the two circuits to be staggered, e.g. one at 5 seconds and the other at 10 seconds, so that the two circuit breakers do not re-close simultaneously following a fault affecting both circuits.

For multi-shot auto-reclose cycles, the second and subsequent shot dead times are usually longer than the first shot, to allow time for “semi-permanent” faults to burn clear, and to allow for the CB rated duty cycle and spring charging time. Typical second and third shot dead time settings are 30 seconds and 60 seconds respectively.

3.1.1.3.2 Load Requirements

Some types of electrical load might have specific requirements for minimum and/or maximum dead time, to prevent damage and ensure minimum disruption. For example, synchronous motors are only capable of tolerating extremely short interruptions of supply without loss of synchronism. In practice it is desirable to disconnect the motor from the supply in the event of a fault; the dead time would normally be sufficient to allow the motor no-volt device to operate. Induction motors, on the other hand, can withstand supply interruptions up to typically 0.5 seconds and re-accelerate successfully.

3.1.1.3.3 Circuit Breaker

For high speed auto-reclose the minimum dead time of the power system will depend on the minimum time delays imposed by the circuit breaker during a tripping and re-closing operation.

After tripping, time must be allowed for the mechanism to reset before applying a closing pulse; otherwise, the circuit breaker might fail to close correctly. This resetting time will vary depending on the circuit breaker, but is typically 0.1 seconds.

Once the mechanism has reset, a CB Close signal can be applied. The time interval between the energization of the closing mechanism and the making of the contacts is termed the closing time. Owing to the time constant of a solenoid closing mechanism and the inertia of the plunger, a solenoid closing mechanism may take 0.3s. A spring operated breaker, on the other hand, can close in less than 0.1 seconds.

Where high speed re-closing is required, for the majority of medium voltage applications, the circuit breaker mechanism reset time itself dictates the minimum dead time. The minimum system dead time only considering the CB is the mechanism reset time plus the CB closing time. Thus, a solenoid mechanism will not be suitable for high speed auto-reclose as the closing time is generally too long.

For most circuit breakers, after one re-closure, it is necessary to recharge the closing mechanism energy source, (spring, gas pressure etc.) before a further re-closure can take place. Therefore the dead time for second and subsequent shots in a multi-shot sequence must be set longer than the spring or gas pressure recharge time.

3.1.1.3.4 Fault De-Ionizing Time

For high speed auto-reclose the fault de-ionizing time may be the most important factor when considering the dead time. This is the time required for ionized air to disperse around the fault position so that the insulation level of the air is restored. It cannot be accurately predicted. However, it can be approximated from the following formula, based on extensive experience on many transmission and distribution systems throughout the world:

De-ionizing time	=	(10.5 + ((system voltage in kV)/34.5))/frequency
For 66 kV	=	0.25s (50Hz)
For 132 kV	=	0.29s (50 Hz)

3.1.1.3.5 Protection Reset

It is essential that any time graded protection fully resets during the dead time, so that correct time discrimination will be maintained after re-closure on to a fault. For high speed auto-reclose, instantaneous reset of protection is required. However at distribution level, where the protection is predominantly made up of overcurrent and earthfault relays, the protection reset time may not be instantaneous (e.g. induction disk relays). In the event that the circuit breaker re-closes on to a fault and the protection has not fully reset, discrimination may be lost with the downstream protection. To avoid this condition the dead time must be set in excess of the slowest reset time of either the local relay or any downstream protection.

Typical 11/33kV dead time settings in the UK are as follows:

1st dead time	=	5 - 10 seconds
2nd dead time	=	30 seconds
3rd dead time	=	60 - 180 seconds

4th dead time (uncommon in the UK, however used in South Africa) = 1 - 30 minutes

3.1.1.4 Reclaim Timer Setting

A number of factors influence the choice of the reclaim timer, such as:

- Supply continuity - Large reclaim times can result in unnecessary lockout for transient faults
- Fault incidence/Past experience - Small reclaim times may be required where there is a high incidence of lightning strikes to prevent unnecessary lockout for transient faults
- Spring charging time - For high speed auto-reclose the reclaim time may be set longer than the spring charging time to ensure there is sufficient energy in the circuit breaker to perform a trip-close-trip cycle. For delayed auto-reclose there is no need as the dead time can be extended by an extra CB healthy check window time if there is insufficient energy in the CB. If there is insufficient energy after the check window time the relay will lockout
- Switchgear maintenance - Excessive operation resulting from short reclaim times can mean shorter maintenance periods. A minimum reclaim time of >5s may be needed to allow the CB time to recover after a trip and close before it can perform another trip-close-trip cycle. This time will depend on the duty (rating) of the CB

The reclaim time must be long enough to allow any time delayed protection initiating auto-reclose to operate. Failure to do so would result in premature resetting of the auto-reclose scheme and re-enabling of instantaneous protection. If this condition arose, a permanent fault would effectively look like a number of transient faults, resulting in continuous auto-reclosing unless additional measures were taken to overcome this such as excessive fault frequency lockout protection

Sensitive earth fault protection is applied to detect high resistance earth faults and usually has a long time delay, typically 10 - 15s. This longer time may have to be taken into consideration, if auto-reclosing from SEF protection, when deciding on a reclaim time, if the reclaim time is not blocked by an SEF protection start signal. High resistance earth faults, for example, a broken overhead conductor in contact with dry ground or a wood fence, is rarely transient and may be a danger to the public. It is therefore common practice to block auto-reclose by operation of sensitive earth fault protection and lockout the circuit breaker.

A typical 11/33kV reclaim time in the UK is 5 - 10 seconds, this prevents unnecessary lockout during thunderstorms. However, times up to 60 - 180 seconds may be used elsewhere in the world.

3.2 Function Keys

The following default PSL logic illustrates the programming of function keys to enable/disable the auto-reclose functionality. Please note the auto-reclose functionality should be enabled in the Configuration column for this feature to work.

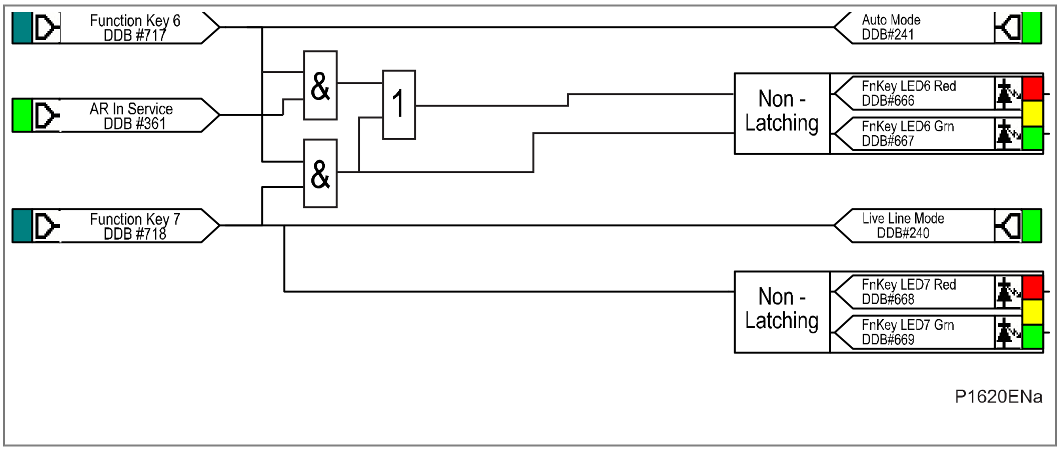


Figure 22 - Auto-reclose default PSL

Note	*Energizing two inputs to an LED conditioner creates a YELLOW illumination.*

Function Key 6 is set to ‘Toggle’ mode and on activation of the key, the auto-reclose function will be in service as long as the auto-reclose function has been enabled in the “Configuration” menu. The associated LED will indicate the state of the ARC function in service as RED. The LED indication will show YELLOW should the ‘Live Line mode’ be activated whilst the ARC in service function key is active.

Function Key 7 is set to ‘Toggle’ mode and on activation of the key, the auto-reclose function will be set to the ‘Live Line Mode’ with the auto-reclose enabled in the “Configuration” menu. The associated LED will indicate the state of the ARC function in ‘Live Line’ as RED.

3.3 Current Transformer Supervision (CTS)

The Current Transformer Supervision (CTS) feature is used to detect failure of one or more of the ac phase current inputs to the relay. Failure of a phase CT or an open circuit of the interconnecting wiring can result in incorrect operation of any current operated element. Additionally, interruption in the ac current circuits risks dangerous CT secondary voltages being generated.

3.3.1 Setting the CT Supervision Element

The residual voltage setting, **CTS Vn< Inhibit** and the residual current setting, **CTS In> set**, should be set to avoid unwanted operation during healthy system conditions. For example **CTS Vn< Inhibit** should be set to at least 120% of the maximum steady state residual voltage. The **CTS In> set** will typically be set below minimum load current. The time-delayed alarm, **CTS Time Delay**, is generally set to 5 seconds.

Where the magnitude of residual voltage during a ground/earth fault is unpredictable, the element can be disabled to prevent protection elements being blocked during fault conditions.

3.4 Circuit Breaker Condition Monitoring

Periodic maintenance of circuit breakers is necessary to ensure that the trip circuit and mechanism operate correctly, and also that the interrupting capability has not been compromised due to previous fault interruptions. Generally, such maintenance is based on a fixed time interval, or a fixed number of fault current interruptions. These methods of monitoring circuit breaker condition give a rough guide only and can lead to excessive maintenance.

3.4.1 Setting Guidelines

3.4.1.1 Setting the Σ I^ Thresholds

Where overhead lines are prone to frequent faults and are protected by Oil Circuit Breakers (OCBs), oil changes account for a large proportion of the life cycle cost of the switchgear. Generally, oil changes are performed at a fixed interval of circuit breaker fault operations. However, this may result in premature maintenance where fault currents tend to be low, and hence oil degradation is slower than expected. The Σ I^ counter monitors the cumulative severity of the duty placed on the interrupter allowing a more accurate assessment of the circuit breaker condition to be made.

For OCBs, the dielectric withstand of the oil generally decreases as a function of ΣI^2t. This is where ‘I’ is the fault current broken, and ‘t’ is the arcing time within the interrupter tank (not the interrupting time). As the arcing time cannot be determined accurately, the relay would normally be set to monitor the sum of the broken current squared, by setting ‘Broken I^’ = 2.

For other types of circuit breaker, especially those operating on higher voltage systems, practical evidence suggests that the value of ‘**Broken I^**’ = 2 may be inappropriate. In such applications ‘**Broken I^**’ may be set lower, typically 1.4 or 1.5. An alarm in this instance may be indicative of the need for gas/vacuum interrupter HV pressure testing, for example. The setting range for ‘**Broken I^**’ is variable between 1.0 and 2.0 in 0.1 steps. It is imperative that any maintenance program must be fully compliant with the switchgear manufacturer’s instructions.

3.4.1.2 Setting the Number of Operations Thresholds

Every operation of a circuit breaker results in some degree of wear for its components. Therefore, routine maintenance, such as oiling of mechanisms, may be based upon the number of operations. Suitable setting of the maintenance threshold will allow an alarm to be raised, indicating when preventative maintenance is due. Should maintenance not be carried out, the relay can be set to lockout the auto-reclose function on reaching a second operations threshold. This prevents further reclosure when the circuit breaker has not been maintained to the standard demanded by the switchgear manufacturer’s maintenance instructions.

Certain circuit breakers, such as Oil Circuit Breakers (OCBs) can only perform a certain number of fault interruptions before requiring maintenance attention. This is because each fault interruption causes carbonizing of the oil, degrading its dielectric properties. The maintenance alarm threshold **No CB Ops. Maint.** may be set to indicate the requirement for oil sampling for dielectric testing, or for more comprehensive maintenance. Again, the lockout threshold **No CB Ops. Lock** may be set to disable auto-reclosure when repeated further fault interruptions could not be guaranteed. This minimizes the risk of oil fires or explosion.

3.4.1.3 Setting the Operating Time Thresholds

Slow CB operation is also indicative of the need for mechanism maintenance. Therefore, alarm and lockout thresholds (CB Time Maint./CB Time Lockout) are provided and are settable in the range of 5 to 500 ms. This time is set in relation to the specified interrupting time of the circuit breaker.

3.4.1.4 Setting the Excessive Fault Frequency Thresholds

Persistent faults will generally cause auto-reclose lockout, with subsequent maintenance attention. Intermittent faults such as clashing vegetation may repeat outside of any reclaim time, and the common cause might never be investigated. For this reason it is possible to set a frequent operations counter on the relay which allows the number of operations **Fault Freq. Count** over a set time period **Fault Freq. Time** to be monitored. A separate alarm and lockout threshold can be set.

3.5 Calculating the Rate of Change of Frequency for Load Shedding

In the event of severe system overload or loss of generation conditions, the system frequency will decline exponentially and theoretically stabilize at a steady state level somewhere below the nominal frequency. The time constant of the exponential decay as well as the steady state level is governed by certain parameters such as the system inertia constant, system damping constant etc. The following is an available theory for calculating the rate of change of frequency for a particular system contingency.

Assuming that the load and generation remain constant as the frequency changes, the instantaneous rate of change of frequency at the time of an overload is given by:

Equation 1 - Instantaneous rate of change of frequency:

$$\frac{df}{dt} = \frac{\Delta P.fn}{2H}$$

Where:

$$\Delta P = \text{overload in per unit} = \frac{\text{Connected Load} - \text{Available Generation}}{\text{Available Generation}}$$

f_n = nominal system frequency (in Hz)

H = combined inertia constant of the power system (MWsec/MVA)

$$H = \left(\frac{H_1 MVA_1 + ... + H_n MVA_n}{MVA_1 + ... + MVA_n} \right)$$

Where n subscripts 1, 2, …, n refer to individual generating units

The inertia constant used in Equation 1, is essentially a measure of the kinetic energy in a generator rotor. For some types of large steam generator sets, the inertia constant can have a value of 10 but a figure of less than 5 is more prevalent especially when considering other generator types. Lower values tend to dominate with smaller rotor masses e.g. wind turbines, and can make the power system more prone to serious frequency disturbances for sudden load changes. Typically values between 2 and 5 may be used if no other knowledge is available.

Real loads, particularly motor loads, do vary with frequency and have a tendency to decrease as frequency reduces. This will have some beneficial effect on system stability and will reduce the effects of the overload condition. Taking this load reduction factor into account, the frequency deviation from nominal is given by:

Equation 2 - Frequency deviation from nominal:

$$\Delta f = \frac{\Delta P.f_n}{d} \left(1 - e^{-\left(\frac{t.d}{2H} \right)} \right)$$

Where:

d = load reduction (or damping) factor

$$d = \frac{\text{Percentage change in load}}{\text{Percentage change in frequency}}$$

The above equations are a result of vast simplifications. The actual frequency change will be influenced by governor droop characteristics, load dynamics, interconnections between various generators, system stabilizers etc. However the frequency deviations calculated in the formulae described may be a good measure of the rate of change of frequency for the purpose of setting the relay.

Warning	**The frequency profile is system and situation specific. A good knowledge of the system behavior under a variety of conditions is essential so you can decide on suitable settings for the frequency protection.**

3.5.1 Example of Frequency Behavior During Overload Conditions

Using the theoretical formulae given in section 3.1, it is possible to calculate the theoretical behavior of a simple network, shown below:

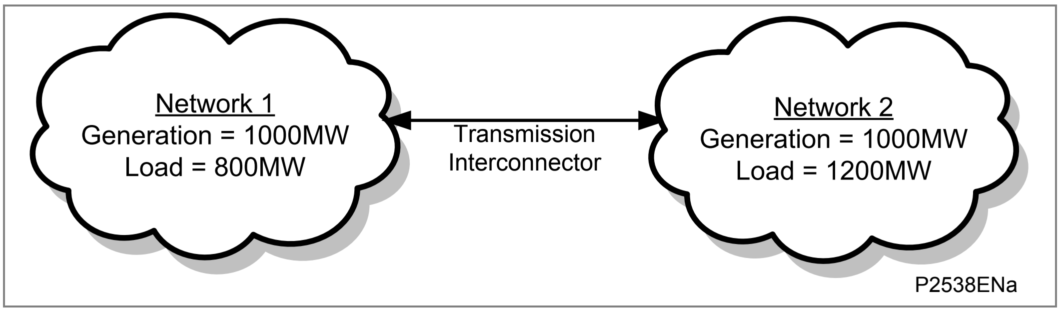


Figure 23 - Simple interconnected system to highlight frequency behavior calculations

In the simple network of Figure 23, it can be easily seen that Network 2 has a generation deficit of 200MW which is normally supplied from Network 1 through the transmission interconnector. In the event of loss of this interconnection, and assuming that the System Inertia Constant (H) of Network 2 is equal to 4, we can calculate that the rate of change of frequency at the time of the overload using Equation 1.

Equation 3 - Instantaneous rate of change of frequency - example:

$$\frac{df}{dt} = \frac{\Delta P.f_n}{2H}$$

$$\frac{df}{dt} = \left(\frac{\left(\frac{1200 - 1000}{1000}\right).50}{8}\right)$$

$$\frac{df}{dt} = -1.25 \text{ Hz/s}$$

It is clear from this calculation that if the inertia constant reduces, the rate of change will increase. For example if H=1, then df/dt = -5Hz/s.

We can also introduce the concept of damping factor that assumes that as the frequency reduces, there is a corresponding load reduction, by using Equation 2. If we assume that there is a 1% change in load for every 1% change in frequency, we have a damping factor of 1, and the frequency deviation after 1s will be:

Equation 4 - Frequency deviation from nominal - example:

$$\Delta f = \frac{\Delta P.f_n}{d}\left(1 - e^{-\left(\frac{t.d}{2H}\right)}\right)$$

$$\Delta f = \frac{0.2x50}{1}\left(1 - e^{-\left(\frac{1}{8}\right)}\right)$$

$$\Delta f = \quad 1.175\text{Hz}$$

In other words, if the system was originally operating at 50Hz, after 1s the system frequency would have dropped to 48.825Hz. Here we notice the effects of the damping factor since the first calculation assumed an initial rate of change of frequency of -1.25Hz/s, which in turn would lead us to consider a system frequency of 48.75Hz after 1s of overload.

Figure 24 shows a set of curves highlighting the frequency of the example system assuming different overload levels and inertia constants for 35s after onset of the overload condition. The damping factor, d, in all cases is 1.

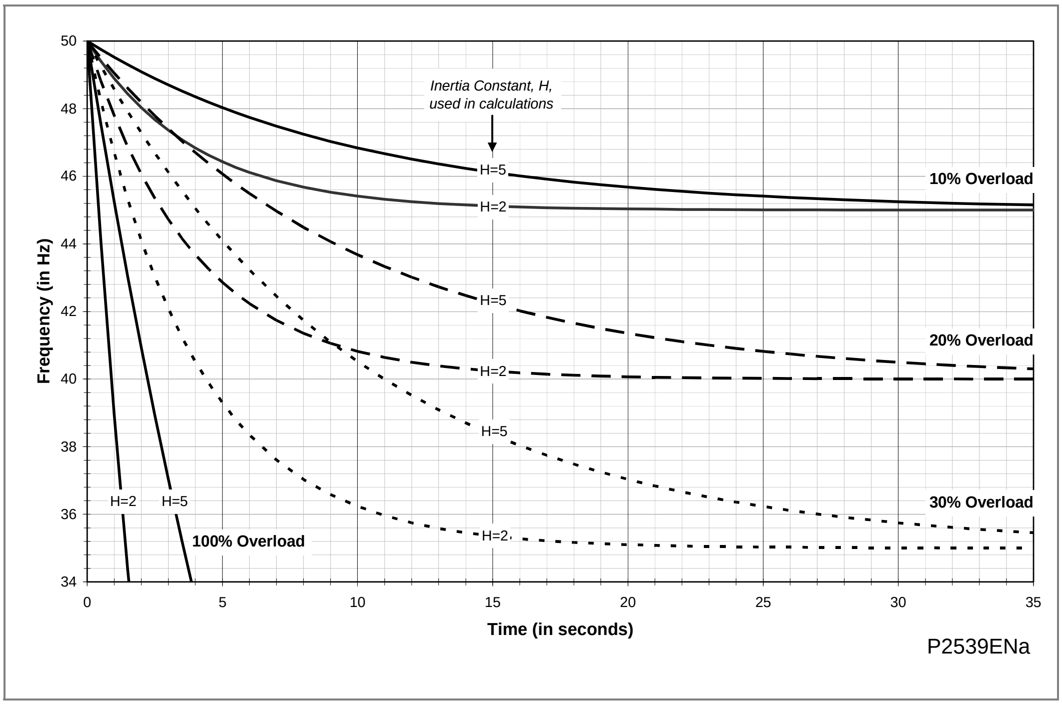


Figure 24 - Frequency profile of the example system for various overload conditions

3.6 Effect of Averaging Cycles

The P140 relays use a 1-cycle Discrete Fourier transform (DFT) in order to track the system frequency and maintain the sampling rate (see P14x/EN FD). Two times per cycle, a new frequency measurement is made available to the frequency protection algorithms. However, in order to assist stability of the measurement, various averaging techniques are used and their effects are discussed in the following two sections.

3.6.1 Frequency Averaging Cycles

Two times per cycle, a new “raw” frequency measurement is made available by the DFT and placed into the frequency averaging buffer. The size of this buffer is user-selectable up to 48 cycles for software version 43. It is the output of this buffer that is checked against any frequency setting to establish whether the element should start operation or not. The purpose of this averaging process is to smooth the frequency measurement since real frequency excursions are highly oscillatory, but as a consequence the operating and reset times will extend depending upon the exact system conditions and relay settings.

Due to the techniques used and the myriad of different frequency conditions that can be exposed to the relay, it is difficult to provide an exact formula to calculate the extension of times associated with the number of frequency averaging cycles. However, as a result of extensive relay testing, it is possible to give the following graphs that indicate typical additional times. These values must be added to the operation time for the relay with a frequency averaging cycle setting of zero (see P14x/EN TD).

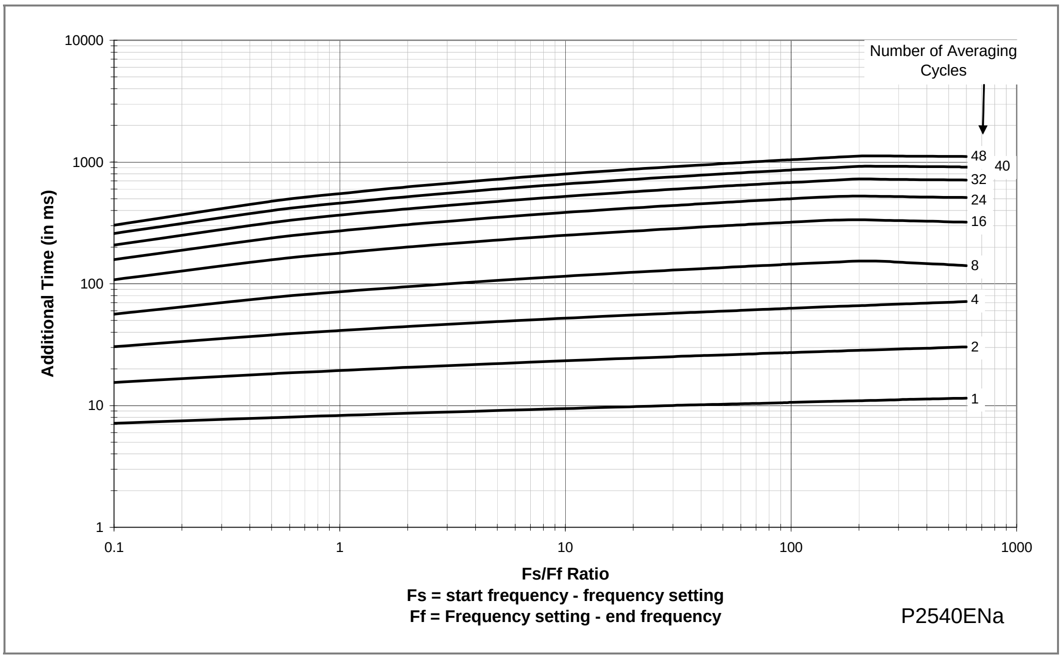


Figure 25 - Additional operating time for underfrequency thresholds

In Figure 25, the Fs/Ff ratio is related to a test scenario where the start frequency is above the underfrequency setting and the end frequency is below the frequency setting.

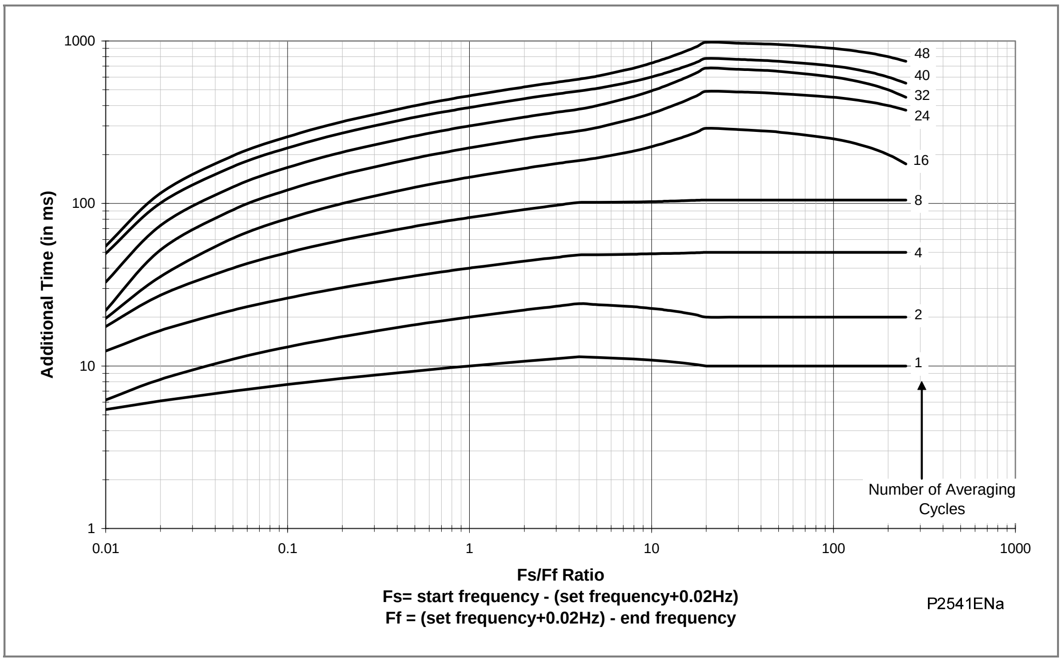


Figure 26 - Additional reset time for underfrequency thresholds

In Figure 26, the Fs/Ff ratio is related to a test scenario where the start frequency is below the underfrequency setting and the end frequency is above the frequency setting.

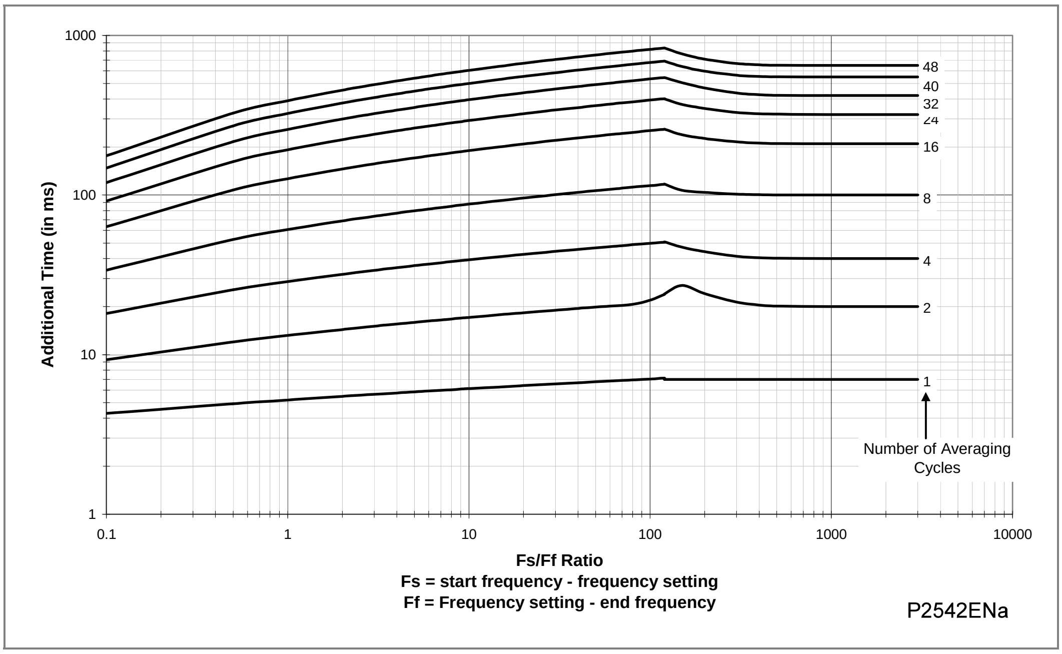


Figure 27 - Additional operating time for overfrequency thresholds

In Figure 27, the Fs/Ff ratio is related to a test scenario where the start frequency is below the overfrequency setting and the end frequency is above the frequency setting.

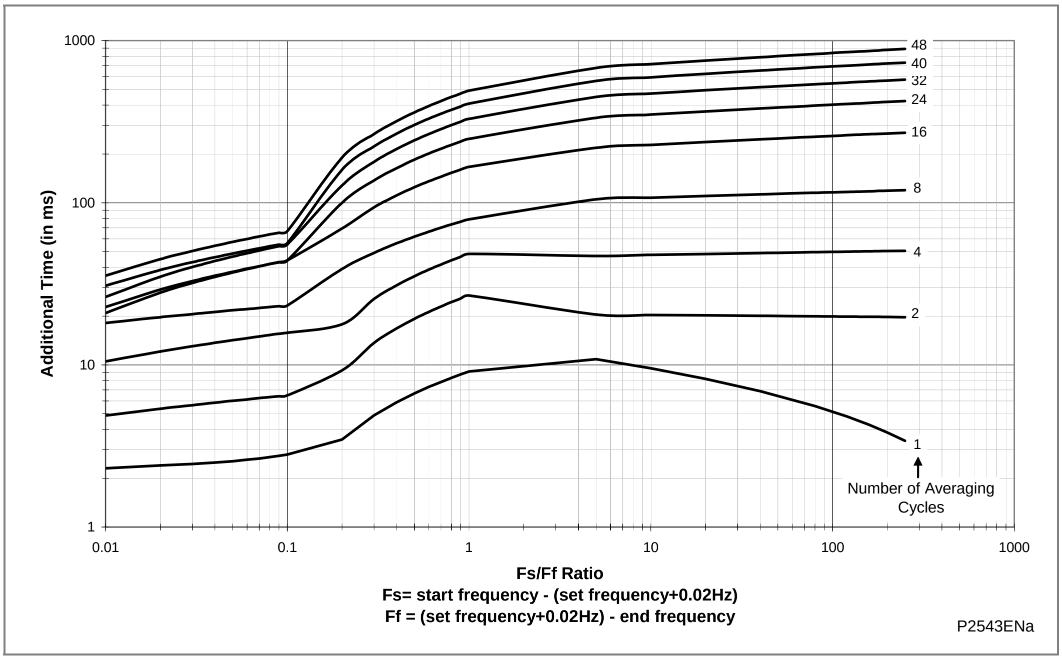


Figure 28 - Additional reset time for overfrequency thresholds

In Figure 28, the Fs/Ff ratio is related to a test scenario where the start frequency is above the overfrequency setting and the end frequency is below the frequency setting.

All frequency settings are affected by the selection of frequency averaging cycles. In other words, the f+t [81O/81U], the f+df/dt [81RF], the f+Df/Dt [81RAV], load restoration and generator abnormal protection [81AB] will all use the averaged frequency measurements.

3.6.2 df/dt Averaging Cycles

As for the frequency measurements, two times per cycle a new “raw” df/dt measurement is passed into the df/dt averaging buffer. The size of this buffer is user-selectable up to 48 cycles for software version 43. It is the output of this buffer that is checked against any df/dt setting to establish whether the element should start operation or not. The purpose of this averaging process is to smooth the df/dt measurement since real frequency excursions are highly oscillatory, but as a consequence the operating and reset times will extend depending upon the exact system conditions and relay settings.

Due to the techniques used and the myriad of different conditions that can be exposed to the relay, it is difficult to provide an exact formula to calculate the extension of times associated with the number of df/dt averaging cycles. However, as a result of extensive relay testing, it is possible to give the following graphs that indicate typical additional times. These values must be added to the operation time for the relay with a df/dt averaging cycle setting of zero (see P14x/EN TD).

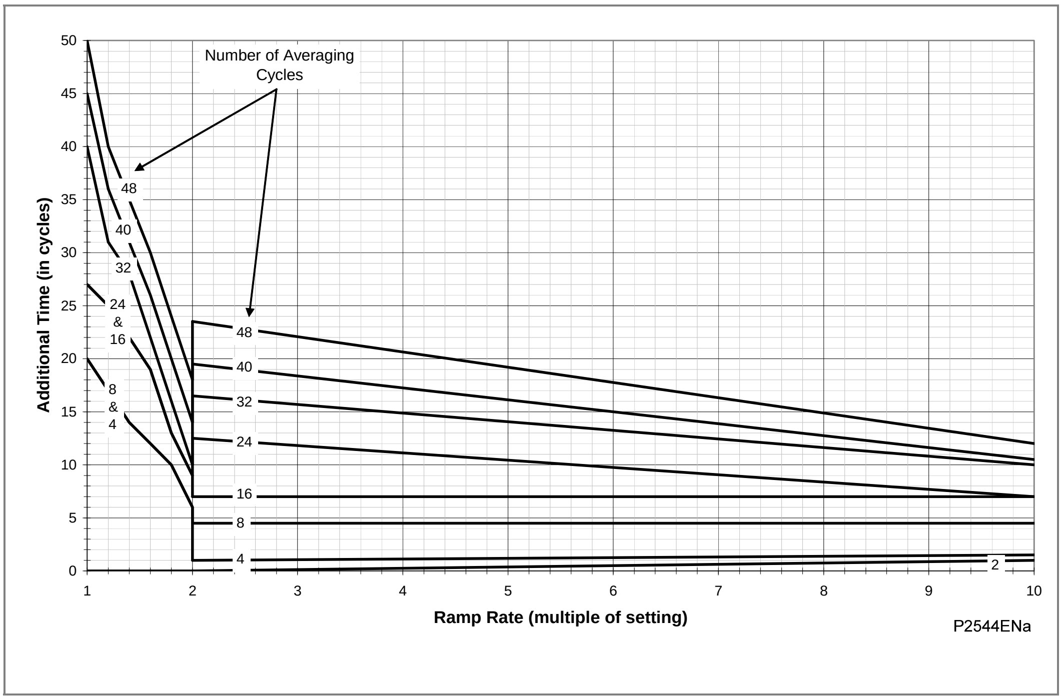


Figure 29 - Additional operating time for falling frequency conditions

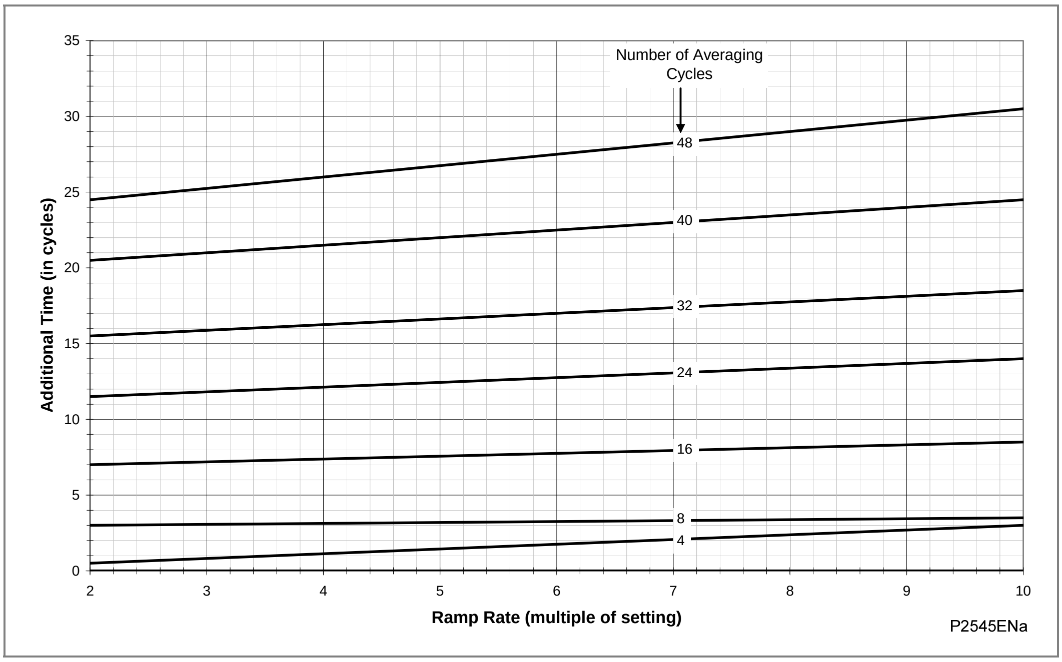


Figure 30 - Additional reset time for falling frequency conditions

In Figure 30, the ramp rate refers to the rate of rise of frequency as a multiple of the df/dt setting.

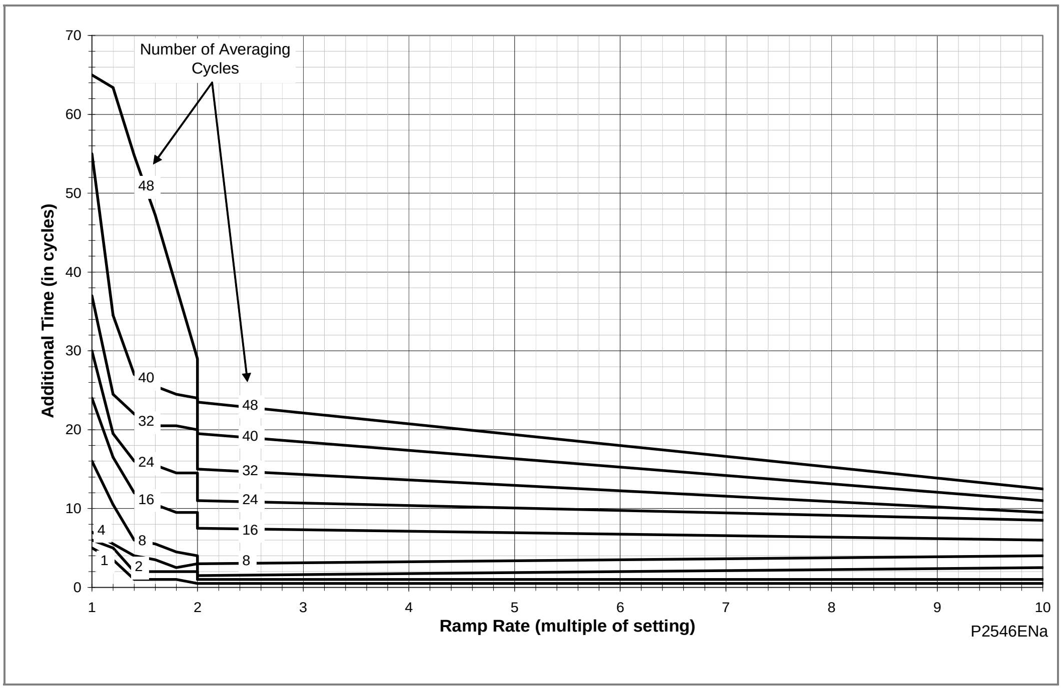


Figure 31 - Additional operating time for rising frequency conditions

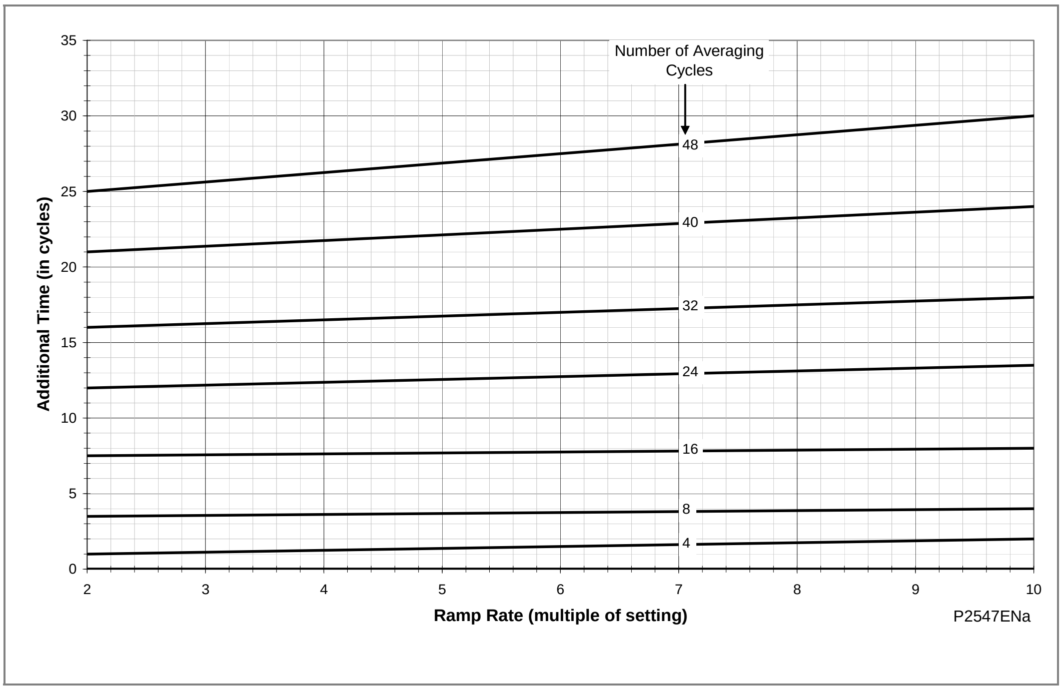


Figure 32 - Additional reset time for rising frequency conditions

In Figure 32, the ramp rate refers to the rate of fall of frequency as a multiple of the df/dt setting.

All instantaneous rate of change of frequency settings are affected by the selection of df/dt averaging cycles. In other words, the df/dt+t [81R] and the f+df/dt [81RF] will both use the averaged df/dt measurements. The f+Df/Dt[81RAV] is unaffected by the df/dt averaging cycles setting as both the frequency and average rate of change of frequency measurements are based upon actual frequency measurements which are controlled by the frequency averaging cycles setting.

3.6.3 Setting Recommendation for df/dt Averaging Cycles

One of the enhancements in version 43 software was the reduction of the lower setting limit of the df/dt threshold to 0.01Hz/s. This sensitive setting range makes the relay prone to "chatter" as a result of the oscillations that will be present during the frequency excursion, and therefore it is necessary to stabilize the relay using the averaging cycles setting and/or time delays. Figure 33 shows the minimum recommended df/dt averaging cycles that should be used if no intentional time delays are set for the element.

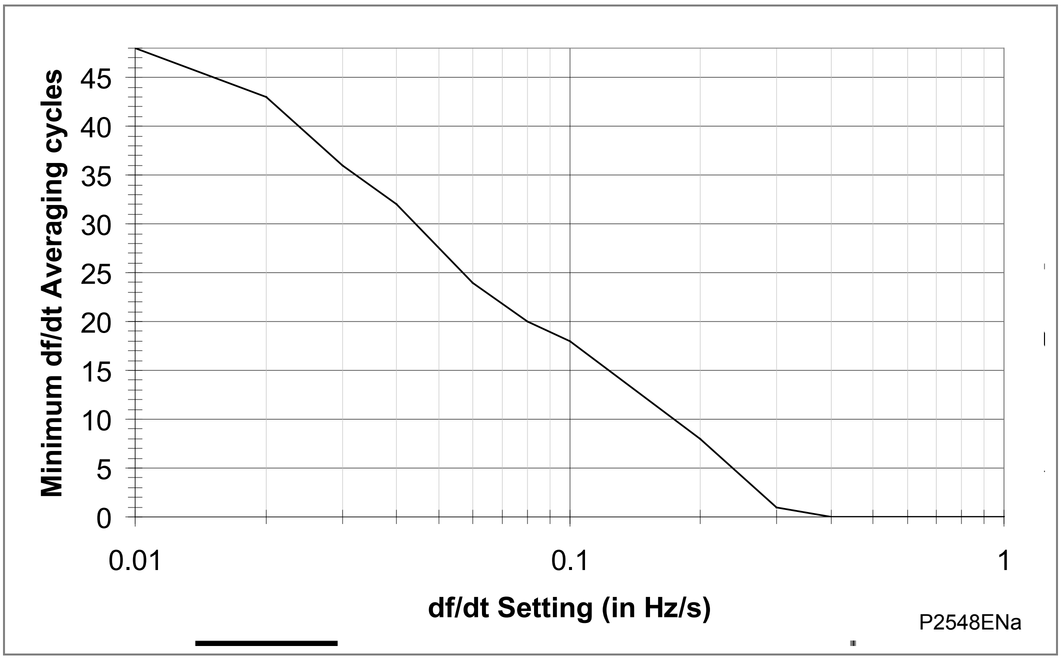


Figure 33 - Additional reset time for rising frequency conditions

3.7 Trip Circuit Supervision (TCS)

The trip circuit, in most protective schemes, extends beyond the relay enclosure and passes through components such as fuses, links, relay contacts, auxiliary switches and other terminal boards. This complex arrangement, coupled with the importance of the trip circuit, has led to dedicated schemes for its supervision.

Several Trip Circuit Supervision (TCS) schemes with various features can be produced with the P145 range. Although there are no dedicated settings for TCS, in the P145, the following schemes can be produced using the Programmable Scheme Logic (PSL). A user alarm is used in the PSL to issue an alarm message on the relay front display. If necessary, the user alarm can be re-named using the menu text editor to indicate that there is a fault with the trip circuit.

3.7.1 TCS Scheme 1

3.7.1.1 Scheme Description

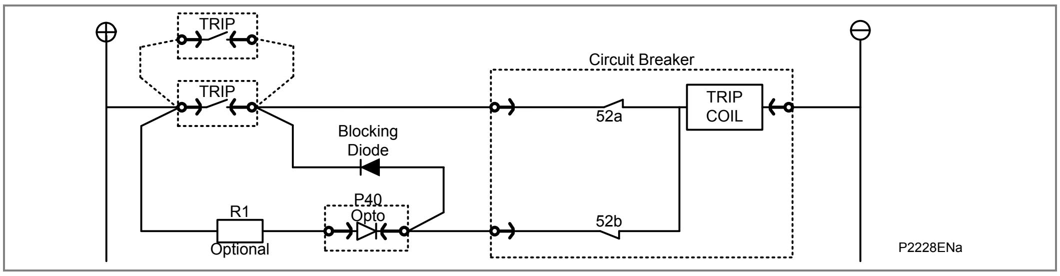


Figure 34 - TCS scheme 1

This scheme provides supervision of the trip coil with the breaker open or closed, however, pre-closing supervision is not provided. This scheme is also incompatible with latched trip contacts, as a latched contact will short out the opto for greater than the recommended DDO timer setting of 400ms. If breaker status monitoring is required a further 1 or 2 opto inputs must be used.

Note	*A 52a CB auxiliary contact follows the CB position and a 52b contact is the opposite.*

When the breaker is closed, supervision current passes through the opto input, blocking diode and trip coil. When the breaker is open current still flows through the opto input and into the trip coil via the 52b auxiliary contact. Hence, no supervision of the trip path is provided whilst the breaker is open. Any fault in the trip path will only be detected on CB closing, after a 400ms delay.
Resistor R1 is an optional resistor that can be fitted to prevent maloperation of the circuit breaker if the opto input is inadvertently shorted, by limiting the current to <60mA. The resistor should not be fitted for auxiliary voltage ranges of 30/34 volts or less, as satisfactory operation can no longer be guaranteed. The table below shows the appropriate resistor value and voltage setting (**Opto Config.** menu) for this scheme. This TCS scheme will function correctly even without resistor R1, since the opto input automatically limits the supervision current to less that 10mA. However, if the opto is accidentally shorted the circuit breaker may trip.

Auxiliary Voltage (Vx)	Resistor R1 (ohms)	Opto Voltage Setting with R1 Fitted
24/27	-	-
30/34	-	-
48/54	1.2k	24/27
110/250	2.5k	48/54
220/250	5.0k	110/125

Note	*When R1 is not fitted the opto voltage setting must be set equal to supply voltage of the supervision circuit.*

3.7.2 Scheme 1 PSL

The next figure shows the scheme logic diagram for the TCS scheme 1. Any of the available opto inputs can be used to show whether or not the trip circuit is healthy. The delay on drop off timer operates as soon as the opto is energized, but will take 400ms to drop off/reset in the event of a trip circuit failure. The 400ms delay prevents a false alarm due to voltage dips caused by faults in other circuits or during normal tripping operation when the opto input is shorted by a self-reset trip contact. When the timer is operated the NC (normally closed) output relay opens and the LED and user alarms are reset.

The 50ms delay on pick-up timer prevents false LED and user alarm indications during the relay power up time, following an auxiliary supply interruption.

3.7.3 TCS Scheme 2

3.7.3.1 Scheme Description

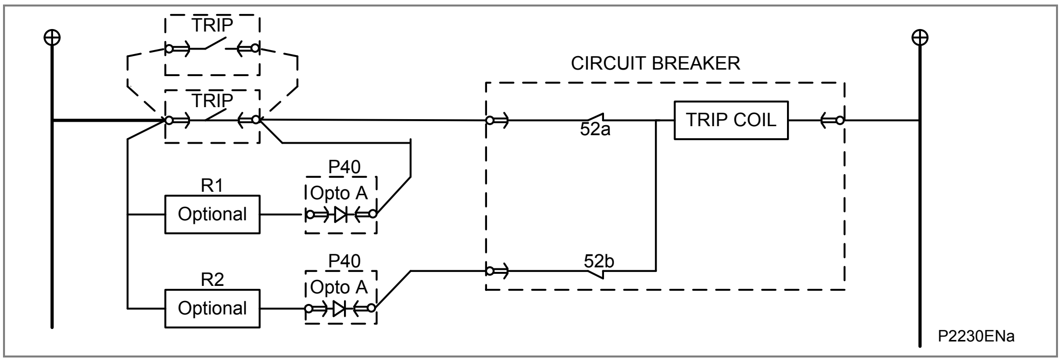


Figure 35 - TCS scheme 2

Much like scheme 1, this scheme provides supervision of the trip coil with the breaker open or closed and also does not provide pre-closing supervision. However, using two opto inputs allows the relay to correctly monitor the circuit breaker status since they are connected in series with the CB auxiliary contacts. This is achieved by assigning Opto A to the 52a contact and Opto B to the 52b contact. Provided the **Circuit Breaker Status** is set to **52a and 52b** (CB CONTROL column) the relay will correctly monitor the status of the breaker. This scheme is also fully compatible with latched contacts as the supervision current will be maintained through the 52b contact when the trip contact is closed.

When the breaker is closed, supervision current passes through opto input A and the trip coil. When the breaker is open current flows through opto input B and the trip coil. As with scheme 1, no supervision of the trip path is provided whilst the breaker is open. Any fault in the trip path will only be detected on CB closing, after a 400 ms delay.

As with scheme 1, optional resistors R1 and R2 can be added to prevent tripping of the CB if either opto is shorted. The resistor values of R1 and R2 are equal and can be set the same as R1 in scheme 1.

3.7.4 Scheme 2 PSL

The PSL for this scheme (is practically the same as that of scheme 1. The main difference being that both opto inputs must be off before a trip circuit fail alarm is given.

3.7.5 TCS Scheme 3

3.7.5.1 Scheme Description

Scheme 3 is designed to provide supervision of the trip coil with the breaker open or closed, but unlike schemes 1 and 2, it also provides pre-closing supervision. Since only one opto input is used, this scheme is not compatible with latched trip contacts. If circuit breaker status monitoring is required a further 1 or 2 opto inputs must be used.

When the breaker is closed, supervision current passes through the opto input, resistor R2 and the trip coil. When the breaker is open current flows through the opto input, resistors R1 and R2 (in parallel), resistor R3 and the trip coil. Unlike schemes 1 and 2, supervision current is maintained through the trip path with the breaker in either state, thus giving pre-closing supervision.

As with schemes 1 and 2, resistors R1 and R2 are used to prevent false tripping, if the opto-input is accidentally shorted. However, unlike the other two schemes, this scheme is dependent upon the position and value of these resistors. Removing them would result in incomplete trip circuit monitoring. The table below shows the resistor values and voltage settings required for satisfactory operation.

Auxiliary Voltage (Vx)	Resistor R1 & R2 (ohms)	Resistor R3 (ohms)	Opto Voltage Setting
24/27	-	-	-
30/34	-	-	-
48/54	1.2k	0.6k	24/27
110/250	2.5k	1.2k	48/54
220/250	5.0k	2.5k	110/125

Note	*Scheme 3 is not compatible with auxiliary supply voltages of 30/34 volts and below.*

3.7.6 Scheme 3 PSL

The PSL for scheme 3 is identical to that of scheme 1.

3.8 Fault Locator

Fault location is part of the data included within the relay fault record and therefore the fault locator is triggered whenever a fault record is generated. This is controlled by DDB 144: Fault REC TRIG; in the default PSL this signal is energized from operation of any protection trip.

3.8.1 Setting Example

Assuming the following data for the protected line:

230kV transmission line

CT ratio	=	1200/5
VT ratio	=	230,000/115
Line length	=	10km

Positive sequence line impedance	ZL1	=	0.089+j0.476 Ohms/km
Zero sequence line impedance	ZL0	=	0.34+j1.03 ohms/km
Zero sequence mutual impedance	ZM0	=	0.1068+j0.5712 Ohms/km

The line length can be set in either meters or miles.

Therefore for this example set line length = 10km.

The line impedance magnitude and angle settings are calculated as follows:

Ratio of secondary to primary impedance	=	CT ratio/VT ratio = 0.12
Positive sequence line impedance ZL1	=	$0.12 \times 10(0.484\angle 79.4°)$
	=	$0.58 \angle 79.4°$
Therefore set line length	=	0.58
Line angle	=	79°

The residual impedance compensation magnitude and angle are calculated using the following formula:

Equation 5 – Residual Impedance Compensation Magnitude and Angle:

$$KZn = \frac{ZL0 - ZL1}{3\ ZL1}$$

$$KZn = \frac{(0.34 + j1.03) - (0.089 + j0.476)}{3 \times (0.484 \angle 79.4°)}$$

$$KZn = \frac{0.6 \angle 65.2°}{1.45 \angle 79.4°}$$

$$KZn = 0.41 \angle -14.2°$$

Therefore set kZn Residual	=	0.41
kZn Res. Angle	=	$\angle$-14°

3.9 VT Connections

3.9.1 Open Delta (Vee Connected) VT's

MiCOM relays can be used with V-connected VTs by connecting the VT secondaries to:

- C19, C20 and C21 input terminals, with the C22 input left unconnected for P14x, P443, P445, P543, P544 and P841A
- D19, D20 and D21 input terminals, with the D22 input left unconnected for P446, P545, P546, P547 and P841B
- C2, C4 and E2 input terminals, with the Vn input left unconnected for P64x (P642, P643 & P645)

For more details, see the see the *Connection Diagrams* chapter.

This type of VT arrangement cannot pass zero-sequence (residual) voltage to the relay, or provide any phase to neutral voltage quantities. Therefore any protection that is dependent upon phase to neutral voltage measurements should be disabled.

The under and over voltage protection can be set as phase to phase measurement with vee connected VTs. The voltage dependent overcurrent use phase-phase voltages anyway, therefore the accuracy should not be affected. Directional earth fault and sensitive directional earth fault protection should be disabled as the neutral voltage will always be zero, even in the event of an earth fault. CT supervision should also be disabled, as this is also dependent upon the measurement of zero sequence voltage.

The accuracy of the single-phase voltage measurements can be impaired when using vee connected VT's. The relay attempts to derive the phase to neutral voltages from the phase to phase voltage vectors. If the impedance of the voltage inputs were perfectly matched the phase to neutral voltage measurements would be correct, provided the phase to phase voltage vectors were balanced. However, in practice there are small differences in the impedance of the voltage inputs, which can cause small errors in the phase to neutral voltage measurements. This may give rise to an apparent residual voltage. This problem also extends to single-phase power measurements that are also dependent upon their respective single-phase voltages.

The phase to neutral voltage measurement accuracy can be improved by connecting three, well-matched, load resistors between the relevant phase voltage inputs and neutral thus creating a 'virtual' neutral point. The load resistor values must be chosen so that their power consumption is within the limits of the VT. It is recommended that 10 kΩ ±1% (6 W) resistors are used for the 110 V (Vn) rated relay, assuming the VT can supply this burden.

The connections are as follows for different MiCOM IEDs:

Phase Voltage Inputs	Neutral	MiCOM IEDs
C19, C20, C21	C22	P145/P443/P445/P446/P543/P544/P841A
D19, D20, D21	D22	P545/P546/P841B

3.9.2 VT Single Point Earthing

The MiCOM P145/P443/P445/P446/P54x/P547/P64x/P841 will function correctly with conventional 3-phase VTs earthed at any one point on the VT secondary circuit. Typical earthing examples being neutral earthing, or B-phase (UK: "**yellow phase**" earthing).

3.10 Read Only Mode

With IEC 61850 and Ethernet/Internet communication capabilities, security has become a pressing issue. The Px40 IED provides a facility to allow the user to enable or disable the change in configuration remotely.

Read Only mode can be enabled/disabled for the following rear ports:

- Rear Port 1 - IEC 60870-5-103 and Courier protocols
- Rear Port 2 (if fitted) - Courier protocol
- Ethernet Port (if fitted) - Courier protocol (**tunnelled**)

4 CURRENT TRANSFORMER (CT) REQUIREMENTS

The Current Transformer (CT) requirements are based on a maximum prospective fault current of 50 times the relay rated current (In) and the relay having an instantaneous setting of 25 times rated current (In). The current transformer requirements are designed to provide operation of all protection elements.

Where the criteria for a specific application are in excess of those detailed above, or the actual lead resistance exceeds the limiting value quoted, the CT requirements may need to be increased according to the formulae in the following sections:

Nominal Rating	Nominal Output	Accuracy Class	Accuracy Limited Factor	Limiting Lead Resistance
1A	2.5VA	10P	20	1.3 ohms
5A	7.5VA	10P	20	0.11 ohms

Table 14 - CT Requirements

Separate requirements for Restricted Earth Fault are given in section 4.6 and 4.7.

4.1 Non-Directional Definite Time/IDMT Overcurrent & Earth Fault Protection

Equation 6 – Time-Delayed Phase Overcurrent Elements

VK ≥ Icp/2 * (RCT + RL + Rrp)

Equation 7 – Time-Delayed Earth Fault Overcurrent Elements

VK ≥ Icn/2 * (RCT + 2RL + Rrp + Rrn)

4.2 Non-Directional Instantaneous Overcurrent & Earth Fault Protection

Equation 8 – CT Requirements for Instantaneous Phase Overcurrent Elements

VK ≥ Isp x (RCT + RL + Rrp)

Equation 9 – CT Requirements for Instantaneous Earth Fault Overcurrent Elements

VK ≥ Isn x (RCT + 2RL + Rrp + Rrn)

4.3 Directional Definite Time/IDMT Overcurrent & Earth Fault Protection

Equation 10 – Time-Delayed Phase Overcurrent Elements

VK ≥ Icp/2 * (RCT + RL + Rrp)

Equation 11 – Time-Delayed Earth Fault Overcurrent Elements

VK ≥ Icn/2 * (RCT + 2RL + Rrp + Rrn)

4.4 Directional Instantaneous Overcurrent & Earth Fault Protection

Equation 12 – CT Requirements for Instantaneous Phase Overcurrent Elements

VK ≥ Ifp/2 * (RCT + RL + Rrp)

Equation 13 – CT Requirements for Instantaneous Earth Fault Overcurrent Elements

VK ≥ Ifn/2 * (RCT + 2RL + Rrp + Rrn)

4.5 Non-Directional/Directional Definite Time/IDMT Sensitive Earth Fault (SEF) Protection

Equation 14 – Non-Directional Time Delayed SEF Protection (Residually Connected)

VK ≥ Icn/2 * (RCT + 2RL + Rrp + Rrn)

Equation 15 – Non-Directional Instantaneous SEF Protection (Residually Connected)

VK ≥ Isn x (RCT + 2RL + Rrp + Rrn)

Equation 16 – Directional Time Delayed SEF protection (Residually Connected)

VK ≥ Icn/2 x (RCT + 2RL + Rrp + Rrn)

Equation 17 – Directional Instantaneous SEF Protection (Residually connected)

VK ≥ Ifn/2 * (RCT + 2RL + Rrp + Rrn)

4.5.1 SEF Protection - as fed from a Core-Balance CT

Core balance current transformers of metering class accuracy are required and should have a limiting secondary voltage satisfying the formulae given below:

Equation 18 – Directional/non-directional time delayed element:

VK ≥ Icn/2 * (RCT + 2RL + Rrn)

Equation 19 – Directional instantaneous element:

VK ≥ Ifn/2 * (RCT + 2RL + Rrn)

Equation 20 – Non-directional element:

VK ≥ Isn x (RCT + 2RL + Rrn)

Note	*In addition, it should be ensured that the phase error of the applied core balance current transformer is less than 90 minutes at 10% of rated current and less than 150 minutes at 1% of rated current.*

Abbreviations used in the previous formulae are explained below:

VK	=	Required CT knee-point voltage (volts)
Ifn	=	Maximum prospective secondary earth fault current (amps)
Ifp	=	Maximum prospective secondary phase fault current (amps)
Icn	=	Maximum prospective secondary earth fault current or 31 times I> setting (whichever is lower) (amps)
Icp	=	Maximum prospective secondary phase fault current or 31 times I> setting (whichever is lower) (amps)
Isn	=	Stage 2 & 3 earth fault setting (amps)
Isp	=	Stage 2 and 3 setting (amps)
RCT	=	Resistance of current transformer secondary winding (ohms)
RL (ohms)	=	Resistance of a single lead from relay to current transformer
Rrp	=	Impedance of relay phase current input at 30In (ohms)
Rrn	=	Impedance of the relay neutral current input at 30In (ohms)

4.6 Low Impedance Restricted Earth Fault Protection

Equation 21 – Low Impedance Restricted Earth Fault

VK ≥ 24 * In * (RCT + 2RL) for X/R < 40 and if < 15In

VK ≥ 48 * In * (RCT + 2RL) for X/R < 40,
15In < If < 40In and 40 <X/R
< 120, If < 15In

Where:

VK = Required CT knee point voltage (volts)

In = rated secondary current (amps)

RCT = Resistance of current transformer secondary winding (ohms)

RL = Resistance of a single lead from relay to current transformer (ohms)

If = Maximum through fault current level (amps)

Note	*Class x or Class 5P CT's should be used for low impedance restricted earth fault applications.*

4.7 High Impedance Restricted Earth Fault Protection

The high impedance restricted earth fault element shall maintain stability for through faults and operate in less than 40ms for internal faults provided the following equations are met:

Equation 22 – High Impedance Restricted Earth Fault Protection

$$R_{st} = \frac{I_F\,(R_{CT} + 2_{RL})}{I_s}$$

VK ≥ 4 * Is * Rst

Where:

VK = Required CT knee-point voltage (volts)

Rst = Value of stabilizing resistor (ohms)

If = Maximum secondary through fault current level (amps)

VK = CT knee point voltage (volts)

IS = Current setting of REF element (amps), (IREF>Is)

RCT = Resistance of current transformer secondary winding (ohms)

RL = Resistance of a single lead from relay to current transformer (ohms)

Note	*Class x CT's should be used for high impedance restricted earth fault applications.*

4.8 Use of ANSI/IEEE "C" Class CTs

Where American/IEEE standards are used to specify CTs, the C class voltage rating can be checked to determine the equivalent Vk (knee point voltage according to IEC). The equivalence formula is:

Equation 23 – Knee Point Voltage

$$V_k = [(\text{C rating in volts}) \times 1.05] + [100 \times R_{CT}]$$

5 AUXILIARY SUPPLY FUSE RATING

In the Safety Information part of this manual, the maximum allowable fuse rating of 16A is quoted. To allow time grading with fuses upstream, a lower fuselink current rating is often preferable. Use of standard ratings of between 6A and 16A is recommended. Low voltage fuselinks, rated at 250V minimum and compliant with IEC60269-2 general application type gG are acceptable, with high rupturing capacity. This gives equivalent characteristics to HRC "red spot" fuses type NIT/TIA often specified historically.

The table below recommends advisory limits on relays connected per fused spur. This applies to MiCOM Px40 series devices with hardware suffix C and higher, as these have inrush current limitation on switch-on, to conserve the fuse-link.

Maximum Number of MiCOM Px40 Relays Recommended Per Fuse				
Battery Nominal Voltage	**6A**	**10A Fuse**	**15 or 16A Fuse**	**Fuse Rating > 16A**
24 to 54V	2	4	6	Not permitted
60 to 125V	4	8	12	Not permitted
138 to 250V	6	10	16	Not permitted
Alternatively, Miniature Circuit Breakers (MCBs) may be used to protect the auxiliary supply circuits.				

Notes:

USING THE PSL EDITOR

CHAPTER 8

Date:	10/2014	
Products covered by this chapter:	This chapter covers the specific versions of the MiCOM products listed below. This includes ***only*** the following combinations of Software Version and Hardware Suffix.	
Hardware Suffix:	All MiCOM Px4x products	
Software Version:	All MiCOM Px4x products	
Connection Diagrams:	10P141xx (xx = 01 to 07) 10P142xx (xx = 01 to 07) 10P143xx (xx = 01 to 07) 10P145xx (xx = 01 to 07) 10P241xx (xx = 01 to 02) 10P242xx (xx = 01) 10P243xx (xx = 01) 10P342xx (xx = 01 to 17) 10P343xx (xx = 01 to 19) 10P344xx (xx = 01 to 12) 10P345xx (xx = 01 to 07) 10P44303 (SH 01 and 03) 10P44304 (SH 01 and 03) 10P44305 (SH 01 and 03) 10P44306 (SH 01 and 03) 10P445xx (xx = 01 to 04) 10P44600 10P44601 (SH 1 to 2) 10P44602 (SH 1 to 2) 10P44603 (SH 1 to 2) 10P54302 (SH 1 to 2) 10P54303 (SH 1 to 2)	10P54400 10P54404 (SH 1 to 2) 10P54405 (SH 1 to 2) 10P54502 (SH 1 to 2) 10P54503 (SH 1 to 2) 10P54600 10P54604 (SH 1 to 2) 10P54605 (SH 1 to 2) 10P54606 (SH 1 to 2) 10P54702xx (xx = 01 to 02) 10P54703xx (xx = 01 to 02) 10P54704xx (xx = 01 to 02) 10P54705xx (xx = 01 to 02) 10P642xx (xx = 1 to 10) 10P643xx (xx = 1 to 6) 10P645xx (xx = 1 to 9) 10P740xx (xx = 01 to 07) 10P746xx (xx = 01 to 07) 10P8401 10P8402 10P8401 10P8402 10P8403 10P849xx (xx = 01 to 06)

CONTENTS

FIGURES

TABLES

1 OVERVIEW

The purpose of the Programmable Scheme Logic (PSL) is to allow the relay user to configure an individual protection scheme to suit their own particular application. This is achieved through the use of programmable logic gates and delay timers.

The input to the PSL is any combination of the status of opto inputs. It is also used to assign the mapping of functions to the opto inputs and output contacts, the outputs of the protection elements, e.g. protection starts and trips, and the outputs of the fixed protection scheme logic. The fixed scheme logic provides the relay's standard protection schemes.

The PSL itself consists of software logic gates and timers. The logic gates can be programmed to perform a range of different logic functions and can accept any number of inputs. The timers are used either to create a programmable delay, and/or to condition the logic outputs, e.g. to create a pulse of fixed duration on the output regardless of the length of the pulse on the input. The outputs of the PSL are the LEDs on the front panel of the relay and the output contacts at the rear.

The execution of the PSL logic is event driven; the logic is processed whenever any of its inputs change, for example as a result of a change in one of the digital input signals or a trip output from a protection element. Also, only the part of the PSL logic that is affected by the particular input change that has occurred is processed. This reduces the amount of processing time that is used by the PSL; even with large, complex PSL schemes the relay trip time will not lengthen.

This system provides flexibility for the user to create their own scheme logic design. However, it also means that the PSL can be configured into a very complex system; hence setting of the PSL is implemented through the PC support package MiCOM S1 Studio.

2 MICOM S1 STUDIO PSL EDITOR

The PSL Editor software can be used from within MiCOM S1 Studio or directly.

This chapter assumes that you are using the PSL Editor from within MiCOM S1 Studio.

If you use it from MiCOM S1 Studio, the S1 Studio software will be locked whilst you are using the PSL editor software. The S1 Studio software will be unlocked when you close the PSL Editor software.

The MiCOM S1 Studio product is updated periodically. These updates provide support for new features (such as allowing you to manage new MiCOM products, as well as using new software releases and hardware suffixes). The updates may also include fixes. **Accordingly, we strongly advise customers to use the latest Schneider Electric version of MiCOM S1 Studio.**

2.1 How to Obtain MiCOM S1 Studio Software

The MiCOM S1 Studio software is avilable from the Schneider Electric website:

- www.schneider-electric.com

2.2 To Start the MiCOM S1 Studio

To Start the MiCOM S1 Studio software, click the **Start** > **Programs** > **Schneider Electric** > **MiCOM S1 Studio** > **MiCOM S1 Studio** menu option.

2.3 To Open a Pre-Existing System

Within MiCOM S1 Studio, click the **File** + **Open System** menu option.

Navigate to where the scheme is stored, then double-click to open the scheme.

2.4 To Start the PSL Editor

The PSL editor lets you connect to any MiCOM device front port, retrieve and edit its PSL files and send the modified file back to a suitable MiCOM device.

Px30 and Px40 products are edited different versions of the PSL Editor. There is one link to the Px30 editor and one link to the Px40 editor.

To start the PSL editor for Px40 products:

Highlight the PSL file you wish to edit, and then either:

Double-click the highlighted PSL file,

Click the open icon or

In the MiCOM S1 Studio main menu, select Tools > PSL PSL editor (Px40) menu.

The PSL Editor will then start, and show you the relevant PSL Diagram(s) for the file you have opened. An example of such a PSL diagram is shown in Figure 1.

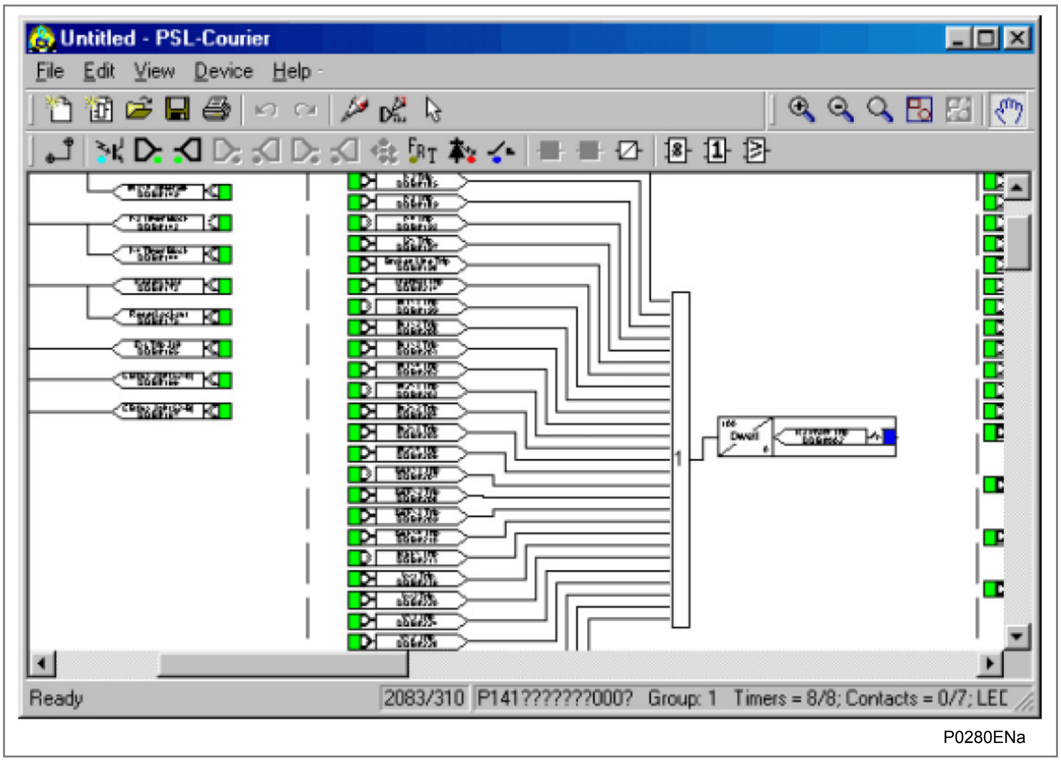


Figure 1 - Example of a PSL editor module

2.5 How to use MiCOM PSL Editor

The MiCOM PSL editor lets you:

- Start a new PSL diagram
- Extract a PSL file from a MiCOM Px40 IED
- Open a diagram from a PSL file
- Add logic components to a PSL file
- Move components in a PSL file
- Edit link of a PSL file
- Add link to a PSL file
- Highlight path in a PSL file
- Use a conditioner output to control logic
- Download PSL file to a MiCOM Px40 IED
- Print PSL files

For a detailed discussion on how to use these functions, please refer to MiCOM S1 Studio Users Manual.

2.6 Warnings

Before the scheme is sent to the relay checks are done. Various warning messages may be displayed as a result of these checks.

The Editor first reads in the model number of the connected relay, then compares it with the stored model number. A "wildcard" comparison is used. If a model mismatch occurs, a warning is generated before sending starts. Both the stored model number and the number read from the relay are displayed with the warning. However, the user must decide if the settings to be sent are compatible with the relay that is connected. Ignoring the warning could lead to undesired behavior of the relay.

If there are any potential problems of an obvious nature then a list will be generated. The types of potential problems that the program attempts to detect are:

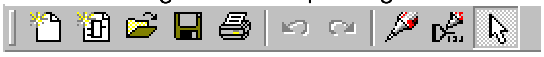
- One or more gates, LED signals, contact signals, and/or timers have their outputs linked directly back to their inputs. An erroneous link of this sort could lock up the relay, or cause other more subtle problems to arise.
- Inputs to Trigger (ITT) exceeds the number of inputs. If a programmable gate has its ITT value set to greater than the number of actual inputs; the gate can never activate. There is no lower ITT value check. A 0-value does not generate a warning.
- Too many gates. There is a theoretical upper limit of 256 gates in a scheme, but the practical limit is determined by the complexity of the logic. In practice the scheme would have to be very complex, and this error is unlikely to occur.
- Too many links. There is no fixed upper limit to the number of links in a scheme. However, as with the maximum number of gates, the practical limit is determined by the complexity of the logic. In practice the scheme would have to be very complex, and this error is unlikely to occur.

3 TOOLBAR AND COMMANDS

There are a number of toolbars available for easy navigation and editing of PSL.

3.1 Standard Tools

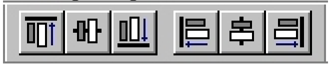
For file management and printing.

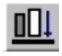


	Blank Scheme	Create a blank scheme based on a relay model.
	Default Configuration	Create a default scheme based on a relay model.
	Open	Open an existing diagram.
	Save	Save the active diagram.
	Print	Display the Windows Print dialog, enabling you to print the current diagram.
	Undo	Undo the last action.
	Redo	Redo the previously undone action.
	Redraw	Redraw the diagram.
	Number of DDBs	Display the DDB numbers of the links.
	Calculate CRC	Calculate unique number based on both the function and layout of the logic.
	Compare Files	Compare current file with another stored on disk.
	Select	Enable the select function. While this button is active, the mouse pointer is displayed as an arrow. This is the default mouse pointer. It is sometimes referred to as the selection pointer. Point to a component and click the left mouse button to select it. Several components may be selected by clicking the left mouse button on the diagram and dragging the pointer to create a rectangular selection area.

3.2 Alignment Tools

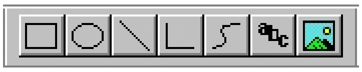
To align logic elements horizontally or vertically into groups.



	Align Top	Align all selected components so the top of each is level with the others.
	Align Middle	Align all selected components so the middle of each is level with the others.
	Align Bottom	Align all selected components so the bottom of each is level with the others.
	Align Left	Align all selected components so the leftmost point of each is level with the others.
	Align Centre	Align all selected components so the centre of each is level with the others.
	Align Right	Align all selected components so the rightmost point of each is level with the others.

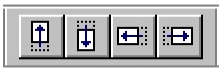
3.3 Drawing Tools

To add text comments and other annotations, for easier reading of PSL schemes.



	Rectangle	When selected, move the mouse pointer to where you want one of the corners to be hold down the left mouse button and move it to where you want the diagonally opposite corner to be. Release the button. To draw a square hold down the SHIFT key to ensure height and width remain the same.
	Ellipse	When selected, move the mouse pointer to where you want one of the corners to be hold down the left mouse button and move until the ellipse is the size you want it to be. Release the button. To draw a circle hold down the SHIFT key to ensure height and width remain the same.
	Line	When selected, move the mouse pointer to where you want the line to start, hold down left mouse, move to the position of the end of the line and release button. To draw horizontal or vertical lines only hold down the SHIFT key.
	Polyline	When selected, move the mouse pointer to where you want the polyline to start and click the left mouse button. Now move to the next point on the line and click the left button. Double click to indicate the final point in the polyline.
	Curve	When selected, move the mouse pointer to where you want the polycurve to start and click the left mouse button. Each time you click the button after this a line will be drawn, each line bisects its associated curve. Double click to end. The straight lines will disappear leaving the polycurve. Note: whilst drawing the lines associated with the polycurve, a curve will not be displayed untileither three lines in succession have been drawn or the polycurve line is complete.
	Text	When selected, move the mouse pointer to where you want the text to begin and click the left mouse button. To change the font, size or colour, or text attributes select Properties from the right mouse button menu.
	Image	When selected, the Open dialog is displayed, enabling you to select a bitmap or icon file. Click Open, position the mouse pointer where you want the image to be and click the left mouse button.

3.4 Nudge Tools



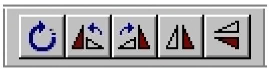
To move logic elements.

The nudge tool buttons enable you to shift a selected component a single unit in the selected direction, or five pixels if the SHIFT key is held down.

As well as using the tool buttons, single unit nudge actions on the selected components can be achieved using the arrow keys on the keyboard.

:	Nudge Up	Shift the selected component(s) upwards by one unit. Holding down the SHIFT key while clicking on this button will shift the component five units upwards.
:	Nudge Down	Shift the selected component(s) downwards by one unit. Holding down the SHIFT key while clicking on this button will shift the component five units downwards.
:	Nudge Left	Shift the selected component(s) to the left by one unit. Holding down the SHIFT key while clicking on this button will shift the component five units to the left.
:	Nudge Right	Shift the selected component(s) to the right by one unit. Holding down the SHIFT key while clicking on this button will shift the component five units to the right.

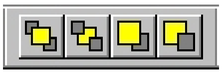
3.5 Rotation Tools

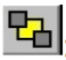
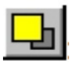


To spin, mirror and flip.

:	Free Rotate	Enable the rotation function. While rotation is active components may be rotated as required. Press the ESC key or click on the diagram to disable the function.
:	Rotate Left	Rotate the selected component 90 degrees to the left.
:	Rotate Right	Rotate the selected component 90 degrees to the right.
:	Flip Horizontal	Flip the component horizontally.
:	Flip Vertical	Flip the component vertically.

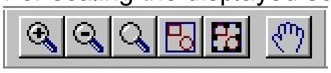
3.6 Structure Tools

To change the stacking order of logic components. 

	Bring to Front	Bring the selected components in front of all other components.
	Send to Back	Bring the selected components behind all other components.
	Bring Forward	Bring the selected component forward one layer.
	Send Backward	Send the selected component backwards one layer.

3.7 Zoom and Pan Tools

For scaling the displayed screen size, viewing the entire PSL, or zooming to a selection.

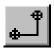


	Zoom In	Increases the Zoom magnification by 25%.
	Zoom Out	Decreases the Zoom magnification by 25%.
	Zoom	Enable the zoom function. While this button is active, the mouse pointer is displayed as a magnifying glass. Right-clicking will zoom out and left-clicking will zoom in. Press the ESC key to return to the selection pointer. Click and drag to zoom in to an area.
	Zoom to Fit	Display at the highest magnification that will show all the diagram's components.
	Zoom to Selection	Display at the highest magnification that will show the selected component(s).
	Pan	Enable the pan function. While this button is active, the mouse pointer is displayed as a hand. Hold down the left mouse button and drag the pointer across the diagram to pan. Press the ESC key to return to the selection pointer.

3.8 Logic Symbols

This toolbar provides icons to place each type of logic element into the scheme diagram. Not all elements are available in all devices. Icons will only be displayed for those elements available in the selected device. Depending on the device, the toolbar may not include Function key or coloured LED conditioner/signal or Contact conditioner or SR Gate icons.

P2718ENa



Link
Create a link between two logic symbols.

Opto Signal
Create an opto signal.

Input Signal
Create an input signal.

Output Signal
Create an output signal.

GOOSE In
Create an input signal to logic to receive a UCA2.0 or IEC 61850 GOOSE message transmitted from another IED.

GOOSE Out
Create an output signal from logic to transmit a UCA2.0 or IEC 61850 GOOSE message to another IED.

Control In
Create an input signal to logic that can be operated from an external command.

Integral Intertripping In/InterMiCOM In
Create an input signal to logic to receive a MiCOM command transmitted from another IED. InterMiCOM is not available for all products.

Integral Intertripping Out/InterMiCOM Out  Create an output signal from logic to transmit a MiCOM command to another IED. InterMiCOM is not available for all products.

Function Key
Create a function key input signal.

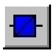
Trigger Signal
Create a fault record trigger.

LED Signal

Create an LED input signal that repeats the status of the LED.
The icon colour shows whether the product uses mono-colour or tri-color LEDs.

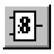
Contact Signal
Create a contact signal.

LED Conditioner
Create a LED conditioner.
The icon colour shows whether the product uses mono-colour or tri-color LEDs.

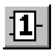


Contact Conditioner
Create a contact conditioner. Contact conditioning is not available for all products.

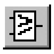
Timer
Create a timer.



AND Gate
Create an AND Gate.



OR Gate
Create an OR Gate.



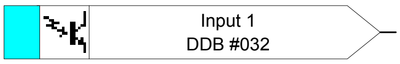
Programmable Gate
Create a programmable gate.

SR gate
Create an SR gate.

4 PSL LOGIC SIGNALS PROPERTIES

The logic signal toolbar is used for the selection of logic signals.

This allows you to link signals together to program the PSL. A number of different properties are associated with each signal. In the following sections these are characterized by the use of an icon from the toolbar; together with a signal name and a DDB number. The name and DDB number are shown in a pointed rectangular block, which includes a colour code, the icon, the name, DDB No and a directional pointer. One example of such a block (for P54x for Opto Signal 1 DDB No #032) is shown below:



More examples of these are shown in the following properties sections.

Important	**The DDB Numbers vary according to the particular product and the particular name, so that Opto Signal 1 may not be DDB No #032 for all products. The various names and DDB numbers illustrated below are provided as an example.** **You need to look up the DDB numbers for the signal and the specific MiCOM product you are working on in the relevant DDB table for your chosen product.**

4.1 Signal Properties Menu

The logic signal toolbar is used for the selection of logic signals. To use this:

Use the logic toolbar to select logic signals.
This is enabled by default but to hide or show it, select **View** > **Logic Toolbar**.

Zoom in or out of a logic diagram using the toolbar icon or select **View** > **Zoom Percent**.

Right-click any logic signal and a context-sensitive menu appears.

Certain logic elements show the **Properties…** option. Select this and a **Component Properties** window appears. The Component Properties window and the signals listed vary depending on the logic symbol selected.

The following subsections describe each of the available logic symbols.

4.2 Link Properties

Links form the logical link between the output of a signal, gate or condition and the input to any element.

Any link that is connected to the input of a gate can be inverted. Right-click the input and select **Properties…**. The **Link Properties** window appears.

Figure 2 - Link properties

4.2.1 Rules for Linking Symbols

An inverted link is shown with a small circle on the input to a gate. A link must be connected to the input of a gate to be inverted.

Links can only be started from the output of a signal, gate, or conditioner, and can only be ended at an input to any element.

Signals can only be an input or an output. To follow the convention for gates and conditioners, input signals are connected from the left and output signals to the right. The Editor automatically enforces this convention.

A link is refused for the following reasons:

- An attempt to connect to a signal that is already driven. The reason for the refusal may not be obvious because the signal symbol may appear elsewhere in the diagram.

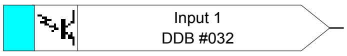
  Right-click the link and select Highlight to find the other signal. Click anywhere on the diagram to disable the highlight.

- An attempt is made to repeat a link between two symbols. The reason for the refusal may not be obvious because the existing link may be represented elsewhere in the diagram.

4.3 Opto Signal Properties

Each opto input can be selected and used for programming in PSL. Activation of the opto input drives an associated DDB signal.

For example, activating opto Input L1 asserts DDB 032 in the PSL for the P14x, P34x, P44y, P445, P54x, P547, P74x, P746, P841, P849product.

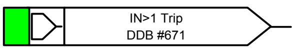


DDB Nos	*“Input 1 DDB #064” applies to: P24x, P64x.* *“Opto Label DDB #064” applies to: P44x.*

4.4 Input Signal Properties

Relay logic functions provide logic output signals that can be used for programming in PSL. Depending on the relay functionality, operation of an active relay function drives an associated DDB signal in PSL.

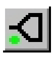
For example, DDB 671 is asserted in the PSL for the P44y, P547 & P841 product if the active earth fault 1, stage 1 protection operate/trip.

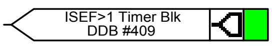


4.5 Output Signal Properties

Relay logic functions provide logic input signals that can be used for programming in PSL. Depending on the relay functionality, activation of the output signal will drive an associated DDB signal in PSL and cause an associated response to the relay function.

For example, if DDB 409 is asserted in the PSL for the P44y, P54x, P547 and P841 product, it will block the sensitive earth function stage 1 timer.





4.6 GOOSE Input Signal Properties

The PSL interfaces with the GOOSE Scheme Logic using virtual inputs. The Virtual Inputs can be used in much the same way as the Opto Input signals.

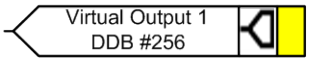
The logic that drives each of the Virtual Inputs is contained within the relay’s GOOSE Scheme Logic file. It is possible to map any number of bit-pairs, from any enrolled device, using logic gates onto a Virtual Input (see MiCOM S1 Studio Users Manual for more details). The number of available GOOSE virtual inputs is shown in the *Programmable Logic* chapter.

For example DDB 224 will be asserted in PSL for the P44y, P54x, P547 & P841 product should virtual input 1 operate.


4.7 GOOSE Output Signal Properties

The PSL interfaces with the GOOSE Scheme Logic using 32 virtual outputs. Virtual outputs can be mapped to bit-pairs for transmitting to any enrolled devices.

For example if DDB 256 is asserted in PSL for the P44y, P54x, P547 and P841 product, Virtual Output 32 and its associated mappings will operate.

4.8 Control In Signal Properties

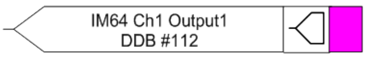
There are 32 control inputs which can be activated via the relay menu, ‘hotkeys’ or via rear communications. Depending on the programmed setting i.e. latched or pulsed, an associated DDB signal will be activated in PSL when a control input is operated.

For example operate control input 1 to assert DDB 192 in the PSL for the P44y, P54x, P547 and P841 product.


4.9 InterMiCOM Output Commands Properties

Important	**This does not apply to these products: P24x, P34x, P44x, P64x, P547, P74x, P746, P841 & P849.**

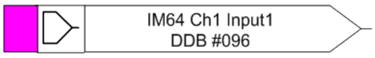
There are 16 InterMiCOM outputs that could be selected and use for teleprotection, remote commands, etc. “InterMiCOM Out” is a send command to a remote end that could be mapped to any logic output or opto input. This will be transmitted to the remote end as corresponding “InterMiCOM In” command for the P14x, P44y, P445 & P54x product.

4.10 InterMiCOM Input Commands Properties

Important	This does not apply to these products: P24x, P34x, P44x, P64x, P547, P74x, P746, P841 & P849.

There are 16 InterMiCOM inputs that could be selected and use for teleprotection, remote commands, etc. “InterMiCOM In” is a received signal from remote end that could be mapped to a selected output relay or logic input for the P14x, P44y, P445 & P54x, product.

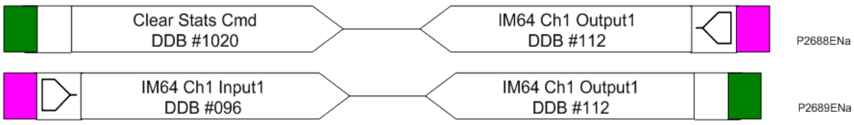


Example:

Relay End A — At end A, InterMiCOM Output 1 is mapped to the command indication “Clear Statistics” (issued at end A).

Relay End B — At end B, InterMiCOM Input 1 is mapped to the command “Clear Statistics”.

Upon receive of IM64 1 from relay at end A, the relay at end B will reset its statistics.



4.11 Function Key Properties

Each function key can be selected and used for programming in PSL. Activation of the function key will drive an associated DDB signal and the DDB signal will remain active depending on the programmed setting i.e. toggled or normal. Toggled mode means the DDB signal will remain latched or unlatched on key press and normal means the DDB will only be active for the duration of the key press.

For example, operate function key 1 to assert DDB 1096 in the PSL for the P44y, P54x, P547 or P841 product.

4.12 Fault Recorder Trigger Properties

The fault recording facility can be activated, by driving the fault recorder trigger DDB signal.

For example assert DDB 702 to activate the fault recording in the PSL for the P44y, P54x, P547 or P841 product.

4.13 LED Signal Properties

All programmable LEDs will drive associated DDB signal when the LED is activated.

For example DDB 1036 will be asserted when LED 7 is activated for the P44y, P54x, P547 or P841 product.

4.14 Contact Signal Properties

All relay output contacts will drive associated DDB signal when the output contact is activated.

For example DDB 009 will be asserted when output R10 is activated for all products.

4.15 LED Conditioner Properties

1. Select the **LED name** from the list (only shown when inserting a new symbol).
2. Configure the LED output to be Red, Yellow or Green.

   Configure a Green LED by driving the Green DDB input.
   Configure a RED LED by driving the RED DDB input.
   Configure a Yellow LED by driving the RED and GREEN DDB inputs simultaneously.

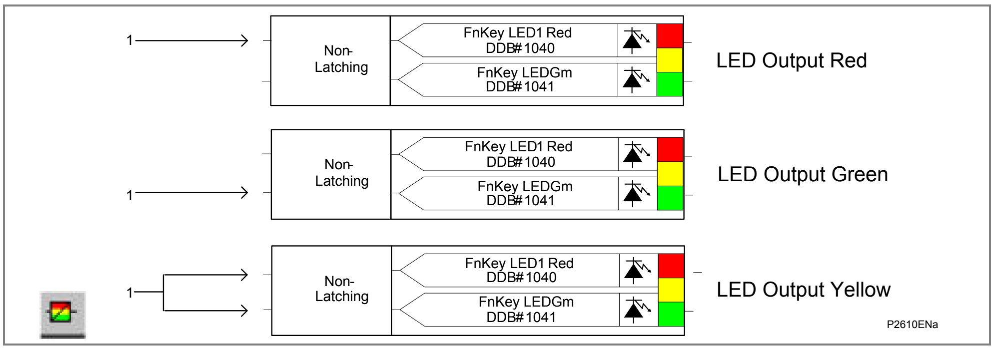


Figure 3 - Red, green and yellow LED outputs

3. Configure the LED output to be latching or non-latching.

DDB #642 and DDB #643 applies to these products: P14x, P44x, P74x, P746 and P849.

DDB #1040 and DDB #1041 applies to these products: P24x, P34x, P44y, P54x, P547, P64x and P841.

4.16 Contact Conditioner Properties

Each contact can be conditioned with an associated timer that can be selected for pick up, drop off, dwell, pulse, pick-up/drop-off, straight-through, or latching operation.

Straight-through means it is not conditioned in any way whereas **Latching** is used to create a sealed-in or lockout type function.

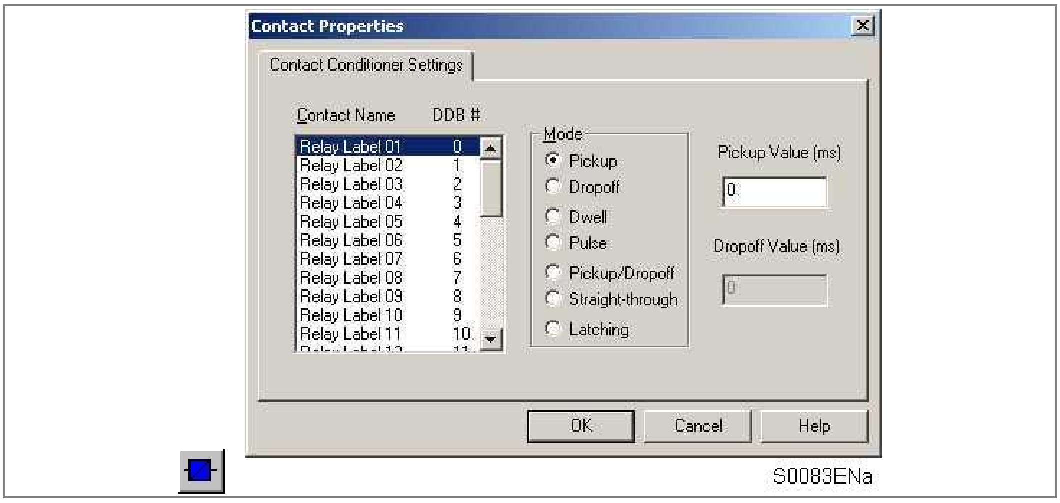


Figure 4 - Contact conditioner settings

1. Select the contact **name** from the **Contact Name** list (only shown when inserting a new symbol).
2. Choose the conditioner type required in the **Mode** tick list.
3. Set the **Pick-up** Time (in milliseconds), if required.
4. Set the **Drop-off** Time (in milliseconds), if required.

4.17 Timer Properties

Each timer can be selected for pick up, drop off, dwell, pulse or pick-up/drop-off operation.

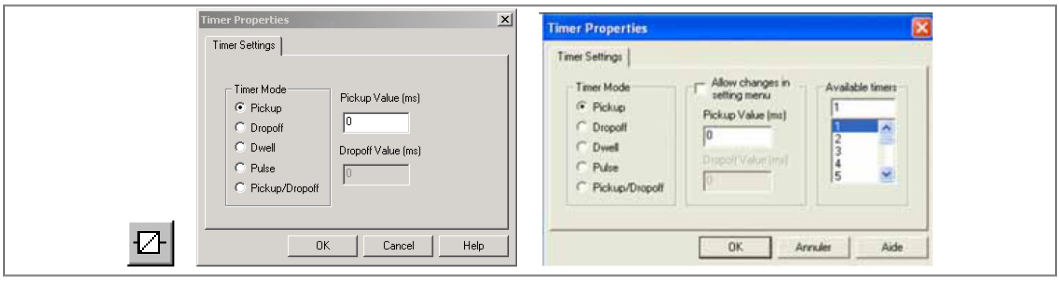


Figure 5 - Timer settings

1. Choose the operation mode from the **Timer Mode** tick list.
2. Set the Pick-up Time (in milliseconds), if required.
3. Set the Drop-off Time (in milliseconds), if required.

4.18 Gate Properties

A Gate may be an AND, OR, or programmable gate.

An **AND** gate requires that all inputs are TRUE for the output to be TRUE.

An **OR** gate requires that one or more input is TRUE for the output to be TRUE.

A **Programmable** gate requires that the number of inputs that are TRUE is equal to or greater than its ‘Inputs to Trigger’ setting for the output to be TRUE.

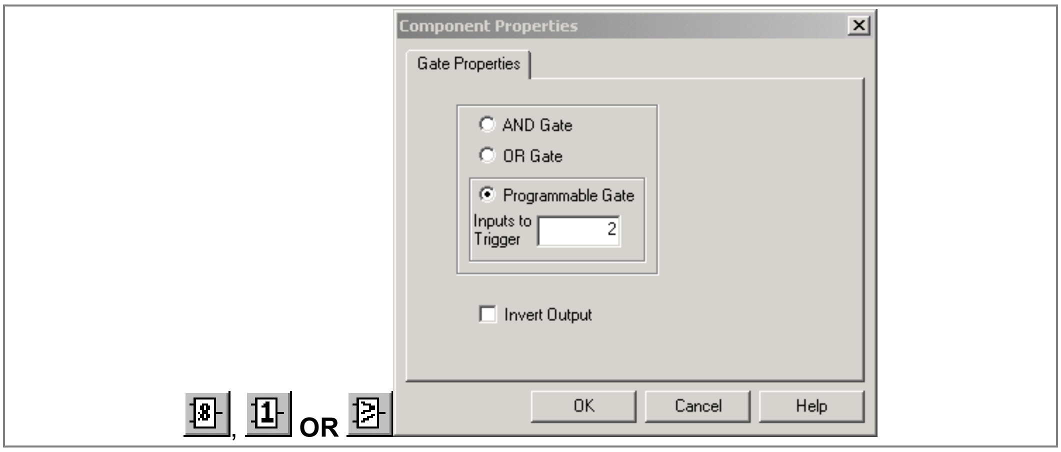


Figure 6 - Gate properties

1. Select the Gate type AND, OR, or Programmable.
2. Set the number of inputs to trigger when Programmable is selected.
3. Select if the output of the gate should be inverted using the Invert Output check box. An inverted output is indicated with a "bubble" on the gate output.

4.19 SR Programmable Gate Properties

For many products a number of programmable SR Latches are added. They are configured by an appropriate version of PSL Editor (S1v2.14 version 5.0.0 or greater) where an SRQ icon features on the toolbar.

Each SR latch has a Q output. The Q output may be inverted in the PSL Editor under the SR Latch component properties window. The SR Latches may be configured as Standard (no input dominant), Set Dominant or Reset Dominant in the PSL Editor under the SR Latch component properties window. The truth table for the SR Latches is given below.

A **Programmable** SR gate can be selected to operate with these latch properties:

S input	R input	O - Standard	O – Set input dominant	O – Rest input dominant
0	0	0	0	0
0	1	0	0	0
1	0	1	1	1
1	1	0	1	1

Table 1 - SR programmable gate properties

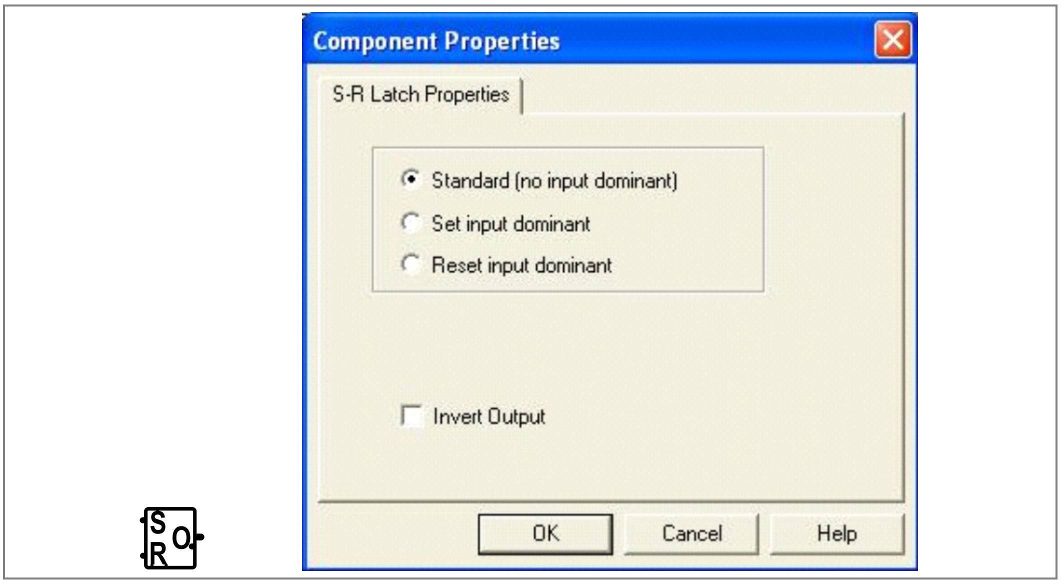


Figure 7 - SR latch component properties

Select if the output of the gate should be inverted using the Invert Output check box. An inverted output is indicated with a "bubble" on the gate output.

5 MAKING A RECORD OF MICOM PX40 DEVICE SETTINGS

5.1 Using MiCOM S1 Studio to Manage Device Settings

An engineer often needs to create a record of what settings have been applied to a device. In the past, they could have used paper printouts of all the available settings, and mark up the ones they had used. Keeping such a paper-based Settings Records could be time-consuming and prone to error (e.g. due to being settings written down incorrectly).

The MiCOM S1 Studio software lets you read from or write to MiCOM devices.

- **Extract** lets you download all the settings from a MiCOM Px40 device. A summary is given in Extract Settings from a MiCOM Px40 Device below.
- **Send** lets you send the settings you currently have open in MiCOM S1 Studio. A summary is given in Send Settings to a MiCOM Px40 Device below.

In most cases, it will be quicker and less error prone to extract settings electronically and store them in a settings file on a memory stick. In this way, there will be a digital record which is certain to be accurate. It is also possible to archive these settings files in a repository; so they can be used again or adapted for another use.

Full details of how to do these tasks is provided in the MiCOM S1 Studio help. A quick summary of the main steps is given below. In each case you need to make sure that:

- Your computer includes the MiCOM S1 Studio software.
- Your computer and the MiCOM device are powered on.
- You have used a suitable cable to connect your computer to the MiCOM device (Front Port, Rear Port, Ethernet port or Modem as available).

5.2 Extract Settings from a MiCOM Px40 Device

Full details of how to do this is provided in the MiCOM S1 Studio help.

As a quick guide, you need to do the following:

1. In MiCOM S1 Studio, click the Quick Connect… button.
2. Select the relevant Device Type in the Quick Connect dialog box.
3. Click the relevant port in the Port Selection dialog box.
4. Enter the relevant connection parameters in the Connection Parameters dialog box and click the Finish button
5. MiCOM S1 Studio will try to communicate with the Px40 device. It will display a connected message if the connection attempt is successful.
6. The device will appear in the Studio Explorer pane on the top-left hand side of the interface.
7. Click the + button to expand the options for the device, then click on the Settings folder.
8. Right-click on Settings and select the Extract Settings link to read the settings on the device and store them on your computer or a memory stick attached to your computer.
9. After retrieving the settings file, close the dialog box by clicking the Close button.

5.3 Send Settings to a MiCOM Px40 Device

Full details of how to do this is provided in the MiCOM S1 Studio help.

As a quick guide, you need to do the following:

1. In MiCOM S1 Studio, click the Quick Connect… button.
2. Select the relevant Device Type in the Quick Connect dialog box.
3. Click the relevant port in the Port Selection dialog box.
4. Enter the relevant connection parameters in the Connection Parameters dialog box and click the Finish button
5. MiCOM S1 Studio will try to communicate with the Px40 device. It will display a connected message if the connection attempt is successful.
6. The device will appear in the Studio Explorer pane on the top-left hand side of the interface.
7. Click the + button to expand the options for the device, then click on the Settings link.
8. Right-click on the device name and select the Send link.

Note	*When you send settings to a MiCOM Px40 device, the data is stored in a temporary location at first. This temporary data is tested to make sure it is complete. If the temporary data is complete, it will be programmed into the MiCOM Px40 device. This avoids the risk of a device being programmed with incomplete or corrupt settings.*

9. In the Send To dialog box, select the settings file(s) you wish to send, then click the Send button.
10. Close the the Send To dialog box by clicking the Close button.

PROGRAMMABLE LOGIC

CHAPTER NO 9

Date:	10/2014
Products covered by this chapter:	This chapter covers the specific versions of the MiCOM products listed below. This includes ***only*** the following combinations of Software Version and Hardware Suffix.
Hardware Suffix:	L (P141, P142 & P143) & M (P145)
Software Version:	A0 - P14x (P141, P142, P143 & P145)
Connection Diagrams:	10P141xx (xx = 01 to 07) 10P142xx (xx = 01 to 07) 10P143xx (xx = 01 to 07) 10P145xx (xx = 01 to 07)

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TABLES

1 OVERVIEW

The purpose of the Programmable Scheme Logic (PSL) is to allow the user to configure an individual protection scheme to suit their own particular application. This is achieved through the use of programmable logic gates and delay timers.

The input to the PSL is any combination of the status of opto inputs. It is also used to assign the mapping of functions to the opto inputs and output contacts, the outputs of the protection elements, e.g. protection starts and trips, and the outputs of the fixed protection scheme logic. The fixed scheme logic provides the relay's standard protection schemes.

The PSL itself consists of software logic gates and timers. The logic gates can be programmed to perform a range of different logic functions and can accept any number of inputs. The timers are used either to create a programmable delay, and/or to condition the logic outputs, e.g. to create a pulse of fixed duration on the output regardless of the length of the pulse on the input. The outputs of the PSL are the LEDs on the front panel of the relay and the output contacts at the rear.

The execution of the PSL logic is event driven; the logic is processed whenever any of its inputs change, for example as a result of a change in one of the digital input signals. Also, only the part of the PSL logic that is affected by the particular input change that has occurred is processed. This reduces the amount of processing time that is used by the PSL. This means that even with large, complex PSL schemes the device trip time will not lengthen.

This system provides flexibility for the user to create their own scheme logic design. It also means that the PSL can be configured into a very complex system, hence setting of the PSL is implemented through the PC support package MiCOM S1 Studio.

How to edit the PSL schemes is described in the "Using the PSL Editor" chapter.

This chapter contains details of the logic nodes which are specific to this product, together with any PSL diagrams which we have published for this product.

2 DESCRIPTION OF LOGIC NODES

DDB no.	English text	Source	Description
0	Output Label 1 (Setting)	Output Conditioner	Output signal from output relay 1 when activated
31	Output Label 32 (Setting)	Output Conditioner	Output signal from output relay 32 when activated
32	Opto Label 1 (Setting)	Opto Input	From opto input 1 - when opto energized
63	Opto Label 32 (Setting)	Opto Input	From opto input 32 - when opto energized
64	LED 1	PSL	Assignment of input signal to drive output LED 1 (Exclude P145)
71	LED 8	PSL	Assignment of input signal to drive output LED 8 (Exclude P145)
72	Relay Cond. 1	PSL	Input to relay output conditioner
73	Relay Cond. 2	PSL	Input to relay output conditioner
74	Any Trip	PSL	Input to Relay Output Conditioner
75	Relay Cond. 4	PSL	Input to relay output conditioner
103	Relay Cond. 4	PSL	Input to relay output conditioner
104 - 111			Unused
112	Timer in 1	PSL	Input to auxiliary timer 1
127	Timer in 16	PSL	Input to auxiliary timer 16
128	Timer out 1	Auxiliary Timer	Output from auxiliary timer 1
129 - 242	Timer out 2 …15	Auxiliary Timer	Output from auxiliary timer 2 …15
143	Timer out 16	Auxiliary Timer	Output from auxiliary timer 16
144	Fault REC TRIG	PSL	Input Trigger for Fault Recorder
145	SG-opto Invalid	Group Selection	Setting group selection opto inputs have detected an invalid (disabled) settings group
146	Prot'n. Disabled	Commissioning Test	Protection disabled - typically out of service due to test mode
147	F out of Range	Frequency Tracking	Frequency out of range alarm
148	VT Fail Alarm	VT Supervision	VTS indication alarm- failed VT (fuse blow) detected by VT supervision
149	CT Fail Alarm	CT Supervision	CTS indication alarm (CT supervision alarm)
150	CB Fail Alarm	CB Fail	Circuit breaker fail alarm
151	I^ Maint. Alarm	CB Monitoring	Broken current maintenance alarm - circuit breaker cumulative duty alarm set-point
152	I^ Lockout Alarm	CB Monitoring	Broken current lockout alarm - circuit breaker cumulative duty has been exceeded
153	CB Ops Maint.	CB Monitoring	No of circuit breaker operations maintenance alarm - indicated due to circuit breaker trip operations threshold
154	CB Ops Lockout	CB Monitoring	No of circuit breaker operations maintenance lockout - excessive number of circuit breaker trip operations, safety lockout
155	CB Op Time Maint.	CB Monitoring	Excessive circuit breaker operating time maintenance alarm - excessive operation time alarm for the circuit breaker (slow interruption time)
156	CB Op Time Lock	CB Monitoring	Excessive circuit breaker operating time lockout alarm - excessive operation time alarm for the circuit breaker (too slow interruption)
157	Fault Freq. Lock	CB Monitoring	Excessive fault frequency lockout alarm
158	CB Status Alarm	CB Status	Indication of problems by circuit breaker state monitoring - example defective auxiliary contacts

DDB no.	English text	Source	Description
159	Man CB Trip Fail	CB Control	Circuit breaker failed to trip (after a manual/operator trip command)
160	Man CB Cls. Fail	CB Control	Circuit breaker failed to close (after a manual/operator or auto-reclose close command)
161	Man CB Unhealthy	CB Control	Manual circuit breaker unhealthy output signal indicating that the circuit breaker has not closed successfully after a manual close command. (A successful close also requires the circuit breaker healthy signal to reappear within the "healthy window" timeout)
162	Man No Check Sync.	CB Control	Indicates that the check synchronism signal has failed to appear for a manual close
163	AR Lockout	Auto-Reclose	Indicates an auto-reclose lockout condition - no further auto-reclosures possible until resetting
164	AR CB Unhealthy	Auto-Reclose	Auto-reclose circuit breaker unhealthy signal, output from auto-reclose logic. Indicates during auto-reclose in progress, if the circuit breaker has not become healthy within the circuit breaker healthy time window
165	AR No Sys. Checks	Auto-Reclose	Indicates during auto-reclose in progress, if system checks have not been satisfied within the check synchronizing time window
166	System Split	Check Sync.	System split alarm - will be raised if the system is split (remains permanently out of synchronism) for the duration of the system split timer
167	Under Voltage Block	Undervoltage	Under voltage block - blocks the advanced frequency load shedding
168 - 185	SR User Alarm 1 - 18	PSL	Triggers user alarm 1 - 18 message to be alarmed on LCD display (self-resetting)
186 - 202	SR User Alarm 19 - 35	PSL	Triggers user alarm 19 - 35 message to be alarmed on LCD display (manual-resetting)
203	I>1 Timer Block	PSL	Block phase overcurrent stage 1 time delay
204	I>2 Timer Block	PSL	Block phase overcurrent stage 2 time delay
205	I>3 Timer Block	PSL	Block phase overcurrent stage 3 time delay
206	I>4 Timer Block	PSL	Block phase overcurrent stage 4 time delay
207	Inhibit CBF	PSL	Inhibit CB Fail
208	IN1>1 Timer Blk.	PSL	Block earth fault measured stage 1 time delay
209	IN1>2 Timer Blk.	PSL	Block earth fault measured stage 2 time delay
210	IN1>3 Timer Blk.	PSL	Block earth fault measured stage 3 time delay
211	IN1>4 Timer Blk.	PSL	Block earth fault measured stage 4 time delay
212	IN2>1 Timer Blk.	PSL	Block earth fault derived stage 1 time delay
213	IN2>2 Timer Blk.	PSL	Block earth fault derived stage 2 time delay
214	IN2>3 Timer Blk.	PSL	Block earth fault derived stage 3 time delay
215	IN2>4 Timer Blk.	PSL	Block earth fault derived stage 4 time delay
216	ISEF>1 Timer Blk.	PSL	Block sensitive earth fault stage 1 time delay
217	ISEF>2 Timer Blk.	PSL	Block sensitive earth fault stage 2 time delay
218	ISEF>3 Timer Blk.	PSL	Block sensitive earth fault stage 3 time delay
219	ISEF>4 Timer Blk.	PSL	Block sensitive earth fault stage 4 time delay
220	VN>1 Timer Blk.	PSL	Block residual overvoltage stage 1 time delay
221	VN>2 Timer Blk.	PSL	Block residual overvoltage stage 2 time delay
222	V<1 Timer Block	PSL	Block phase undervoltage stage 1 time delay
223	V<2 Timer Block	PSL	Block phase undervoltage stage 2 time delay

DDB no.	English text	Source	Description
224	V>1 Timer Block	PSL	Block phase overvoltage stage 1 time delay
225	V>2 Timer Block	PSL	Block phase overvoltage stage 2 time delay
226	CLP Initiate	PSL	Initiate cold load pick-up
227	Ext. Trip 3ph	PSL	External trip 3 phase - allows external protection to initiate breaker fail, circuit breaker condition monitoring statistics, and internal auto-reclose (if enabled)
228	CB Aux. 3ph(52-A)	PSL	52-A (CB closed) CB auxiliary input (3 phase)
229	CB Aux. 3ph(52-B)	PSL	52-B (CB open) CB auxiliary input (3 phase)
230	CB Healthy	PSL	Circuit breaker healthy (input to auto-recloser - that the CB has enough energy to allow re-closing)
231	MCB/VTS	PSL	VT supervision input - signal from external miniature circuit breaker showing MCB tripped
232	Init. Trip CB	PSL	Initiate tripping of circuit breaker from a manual command
233	Init. Close CB	PSL	Initiate closing of circuit breaker from a manual command
234	Reset Close Dly.	PSL	Reset manual circuit breaker close time delay
235	Reset Relays/LED	PSL	Reset latched relays & LEDs (manual reset of any lockout trip contacts, auto-reclose lockout, and LEDs)
236	Reset Thermal	PSL	Reset thermal state to 0%
237	Reset Lockout	PSL	Manual control to reset auto-recloser from lockout
238	Reset CB Data	PSL	Reset circuit breaker maintenance values
239	Block A/R	PSL	Block the auto-reclose function from an external input
240	Live Line Mode	PSL	Auto-reclose live line mode operation-switches the auto-reclose out of service and protection functions are not blocked. If DDB is active, the scheme is forced to live line mode, irrespective of the auto-reclose mode select setting and auto mode and telecontrol input DDBs
241	Auto Mode	PSL	Auto-recloser auto mode operation-switches the auto-reclose in service
242	Telecontrol Mode	PSL	Telecontrol mode operation selection-whereby the auto and non-auto modes of auto-reclose can be selected remotely
243	I>1 Trip	Phase Overcurrent	1st stage overcurrent trip 3ph
244	I>1 Trip A	Phase Overcurrent	1st stage overcurrent trip A
245	I>1 Trip B	Phase Overcurrent	1st stage overcurrent trip B
246	I>1 Trip C	Phase Overcurrent	1st stage overcurrent trip C
247	I>2 Trip	Phase Overcurrent	2nd stage overcurrent trip 3ph
248	I>2 Trip A	Phase Overcurrent	2nd stage overcurrent trip A
249	I>2 Trip B	Phase Overcurrent	2nd stage overcurrent trip B
250	I>2 Trip C	Phase Overcurrent	2nd stage overcurrent trip C
251	I>3 Trip	Phase Overcurrent	3rd stage overcurrent trip 3ph
252	I>3 Trip A	Phase Overcurrent	3rd stage overcurrent trip A
253	I>3 Trip B	Phase Overcurrent	3rd stage overcurrent trip B
254	I>3 Trip C	Phase Overcurrent	3rd stage overcurrent trip C
255	I>4 Trip	Phase Overcurrent	4th stage overcurrent trip 3ph
256	I>4 Trip A	Phase Overcurrent	4th stage overcurrent trip A
257	I>4 Trip B	Phase Overcurrent	4th stage overcurrent trip B
258	I>4 Trip C	Phase Overcurrent	4th stage overcurrent trip C

DDB no.	English text	Source	Description
259			Unused
260	Broken Line Trip	Broken Conductor	Broken conductor trip
261	IN1>1 Trip	Earth Fault 1	1st stage measured earth fault trip
262	IN1>2 Trip	Earth Fault 1	2nd stage measured earth fault trip
263	IN1>3 Trip	Earth Fault 1	3rd stage measured earth fault trip
264	IN1>4 Trip	Earth Fault 1	4th stage measured earth fault trip
265	IN2>1 Trip	Earth Fault 2	1st stage derived earth fault trip
266	IN2>2 Trip	Earth Fault 2	2nd stage derived earth fault trip
267	IN2>3 Trip	Earth Fault 2	3rd stage derived earth fault trip
268	IN2>4 Trip	Earth Fault 2	4th stage derived earth fault trip
269	ISEF>1 Trip	Sensitive Earth Fault	1st stage sensitive earth fault trip
270	ISEF>2 Trip	Sensitive Earth Fault	2nd stage sensitive earth fault trip
271	ISEF>3 Trip	Sensitive Earth Fault	3rd stage sensitive earth fault trip
272	ISEF>4 Trip	Sensitive Earth Fault	4th stage sensitive earth fault trip
273	IREF> Trip	Restricted Earth Fault	Restricted earth fault trip
274	VN>1 Trip	Residual Overvoltage	1st stage residual overvoltage trip
275	VN>2 Trip	Residual Overvoltage	2nd stage residual overvoltage trip
276	Thermal Trip	Thermal Overload	Thermal overload trip
277	V2> Trip	Neg. Sequence O/V	Negative sequence overvoltage trip
278	V<1 Trip	Undervoltage	1st stage phase undervoltage trip 3ph
279	V<1 Trip A/AB	Undervoltage	1st stage phase undervoltage trip A/AB
280	V<1 Trip B/BC	Undervoltage	1st stage phase undervoltage trip B/BC
281	V<1 Trip C/CA	Undervoltage	1st stage phase undervoltage trip C/CA
282	V<2 Trip	Undervoltage	2nd stage phase undervoltage trip 3ph
283	V<2 Trip A/AB	Undervoltage	2nd stage phase undervoltage trip A/AB
284	V<2 Trip B/BC	Undervoltage	2nd stage phase undervoltage trip B/BC
285	V<2 Trip C/CA	Undervoltage	2nd stage phase undervoltage trip C/CA
286	V>1 Trip	Overvoltage	1st stage phase overvoltage trip 3ph
287	V>1 Trip A/AB	Overvoltage	1st stage phase overvoltage trip A/AB
288	V>1 Trip B/BC	Overvoltage	1st stage phase overvoltage trip B/BC
289	V>1 Trip C/CA	Overvoltage	1st stage phase overvoltage trip C/CA
290	V>2 Trip	Overvoltage	2nd stage phase overvoltage trip 3ph
291	V>2 Trip A/AB	Overvoltage	2nd stage phase overvoltage trip A/AB
292	V>2 Trip B/BC	Overvoltage	2nd stage phase overvoltage trip B/BC
293	V>2 Trip C/CA	Overvoltage	2nd stage phase overvoltage trip C/CA
294	Any Start	All Protection	Any start
295	I>1 Start	Phase Overcurrent	1st stage overcurrent start 3ph
296	I>1 Start A	Phase Overcurrent	1st stage overcurrent start A
297	I>1 Start B	Phase Overcurrent	1st stage overcurrent start B
298	I>1 Start C	Phase Overcurrent	1st stage overcurrent start C
299	I>2 Start	Phase Overcurrent	2nd stage overcurrent start 3ph
300	I>2 Start A	Phase Overcurrent	2nd stage overcurrent start A
301	I>2 Start B	Phase Overcurrent	2nd stage overcurrent start B
302	I>2 Start C	Phase Overcurrent	2nd stage overcurrent start C

DDB no.	English text	Source	Description
303	I>3 Start	Phase Overcurrent	3rd stage overcurrent start 3ph
304	I>3 Start A	Phase Overcurrent	3rd stage overcurrent start A
305	I>3 Start B	Phase Overcurrent	3rd stage overcurrent start B
306	I>3 Start C	Phase Overcurrent	3rd stage overcurrent start C
307	I>4 Start	Phase Overcurrent	4th stage overcurrent start 3ph
308	I>4 Start A	Phase Overcurrent	4th stage overcurrent start A
309	I>4 Start B	Phase Overcurrent	4th stage overcurrent start B
310	I>4 Start C	Phase Overcurrent	4th stage overcurrent start C
311	VDep OC Start AB	Voltage Dependent O/C	Voltage Dependent overcurrent start AB
312	VDep OC Start BC	Voltage Dependent O/C	Voltage Dependent overcurrent start BC
313	VDep OC Start CA	Voltage Dependent O/C	Voltage Dependent overcurrent start CA
314			Unused
315	IN1>1 Start	Earth Fault 1	1st stage measured earth fault start
316	IN1>2 Start	Earth Fault 1	2nd stage measured earth fault start
317	IN1>3 Start	Earth Fault 1	3rd stage measured earth fault start
318	IN1>4 Start	Earth Fault 1	4th stage measured earth fault start
319	IN2>1 Start	Earth Fault 2	1st stage derived earth fault start
320	IN2>2 Start	Earth Fault 2	2nd stage derived earth fault start
321	IN2>3 Start	Earth Fault 2	3rd stage derived earth fault start
322	IN2>4 Start	Earth Fault 2	4th stage derived earth fault start
323	ISEF>1 Start	Sensitive Earth Fault	1st stage sensitive earth fault start
324	ISEF>2 Start	Sensitive Earth Fault	2nd stage sensitive earth fault start
325	ISEF>3 Start	Sensitive Earth Fault	3rd stage sensitive earth fault start
326	ISEF>4 Start	Sensitive Earth Fault	4th stage sensitive earth fault start
327	VN>1 Start	Residual Overvoltage	1st stage residual overvoltage start
328	VN>2 Start	Residual Overvoltage	2nd stage residual overvoltage start
329	Thermal Alarm	Thermal Overload	Thermal overload alarm
330	V2> Start	Neg. Sequence O/V	Negative sequence overvoltage start
331	V<1 Start	Undervoltage	1st stage phase undervoltage start 3ph
332	V<1 Start A/AB	Undervoltage	1st stage phase undervoltage start A/AB
333	V<1 Start B/BC	Undervoltage	1st stage phase undervoltage start B/BC
334	V<1 Start C/CA	Undervoltage	1st stage phase undervoltage start C/CA
335	V<2 Start	Undervoltage	2nd stage phase undervoltage start 3ph
336	V<2 Start A/AB	Undervoltage	2nd stage phase undervoltage start A/AB
337	V<2 Start B/BC	Undervoltage	2nd stage phase undervoltage start B/BC
338	V<2 Start C/CA	Undervoltage	2nd stage phase undervoltage start C/CA
339	V>1 Start	Overvoltage	1st stage phase overvoltage start 3ph
340	V>1 Start A/AB	Overvoltage	1st stage phase overvoltage start A/AB
341	V>1 Start B/BC	Overvoltage	1st stage phase overvoltage start B/BC
342	V>1 Start C/CA	Overvoltage	1st stage phase overvoltage start C/CA
343	V>2 Start	Overvoltage	2nd stage phase overvoltage start 3ph
344	V>2 Start A/AB	Overvoltage	2nd stage phase overvoltage start A/AB
345	V>2 Start B/BC	Overvoltage	2nd stage phase overvoltage start B/BC
346	V>2 Start C/CA	Overvoltage	2nd stage phase overvoltage start C/CA

DDB no.	English text	Source	Description
347	CLP Operation	Cold Load Pickup	Indicates the cold load pick-up logic is in operation
348	I> BlockStart	CBF & POC	I> blocked overcurrent start
349	IN/SEF>Blk Start	CBF & IN1/IN2/SEF	IN/ISEF> blocked overcurrent start
350	VTS Fast Block	VT Supervision	VT supervision fast block - blocks elements which would otherwise mal-operate immediately a fuse failure event occurs
351	VTS Slow Block	VT Supervision	VT supervision slow block - blocks elements which would otherwise mal-operate some time after a fuse failure event occurs
352	CTS Block	CT Supervision	CT supervision block (current transformer supervision)
353	Bfail1 Trip 3ph	CB Fail	tBF1 trip 3Ph - three phase output from circuit breaker failure logic, stage 1 timer
354	Bfail2 Trip 3ph	CB Fail	tBF2 trip 3Ph - three phase output from circuit breaker failure logic, stage 2 timer
355	Control Trip	CB Control	Control trip - operator trip instruction to the circuit breaker, via menu, or SCADA. (Does not operate for protection element trips)
356	Control Close	CB Control	Control close command to the circuit breaker. operates for a manual close command (menu, SCADA), and additionally is driven by the auto-reclose close command
357	Close in Prog.	CB Control	Control close in progress - the relay has been given an instruction to close the circuit breaker, but the manual close timer delay has not yet finished timing out
358	Block Main Prot.	Auto-Reclose	Auto-reclose block main protection during auto-reclose cycle. Can be used to block external protection via relay output contacts
359	Block SEF Prot.	Auto-Reclose	Auto-reclose block sensitive earth fault protection during auto-reclose cycle. Can be used to block external protection via relay output contacts
360	AR In Progress	Auto-Reclose	Auto-reclose in progress
361	AR In Service	Auto-Reclose	Auto-reclose in/out of service - the auto-reclose function has been enabled either in the relay menu, or by an opto input
362	Seq. Counter = 0	Auto-Reclose	Auto-reclose sequence counter is at zero - no previous faults have been cleared within recent history. The sequence count is at zero because no reclaim times are timing out, and the auto-recloser is not locked out. The recloser is awaiting the first protection trip, and all programmed cycles are free to follow
363	Seq. Counter = 1	Auto-Reclose	The first fault trip has happened in a new auto-reclose sequence. Dead time 1, or reclaim time 1 are in the process of timing out
366	Seq. Counter = 4	Auto-Reclose	Auto-reclose sequence counter is at 4. This means that the initial fault trip happened, and then 3 trips followed, moving the counter on to 4
367	Successful Close	Auto-Reclose	Successful re-closure indication. The circuit breaker was re-closed by the auto-reclose function, and stayed closed. This indication is raised at the expiry of the reclaim time
368	Dead T in Prog.	Auto-Reclose	Indicates dead time in progress
369	Protection Lockt.	Auto-Reclose	Indicates a protection lockout of auto-reclose when the AR is set to live line or non-auto modes
370	Reset Lckout Alm.	Auto-Reclose	Auto-reclose reset lockout alarm indication
371	Auto Close	Auto-Reclose	Auto-reclose command to the circuit breaker

DDB no.	English text	Source	Description
372	A/R Trip Test	Auto-Reclose	Auto-reclose trip test which initiates an auto-reclose cycle
373	IA< Start	Undercurrent	A phase undercurrent start
374	IB< Start	Undercurrent	B phase undercurrent start
375	IC< Start	Undercurrent	C phase undercurrent start
376	IN< Start	Undercurrent	Earth fault undercurrent start
377	ISEF< Start	Undercurrent	Sensitive earth fault undercurrent start
378	CB Open 3 ph	CB Status	Three phase circuit breaker open status
379	CB Closed 3 ph	CB Status	Three phase circuit breaker closed status
380	All Poles Dead	Poledead	Pole dead logic detects 3 phase breaker open condition
381	Any Pole Dead	Poledead	Pole dead logic detects at least one breaker pole open
382	Pole Dead A	Poledead	Phase A pole dead
383	Pole Dead B	Poledead	Phase B pole dead
384	Pole Dead C	Poledead	Phase C pole dead
385	VTS Acc. Ind.	VT Supervision (hidden)	Voltage transformer supervision accelerate indication signal form a fast tripping voltage dependent function used to accelerate indications when the indicate only option is selected
386	VTS Volt Dep.	VT Supervision Input (hidden)	Outputs from any function that utilizes the system voltage, if any of these elements operate before a VTS is detected; the VTS is blocked from operation. The outputs include starts and trips
387	VTS Ia>	VT Supervision (hidden)	VTS A phase current level detector is over threshold
388	VTS Ib>	VT Supervision (hidden)	VTS B phase current level detector is over threshold
389	VTS Ic>	VT Supervision (hidden)	VTS C phase current level detector is over threshold
390	VTS Va>	VT Supervision (hidden)	VTS A phase voltage level detector is over threshold
391	VTS Vb>	VT Supervision (hidden)	VTS B phase voltage level detector is over threshold
392	VTS Vc>	VT Supervision (hidden)	VTS C phase voltage level detector is over threshold
393	VTS I2>	VT Supervision (hidden)	VTS negative sequence current level detector is over threshold
394	VTS V2>	VT Supervision (hidden)	VTS negative sequence voltage level detector is over threshold
395	VTS Ia delta>	VT Supervision (hidden)	Superimposed A phase current over threshold
396	VTS Ib delta>	VT Supervision (hidden)	Superimposed B phase current over threshold
397	VTS Ic delta >	VT Supervision (hidden)	Superimposed C phase current over threshold
398	CBF SEF Trip	Breaker Fail (Fixed Logic) (hidden)	Internal signal for the circuit breaker fail logic to indicate general sensitive earth fault trip condition
399	CBF Non I Trip	Breaker Fail (Fixed Logic) (hidden)	Internal signal for the circuit breaker fail logic to indicate general non-current based protection trip
400	CBF SEF Trip-1	Breaker Fail (Fixed Logic) (hidden)	Internal signal for the circuit breaker fail logic to indicate a sensitive earth fault stage trip condition
401	CBF Non I Trip-1	Breaker Fail (Fixed Logic) (hidden)	Internal signal for the circuit breaker fail logic to indicate non-current protection stage trip
402	Man Check Sync.	PSL	Input to the circuit breaker control logic to indicate manual check synchronization conditions are satisfied
403	AR SysChecks OK	PSL	Input to the auto-reclose logic to indicate auto-reclose check synchronization conditions are satisfied
404	Lockout Alarm	CB Monitoring	Composite lockout alarm

DDB no.	English text	Source	Description
405	Pre-Lockout	CB Monitoring (hidden)	Pre-lockout alarm indicates the auto-reclose will lockout on the next shot
406	Freq. High	Frequency Tracking (hidden)	Frequency tracking detects frequency above the allowed range
407	Freq. Low	Frequency Tracking (hidden)	Frequency tracking detects frequency below the allowed range
408	Stop Freq. Track	Fixed Logic (hidden)	Stop frequency tracking signal - indicates under legitimate conditions when the relay suspends frequency tracking on the instruction of the protection elements
409	Start N	EF1/EF2/SEF/VN/YN (hidden)	Composite earth fault start
410	Field Volts Fail	Field Voltage Monitor	48V field voltage failure
411	Freq. Not Found	Frequency Tracking (hidden)	Frequency not found by the frequency tracking
412	F<1 Timer Block	PSL	Block underfrequency stage 1 timer
413	F<2 Timer Block	PSL	Block underfrequency stage 2 timer
414	F<3 Timer Block	PSL	Block underfrequency stage 3 timer
415	F<4 Timer Block	PSL	Block underfrequency stage 4 timer
416	F>1 Timer Block	PSL	Block overfrequency stage 1 timer
417	F>2 Timer Block	PSL	Block overfrequency stage 2 timer
418	F<1 Start	Frequency Protection	Underfrequency stage 1 start
419	F<2 Start	Frequency Protection	Underfrequency stage 2 start
420	F<3 Start	Frequency Protection	Underfrequency stage 3 start
421	F<4 Start	Frequency Protection	Underfrequency stage 4 start
422	F>1 Start	Frequency Protection	Overfrequency stage 1 start
423	F>2 Start	Frequency Protection	Overfrequency stage 2 start
424	F<1 Trip	Frequency Protection	Underfrequency stage 1 trip
425	F<2 Trip	Frequency Protection	Underfrequency stage 2 trip
426	F<3 Trip	Frequency Protection	Underfrequency stage 3 trip
427	F<4 Trip	Frequency Protection	Underfrequency stage 4 trip
428	F>1 Trip	Frequency Protection	Overfrequency stage 1 trip
429	F>2 Trip	Frequency Protection	Overfrequency stage 2 trip
430	YN> Timer Block	PSL	Block overadmittance timer
431	GN> Timer Block	PSL	Block overconductance timer
432	BN> Timer Block	PSL	Block oversusceptance timer
433	YN> Start	Admittance Protection	Overadmittance start
434	GN> Start	Admittance Protection	Overconductance start
435	BN> Start	Admittance Protection	Oversusceptance start
436	YN> Trip	Admittance Protection	Overadmittance trip
437	GN> Trip	Admittance Protection	Overconductance trip
438	BN> Trip	Admittance Protection	Oversusceptance trip
439	Ext. AR Prot. Trip	PSL	Initiate auto-reclose from an external protection device trip
440	Ext. AR Prot. Strt.	PSL	Initiate auto-reclose from an external protection device start
441	Test Mode	PSL	Initiate test mode which takes the relay out of service and allows secondary injection testing of the relay

DDB no.	English text	Source	Description
442	Inhibit SEF	PSL	Inhibit sensitive earth fault protection - all stages
443	Live Line	Voltage Monitors	Indicates live line condition is detected
444	Dead Line	Voltage Monitors	Indicates dead line condition is detected
445	Live Bus	Voltage Monitors	Indicates live bus condition is detected
446	Dead Bus	Voltage Monitors	Indicates dead bus condition is detected
447	Check Sync. 1 OK	Check Synchronization	Check sync. stage 1 OK
448	Check Sync. 2 OK	Check Synchronization	Check sync. stage 2 OK
449	SysChks Inactive	Check Synchronization	System checks inactive (output from the check synchronism, and other voltage checks)
450	CS1 Enabled	PSL	Check sync. stage 1 enabled
451	CS2 Enabled	PSL	Check sync. stage 2 enabled
452	SysSplit Enabled	PSL	System split function enabled
453	DAR Complete	PSL	Delayed auto-reclose complete
454	CB In Service	PSL	Circuit breaker is in service
455	AR Restart	PSL	Auto-reclose restart input to initiate an auto-reclose cycle irrespective of the normal AR interlock conditions
456	AR In Progress 1	Auto-Reclose	Auto-reclose in progress indication which is active during AR cycle and is reset by the ‘DAR Complete’ DDB if mapped or otherwise by the ‘AR in Progress’ DDB
457	DeadTime Enabled	PSL	Dead time enabled
458	DT OK To Start	PSL	Dead time OK to start input to the dead time initiation logic. Allows an interlock condition besides CB open and protection reset to ‘prime’ the dead time logic
459	DT Complete	Auto-Reclose	Dead time complete indication and operates at the end of the set dead time period
460	Reclose Checks	Auto-Reclose	Re-close checks indicates the dead time logic is ‘primed’
461	Circuits OK	PSL	Input to the auto-reclose logic to indicate live/dead circuit conditions are satisfied when AR with ‘Live/Dead Ccts’ is enabled
462	AR Sync. Check	Auto-Reclose	Auto-reclose check synchronism OK (system checks passed)
463	AR SysChecksOK	Auto-Reclose	Auto-reclose system check OK conditions are confirmed by the system checks function
464	AR Init. TripTest	PSL	Initiates a trip and auto-reclose cycle and is usually mapped to an opto input
465	Monitor Block	PSL	For IEC-870-5-103 protocol only, used for "Monitor Blocking" (relay is quiet - issues no messages via SCADA port)
466	Command Block	PSL	For IEC-870-5-103 protocol only, used for "Command Blocking" (relay ignores SCADA commands)
467	ISEF>1 Start 2	Sensitive Earth Fault	1st stage sensitive earth fault second start indication
468	ISEF>2 Start 2	Sensitive Earth Fault	2nd stage sensitive earth fault second start indication
469	ISEF>3 Start 2	Sensitive Earth Fault	3rd stage sensitive earth fault second start indication
470	ISEF>4 Start 2	Sensitive Earth Fault	4th stage sensitive earth fault second start indication
471	CS1 Slipfreq.>	Check Synchronization	Operates when 1st stage check sync. slip frequency is above the check sync. 1 slip frequency setting
472	CS1 Slipfreq.<	Check Synchronization	Operates when 1st stage check sync. slip frequency is below the check sync. 1 slip frequency setting
473	CS2 Slipfreq.>	Check Synchronization	Operates when 2nd stage check sync. slip frequency is above the check sync. 2 slip frequency setting

DDB no.	English text	Source	Description
474	CS2 Slipfreq.<	Check Synchronization	Operates when 2nd stage check sync. slip frequency is below the check sync. 2 slip frequency setting
475	Time Sync.	PSL	Time synchronism by opto pulse
476 - 488			Unused
489	CS Vline<	Check Synchronization	Indicates the line voltage is less than the check sync. undervoltage setting
490	CS Vbus<	Check Synchronization	Indicates the bus voltage is less than the check sync. undervoltage setting
491	CS Vline>	Check Synchronization	Indicates the line voltage is greater than the check sync. overvoltage setting
492	CS Vbus>	Check Synchronization	Indicates the bus voltage is greater than the check sync. overvoltage setting
493	CS Vline>Vbus	Check Synchronization	Indicates that the line voltage is greater than bus voltage + check sync. differential voltage setting
494	CS Vline<Vbus	Check Synchronization	Indicates the bus voltage is greater than line voltage + check sync. differential voltage setting
495	CS1 Fline>Fbus	Check Synchronization	Indicates the line frequency is greater than the bus frequency + check sync. 1 slip frequency setting where check sync. 1 slip control is set to frequency
496	CS1 Fline<Fbus	Check Synchronization	Indicates the bus frequency is greater than line frequency + check sync. 1 slip frequency setting where check sync. 1 slip control is set to frequency
497	CS1 Ang. Not OK +	Check Synchronization	Indicates the line angle leads the bus angle and falls in range + CS1 phase angle (deg.) to 180°
498	CS1 Ang. Not OK -	Check Synchronization	Indicates if the line angle lags the bus angle and falls in range - CS1 phase angle (deg.) to -180°
499	External Trip A	PSL	External trip A input
500	External Trip B	PSL	External trip B input
501	External Trip C	PSL	External trip C input
502	External Trip EF	PSL	External trip earth fault input
503	External TripSEF	PSL	External trip sensitive earth fault input
504	I2> Inhibit	PSL	Inhibit all negative sequence overcurrent stages
505	I2>1 Tmr. Blk.	PSL	Block negative sequence overcurrent stage 1 timer
506	I2>2 Tmr. Blk.	PSL	Block negative sequence overcurrent stage 2 timer
507	I2>3 Tmr. Blk.	PSL	Block negative sequence overcurrent stage 3 timer
508	I2>4 Tmr. Blk.	PSL	Block negative sequence overcurrent stage 4 timer
509	I2>1 Start	Neg. Sequence O/C	1st stage negative sequence overcurrent start
510	I2>2 Start	Neg. Sequence O/C	2nd stage negative sequence overcurrent start
511	I2>3 Start	Neg. Sequence O/C	3rd stage negative sequence overcurrent start
512	I2>4 Start	Neg. Sequence O/C	4th stage negative sequence overcurrent start
513	I2>1 Trip	Neg. Sequence O/C	1st stage negative sequence overcurrent trip
514	I2>2 Trip	Neg. Sequence O/C	2nd stage negative sequence overcurrent trip
515	I2>3 Trip	Neg. Sequence O/C	3rd stage negative sequence overcurrent trip
516	I2>4 Trip	Neg. Sequence O/C	4th stage negative sequence overcurrent trip
517	V2> Accelerate	PSL	Input to accelerate negative sequence overvoltage (V2> protection) instantaneous operating time
518	Trip LED	PSL	Input to trigger trip LED (other than relay 3)

DDB no.	English text	Source	Description
519	CS2 Fline>Fbus	Check Synchronization	Indicates the line frequency is greater than the bus frequency + check sync. 2 slip frequency setting where check sync. 2 slip control is set to frequency
520	CS2 Fline<Fbus	Check Synchronization	Indicates the bus frequency is greater than line frequency + check sync. 2 slip frequency setting where check sync. 2 slip control is set to frequency
521	CS2 Ang. Not OK +	Check Synchronization	Indicates the line angle leads the bus angle and falls in range + check sync. 2 phase angle (deg.) to 180°
522	CS2 Ang. Not OK	Check Synchronization	Indicates the line angle lags the bus angle and falls in range - check sync. 2 phase angle (deg.) to -180°
523	CS Ang. Rot ACW	Check Synchronization	The direction of rotation of line angle, using bus as a reference, is anti-clockwise (ACW)
524	CS Ang. Rot CW	Check Synchronization	The direction of rotation of line angle, using bus as a reference, is clockwise (CW)
525	Blk. Rmt. CB Ops	PSL	Block remote CB trip/close commands
526	SG Select x1	PSL	Setting group selector X1 (low bit)-selects SG2 if only DDB 526 signal is active. SG1 is active if both DDB 526 & DDB 527=0 SG4 is active if both DDB 526 & DDB 527=1
527	SG Select 1x	PSL	Setting group selector 1X (high bit)-selects SG3 if only DDB 527 is active. SG1 is active if both DDB 526 & DDB 527=0 SG4 is active if both DDB 526 & DDB 527=1
528	IN1> Inhibit	PSL	Inhibit earth fault 1 protection
529	IN2> Inhibit	PSL	Inhibit earth fault 2 protection
530	AR Skip Shot 1	PSL	When active skips the first auto-reclose shot in an auto-reclose cycle
531	Logic 0 Ref.	Reference DDB Signal	Logic zero reference DDB signal
532	Inh Reclaim Time	PSL	Inhibit AR reclaim timer
533	Reclaim In Prog		AR reclaim time in progress
534	Reclaim Complete		AR reclaim time complete
535	BrokenLine Start		Broken conductor start
536	Trip Command In		Trip command initiated by DDB_TRIP_INITIATE
537	Trip Command Out		Initiate trip
538	IA2H Start		2nd Harmonic over threshold in IA
539	IB2H Start		2nd Harmonic over threshold in IB
540	IC2H Start		2nd Harmonic over threshold in IC
541	I2H Any Start		2nd Harmonic over threshold in any of IA, IB or IC
542	RP1 Read Only		Remote Read Only 1
543	RP2 Read Only		Remote Read Only 2
544	NIC Read Only		Remote Read Only NIC
545	dv/dt1 Start A/AB		dv/dt stage 1 Phase A or AB start
546	dv/dt1 Start B/BC		dv/dt stage 1 Phase B or BC start
547	dv/dt1 Start C/CA		dv/dt stage 1 Phase C or CA start
548	dv/dt1 Start		dv/dt stage 1 General start
549	dv/dt2 Start A/AB		dv/dt stage 2 Phase A or AB start
550	dv/dt2 Start B/BC		dv/dt stage 2 Phase B or BC start
551	dv/dt2 Start C/CA		dv/dt stage 2 Phase C or CA start

DDB no.	English text	Source	Description
552	dv/dt2 Start		dv/dt stage 2 General start
553	dv/dt1 trip A/AB		dv/dt stage 1 Phase A or AB trip
554	dv/dt1 trip B/BC		dv/dt stage 1 Phase B or BC trip
555	dv/dt1 trip C/CA		dv/dt stage 1 Phase C or CA trip
556	dv/dt1 trip		dv/dt stage 1 General trip
557	dv/dt2 trip A/AB		dv/dt stage 2 Phase A or AB trip
558	dv/dt2 trip B/BC		dv/dt stage 2 Phase B or BC trip
559	dv/dt2 trip C/CA		dv/dt stage 2 Phase C or CA trip
560	dv/dt2 trip		dv/dt stage 2 General trip
561	dv/dt1 Blocking		dv/dt stage 1 Block signal
562	dv/dt2 Blocking		dv/dt stage 2 Block signal
563	ZCD IA<	CB Fail (Hidden)	Zero crossing undercurrent Phase A
564	ZCD IB<	CB Fail (Hidden)	Zero crossing undercurrent Phase B
565	ZCD IC<	CB Fail (Hidden)	Zero crossing undercurrent Phase C
566	ZCD IN<	CB Fail (Hidden)	Zero crossing undercurrent EF
567	I>5 Timer Block		Block phase over current stage 5 time delay
568	I>6 Timer Block		Block phase over current stage 6 time delay
569	ZCD ISEF<	CB Fail (Hidden)	Zero crossing undercurrent SEF
570	I>5 trip		5th stage O/C trip 3 phase
571	I>5 trip A		5th stage O/C trip A phase
572	I>5 trip B		5th stage O/C trip B phase
573	I>5 trip C		5th stage O/C trip C phase
574	I>6 trip		6th stage O/C trip 3 phase
575	I>6 trip A		6th stage O/C trip A phase
576	I>6 trip B		6th stage O/C trip B phase
577	I>6 trip C		6th stage O/C trip C phase
578	Unused		
579	I>5 Start		5^{th} stage O/C Start 3 phase
580	I>5 Start A		5^{th} stage O/C Start A phase
581	I>5 Start B		5^{th} stage O/C Start B phase
582	I>5 Start C		5^{th} stage O/C Start C phase
583	I>6 Start		6^{th} stage O/C Start 3 phase
584	I>6 Start A		6^{th} stage O/C Start A phase
585	I>6 Start B		6^{th} stage O/C Start B phase
586	I>6 Start C		6^{th} stage O/C Start C phase
587-8	Unused		
589	Monitor bit 1		Monitor bit 1
590	Monitor bit 2		Monitor bit 2
591	Monitor bit 3		Monitor bit 3
592	Monitor bit 4		Monitor bit 4
593	Monitor bit 5		Monitor bit 5
594	Monitor bit 6		Monitor bit 6
595	Monitor bit 7		Monitor bit 7
596	Monitor bit 8		Monitor bit 8

DDB no.	English text	Source	Description
597 - 609	Unused		
610	IRIG-B Valid		IRIG-B signal is valid
611 - 626	Unused		
627	Blinder Inhibit	PSL	Blinder Inhibit
628	A FWD Blinder		A FWD Blinder
629	A REV Blinder		A REV Blinder
630	A Load Blinder		A Load Blinder
631	B FWD Blinder		B FWD Blinder
632	B REV Blinder		B REV Blinder
633	B Load Blinder		B Load Blinder
634	C FWD Blinder		C FWD Blinder
635	C REV Blinder		C REV Blinder
636	C Load Blinder		C Load Blinder
637	Z1 FWD Blinder		Z1 FWD Blinder
638	Z1 REV Blinder		Z1 REV Blinder
639	Z1 Load Blinder		Z1C Load Blinder
640	LED1 Red	Output Conditioner	Programmable LED 1 red is energized
641	LED1 Grn.	Output Conditioner	Programmable LED 1 green is energized
654	LED8 Red	Output Conditioner	Programmable LED 8 red is energized
655	LED8 Grn.	Output Conditioner	Programmable LED 8 green is energized
656	FnKey LED1 Red	Output Conditioner	Programmable function key LED 1 red is energized
657	FnKey LED1 Grn.	Output Conditioner	Programmable function key LED 1 green is energized
674	FnKey LED10 Red	Output Conditioner	Programmable function key LED 10 red is energized
675	FnKey LED10 Grn.	Output Conditioner	Programmable function key LED 10 green is energized
676	LED1 Con R	PSL	Assignment of input signal to drive output LED 1 red
677	LED1 Con G	PSL	Assignment of signal to drive output LED 1 green to drive LED 1 yellow DDB 676 and DDB 677 must be driven at the same time
690	LED8 Con R	PSL	Assignment of signal to drive output LED 8 red
691	LED8 Con G	PSL	Assignment of signal to drive output LED 8 green. To drive LED 8 yellow DDB 690 and DDB 691 must be active at the same time
692	FnKey LED1 ConR	PSL	Assignment of signal to drive output function key LED 1 red. This LED is associated with function key 1
693	FnKey LED1 ConG	PSL	Assignment of signal to drive output function key LED 1 green. This LED is associated with function key 1. To drive function key LED, yellow DDB 692 and DDB 693 must be active at the same time
710	FnKey LED10 ConR	PSL	Assignment of signal to drive output function key LED 10 red. This LED is associated with function key 10
711	FnKey LED10 ConG	PSL	Assignment of signal to drive output function key LED 10 green. This LED is associated with function key 10. To drive function key LED 1 yellow, DDB 710 and DDB 711 must be active at the same time
712	Function Key 1	Function Key	Function key 1 is activated. In ‘Normal’ mode it is high on keypress and in ‘Toggle’ mode remains high/low on single keypress

DDB no.	English text	Source	Description
721	Function Key 10	Function Key	Function key 10 is activated. In ‘Normal’ mode it is high on keypress and in ‘Toggle’ mode remains high/low on single keypress
722	Power>1 3Phstart	Power	1st stage overpower start 3 phase
723	Power>1 A Start	Power	1st stage overpower start A phase
724	Power>1 B Start	Power	1st stage overpower start B phase
725	Power>1 C Start	Power	1st stage overpower start C phase
726	Power>2 3Phstart	Power	2nd stage overpower start 3 phase
727	Power>2 A Start	Power	2nd stage overpower start A phase
728	Power>2 B Start	Power	2nd stage overpower start B phase
729	Power>2 C Start	Power	2nd stage overpower start C phase
730	Power<1 3Phstart	Power	1st stage underpower start 3 phase
731	Power<1 A Start	Power	1st stage underpower start A phase
732	Power<1 B Start	Power	1st stage underpower start B phase
733	Power<1 C Start	Power	1st stage underpower start C phase
734	Power<2 3Phstart	Power	2nd stage unde power start 3 phase
735	Power<2 A Start	Power	2nd stage underpower start A phase
736	Power<2 B Start	Power	2nd stage underpower start B phase
737	Power<2 C Start	Power	2nd stage underpower start C phase
738	Power>1 3Ph Trip	Power	1st stage overpower trip 3 phase
739	Power>1 A Trip	Power	1st stage overpower trip A phase
740	Power>1 B Trip	Power	1st stage overpower trip B phase
741	Power>1 C Trip	Power	1st stage overpower trip C phase
742	Power>2 3Ph Trip	Power	2nd stage overpower trip 3 phase
743	Power>2 A Trip	Power	2nd stage overpower trip A phase
744	Power>2 B Trip	Power	2nd stage overpower trip B phase
745	Power>2 C Trip	Power	2nd stage overpower trip C phase
746	Power<1 3Ph Trip	Power	1st stage underpower trip 3 phase
747	Power<1 A Trip	Power	1st stage underpower trip A phase
748	Power<1 B Trip	Power	1st stage underpower trip B phase
749	Power<1 C Trip	Power	1st stage underpower trip C phase
750	Power<2 3Ph Trip	Power	2nd stage underpower trip 3 phase
751	Power<2 A Trip	Power	2nd stage underpower trip A phase
752	Power<2 B Trip	Power	2nd stage underpower trip B phase
753	Power<2 C Trip	Power	2nd stage underpower trip C phase
754	Power>1 Block	Power	1st stage overpower block
755	Power>2 Block	Power	2nd stage overpower block
756	Power<1 Block	Power	1st stage underpower block
757	Power<2 Block	Power	2nd stage underpower block
758	SensP1 StartA		Sensitive A phase power 1st stage start
759	SensP2 StartA		Sensitive A phase power 2nd stage start
760	SensP1 TripA		Sensitive A phase power 1st stage trip
761	SensP2 TripA		Sensitive A phase power 2nd stage trip
762 - 768			Unused
769	Battery Fail		Battery fail alarm

DDB no.	English text	Source	Description
770	Rear Comms Fail		Rear comms failed
771	GOOSE IED Absent		The IED is not subscribed to a publishing IED in the current scheme
772	NIC Not Fitted		Ethernet board not fitted
773	NIC No Response		Ethernet board not responding
774	NIC Fatal Error		Ethernet board unrecoverable error
775	NIC Soft Reload		Ethernet card software reload alarm
776	Bad TCP/IP Cfg.		Bad TCP/IP configuration alarm
777	Bad OSI Config.		Bad OSI configuration alarm
778	NIC Link Fail		Ethernet link lost
779	NIC SW Mis-Match		Ethernet board software not compatible with main CPU
780	IP Addr Conflict		The IP address of the IED is already used by another IED
781	IM Loopback	InterMiCOM	InterMiCOM indication that loopback testing is in progress
782	IM Message Fail	InterMiCOM	InterMiCOM message failure alarm
783	IM Data CD Fail	InterMiCOM	InterMiCOM data channel detect fail
784	IM Channel Fail	InterMiCOM	InterMiCOM channel failure alarm
785	Backup Setting		Backup settings in use alarm
786	Backup UsrCurve		Backup user curve in use alarm
787 - 799			Unused
800	Control Input 1	Control Input Command	Control input 1 - for SCADA and menu commands into PSL
831	Control Input 32	Control Input Command	Control input 32 - for SCADA and menu commands into PSL
832 - 895	Virtual Input 1-64	GOOSE Input Command	GOOSE input 1 - 64 - allows binary signals that are mapped to virtual inputs to interface into PSL
896 - 903	InterMiCOM in 1 - 8	InterMiCOM	InterMiCOM in 1 to 8 - is driven by a message from the remote line end
904 - 911	InterMiCOM out 1 - 8	PSL	InterMiCOM out 1 - 8 - mapping what will be sent to the remote line end
912 - 922	Unused		
923 - 1022	PSL internal		
1023	Unused		
1024 - 1055	Virtual Output 1 - 32	PSL	GOOSE output 1 - 32 - output allows user to control a binary signal which can be mapped via SCADA protocol output to other devices
1056 - 1119	Quality VIP 1 - 64		GOOSE Virtual input 1 - 64 - provides the Quality attributes of any data object in an incoming GOOSE message
1120 - 1183	PubPres VIP 1 - 64		GOOSE Virtual input 1 - 64 - indicates if the GOOSE publisher responsible for publishing the data that derives a virtual input is present
1184	HMI Access Lvl1		Bit0 of the level access for HMI interface
1185	HMI Access Lvl1		Bit1 of the level access for HMI interface
1186	FPort Access Lvl1		Bit0 of the level access for front port interface
1187	FPort Access Lvl1		Bit1 of the level access for front port interface
1188	RPrt1 Access Lvl1		Bit0 of the level access for Rear Port1 interface
1189	RPrt1 Access Lvl1		Bit1 of the level access for Rear Port1 interface

DDB no.	English text	Source	Description
1190	RPrt2 Access Lvl1		Bit0 of the level access for Rear Port2 interface
1191	RPrt2 Access Lvl1		Bit1 of the level access for Rear Port2 interface
1192	Ext Rst CBF	CB Fail	External reset CB fail
1193 - 1196	Unused		
1197 - 1212	Ctrl Setg I/P 33 - 48		Custom input 33 - 48
1213 - 1279	Unused		
1280	Adv Freq Inh		Inhibits advanced frequency protection
1281	Stg1 f+t Sta		Stage 1 f+t element start
1282	Stg1 f+t Trp		Stage 1 f+t element trip
1283	Stg1 f+df/dt Trp		Stage 1 f+df/dt element trip
1284	Stg1 df/dt +t Sta		Stage 1 df/dt +t element start
1285	Stg1 df/dt +t Trp		Stage 1 df/dt +t element trip
1286	Stg1 f+DF/DT Sta		Stage 1 f+DeltaF/DeltaT element start
1287	Stg1 f+DF/DT Trp		Stage 1 f+DeltaF/DeltaT element trip
1288	Stg1 Block		Stage 1 advance frequency block
1289 - 1290			Unused
1291	Stg1 Resore Cls		Stage 1 load restoration close
1292	Stg1 Resore Sta		Stage 1 load restoration start
1293 - 1294			Unused
1295	Stg2 f+t Sta		Stage 2 f+t element start
1296	Stg2 f+t Trp		Stage 2 f+t element trip
1297	Stg2 f+df/dt Trp		Stage 2 f+df/dt element trip
1298	Stg2 df/dt +t Sta		Stage 2 df/dt +t element start
1299	Stg2 df/dt +t Trp		Stage 2 df/dt +t element trip
1300	Stg2 f+DF/DT Sta		Stage 2 f+DeltaF/DeltaT element start
1301	Stg2 f+DF/DT Trp		Stage 2 f+DeltaF/DeltaT element trip
1302	Stg2 Block		Stage 2 advance frequency block
1303 - 1304			Unused
1305	Stg2 Resore Cls		Stage 2 load restoration close
1306	Stg2 Resore Sta		Stage 2 load restoration start
1307 - 1308			Unused
1309	Stg3 f+t Sta		Stage 3 f+t element start
1310	Stg3 f+t Trp		Stage 3 f+t element trip
1311	Stg3 f+df/dt Trp		Stage 3 f+df/dt element trip
1312	Stg3 df/dt +t Sta		Stage 3 df/dt +t element start
1313	Stg3 df/dt +t Trp		Stage 3 df/dt +t element trip
1314	Stg3 f+DF/DT Sta		Stage 3 f+DeltaF/DeltaT element start
1315	Stg3 f+DF/DT Trp		Stage 3 f+DeltaF/DeltaT element trip
1316	Stg3 Block		Stage 3 advance frequency block
1317 - 1318			Unused
1319	Stg3 Resore Cls		Stage 3 load restoration close
1320	Stg3 Resore Sta		Stage 3 load restoration start
1321 - 1322			Unused
1323	Stg4 f+t Sta		Stage 4 f+t element start

DDB no.	English text	Source	Description
1324	Stg4 f+t Trp		Stage 4 f+t element trip
1325	Stg4 f+df/dt Trp		Stage 4 f+df/dt element trip
1326	Stg4 df/dt +t Sta		Stage 4 df/dt +t element start
1327	Stg4 df/dt +t Trp		Stage 4 df/dt +t element trip
1328	Stg4 f+DF/DT Sta		Stage 4 f+DeltaF/DeltaT element start
1329	Stg4 f+DF/DT Trp		Stage 4 f+DeltaF/DeltaT element trip
1330	Stg4 Block		Stage 4 advance frequency block
1331 - 1332			Unused
1333	Stg4 Resore Cls		Stage 4 load restoration close
1334	Stg4 Resore Sta		Stage 4 load restoration start
1335 - 1336			Unused
1337	Stg5 f+t Sta		Stage 5 f+t element start
1338	Stg5 f+t Trp		Stage 5 f+t element trip
1339	Stg5 f+df/dt Trp		Stage 5 f+df/dt element trip
1340	Stg5 df/dt +t Sta		Stage 5 df/dt +t element start
1341	Stg5 df/dt +t Trp		Stage 5 df/dt +t element trip
1342	Stg5 f+DF/DT Sta		Stage 5 f+DeltaF/DeltaT element start
1343	Stg5 f+DF/DT Trp		Stage 5 f+DeltaF/DeltaT element trip
1344	Stg5 Block		Stage 5 advance frequency block
1345 - 1346			Unused
1347	Stg5 Resore Cls		Stage 5 load restoration close
1348	Stg5 Resore Sta		Stage 5 load restoration start
1349 - 1350			Unused
1351	Stg6 f+t Sta		Stage 6 f+t element start
1352	Stg6 f+t Trp		Stage 6 f+t element trip
1353	Stg6 f+df/dt Trp		Stage 6 f+df/dt element trip
1354	Stg6 df/dt +t Sta		Stage 6 df/dt +t element start
1355	Stg6 df/dt +t Trp		Stage 6 df/dt +t element trip
1356	Stg6 f+DF/DT Sta		Stage 6 f+DeltaF/DeltaT element start
1357	Stg6 f+DF/DT Trp		Stage 6 f+DeltaF/DeltaT element trip
1358	Stg6 Block		Stage 6 advance frequency block
1359 - 1360			Unused
1361	Stg6 Resore Cls		Stage 6 load restoration close
1362	Stg6 Resore Sta		Stage 6 load restoration start
1363 - 1364			Unused
1365	Stg7 f+t Sta		Stage 7 f+t element start
1366	Stg7 f+t Trp		Stage 7 f+t element trip
1367	Stg7 f+df/dt Trp		Stage 7 f+df/dt element trip
1368	Stg7 df/dt +t Sta		Stage 7 df/dt +t element start
1369	Stg7 df/dt +t Trp		Stage 7 df/dt +t element trip
1370	Stg7 f+DF/DT Sta		Stage 7 f+DeltaF/DeltaT element start
1371	Stg7 f+DF/DT Trp		Stage 7 f+DeltaF/DeltaT element trip
1372	Stg7 Block		Stage 7 advance frequency block
1373 - 1374			Unused

DDB no.	English text	Source	Description
1375	Stg7 Resore Cls		Stage 7 load restoration close
1376	Stg7 Resore Sta		Stage 7 load restoration start
1377 - 1378			Unused
1379	Stg8 f+t Sta		Stage 8 f+t element start
1380	Stg8 f+t Trp		Stage 8 f+t element trip
1381	Stg8 f+df/dt Trp		Stage 8 f+df/dt element trip
1382	Stg8 df/dt +t Sta		Stage 8 df/dt +t element start
1383	Stg8 df/dt +t Trp		Stage 8 df/dt +t element trip
1384	Stg8 f+DF/DT Sta		Stage 8 f+DeltaF/DeltaT element start
1385	Stg8 f+DF/DT Trp		Stage 8 f+DeltaF/DeltaT element trip
1386	Stg8 Block		Stage 8 advance frequency block
1387 - 1388			Unused
1389	Stg8 Resore Cls		Stage 8 load restoration close
1390	Stg8 Resore Sta		Stage 8 load restoration start
1391 - 1392			Unused
1393	Stg9 f+t Sta		Stage 9 f+t element start
1394	Stg9 f+t Trp		Stage 9 f+t element trip
1395	Stg9 f+df/dt Trp		Stage 9 f+df/dt element trip
1396	Stg9 df/dt +t Sta		Stage 9 df/dt +t element start
1397	Stg9 df/dt +t Trp		Stage 9 df/dt +t element trip
1398	Stg9 f+DF/DT Sta		Stage 9 f+DeltaF/DeltaT element start
1399	Stg9 f+DF/DT Trp		Stage 9 f+DeltaF/DeltaT element trip
1400	Stg9 Block		Stage 9 advance frequency block
1401 - 1402			Unused
1403	Stg9 Resore Cls		Stage 9 load restoration close
1404	Stg9 Resore Sta		Stage 9 load restoration start
1405	Resore Reset		Resets all load restoration stages
1406	Reset Sta		Resets all statistics counters
1407 - 1470	Virtual Input 65 - 128	GOOSE Input Command	GOOSE input 65 - 128 - allows binary signals that are mapped to virtual inputs to interface into PSL
1471 - 1534	Quality VIP 65 - 128		GOOSE Virtual input 65 - 128 - provides the Quality attributes of any data object in an incoming GOOSE message
1535 - 1598	PubPres VIP 65 - 128		GOOSE Virtual input 65 - 128 - indicates if the GOOSE publisher responsible for publishing the data that derives a virtual input is present
1599 - 1798	PSL internal		
1799 - 2047			Unused

Table 1 - Description of Logic Nodes

2.1 Factory Default Programmable Scheme Logic

The following section details the default settings of the PSL.

Note	The default PSL has been implemented for the base variants of the P14x with no expansion as highlighted in the table.

The P14x model options are as follows:

Model	P141 Inputs/Outputs	P142 Inputs/Outputs	P143 Inputs/Outputs	P145 Inputs/Outputs
P14xxxxAxxxxxxJ	8/7	8/7	16/14	16I/16O
P14xxxxBxxxxxxJ		12/11	N/A	12/12
P14xxxxCxxxxxxJ		16/7	24/14	24/16
P14xxxxDxxxxxxJ		8/15	16/22	16/24
P14xxxxExxxxxxJ			24/22	24/24
P14xxxxFxxxxxxJ			32/14	32/16
P14xxxxGxxxxxxJ			16/30	16/32
P14xxxxHxxxxxxJ		8/7 + 4 High-Break Output Relays	16/14 + 4 High-Break Output Relays	12/12 + 4 High-Break Output Relays
P14xxxxJxxxxxxJ			24/14 + 4 High-Break Output Relays	20/12 + 4 High-Break Output Relays
P14xxxxKxxxxxxJ			16/22 + 4 High-Break Output Relays	12/20 + 4 High-Break Output Relays
P14xxxxLxxxxxxJ			16/14 + 8 High-Break Output Relays	12/12 + 8 High-Break Output Relays
P14xxxxMxxxxxxJ			32/32	
P14xxxxNxxxxxxJ	8/8			

Table 2 - P14x model options

2.2 Logic Input Mapping

The default mappings for each of the opto-isolated inputs are as shown in the following tables for all P14x models:

2.2.1 P141/P142/P143 Models

Opto-Input No	P141 Relay Text	P142 Relay Text	P143 Relay Text	Function
1	Input L1	Input L1	Input L1	Setting group selection
2	Input L2	Input L2	Input L2	Setting group selection
3	Input L3	Input L3	Input L3	Block earth fault stages IN1>3 & 4
4	Input L4	Input L4	Input L4	Block overcurrent stages I>3 & 4
5	Input L5	Input L5	Input L5	Reset input for lockout trip contacts, auto-reclose lockout and LEDs
6	Input L6	Input L6	Input L6	External trip input
7	Input L7	Input L7	Input L7	Circuit breaker 52-A auxiliary contact input
8	Input L8	Input L8	Input L8	Circuit Breaker 52-B auxiliary contact input
9		L9 Not Mapped (A)	Input L9	Auto-reclose in service input
10		L10 Not Mapped (A)	Input L10	Activates telecontrol mode for AR
11		L11 Not Mapped (A)	Input L11	Activates live line mode
12		L12 Not Mapped (A)	Input L12	Circuit breaker healthy input
13		L13 Not Mapped (B)	Input L9	External auto-reclose block
14		L14 Not Mapped (B)	Input L10	External AR lockout reset
15		L15 Not Mapped (B)	L15 Not Mapped	L15 Not Mapped
16		L16 Not Mapped (B)	L16 Not Mapped	L16 Not Mapped
17			L17 Not Mapped (B)	L17 Not Mapped
18			L18 Not Mapped (B)	L18 Not Mapped
19			L19 Not Mapped (B)	L19 Not Mapped
20			L20 Not Mapped (B)	L20 Not Mapped
21			L21 Not Mapped (B)	L21 Not Mapped
22			L22 Not Mapped (B)	L22 Not Mapped
23			L23 Not Mapped (B)	L23 Not Mapped
24			L24 Not Mapped (B)	L24 Not Mapped
25			L25 Not Mapped (C)	L25 Not Mapped
26			L26 Not Mapped (C)	L26 Not Mapped
27			L27 Not Mapped (C)	L27 Not Mapped
28			L28 Not Mapped (C)	L28 Not Mapped
29			L29 Not Mapped (C)	L29 Not Mapped
30			L30 Not Mapped (C)	L30 Not Mapped
31			L31 Not Mapped (C)	L31 Not Mapped
32			L32 Not Mapped (C)	L32 Not Mapped
Note A	Represents 4 + 4 or additional 8 input expansion			
Note B	Represents additional 8 input expansion only			
Note C	Represents 2nd additional 8 input expansion only			

Table 3 - Logic Input Mapping for P141/P142/P143

2.2.2 P145 Model

Opto-Input No	P145 Relay Text	Function
1	Input L1	Setting group selection
2	Input L2	Setting group selection
3	Input L3	Block earth fault stages IN1>3 & 4
4	Input L4	Block overcurrent stages I>3 & 4
5	Input L5	L5 not mapped
6	Input L6	External 3-phase trip input
7	Input L7	Circuit breaker 52-A auxiliary contact input
8	Input L8	Circuit breaker 52-B auxiliary contact input
9	Input L9	L9 not mapped
10	Input L10	Activates telecontrol mode for AR
11	Input L11	External auto-reclose block
12	Input L12	Circuit breaker healthy input
13	L13 Not Mapped	L13 Not Mapped
14	L14 Not Mapped	L14 Not Mapped
15	L15 Not Mapped	L15 Not Mapped
16	L16 Not Mapped	L16 Not Mapped
17	L17 Not Mapped	L17 Not Mapped
18	L18 Not Mapped	L18 Not Mapped
19	L19 Not Mapped	L19 Not Mapped
20	L20 Not Mapped	L20 Not Mapped
21	L21 Not Mapped	L21 Not Mapped
22	L22 Not Mapped	L22 Not Mapped
23	L23 Not Mapped	L23 Not Mapped
24	L24 Not Mapped	L24 Not Mapped
25	L25 Not Mapped	L25 Not Mapped
26	L26 Not Mapped	L26 Not Mapped
27	L27 Not Mapped	L27 Not Mapped
28	L28 Not Mapped	L28 Not Mapped
29	L29 Not Mapped	L29 Not Mapped
30	L30 Not Mapped	L30 Not Mapped
31	L31 Not Mapped	L31 Not Mapped
32	L32 Not Mapped	L32 Not Mapped

Table 4 - Logic Input Mapping for P145

2.3 Relay Output Contact Mapping

The default mappings for each of the relay output contacts are as shown in the following table:

2.3.1 P141/P142/P143 Models

Relay Contact Number	P141 Relay Text	P142 Relay Text	P143 Relay Text	Function
1	Output R1	Output R1	Output R1	Earth fault/sensitive earth fault started IN>/ISEF> start
2	Output R2	Output R2	Output R2	Overcurrent I> start
3	Output R3	Output R3	Output R3	Protection trip output
4	Output R4	Output R4	Output R4	General alarm output
5	Output R5	Output R5	Output R5	Circuit breaker fail tmr. 1 trip
6	Output R6	Output R6	Output R6	Circuit breaker control close
7	Output R7	Output R7	Output R7	Circuit breaker control trip
8		R8 Not Mapped (A)	Output R8	Any protection start output
9		R9 Not Mapped (A)	Output R9	Auto-reclose successful close indication
10		R10 Not Mapped (A)	Output R10	R10 non-auto
11		R11 Not Mapped (A)	Output R11	Auto-reclose in progress indication
12		R12 Not Mapped (B)	Output R12	Auto-reclose lockout indication
13		R13 Not Mapped (B)	Output R13	Auto-reclose in service indication
14		R14 Not Mapped (B)	Output R14	Auto-reclose in liveline mode indication
15		R15 Not Mapped (B)	R15 Not Mapped (B)	R15 Not Mapped
16			R16 Not Mapped (B)	R16 Not Mapped
17			R17 Not Mapped (B)	R17 Not Mapped
18			R18 Not Mapped (B)	R18 Not Mapped
19			R19 Not Mapped (B)	R19 Not Mapped
20			R20 Not Mapped (B)	R20 Not Mapped
21			R21 Not Mapped (B)	R21 Not Mapped
22			R22 Not Mapped (B)	R22 Not Mapped
23			R23 Not Mapped (C)	R23 Not Mapped
24			R24 Not Mapped (C)	R24 Not Mapped
25			R25 Not Mapped (C)	R25 Not Mapped
26			R26 Not Mapped (C)	R26 Not Mapped
27			R27 Not Mapped (C)	R27 Not Mapped
28			R28 Not Mapped (C)	R28 Not Mapped
29			R29 Not Mapped (C)	R29 Not Mapped
30			R30 Not Mapped (C)	R30 Not Mapped
31			R31 Not Mapped (C)	R31 Not Mapped
32			R32 Not Mapped (C)	R32 Not Mapped
Note A Represents 4 + 4 or additional 8 input expansion				
Note B Represents additional 8 input expansion only				
Note C Represents 2nd additional 8 input expansion only				

Table 5 - Relay Output Contact Mapping for P141/P142/P143

A fault record can be generated by connecting one or a number of contacts to the "**Fault Record Trigger**" in PSL. It is recommended that the triggering contact be '**self reset**' and not latching. If a latching contact was chosen the fault record would not be generated until the contact had fully reset.

The default conditioning of each of the output contacts is as shown in the following table:

Relay Contact Number	P141 Relay Text	P142 Relay Text	P143 Relay Text
1	Straight	Straight	Straight
2	Straight	Straight	Straight
3	Dwell 100ms	Dwell 100ms	Dwell 100ms
4	Dwell 100ms	Dwell 100ms	Dwell 100ms
5	Dwell 100ms	Dwell 100ms	Dwell 100ms
6	Straight	Straight	Straight
7	Straight	Straight	Straight
8		R8 Not Mapped (A)	Straight
9		R9 Not Mapped (A)	Straight
10		R10 Not Mapped (A)	Straight
11		R11 Not Mapped (A)	Straight
12		R12 Not Mapped (B)	Straight
13		R13 Not Mapped (B)	Straight
14		R14 Not Mapped (B)	Straight
15		R15 Not Mapped (B)	R15 Not Mapped (B)
16			R16 Not Mapped (B)
17			R17 Not Mapped (B)
18			R18 Not Mapped (B)
19			R19 Not Mapped (B)
20			R20 Not Mapped (B)
21			R21 Not Mapped (B)
22			R22 Not Mapped (B)
23			R23 Not Mapped (C)
24			R24 Not Mapped (C)
25			R25 Not Mapped (C)
26			R26 Not Mapped (C)
27			R27 Not Mapped (C)
28			R28 Not Mapped (C)
29			R29 Not Mapped (C)
30			R30 Not Mapped (C)
Note A Represents 4 + 4 or additional 8 input expansion			
Note B Represents additional 8 input expansion only			
Note C Represents 2nd additional 8 input expansion only			

Table 6 - Default conditioning for P141/P142/P143

2.3.2 P145 Model

Relay Contact Number	P145 Relay Text	P145 Relay Conditioner	Function
1	Output R1	Straight	Earth fault/sensitive earth fault started IN>/ISEF> start
2	Output R2	Straight	Overcurrent I> start
3	Output R3	Dwell 100ms	Protection trip output
4	Output R4	Dwell 100ms	General alarm output
5	Output R5	Dwell 100ms	Circuit breaker fail tmr. 1 trip
6	Output R6	Straight	Circuit breaker control close
7	Output R7	Straight	Circuit breaker control trip
8	Output R8	Straight	Any protection start output
9	Output R9	Straight	Auto-reclose successful close indication
10	Output R10	Straight	Auto-reclose in service indication
11	Output R11	Straight	Auto-reclose in progress indication
12	Output R12	Straight	Auto-reclose lockout indication
13	R13 Not Mapped	Not Mapped	R13 Not Mapped
14	R14 Not Mapped	Not Mapped	R14 Not Mapped
15	R15 Not Mapped	Not Mapped	R15 Not Mapped
16	R16 Not Mapped	Not Mapped	R16 Not Mapped
17	R17 Not Mapped	Not Mapped	R17 Not Mapped
18	R18 Not Mapped	Not Mapped	R18 Not Mapped
19	R19 Not Mapped	Not Mapped	R19 Not Mapped
20	R20 Not Mapped	Not Mapped	R20 Not Mapped
21	R21 Not Mapped	Not Mapped	R21 Not Mapped
22	R22 Not Mapped	Not Mapped	R22 Not Mapped
23	R23 Not Mapped	Not Mapped	R23 Not Mapped
24	R24 Not Mapped	Not Mapped	R24 Not Mapped
25	R25 Not Mapped	Not Mapped	R25 Not Mapped
26	R26 Not Mapped	Not Mapped	R26 Not Mapped
27	R27 Not Mapped	Not Mapped	R27 Not Mapped
28	R28 Not Mapped	Not Mapped	R28 Not Mapped
29	R29 Not Mapped	Not Mapped	R29 Not Mapped
30	R30 Not Mapped	Not Mapped	R30 Not Mapped
31	R31 Not Mapped	Not Mapped	R31 Not Mapped
32	R32 Not Mapped	Not Mapped	R32 Not Mapped
	Note It is essential that Relay 3 is used for tripping purposes as this output drives the trip LED on the frontplate. It also feeds into other logic sections that require CB trip information such as the CB fail, auto-reclose, condition monitoring etc.		

Table 7 - Relay Output Contact Mapping for P145

A fault record can be generated by connecting one or a number of contacts to the "**Fault Record Trigger**" in PSL. It is recommended that the triggering contact be '**self reset**' and not latching. If a latching contact were chosen the fault record would not be generated until the contact had fully reset.

2.4 Programmable LED Output Mapping

The default mappings for each of the programmable LEDs are as shown in the following table:

2.4.1 P141/P142/P143 Models

LED No	P141 Relay	P142 Relay	P143 Relay
1	E/F Trip	E/F Trip	E/F Trip
2	I>1/2 Trip	I>1/2 Trip	I>1/2 Trip
3	I>3/4 Trip	I>3/4 Trip	I>3/4 Trip
4	Thermal Alarm	A/R In Progress	A/R In Progress
5	Thermal Trip	A/R Lockout	A/R Lockout
6	Any Start	Any Start	Any Start
7	CB Open	CB Open	CB Open
8	CB Closed	CB Closed	CB Closed

Table 8 - P141/P142/P143 programmable LED output mapping

2.4.2 P145 Model

LED No	LED Input Connection/Text	Latched	P145 LED Function Indication
1	LED 1 Red	Yes	E/F Trip Indication
2	LED 2 Red	Yes	Overcurrent Stage I>1/2 Trip
3	LED 3 Red	Yes	Overcurrent Stage I>3/4 Trip
4	LED 4 Red	No	Auto-reclose In Progress
5	LED 5 Red	No	Auto-reclose Lockout
6	LED 6 Red	No	Any Start
7	LED 7 Grn.	No	Circuit Breaker Open
8	LED 8 Red	No	Circuit Breaker Closed
9	FnKey LED1 Red	No	Remote SCADA Comms. CB operation enabled
10	FnKey LED2 Red/ FnKey LED2 Grn. (Yellow)	No	Circuit Breaker Trip
11	FnKey LED3 Red/ FnKey LED3 Grn. (Yellow)	No	Circuit Breaker Close
12	FnKey LED4 Red	No	Sensitive Earth Fault Protection Enable
13	FnKey LED5 Red	No	Enable Setting Group 2
14	FnKey LED6 Red	No	Enable Auto-reclose
15	FnKey LED7 Red	No	Enable Live Line Mode
16	FnKey LED8 Red	No	Not Mapped
17	FnKey LED9 Red/ FnKey LED9 Grn.	No	Reset Alarms/LEDs
18	FnKey LED10 Red	No	Reset Auto-reclose Lockout

Table 9 - P145 programmable LED output mapping

2.5 Fault Recorder Start Mapping

The default mapping for the signal which initiates a fault record is as shown in the following table:

Initiating Signal	Fault Trigger
Output R3	Initiate fault recording from main protection trip

Table 10 - Fault recorder start mapping

2.6 PSL DATA Column

The relay contains a PSL DATA column that can be used to track PSL modifications. A total of 12 cells are contained in the PSL DATA column, 3 for each setting group. The function for each cell is shown below:

Grp PSL Ref	When downloading a PSL to the relay, the user will be prompted to enter which groups the PSL is for and a reference ID. The first 32 characters of the reference ID will be displayed in this cell. The ⇦ and ⇨ keys can be used to scroll through 32 characters as only 16 can be displayed at any one time.
18 Nov 2002 08:59:32.047	This cell displays the date and time when the PSL was down loaded to the relay.
Grp 1 PSL ID - 2062813232	This is a unique number for the PSL that has been entered. Any change in the PSL will result in a different number being displayed.

Note *The above cells are repeated for each setting group.*

2.7 Monitor Bits in PSL

Monitor bits are included in PSL, which gives greater flexibility when testing. The eight 'Monitor Bit' cells allow the user to select the status of which digital data bus signals can be observed in the 'Test Port Status' cell or via the monitor / download port. Eight DDBs are provided in the psl, which allows mapped monitor signals to be mapped to disturbance recorder or contacts.

DDB Signals:

Element Name	Ordinal	Description
DDB_MONITOR1	589	Monitor Bit 1
DDB_MONITOR2	590	Monitor Bit 2
DDB_MONITOR3	591	Monitor Bit 3
DDB_MONITOR4	592	Monitor Bit 4
DDB_MONITOR5	593	Monitor Bit 5
DDB_MONITOR6	594	Monitor Bit 6
DDB_MONITOR7	595	Monitor Bit 7
DDB_MONITOR8	596	Monitor Bit 8

Table 11 - Monitor Bits in PSL

3 VIEWING AND PRINTING DEFAULT PSL DIAGRAMS

3.1 Typical Mappings

It is possible to view and print the default PSL diagrams for the device. Typically, these diagrams allow you to see these mappings:

- Opto Input Mappings
- Output Relay Mappings
- LED Mappings
- Start Indications
- Phase Trip Mappings
- System Check Mapping

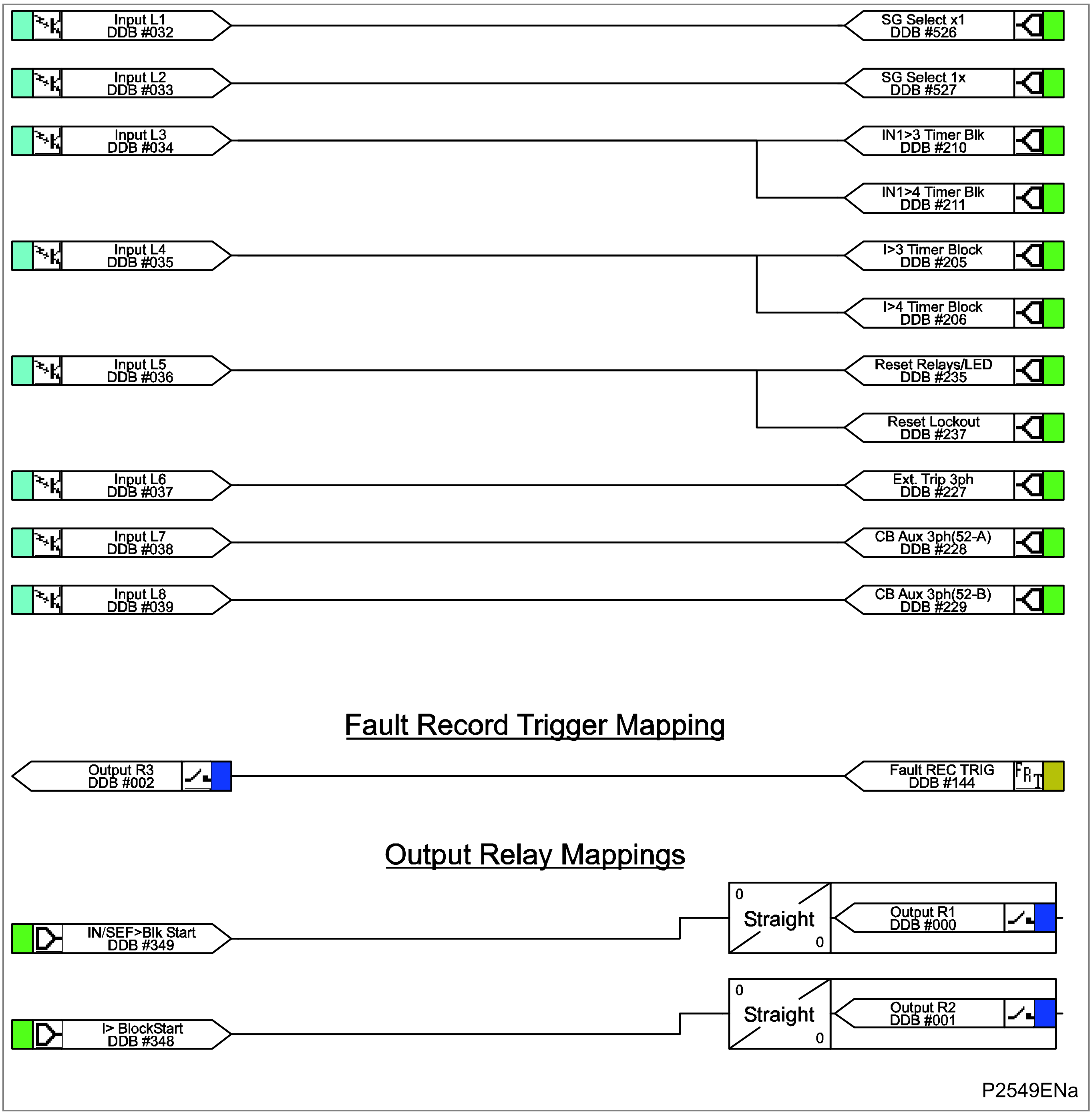
3.2 Download and Print PSL Diagrams

To download and print the default PSL diagrams for the device:

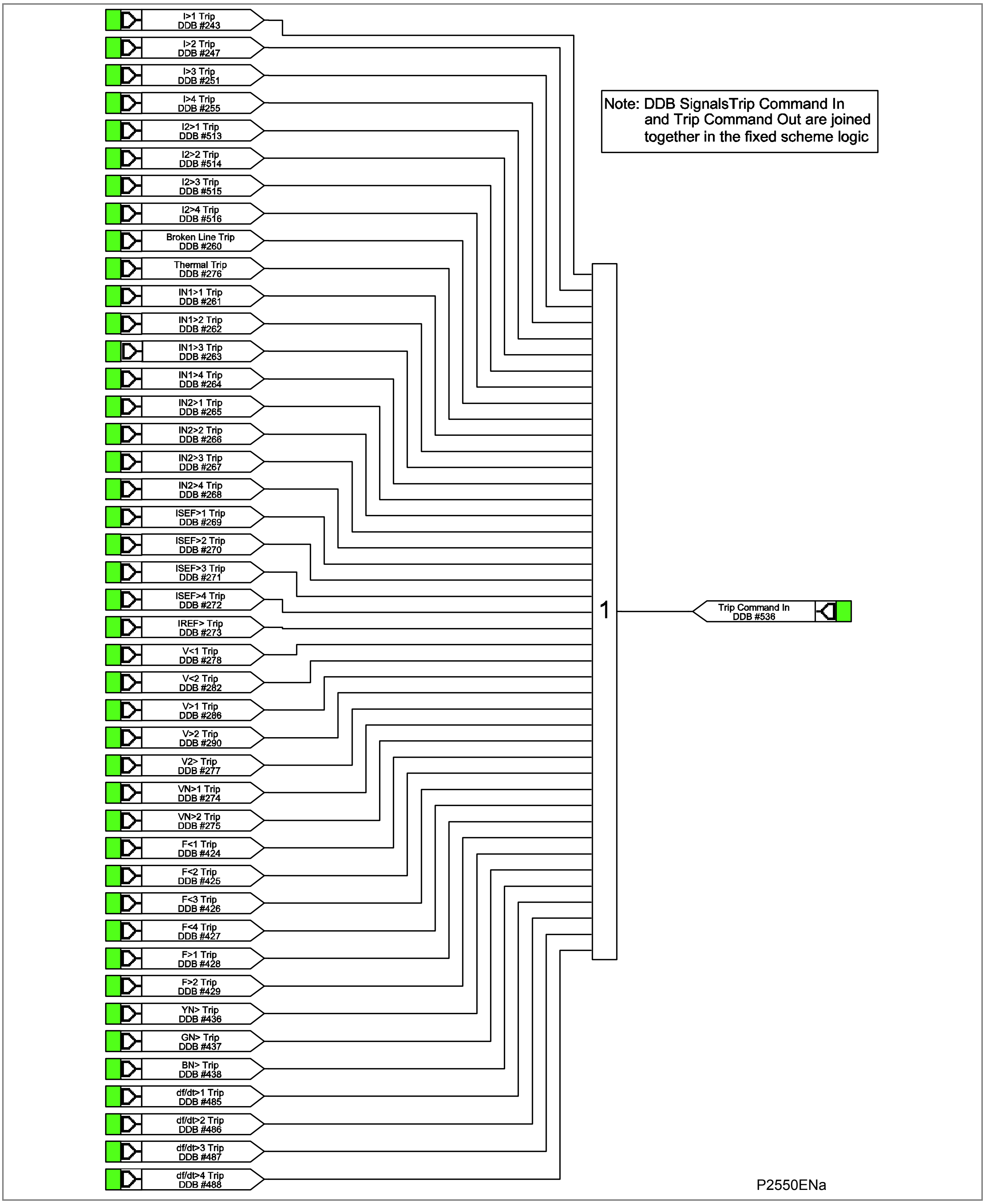
1. Close MiCOM S1 Studio.
2. Select **Programs** > then navigate through to > **MiCOM S1 Studio** > **Data Model Manager**.
3. Click **Add** then **Next**.
4. Click **Internet** then **Next**.
5. Select your language then click **Next**.
6. From the tree view, select the model and software version.
7. Click **Install**. When complete click **OK**.
8. Close the Data Model Manager and start MiCOM S1 Studio.
9. Select Tools > PSL Editor (Px40).
10. In the PSL Editor select **File** > **Open**. The downloaded psl files are in C:\Program Files\ directory located in the \MiCOM S1\Courier\PSL\Defaults sub-directory.
11. Highlight the required psl diagram and select **File** > **Print**.

4 P141 PROGRAMMABLE SCHEME LOGIC

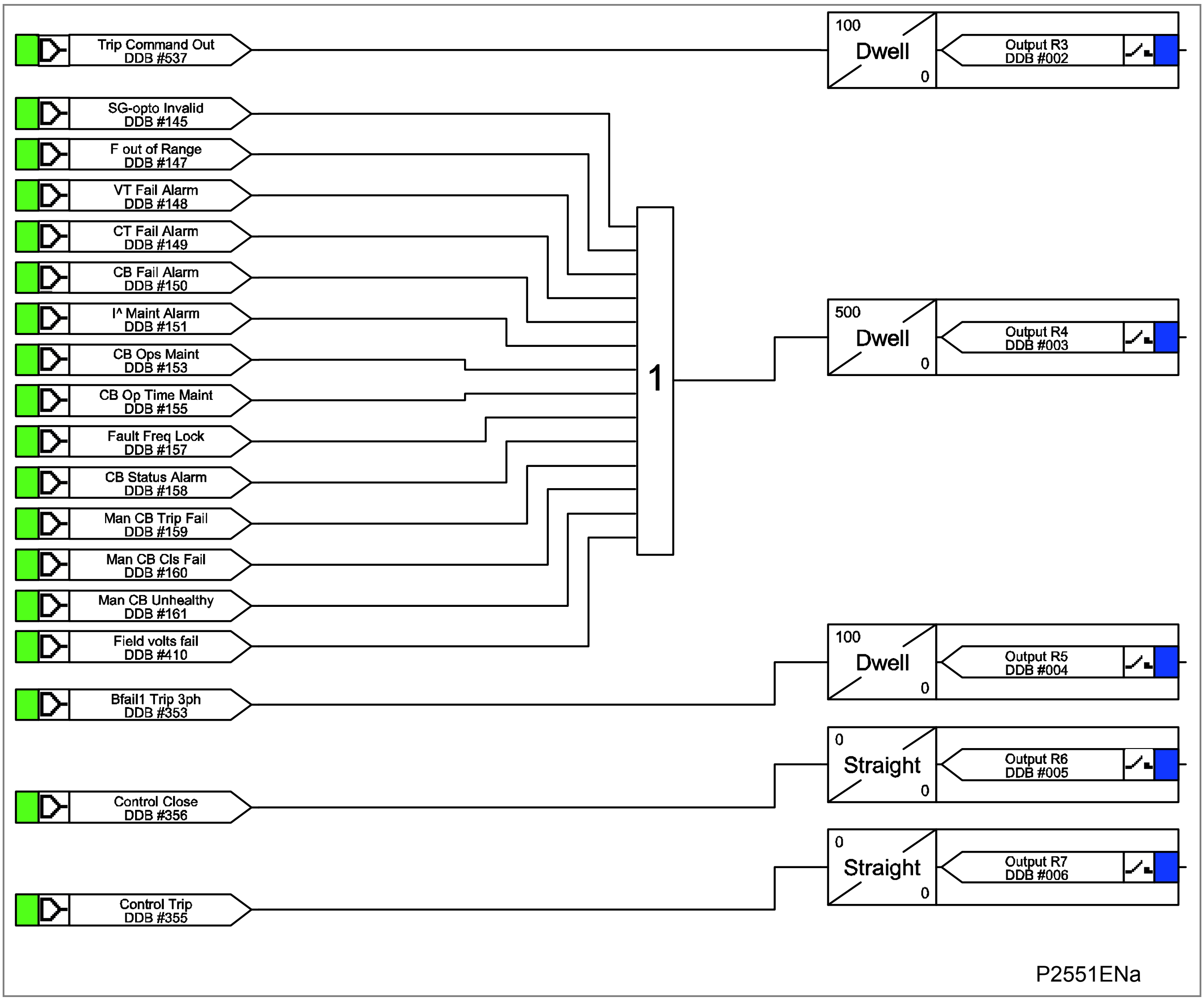
4.1 Opto Input Mappings



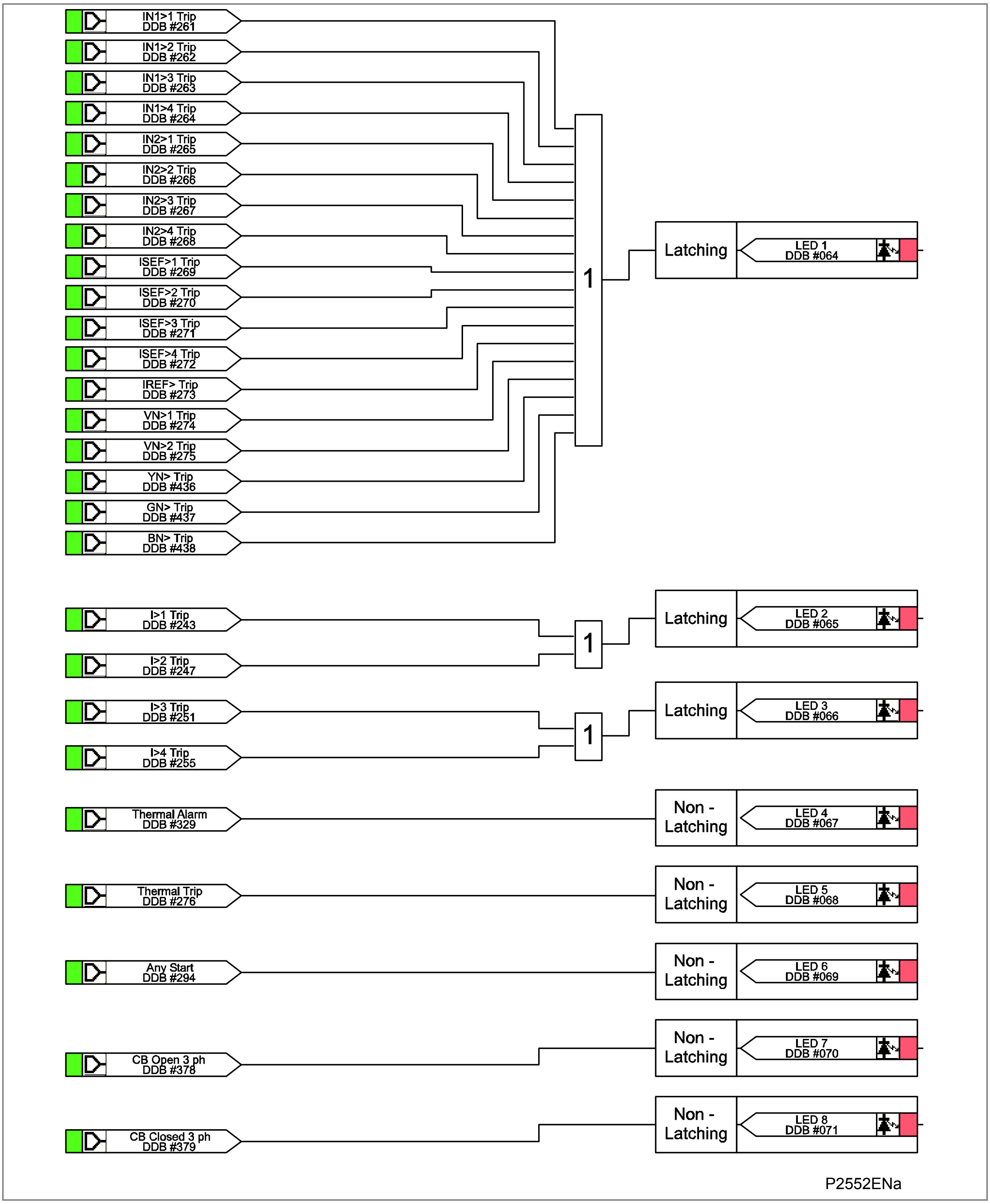
4.2 Trip Relay Mappings



4.3 Output Relay Mappings

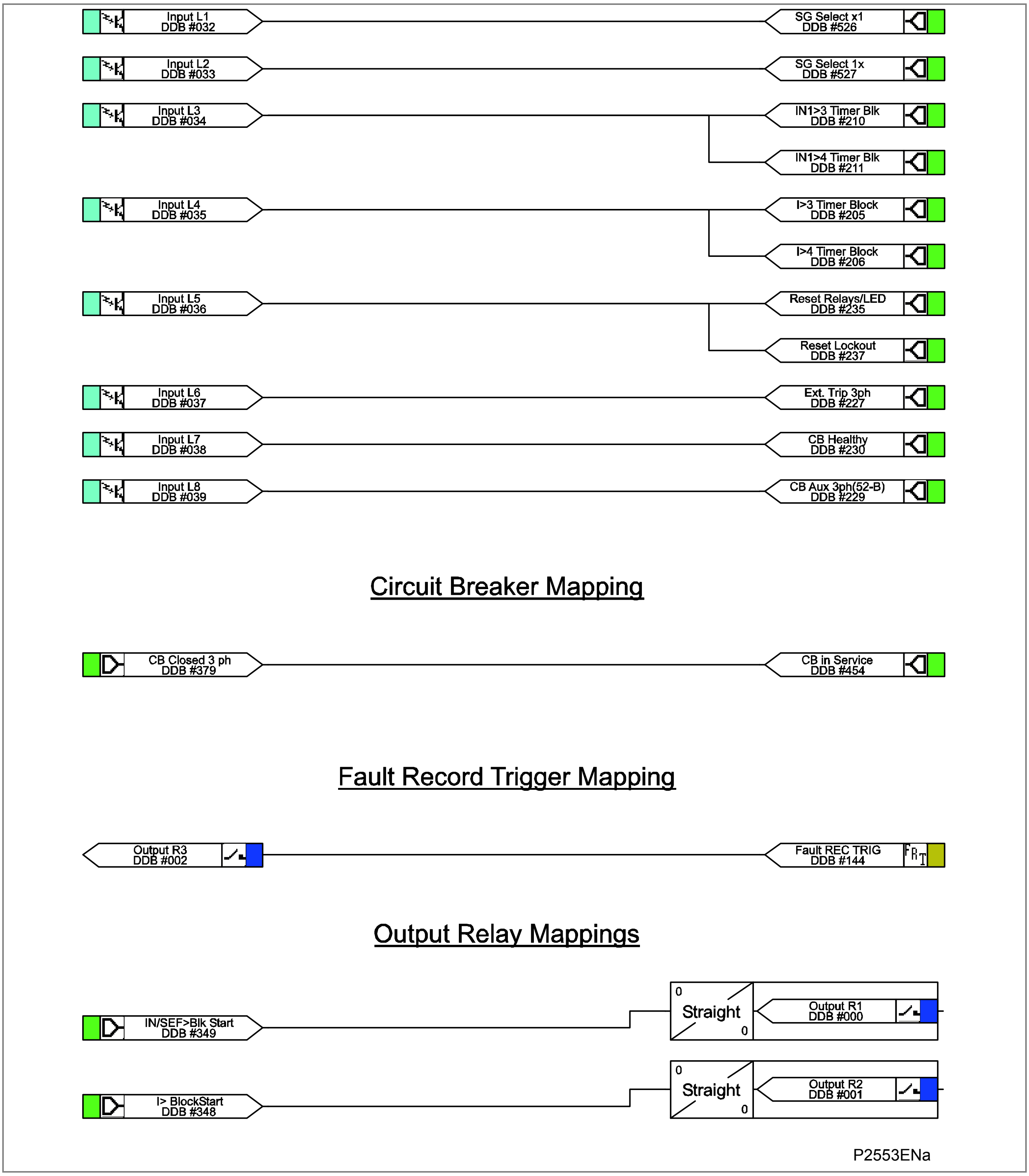


4.4 LED Mappings

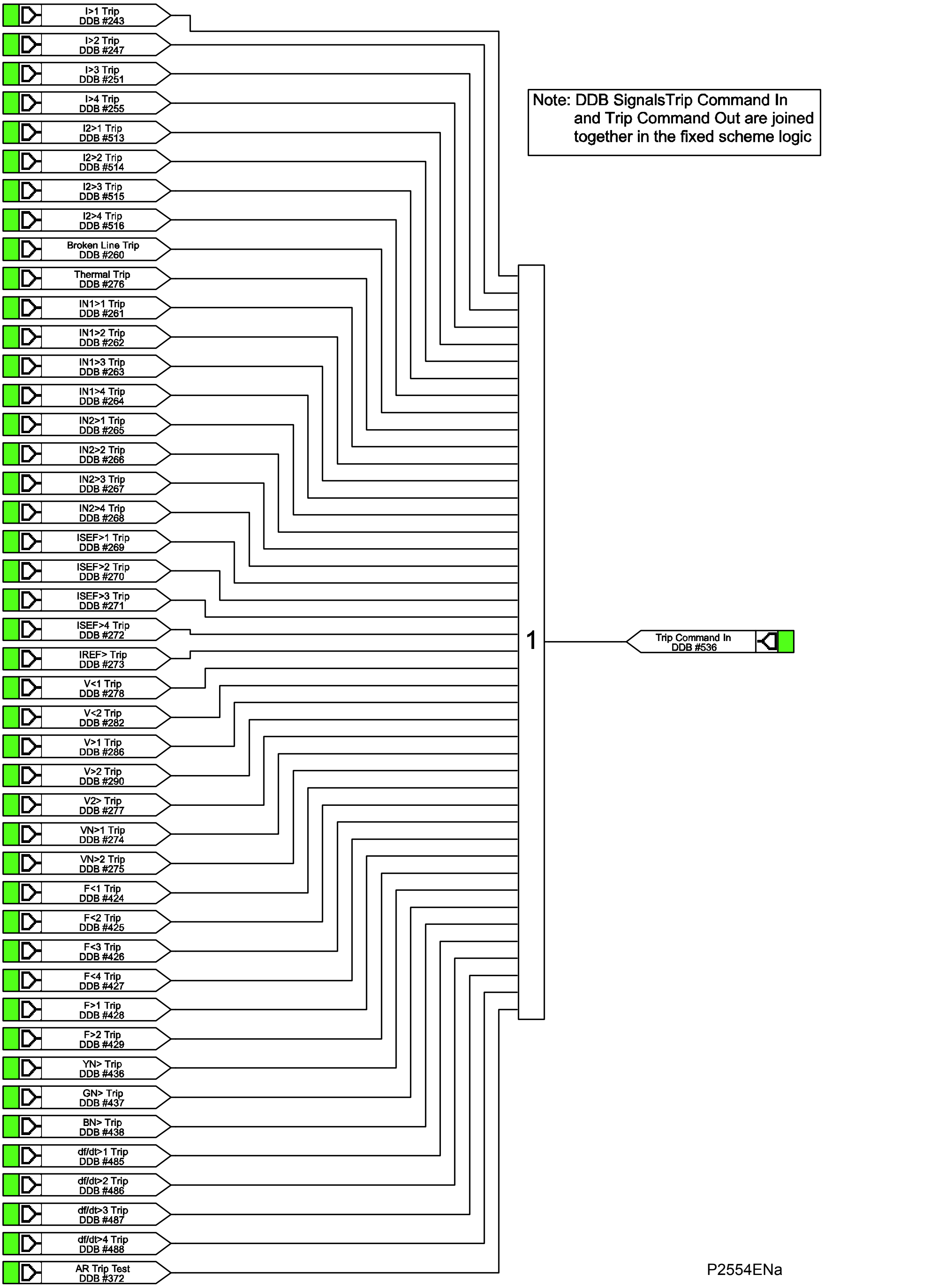


5 P142 PROGRAMMABLE SCHEME LOGIC

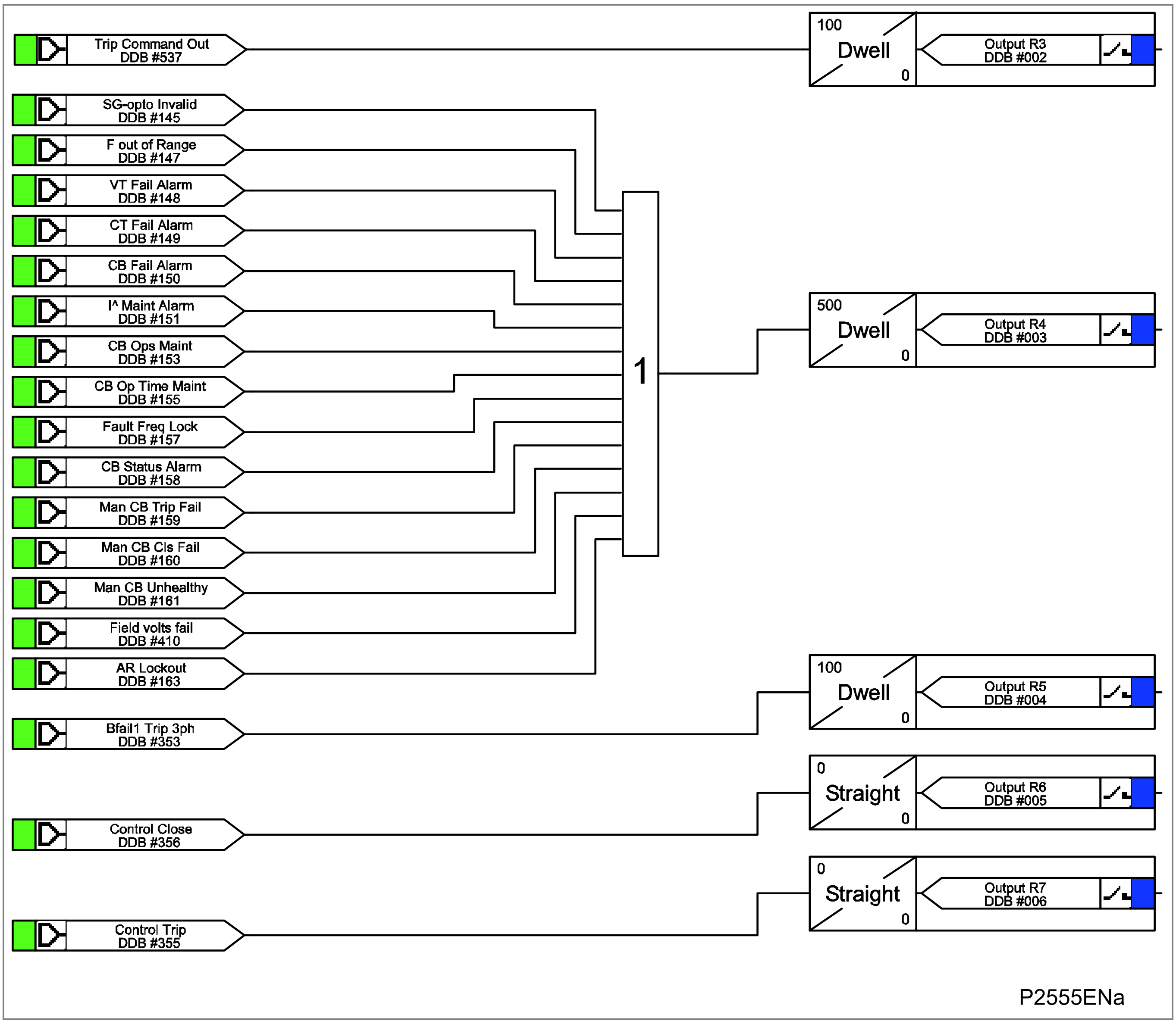
5.1 Opto Input Mappings



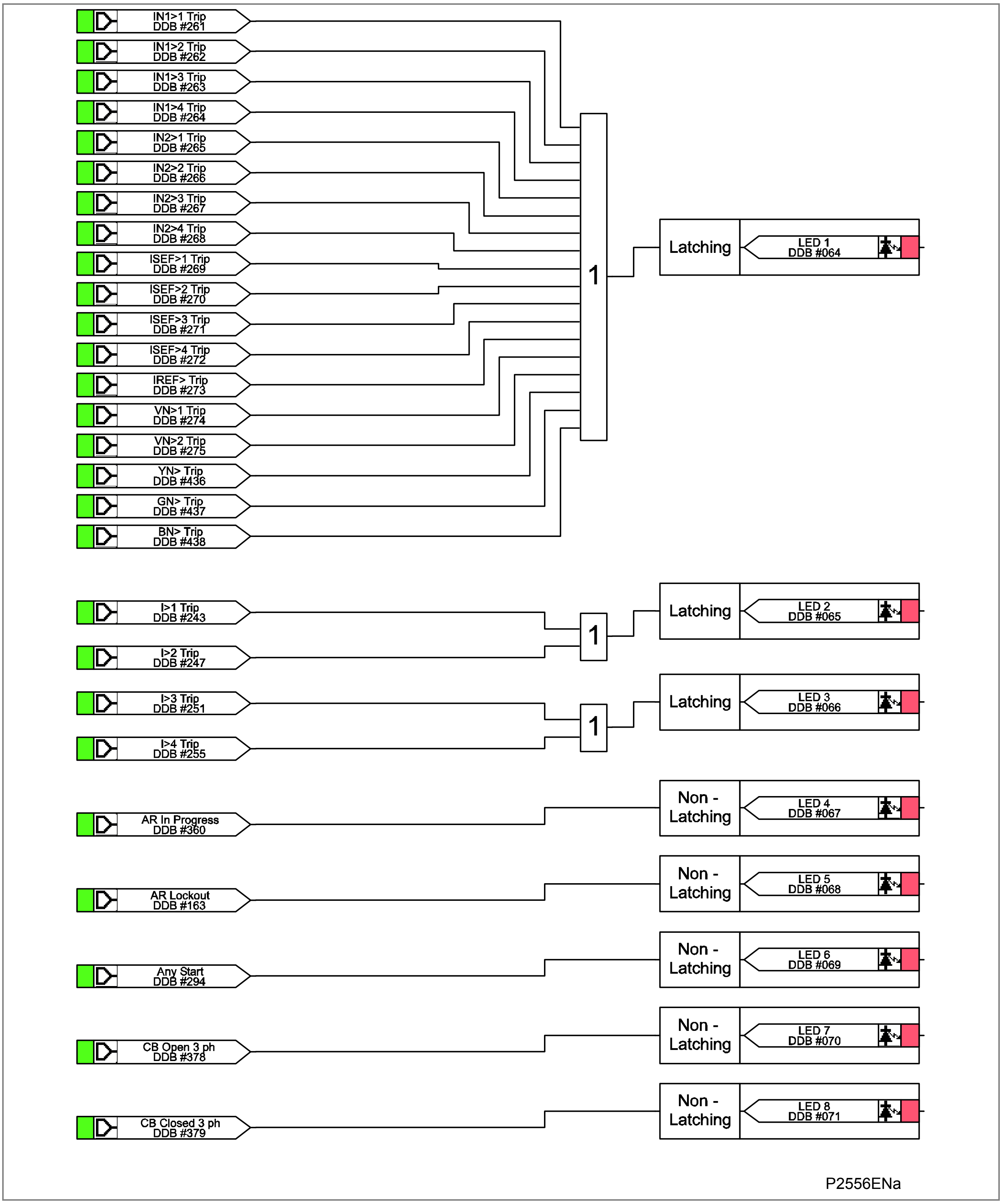
5.2 Trip Relay Mappings



5.3 Output Relay Mappings

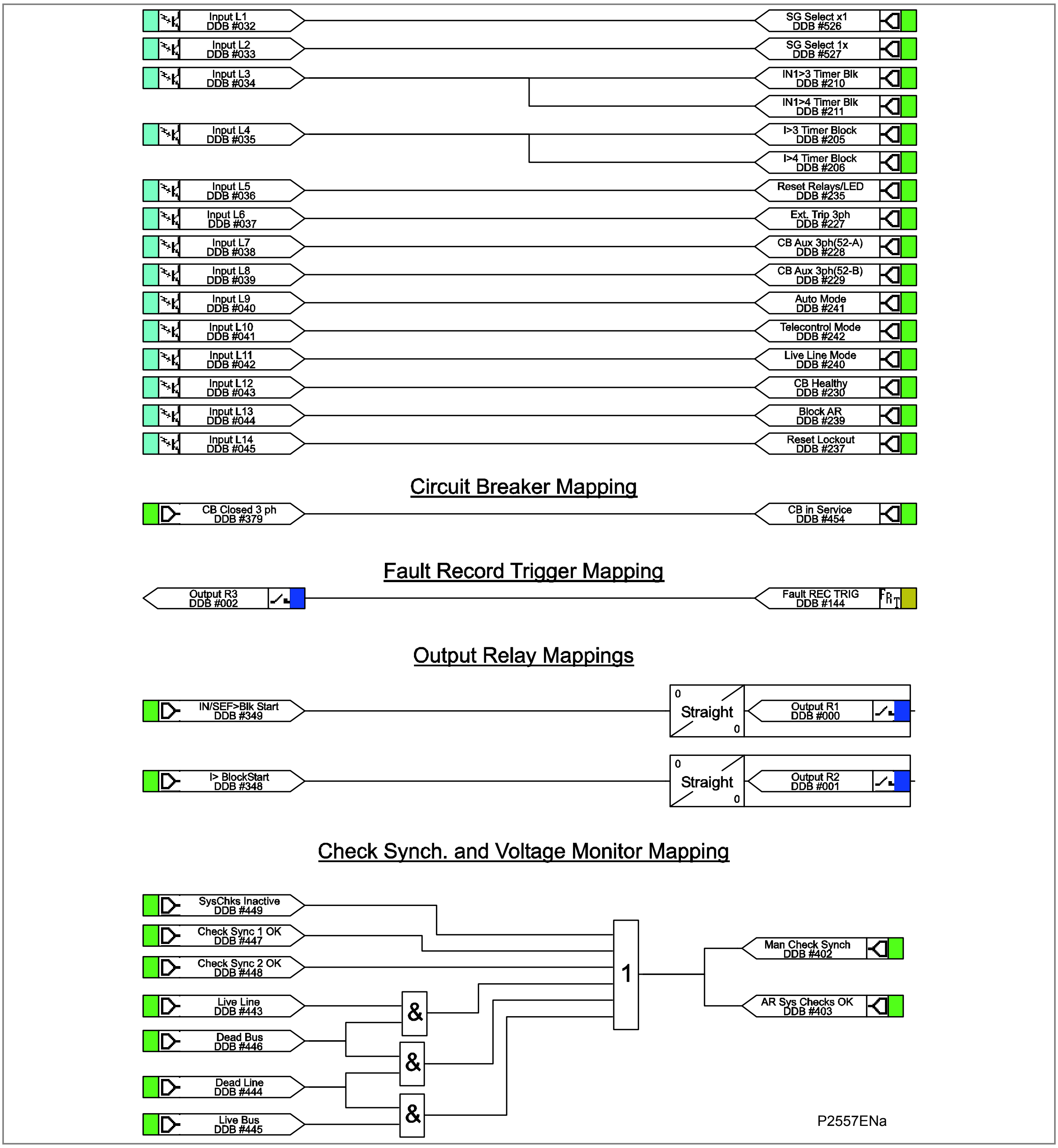


5.4 LED Mappings

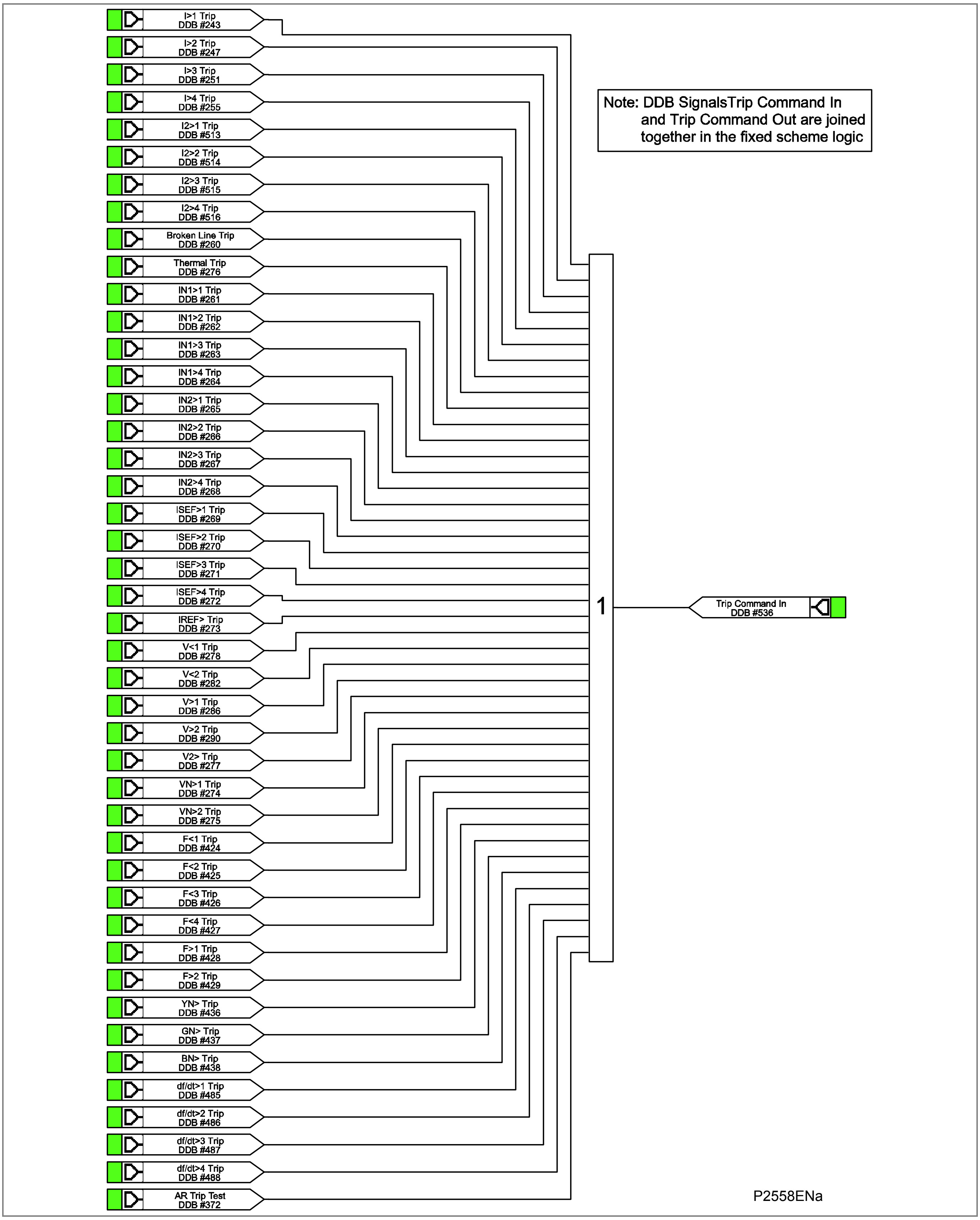


6 P143 PROGRAMMABLE SCHEME LOGIC

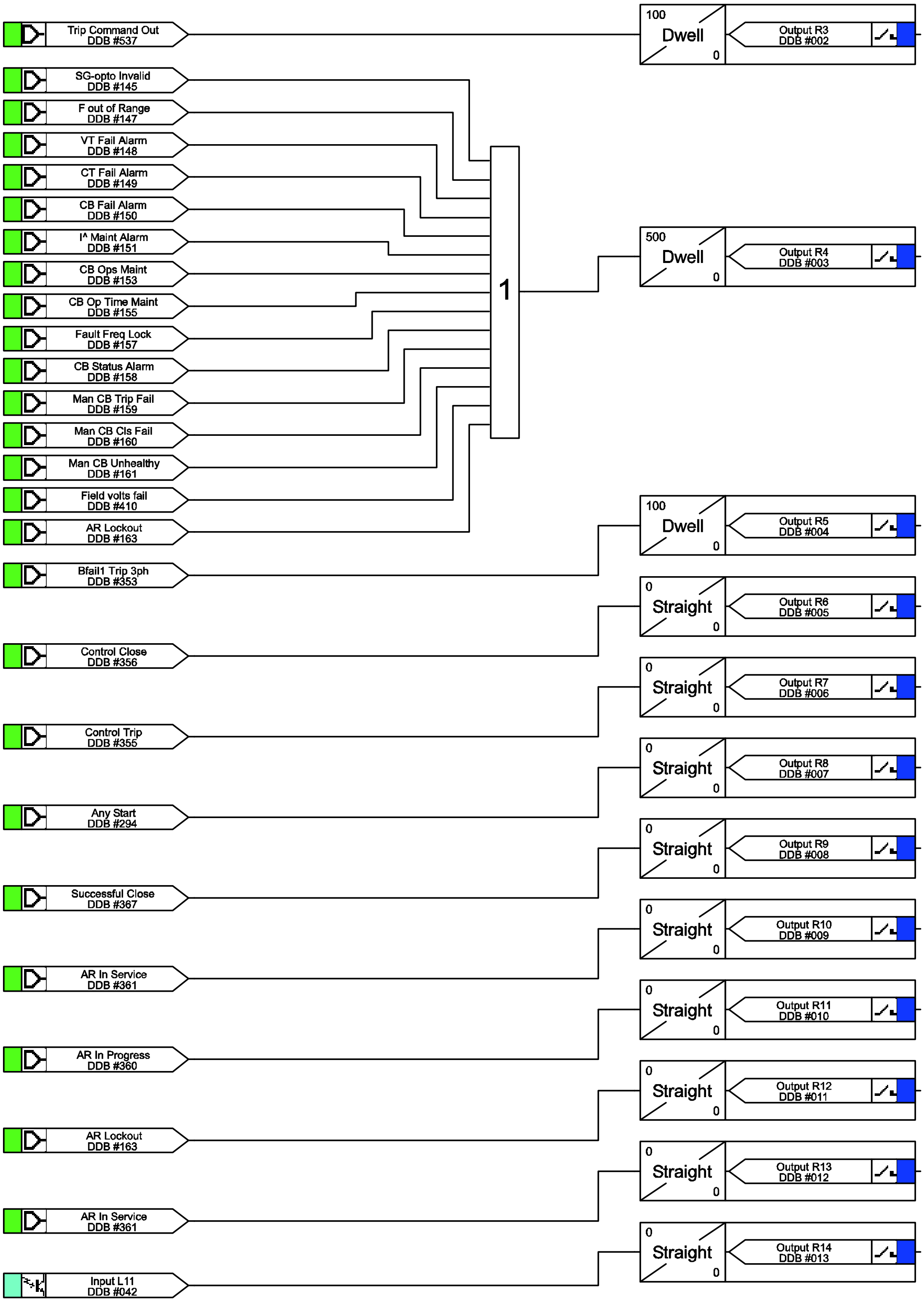
6.1 Opto Input Mappings



6.2 Trip Relay Mappings

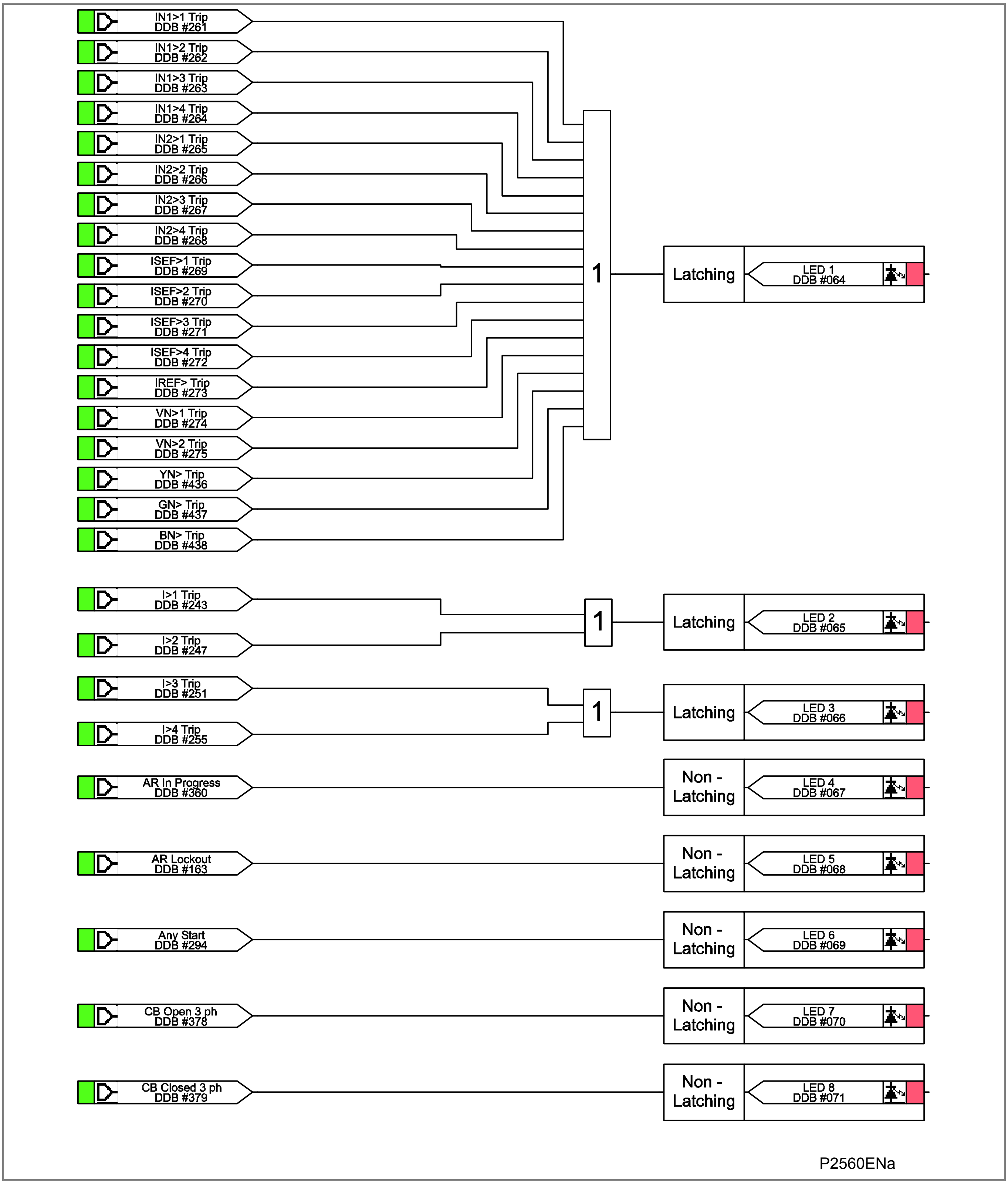


6.3 Output Relay Mappings



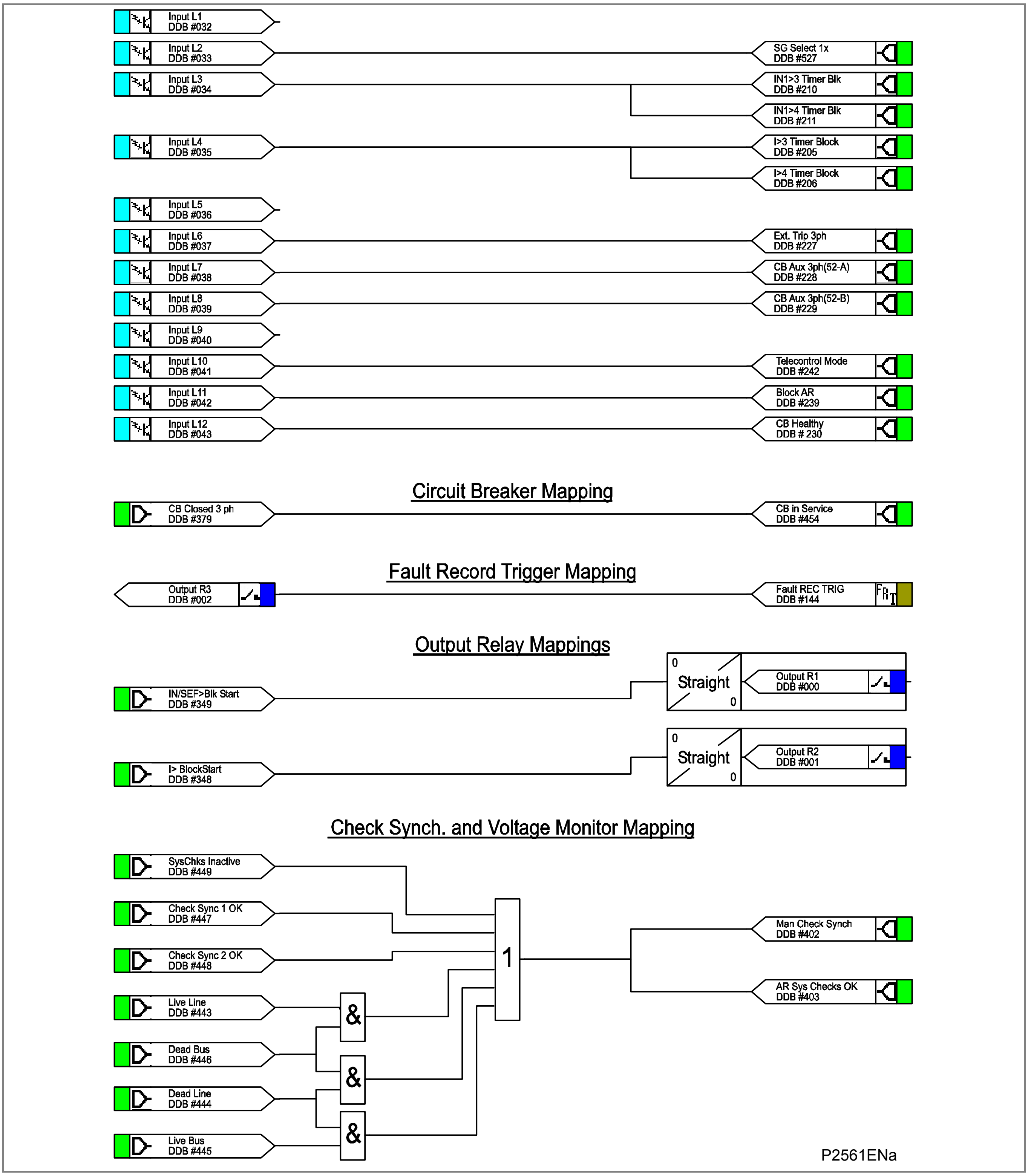
P2559ENa

6.4 LED Mappings

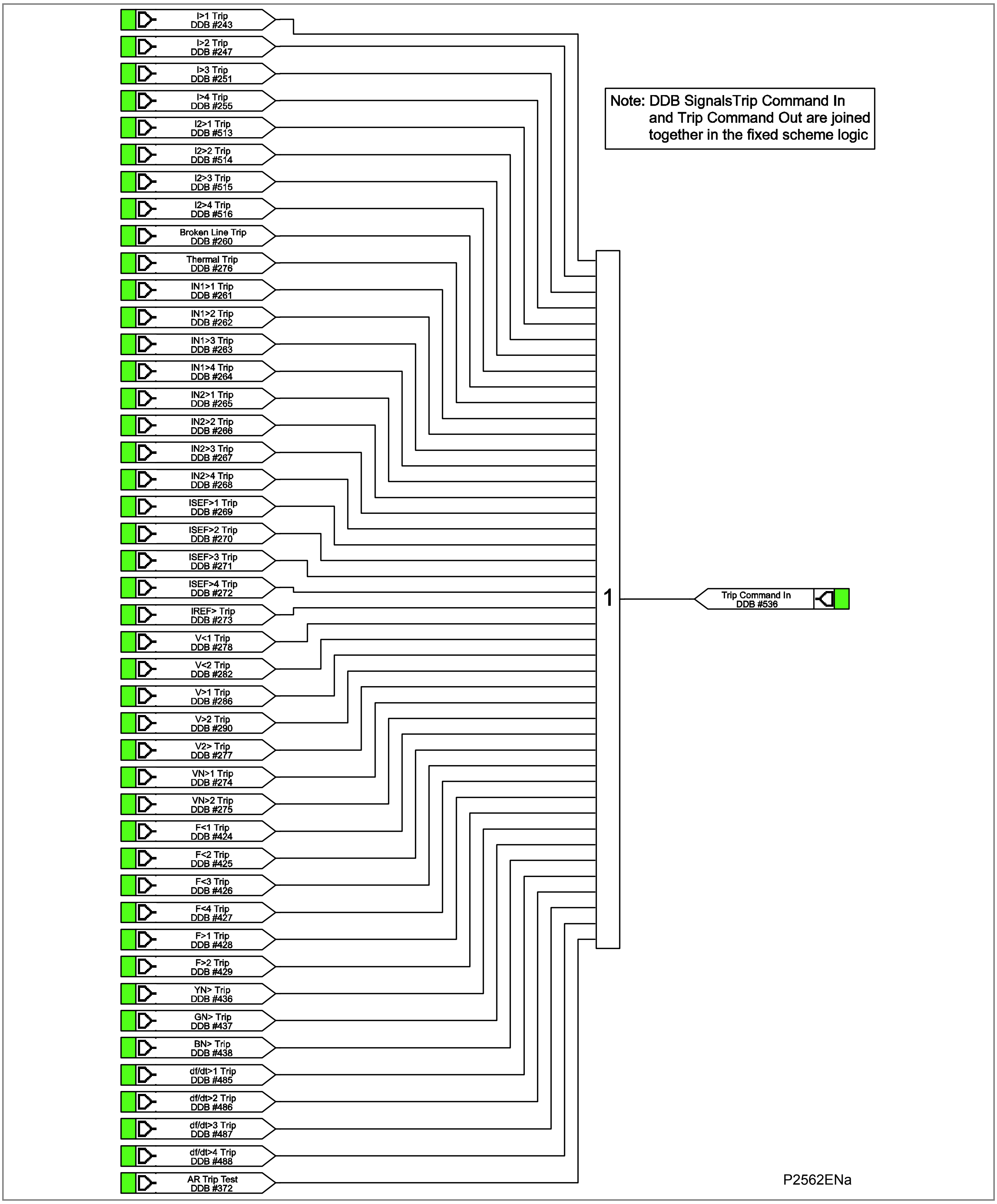


7 P145 PROGRAMMABLE SCHEME LOGIC

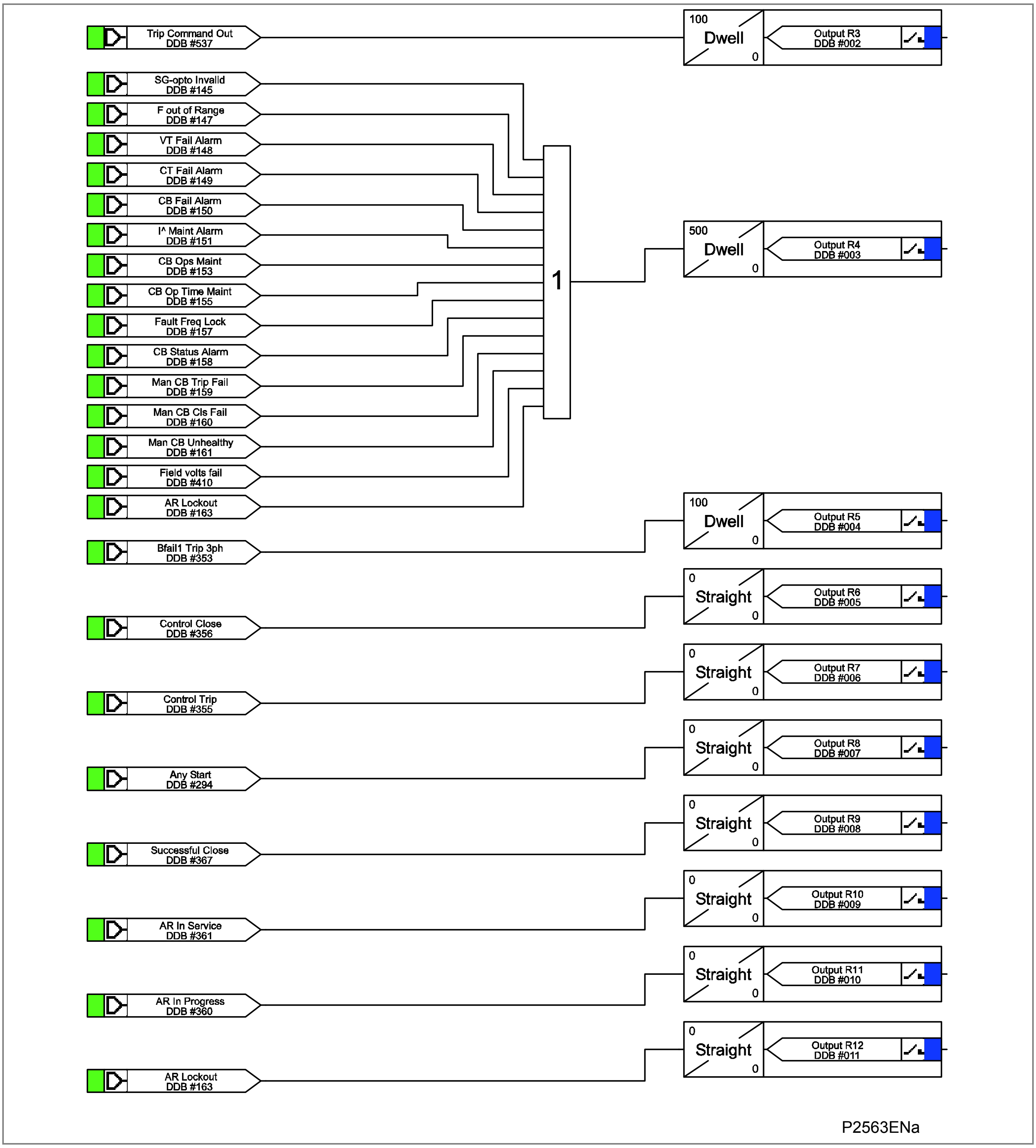
7.1 Opto Input Mappings



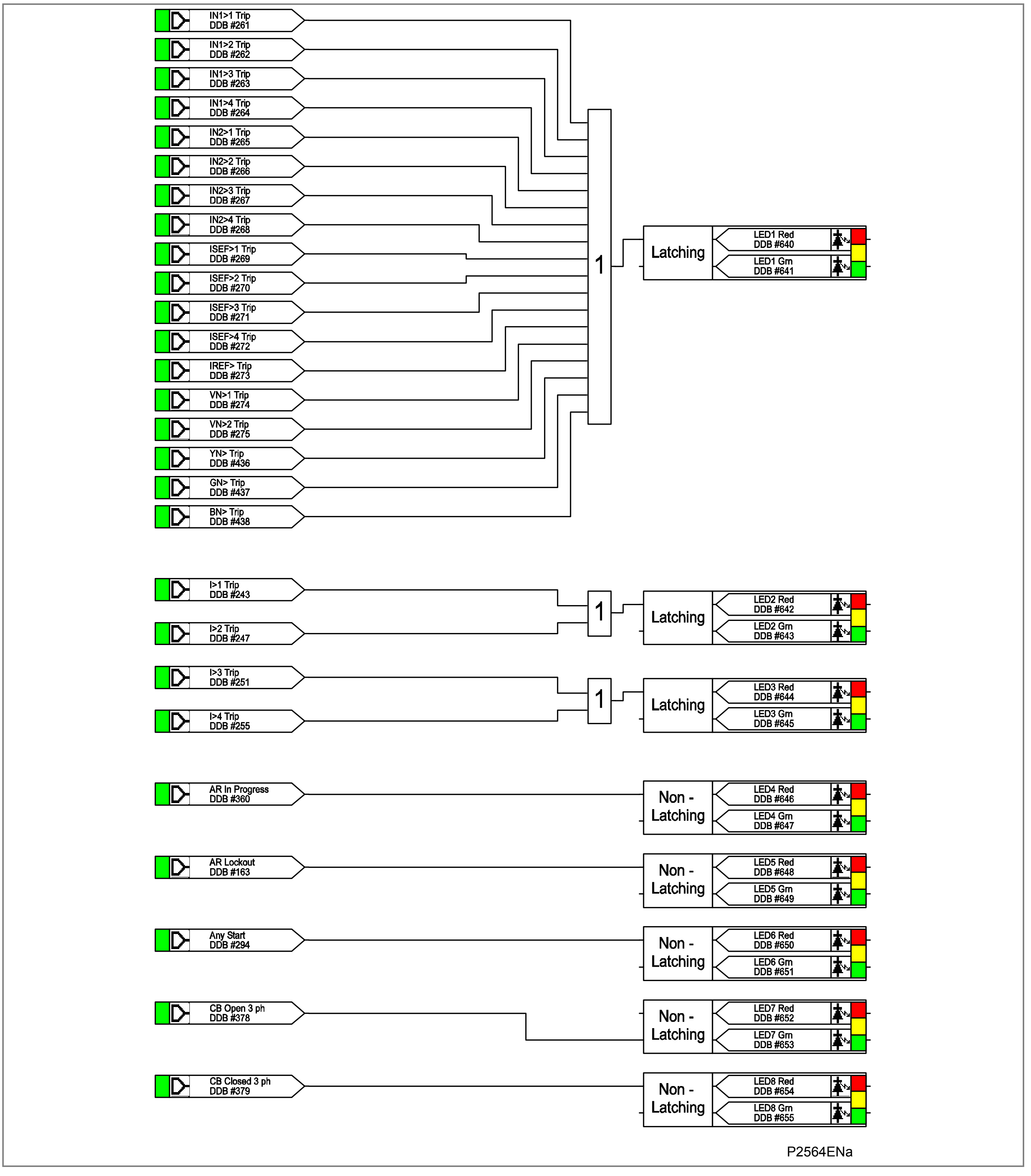
7.2 Trip Relay Mappings



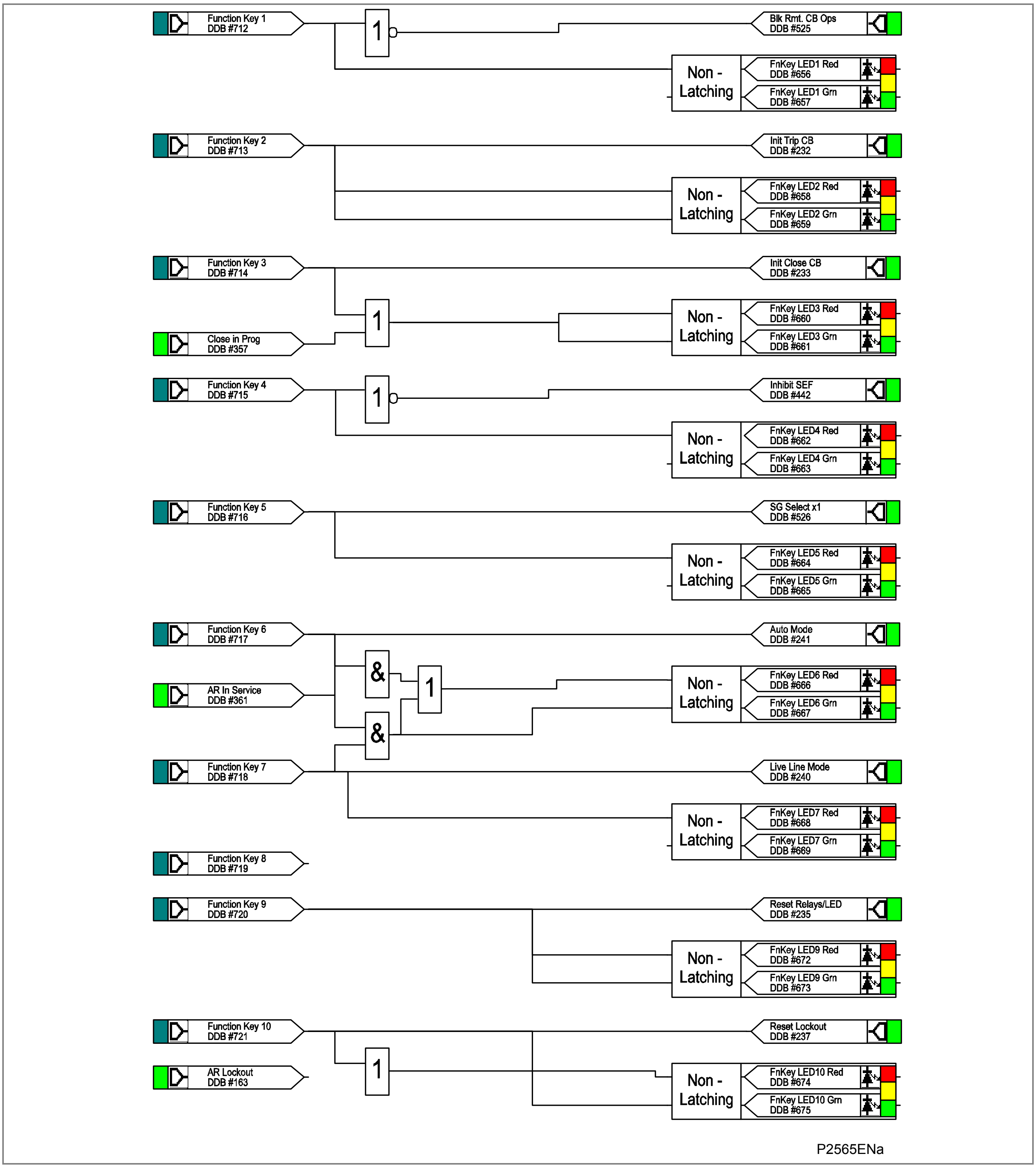
7.3 Output Relay Mappings



7.4 LED Mappings



7.5 Function Key Mappings



Notes:

MEASUREMENTS AND RECORDING

CHAPTER NO 10

Date:	10/2014
Products covered by this chapter:	This chapter covers the specific versions of the MiCOM products listed below. This includes ***only*** the following combinations of Software Version and Hardware Suffix.
Hardware Suffix:	L (P141, P142 & P143) & M (P145)
Software Version:	A0 - P14x (P141, P142, P143 & P145)
Connection Diagrams:	10P141xx (xx = 01 to 07) 10P142xx (xx = 01 to 07) 10P143xx (xx = 01 to 07) 10P145xx (xx = 01 to 07)

CONTENTS

TABLES

1 INTRODUCTION

The relay is equipped with integral measurements, event, fault and disturbance recording facilities suitable for analysis of complex system disturbances.

The relay is flexible enough to allow for the programming of these facilities to specific user application requirements. These requirements are discussed in the sections which follow.

2 EVENT & FAULT RECORDS

The relay records and time tags up to 250 or 512 events (only up to 250 events in the P24x and P44x) and stores them in non-volatile (battery-backed up) memory. This lets the system operator establish the sequence of events that occurred in the relay following a particular power system condition or switching sequence. When the available space is used up, the oldest event is automatically overwritten by the new one (i.e. first in, first out).

The relay's real-time clock provides the time tag to each event, to a resolution of 1 ms.

The event records can be viewed either from the front plate LCD or remotely using the communications ports (using any available protocols, such as Courier or MODBUS).

For local viewing on the LCD of event, fault and maintenance records, select the **VIEW RECORDS** menu column.

For extraction from a remote source using communications, see the *SCADA Communications* chapter or the MiCOM S1 Studio instructions.

For a full list of all the event types and the meaning of their values, see the Menu Database document.

VIEW RECORDS	
LCD Reference	**Description**
Select Event	Setting range from 0 to 511. This selects the required event record from the possible 512 that may be stored. A value of 0 corresponds to the latest event and so on.
Time & Date	Time & Date Stamp for the event given by the internal Real Time Clock.
Event Text	Up to 16 Character description of the Event refer to following sections).
Event Value	Up to 32 Bit Binary Flag or integer representative of the Event (refer to following sections).
Select Fault	Setting range from 0 to 9. This selects the required fault record from the possible 10 that may be stored. A value of 0 corresponds to the latest fault and so on.
	The following cells show all the fault flags, protection starts, protection trips, fault location, measurements etc. associated with the fault, i.e. the complete fault record.
Select Maint.	Setting range from 0 to 9. This selects the required maintenance report from the possible 10 that may be stored. A value of 0 corresponds to the latest report and so on.
Maint. Text	Up to 16 Character description of the occurrence (refer to following sections).
Maint. Type/Main Data	These cells are numbers representative of the occurrence. They form a specific error code which should be quoted in any related correspondence to Report Data.
Reset Indication	Either Yes or No. This serves to reset the trip LED indications provided that the relevant protection element has reset.

Table 1 - View Records

2.1 Types of Event

An event may be a change of state of a control input or output relay, an alarm condition, or a setting change. The following sections show the various items that constitute an event:

2.1.1 Change of State of Opto-Isolated Inputs

If one or more of the opto (logic) inputs has changed state since the last time the protection algorithm ran, the new status is logged as an event. When this event is selected to be viewed on the LCD, three cells appear, as in shown here:

```
Time & date of event
“LOGIC INPUTS1 (or 2)”
“Event Value 0101010101010101”
```

The Event Value is a multi-bit word (see note) showing the status of the opto inputs, where the least significant bit (extreme right) corresponds to opto input 1. The same information is present if the event is extracted and viewed using a PC.

Note	*For P14x the Event Value is a 12, 16, 24 or 32-bit word.*

2.1.2 Change of State of one or more Output Relay Contacts

If one or more of the output relay contacts have changed state since the last time the protection algorithm ran, the new status is logged as an event. When this event is selected to be viewed on the LCD, three cells appear, as shown here:

```
Time and Date of Event
Output Contacts1
Event Value 010101010101010101010
```

The Event Value is a multi-bit word (see Note) showing the status of the output contacts, where the least significant bit (extreme right) corresponds to output contact 1, etc. The same information is present if the event is extracted and viewed using a PC.

Note	*For P14x the Event Value is a 12, 16, 24 or 32 bit word.*

2.1.3 Relay Alarm Conditions

Any alarm conditions generated by the relays are logged as individual events. The following table shows examples of some of the alarm conditions and how they appear in the event list:

Alarm Condition	Event Text	Event Value
Battery Fail	Battery Fail ON/OFF	Bit position 0 in 32 bit field
Field Voltage Fail	Field Volt Fail ON/OFF	Bit position 1 in 32 bit field
Setting Group via Opto Invalid	Setting Grp. Invalid ON/OFF	Bit position 2 in 32 bit field
Protection Disabled	Prot'n. Disabled ON/OFF	Bit position 3 in 32 bit field
Frequency out of Range	Freq. out of Range ON/OFF	Bit position 4 in 32 bit field
VTS Alarm	VT Fail Alarm ON/OFF	Bit position 5 in 32 bit field
CB Trip Fail Protection	CB Fail ON/OFF	Bit position 7 in 32 bit field

Table 2 - Alarm Conditions

The previous table shows the abbreviated description given to the various alarm conditions and a corresponding value between 0 and 31. This value is appended to each alarm event in a similar way to the input and output events described previously. It is used by the event extraction software, such as MiCOM S1 Studio, to identify the alarm and is therefore invisible if the event is viewed on the LCD. ON or OFF is shown after the description to signify whether the particular condition has become operated or has reset.

2.1.4 Protection Element Starts and Trips

Any operation of protection elements, (either a start or a trip condition) is logged as an event record, consisting of a text string indicating the operated element and an event value. This value is intended for use by the event extraction software, such as MiCOM S1 Studio, rather than for the user, and is invisible when the event is viewed on the LCD.

2.1.5 General Events

Several events come under the heading of **General Events**. An example appears here.

Nature of event	Displayed text in event record	Displayed value
Password modified, either from the front or the rear port.	PW modified F, R or R2	0 F=11, R=16, R2=38. For P44x, the value displayed is 0.

A complete list of the General Events is in the Relay Menu Database document. This is a separate document, for each MiCOM Px4x product or product range. They are normally available for download from www.schneider-electric.com

2.1.6 Fault Records

Each time a fault record is generated, an event is also created. The event states that a fault record was generated, with a corresponding time stamp.

Further down the **VIEW RECORDS** column, select the **Select Fault** cell to view the actual fault record, which is selectable from up to 5, 15 or 20 records (see Note). These records consist of fault flags, fault location, fault measurements, etc. The time stamp given in the fault record is more accurate than the corresponding stamp given in the event record as the event is logged some time after the actual fault record is generated.

Note	*Up to 5 records for the P14x, P24x, P34x, P44x and P74x.* *Up to 15 records for the P445, P44y, P54x, P547 and P841.* *Up to 20 records for the P746.*

The fault record is triggered from the **Fault REC. TRIG.** signal assigned in the default programmable scheme logic to relay 3, protection trip (or 87BB or 50BF trip in the P746). The fault measurements in the fault record are given at the time of the protection start.

The fault recorder does not stop recording until the reset of the ‘Fault REC. TRIG.’ signal in order to record all the protection flags during the fault.

It is recommended that the triggering contact be ‘self reset’ and not latching. If a latching contact were chosen the fault record would not be generated until the contact had fully reset.

2.1.7 Maintenance Reports

Internal failures detected by the self-monitoring circuitry, such as watchdog failure, field voltage failure etc. are logged into a maintenance report. The maintenance report holds up to 10 such ‘**events**’ (only 5 events for the P24x/P54x/P547) and is accessed from the "**Select Report**" cell at the bottom of the "**VIEW RECORDS**" column.

Each entry consists of a self explanatory text string and a ‘**Type**’ and ‘**Data**’ cell, which are explained in the menu extract at the beginning of this section.

Each time a Maintenance Report is generated, an event is also created. The event simply states that a report was generated, with a corresponding time stamp.

2.1.8 Setting Changes

Changes to any setting within the relay are logged as an event. Two examples are shown in the following table:

Type of Setting Change	Displayed Text in Event Record
Control/Support Setting	C & S Changed
Group 1 / 2 / 3 or 4 Change	Group 1, 2, 3 or 4 updated
Disturbance setting	Disturbance recorder
Active group change	Active group changed

Note	*Control/Support settings are communications, measurement, CT/VT ratio settings etc, which are not duplicated within the four setting groups. When any of these settings are changed, the event record is created simultaneously. However, changes to protection or disturbance recorder settings will only generate an event once the settings have been confirmed at the ‘setting trap’.*

2.2 Resetting of Event/Fault Records

To delete the event, fault or maintenance reports, use the **RECORD CONTROL** column.

2.3 Viewing Event Records via MiCOM S1 Support Software

When the event records are extracted and viewed on a PC they look slightly different than when viewed on the LCD. The following shows an example of how various events appear when displayed using MiCOM S1 Studio:

Monday 03 January 2005 15:32:49 GMT I>1 Start ON

MiCOM: MiCOM P145
Model Number: P145318B4M0430J
Address: 001 Column: 00 Row: 23
Event Type: Protection operation

Monday 03 January 2005 15:32:52 GMT Fault Recorded

MiCOM: MiCOM P145
Model Number: P145318B4M0430J
Address: 001 Column: 01 Row: 00
Event Type: Fault record

Monday 03 January 2005 15:33:11 GMT Logic Inputs

MiCOM: MiCOM P145
Model Number: P145318B4M0430J
Address: 001 Column: 00 Row: 20
Event Type: Logic input changed state

Monday 03 January 2005 15:34:54 GMT Output Contacts

MiCOM: MiCOM P145
Model Number: P145318B4M0430J
Address: 001 Column: 00 Row: 21
Event Type: Relay output changed state

Monday 03 January 2005 15:35:55 GMT A/R Lockout ON

MiCOM: MiCOM P145
Model Number: P145318B4M0430J
Address: 001 Column: 00 Row: 22
Event Type: Alarm event

Tuesday 04 January 2005 20:18:22.988 GMT V<1 Trip ON

MiCOM: MiCOM P145
Model Number: P145318B4M0430J
Address: 001 Column: 0F Row: 28
Event Type: Setting event

The first line gives the description and time stamp for the event, while the additional information displayed below may be collapsed using the +/– symbol.

For further information regarding events and their specific meaning, refer to the *Relay Menu Database* document. This is a standalone document not included in this manual.

2.4 Event Filtering

Event reporting can be disabled from all interfaces that support setting changes. The settings that control the various types of events are in the RECORD CONTROL column. The effect of setting each to disabled is in shown in the following table:

Note	*Some occurrences can result in more than one type of event, e.g. a battery failure will produce an alarm event and a maintenance record event.*

If the Protection Event setting is Enabled, a further set of settings is revealed which allow the event generation by individual DDB signals to be enabled or disabled.

For further information on events and their specific meaning, see the *Relay Menu Database* document.

Menu Text	Default Setting	Available Settings
Clear Event	No	No or Yes
Selecting “Yes” will cause the existing event log to be cleared and an event will be generated indicating that the events have been erased.		
Clear Faults	No	No or Yes
Selecting “Yes” will cause the existing fault records to be erased from the relay.		
Clear Maint.	No	No or Yes
Selecting “Yes” will cause the existing maintenance records to be erased from the relay.		
Alarm Event	Enabled	Enabled or Disabled
Disabling this setting means that all the occurrences that produce an alarm will result in no event being generated.		
Relay O/P Event	Enabled	Enabled or Disabled
Disabling this setting means that no event will be generated for any change in logic input state.		
Opto Input Event	Enabled	Enabled or Disabled
Disabling this setting means that no event will be generated for any change in logic input state.		
General Event	Enabled	Enabled or Disabled
Disabling this setting means that no General Events will be generated		
Fault Rec. Event	Enabled	Enabled or Disabled
Disabling this setting means that no event will be generated for any fault that produces a fault record		
Maint. Rec. Event	Enabled	Enabled or Disabled
Disabling this setting means that no event will be generated for any occurrence that produces a maintenance record.		
Protection Event	Enabled	Enabled or Disabled
Disabling this setting means that any operation of protection elements will not be logged as an event.		
DDB 31 - 0	11111111111111111111111111111111	
Displays the status of DDB signals 0 – 31.		
DDB 1022 - 992	11111111111111111111111111111111	
Displays the status of DDB signals 1022 – 992.		
Note: *Some occurrences will result in more than one type of event, e.g. a battery failure will produce an alarm event and a maintenance record event.*		

Table 3 - Event Filtering

3 DISTURBANCE RECORDER

The integral enhanced disturbance recorder has an area of memory specifically set aside for record storage. The number of records that may be stored by the relay is dependent on the selected recording duration and the installed software release.

The relay can typically store a pre-set minimum number of records, each of a pre-set duration. These may vary between different MiCOM products.

Disturbance records continue to be recorded until the available memory is exhausted, at which time the oldest record(s) are overwritten to make space for the newest one.

The recorder stores actual samples that are taken at a rate of pre-defined number of samples per cycle. Again, this may vary between different MiCOM products.

Each disturbance record consists of a number of analog data channels and digital data channels.

The relevant CT and VT ratios for the analog channels are also extracted to enable scaling to primary quantities. If a CT ratio is set less than unity, the relay will choose a scaling factor of zero for the appropriate channel.

This relay can typically store a minimum of 50 records each of 1.5 seconds duration. However, relays with IEC 60870-5 CD 103 (VDEW) have the same total record length but the IEC 60870-5 CD 103 protocol dictates that only 8 records (of 3 seconds duration) can be extracted via the rear port.

The record stores samples taken at 24 samples per second.

Each disturbance record consists of 9 analog data channels and 128 (XCPU3) digital data channels.

The "**DISTURBANCE RECORDER**" menu column is shown in Table 4:

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
DISTURB. RECORDER				
Duration	XCPU2 (3s) XCPU3 (1.5s)	0.1s	XCPU2 (3s) XCPU3 (10.5s)	0.01s
This sets the overall recording time.				
Trigger Position	XCPU2 (16.7%) XCPU3 (33.3%)	0	XCPU2 (16.7%) XCPU3 (100%)	0.1%
This sets the trigger point as a percentage of the duration. For example, the default settings show that the overall recording time is set to 1.5s with the trigger point being at 33.3% of this, giving 0.5s pre-fault and 1s post fault recording times.				
Trigger Mode	Single	Single or Extended		
If set to single mode, if a further trigger occurs whilst a recording is taking place, the recorder will ignore the trigger. However, if this has been set to "Extended", the post trigger timer will be reset to zero, thereby extending the recording time.				
Analog. Channel 1	VA	VA, VB, VC, VCHECKSYNC., IA, IB, IC, IN, IN Sensitive		
Selects any available analog input to be assigned to this channel.				
Analog. Channel 2	VB	As above		
Analog. Channel 3	VC	As above		
Analog. Channel 4	IA	As above		
Analog. Channel 5	IB	As above		
Analog. Channel 6	IC	As above		
Analog. Channel 7	IN	As above		
Analog. Channel 8	IN Sensitive	As above		

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
Analog. Channel 9	Frequency	As above		
Digital Inputs 1 to 128	Relays 1 to 12 and Opto's 1 to 12	Any of 12 O/P Contacts or Any of 12 Opto Inputs or Internal Digital Signals		
The digital channels may be mapped to any of the opto isolated inputs or output contacts, in addition to a number of internal relay digital signals, such as protection starts, LEDs etc.				
Inputs 1 to 128 Trigger	No Trigger except Dedicated Trip Relay O/P's which are set to Trigger L/H	No Trigger, Trigger L/H, Trigger H/L		
Any of the digital channels may be selected to trigger the disturbance recorder on either a low to high or a high to low transition.				
Digital Inputs 33 to 128	Unused	Any of 12 O/P Contacts or Any of 12 Opto Inputs or Internal Digital Signals		
The digital channels may be mapped to any of the opto isolated inputs or output contacts, in addition to a number of internal relay digital signals, such as protection starts, LEDs etc.				

Table 4 - Disturbance Recorder

The pre and post fault recording times are set by a combination of the **Duration** and **Trigger Position** cells. **Duration** sets the overall recording time and the **Trigger Position** sets the trigger point as a percentage of the duration.

- For example, the default settings show that the overall recording time is set to 1.5 s with the trigger point being at 33.3% of this, giving 0.5 s pre-fault and 1 s post-fault recording times.

If a further trigger occurs while a recording is taking place, the recorder ignores the trigger if the **Trigger Mode** is set to **Single**. However, if this is set to **Extended**, the post-trigger timer is reset to zero, extending the recording time.

As can be seen from the menu, each of the analog channels is selectable from the available analog inputs to the relay. The digital channels may be mapped to any of the opto isolated inputs or output contacts, in addition to several internal relay digital signals, such as protection starts and LEDs. The complete list of these signals may be found by viewing the available settings in the relay menu or using a setting file in MiCOM S1 Studio. Any of the digital channels may be selected to trigger the disturbance recorder on either a low-to-high or a high-to-low transition, using the **Input Trigger** cell. The default trigger settings are that any dedicated trip output contacts, such as relay 3, trigger the recorder.

It is not possible to view the disturbance records locally using the LCD; they must be extracted using suitable software such as MiCOM S1 Studio. This process is fully explained in the *SCADA Communications* chapter.

This feature lets the user define customizable labels for digital channels in P14X relays. The label is available only in the Comtrade file. The label can be disabled by placing a ' ' (Space) in the 1st character of the label. If the user does not want to call the digital channel with a special name, the feature will be disabled and will display its original label.

4 MEASUREMENTS

The relay produces a variety of both directly measured and calculated power system quantities. These measurement values are updated every second and can be viewed in the **Measurements** columns (up to three) of the relay or using the MiCOM S1 Studio Measurement viewer.

The relay can measure and display these quantities:

- Phase voltages and currents
- Phase to phase voltage and currents
- Sequence voltages and currents
- Slip frequency
- Power and energy quantities
- Rms. voltages and currents
- Peak, fixed and rolling demand values

There are also measured values from the protection functions, which are also displayed under the measurement columns of the menu; these are described in the section on the relevant protection function.

4.1 Measured Voltages and Currents

The relay produces both phase-to-ground and phase-to-phase voltage and current values. They are produced directly from the Discrete Fourier Transform (DFT) used by the relay protection functions and present both magnitude and phase angle measurement.

4.2 Sequence Voltages and Currents

Sequence quantities are produced by the relay from the measured Fourier values; these are displayed as magnitude and phase angle values.

4.3 Slip Frequency

The relay produces a slip frequency measurement by measuring the rate of change of phase angle, between the bus and line voltages, over a one-cycle period. The slip frequency measurement assumes the bus voltage to be the reference phasor.

4.4 Power and Energy Quantities

Using the measured voltages and currents the relay calculates the apparent, real and reactive power quantities. These are produced phase-by-phase. Three-phase values are based on the sum of the three individual phase values. The signing of the real and reactive power measurements can be controlled using the measurement mode setting. The options are as follows.

Measurement mode	Parameter	Signing
0 (Default)	Export Power Import Power Lagging Vars Leading VArs	+ – + –
1	Export Power Import Power Lagging Vars Leading VArs	– + + –
2	Export Power Import Power Lagging Vars Leading VArs	+ – – +
3	Export Power Import Power Lagging Vars Leading VArs	– + – +

In addition to the measured power quantities, the relay calculates the power factor phase-by-phase, in addition to a three-phase power factor.

These power values are also used to increment the total real and reactive energy measurements. Separate energy measurements are maintained for the total exported and imported energy. The energy measurements are incremented up to maximum values of 1000 GWhr or 1000 GVARhr, at which point they reset to zero. It is also possible to reset these values using the menu or remote interfaces using the **Reset Demand** cell.

4.5 RMS. Voltages and Currents

RMS phase voltage and current values are calculated by the relay using the sum of the samples squared over a cycle of sampled data.

4.6 Demand Values

The relay produces fixed, rolling and peak demand values. Using the reset demand menu cell it is possible to reset these quantities from the user interface or the remote communications.

4.6.1 Fixed Demand Values

The fixed demand value is the average value of a quantity over the specified interval; values are produced for each phase current and for three-phase real and reactive power. The fixed demand values displayed by the relay are those for the previous interval. The values are updated at the end of the fixed demand period.

4.6.2 Rolling Demand Values

The rolling demand values are similar to the fixed demand values, the difference being that a sliding window is used. The rolling demand window consists of several smaller sub-periods. The resolution of the sliding window is the sub-period length, with the displayed values updated at the end of each of the sub-periods.

4.6.3 Peak Demand Values

Peak demand values are produced for each phase current and the real and reactive power quantities. These display the maximum value of the measured quantity since the last reset of the demand values.

4.7 Settings

The settings shown under the heading **MEASURE'T SETUP** can be used to configure the relay measurement function. See the following Measurements table for more details:

Menu Text	Default Settings	Available settings
MEASUREMENT SETUP		
Default Display	Description	Description/Plant Reference/ Frequency/Access Level/3Ph + N Current/3Ph Voltage/Power/Date and Time
This setting can be used to select the default display from a range of options. *Note: It is also possible to view the other default displays whilst at the default level using the and keys. However once the 15 minute timeout elapses the default display will revert to that selected by this setting.*		
Local Values	Primary	Primary/Secondary
This setting controls whether measured values via the front panel user interface and the front courier port are displayed as primary or secondary quantities.		
Remote Values	Primary	Primary/Secondary
This setting controls whether measured values via the rear communication port are displayed as primary or secondary quantities.		
Measurement Ref.	VA	VA/VB/VC/IA/IB/IC
Using this setting the phase reference for all angular measurements by the relay can be selected.		
Measurement Mode	0	0 to 3 step 1
This setting is used to control the signing of the real and reactive power quantities; the signing convention used is defined in section 4.4.		
Fix Dem. Period	30 minutes	1 to 99 minutes step 1 minute
This setting defines the length of the fixed demand window.		
Roll Sub Period	30 minutes	1 to 99 minutes step 1 minute
These two settings are used to set the length of the window used for the calculation of rolling demand quantities.		
Num. Sub Periods	1	1 to 15 step 1
This setting is used to set the resolution of the rolling sub window.		
Distance Unit*	km	km/miles
This setting is used to select the unit of distance for fault location purposes. *Note: The length of the line is preserved when converting from km to miles and vice versa.*		
Fault Location*	Distance	Distance/Ohms/% of Line
The calculated fault location can be displayed using one of several options selected using this setting		

Table 5 - Measurement setup

4.8 Measurement Display Quantities

The relay has Measurement columns for viewing measurement quantities. These can also be viewed with MiCOM S1 Studio and are shown below.

MEASUREMENTS 1		MEASUREMENTS 2		MEASUREMENTS 3	
IA Magnitude	0 A	A Phase Watts	0 W	Highest Phase I	0 A
IA Phase Angle	0 deg.	B Phase Watts	0 W	Thermal State	0%
IB Magnitude	0 A	C Phase Watts	0 W	Reset Thermal	No
IB Phase Angle	0 deg.	A Phase VArs	0 Var	IREF Diff.	1.000 A
IC Magnitude	0 A	B Phase VArs	0 Var	IREF Bias	1.000 A
IC Phase Angle	0 deg.	C Phase VArs	0 Var	Admittance	0 S
IN Measured Mag.	0 A	A Phase VA	0 VA	Conductance	0 S
IN Measured Ang.	0 deg.	B Phase VA	0 VA	Susceptance	0 S
IN Derived Mag.	0 A	C Phase VA	0 VA	Admittance	0 S
IN Derived Angle	0 deg.	3 Phase Watts	0 W	Conductance	0 S
ISEF Magnitude	0 A	3 Phase VArs	0 VAr	Susceptance	0 S
ISEF Angle	0 deg.	3 Phase VA	0 VA	I2/I1 Ratio	0
I1 Magnitude	0 A	3Ph Power Factor	0	SEF Power	0 W
I2 Magnitude	0 A	APh Power Factor	0	df/dt	
I0 Magnitude	0 A	BPh Power Factor	0		
IA RMS	0 A	CPh Power Factor	0		
IB RMS	0 A	3Ph WHours Fwd	0 Wh		
IC RMS	0 A	3Ph WHours Rev	0 Wh		
VAB Magnitude	0 V	3Ph VArHours Fwd	0 VArh		
VAB Phase Angle	0 deg.	3Ph VArHours Rev	0 VArh		
VBC Magnitude	0 V	3Ph W Fix Demand	0 W		
VBC Phase Angle	0 deg.	3Ph VArs Fix Dem.	0 VAr		
VCA Magnitude	0 V	IA Fixed Demand	0 A		
VCA Phase Angle	0 deg.	IB Fixed Demand	0 A		
VAN Magnitude	0 V	IC Fixed Demand	0 A		
VAN Phase Angle	0 deg.	3 Ph W Roll Dem.	0 W		
VBN Magnitude	0 V	3Ph VArs Roll Dem.	0 VAr		
VBN Phase Angle	0 deg.	IA Roll Demand	0 A		
VCN Magnitude	0 V	IB Roll Demand	0 A		
VCN Phase Angle	0 deg.	IC Roll Demand	0 A		
VN Derived Mag.	0 V	3Ph W Peak Dem.	0 W		
VN Derived Ang.	0 deg.	3Ph VAr Peak Dem.	0 VAr		
V1 Magnitude	0 V	IA Peak Demand	0 A		
V2 Magnitude	0 V	IB Peak Demand	0 A		
V0 Magnitude	0 V	IC Peak Demand	0 A		
VAN RMS	0 V	Reset Demand	No		
VBN RMS	0 V				
VCN RMS	0 V				
Frequency					
C/S Voltage Mag.	0 V				

MEASUREMENTS 1		MEASUREMENTS 2		MEASUREMENTS 3	
C/S Voltage Ang.	0 deg.				
C/S Bus-Line Ang.	0 deg.				
Slip Frequency					
I1 Magnitude	0 A				
I1 Phase Angle	0 deg.				
I2 Magnitude	0 A				
I2 Phase Angle	0 deg.				
I0 Magnitude	0 A				
I0 Phase Angle	0 deg.				
V1 Magnitude	0 V				
V1 Phase Angle	0 deg.				
V2 Magnitude	0 V				
V2 Phase Angle	0 deg.				
V0 Magnitude	0 V				
V0 Phase Angle	0 deg.				

Table 6 - Measurements

PRODUCT DESIGN

CHAPTER NO 11

Date:	10/2014
Products covered by this chapter:	This chapter covers the specific versions of the MiCOM products listed below. This includes ***only*** the following combinations of Software Version and Hardware Suffix.
Hardware Suffix:	L (P141, P142, P143) & M (P145)
Software Version:	A0 - P14x (P141, P142, P143 & P145)
Connection Diagrams:	10P141xx (xx = 01 to 07) 10P142xx (xx = 01 to 07) 10P143xx (xx = 01 to 07) 10P145xx (xx = 01 to 07)

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1 RELAY SYSTEM OVERVIEW

1.1 Hardware Overview

The relay hardware is based on a modular design whereby the relay is made up of an assemblage of several modules that are drawn from a standard range. Some modules are essential while others are optional depending on the user's requirements.

The different modules that can be present in the relay are as follows:

1.1.1 Processor Board

The processor board performs all calculations for the relay and controls the operation of all other modules within the relay. The processor board also contains and controls the user interfaces (LCD, LEDs, keypad, function keys and communication interfaces).

1.1.2 Input Module

The input module converts the information contained in the analog and digital input signals into a format suitable for processing by the processor board. The standard input module consists of two boards; a transformer board to provide electrical isolation and a main input board which provides analog to digital conversion and the isolated digital inputs.

1.1.3 Power Supply Module

The power supply module provides a power supply to all of the other modules in the relay, at three different voltage levels. The power supply board also provides the EIA(RS)485 electrical connection for the rear communication port. On a second board the power supply module contains the relays that provide the output contacts.

The power supply module also provides a 48V external field supply output to drive the opto isolated digital inputs (or the substation battery may be used to drive the optos).

1.1.4 IRIG-B Board

This board, which is optional, can be used where an IRIG-B signal is available to provide an accurate time reference for the relay. There is also an option on this board to specify a fiber optic rear communication port, for use with Courier, MODBUS, DNP3.0 and IEC 60870-5-103 communication.

1.1.5 Second Rear Comms. Board

The optional second rear port is designed typically for dial-up modem access by protection engineers/operators, when the main port is reserved for SCADA traffic. Communication is via one of three physical links; K-Bus, EIA(RS)485 or EIA(RS)232. The port supports full local or remote protection and control access by MiCOM S1 software. The second rear port is also available with an on board IRIG-B input.

1.1.6 Ethernet Board

This is a mandatory board for IEC 61850 enabled relays. It provides network connectivity through either copper or fiber media at rates of 10Mb/s (copper only) or 100Mb/s. There is also an option on this board to specify IRIG-B board port (modulated or un-modulated). This board, the IRIG-B board mentioned in section 1.1.4 and second rear comms. board mentioned in section 1.1.5 are mutually exclusive as they all utilize slot A within the relay case.

All modules are connected by a parallel data and address bus that allows the processor board to send and receive information to and from the other modules as required. There is also a separate serial data bus for conveying sample data from the input module to the processor. Figure 1 shows the modules of the relay and the flow of information between them.

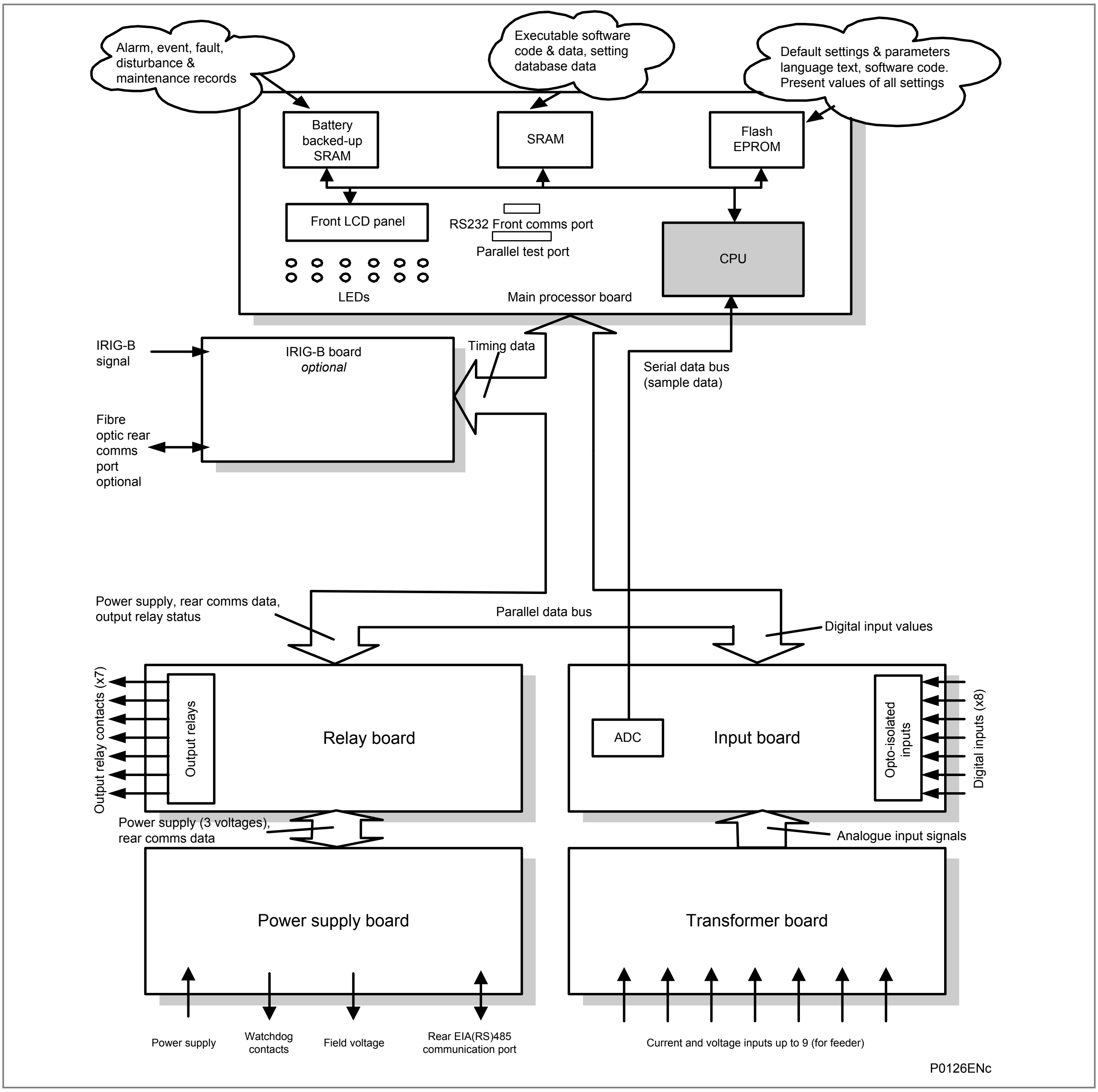

Figure 1 -Relay modules and information flow

1.2 Software Overview

The software for the relay can be conceptually split into four elements; the real-time operating system, the system services software, the platform software and the protection and control software. These four elements are not distinguishable to the user, and are all processed by the same processor board. The distinction between the four parts of the software is made purely for the purpose of explanation here:

1.2.1 Real-time Operating System

The real time operating system is used to provide a framework for the different parts of the relay's software to operate within. To this end the software is split into tasks.

The real-time operating system is responsible for scheduling the processing of these tasks such that they are carried out in the time available and in the desired order of priority. The operating system is also responsible for the exchange of information between tasks, in the form of messages.

1.2.2 System Services Software

The system services software provides the low-level control of the relay hardware. For example, the system services software controls the boot of the relay's software from the non-volatile flash EPROM memory at power-on, and provides driver software for the user interface via the LCD and keypad, and via the serial communication ports. The system services software provides an interface layer between the control of the relay's hardware and the rest of the relay software.

1.2.3 Platform Software

The platform software deals with the management of the relay settings, the user interfaces and logging of event, alarm, fault and maintenance records. All of the relay settings are stored in a database within the relay that provides direct compatibility with Courier communications. For all other interfaces (i.e. the front panel keypad and LCD interface, MODBUS, IEC60870-5-103, DNP3.0 and IEC 61850) the platform software converts the information from the database into the format required. The platform software notifies the protection & control software of all settings changes and logs data as specified by the protection & control software.

1.2.4 Protection and Control Software

The protection and control software performs the calculations for all of the protection algorithms of the relay. This includes digital signal processing such as Fourier filtering and ancillary tasks such as the measurements. The protection & control software interfaces with the platform software for settings changes and logging of records, and with the system services software for acquisition of sample data and access to output relays and digital opto-isolated inputs.

1.2.5 Disturbance Recorder

The analog values and logic signals are routed from the protection and control software to the disturbance recorder software. The platform software interfaces to the disturbance recorder to allow extraction of the stored records.

2 HARDWARE MODULES

The relay is based on a modular hardware design where each module performs a separate function within the relay operation. This section describes the functional operation of the various hardware modules.

2.1 Processor Board

The relay is based around a TMS320VC33 floating point, 32-bit Digital Signal Processor (DSP) operating at a clock frequency of 75MHz. This processor performs all of the calculations for the relay, including the protection functions, control of the data communication and user interfaces including the operation of the LCD, keypad and LEDs.

The processor board is located directly behind the relay's front panel which allows the LCD, function keys and LEDs to be mounted on the processor board along with the front panel communication ports. These comprise the 9-pin D-connector for EIA(RS)232 serial communications (e.g. using MiCOM S1 and Courier communications) and the 25-pin D-connector relay test port for parallel communication. All serial communication is handled using a Field Programmable Gate Array (FPGA).

The memory provided on the main processor board is split into two categories, volatile and non-volatile; the volatile memory is fast access SRAM which is used for the storage and execution of the processor software, and data storage as required during the processor's calculations. The non-volatile memory is sub-divided into 2 groups; 4MB of flash memory for non-volatile storage of software code, present setting values, text, configuration data, latched data signals (from control inputs, function keys, LEDs, relay outputs) and 4MB of battery backed-up SRAM for the storage of disturbance, event, fault and maintenance record data.

2.2 Internal Communication Buses

The relay has two internal buses for the communication of data between different modules. The main bus is a parallel link that is part of a 64-way ribbon cable. The ribbon cable carries the data and address bus signals in addition to control signals and all power supply lines. Operation of the bus is driven by the main processor board that operates as a master while all other modules within the relay are slaves.

The second bus is a serial link that is used exclusively for communicating the digital sample values from the input module to the main processor board. The DSP processor has a built-in serial port that is used to read the sample data from the serial bus. The serial bus is also carried on the 64-way ribbon cable.

2.3 Input Module

The input module provides the interface between the relay processor board and the analog and digital signals coming into the relay. The input module consists of two PCBs; the main input board and a transformer board. The relay provides an additional voltage input for the check sync. function.

2.3.1 Transformer Board

The transformer board holds up to four Voltage Transformers (VTs) and up to five Current Transformers (CTs). The current inputs will accept either 1A or 5A nominal current (menu and wiring options) and the voltage inputs can be specified for either 110V or 440V nominal voltage (order option). The transformers are used both to step-down the currents and voltages to levels appropriate to the relay's electronic circuitry and to provide effective isolation between the relay and the power system. The connection arrangements of both the current and voltage transformer secondary's provide differential input signals to the main input board to reduce noise.

2.3.2 Input Board

The main input board is shown as a block diagram in Figure 2. It provides the circuitry for the digital input signals and the analog-to-digital conversion for the analog signals. Hence it takes the differential analog signals from the CTs and VTs on the transformer board(s), converts these to digital samples and transmits the samples to the processor board via the serial data bus. On the input board the analog signals are passed through an anti-alias filter before being multiplexed into a single analog to digital converter chip. The A - D converter provides 16-bit resolution and a serial data stream output. The digital input signals are opto isolated on this board to prevent excessive voltages on these inputs causing damage to the relay's internal circuitry.

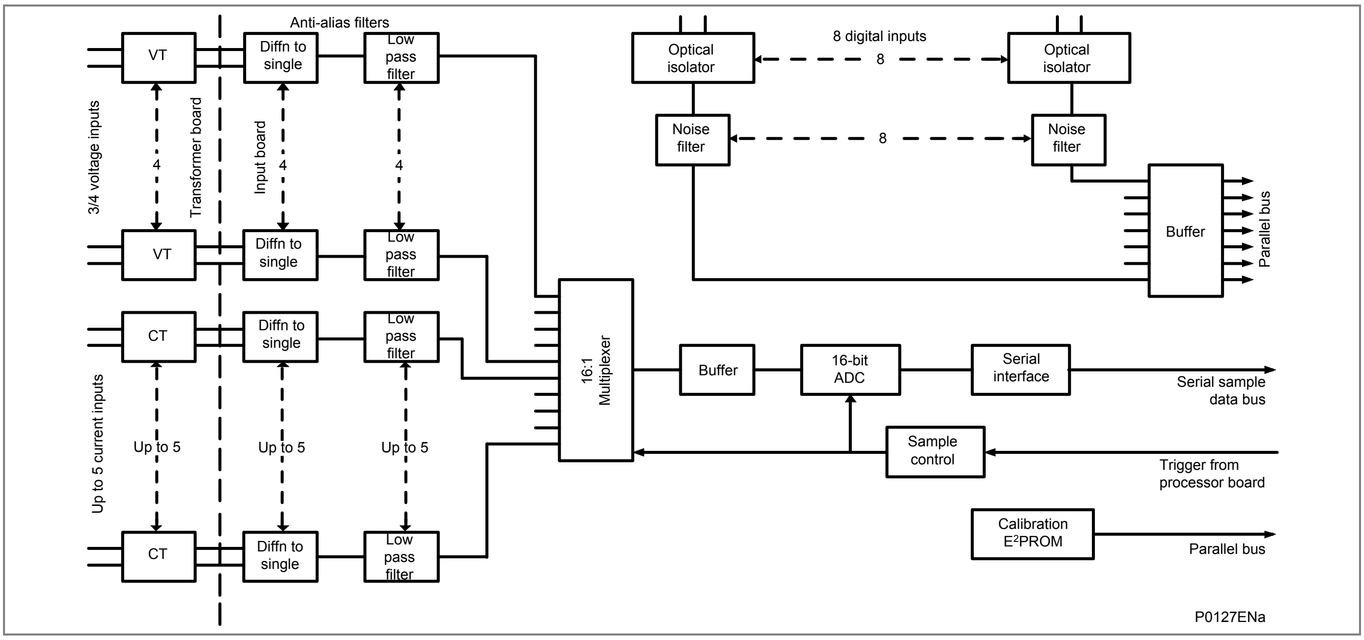

Figure 2 -Main input board

The signal multiplexing arrangement provides for 16 analog channels to be sampled. The P14x relay provides 5 current inputs and 4 voltage inputs. 3 spare channels are used to sample 3 different reference voltages for the purpose of continually checking the operation of the multiplexer and the accuracy of the A - D converter. The sample rate is maintained at 24 samples per cycle of the power waveform by a logic control circuit that is driven by the frequency tracking function on the main processor board. The calibration E^2PROM holds the calibration coefficients that are used by the processor board to correct for any amplitude or phase errors introduced by the transformers and analog circuitry.

The other function of the input board is to read the state of the signals present on the digital inputs and present this to the parallel data bus for processing. The input board holds 8 optical isolators for the connection of up to eight digital input signals. The opto-isolators are used with the digital signals for the same reason as the transformers with the analog signals; to isolate the relay's electronics from the power system environment. The input board provides some hardware filtering of the digital signals to remove unwanted noise before buffering the signals for reading on the parallel data bus.

2.3.3 Universal Opto Isolated Logic Inputs

The P14x relay is fitted with universal opto isolated logic inputs that can be programmed for the nominal battery voltage of the circuit of which they are a part. The inputs can be programmed with a pick-up/drop-off characteristic selectable as the standard 60% - 80% value or an optional characteristic of 50% - 70%. This implies, that they nominally provide a Logic 1 or On value for Voltages ≥80% or 70% of the set lower nominal voltage and a Logic 0 or Off value for the voltages ≤60% or 50% of the set higher nominal voltage. This lower value eliminates fleeting pickups that may occur during a battery earth fault, when stray capacitance may present up to 50% of battery voltage across an input. Each input also has a selectable filter of ½ cycle which renders the input immune to induced noise on the wiring; although this method is secure it can be slow, particularly for intertripping and back-tripping. This can be improved by switching off the ½ cycle filter in which case one of the following methods to reduce ac noise should be considered. The first method is to use double pole switching on the input, the second is to use screened twisted cable on the input circuit.

In the Opto Config. menu the nominal battery voltage can be selected for all opto inputs by selecting one of the five standard ratings in the Global Nominal V settings. If Custom is selected then each opto input can individually be set to a nominal voltage value.

Depending on the model, the P14x can have up to three opto-input cards that will increase the total number of opto inputs to 32.

Menu Text	Default Setting	Setting Range		Step Size
		Min.	Max.	
OPTO CONFIG				
Global Nominal V	24-27	24 - 27, 30 - 34, 48 - 54, 110 - 125, 220 - 250, Custom		
Opto Input 1	24-27	24 - 27, 30 - 34, 48 - 54, 110 - 125, 220 - 250		
Opto Input 2-32	24-27	24 - 27, 30 - 34, 48 - 54, 110 - 125, 220 - 250		
Opto Filter Cntrl.	111111111111			
Characteristic	Standard 60% - 80%	Standard 60% - 80%, 50% - 70%		

Table 1 - Opto Config

Each opto input also has a pre-set filter of ½ cycle which renders the input immune to induced noise on the wiring; although this method is secure it can be slow, particularly for intertripping.

For the P14x feeder protection relay, the protection task is executed twice per cycle, i.e. after every 12 samples for the sample rate of 24 samples per power cycle used by the relay. Therefore, the time taken to register a change in the state of an opto input can vary between a half to one cycle. The time to register the change of state will depend on if the opto input changes state at the start or end of a protection task cycle with the additional half cycle filtering time.

2.4 Power Supply Module (Including Output Relays)

The power supply module contains two PCBs, one for the power supply unit itself and the other for the output relays. The power supply board also contains the input and output hardware for the rear communication port which provides an EIA(RS)485 communication interface.

2.4.1 Power Supply Board (Including EIA(RS)485 Communication Interface)

One of three different configurations of the power supply board can be fitted to the relay. This will be specified at the time of order and depends on the nature of the supply voltage that will be connected to the relay. The three options are shown in Table 2:

Nominal dc Range	Nominal ac Range
24/54 V	DC only
48/125 V	30/100 Vrms
110/250 V	100/240 Vrms

Table 2 - Power supply options

The output from all versions of the power supply module are used to provide isolated power supply rails to all of the other modules within the relay. Three voltage levels are used within the relay, 5.1V for all of the digital circuits, ±16V for the analog electronics, e.g. on the input board, and 22V for driving the output relay coils. All power supply voltages including the 0V earth line are distributed around the relay via the 64-way ribbon cable. The power supply board provides one further voltage level that is the field voltage of 48V. This is brought out to terminals on the back of the relay so that it can be used to drive the optically isolated digital inputs.

The two other functions provided by the power supply board are the EIA(RS)485 communications interface and the watchdog contacts for the relay. The EIA(RS)485 interface is used with the relay's rear communication port to provide communication using one of either Courier, MODBUS, IEC60870-5-103 or DNP3.0 protocols. The EIA(RS)485 hardware supports half-duplex communication and provides optical isolation of the serial data being transmitted and received. All internal communication of data from the power supply board is conducted via the output relay board that is connected to the parallel bus.

The watchdog facility provides two output relay contacts, one normally open and one normally closed that are driven by the processor board. These are provided to give an indication that the relay is in a healthy state.

The power supply board incorporates inrush current limiting. This limits the peak inrush current, during energization, to approximately 10A.

2.4.2 Output Relay Board

The output relay board holds eight relays, six with normally open contacts and two with changeover contacts. The relays are driven from the 22V power supply line. The relays' state is written to or read from using the parallel data bus.

Depending on the relay model, up to three output relay boards may be fitted to the P145 relay to provide a total number of 32 relay outputs.

2.4.3 High Break Relay Board

One '**high break**' output relay board consisting of four normally open output contacts is available for the P142/4 and one or two boards is available for the P143/5 as an option.

This board contains a hybrid of MOSFET solid state devices (SSD) in parallel with high capacity relay output contacts. The MOSFET has a varistor across it to provide protection which is required when switching off inductive loads as the stored energy in the inductor causes a reverse high voltage which could damage the MOSFET.

When there is a control input command to operate an output contact the miniature relay is operated at the same time as the SSD. The miniature relay contact closes in nominally 3.5 mS and is used to carry the continuous load current; the SSD operates in <0.2ms and is switched off after 7.5mS. When the control input resets to open the contacts, the SSD is again turned on for 7.5mS. The miniature relay resets in nominally 3.5ms before the SSD and so the SSD is used to break the load. The SSD absorbs the energy when breaking inductive loads and so limits the resulting voltage surge. This contact arrangement is for switching dc circuits only. As the SSD comes on very fast (<0.2ms) then these high break output contacts have the added advantage of being very fast operating.

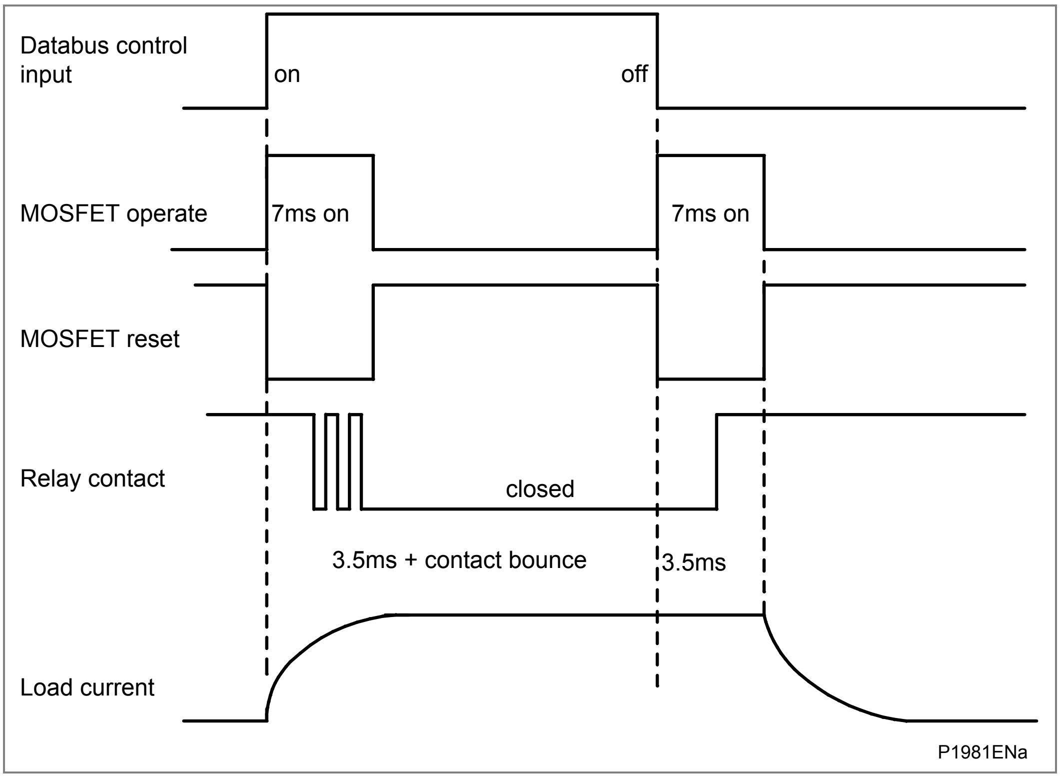

Figure 3 - High break contact operation

2.4.4 Input/Output (4 + 4) Relay Board

The input/output relay board holds four isolated digital inputs and four output relays, two with normally open contacts and two with changeover contacts. The output relays are driven from the 22V power supply line. The relays' state is written to or read from using the parallel data bus.

This is used with the B model variant of the P145 relay that has 12 opto inputs and 12 output contacts.

2.4.5 IRIG-B Board

The IRIG-B board is an order option that can be fitted to provide an accurate timing reference for the relay. This is available as a modulated or de-modulated option depending on the requirements. The IRIG-B signal is connected to the board via a BNC connector on the back of the relay. The timing information is used to synchronize the relay's internal real-time clock to an accuracy of 1ms in the case of modulated. The internal clock is then used for the time tagging of the event, fault maintenance and disturbance records.

The IRIG-B board can also be specified with a fiber optic transmitter/receiver that can be used for the rear communication port instead of the EIA(RS)485 electrical connection (Courier, MODBUS, DNP3.0 and IEC60870-5-103).

2.4.6 Second Rear Communications Board

For relays with Courier, MODBUS, IEC60870-5-103 or DNP3.0 protocol on the first rear communications port there is the hardware option of a second rear communications port, which will run the Courier language. This can be used over one of three physical links: twisted pair K-Bus (non-polarity sensitive), twisted pair EIA(RS)485 (connection polarity sensitive) or EIA(RS)232.

The second rear comms. board and IRIG-B board are mutually exclusive since they use the same hardware slot. For this reason two versions of second rear comms. board are available; one with an IRIG-B input and one without. The InterMiCOM port is available on rear socket SK5, which is based on the EIA232 standard. The physical layout of the second rear comms. board is shown in Figure 4.

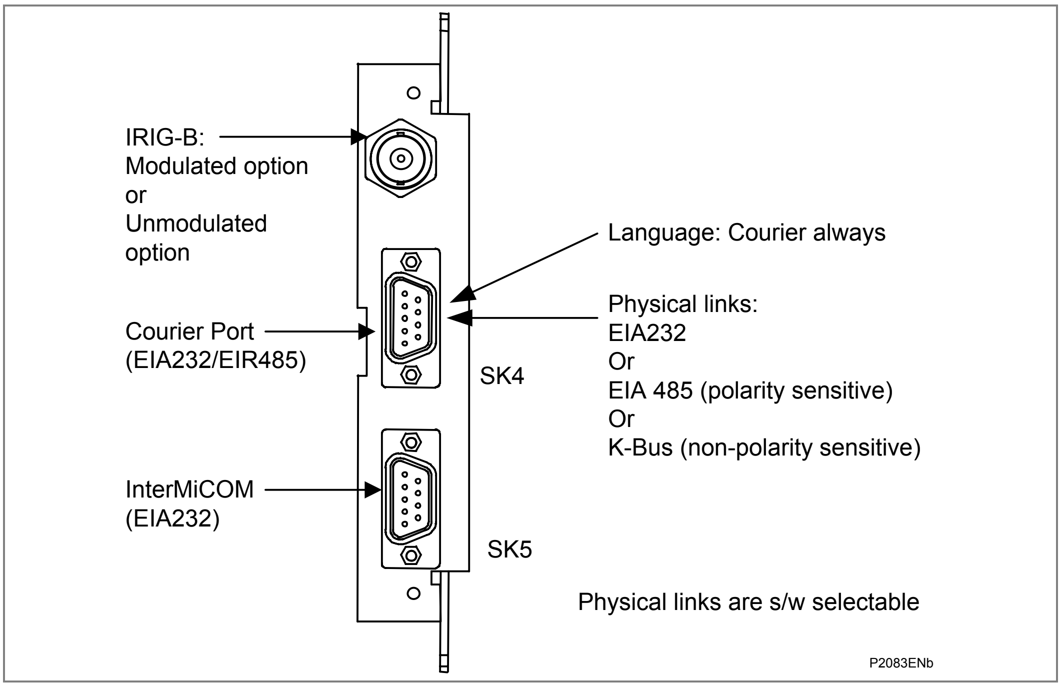

Figure 4 - Rear comms. Port

2.5 Ethernet Board

The optional Ethernet board (ZN0049) has 3 variants which support the IEC 61850 implementation:

- 100 Mbits/s Fiber Optic + 10/100 Mbits/s Copper
- 100 Mbits/s Fiber Optic + 10/100 Mbits/s Copper + modulated IRIG-B
- 100 Mbits/s Fiber Optic + 10/100 Mbits/s Copper + un-modulated IRIG-B

This card is fitted into Slot A of the relay, which is the optional communications slot. Each Ethernet card has a unique MAC address used for Ethernet communications. This is printed on the rear of the card, alongside the Ethernet sockets.

The 100 Mbits/s Fiber Optic ports use ST type connectors and are suitable for 1300nm multi-mode fiber type.

Copper ports use RJ45 type connectors. When using copper Ethernet, it is important to use Shielded Twisted Pair (STP) or Foil Twisted Pair (FTP) cables, to shield the IEC 61850 communications against electromagnetic interference. The RJ45 connector at each end of the cable must be shielded, and the cable shield must be connected to this RJ45 connector shield, so that the shield is grounded to the relay case. Both the cable and the RJ45 connector at each end of the cable must be Category 5 minimum, as specified by the IEC 61850 standard. It is recommended that each copper Ethernet cable is limited to a maximum length of 3 meters and confined within one bay/cubicle.

When using IEC 61850 communications through the Ethernet card, the rear EIA(RS)485 and front EIA(RS)232 ports are also available for simultaneous use, both using the Courier protocol.

2.6 Mechanical Layout

The case materials of the relay are constructed from pre-finished steel that has a conductive covering of aluminum and zinc. This provides good earthing at all joints giving a low impedance path to earth that is essential for performance in the presence of external noise. The boards and modules use a multi-point earthing strategy to improve the immunity to external noise and minimize the effect of circuit noise. Ground planes are used on boards to reduce impedance paths and spring clips are used to ground the module metalwork.

Heavy duty terminal blocks are used at the rear of the relay for the current and voltage signal connections. Medium duty terminal blocks are used for the digital logic input signals, the output relay contacts, the power supply and the rear communication port. A BNC connector is used for the optional IRIG-B signal. 9-pin and 25-pin female D-connectors are used at the front of the relay for data communication.

Inside the relay the PCBs plug into the connector blocks at the rear, and can be removed from the front of the relay only. The connector blocks to the relay's CT inputs are provided with internal shorting links inside the relay which will automatically short the current transformer circuits before they are broken when the board is removed.

The front panel consists of a membrane keypad with tactile dome keys, an LCD and 12 LEDs mounted on an aluminum backing plate.

3 RELAY SOFTWARE

The relay software was introduced in the overview of the relay at the start of this manual. The software can be considered to be made up of four sections:

- The real-time operating system
- The system services software
- The platform software
- The protection & control software

This section describes in detail the latter two of these, the platform software and the protection & control software, which between them control the functional behavior of the relay. Figure 5 shows the structure of the relay software.

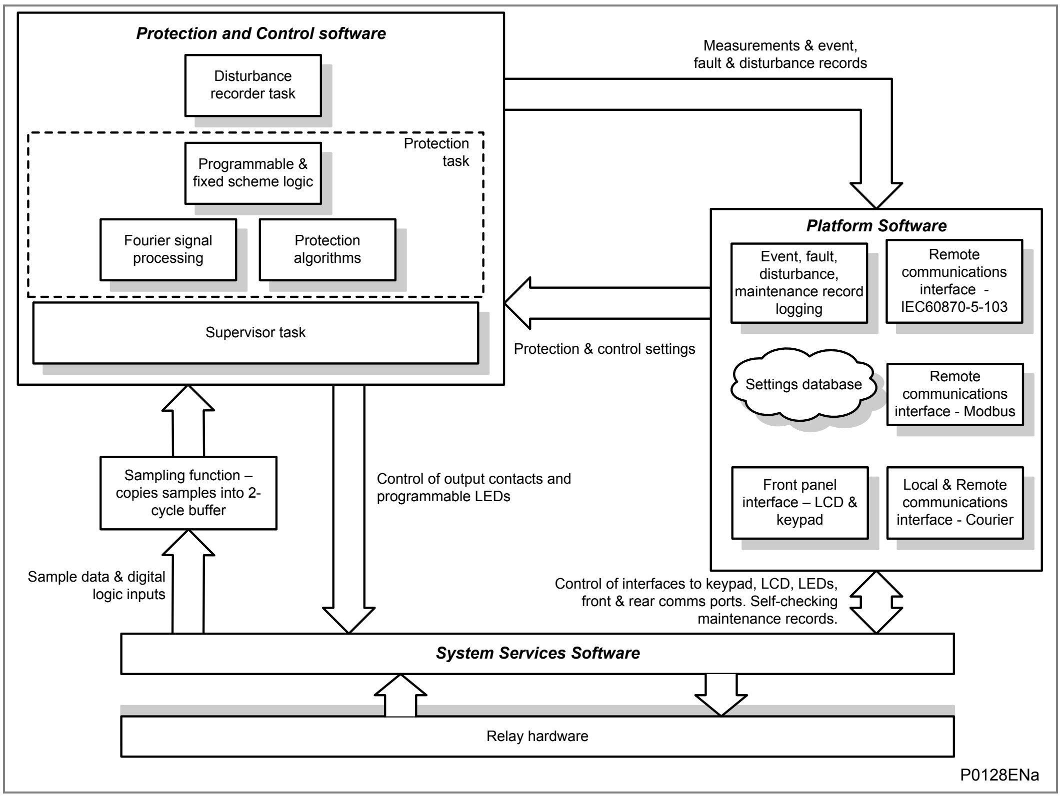

Figure 5 - Relay software structure

3.1 Real-Time Operating System

The software is split into tasks; the real-time operating system is used to schedule the processing of the tasks to ensure that they are processed in the time available and in the desired order of priority. The operating system is also responsible in part for controlling the communication between the software tasks through the use of operating system messages.

3.2 System Services Software

As shown in Figure 5, the system services software provides the interface between the relay's hardware and the higher-level functionality of the platform software and the protection & control software. For example, the system services software provides drivers for items such as the LCD display, the keypad and the remote communication ports, and controls the boot of the processor and downloading of the processor code into SRAM from flash EPROM at power up.

3.3 Platform Software

The platform software has three main functions:

- To control the logging of records that are generated by the protection software, including alarms and event, fault, and maintenance records.
- To store and maintain a database of all of the relay's settings in non-volatile memory.
- To provide the internal interface between the settings database and each of the relay's user interfaces, i.e. the front panel interface and the front and rear communication ports, using whichever communication protocol has been specified (Courier, MODBUS, IEC 60870-5-103, DNP3.0 or IEC 61850).

3.3.1 Record Logging

The logging function is provided to store all alarms, events, faults and maintenance records. The records for all of these incidents are logged in battery backed-up SRAM in order to provide a non-volatile log of what has happened. The relay maintains four logs: one each for up to 32 alarms, 512 event records, 5 fault records and 5 maintenance records. The logs are maintained such that the oldest record is overwritten with the newest record. The logging function can be initiated from the protection software or the platform software is responsible for logging of a maintenance record in the event of a relay failure. This includes errors that have been detected by the platform software itself or error that are detected by either the system services or the protection software function. See also the section on supervision and diagnostics later in this chapter.

3.3.2 Settings Database

The settings database contains all of the settings and data for the relay, including the protection, disturbance recorder and control & support settings. The settings are maintained in non-volatile memory. The platform software's management of the settings database includes the responsibility of ensuring that only one user interface modifies the settings of the database at any one time. This feature is employed to avoid conflict between different parts of the software during a setting change. For changes to protection settings and disturbance recorder settings, the platform software operates a '**scratchpad**' in SRAM memory. This allows a number of setting changes to be applied to the protection elements, disturbance recorder and saved in the database in non-volatile memory. (See also the Introduction to this manual (P14x/EN IT) on the user interface). If a setting change affects the protection & control task, the database advises it of the new values.

3.3.3 Database Interface

The other function of the platform software is to implement the relay's internal interface between the database and each of the relay's user interfaces. The database of settings and measurements must be accessible from all of the relay's user interfaces to allow read and modify operations. The platform software presents the data in the appropriate format for each user interface.

3.4 Protection and Control Software

The protection and control software task is responsible for processing all of the protection elements and measurement functions of the relay. To achieve this it has to communicate with both the system services software and the platform software as well as organize its own operations. The protection software has the highest priority of any of the software tasks in the relay in order to provide the fastest possible protection response. The protection and control software has a supervisor task that controls the start-up of the task and deals with the exchange of messages between the task and the platform software.

3.4.1 Overview - Protection and Control Scheduling

After initialization at start-up, the protection and control task is suspended until there are sufficient samples available for it to process. The acquisition of samples is controlled by a '**sampling function**' which is called by the system services software and takes each set of new samples from the input module and stores them in a two-cycle buffer. The protection and control software resumes execution when the number of unprocessed samples in the buffer reaches a certain number. For the P14x feeder protection relay, the protection task is executed twice per cycle, i.e. after every 12 samples for the sample rate of 24 samples per power cycle used by the relay. The protection and control software is suspended again when all of its processing on a set of samples is complete. This allows operations by other software tasks to take place.

3.4.2 Signal Processing

The sampling function provides filtering of the digital input signals from the opto-isolators and frequency tracking of the analog signals. The digital inputs are checked against their previous value over a period of half a cycle. Hence a change in the state of one of the inputs must be maintained over at least half a cycle before it is registered with the protection and control software.

The frequency tracking of the analog input signals is achieved by a recursive Fourier algorithm which is applied to one of the input signals, and works by detecting a change in the measured signal's phase angle. The calculated value of the frequency is used to modify the sample rate being used by the input module so as to achieve a constant sample rate of 24 samples per cycle of the power waveform. The value of the frequency is also stored for use by the protection and control task.

3.4.3 Fourier Filtering

When the protection and control task is re-started by the sampling function, it calculates the Fourier components for the analog signals. With the exception of the RMS measurements all other measurements and protection functions are based on the Fourier derived fundamental component. The Fourier components are calculated using a one-cycle, 24-sample Discrete Fourier Transform (DFT). The DFT is always calculated using the last cycle of samples from the 2-cycle buffer, i.e. the most recent data is used. The DFT used in this way extracts the power frequency fundamental component from the signal and produces the magnitude and phase angle of the fundamental in rectangular component format. This gives good harmonic rejection for frequencies up to the 23^{rd} harmonic. The 23^{rd} is the first predominant harmonic that is not attenuated by the Fourier filter and this is known as '**Alias**'. However, the Alias is attenuated by approximately 85% by an additional, analog, '**anti-aliasing**' filter (low pass filter). The combined affect of the anti-aliasing and Fourier filters is shown in Figure 6:

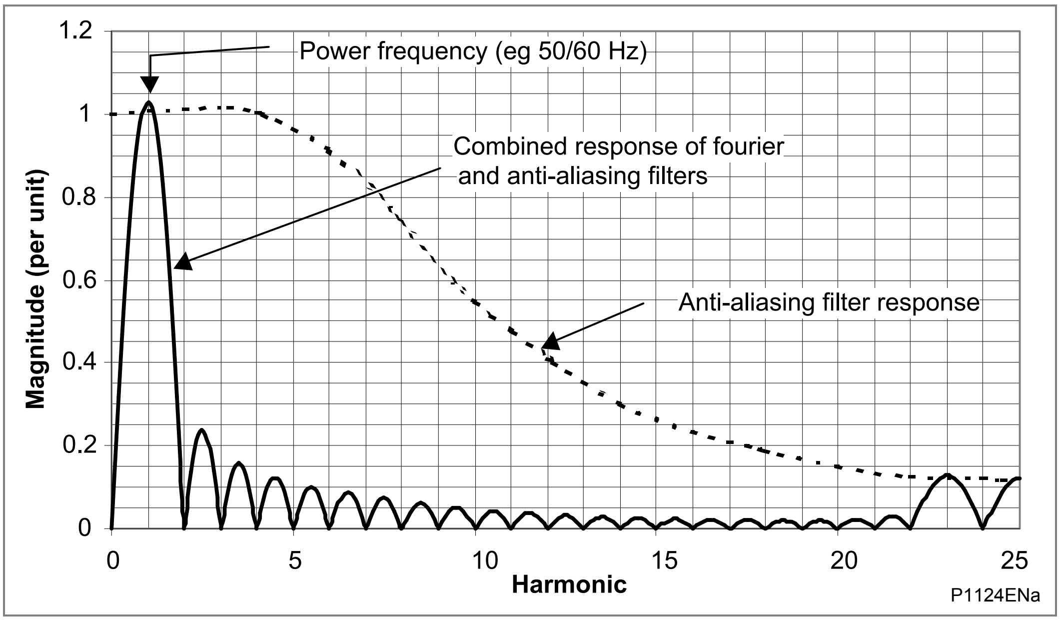

Figure 6 - Frequency response

The Fourier components of the input current and voltage signals are stored in memory so that they can be accessed by all of the protection elements' algorithms. The samples from the input module are also used in an unprocessed form by the disturbance recorder for waveform recording and to calculate true rms. values of current, voltage and power for metering purposes.

3.4.4 Programmable Scheme Logic (PSL)

The purpose of the Programmable Scheme Logic (PSL) is to allow the relay user to configure an individual protection scheme to suit their own particular application. This is achieved through the use of programmable logic gates and delay timers.

The input to the PSL is any combination of the status of the digital input signals from the opto-isolators on the input board, the outputs of the protection elements, e.g. protection starts and trips, control inputs, function keys and the outputs of the fixed protection scheme logic. The fixed scheme logic provides the relay's standard protection schemes. The PSL itself consists of software logic gates and timers. The logic gates can be programmed to perform a range of different logic functions and can accept any number of inputs. The timers are used either to create a programmable delay, and/or to condition the logic outputs, e.g. to create a pulse of fixed duration on the output regardless of the length of the pulse on the input. The outputs of the PSL are the LEDs on the front panel of the relay and the output contacts at the rear.

The execution of the PSL logic is event driven; the logic is processed whenever any of its inputs change, for example as a result of a change in one of the digital input signals or a trip output from a protection element. Also, only the part of the PSL logic that is affected by the particular input change that has occurred is processed. This reduces the amount of processing time that is used by the PSL. The protection and control software updates the logic delay timers and checks for a change in the PSL input signals every time it runs.

This system provides flexibility for the user to create their own scheme logic design. However, it also means that the PSL can be configured into a very complex system, and because of this setting of the PSL is implemented through the PC support package MiCOM S1.

3.4.5 Function Key Interface

The ten function keys interface directly into the PSL as digital input signals and are processed based on the PSLs event driven execution. However, a change of state is only recognized when a keypress is executed on average for longer than 200 ms. The time to register a change of state, depends on whether the function key press is executed at the start or the end of a protection task cycle, with the additional hardware and software scan time included. A function key press can provide a latched (toggled mode) or output on key press only (normal mode) depending on how it is programmed and can be configured to individual protection scheme requirements. The latched state signal for each function key is written to non-volatile memory and read from non-volatile memory during relay power up thus allowing the function Key state to be reinstated after power-up should relay power be inadvertently lost.

3.4.6 Event and Fault Recording

A change in any digital input signal or protection element output signal causes an event record to be created. When this happens, the protection and control task sends a message to the supervisor task to indicate that an event is available to be processed and writes the event data to a fast buffer in SRAM which is controlled by the supervisor task. When the supervisor task receives either an event or fault record message, it instructs the platform software to create the appropriate log in battery backed-up SRAM. The operation of the record logging to battery backed-up SRAM is slower than the supervisor’s buffer. This means that the protection software is not delayed waiting for the records to be logged by the platform software. However, in the rare case when a large number of records to be logged are created in a short period of time, it is possible that some will be lost if the supervisor’s buffer is full before the platform software is able to create a new log in battery backed-up SRAM. If this occurs then an event is logged to indicate this loss of information.

3.4.7 Disturbance Recorder

The disturbance recorder operates as a separate task from the protection and control task. It can record the waveforms for up to 8 analog channels and the values of up to 32 digital signals. The recording time is user selectable up to a maximum of 10 seconds. The disturbance recorder is supplied with data by the protection and control task once per cycle. The disturbance recorder collates the data that it receives into the required length disturbance record. The disturbance records can be extracted by MiCOM S1 that can also store the data in COMTRADE format, thus allowing the use of other packages to view the recorded data.

3.4.8 Fault Locator

The fault locator task is also separate from the protection and control task. The fault locator is invoked by the protection and control task when a fault is detected. The fault locator uses a 12-cycle buffer of the analog input signals and returns the calculated location of the fault to the protection and control task which includes it in the fault record for the fault. When the fault record is complete (i.e. includes the fault location), the protection and control task can send a message to the supervisor task to log the fault record.

4 FAULT LOCATOR

The relay has an integral fault locator that uses information from the current and voltage inputs to provide a distance to fault location feature. The sampled data from the analog input circuits is written to a cyclic buffer until a fault condition is detected. The data in the input buffer is then held to allow the fault calculation to be made. When the fault calculation is complete the fault location information is available in the relay fault record.

4.1 Basic Theory for Ground Faults

A two-machine equivalent circuit of a faulted power system is shown in Figure 7.

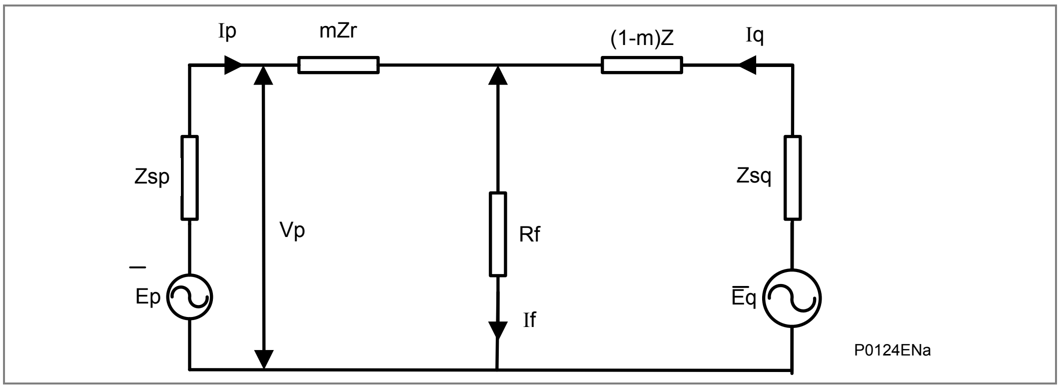

Figure 7 - Two machine equivalent circuit

From this diagram:

Equation 1

$$Vp = mIpZr + IfRf$$

The fault location, m, can be found if If can be estimated allowing Equation 1 to be solved.

4.2 Data Acquisition and Buffer Processing

The fault locator stores the sampled data within a 12 cycle cyclic buffer at a resolution of 24 samples per cycle. When the fault recorder is triggered the data in the buffer is frozen such that the buffer contains 6 cycles of pre-trigger data and 6 cycles of post-trigger data. Fault calculation commences shortly after this trigger point.

The trigger for the fault locator is user selectable via the PSL.

The fault locator can store data for up to four faults. This ensures that fault location can be calculated for all shots on a typical multiple re-close sequence.

4.3 Faulted Phase Selection

Selection of the faulted phase(s) is performed by comparing the magnitude of the pre fault and post fault values of the three phase-to-phase currents. A single phase-to-ground fault produces the same change on two of these signals and zero on the third. A phase-to-phase or double phase-to-ground fault produces one signal that is larger than the other two. A three-phase fault produces the same change on all 3 currents.

Current changes are considered to be the same if they are within 20% of each other. Phase selection and fault location calculation can only be made if the current change exceeds 5%In.

4.4 Fault Location Calculation

This works by:

1. First obtaining the vectors
2. Selecting the faulted phase(s)
3. Estimating the phase of the fault current, If, for the faulted phase(s)
4. Solving Equation 1 for the fault location m at the instant of time where If = 0

4.4.1 Obtaining the Vectors

Different sets of vectors are chosen depending on the type of fault identified by the phase selection algorithm. The calculation using Equation 1 is applied for either a phase to ground fault or a phase to phase fault.

Thus for an A phase to ground fault:

Equation 2

IpZr = Ia (Zline /THETA line) + In (Zresidual /THETA residual)

And

Vp = VA

and for an A phase to B phase fault:

Equation 3

IpZr = Ia (Zline /THETA line) – Ib (Zresidual /THETA residual)

And

Vp = VA – VB

4.4.2 Solving the Equation for the Fault Location

As the sine wave of If passes through zero, the instantaneous values of the sine waves Vp and Ip can be used to solve Equation 1 for the fault location m. (The term IfRf being zero.)

This is determined by shifting the calculated vectors of Vp and IpZr by the angle (90° - angle of fault current) and then dividing the real component of Vp by the real component of IpZr. See Figure 8 below.

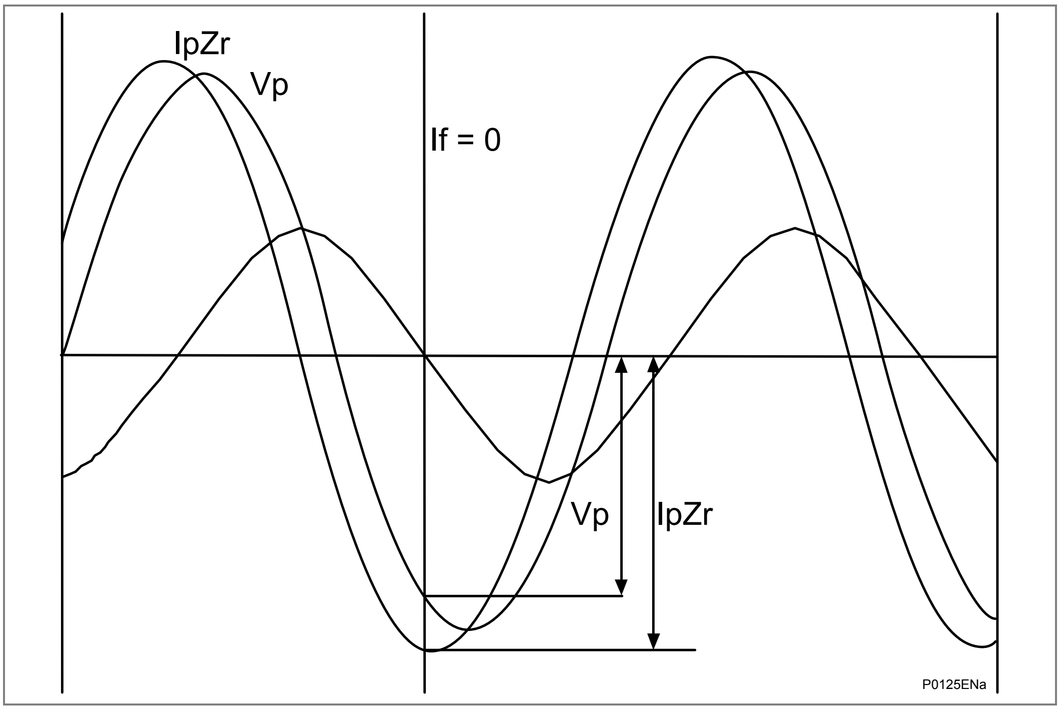

Figure 8 - Fault locator selection of fault current zero

i.e.:

Phase advanced vector Vp

= | Vp | (cos(s) + jsin(s)) * (sin(d) + jcos(d))

= | Vp | [- sin(s-d) + jcos(s-d)]

Phase advanced vector IpZr

= | IpZr | (cos (e) + jsin (e)) * (sin (d) + jcos (d))

= | IpZr | [- sin(e-d) + jcos(e-d)]

therefore from Equation 1

m = Vp ÷ (Ip * Zr) at If = 0

= Vpsin(s-d) / (IpZr * sin(e-d))

where

d = angle of fault current If

s = angle of Vp

e = angle of IpZr

Thus the relay evaluates m which is the fault location as a percentage of the fault locator line impedance setting and then calculates the output fault location by multiplying this by the line length setting. When calculated, the fault location can be found in the fault record under the "**VIEW RECORDS**" column in the Fault Location cells. Distance to fault is available in kilometers, miles, impedance or percentage of line length.

5 SELF TESTING AND DIAGNOSTICS

The relay includes a number of self-monitoring functions to check the operation of its hardware and software when it is in service. These are included so that if an error or fault occurs within the relay's hardware or software, the relay is able to detect and report the problem and attempt to resolve it by performing a re-boot. This involves the relay being out of service for a short period of time which is indicated by the '**Healthy**' LED on the front of the relay being extinguished and the watchdog contact at the rear operating. If the restart fails to resolve the problem, then the relay will take itself permanently out of service. Again this will be indicated by the LED and watchdog contact.

If a problem is detected by the self-monitoring functions, the relay attempts to store a maintenance record in battery backed-up SRAM to allow the nature of the problem to be notified to the user.

The self-monitoring is implemented in two stages: firstly a thorough diagnostic check which is performed when the relay is booted-up, e.g. at power-on, and secondly a continuous self-checking operation which checks the operation of the relay's critical functions whilst it is in service.

5.1 Start-up Self-Testing

The self-testing which is carried out when the relay is started takes a few seconds to complete, during which time the relay's protection is unavailable. This is signaled by the '**Healthy**' LED on the front of the relay which will illuminate when the relay has passed all of the tests and entered operation. If the testing detects a problem, the relay will remain out of service until it is manually restored to working order.

The operations that are performed at start-up are System Boot, then Initialization Software and then Platform Software Initialization and Monitoring.

5.1.1 System Boot

The integrity of the flash memory is verified using a checksum before the program code and data stored in it is copied into SRAM to be used for execution by the processor. When the copy has been completed the data then held in SRAM is compared to that in the flash to ensure that the two are the same and that no errors have occurred in the transfer of data from flash to SRAM. The entry point of the software code in SRAM is then called which is the relay initialization code.

5.1.2 Initialization Software

The initialization process includes the operations of initializing the processor registers and interrupts, starting the watchdog timers (used by the hardware to determine whether the software is still running), starting the real-time operating system and creating and starting the supervisor task. In the course of the initialization process the relay checks:

- The status of the battery
- The integrity of the battery backed-up SRAM that is used to store event, fault and disturbance records
- The voltage level of the field voltage supply which is used to drive the opto-isolated inputs
- The operation of the LCD controller
- The watchdog operation

At the conclusion of the initialization software the supervisor task begins the process of starting the platform software.

5.1.3 Platform Software Initialization and Monitoring

In starting the platform software, the relay checks the integrity of the data held in non-volatile memory with a checksum, the operation of the real-time clock, and the IRIG-B board if fitted. The final test that is made concerns the input and output of data; the presence and healthy condition of the input board is checked and the analog data acquisition system is checked through sampling the reference voltage.

At the successful conclusion of all of these tests the relay is entered into service and the protection started-up.

5.2 Continuous Self-Testing

When the relay is in service, it continually checks the operation of the critical parts of its hardware and software. The checking is carried out by the system services software (see section on relay software earlier in this document and the results reported to the platform software. The functions that are checked are as follows:

- The flash containing all program code setting values and language text is verified by a checksum
- The code and constant data held in SRAM is checked against the corresponding data in flash to check for data corruption
- The SRAM containing all data other than the code and constant data is verified with a checksum
- The battery status
- The level of the field voltage
- The integrity of the digital signal I/O data from the opto-isolated inputs and the relay contacts is checked by the data acquisition function every time it is executed. The operation of the analog data acquisition system is continuously checked by the acquisition function every time it is executed, by means of sampling the reference voltages
- The operation of the IRIG-B board is checked, where it is fitted, by the software that reads the time and date from the board
- The operation of the Ethernet board is checked, where it is fitted, by the software on the main processor card. If the Ethernet board fails to respond an alarm is raised and the card is reset in an attempt to resolve the problem

In the unlikely event that one of the checks detects an error within the relay’s subsystems, the platform software is notified and it will attempt to log a maintenance record in battery backed-up SRAM. If the problem is with the battery status or the IRIG-B board, the relay will continue in operation. However, for problems detected in any other area the relay will initiate a shutdown and re-boot. This will result in a period of up to 5 seconds when the protection is unavailable, but the complete restart of the relay including all initializations should clear most problems that could occur. As described above, an integral part of the start-up procedure is a thorough diagnostic self-check. If this detects the same problem that caused the relay to restart, i.e. the restart has not cleared the problem, then the relay will take itself permanently out of service. This is indicated by the ‘**Healthy**’ LED on the front of the relay, which will extinguish, and the watchdog contact that will operate.

COMMISSIONING

CHAPTER NO 12

Date:	10/2014
Products covered by this chapter:	This chapter covers the specific versions of the MiCOM products listed below. This includes ***only*** the following combinations of Software Version and Hardware Suffix.
Hardware Suffix:	L (P141, P142 & P143) & M (P145)
Software Version:	A0 - P14x (P141, P142, P143 & P145)
Connection Diagrams:	10P141xx (xx = 01 to 07) 10P142xx (xx = 01 to 07) 10P143xx (xx = 01 to 07) 10P145xx (xx = 01 to 07)

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Notes:

1 INTRODUCTION

MiCOM P40 relays are fully numerical in their design, implementing all protection and non-protection functions in software. The relays use a high degree of self-checking and give an alarm in the unlikely event of a failure. Therefore, the commissioning tests do not need to be as extensive as with non-numeric electronic or electro-mechanical relays.

To commission numeric relays, it is only necessary to verify that the hardware is functioning correctly and the application-specific software settings have been applied to the relay. It is considered unnecessary to test every function of the relay if the settings have been verified by one of the following methods:

- Extracting the settings applied to the relay using appropriate setting software (preferred method)
- Using the operator interface

To confirm that the product is operating correctly once the application-specific settings have been applied, perform a test on a single protection element.

Unless previously agreed to the contrary, the customer is responsible for determining the application-specific settings to be applied to the relay and for testing any scheme logic applied by external wiring or configuration of the relay's internal programmable scheme logic.

Blank commissioning test and setting records are provided within this manual for completion as required.

As the relay's menu language is user-selectable, the Commissioning Engineer can change it to allow accurate testing as long as the menu is restored to the customer's preferred language on completion.

To simplify the specifying of menu cell locations in these Commissioning Instructions, they are given in the form [courier reference: COLUMN HEADING, Cell Text]. For example, the cell for selecting the menu language (first cell under the column heading) is in the System Data column (column 00) so it is given as [0001: SYSTEM DATA, Language].

Caution	**Before carrying out any work on the equipment, the user should be familiar with the contents of the Safety and Technical Data sections and the ratings on the equipment's rating label.**

Caution	**The relay must not be disassembled in any way during commissioning.**

2 RELAY COMMISSIONING TOOLS

To help minimize the time needed to test MiCOM relays the relay provides several test facilities under the '**COMMISSION TESTS**' menu heading. There are menu cells which allow the status of the opto-isolated inputs, output relay contacts, internal Digital Data Bus (DDB) signals and user-programmable LEDs to be monitored. Additionally there are cells to test the operation of the output contacts, user-programmable LEDs and, where available, the auto-reclose cycles.

The following table shows the relay menu of commissioning tests, including the available setting ranges and factory defaults. Each of the main menu tests are described in more detail in the following sections.

COMMISSION TESTS for P14x		
Menu Text	**Default Setting**	**Settings**
Opto I/P Status	-	-
Relay O/P Status	-	-
Test Port Status	-	-
LED Status	-	-
Monitor Bit 1	64 - (LED 1)	0 to 1022
Monitor Bit 2	65 - (LED 2)	0 to 1022
Monitor Bit 3	66 - (LED 3)	0 to 1022
Monitor Bit 4	67 - (LED 4)	0 to 1022
Monitor Bit 5	68 - (LED 5)	0 to 1022
Monitor Bit 6	69 - (LED 6)	0 to 1022
Monitor Bit 7	70 - (LED 7)	0 to 1022
Monitor Bit 8	71 - (LED 8)	0 to 1022
Test Mode	Disabled	Disabled, Test Mode, Contacts Blocked
Test Pattern	All bits set to 0	0 = Not Operated, 1 = Operated
Contact Test	No Operation	No Operation, Apply Test, Remove Test
Test LEDs	No Operation	No Operation, Apply Test
Test Auto-reclose	No Operation	No Operation, 3 Pole Test
Red LED Status	P145 only	-
Green LED Status	P145 only	-
Note *See Relay Menu Database for details of DDB signals*		

Table 1 - Commission Tests

2.1 Opto I/P Status

This menu cell displays the status of the relay's opto-isolated inputs as a binary string, a '**1**' indicating an energized opto-isolated input and a '**0**' a de-energized one. If the cursor is moved along the binary numbers the corresponding label text will be displayed for each logic input.

It can be used during commissioning or routine testing to monitor the status of the opto-isolated inputs whilst they are sequentially energized with a suitable dc voltage.

2.2 Relay O/P Status

This menu cell displays the status of the Digital Data Bus (DDB) signals that result in energization of the output relays as a binary string, a '**1**' indicating an operated state and '**0**' a non-operated state. If the cursor is moved along the binary numbers the corresponding label text will be displayed for each relay output.

The information displayed can be used during commissioning or routine testing to indicate the status of the output relays when the relay is '**in service**'. Additionally fault finding for output relay damage can be performed by comparing the status of the output contact under investigation with it's associated bit.

Note	*When the '**Test Mode**' cell is set to '**Enabled**' this cell will continue to indicate which contacts would operate if the relay was in-service, it does not show the actual status of the output relays.*

2.3 Test Port Status

This menu cell displays the status of the eight Digital Data Bus (DDB) signals that have been allocated in the '**Monitor Bit**' cells. If the cursor is moved along the binary numbers the corresponding DDB signal text string will be displayed for each monitor bit.

By using this cell with suitable monitor bit settings, the state of the DDB signals can be displayed as various operating conditions or sequences are applied to the relay. Thus the programmable scheme logic can be tested.

As an alternative to using this cell, the optional monitor/download port test box can be plugged into the monitor/download port located behind the bottom access cover. Details of the monitor/download port test box can be found in the *Using a Monitor/Download Port Test Box* section of this chapter.

2.4 LED Status

The '**LED Status**' is an eight bit binary strings that indicate which of the user-programmable LEDs on the relay are illuminated when accessing the relay from a remote location, a '**1**' indicating a particular LED is lit and a '**0**' not lit.

2.5 Monitor Bits 1 to 8

The eight '**Monitor Bit**' cells allow the user to select the status of which digital data bus signals can be observed in the '**Test Port Status**' cell or via the monitor/download port.

Each '**Monitor Bit**' is set by entering the required Digital Data Bus (DDB) signal number from the list of available DDB signals in the Programmable Logic chapter. The pins of the monitor/download port used for monitor bits are given in the following table. The signal ground is available on pins 18, 19, 22 and 25.

Note	*The the required Digital Data Bus (DDB) signal numbers are as follows:* *0 – 511 for P64x* *0 - 1022 for P14x/P24x* *0 - 1791 for P44y/P54x/P547/P841* *0 - 2027 for P34x*

Monitor bit	1	2	3	4	5	6	7	8
Monitor/download port pin	11	12	15	13	20	21	23	24

Table 2 - Monitor bit pins

Warning	THE MONITOR/DOWNLOAD PORT DOES NOT HAVE ELECTRICAL ISOLATED AGAINST INDUCED VOLTAGES ON THE COMMUNICATIONS CHANNEL. IT SHOULD THEREFORE ONLY BE USED FOR LOCAL COMMUNICATIONS.

2.6 Test Mode

The Test Mode menu cell (in the Commissioning column) is used to allow secondary injection testing to be performed on the relay without operation of the trip contacts. It also enables a facility to directly test the output contacts by applying menu controlled test signals.

To select test mode the Test Mode menu cell should be set to '**Test Mode**' that takes the relay out of service and blocks operation of output contacts and maintenance counters. It also causes an alarm condition to be recorded and the yellow '**Out of Service**' LED to illuminate and an alarm message '**Prot'n. Disabled**' is given.

This also freezes any information stored in the CB CONDITION column and in IEC60870-5-103 builds changes the Cause of Transmission, COT, to Test Mode. To enable testing of output contacts the Test Mode cell should be set to Contacts Blocked. This blocks the protection from operating the contacts and enables the test pattern and contact test functions which can be used to manually operate the output contacts.

Once testing is complete the cell must be set back to '**Disabled**' to restore the relay back to service.

Caution	**When the 'Test Mode' cell is set to 'Blocked' the relay scheme logic does not drive the output relays and hence the protection will not trip the associated circuit breaker if a fault occurs.**

2.7 Test Pattern

The '**Test Pattern**' cell is used to select the output relay contacts that will be tested when the '**Contact Test**' cell is set to '**Apply Test**'. The cell has a binary string with one bit for each user-configurable output contact which can be set to '**1**' to operate the output under test conditions and '**0**' to not operate it.

2.8 Contact Test

When the '**Apply Test**' command in this cell is issued the contacts set for operation (set to '**1**') in the '**Test Pattern**' cell change state. After the test has been applied the command text on the LCD will change to '**No Operation**' and the contacts will remain in the Test State until reset issuing the '**Remove Test**' command. The command text on the LCD will again revert to '**No Operation**' after the '**Remove Test**' command has been issued.

Note	*When the '**Test Mode**' cell is set to '**Enabled**' the '**Relay O/P Status**' cell does not show the current status of the output relays and hence can not be used to confirm operation of the output relays. Therefore it will be necessary to monitor the state of each contact in turn.*

2.9 Test LEDs

When the '**Apply Test**' command in this cell is issued the eight/eighteen user-programmable LEDs will illuminate for approximately 2 seconds before they extinguish and the command text on the LCD reverts to '**No Operation**'.

2.10 Test Auto-Reclose

Where the relay provides an auto-reclose function, this cell will be available for testing the sequence of circuit breaker trip and auto-reclose cycles with the settings applied.

Issuing the command '**3 Pole Trip**' will cause the relay to perform the first three-phase trip/reclose cycle so that associated output contacts can be checked for operation at the correct times during the cycle. Once the trip output has operated the command text will revert to '**No Operation**' whilst the rest of the auto-reclose cycle is performed. To test subsequent three-phase auto-reclose cycles repeat the '**3 Pole Trip**' command.

Note	*The factory settings for the relay's programmable scheme logic has the '**AR Trip Test**' signal mapped to relay 3. If the programmable scheme logic has been changed, it is essential that this signal remains mapped to relay 3 for the '**Test Auto-reclose**' facility to work.*

2.11 Red LED Status and Green LED Status (P145 Model Only)

The '**Red LED Status**' and '**Green LED Status**' cells are eighteen bit binary strings that indicate which of the user-programmable LEDs on the relay are illuminated when accessing the relay from a remote location, a '**1**' indicating a particular LED is lit and a '**0**' not lit. When the status of a particular LED in both cells are '**1**', this indicates the LEDs illumination is yellow.

2.12 Using a Monitor/Download Port Test Box

A monitor/download port test box containing 8 LEDs and a switchable audible indicator is available from Schneider Electric, or one of their regional sales offices. It is housed in a small plastic box with a 25-pin male D-connector that plugs directly into the relay's monitor/download port. There is also a 25-pin female D-connector which allows other connections to be made to the monitor/download port whilst the monitor/download port test box is in place.

Each LED corresponds to one of the monitor bit pins on the monitor/download port with '**Monitor Bit 1**' being on the left hand side when viewing from the front of the relay. The audible indicator can either be selected to sound if a voltage appears on any of the eight monitor pins or remain silent so that indication of state is by LED alone.

3 SETTING FAMILIARIZATION

When first commissioning a relay, allow sufficient time to become familiar with how to apply the settings.

The *Relay Menu Database document* and the *Introduction* or *Settings* chapters contain a detailed description of the menu structure of Schneider Electric relays. The relay menu database is a separate document which can be downloaded from our website:

www.schneider-electric.com

With the secondary front cover in place, all keys except the ↵ key are accessible. All menu cells can be read. LEDs and alarms can be reset. However, no protection or configuration settings can be changed, or fault and event records cleared.

Removing the secondary front cover allows access to all keys so that settings can be changed, LEDs and alarms reset, and fault and event records cleared. However, to make changes to menu cells, the appropriate user role and password is needed.

Alternatively, if a portable PC with suitable setting software is available (such as MiCOM S1 Studio), the menu can be viewed one page at a time, to display a full column of data and text. This PC software also allows settings to be entered more easily, saved to a file for future reference, or printed to produce a settings record. Refer to the PC software user manual for details. If the software is being used for the first time, allow sufficient time to become familiar with its operation.

4 EQUIPMENT REQUIRED FOR COMMISSIONING

4.1 Minimum Equipment Required

The minimum equipment needed varies slightly, depending on the features provided by each type of MiCOM product. The list of minimum equipment is given below:

- Multifunctional dynamic current and voltage injection test set.
- Multimeter with suitable ac current range, and ac and dc voltage ranges of 0 - 440V and 0 - 250V respectively.
- Continuity tester (if not included in multimeter).
- Phase angle meter.
- Phase rotation meter.

Note	*Modern test equipment may contain many of the above features in one unit.*

- Fiber optic power meter.
- Fiber optic test leads (type and number according to application).
- P594 Commissioning Instructions. If the scheme features P594 time synchronizing devices, these will need commissioning. Separate documentation containing commissioning instructions is available for the P594.
- Overcurrent test set with interval timer
- 110 V ac voltage supply (if stage 1 of the overcurrent function is set directional)
- 100 Ω precision wire wound or metal film resistor, 0.1% tolerance (0°C ±2°C)

4.2 Optional Equipment

- Multi-finger test plug type MMLB01 (if test block type MMLG is installed)
- An electronic or brushless insulation tester with a dc output not exceeding 500 V (for insulation resistance testing when required)
- A portable PC, with appropriate software (enabling the rear communications port to be tested, if this is to be used, and saves considerable time during commissioning)
- KITZ K-Bus to EIA(RS)232 protocol converter (if the first rear EIA(RS)485 K-Bus port or second rear port configured for K-Bus is being tested and one is not already installed)
- EIA(RS)485 to EIA(RS)232 converter (if first rear EIA(RS)485 port or second rear port configured for EIA(RS)485 is being tested)
- A printer, for printing a setting record from the portable PC

5 PRODUCT CHECKS

These product checks cover all aspects of the relay that need to be checked to ensure that:

- it has not been physically damaged before commissioning
- it is functioning correctly and
- all input quantity measurements are within the stated tolerances

If the application-specific settings have been applied to the relay before commissioning, it is advisable to make a copy of the settings to allow their restoration later.

For P14x, P34x, P44y & P547, if Programmable Scheme Logic (PSL) (other than the default settings with which the relay is supplied) has been applied, the default settings should be restored before commissioning. This can be done by:

- Obtaining a setting file from the customer. This requires a portable PC with appropriate setting software for transferring the settings from the PC to the relay.
- Extracting the settings from the relay itself. This requires a portable PC with appropriate setting software.
- Manually creating a setting record. This could be done stepping through the front panel menu using the front panel user interface.

If password protection is enabled, and the customer has changed password 2 that prevents unauthorized changes to some of the settings, either the revised password 2 should be provided, or the customer should restore the original password before testing is started.

Note	*If the password has been lost, a recovery password can be obtained from Schneider Electric by quoting the serial number of the relay. The recovery password is unique to that relay and will not work on any other relay.*

5.1 With the Relay De-Energized

The following group of tests should be carried out without the auxiliary supply applied to the relay and with the trip circuit isolated.

Before inserting the test plug, refer to the scheme diagram to ensure this will not cause damage or a safety hazard. For example, the test block may be associated with protection current transformer circuits. Before the test plug is inserted into the test block, make sure the sockets in the test plug which correspond to the current transformer secondary windings are linked.

Warning	**The current and voltage transformer connections must be isolated from the relay for these checks. If a P991 or MMLG test block is provided, insert the test plug type P992 or MMLB01, which open-circuits all wiring routed through the test block.**

Danger	**Never open-circuit the secondary circuit of a current transformer because the high voltage produced may be lethal. It could also damage insulation.**

If a test block is not provided, isolate the voltage transformer supply to the relay using the panel links or connecting blocks. Short-circuit and disconnect the line current transformers from the relay terminals. Where means of isolating the auxiliary supply and trip circuit (such as isolation links, fuses and MCB) are provided, these should be used. If this is impossible, the wiring to these circuits must be disconnected and the exposed ends suitably terminated to prevent them from being a safety hazard.

5.1.1 Visual Inspection

Caution	**Check the rating information under the top access cover on the front of the relay. Check that the relay being tested is correct for the protected line or circuit. Ensure that the circuit reference and system details are entered onto the setting record sheet. Double-check the CT secondary current rating, and be sure to record the actual CT tap which is in use.**

Carefully examine the relay to see that no physical damage has occurred since installation.

Ensure that the case earthing connections, at the bottom left-hand corner at the rear of the relay case, are used to connect the relay to a local earth bar using an adequate conductor.

5.1.2 Current Transformer Shorting Contacts (Optional Check)

If required, the current transformer shorting contacts can be checked to ensure that they close when the heavy duty terminal block shown in the following figure(s)is disconnected from the current input PCB. Except as stated below, the heavy duty terminal block is shown as block reference C.

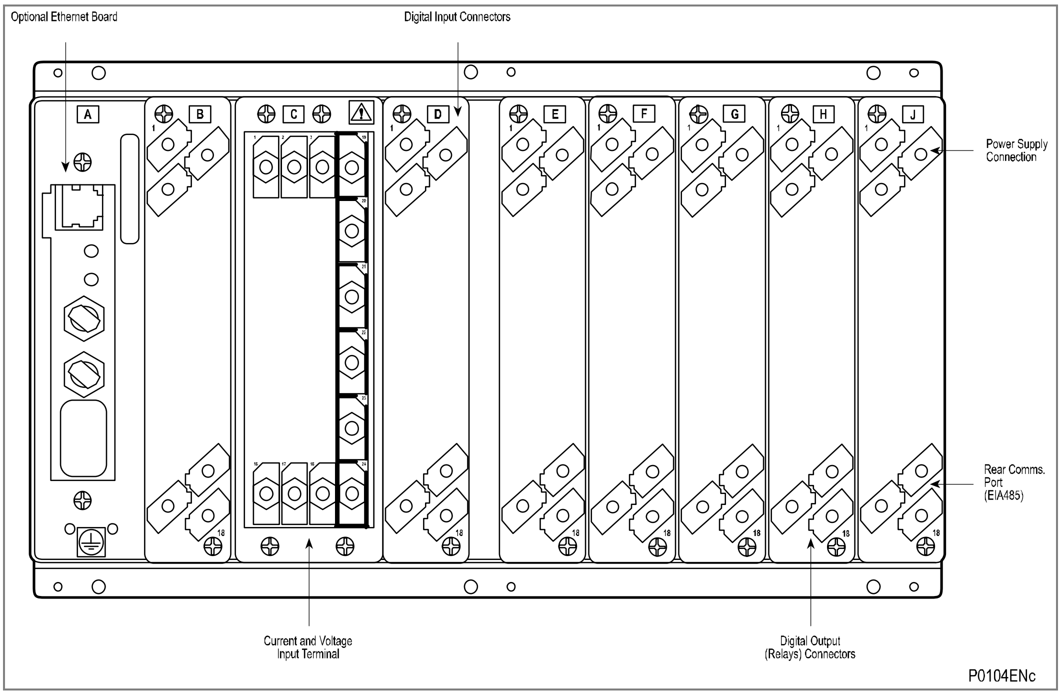

Figure 1 - Rear terminal blocks on size 60TE case (G variant) (P145 G variant shown)

Heavy duty terminal blocks are fastened to the rear panel using four crosshead screws. These are at the top and bottom between the first and second, and third and fourth, columns of terminals (see the *Location of Securing Screws for Terminal Blocks* diagram below).

Note	*Use a magnetic-bladed screwdriver to avoid losing screws or leaving them in the terminal block.*

Pull the terminal block away from the rear of the case and check with a continuity tester that all the shorting switches being used are closed. The following table(s) shows the terminals between which shorting contacts are fitted.

Current Input	Shorting Contact Between Terminals	
	1A CT's	5A CT's
IA	C3 - C2	C1 - C2
IB	C6 - C5	C4 - C5
IC	C9 - C8	C7 - C8
IN	C12 - C11	C10 - C11
IN SENSITIVE	C15 - C14	C13 - C14

Table 3 - Current transformer shorting contact locations

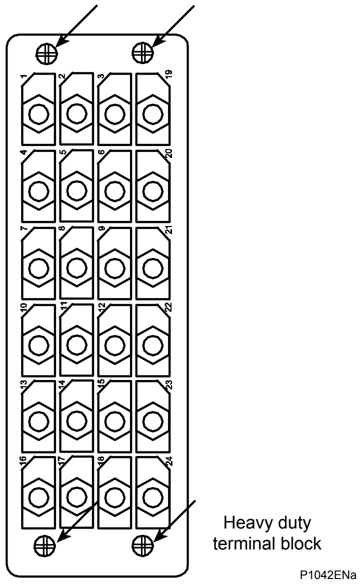

Figure 2 - Location of securing screws for heavy duty terminal blocks

5.1.3 Insulation

Insulation resistance tests are only necessary during commissioning if it is required for them to be done and they haven't been performed during installation.

Isolate all wiring from the earth and test the insulation with an electronic or brushless insulation tester at a dc voltage not exceeding 500 V. Terminals of the same circuits should be temporarily connected together.

The main groups of relay terminals are:

- Voltage transformer circuits
- Current transformer circuits
- Auxiliary voltage supply
- Field voltage output and opto-isolated control inputs
- Relay contacts
- First rear EIA(RS)485 communication port
- RTD inputs (where available)
- Current Loop (analog) Inputs and Outputs (CLIO) (where available)
- Case earth

The insulation resistance should be greater than 100 MΩ at 500 V.

On completion of the insulation resistance tests, ensure all external wiring is correctly reconnected to the unit.

5.1.4 External Wiring

Caution	Check that the external wiring is correct to the relevant relay diagram and scheme diagram. Ensure as far as practical that phasing/phase rotation appears to be as expected. The relay diagram number appears on the rating label under the top access cover on the front of the relay. Schneider Electric supply the corresponding connection diagram with the order acknowledgement for the relay.

If a P991 or MMLG test block is provided, check the connections against the wiring diagram. It is recommended that the supply connections are to the live side of the test block (colored orange with the odd numbered terminals 1, 3, 5, 7, and so on). The auxiliary supply is normally routed through terminals 13 (supply positive) and 15 (supply negative), with terminals 14 and 16 connected to the relay's positive and negative auxiliary supply terminals respectively. However, check the wiring against the schematic diagram for the installation to ensure compliance with the customer's normal practice.

5.1.5 Watchdog Contacts

Using a continuity tester, check that the watchdog contacts are in the states shown in the following table for a de-energized relay.

Terminals		Contact State	
		Relay De-energized	Relay Energized
F11 - F12	(P141/P142)	Closed	Open
F13 - F14	(P141/P142)	Open	Closed
J11 – J12	(P143/P145)	Closed	Open
J13 – J14	(P143/P145)	Open	Closed

Table 4 - Watchdog contact status

5.1.6 Auxiliary Supply

Caution	The relay can be operated from either a dc only or an ac/dc auxiliary supply depending on the relay's nominal supply rating. The incoming voltage must be within the operating range specified in the following table.

Without energizing the relay, measure the auxiliary supply to ensure it is within the operating range.

Note	*The relay can withstand an ac ripple of up to 12% of the upper rated voltage on the dc auxiliary supply.*

Nominal Supply Rating		Operating Range	
DC	AC	DC	AC
24 - 32V dc	-	19 to 65V dc	-
48 - 110V dc	-	37 to 150V dc	32 - 110V ac
125 - 250V dc	100 - 240V ac rms	87 to 300V dc	80 to 265V ac

Table 5 - Operational range of auxiliary supply Vx

Caution	Do not energize the relay using the battery charger with the battery disconnected as this can irreparably damage the relay's power supply circuitry.

Caution	Energize the relay only if the auxiliary supply is within the operating range. If a test block is provided, it may be necessary to link across the front of the test plug to connect the auxiliary supply to the relay.

5.2 With the Relay Energized

The following group of tests verify that the relay hardware and software is functioning correctly and should be carried out with the auxiliary supply applied to the relay.

Caution	The current and voltage transformer connections must remain isolated from the relay for these checks. The trip circuit should also remain isolated to prevent accidental operation of the associated circuit breaker.

5.2.1 Watchdog Contacts

Using a continuity tester, check the watchdog contacts are in the states given in Table 2 for an energized relay.

5.2.2 LCD Front Panel Display

The Liquid Crystal Display (LCD) is designed to operate in a wide range of substation ambient temperatures. For this purpose, the Px40 relays have an **LCD Contrast** setting. This allows the user to adjust the lightness or darkness of the displayed characters. The contrast is factory preset to account for a standard room temperature, however it may be necessary to adjust the contrast to give the best in-service display. To change the contrast, at the bottom of the **CONFIGURATION** column, use cell [09FF: LCD Contrast] to increment (darker) or decrement (lighter), as required.

Important	Before applying a contrast setting, ensure that it does not make the display too light or dark so the menu text becomes unreadable. If this happens, it is possible to restore the display by downloading a MiCOM S1 Studio setting file, with the LCD Contrast set in the typical range of 7 to 11.

5.2.3 Date and Time

Before setting the date and time, ensure that the factory-fitted battery isolation strip that prevents battery drain during transportation and storage has been removed. With the lower access cover open, the presence of the battery isolation strip can be checked by a red tab protruding from the positive side of the battery compartment. Lightly pressing the battery to prevent it falling out of the battery compartment, pull the red tab to remove the isolation strip.

The data and time should now be set to the correct values. The method of setting depends on whether accuracy is being maintained through the optional inter-range instrumentation group standard B (IRIG-B) port on the rear of the relay.

5.2.3.1 With an IRIG-B Signal

Note	*For P741 the IRIG-B signal may apply to the Central Unit only.*

If a satellite time clock signal conforming to IRIG-B is provided and the relay has the optional IRIG-B port fitted, the satellite clock equipment should be energized.

To allow the relay's time and date to be maintained from an external IRIG-B source cell [0804: DATE and TIME, IRIG-B Sync.] must be set to **Enabled**.

Ensure the relay is receiving the IRIG-B signal by checking that cell [0805: DATE and TIME, IRIG-B Status] reads **Active**.

Once the IRIG-B signal is active, adjust the time offset of the universal coordinated time (satellite clock time) on the satellite clock equipment so that local time is displayed.

Check the time, date and month are correct in cell [0801: DATE and TIME, Date/Time]. The IRIG-B signal does not contain the current year so needs to be set manually in this cell.

If the auxiliary supply fails, with a battery fitted in the compartment behind the bottom access cover, the time and date is maintained. Therefore, when the auxiliary supply is restored, the time and date are correct and need not be set again.

To test this, remove the IRIG-B signal, then remove the auxiliary supply from the relay. Leave the relay de-energized for approximately 30 seconds. On re-energization, the time in cell [0801: DATE and TIME, Date/Time] should be correct. Then reconnect the IRIG-B signal.

5.2.3.2 Without an IRIG-B Signal

Note	*For P741 the IRIG-B signal may not apply to the Central Unit only. For the P742/P743 it may apply to the Peripheral Unit only.*

If the time and date is not being maintained by an IRIG-B signal, ensure that cell [0804: DATE and TIME, IRIG-B Sync.] is set to **Disabled**.

Set the date and time to the correct local time and date using cell [0801: DATE and TIME, Date/Time].

If the auxiliary supply fails, with a battery fitted in the compartment behind the bottom access cover, the time and date are maintained. Therefore when the auxiliary supply is restored, the time and date are correct and need not be set again.

To test this, remove the auxiliary supply from the relay for approximately 30 seconds. On re-energization, the time in cell [0801: DATE and TIME, Date/Time] should be correct.

5.2.4 Light Emitting Diodes (LEDs)

On power-up, the green LED should switch on and stay on, indicating that the relay is healthy. The relay has non-volatile memory which stores the state (on or off) of the alarm, trip and, if configured to latch, user-programmable LED indicators when the relay was last energized from an auxiliary supply. Therefore, these indicators may also switch on when the auxiliary supply is applied.

If any of these LEDs are on, reset them before proceeding with further testing. If the LED successfully resets (the LED switches off), there is no testing required for that LED because it is known to be operational.

Note	*It is likely that alarms related to the communications channels will not reset at this stage.*

5.2.4.1 Testing the Alarm and Out-Of-Service LEDs

The alarm and out of service LEDs can be tested using the **COMMISSIONING TESTS** menu column. Set cell [0F0D: COMMISSIONING TESTS, Test Mode] to **Contacts Blocked**. Check that the out of service LED is on continuously and the alarm LED flashes.

It is not necessary to return cell [0F0D: COMMISSIONING TESTS, Test Mode] to **Disabled** at this stage because the test mode will be required for later tests.

5.2.4.2 Testing the Trip LED

The trip LED can be tested by initiating a manual circuit breaker trip from the relay. However, the trip LED will operate during the setting checks performed later. Therefore, no further testing of the trip LED is required at this stage.

5.2.4.3 Testing the User-Programmable LEDs

To test the user-programmable LEDs set cell [0F10: COMMISSIONING TESTS, Test LEDs] to **Apply Test**. Check that all the programmable LEDs on the relay switch on.

5.2.5 Field Voltage Supply

The relay generates a field voltage of nominally 48 V that can be used to energize the opto-isolated inputs (alternatively the substation battery may be used).

Measure the field voltage across terminals 7 and 9 on the terminal block shown in the following table. Check that the field voltage is in the range 40 V to 60 V when no load is connected and that the polarity is correct.

Repeat for terminals 8 and 10

Supply Rail	Terminals	
	MiCOM P141/P142	MiCOM P143/P145
+ve	F7/F8	J7/J8
–ve	F9/F10	J9/J10

Table 6 - Field voltage terminals

5.2.6 Input Opto-Isolators

This test checks that all the opto-isolated inputs on the relay are functioning correctly.

Model	P141	P142	P143	P145
P14**x**xxxAxxxxxxJ	8 inputs	8 inputs	16 inputs	16 inputs
P14**x**xxxBxxxxxxJ		12 inputs	N/A	12 inputs
P14**x**xxxCxxxxxxJ		16 inputs	24 inputs	24 inputs
P14**x**xxxDxxxxxxJ		8 inputs	16 inputs	16 inputs
P14**x**xxxExxxxxxJ			24 inputs	24 inputs
P14**x**xxxFxxxxxxJ			32 inputs	32 inputs
P14**x**xxxGxxxxxxJ			16 inputs	16 inputs
P14**x**xxxHxxxxxxJ		8 inputs	16 inputs	12 inputs
P14**x**xxxJxxxxxJ			24 inputs	20 inputs
P14**x**xxxKxxxxxxJ			16 inputs	12 inputs
P14**x**xxxLxxxxxxJ			16 inputs	12 inputs

Table 7 - Opto-isolated inputs

Energize the opto-isolated inputs one at a time; see the external connection diagrams in the *Connection Diagrams* chapter for terminal numbers. Ensure that the correct opto input nominal voltage is set in the **Opto Config**. Menu. Ensure correct polarity and connect the field supply voltage to the appropriate terminals for the input being tested. Each opto input also has selectable filtering. This allows use of a pre-set filter of ½ cycle that renders the input immune to induced noise on the wiring.

Note	*The opto-isolated inputs may be energized from an external dc auxiliary supply (such as the station battery) in some installations. Check that this is not the case before connecting the field voltage, otherwise damage to the relay may result. If an external 24/27 V, 30/34 V, 48/54 V, 110/125 V, 220/250 V supply is being used it will be connected to the relay's optically isolated inputs directly. If an external supply is used it must be energized for this test, but only after confirming that it is suitably rated, with less than 12% ac ripple.*

The status of each opto-isolated input can be viewed using either cell [0020: SYSTEM DATA, Opto I/P Status] or [0F01: COMMISSIONING TESTS, Opto I/P Status], a **1** indicating an energized input and a **0** indicating a de-energized input. When each opto-isolated input is energized, one of the characters on the bottom line of the display changes, to indicate the new state of the inputs.

5.2.7 Output Relays

This test checks that all the output relays are functioning correctly.

Model	P141	P142	P143	P145
P14**x**xxxAxxxxxxJ	7 outputs	7 outputs	14 outputs	16 outputs
P14**x**xxxBxxxxxxJ		11 outputs	N/A	12 outputs
P14**x**xxxCxxxxxxJ		7 outputs	14 outputs	16 outputs
P14**x**xxxDxxxxxxJ		15 outputs	22 outputs	24 outputs
P14**x**xxxExxxxxxJ			22 outputs	24 outputs
P14**x**xxxFxxxxxxJ			14 outputs	16 outputs
P14**x**xxxGxxxxxxJ			30 outputs	32 outputs
P14**x**xxxHxxxxxxJ		7 + 4 High-Break output relays	14 + 4 High-Break output relays	12 + 4 High-Break output relays

Model	P141	P142	P143	P145
P14**x**xxxJxxxxxJ			14 + 4 High-Break output relays	12 + 4 High-Break output relays
P14**x**xxxKxxxxxxJ			22 + 4 High-Break output relays	20 + 4 High-Break output relays
P14**x**xxxLxxxxxxJ			14 + 8 High-Break output relays	12 + 8 High-Break output relays

Table 8 - Output relays

Ensure that the relay is still in test mode by viewing cell [0F0D: COMMISSION TESTS, Test Mode] to ensure that it is set to '**Blocked**'.

The output relays should be energized one at a time. To select output relay 1 for testing, set cell [0F0E: COMMISSION TESTS, Test Pattern] as appropriate.

Connect a continuity tester across the terminals corresponding to output relay 1 as given in external connection diagram (P14x/EN IN).

To operate the output relay set cell [0F0F: COMMISSION TESTS, Contact Test] to '**Apply Test**'. Operation will be confirmed by the continuity tester operating for a normally open contact and ceasing to operate for a normally closed contact. Measure the resistance of the contacts in the closed state.

Reset the output relay by setting cell [0F0F: COMMISSION TESTS, Contact Test] to '**Remove Test**'.

Note	*It should be ensured that thermal ratings of anything connected to the output relays during the contact test procedure are not exceeded by the associated output relay being operated for too long. It is therefore advised that the time between application and removal of the contact test is kept to the minimum.*

Repeat the test for all the relay outputs of the particular hardware model.

Return the relay to service by setting cell [0F0D: COMMISSION TESTS, Test Mode] to '**Disabled**'.

5.2.8 Rear Communications Port

This test should only be performed where the relay is to be accessed from a remote location and varies depending on the communications standard adopted.

It is not the intention of the test to verify the operation of the complete system from the relay to the remote location, just the relay's rear communications port and any protocol converter necessary.

A variety of communications protocols may be available. For further details, please see whichever of these sections are relevant for the device you are commissioning:

5.2.8.1 Courier Communications

If a K-Bus to EIA(RS)232 KITZ protocol converter is installed, connect a portable PC running the appropriate software (such as MiCOM S1 Studio or PAS&T) to the incoming (remote from relay) side of the protocol converter.

If a KITZ protocol converter is not installed, it may not be possible to connect the PC to the relay installed. In this case a KITZ protocol converter and portable PC running appropriate software should be temporarily connected to the relay’s first rear K-Bus port. The terminal numbers for the relay’s first rear K-Bus port are shown in the following table. However, as the installed protocol converter is not being used in the test, only the correct operation of the relay’s K-Bus port will be confirmed.

Connection		Terminal	
K-Bus	**IEC60870-5-103 or DNP3.0**	**P141/2/4**	**P143/P145**
Screen	Screen	F16	J16
1	+ve	F18	J18
2	–ve	F17	J17

Table 9 - EIA(RS)485 terminals

Ensure that the communications baud rate and parity settings in the application software are set the same as those on the protocol converter (usually a KITZ but could be a SCADA RTU). The relay’s Courier address in cell [0E02: COMMUNICATIONS, Remote Address] must be set to a value between 1 and 254.

Check that communications can be established with this relay using the portable PC.

If the relay has the optional fiber optic communications port fitted, the port to be used should be selected by setting cell [0E07: COMMUNICATIONS, Physical Link] to **Fiber Optic**. Ensure that the relay address and baud rate settings in the application software are set the same as those in cell [0E04 COMMUNICATIONS, Baud Rate] of the relay. Check, using the Master Station, that communications with the relay can be established.

5.2.8.2 IEC60870-5-103 (VDEW) Communications

If the relay has the optional fiber optic communications port fitted, the port to be used should be selected by setting cell [xxxx: COMMUNICATIONS, Physical Link] to **Fiber Optic** or **EIA(RS)485**.

- xxxx = 0E07 for P14x, P24x, P34x, P44y, P445, P54x, P547, P64x or P841
  xxxx = 0E09 for P44x

IEC60870-5-103/VDEW communication systems are designed to have a local Master Station and this should be used to verify that the relay’s rear fiber optic or EIA(RS)485 port, as appropriate, is working.

Ensure that the relay address and baud rate settings in the application software are set the same as those in cells [0E02: COMMUNICATIONS, Remote Address] and [0E04: COMMUNICATIONS, Baud Rate] of the relay.

Check, using the Master Station, that communications with the relay can be established.

5.2.8.3 DNP 3.0 Interface

Connect a portable PC running the appropriate DNP3.0 Master Station Software to the relay's first rear EIA(RS)485 port using an EIA(RS)485 to EIA(RS)232 interface converter. The terminal numbers for the relay's EIA(RS)485 port are shown in the *EIA(RS)485 terminals* table.

Ensure that the relay address, baud rate and parity settings in the application software are set the same as those in cells [0E02: COMMUNICATIONS, Remote address], [0E04: COMMUNICATIONS, Baud Rate] and [0E05: COMMUNICATIONS, Parity] of the relay.

Check that communications with this relay can be established.

If the relay has the optional fiber optic communications port fitted, the port to be used should be selected by setting cell [0E07: COMMUNICATIONS, Physical Link] to **Fiber Optic**. Ensure that the relay address and baud rate settings in the application software are set the same as those in cell [0E04: COMMUNICATIONS, Baud Rate] of the relay. Check that, using the Master Station, communications with the relay can be established.

5.2.8.4 MODBUS Communications

Connect a portable PC running the appropriate MODBUS Master Station software to the relay's first rear EIA(RS)485 port using an EIA(RS)485 to EIA(RS)232 interface converter. The terminal numbers for the relay's EIA(RS)485 port are shown in the *EIS(RS)485 terminals* table.

Ensure that the relay address, baud rate and parity settings in the application software are set the same as those in cells [xxxx: COMMUNICATIONS, Remote Address], [yyyy: COMMUNICATIONS, Baud Rate] and [zzzz: COMMUNICATIONS, Parity] of the relay.

- xxxx = 0E03 for P44x, 0E02 for P14x, P24x, P34x or P64x
- yyyy = 0E06 for P44x, 0E04 for P14x, P24x, P34x or P64x
- zzzz = 0E07 for P44x, 0E05 for P14x, P24x, P34x or P64x

Check that communications with this relay can be established.

5.2.9 Second Rear Communications Port

This test should only be performed where the relay is to be accessed from a remote location and varies depending on the communications standard being adopted.

It is not the intention of the test to verify the operation of the complete system from the relay to the remote location, just the relay's rear communications port and any protocol converter necessary.

A variety of communications protocols may be available. For further details, please see whichever of these sections are relevant for the device you are commissioning:

5.2.9.1 K-Bus Configuration

If a K-Bus to EIA(RS)232 KITZ protocol converter is installed, connect a portable PC running the appropriate software (MiCOM S1 Studio or PAS&T) to the incoming (remote from relay) side of the protocol converter.

If a KITZ protocol converter is not installed, it may not be possible to connect the PC to the relay installed. In this case a KITZ protocol converter and portable PC running appropriate software should be temporarily connected to the relay's second rear communications port configured for K-Bus. The terminal numbers for the relay's K-Bus port are shown in the following table. However, as the installed protocol converter is not being used in the test, only the correct operation of the relay's K-Bus port is confirmed.

Pin*	Connection
4	EIA(RS)485 - 1 (+ ve)
7	EIA(RS)485 - 2 (- ve)
* - All other pins unconnected.	

Table 10 - 2nd rear communications port K-Bus terminals

Ensure that the communications baud rate and parity settings in the application software are set the same as those on the protocol converter (usually a KITZ but could be a SCADA RTU). The relay's Courier address in cell [0E90: COMMUNICATIONS, RP2 Address] must be set to a value between 1 and 254. The second rear communication's port configuration [0E88: COMMUNICATIONS RP2 Port Config.] must be set to K-Bus.

Check that communications can be established with this relay using the portable PC.

5.2.9.2 EIA(RS)485 Configuration

If an EIA(RS)485 to EIA(RS)232 converter (Schneider Electric CK222) is installed, connect a portable PC running the appropriate software (MiCOM S1 Studio) to the EIA(RS)232 side of the converter and the second rear communications port of the relay to the EIA(RS)485 side of the converter.

The terminal numbers for the relay's EIA(RS)485 port are shown in the *Second rear communications port EIA(RS)232 terminals* table.

Ensure that the communications baud rate and parity settings in the application software are the same as those in the relay. The relay's Courier address in cell [0E90: COMMUNICATIONS, RP2 Address] must be set to a value between 1 and 254. The second rear communications port's configuration [0E88: COMMUNICATIONS RP2 Port Config.] must be set to EIA(RS)485.

Check that communications can be established with this relay using the portable PC.

5.2.9.3 EIA(RS)232 Configuration

Connect a portable PC running the appropriate software (MiCOM S1 Studio) to the rear EIA(RS)232 port of the relay. This port is actually compliant with EIA(RS)574; the 9-pin version of EIA(RS)232, see www.tiaonline.org.

The second rear communications port connects using the 9-way female D-type connector (SK4). The connection is compliant with EIA(RS)574.

Pin	Connection
1	No Connection
2	RxD
3	TxD
4	DTR#
5	Ground
6	No Connection
7	RTS#
8	CTS#
9	No Connection
# - These pins are control lines for use with a modem.	

Table 11 - Second rear communications port EIA(RS)232 terminals

Connections to the second rear port configured for EIA(RS)232 operation can be made using a screened multi-core communication cable up to 15 m long, or a total capacitance of 2500 pF. Terminate the cable at the relay end with a 9-way, metal-shelled, D-type male plug. The terminal numbers for the relay's EIA(RS)232 port are shown in the previous table.

Ensure that the communications baud rate and parity settings in the application software are set the same as those in the relay. The relay's Courier address in cell [0E90: COMMUNICATIONS, RP2 Address] must be set to a value between 1 and 254. The second rear communication's port configuration [0E88: COMMUNICATIONS RP2 Port Config] must be set to EIA(RS)232.

Check that communications can be established with this relay using the portable PC.

5.2.10 Current Inputs

This test verifies that the accuracy of current measurement is within acceptable tolerances.

All relays leave the factory set for operation at a system frequency of 50 Hz. If operation at 60 Hz is required, this must be set in cell [0009: SYSTEM DATA, Frequency].

Caution	To avoid spurious operation of protection elements during injection testing, ensure that current operated elements are disabled.

Apply current equal to the line current transformer secondary winding rating to each current transformer input of the corresponding rating in turn, checking its magnitude using a multimeter. Refer to the *Current input terminals* table for the corresponding reading in the relay's **MEASUREMENTS 1** columns, as appropriate, and record the value displayed.

The measured current values displayed on the relay LCD, or on a portable PC connected to the front communication port, are either in primary or secondary Amperes. If cell [0D02: MEASURE'T SETUP, Local Values] is set to **Primary**, the values displayed should be equal to the applied current multiplied by the corresponding current transformer ratio set in the **CT and VT RATIOS** menu column (see the *CT ratio settings* table). If cell [0D02: MEASURE'T SETUP, Local Values] is set to **Secondary**, the value displayed should be equal to the applied current.

Note	*In the case of a P841B (dual CT inputs), the "measured" value is taken from a combination of the two sets of CTs connected. The check should be performed by first injecting only into the CTs associated with CB1 (IA, IB, IC) and checking the measured IA, IB, and IC values, and then by injecting only into the CTs associated with CB2 (IA2, IB2, IC2) and checking the measured IA, IB, and IC values.*

Note	*If a PC connected to the relay's rear communications port is used to display the measured current, the process is similar. However, the setting of cell [0D03: MEASURE'T SETUP, Remote Values] determines whether the displayed values are in primary or secondary Amperes.*

The measurement accuracy of the relay is ±1% (5% for P746). However, an additional allowance must be made for the accuracy of the test equipment being used.

Cell in MEASUREMENTS 1 column (02)	Corresponding CT Ratio (in 'CT and VT RATIOS' column(0A) of menu)
[0201: IA Magnitude] [0203: IB Magnitude] [0205: IC Magnitude]	[0A07 : Phase CT Primary] [0A08 : Phase CT Secondary]
[0232: IN Measured Magnitude]	[0A07 : E/F CT Primary] [0A08 : E/F CT Secondary]
[0232: ISEF Magnitude]	[0A07 : SEF CT Primary] [0A08 : SEF CT Secondary]

Table 12 - CT ratio settings

5.2.11 Voltage Inputs

This test verifies that the accuracy of voltage measurement is within the acceptable tolerances.

For the P24x: Three modes of connection are available on the P24x relay: either 3VTs connection, or 2VTs plus residual VT connection or 2VTs plus remanent voltage VT connection (see the Connection Diagrams for detailed information).

The following tests will be realized with the VT Connecting Mode set to 3 VT which is the most used configuration.

Apply rated voltage to each voltage transformer input in turn, checking its magnitude using a multimeter. Refer to the *Voltage Input Terminals* table for the corresponding reading in the relay's **MEASUREMENTS 1** column and record the value displayed.

	Voltage Applied To
Cell in MEASUREMENTS 1 column	**MiCOM P14x**
[021A: VAN Magnitude]	C19 - C22
[021C: VBN Magnitude]	C20 - C22
[021E: VCN Magnitude]	C21 - C22
[022E: C/S Voltage Mag.] [P143]	C23 - C24
[0222: Voltage Mag.]	C23 - C24

Table 13 - Voltage input terminals

Note	*For P44x, this can be PGnd or PP reference with VT bus side or VT line (see Setting description in the Application Notes chapter).*

The measured voltage values displayed on the relay LCD or a portable PC connected to the front communication port are either in primary or secondary volts. If cell [0D02: MEASURE'T SETUP, Local Values] is set to **Primary**, the values displayed should be equal to the applied voltage multiplied by the corresponding voltage transformer ratio set in the **VT and CT RATIOS** menu column (see the following *VT ratio settings* table). If cell [0D02: MEASURE'T SETUP, Local Values] is set to **Secondary**, the value displayed should be equal to the applied voltage.

Note	*If a PC connected to the relay's rear communications port is used to display the measured voltage, the process is similar. However, the setting of cell [0D03: MEASURE'T SETUP, Remote Values] determines whether the displayed values are in primary or secondary volts.*

The measurement accuracy of the relay is ±1% (P44x is ±2%). However, an additional allowance must be made for the accuracy of the test equipment being used.

Cell in MEASUREMENTS 1 column (02)	Corresponding CT Ratio (in 'CT and VT RATIO' column(0A) of menu)
[021A: VAN Magnitude] [021C: VBN Magnitude] [021E: VCN Magnitude]	$\frac{\text{[0A01 : Main VT Primary]}}{\text{[0A02 : Main VT Secondary]}}$
[022E: C/S Voltage Mag.] (Applicable to P143/P145 models only)	$\frac{\text{[0A03 : C/S VT Primary]}}{\text{[0A04 : C/S VT Secondary]}}$

Table 14 - VT ratio settings

6 SETTING CHECKS

The setting checks ensure that all of the application-specific relay settings (both the relay's function and Programmable Scheme Logic (PSL) settings) for the particular installation have been correctly applied to the relay.

Caution	**The trip circuit should remain isolated during these checks to prevent accidental operation of the associated circuit breaker.**

Important	**If the application-specific settings are not available, ignore sections 6.1 and 6.2.**

Note	*The trip circuit should remain isolated during these checks to prevent accidental operation of the associated circuit breaker.*

6.1 Apply Application-Specific Settings

There are different methods of applying the settings:

- Transferring settings from a pre-prepared setting file to the relay using a portable PC running the appropriate software (such as MiCOM S1 Studio) use the front EIA(RS)232 port (under the bottom access cover), or the first rear communications port (Courier protocol with a KITZ protocol converter connected), or the second rear communications port. This is the preferred method for transferring function settings as it is much faster and there is less margin for error. If PSL other than the default settings with which the relay is supplied is used, this is the only way of changing the settings.
- If a setting file has been created for the particular application and provided on a memory device, the commissioning time is further reduced, especially if application-specific PSL is applied to the relay.

Enter the settings manually using the relay's operator interface. This method is not suitable for changing the PSL.

Caution	**When the installation needs application-specific Programmable Scheme Logic (PSL), it is essential that the appropriate .psl file is downloaded (sent) to the relay, for each setting group that will be used. If the user fails to download the required .psl file to any setting group that may be brought into service, the factory default PSL will still be resident. This may have severe operational and safety consequences.**

6.2 Demonstrate Correct Relay Operation

Tests 5.2.9 and 5.2.10 have already demonstrated that the relay is within calibration, thus the purpose of these tests is as follows:

- To determine that the primary protection functions of the relay, overcurrent, earth-fault etc. can trip according to the correct application settings.

- To verify correct assignment of the trip contacts, by monitoring the response to a selection of fault injections.

6.2.1 Overcurrent Protection Testing

This test, performed on stage 1 of the overcurrent protection function in setting group 1, demonstrates that the relay is operating correctly at the application-specific settings.

It is not considered necessary to check the boundaries of operation where cell [3502: GROUP 1 OVERCURRENT, I>1 Direction] is set to '**Directional Fwd**' or '**Directional Rev.**' as tests detailed already confirm the correct functionality between current and voltage inputs, processor and outputs and earlier checks confirmed the measurement accuracy is within the stated tolerance.

6.2.1.1 Connection and Preliminaries

Determine which output relay has been selected to operate when an I>1 trip occurs by viewing the relay's programmable scheme logic.

The programmable scheme logic can only be changed using the appropriate software. If this software has not been available then the default output relay allocations will still be applicable.

If the trip outputs are phase-segregated (i.e. a different output relay allocated for each phase), the relay assigned for tripping on '**A**' phase faults should be used.

If stage 1 is not mapped directly to an output relay in the programmable scheme logic, output relay 3 should be used for the test as it operates for any trip condition.

The associated terminal numbers can be found from the external connection diagram (P14x/EN IN).

Connect the output relay so that its operation will trip the test set and stop the timer.

Connect the current output of the test set to the '**A**' phase current transformer input of the relay (terminals C3 and C2 where 1A current transformers are being used and terminals C1 and C2 for 5A current transformers).

If [3502: GROUP 1 OVERCURRENT, I>1 Direction] is set to '**Directional Fwd**', the current should flow out of terminal C2 but into C2 if set to '**Directional Rev**'.

If cell [351D: GROUP 1 OVERCURRENT, VCO Status] is set to '**Enabled**' (overcurrent function configured for voltage controlled overcurrent operation) or [3502: GROUP 1 OVERCURRENT, I>1 Direction] has been set to '**Directional Fwd**' or '**Directional Rev**' then rated voltage should be applied to terminals C20 and C21.

Ensure that the timer will start when the current is applied to the relay.

Note	*If the timer does not start when the current is applied and stage 1 has been set for directional operation, the connections may be incorrect for the direction of operation set. Try again with the current connections reversed.*

6.2.1.2 Perform the Test

Ensure that the timer is reset.

Apply a current of twice the setting in cell [3503: GROUP 1 OVERCURRENT, I>1 Current Set] to the relay and note the time displayed when the timer stops.

Check that the red trip LED has illuminated. The display will show Alarms/Faults present and the Alarm and Trip LEDs will illuminate. To view the alarm message press the read key, repeat presses of this key should be used to verify that phase A was the "**Start**

Element”. Keep pressing the key until the yellow alarm LED changes from flashing to being steadily on. At the prompt ‘**Press clear to reset alarms**’, press the ‘**C**’ key. This will clear the fault record from the display.

6.2.1.3 Check the Operating Time

Check that the operating time recorded by the timer is within the range shown in Table 15.

Note	*Except for the definite time characteristic, the operating times given in Table 12 are for a time multiplier or time dial setting of 1. Therefore, to obtain the operating time at other time multiplier or time dial settings, the time given in Table 12 must be multiplied by the setting of cell [3505: GROUP 1 OVERCURRENT, I>1 TMS] for IEC and UK characteristics or cell [3506: GROUP 1 OVERCURRENT, Time Dial] for IEEE and US characteristics.* *In addition, for definite time and inverse characteristics there is an additional delay of up to 0.02 second and 0.08 second respectively that may need to be added to the relay’s acceptable range of operating times.* *For all characteristics, allowance must be made for the accuracy of the test equipment being used.*

Characteristic	Operating Time at Twice Current Setting and Time Multiplier/Time Dial Setting of 1.0	
	Nominal (Seconds)	Range (Seconds)
DT	[3504: I>1 Time Delay] Setting	Setting ±5%
IEC S Inverse	10.03	9.53 - 0.53
IEC V Inverse	13.50	12.83 - 14.18
IEC E Inverse	26.67	24.67 - 28.67
UK LT Inverse	120.00	114.00 - 126.00
IEEE M Inverse	3.8	3.61 - 3.99
IEEE V Inverse	7.03	6.68 - 7.38
IEEE E Inverse	9.52	9.04 - 10
US Inverse	2.16	2.05 - 2.27
US ST Inverse	12.12	11.51 - 12.73

Table 15 - Characteristic operating times for I>1

Reconfigure to test a B phase fault. Repeat the test in section 6.2.1.2, this time ensuring that the breaker trip contacts relative to B phase operation close correctly. Record the phase B trip time. Repeat for C phase fault. Switch OFF the ac supply and reset the alarms.

6.3 Signaling Channel Check

6.3.1 EIA(RS)232 InterMiCOM Communications

6.3.1.1 InterMiCOM Loopback Testing & Diagnostics

The “**Loopback**” test facilities, located within the [15 INTERMICOM COMMS] column of the relay menu, provide a user with the ability to check the software and hardware of the InterMiCOM signaling. If ‘**INTERMICOM COMMS**’ column is not visible, check that [0490 InterMiCOM] is enabled in the [09 CONFIGURATION] column.

Note	*By selecting the [1550 Loopback Mode] to "**Internal**", only the internal software of the relay is checked whereas "**External**" will check both the software and hardware used by InterMiCOM. When relay is switched into either '**Loopback Mode**' the relay will automatically use generic addresses and will inhibit the InterMiCOM messages to the PSL by setting all eight InterMiCOM message states to zero.*

Set '**External**' and connect the transmit and receive pins together (pins 2 and 3) and ensure that the DCD signal is held high (connect pin 1 and pin 4 together) as shown in Figure 3 below. The loopback mode will be indicated on the relay frontplate by the amber Alarm LED being illuminated and a LCD alarm message, "**IM Loopback**".

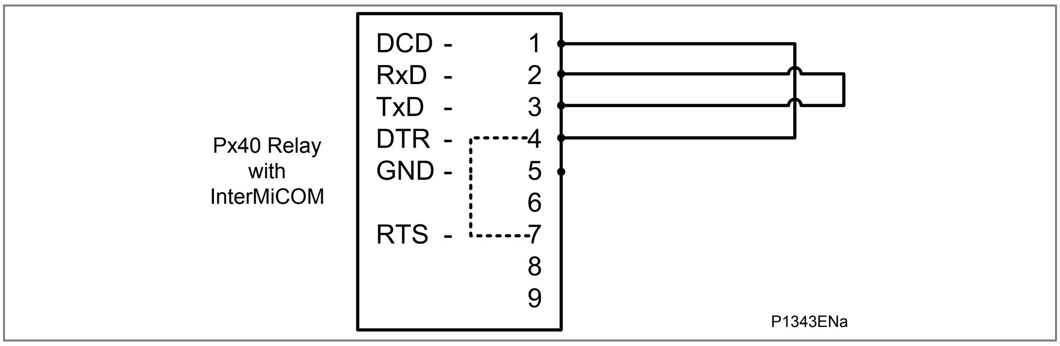

Figure 3 - Connections for external loopback mode

Providing all connections are correct and the software is working correctly, observe that the [1552 Loopback Status] cell that is located within the INTERMICOM COMMS displays "**OK**". Set [1540 Ch Diagnostics] within INTERMICOM COMMS to "**Visible**".

To test the InterMiCOM enter any test pattern in the [1551 Test Pattern] cell by scrolling and changing selected bits between "**1**" and "**0**". The entered pattern will be transmitted through the software and/or hardware. Check that the [1502 IM Output Status] cell matches with the applied '**Test Pattern**'. Also check that all 8 bits in the [1501 IM Input Status] cell are zero.

Check that the Channel Diagnostics status is displaying:

[1541 Data CD Status]	OK
[1542 FrameSync Status]	OK
[1543 Message Status]	OK
[1544 Channel Status]	OK
[1545 IM H/W Status]	OK

To simulate a hardware error, disconnect pin 1. The [1541 Data CD Status] will indicate "**FAIL**". Restore pin 1 connection. Observe that status reverts to "**OK**". To simulate a channel failure, disconnect the link between pins 2 and 3. The [1542 FrameSync Status], [1543 Message Status] and [1544 Channel Status] will all display "**FAIL**".

Note	*[1545 IM H/W Status] cell will remain '**OK**'. If displaying "**Absent**", it means that the rear communications card that includes EIA(RS)232 InterMiCOM is either not fitted or has failed to initialize.*

Alternatively set [0F13 Test Loopback] cell to '**Internal**' and repeat the '**Test Pattern**' test as described above. In this mode it is not necessary to make wiring changes.

6.3.1.2 Loopback Removal and Establishing Service Condition

Once the above loopback tests are completed, switch the InterMiCOM channel back in to service by setting the [1550 Loopback Mode] to “**Disabled**” and restoring the Tx and Rx connections.

The following checks can be made if the remote end is actively communicating, if this is not the case then a comprehensive test cannot be performed until the two ended system is established.

Observe that the amber Alarm LED and a LCD alarm message, “**IM Loopback**” are not present. Check that the [1502 IM Output Status] cell pattern at the local relay matches with the [1501 IM Input Status] at the remote end and vice versa.

Further checks will be necessary to ensure that the communications between the two relays in the scheme are reliable. To facilitate this, set the [1520 Ch Statistics] cell “**Visible**” and view a list of channel statistics and diagnostics available in the ‘**INTERMiCOM COMMS**’ column. The Rx count for Direct, Permissive and Blocking signals (subject to setting) will rise rapidly in proportion to Baud rate setting, whilst the Rx count for “**NewData**” and “**Errored**” and the percentage of “**Lost Messages**” must remain close to zero. Also, all status indications (see above) must display “**OK**”. That would mean that the comms are of a good quality and that the EIA(RS)232 InterMiCOM has been successfully put back in service. Record all statistics in the Commissioning Test Record provided below.

6.4 Check Trip and Auto-Reclose Cycle

If the auto-reclose function is being used, the circuit breaker trip and auto-reclose cycle can be tested automatically at the application-specific settings.

To test the first three-phase auto-reclose cycle, set cell [0F11: COMMISSION TESTS, Test Auto-reclose] to ‘**3 Pole Test**’. The relay will perform a trip/reclose cycle. Repeat this operation to test the subsequent three-phase auto-reclose cycles.

Check all output relays used for circuit breaker tripping and closing, blocking other devices, etc. operate at the correct times during the trip/close cycle.

6.5 Disable All Commissioning Testing Options

Ensure that all Test Mode, and Static Test options have been **disabled**. Clear, then re-read any alarms present to be certain that no alarms relating to these test options remain.

6.6 Check Application Settings

Carefully check applied settings against the required application-specific settings to ensure they have been entered correctly. However, this is not considered essential if a customer-prepared setting file on a memory device has been transferred to the relay using a portable PC.

There are two methods of checking the settings:

- Extract the settings from the relay using a portable PC running the appropriate software (MiCOM S1 Studio) using the front EIA(RS)232 port, under the bottom access cover, or the first rear communications port (Courier protocol with a KITZ protocol converter connected), or the second rear communications port. Compare the settings transferred from the relay with the original written application-specific setting record (for cases where the customer has only provided a printed copy of the required settings but a portable PC is available).
- Step through the settings using the relay's operator interface and compare them with the original application-specific setting record.

Unless previously agreed to the contrary, the application-specific PSL is not checked as part of the commissioning tests.

Due to the versatility and possible complexity of the PSL, it is beyond the scope of these commissioning instructions to detail suitable test procedures. Therefore, when PSL tests must be performed, written tests that satisfactorily demonstrate the correct operation of the application-specific scheme logic should be devised by the engineer who created it. These tests should be provided to the Commissioning Engineer with the memory device containing the PSL setting file.

There are now a series of checks which may need to be made if certain features are being used. Refer to the following sections:

- 7 - On-Load Checks

7 ON-LOAD CHECKS

The objectives of the on-load checks are to:

- Confirm the external wiring to the current and voltage inputs is correct.
- Measure the magnitude of capacitive current
- Ensure the on-load differential current is well below the relay setting
- Check the polarity of the line current transformers at each end is consistent.
- Directionality check for directional elements.

Caution	**Remove all test leads and temporary shorting leads, and replace any external wiring that was removed to allow testing.**

Caution	**If any of the external wiring was disconnected from the relay to run any tests, make sure that all connections are restored according to the external connection or scheme diagram.**

The following on-load measuring checks ensure the external wiring to the current and voltage inputs is correct but can only be carried out if there are no restrictions preventing the energisation of the plant being protected.

7.1 Confirm Current and Voltage Transformer Wiring

7.1.1 Voltage Connections

Caution	**Using a multimeter, measure the voltage transformer secondary voltages to ensure they are correctly rated. Check that the system phase rotation is correct using a phase rotation meter.**

Compare the values of the secondary phase voltages with the relay’s measured values, which can be found in the **MEASUREMENTS 1** menu column.

If cell [0D02: MEASURE’T SETUP, Local Values] is set to **Secondary**, the values displayed on the relay LCD or a portable PC connected to the front EIA(RS)232 communication port should be equal to the applied secondary voltage. The values should be within 1% of the applied secondary voltages/currents (5% for P74x). However, an additional allowance must be made for the accuracy of the test equipment being used.

If cell [0D02: MEASURE’T SETUP, Local Values] is set to **Primary**, the values displayed should be equal to the applied secondary voltage multiplied the corresponding voltage transformer ratio set in the **CT & VT RATIOS** menu column (see the following table). Again, the values should be within 1% of the expected value (5% for P74x), plus an additional allowance for the accuracy of the test equipment being used.

VAB VBC VCA VAN VBN VCN	[0214: VAB Magnitude] [0216: VBC Magnitude] [0218: VCA Magnitude] [021A: VAN Magnitude] [021C: VBN Magnitude] [021E: VCN Magnitude]	[0A01 : Main VT Primary] [0A02 : Main VT Secondary]
VCHECKSYNC. (Applicable to P143/P145 only)	[022E: C/S Voltage Mag.]	[0A03 : C/S VT Primary] [0A04 : C/S VT Secondary]

Table 16 - Measured voltages and VT ratio settings

Caution	**If a single dedicated current transformer is used for the earth fault function, it is not possible to check the relay's measured values.**

7.1.2 Current Connections

Caution	**Measure the current transformer secondary values for each input using a multimeter connected in series with corresponding relay current input.**

Check that the current transformer polarities are correct by measuring the phase angle between the current and voltage, either against a phase meter already installed on site and known to be correct or by determining the direction of power flow by contacting the system control center.

Caution	**Ensure the current flowing in the neutral circuit of the current transformers is negligible.**

Compare the values of the secondary phase currents (and any phase angle) with the relay's measured values, which can be found in the **MEASUREMENTS 1** menu column.

Note	*Under normal load conditions the earth fault function measures little or no current. It is therefore necessary to simulate a phase-to-neutral fault. This can be achieved by temporarily disconnecting one or two of the line current transformer connections to the relay and shorting the terminals of these current transformer secondary windings.*

If cell [0D02: MEASURE'T SETUP, Local Values] is set to **Secondary**, the current displayed on the relay LCD or a portable PC connected to the front EIA(RS)232 communication port should be equal to the applied secondary current. The values should be within 1% (5% for the P746) of the applied secondary currents. However, an additional allowance must be made for the accuracy of the test equipment being used.

If cell [0D02: MEASURE'T SETUP, Local Values] is set to **Primary**, the current displayed should be equal to the applied secondary current multiplied by the corresponding current transformer ratio set in the **CT & VT RATIOS** menu column (see the *Measured Voltages and VT Ratio Settings* table). Again the values should be within 10% (5% for the P746) of the expected value, plus an additional allowance for the accuracy of the test equipment being used.

Note	If the relay is applied with a single dedicated current transformer for the earth fault function, it may not be possible to check the relay's measured values as the neutral current will be almost zero.

7.2 On Load Directional Test

This test is important to ensure that directionalized overcurrent and fault locator functions have the correct forward/reverse response to fault and load conditions.

Firstly the actual direction of power flow on the system must be ascertained, using adjacent instrumentation or protection already in-service, or a knowledge of the prevailing network operation conditions.

- For load current flowing in the Forward direction - i.e. power export to the remote line end, cell [0301: MEASUREMENTS 2, A Phase Watts] should show **positive** power signing
- For load current flowing in the Reverse direction - i.e. power import from the remote line end, cell [0301: MEASUREMENTS 2, A Phase Watts] should show **negative** power signing

Note	The check above applies only for Measurement Modes 0 (default), and 2. This should be checked in [0D05: MEASURE'T. SETUP, Measurement Mode = 0 or 2]. If measurement modes 1 or 3 are used, the expected power flow signing would be opposite to that shown in the bullets above.

In the event of any uncertainty, check the phase angle of the phase currents with respect to their phase voltage.

8 FINAL CHECKS

The tests are now complete.

Caution	**Remove all test or temporary shorting leads. If it has been necessary to disconnect any of the external wiring from the relay to perform the wiring verification tests, make sure all connections are replaced according to the relevant external connection or scheme diagram.**

Ensure that the relay is restored to service by checking that cell [0F0F: COMMISSIONING TESTS, Test Mode] is set to **Disabled**. (0F0D (not 0F0F) for P14x/P24x/P44y/P54x/P841).

For P14x, P44x, P445, P54x or P547, if the relay is in a new installation or the circuit breaker has just been maintained, the circuit breaker maintenance and current counters should be zero. These counters can be reset using cell [xxxx: CB CONDITION, Reset All Values]. If the required access level is not active, the relay will prompt for a password to be entered so that the setting change can be made. (xxxx = 0609 for P14x, P44y or P54x, xxx = 0606 for P24x, xxxx = 0608 for P44x)

If the menu language was changed to allow accurate testing, it should now be restored to the customer's preferred language.

If a P991/MMLG test block is installed, remove the P992/MMLB01 test plug and replace the MMLG cover so that the protection is put into service.

Ensure that all event records, fault records, disturbance records, alarms and LEDs have been reset before leaving the relay.

If applicable, replace the secondary front cover on the relay.

TEST AND SETTING RECORDS

CHAPTER NO 13

Date:	10/2014
Products covered by this chapter:	This chapter covers the specific versions of the MiCOM products listed below. This includes ***only*** the following combinations of Software Version and Hardware Suffix.
Hardware Suffix:	L (P141, P142 & P143) & M (P145)
Software Version:	A0 - P14x (P141, P142, P143 & P145)
Connection Diagrams:	10P141xx (xx = 01 to 07) 10P142xx (xx = 01 to 07) 10P143xx (xx = 01 to 07) 10P145xx (xx = 01 to 07)

CONTENTS

Notes:

1 COMMISSIONING TEST RECORD

1.1 About this Chapter

The Commissioning chapter provides instructions on how to commission the relay – including how to calibrate the it and how to establish that it is functioning as intended.

This chapter provides you with a series of templates. You can use this to record the tests which have been made and the settings which have been used. You should use this chapter in conjunction with the Commissioning chapter and any work instructions you have as to what functionality and settings the relay should use.

1.2 Date Record

Date:		Engineer:	
Station:		Circuit:	
		System Frequency:	……… Hz
VT Ratio:	……… / ……… V	CT Ratio (tap in use):	……… /A

1.3 Front Plate Information

Feeder protection relay	MiCOM P…………
Model number	
Serial number	
Rated current In	1 A or 5 A
Rated voltage Vn	
Auxiliary voltage Vx	

1.4 Test Equipment Used

This section should be completed to allow future identification of protective devices that have been commissioned using equipment that is later found to be defective or incompatible but may not be detected during the commissioning procedure.

Injection test set	Model: Serial No:	
Phase angle meter	Model: Serial No:	
Phase rotation meter	Model: Serial No:	
Insulation tester	Model: Serial No:	
Setting software:	Type: Version:	

		*Delete as appropriate
	Have all relevant safety instructions been followed?	Yes or No

Note *The numbers in **bold** on the left-hand side represent the relevant Section of the Commissioning chapter.*

5.	**Product Checks**	
5.1	**With the relay de-energized**	
5.1.1	Visual inspection	
	Relay damaged?	Yes or No
	Rating information correct for installation?	Yes or No
	Case earth installed?	Yes or No
5.1.2	Current transformer shorting contacts close?	Yes or No or Not checked
5.1.3	Insulation resistance >100MΩ at 500V dc	Yes or No or Not Tested
5.1.4	External wiring	
	Wiring checked against diagram?	Yes or No
	Test block connections checked?	Yes or No or Not tested
5.1.5	Watchdog contacts (auxiliary supply off)	
	Terminals 11 and 12 Contact closed?	Yes or No
	Terminals 13 and 14 Contact open?	Yes or No
5.1.6	Measured auxiliary supply	……………. V ac/dc*
5.2	**With the relay energized**	
5.2.1	Watchdog contacts (auxiliary supply on)	
	Terminals 11 and 12 Contact open?	Yes or No
	Terminals 13 and 14 Contact closed?	Yes or No
5.2.2	LCD front panel display	
	LCD contrast setting used	
5.2.3	Date and time	
	Clock set to local time?	Yes or No
	Time maintained when auxiliary supply removed?	Yes or No
5.2.4	Light emitting diodes	
	Alarm (yellow) LED working?	Yes or No
	Out of service (yellow) LED working?	Yes or No
5.2.4	All 18 programmable LEDs working?	Yes or No
5.2.5	Field supply voltage	
	Value measured between terminals 8 and 9	……………. V dc

5.2.6 Input opto-isolators

Opto input 1 working?	Yes or No
Opto input 2 working?	Yes or No
Opto input 3 working?	Yes or No
Opto input 4 working?	Yes or No
Opto input 5 working?	Yes or No
Opto input 6 working?	Yes or No
Opto input 7 working?	Yes or No
Opto input 8 working?	Yes or No
Opto input 9 working?	Yes or No
Opto input 10 working?	Yes or No
Opto input 11 working?	Yes or No
Opto input 12 working?	Yes or No
Opto input 13 working?	Yes or No or N/A
Opto input 14 working?	Yes or No or N/A
Opto input 15 working?	Yes or No or N/A
Opto input 16 working?	Yes or No or N/A
Opto input 17 working?	Yes or No or N/A
Opto input 18 working?	Yes or No or N/A
Opto input 19 working?	Yes or No or N/A
Opto input 20 working?	Yes or No or N/A
Opto input 21 working?	Yes or No or N/A
Opto input 22 working?	Yes or No or N/A
Opto input 23 working?	Yes or No or N/A
Opto input 24 working?	Yes or No or N/A
Opto input 25 working?	Yes or No or N/A
Opto input 26 working?	Yes or No or N/A
Opto input 27 working?	Yes or No or N/A
Opto input 28 working?	Yes or No or N/A
Opto input 29 working?	Yes or No or N/A
Opto input 30 working?	Yes or No or N/A
Opto input 31 working?	Yes or No or N/A
Opto input 32 working?	Yes or No or N/A

5.2.7 Output relays

Relay 1 working?	Yes or No
Relay 2 working?	Yes or No
Relay 3 working?	Yes or No
Relay 4 working?	Yes or No
Relay 5 working?	Yes or No
Relay 6 working?	Yes or No
Relay 7 working?	Yes or No
Relay 8 working?	Yes or No
Relay 9 working?	Yes or No
Relay 10 working?	Yes or No

Relay 11	working?	Yes or No
Relay 12	working?	Yes or No
Relay 13	working?	Yes or No or N/A
Relay 14	working?	Yes or No or N/A
Relay 15	working?	Yes or No or N/A
Relay 16	working?	Yes or No or N/A
Relay 17	working?	Yes or No or N/A
Relay 18	working?	Yes or No or N/A
Relay 19	working?	Yes or No or N/A
Relay 20	working?	Yes or No or N/A
Relay 21	working?	Yes or No or N/A
Relay 22	working?	Yes or No or N/A
Relay 23	working?	Yes or No or N/A
Relay 24	working?	Yes or No or N/A
Relay 25	working?	Yes or No or N/A
Relay 26	working?	Yes or No or N/A
Relay 27	working?	Yes or No or N/A
Relay 28	working?	Yes or No or N/A
Relay 29	working?	Yes or No or N/A
Relay 30	working?	Yes or No or N/A
Relay 31	working?	Yes or No or N/A
Relay 32	working?	Yes or No or N/A

5.2.8	Communication standard	Courier or MODBUS or IEC60870-5-103 or DNP3.0 or IEC 61850
	Communications established?	Yes or No
	Protocol converter tested?	Yes or No or N/A

5.2.9 Current inputs

Displayed current	Primary or Secondary
Phase CT ratio	……… N/A
Earth fault CT ratio	……… N/A
SEF CT ratio	……… N/A

Input CT	Applied Value	Displayed Value
IA	……… A	……… A
IB	……… A	……… A
IC	……… A	……… A
IN	……… A ……… N/A	……… A ……… N/A
IN Sensitive/ISEF	……… A	……… A

5.2.10 Voltage inputs

Displayed voltage			Primary or Secondary
Main VT ratio			……… N/A
C/S VT ratio			……… N/A
Input VT	Applied Value		Displayed value
VAN	……… V		……… V
VBN	……… V		……… V
VCN	……… V		……… V
C/S voltage	……… V	……… N/A	……… V
V/N Measured	……… V	……… N/A	……… V

6. Setting Checks

6.1	Application-specific function settings applied?	Yes or No
	Application-specific programmable scheme logic settings applied?	Yes or No or N/A
6.2	Protection function timing tested?	Yes or No
	Overcurrent type(set in cell [I>1 Direction])	Directional or Non-Directional
	Applied voltage	……… V / N/A*
	Applied current	……… A
	Expected operating time	……… s
	Measured operating time	……… s
6.3	Trip and auto-reclose cycle checked	Yes or No or N/A
6.4	All commissioning test options disabled?	Yes or No
6.5	Application-specific function settings verified?	Yes or No or N/A
	Application-specific programmable scheme logic tested?	Yes or No or N/A

7. On-load checks

	Test wiring removed?	Yes or No
7.1.1	Voltage inputs and phase rotation OK?	Yes or No
7.1.2	Current inputs and polarities OK?	Yes or No
7.2	On-load test performed? (If “**No**”, give reason why) …	Yes or No
	Relay is correctly directionalized?	Yes or No or N/A

8. Final Checks

All test equipment, leads, shorts and test blocks removed safely?	Yes or No
Disturbed customer wiring re-checked?	Yes or No or N/A
All commissioning tests disabled?	Yes or No
Circuit breaker operations counter reset?	Yes or No or N/A
Current counters reset?	Yes or No or N/A
Event records reset?	Yes or No
Fault records reset?	Yes or No
Disturbance records reset?	Yes or No
Alarms reset?	Yes or No
LEDs reset?	Yes or No
Secondary front cover replaced?	Yes or No or N/A

COMMENTS #
(# Optional, for site observations or utility-specific notes).

Commissioning Engineer	Customer Witness
Date:	Date:

2 CREATING A SETTING RECORD

You often need to create a record of what settings have been applied to a device. In the past, you could have used paper printouts of all the available settings, and mark up the ones you had used. Keeping such a paper-based Settings Records can be time-consuming and prone to error (e.g. due to being settings written down incorrectly).

The MiCOM S1 Studio software lets you read from or write to MiCOM devices.

- **Extract** lets you download all the settings from a MiCOM Px40 device. A summary is given in Extract Settings from a MiCOM Px40 Device below.
- **Send** lets you send the settings you currently have open in MiCOM S1 Studio. A summary is given in Send Settings to a MiCOM Px40 Device below.

The MiCOM S1 Studio product is updated periodically. These updates provide support for new features (such as allowing you to manage new MiCOM products, as well as using new software releases and hardware suffixes). The updates may also include fixes. **Accordingly, we strongly advise customers to use the latest Schneider Electric version of MiCOM S1 Studio.**

In most cases, it will be quicker and less error prone to extract settings electronically and store them in a settings file on a memory stick. In this way, there will be a digital record which is certain to be accurate. It is also possible to archive these settings files in a repository; so they can be used again or adapted for another use.

Full details of how to do these tasks is provided in the MiCOM S1 Studio help.

A quick summary of the main steps is given below.

In each case you need to make sure that:

- Your computer includes the MiCOM S1 Studio software.
- Your computer and the MiCOM device are powered on.
- You have used a suitable cable to connect your computer to the MiCOM device (Front Port, Rear Port, Ethernet port or Modem as available).

2.1 Extract Settings from a MiCOM Px40 Device

Full details of how to do this is provided in the MiCOM S1 Studio help.

As a quick guide, you need to do the following:

1. In MiCOM S1 Studio, click the Quick Connect… button.
2. Select the relevant Device Type in the Quick Connect dialog box.
3. Click the relevant port in the Port Selection dialog box.
4. Enter the relevant connection parameters in the Connection Parameters dialog box and click the Finish button
5. MiCOM S1 Studio will try to communicate with the Px40 device. It will display a connected message if the connection attempt is successful.
6. The device will appear in the Studio Explorer pane on the top-left of the interface.
7. Click the + button to expand the options for the device, then click on the Settings folder.
8. Right-click on Settings and select the Extract Settings link to read the settings on the device and store them on your computer or a memory stick.
9. After retrieving the settings file, close the dialog box by clicking the Close button.

2.2 Send Settings to a MiCOM Px40 Device

Full details of how to do this is provided in the MiCOM S1 Studio help.

As a quick guide, you need to do the following:

1. In MiCOM S1 Studio, click the Quick Connect… button.
2. Select the relevant Device Type in the Quick Connect dialog box.
3. Click the relevant port in the Port Selection dialog box.
4. Enter the relevant connection parameters in the Connection Parameters dialog box and click the Finish button
5. MiCOM S1 Studio will try to communicate with the Px40 device. It will display a connected message if the connection attempt is successful.
6. The device will appear in the Studio Explorer pane on the top-left of the interface.
7. Click the + button to expand the options for the device, then click on the Settings folder.
8. Right-click on Settings and select the Extract Settings link to read the settings on the device and store them on your computer or a memory stick.
9. After retrieving the settings file, close the dialog box by clicking the Close button.

MAINTENANCE

CHAPTER 14

Date:	07/2014	
Products covered by this chapter:	P14x (P141, P142, P143, P144 & P145), P24x (P241, P242 & P243), P341, P34x (P342, P343, P344, P345 & P391), P445, P44x (P441/P442 & P444), P44y (P443 and P446), P547, P54x (P543, P544, P545 & P546), P64x (P642, P643 & P645), P74x (P741, P742 & P743), P746, P841, P842 and P849	
Hardware suffix:	P14x (P141, P142, P143, P144 & P145) J P241 J P242/P243 K P341 J P342 J P343/P344/P345 K P391 A P445 J P44x (P441/P442 & P444) J/K P44y (P443 and P446) K	P547 K P54x (P543, P544, P545 & P546) K P642 J/L P643 K/M P645 K/M P74x (P741, P742 & P743) J/K P746 K P841 K P842 B P849 K
Software version:	P14x (P141, P142, P143, P144 & P145) P24x (P241, P242 & P243): P341 P342, P343, P344, P345 & P391 P445 P44x (P441/P442 & P444) P44y (P443 and P446) P547 P54x (P543, P544, P545 & P546) P64x (P642, P643 & P645) P74x (P741, P742 & P743) P746 P841 P842 P849	43, 44 & 46 57 36 & 71 36 35 & 36 C7.x, D4.x, D5.x & D6.x 55 57 45 & 55 04, A0, B1 51, A0 & B1 A0 45 & 55 04 A0
Connection diagrams:	P14x (P141, P142, P143, P144 & P145): 10P141/2/3/4/5xx (xx = 01 to 07) P24x (P241, P242 & P243): 10P241xx (xx = 01 to 02) 10P24201 10P24301 P341: 10P341xx (xx = 01 to 12) P34x (P342, P343, P344, P345 & P391): 10P342xx (xx = 01 to 17) 10P343xx (xx = 01 to 19) 10P344xx (xx = 01 to 12) 10P345xx (xx = 01 to 07) 10P391xx (xx = 01 to 02) P445: 10P445xx (xx = 01 to 04) P44y: 10P44303/4/5/6 (SH 01 and 03) 10P44600 10P44601/2/3 (SH 1 to 2) P54x (P543, P544, P545 & P546): 10P54302/3xx (xx = 01 to 02) 10P54400 10P54402/3xx (xx = 01 to 02) 10P54502/3xx (xx = 01 to 02) 10P54600 10P54602/3xx (xx = 01 to 02) 10P54603xx (xx = 01 to 02)	P547: 10P54702/3/4/5xx (xx = 01 to 02) P64x (P642, P643 & P645): 10P642xx (xx = 01 to 10) 10P643xx (xx = 01 to 6) 10P644xx (xx = 01 to 9) P74x 10P740xx (xx = 01 to 07) P746: 10P746xx (xx 01 to 07) P841: 10P84100 10P841012/3/4/5 (SH 1 to 2) P842: 10P842xx (xx = 01 to 02) P849: 10P849xx (xx = 01 to 06)

CONTENTS

Notes:

1 MAINTENANCE PERIOD

Warning	**Before inspecting any wiring, performing any tests or carrying out any work on the equipment, you should be familiar with the contents of the Safety Information and Technical Data sections and the information on the equipment's rating label.**

It is recommended that products supplied by Schneider Electric receive periodic monitoring after installation. In view of the critical nature of protective and control equipment, and their infrequent operation, it is desirable to confirm that they are operating correctly at regular intervals.

Schneider Electric protection and control equipment is designed for a life in excess of 20 years.

MiCOM relays are self-supervizing and so require less maintenance than earlier designs. Most problems will result in an alarm so that remedial action can be taken. However, some periodic tests should be done to ensure that the equipment is functioning correctly and the external wiring is intact.

If the customer's organization has a preventative maintenance policy, the recommended product checks should be included in the regular program. Maintenance periods depend on many factors, such as:

- The operating environment
- The accessibility of the site
- The amount of available manpower
- The importance of the installation in the power system
- The consequences of failure

2 MAINTENANCE CHECKS

Although some functionality checks can be performed from a remote location by using the communications ability of the equipment, these are predominantly restricted to checking that the equipment, is measuring the applied currents and voltages accurately, and checking the circuit breaker maintenance counters. Therefore it is recommended that maintenance checks are performed locally (i.e. at the equipment itself).

Warning	**Before carrying out any work on the equipment, the user should be familiar with the contents of the Safety Guide or the Technical Data chapter of this Technical Manual and the information on the equipment's rating label.**

Warning	**If a P391 is used, you should also be familiar with the ratings and warning statements in the P391 technical manual.**

2.1 Alarms

The alarm status LED should first be checked to identify if any alarm conditions exist. If so, press the read key (⊕) repeatedly to step through the alarms.

Clear the alarms to extinguish the LED.

2.2 Opto-Isolators

The opto-isolated inputs can be checked to ensure that the equipment responds to energization by repeating the commissioning test detailed in the Commissioning chapter.

2.3 Output Relays

The output relays can be checked to ensure that they operate by repeating the commissioning test detailed in the Commissioning chapter.

2.4 Measurement Accuracy

If the power system is energized, the values measured by the equipment can be compared with known system values to check that they are in the approximate range that is expected. If they are, the analog/digital conversion and calculations are being performed correctly by the relay. Suitable test methods can be found in the Commissioning chapter.

Alternatively, the values measured by the equipment can be checked against known values injected via the test block, if fitted, or injected directly into the equipment terminals. Suitable test methods can be found in the Commissioning chapter. These tests will prove the calibration accuracy is being maintained.

3 METHOD OF REPAIR

If the equipment should develop a fault whilst in service, depending on the nature of the fault, the watchdog contacts will change state and an alarm condition will be flagged. Due to the extensive use of surface-mount components, faulty Printed Circuit Boards (PCBs) should be replaced, as it is not possible to perform repairs on damaged PCBs. Therefore either the complete equipment module or just the faulty PCB (as identified by the in-built diagnostic software), can be replaced. Advice about identifying the faulty PCB can be found in the Troubleshooting chapter.

The preferred method is to replace the complete equipment module as it ensures that the internal circuitry is protected against electrostatic discharge and physical damage at all times and overcomes the possibility of incompatibility between replacement PCBs. However, it may be difficult to remove installed equipment due to limited access in the back of the cubicle and the rigidity of the scheme wiring.

Replacing PCBs can reduce transport costs but requires clean, dry conditions on site and higher skills from the person performing the repair. If the repair is not performed by an approved service center, the warranty will be invalidated.

Warning	**Before carrying out any work on the equipment, the user should be familiar with the contents of the Safety Guide or the Technical Data chapter of this Technical Manual and also the information on the equipment's rating label.**

This should ensure that no damage is caused by incorrect handling of the electronic components.

3.1 Replacing the Complete Equipment IED/Relay

The case and rear terminal blocks have been designed to facilitate removal of the IED/relay should replacement or repair become necessary without having to disconnect the scheme wiring.

Warning	**Before working at the rear of the equipment, isolate all voltage and current supplies to the equipment.**

Note	*The MiCOM range has integral current transformer shorting switches which will close when the heavy duty terminal block is removed.*

1. Disconnect the equipment's earth, IRIG-B and fiber optic connections, as appropriate, from the rear of the device.

   There are two types of terminal block used on the equipment, medium and heavy duty, which are fastened to the rear panel using crosshead screws. The P64x range also includes an RTD/CLIO terminal block option. These block types are shown in the Commissioning chapter.

Important	*The use of a magnetic bladed screwdriver is recommended to minimize the risk of the screws being left in the terminal block or lost.*

2. Without exerting excessive force or damaging the scheme wiring, pull the terminal blocks away from their internal connectors.
3. Remove the screws used to fasten the equipment to the panel, rack, etc. These are the screws with the larger diameter heads that are accessible when the access covers are fitted and open.

Warning	**If the top and bottom access covers have been removed, do not remove the screws with the smaller diameter heads which are accessible. These screws secure the front panel to the equipment.**

4. Withdraw the equipment carefully from the panel, rack, etc. because it will be heavy due to the internal transformers.

To reinstall the repaired or replacement equipment, follow the above instructions in reverse, ensuring that each terminal block is relocated in the correct position and the case earth, IRIG-B and fiber optic connections are replaced. To facilitate easy identification of each terminal block, they are labeled alphabetically with 'A' on the left-hand side when viewed from the rear.

Once reinstallation is complete, the equipment should be re-commissioned using the instructions in the Commissioning chapter.

3.2 Replacing a PCB

Replacing PCBs and other internal components must be undertaken only by Service Centers approved by Schneider Electric. Failure to obtain the authorization of Schneider Electric after sales engineers prior to commencing work may invalidate the product warranty.

Warning	**Before removing the front panel to replace a PCB, remove the auxiliary supply and wait <u>at least 30 seconds</u> for the capacitors to discharge.** **We strongly recommend that the voltage and current transformer connections and trip circuit are isolated.**

Schneider Electric support teams are available world-wide. We strongly recommend that any repairs be entrusted to those trained personnel. For this reason, details on product disassembly and re-assembly are not included here.

4 RE-CALIBRATION

Re-calibration is not required when a PCB is replaced **unless it happens to be one of the boards in the input module;** the replacement of either directly affects the calibration.

Warning	**Although it is possible to carry out re-calibration on site, this requires test equipment with suitable accuracy and a special calibration program to run on a PC. It is therefore recommended that the work be carried out by the manufacturer, or entrusted to an approved service center.**

5 CHANGING THE BATTERY

Each relay/IED has a battery to maintain status data and the correct time when the auxiliary supply voltage fails. The data maintained includes event, fault and disturbance records and the thermal state at the time of failure.

This battery will periodically need changing, although an alarm will be given as part of the relay's/IED's continuous self-monitoring in the event of a low battery condition.

If the battery-backed facilities are not required to be maintained during an interruption of the auxiliary supply, the steps below can be followed to remove the battery, but do not replace with a new battery.

Warning	**Before carrying out any work on the equipment, the user should be familiar with the contents of the Safety Guide or the Technical Data chapter of this Technical Manual and also the information on the equipment's rating label.**

5.1 Instructions for Replacing the Battery

1. Open the bottom access cover on the front of the equipment.
2. Gently extract the battery from its socket. If necessary, use a small, insulated screwdriver to prize the battery free.
3. Ensure that the metal terminals in the battery socket are free from corrosion, grease and dust.
4. The replacement battery should be removed from its packaging and placed into the battery holder, taking care to ensure that the polarity markings on the battery agree with those adjacent to the socket.

Note	*Only use a type ½AA Lithium battery with a nominal voltage of 3.6 V and safety approvals such as UL (Underwriters Laboratory), CSA (Canadian Standards Association) or VDE (Vereinigung Deutscher Elektrizitätswerke).*

5. Ensure that the battery is securely held in its socket and that the battery terminals are making good contact with the metal terminals of the socket.
6. Close the bottom access cover.

5.2 Post Modification Tests

To ensure that the replacement battery will maintain the time and status data if the auxiliary supply fails, check cell [0806: DATE and TIME, Battery Status] reads 'Healthy'.

If further confirmation that the replacement battery is installed correctly is required, the commissioning test is described in the Commissioning chapter, 'Date and Time', can be performed.

5.3 Battery Disposal

The battery that has been removed should be disposed of in accordance with the disposal procedure for Lithium batteries in the country in which the equipment is installed.

6 CLEANING

Warning	**Before cleaning the equipment ensure that all ac and dc supplies, current transformer and voltage transformer connections are isolated to prevent any chance of an electric shock whilst cleaning.**

The equipment may be cleaned using a lint-free cloth moistened with clean water. The use of detergents, solvents or abrasive cleaners is not recommended as they may damage the relay's surface and leave a conductive residue.

TROUBLESHOOTING

CHAPTER 15

Date:	07/2014	
Products covered by this chapter:	P14x (P141, P142, P143, P144 & P145), P24x (P241, P242 & P243), P341, P34x (P342, P343, P344, P345 & P391), P445, P44x (P441/P442 & P444), P44y (P443 and P446), P547, P54x (P543, P544, P545 & P546), P64x (P642, P643 & P645), P74x (P741, P742 & P743), P746, P841, P842 and P849	
Hardware Suffix:	P14x (P141, P142, P143, P144 & P145) J P241 J P242/P243 K P341 J P342 J P343/P344/P345 K P391 A P445 J P44x (P441/P442 & P444) J/K P44y (P443 and P446) K	P547 K P54x (P543, P544, P545 & P546) K P642 J/L P643 K/M P645 K/M P74x (P741, P742 & P743) J/K P746 K P841 K P842 B P849 K
Software Version:	P14x (P141, P142, P143, P144 & P145) P24x (P241, P242 & P243): P341 P342, P343, P344, P345 & P391 P445 P44x (P441/P442 & P444) P44y (P443 and P446) P547 P54x (P543, P544, P545 & P546) P64x (P642, P643 & P645) P74x (P741, P742 & P743) P746 P841 P842 P849	43, 44 & 46 57 36 & 71 36 35 & 36 C7.x, D4.x, D5.x & D6.x 55 57 45 & 55 04, A0, B1 51, A0 & B1 A0 45 & 55 04 A0
Connection Diagrams:	P14x (P141, P142, P143, P144 & P145): 10P141/2/3/4/5xx (xx = 01 to 07) P24x (P241, P242 & P243): 10P241xx (xx = 01 to 02) 10P24201 10P24301 P341: 10P341xx (xx = 01 to 12) P34x (P342, P343, P344, P345 & P391): 10P342xx (xx = 01 to 17) 10P343xx (xx = 01 to 19) 10P344xx (xx = 01 to 12) 10P345xx (xx = 01 to 07) 10P391xx (xx = 01 to 02) P445: 10P445xx (xx = 01 to 04) P44y: 10P44303/4/5/6 (SH 01 and 03) 10P44600 10P44601/2/3 (SH 1 to 2) P54x (P543, P544, P545 & P546): 10P54302/3xx (xx = 01 to 02) 10P54400 10P54402/3xx (xx = 01 to 02) 10P54502/3xx (xx = 01 to 02) 10P54600 10P54602/3xx (xx = 01 to 02) 10P54603xx (xx = 01 to 02)	P547: 10P54702/3/4/5xx (xx = 01 to 02) P64x (P642, P643 & P645): 10P642xx (xx = 01 to 10) 10P643xx (xx = 01 to 6) 10P644xx (xx = 01 to 9) P74x 10P740xx (xx = 01 to 07) P746: 10P746xx (xx 01 to 07) P841: 10P84100 10P841012/3/4/5 (SH 1 to 2) P842: 10P842xx (xx = 01 to 02) P849: 10P849xx (xx = 01 to 06)

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TABLES

Notes:

1 INTRODUCTION

Warning **Before carrying out any work on the equipment, the user should be familiar with the contents of the Safety Guide or the Technical Data chapter of this Technical Manual and also the ratings on the equipment's rating label.**

The purpose of this chapter of the service manual is to allow an error condition on the relay to be identified so that appropriate corrective action can be taken.

If the relay has developed a fault, it should be possible in most cases to identify which relay module requires attention. The *Maintenance* chapter advises on the recommended method of repair where faulty modules need replacing. It is not possible to perform an on-site repair to a faulted module.

In cases where a faulty relay/module is being returned to the manufacturer or one of their approved service centers, completed copy of the Repair/Modification Return Authorization Form located at the end of this chapter should be included.

2 INITIAL PROBLEM IDENTIFICATION

Consult Table 1 to find the description that best matches the problem experienced, then consult the section referenced to perform a more detailed analysis of the problem.

Symptom	Refer To
Relay fails to power up	Section 3
Relay powers up - but indicates error and halts during power-up sequence	Section 4
Relay Powers up but Out of Service LED is illuminated	Section 5
Error during normal operation	Section 6
Mal-operation of the relay during testing	Section 7

Table 1 - Problem identification

3 POWER UP ERRORS

If the relay does not appear to power up then the following procedure can be used to determine whether the fault is in the external wiring, auxiliary fuse, power supply module of the relay or the relay front panel.

Test	Check	Action
1	Measure auxiliary voltage on terminals 1 and 2; verify voltage level and polarity against rating the label on front. Terminal 1 is –dc, 2 is +dc	If auxiliary voltage is present and correct, then proceed to test 2. Otherwise the wiring/fuses in auxiliary supply should be checked.
2	Do LEDs/and LCD backlight illuminate on power-up, also check the N/O watchdog contact for closing.	If they illuminate or the contact closes and no error code is displayed then error is probably in the main processor board (front panel). If they do not illuminate and the contact does not close then proceed to test 3.
3	Check Field voltage output (nominally 48V DC)	If field voltage is not present then the fault is probably in the relay power supply module.

Table 2 - Failure of relay to power up

4 ERROR MESSAGE/CODE ON POWER-UP

During the power-up sequence of the relay self-testing is performed as indicated by the messages displayed on the LCD. If an error is detected by the relay during these self-tests, an error message will be displayed and the power-up sequence will be halted. If the error occurs when the relay application software is executing, a maintenance record will be created and the relay will reboot.

Test	Check	Action
1	Is an error message or code permanently displayed during power up?	If relay locks up and displays an error code permanently then proceed to test 2. If the relay prompts for input by the user proceed to test 4. If the relay re-boots automatically then proceed to test 5.
2	Record displayed error, then remove and re-apply relay auxiliary supply.	Record whether the same error code is displayed when the relay is rebooted. If no error code is displayed then contact the local service center stating the error code and relay information. If the same code is displayed proceed to test 3.
3	Error code Identification Following text messages (in English) will be displayed if a fundamental problem is detected preventing the system from booting: Bus Fail address lines SRAM Fail data lines FLASH Fail format error FLASH Fail checksum Code Verify Fail These hex error codes relate to errors detected in specific relay modules:	These messages indicate that a problem has been detected on the main processor board of the relay (located in the front panel).
	0c140005/0c0d0000	Input Module (inc. Opto-isolated inputs)
	0c140006/0c0e0000	Output Relay Cards
	Last 4 digits provide details on the actual error.	Other error codes relate to problems within the main processor board hardware or software. It will be necessary to contact Schneider Electric with details of the problem for a full analysis.
4	Relay displays message for corrupt settings and prompts for restoration of defaults to the affected settings.	The power up tests have detected corrupted relay settings, it is possible to restore defaults to allow the power-up to be completed. It will then be necessary to re-apply the application-specific settings.
5	Relay resets on completion of power up - record error code displayed	Error 0x0E080000, Programmable Scheme Logic (PSL) error due to excessive execution time. Restore default settings by performing a power up with and keys depressed, confirm restoration of defaults at prompt using () key. If relay powers up successfully, check PSL for feedback paths. Other error codes will relate to software errors on the main processor board, contact Schneider Electric.

Table 3 - Power-up self-test error

5 OUT OF SERVICE LED ILLUMINATED ON POWER UP

Test	Check	Action	
1	Using the relay menu confirm whether the Commission Test/Test Mode setting is Enabled. Otherwise proceed to test 2.	If the setting is Enabled then disable the test mode and, verify that the Out of Service LED is extinguished.	
2	Select and view the last maintenance record from the menu (in the View Records).	Check for H/W Verify Fail this indicates a discrepancy between the relay model number and the hardware; examine the “**Maint. Data**”, this indicates the causes of the failure using bit fields:	
		Bit	**Meaning**
		0	The application type field in the model number does not match the software ID
		1	The application field in the model number does not match the software ID
		2	The variant 1 field in the model number does not match the software ID
		3	The variant 2 field in the model number does not match the software ID
		4	The protocol field in the model number does not match the software ID
		5	The language field in the model number does not match the software ID
		6	The VT type field in the model number is incorrect (110V VTs fitted)
		7	The VT type field in the model number is incorrect (440V VTs fitted)
		8	The VT type field in the model number is incorrect (no VTs fitted)

Table 4 - Out of service LED illuminated

6 ERROR CODE DURING OPERATION

The relay performs continuous self-checking, if an error is detected then an error message will be displayed, a maintenance record will be logged and the relay will reset (after a 1.6 second delay). A permanent problem (for example due to a hardware fault) will generally be detected on the power up sequence, following which the relay will display an error code and halt. If the problem was transient in nature then the relay should reboot correctly and continue in operation. The nature of the detected fault can be determined by examination of the maintenance record logged.

There are also two cases where a maintenance record will be logged due to a detected error where the relay will not reset. These are detection of a failure of either the field voltage or the lithium battery, in these cases the failure is indicated by an alarm message, however the relay will continue to operate.

If the field voltage is detected to have failed (the voltage level has dropped below threshold), then a scheme logic signal is also set. This allows the scheme logic to be adapted in the case of this failure (for example if a blocking scheme is being used).

In the case of a battery failure it is possible to prevent the relay from issuing an alarm using the setting under the Date and Time section of the menu. This setting '**Battery Alarm**' can be set to '**Disabled**' to allow the relay to be used without a battery, without an alarm message being displayed.

In the case of an RTD board failure, an alarm "RTD board fail" message is displayed, the RTD protection is disabled, but the operation of the rest of the relay functionality is unaffected.

7 MAL-OPERATION OF THE RELAY DURING TESTING

7.1 Failure of Output Contacts

An apparent failure of the relay output contacts may be caused by the relay configuration; the following tests should be performed to identify the real cause of the failure.

Note	The relay self-tests verify that the coil of the contact has been energized, an error will be displayed if there is a fault in the output relay board.

Test	Check	Action
1	Is the Out of Service LED illuminated?	Illumination of this LED may indicate that the relay is in test mode or that the protection has been disabled due to a hardware verify error (see Table 4).
2	Examine the Contact status in the Commissioning section of the menu.	If the relevant bits of the contact status are operated, proceed to test 4, if not proceed to test 3.
3	Verify by examination of the fault record or by using the test port whether the protection element is operating correctly.	If the protection element does not operate verify whether the test is being correctly applied. If the protection element does operate, it will be necessary to check the PSL to ensure that the mapping of the protection element to the contacts is correct.
4	Using the Commissioning/Test mode function apply a test pattern to the relevant relay output contacts and verify whether they operate (note the correct external connection diagram should be consulted). A continuity tester can be used at the rear of the relay for this purpose.	If the output relay does operate, the problem must be in the external wiring to the relay. If the output relay does not operate this could indicate a failure of the output relay contacts (note that the self-tests verify that the relay coil is being energized). Ensure that the closed resistance is not too high for the continuity tester to detect.

Table 5 - Failure of output contacts

7.2 Failure of Opto-Isolated Inputs

The opto-isolated inputs are mapped onto the relay internal signals using the PSL. If an input does not appear to be recognized by the relay scheme logic the Commission Tests/Opto Status menu option can be used to verify whether the problem is in the opto-isolated input itself or the mapping of its signal to the scheme logic functions. If the opto-isolated input does appear to be read correctly then it will be necessary to examine its mapping within the PSL.

Ensure the voltage rating for the opto inputs has been configured correctly with applied voltage. If the opto-isolated input state is not being correctly read by the relay the applied signal should be tested. Verify the connections to the opto-isolated input using the correct wiring diagram and the correct nominal voltage settings in any standard or custom menu settings. Next, using a voltmeter verify that 80% opto setting voltage is present on the terminals of the opto-isolated input in the energized state. If the signal is being correctly applied to the relay then the failure may be on the input card itself. Depending on which opto-isolated input has failed this may require replacement of either the complete analog input module (the board within this module cannot be individually replaced without re-calibration of the relay) or a separate opto board.

7.3 Incorrect Analog Signals

The measurements may be configured in primary or secondary to assist. If it is suspected that the analog quantities being measured by the relay are not correct then the measurement function of the relay can be used to verify the nature of the problem. The measured values displayed by the relay should be compared with the actual magnitudes at the relay terminals. Verify that the correct terminals are being used (in particular the dual rated CT inputs) and that the CT and VT ratios set on the relay are correct. The correct 120 degree displacement of the phase measurements should be used to confirm that the inputs have been correctly connected.

7.4 PSL Editor Troubleshooting

A failure to open a connection could be because of one or more of the following:

- The relay address is not valid (note: this address is always 1 for the front port).
- Password is not valid
- Communication Set-up - COM port, Baud rate, or Framing - is not correct
- Transaction values are not suitable for the relay and/or the type of connection
- Modem configuration is not valid. Changes may be necessary when using a modem
- The connection cable is not wired correctly or broken. See MiCOM S1 connection configurations
- The option switches on any KITZ101/102 that is in use may be incorrectly set

7.4.1 Diagram Reconstruction after Recover from Relay

Although the extraction of a scheme from a relay is supported, the facility is provided as a way of recovering a scheme in the event that the original file is unobtainable.

The recovered scheme will be logically correct, but much of the original graphical information is lost. Many signals will be drawn in a vertical line down the left side of the canvas. Links are drawn orthogonally using the shortest path from A to B.

Any annotation added to the original diagram (titles, notes, etc.) are lost.

Sometimes a gate type may not be what was expected, e.g. a 1-input AND gate in the original scheme will appear as an OR gate when uploaded. Programmable gates with an inputs-to-trigger value of 1 will also appear as OR gates.

7.4.2 PSL Version Check

The PSL is saved with a version reference, time stamp and CRC check. This gives a visual check whether the default PSL is in place or whether a new application has been downloaded.

8 REPAIR AND MODIFICATION PROCEDURE

Please follow these steps to return an Automation product to us:

1. Get the Repair and Modification Authorization Form (RMA).

   A copy of the RMA form is shown at the end of this section.

2. Fill in the RMA form.

   Fill in only the white part of the form.

   Please ensure that all fields marked **(M)** are completed such as:

   Equipment model

   Model No. and Serial No.

   Description of failure or modification required (please be specific)

   Value for customs (in case the product requires export)

   Delivery and invoice addresses

   Contact details

3. Receive from local service contact, the information required to ship the product.

   Your local service contact will provide you with all the information:

   Pricing details

   RMA No

   Repair center address

   If required, an acceptance of the quote must be delivered before going to next stage.

4. Send the product to the repair center.

   Address the shipment to the repair center specified by your local contact.

   Ensure all items are protected by appropriate packaging: anti-static bag and foam protection.

   Ensure a copy of the import invoice is attached with the unit being returned.

   Ensure a copy of the RMA form is attached with the unit being returned.

   E-mail or fax a copy of the import invoice and airway bill document to your local contact.

Notes:

Schneider Electric

REPAIR/MODIFICATION RETURN AUTHORIZATION FORM

FIELDS IN GREY TO BE FILLED IN BY SCHNEIDER ELECTRIC PERSONNEL ONLY

Reference **RMA:**		Date:
Repair Center Address (for shipping)	**Service Type** ☐ Retrofit ☐ Warranty ☐ Paid service ☐ Under repair contract ☐ Wrong supply	LSC PO No.:
Schneider Electric - Local Contact Details Name: Telephone No.: Fax No.: E-mail:		

IDENTIFICATION OF UNIT

Fields marked (M) are mandatory, delays in return will occur if not completed.

Model No./Part No.: **(M)**	Site Name/Project:
Manufacturer Reference: **(M)**	Commissioning Date:
Serial No.: **(M)**	Under Warranty: ☐ Yes ☐ No
Software Version:	Additional Information:
Quantity:	Customer P.O (if paid):

FAULT INFORMATION

Type of Failure	**Found Defective**
Hardware fail ☐	During FAT/inspection ☐
Mechanical fail/visible defect ☐	On receipt ☐
Software fail ☐	During installation/commissioning ☐
Other:	During operation ☐
	Other:
Fault Reproducibility	
Fault persists after removing, checking on test bench ☐	
Fault persists after re-energization ☐	
Intermittent fault ☐	

Description of Failure Observed or Modification Required - *Please be specific* **(M)**

FOR REPAIRS ONLY

Would you like us to install an updated firmware version after repair?	☐	Yes	☐	No

CUSTOMS & INVOICING INFORMATION

Required to allow return of repaired items

Value for Customs (M)	
Customer Invoice Address ((M) if paid)	**Customer Return Delivery Address (full street address) (M)** Part shipment accepted ☐ Yes ☐ No **OR** Full shipment required ☐ Yes ☐ No
Contact Name: Telephone No.: Fax No.: E-mail:	Contact Name: Telephone No.: Fax No.: E-mail:

REPAIR TERMS

1. **Please ensure that a copy of the import invoice is attached with the returned unit, together with the airway bill document.** Please fax/e-mail a copy of the appropriate documentation **(M)**.
2. Please ensure the Purchase Order is released, for paid service, to allow the unit to be shipped.
3. Submission of equipment to Schneider Electric is deemed as authorization to repair and acceptance of quote.
4. Please ensure all items returned are marked as Returned for 'Repair/Modification' and **protected by appropriate packaging** (anti-static bag for each board and foam protection).

SCADA COMMUNICATIONS

CHAPTER NO 16

Date:	10/2014
Products covered by this chapter:	This chapter covers the specific versions of the MiCOM products listed below. This includes ***only*** the following combinations of Software Version and Hardware Suffix.
Hardware Suffix:	L (P141, P142 & P143) & M (P145)
Software Version:	A0 - P14x (P141, P142, P143 & P145)
Connection Diagrams:	10P141xx (xx = 01 to 07) 10P142xx (xx = 01 to 07) 10P143xx (xx = 01 to 07) 10P145xx (xx = 01 to 07)

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1 SCADA COMMUNICATIONS

1.1 Introduction

This section outlines the remote communications interfaces of the MiCOM relay. The relay supports a choice of one of five protocols via the rear communication interface, selected via the model number when ordering. This is in addition to the front serial interface and 2nd rear communications port, which supports the Courier protocol only.

The rear EIA(RS)485 interface is isolated and is suitable for permanent connection whichever protocol is selected. The advantage of this type of connection is that up to 32 relays can be '**daisy chained**' together using a simple twisted pair electrical connection.

It should be noted that the descriptions contained within this section do not aim to fully detail the protocol itself. The relevant documentation for the protocol should be referred to for this information. This section serves to describe the specific implementation of the protocol in the relay.

1.2 Rear Port Information and Connection Advice - EIA(RS)485 Protocols

1.2.1 Rear Communication Port EIA(RS)485 Interface

The rear EIA(RS)485 communication port is provided by a 3-terminal screw connector located on the back of the relay. See section P14x/EN IN for details of the connection terminals. The rear port provides K-Bus/EIA(RS)485 serial data communication and is intended for use with a permanently wired connection to a remote control center. Of the three connections, two are for the signal connection, and the other is for the earth shield of the cable. When the K-Bus option is selected for the rear port, the two signal connections are not polarity conscious, however for MODBUS, IEC60870-5-103 and DNP3.0 care must be taken to observe the correct polarity.

The protocol provided by the relay is indicated in the relay menu in the '**Communications**' column. Using the keypad and LCD, firstly check that the 'Comms. settings' cell in the '**Configuration**' column is set to '**Visible**', then move to the '**Communications**' column. The first cell down the column shows the communication protocol being used by the rear port.

1.2.1.1 EIA(RS)485 Bus

The EIA(RS)485 two-wire connection provides a half-duplex fully isolated serial connection to the product. The connection is polarized and whilst the product's connection diagrams indicate the polarization of the connection terminals it should be borne in mind that there is no agreed definition of which terminal is which. If the master is unable to communicate with the product, and the communication parameters match, then it is possible that the two-wire connection is reversed.

1.2.1.2 Bus Termination

The EIA(RS)485 bus must have 120Ω (Ohm) ½ Watt terminating resistors fitted at either end across the signal wires - see Figure 1. Some devices may be able to provide the bus terminating resistors by different connection or configuration arrangements, in which case separate external components will not be required. However, this product does not provide such a facility, so if it is located at the bus terminus then an external termination resistor will be required.

1.2.1.3 Bus Connections and Topologies

The EIA(RS)485 standard requires that each device be directly connected to the physical cable that is the communications bus. Stubs and tees are expressly forbidden, as are star topologies. Loop bus topologies are not part of the EIA(RS)485 standard and are forbidden by it.

Two-core screened cable is recommended. The specification of the cable will be dependent on the application, although a multi-strand 0.5mm^2 per core is normally adequate. Total cable length must not exceed 1000m. The screen must be continuous and connected to ground at one end, normally at the master connection point; it is important to avoid circulating currents, especially when the cable runs between buildings, for both safety and noise reasons.

This product does not provide a signal ground connection. If a signal ground connection is present in the bus cable then it must be ignored, although it must have continuity for the benefit of other devices connected to the bus. At no stage must the signal ground be connected to the cables screen or to the product's chassis. This is for both safety and noise reasons.

1.2.1.4 Biasing

It may also be necessary to bias the signal wires to prevent jabber. Jabber occurs when the signal level has an indeterminate state because the bus is not being actively driven. This can occur when all the slaves are in receive mode and the master is slow to turn from receive mode to transmit mode. This may be because the master purposefully waits in receive mode, or even in a high impedance state, until it has something to transmit. Jabber causes the receiving device(s) to miss the first bits of the first character in the packet, which results in the slave rejecting the message and consequentially not responding. Symptoms of this are poor response times (due to retries), increasing message error counters, erratic communications, and even a complete failure to communicate.

Biasing requires that the signal lines be weakly pulled to a defined voltage level of about 1V. There should only be one bias point on the bus, which is best situated at the master connection point. The DC source used for the bias must be clean; otherwise noise will be injected.

Note	Some devices may (optionally) be able to provide the bus bias, in which case external components will not be required.

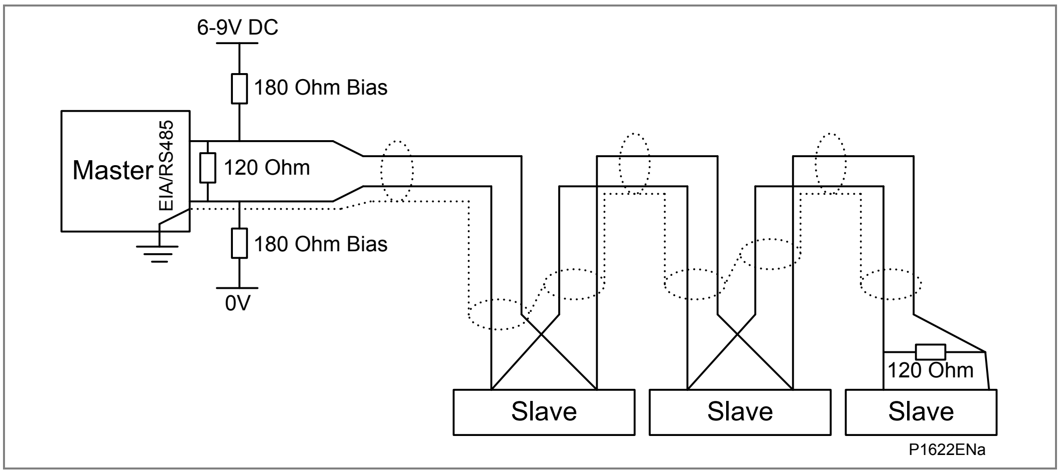


Figure 1 - EIA(RS)485 bus connection arrangements

It is possible to use the products field voltage output (48V DC) to bias the bus using values of 2.2kΩ (½W) as bias resistors instead of the 180Ω resistors shown in the above diagram.

Caution	**It is extremely important that the 120Ω termination resistors are fitted. Failure to do so will result in an excessive bias voltage that may damage the devices connected to the bus.**
Caution	**As the field voltage is much higher than that required, Schneider Electric cannot assume responsibility for any damage that may occur to a device connected to the network as a result of incorrect application of this voltage.**
Caution	**Ensure that the field voltage is not being used for other purposes (i.e. powering logic inputs) as this may cause noise to be passed to the communication network.**

1.2.2 Courier Communication

Courier works on a master/slave basis where the slave units contain information in the form of a database, and respond with information from the database when it is requested by a master unit.

The relay is a slave unit that is designed to be used with a Courier master unit such as MiCOM S1 Studio, MiCOM S10, PAS&T or a SCADA system.

To use the rear port to communicate with a PC-based master station using Courier, a KITZ K-Bus to EIA(RS)232 protocol converter is required. This unit is available from Schneider Electric. A typical connection arrangement is shown in Figure 2. For more detailed information on other possible connection arrangements refer to the manual for the Courier master station software and the manual for the KITZ protocol converter. Each spur of the K-Bus twisted pair wiring can be up to 1000m in length and have up to 32 relays connected to it.

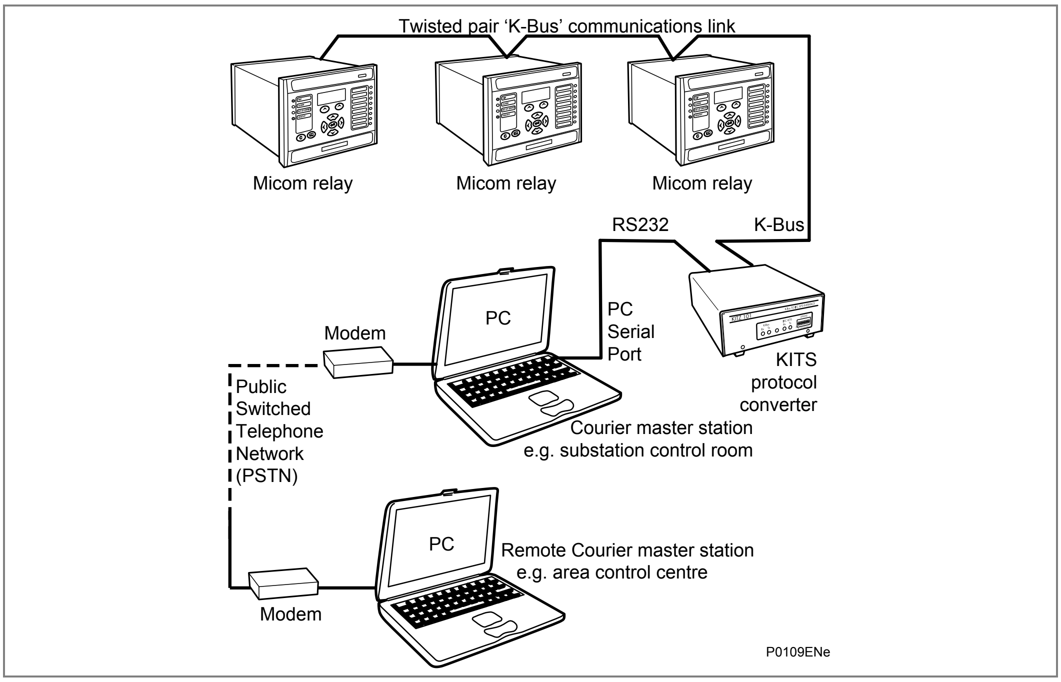


Figure 2 - Remote communication connection arrangements

Having made the physical connection to the relay, the relay's communication settings must be configured. To do this use the keypad and LCD user interface. In the relay menu firstly check that the '**Comms. settings**' cell in the '**Configuration**' column is set to '**Visible**', then move to the '**Communications'** column. Only two settings apply to the rear port using Courier, the relay's address and the inactivity timer. Synchronous communication is used at a fixed baud rate of 64kbits/s.

Move down the '**Communications**' column from the column heading to the first cell down which indicates the communication protocol:

```
Protocol
Courier
```

The next cell down the column controls the address of the relay:

```
Remote address
1
```

Since up to 32 relays can be connected to one K-bus spur, as indicated in Figure 2, it is necessary for each relay to have a unique address so that messages from the master control station are accepted by one relay only. Courier uses an integer number between 0 and 254 for the relay address, which is set with this cell. It is important that no two relays have the same Courier address. The Courier address is then used by the master station to communicate with the relay. Default value of remote address is 255 and must be changed to a value in the range of 1 to 254 before use.

The next cell down controls the inactivity timer:

```
Inactivity timer
10.00 mins.
```

The inactivity timer controls how long the relay will wait without receiving any messages on the rear port before it reverts to its default state, including revoking any password access that was enabled. For the rear port this can be set between 1 and 30 minutes.

Note	*Protection and disturbance recorder settings that are modified using an on-line editor such as PAS&T must be confirmed with a write to the '**Save changes**' cell of the '**Configuration'** column. Off-line editors such as MiCOM S1 Studio do not require this action for the setting changes to take effect.*

1.2.3 MODBUS Communication

MODBUS is a master/slave communication protocol, which can be used for network control. In a similar fashion to Courier, the system works by the master device initiating all actions and the slave devices, (the relays), responding to the master by supplying the requested data or by taking the requested action. MODBUS communication is achieved via a twisted pair EIA(RS)485 connection to the rear port and can be used over a distance of 1000m with up to 32 slave devices.

To use the rear port with MODBUS communication, the relay's communication settings must be configured. To do this use the keypad and LCD user interface. In the relay menu firstly check that the '**Comms. settings**' cell in the '**Configuration**' column is set to '**Visible**', then move to the '**Communications**' column. Four settings apply to the rear port using MODBUS, which are described below. Move down the '**Communications**' column from the column heading to the first cell down which indicates the communication protocol:

```
Protocol
MODBUS
```

The next cell down controls the MODBUS address of the relay:

```
MODBUS address
23
```

Up to 32 relays can be connected to one MODBUS spur, and therefore it is necessary for each relay to have a unique address so that messages from the master control station are accepted by one relay only. MODBUS uses an integer number between 1 and 247 for the relay address. It is important that no two relays have the same MODBUS address. The MODBUS address is then used by the master station to communicate with the relay.

The next cell down controls the inactivity timer:

```
Inactivity timer
10.00 mins.
```

The inactivity timer controls how long the relay will wait without receiving any messages on the rear port before it reverts to its default state, including revoking any password access that was enabled. For the rear port this can be set between 1 and 30 minutes.

The next cell down the column controls the baud rate to be used:

```
Baud rate
9600 bits/s
```

MODBUS communication is asynchronous. Three baud rates are supported by the relay, '**9600 bits/s**', '**19200 bits/s**' and '**38400 bits/s**'. It is important that whatever baud rate is selected on the relay is the same as that set on the MODBUS master station.

The next cell down controls the parity format used in the data frames:

```
Parity
None
```

The parity can be set to be one of '**None**', '**Odd**' or '**Even**'. It is important that whatever parity format is selected on the relay is the same as that set on the MODBUS master station.

The next cell down controls the IEC time format used in the data frames:

```
MODBUS IEC time
Standard
```

The MODBUS IEC time can be set to '**Standard**' or '**Reverse**'. For a complete definition see the relay menu database (P14x/EN MD), datatype G12.

1.2.4 IEC60870-5 CS 103 Communication

The IEC specification IEC60870-5-103: Telecontrol Equipment and Systems, Part 5: Transmission Protocols Section 103 defines the use of standards IEC60870-5-1 to IEC60870-5-5 to perform communication with protection equipment. The standard configuration for the IEC60870-5-103 protocol is to use a twisted pair EIA(RS)485 connection over distances up to 1000m. The relay operates as a slave in the system, responding to commands from a master station.

To use the rear port with IEC60870-5-103 communication, the relay's communication settings must be configured. To do this use the keypad and LCD user interface. In the relay menu firstly check that the '**Comms. settings**' cell in the '**Configuration**' column is set to '**Visible**', then move to the '**Communications**' column. Four settings apply to the rear port using IEC60870-5-103 that are described below. Move down the '**Communications**' column from the column heading to the first cell that indicates the communication protocol:

```
Protocol
IEC60870-5-103
```

The next cell down controls the IEC60870-5-103 address of the relay:

```
Remote address
162
```

Up to 32 relays can be connected to one IEC60870-5-103 spur, and therefore it is necessary for each relay to have a unique address so that messages from the master control station are accepted by one relay only. IEC60870-5-103 uses an integer number between 0 and 254 for the relay address. It is important that no two relays have the same IEC60870-5-103 address. The IEC60870-5-103 address is then used by the master station to communicate with the relay.

The next cell down the column controls the baud rate to be used:

```
Baud rate
9600 bits/s
```

IEC60870-5-103 communication is asynchronous. Two baud rates are supported by the relay, '**9600 bits/s**' and '**19200 bits/s**'. It is important that whatever baud rate is selected on the relay is the same as that set on the IEC60870-5-103 master station.

The next cell down controls the period between IEC60870-5-103 measurements:

```
Measure't. period
30.00 s
```

The IEC60870-5-103 protocol allows the relay to supply measurements at regular intervals. The interval between measurements is controlled by this cell, and can be set between 1 and 60 seconds.

The following cell is not currently used but is available for future expansion

```
Inactive timer
```

The next cell down can be used for monitor or command blocking:

```
CS103 blocking
```

There are three settings associated with this cell; these are:

- Disabled — No blocking selected.
- Monitor Blocking — When the monitor blocking DDB Signal is active high, either by energizing an opto input or control input, reading of the status information and disturbance records is not permitted. When in this mode the relay returns a "**Termination of general interrogation**" message to the master station.
- Command Blocking — When the command blocking DDB signal is active high, either by energizing an opto input or control input, all remote commands will be ignored (i.e. CB Trip/Close, change setting group etc.). When in this mode the relay returns a "**negative acknowledgement of command**" message to the master station.

1.2.5 DNP3.0 Communication

The DNP 3.0 protocol is defined and administered by the DNP User Group. Information about the user group, DNP 3.0 in general and protocol specifications can be found on their website: www.dnp.org

The relay operates as a DNP 3.0 slave and supports subset level 2 of the protocol plus some of the features from level 3. DNP 3.0 communication is achieved via a twisted pair EIA(RS)485 connection to the rear port and can be used over a distance of 1000m with up to 32 slave devices.

To use the rear port with DNP 3.0 communication, the relay's communication settings must be configured. To do this use the keypad and LCD user interface. In the relay menu firstly check that the '**Comms. setting**' cell in the '**Configuration**' column is set to '**Visible**', then move to the '**Communications**' column. Four settings apply to the rear port using DNP 3.0, which are described below. Move down the '**Communications**' column from the column heading to the first cell that indicates the communications protocol:

```
Protocol
DNP 3.0
```

The next cell controls the DNP 3.0 address of the relay:

```
DNP 3.0 address
232
```

Up to 32 relays can be connected to one DNP 3.0 spur, and therefore it is necessary for each relay to have a unique address so that messages from the master control station are accepted by only one relay. DNP 3.0 uses a decimal number between 1 and 65519 for the relay address. It is important that no two relays have the same DNP 3.0 address. The DNP 3.0 address is then used by the master station to communicate with the relay.

The next cell down the column controls the baud rate to be used:

```
Baud rate
9600 bits/s
```

DNP 3.0 communication is asynchronous. Six baud rates are supported by the relay '**1200bits/s**', '**2400bits/s**', '**4800bits/s**', **'9600bits/s**', '**19200bits/s**' and '**38400bits/s**'. It is important that whatever baud rate is selected on the relay is the same as that set on the DNP 3.0 master station.

The next cell down the column controls the parity format used in the data frames:

```
Parity
None
```

The parity can be set to be one of '**None**', '**Odd**' or '**Even**'. It is important that whatever parity format is selected on the relay is the same as that set on the DNP 3.0 master station.

The next cell down the column sets the time synchronization request from the master by the relay:

```
Time Sync.
Enabled
```

The time sync. can be set to either enabled or disabled. If enabled it allows the DNP 3.0 master to synchronize the time.

1.3 Fiber Optic Converter

An optional fiber optic card is available in this product. This converts the EIA(RS)485 protocols into a fiber optic output. This communication card is available for use on Courier, MODBUS, IEC60870-5-103 and DNP3.0 it adds the following setting to the communication column.

This controls the physical media used for the communication:

```
Physical link
Copper
```

The default setting is to select the electrical EIA(RS)485 connection. If the optional fiber optic connectors are fitted to the relay, then this setting can be changed to '**Fiber optic**'. This cell is also invisible if a second rear comms. port, or Ethernet card is fitted, as it is mutually exclusive with the fiber optic connectors, and occupies the same physical location.

1.4 Second Rear Communication Port (SK4)

For relays with Courier, MODBUS, IEC60870-5-103 or DNP3.0 protocol on the first rear communications port there is the hardware option of a second rear communications port, which will run the Courier language. This can be used over one of three physical links: twisted pair K-Bus (non-polarity sensitive), twisted pair EIA(RS)485 (connection polarity sensitive) or EIA(RS)232.

The settings for this port are located immediately below the ones for the first port as described in previous sections of P14x/EN IT. Move down the settings until the following sub heading is displayed.

```
REAR PORT2 (RP2)
```

The next cell down indicates the language, which is fixed at Courier for RP2.

```
RP2 protocol
Courier
```

The next cell down indicates the status of the hardware, e.g.

```
RP2 card status
EIA(RS)232 OK
```

The next cell allows for selection of the port configuration.

```
RP2 port config.
EIA(RS)232
```

The port can be configured for EIA(RS)232, EIA(RS)485 or K-Bus.

In the case of EIA(RS)232 and EIA(RS)485 the next cell selects the communication mode.

```
RP2 comms. Mode
IEC60870 FT1.2
```

The choice is either IEC60870 FT1.2 for normal operation with 11-bit modems, or 10-bit no parity.

The next cell down controls the comms. port address.

```
RP2 address
255
```

Since up to 32 relays can be connected to one K-bus spur, as indicated in 0, it is necessary for each relay to have a unique address so that messages from the master control station are accepted by one relay only. Courier uses an integer number between 0 and 254 for the relay address that is set with this cell. It is important that no two relays have the same Courier address. The Courier address is then used by the master station to communicate with the relay. The default value is 255 and must be changed in the range 0 to 254 before use.

The next cell down controls the inactivity timer.

```
RP2 inactivity timer
15 mins.
```

The inactivity timer controls how long the relay will wait without receiving any messages on the rear port before it reverts to its default state, including revoking any password access that was enabled. For the rear port this can be set between 1 and 30 minutes.

In the case of EIA(RS)232 and EIA(RS)485 the next cell down controls the baud rate. For K-Bus the baud rate is fixed at 64kbit/second between the relay and the KITZ interface at the end of the relay spur.

```
RP2 baud rate
19200
```

Courier communications is asynchronous. Three baud rates are supported by the relay, '**9600 bits/s**', '**19200 bits/s**' and '**38400 bits/s**'.

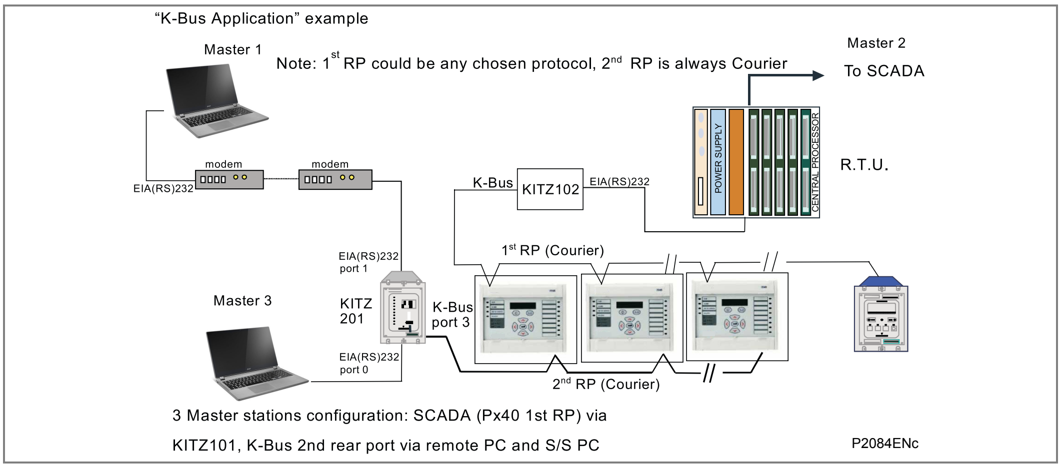


Figure 3 - Second rear port K-Bus application

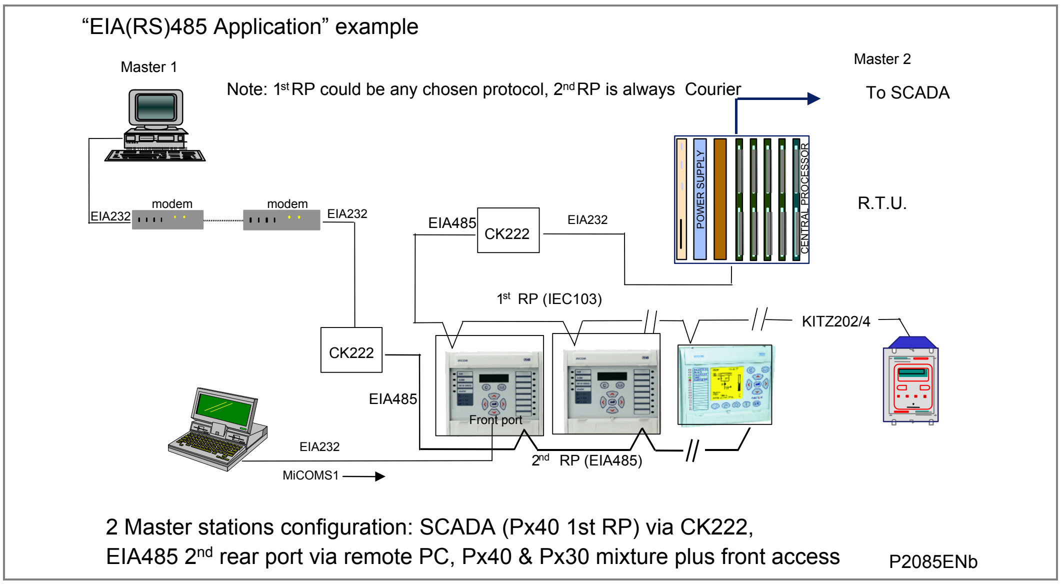


Figure 4 - Second rear port EIA(RS)485 example

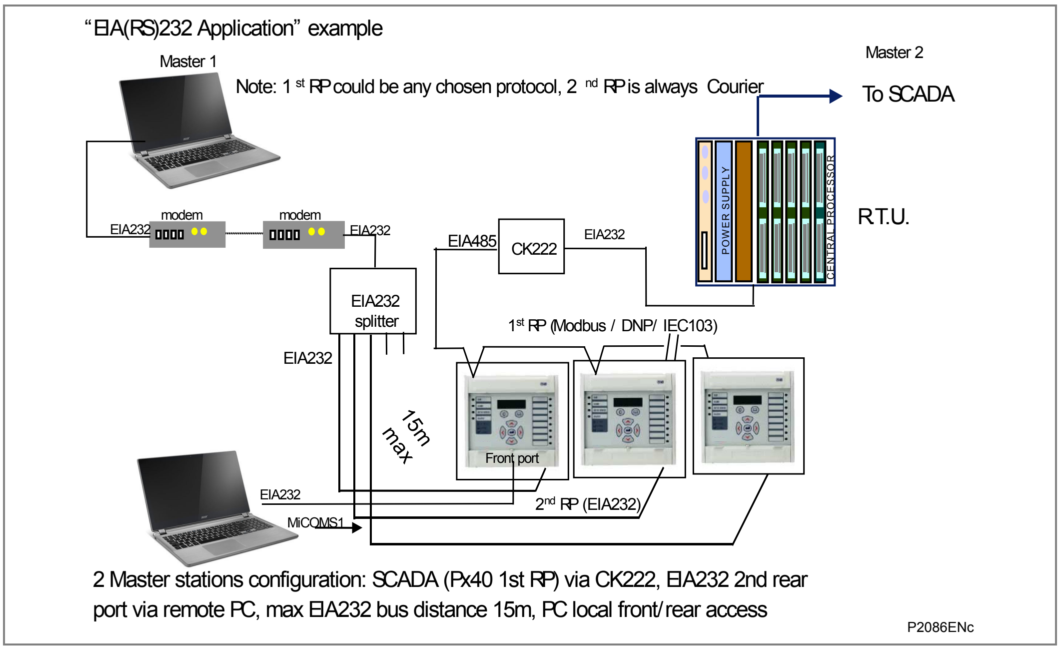


Figure 5 - Second rear port EIA(RS)232 example

2 COURIER INTERFACE

2.1 Courier Protocol

K-Bus is based on EIA(RS)485 voltage levels with HDLC FM0 encoded synchronous signaling and its own frame format. The K-Bus twisted pair connection is unpolarized, whereas the EIA(RS)485 and EIA(RS)232 interfaces are polarized.

The EIA(RS)232 interface uses the IEC60870-5 FT1.2 frame format.

The relay supports an IEC60870-5 FT1.2 connection on the front-port. This is intended for temporary local connection and is not suitable for permanent connection. This interface uses a fixed baud rate, 11-bit frame, and a fixed device address.

The rear interface is used to provide a permanent connection for K-Bus and allows multi-drop connection. It should be noted that although K-Bus is based on EIA(RS)485 voltage levels it is a synchronous HDLC protocol using FM0 encoding. It is not possible to use a standard EIA(RS)232 to EIA(RS)485 converter to convert IEC60870-5 FT1.2 frames to K-Bus. Nor is it possible to connect K-Bus to an EIA(RS)485 computer port. A protocol converter, such as the KITZ101, should be employed for this purpose.

Alternatively for direct connections, the fiber optic converter card may be used to convert the rear EIA(RS)485 port into a fiber optic (ST) port. See section 1.3 for more information.

2.2 Supported Command Set

The following Courier commands are supported by the relay:

Protocol Layer

- Reset Remote Link
- Poll Status
- Poll Buffer*

Low Level Commands

- Send Event*
- Accept Event*
- Send Block
- Store Block Identifier
- Store Block Footer

Menu Browsing

- Get Column Headings
- Get Column Text
- Get Column Values
- Get Strings
- Get Text
- Get Value
- Get Column Setting Limits

Setting Changes

- Enter Setting Mode
- Preload Setting
- Abort Setting
- Execute Setting
- Reset Menu Cell
- Set Value

Control Commands

- Select Setting Group
- Change Device Address*
- Set Real Time

Note	Commands indicated with a * are not supported via the front Courier port.

2.3 Relay Courier Database

The Courier database is a two dimensional structure with each cell in the database being referenced by a row and column address. Both the column and the row can take a range from 0 to 255. Addresses in the database are specified as hexadecimal values; e.g. 0A02 is column 0A (10 decimal) row 02. Associated settings/data will be part of the same column, row zero of the column contains a text string to identify the contents of the column, i.e. a column heading.

P14x/EN MD contains the complete database definition for the relay. For each cell location the following information is stated:

- Cell text
- Cell datatype
- Cell value
- Whether the cell is settable, if so
- Minimum value
- Maximum value
- Step size
- Password level required to allow setting changes
- String information (for Indexed String or Binary flag cells)

2.4 Setting Changes

(See R6512, Courier User Guide - Chapter 9)

There are three categories of settings within the relay database:

- Control and support
- Disturbance recorder
- Protection settings group

Setting changes made to the control and support settings are implemented immediately and stored in non-volatile memory. Changes made to either the disturbance recorder settings or the protection settings groups are stored in a '**scratchpad**' memory and are not immediately implemented by the relay.

To action setting changes stored in the scratchpad the save changes cell in the configuration column must be written to. This allows the changes to either be confirmed and stored in non-volatile memory, or the setting changes to be aborted.

2.4.1 Setting Transfer Mode

If it is necessary to transfer all of the relay settings to or from the relay a cell within the communication system data column can be used. This cell (location BF03) when set to 1 makes all of the relay settings visible. Any setting changes made, with the relay set in this mode, are stored in scratchpad memory (including control and support settings). When the value of BF03 is set back to 0 any setting changes are verified and stored in non-volatile memory.

2.5 Event Extraction

Events can be extracted either automatically (rear port only) or manually (either Courier port). For automatic extraction all events are extracted in sequential order using the standard Courier event mechanism, this includes fault/maintenance data if appropriate. The manual approach allows the user to select events, faults, or maintenance data at random from the stored records.

2.5.1 Automatic Event Extraction

(See Chapter 7 Courier User Guide, publication R6512)

This method is intended for continuous extraction of event and fault information as it is produced. It is only supported via the rear Courier port.

When new event information is created the event bit is set within the status byte, this indicates to the master device that event information is available. The oldest, unextracted event can be extracted from the relay using the send event command. The relay will respond with the event data, which will be either a Courier Type 0 or Type 3 event. The Type 3 event is used for fault records and maintenance records.

Once an event has been extracted from the relay, the accept event can be used to confirm that the event has been successfully extracted. If all events have been extracted then the event bit will reset, if there are more events still to be extracted the next event can be accessed using the send event command as before.

2.5.2 Event Types

Events will be created by the relay under the following circumstances:

- Change of state of output contact
- Change of state of opto input
- Protection element operation
- Alarm condition
- Setting change
- Password entered/timed-out
- Fault record (Type 3 Courier Event)
- Maintenance record (Type 3 Courier Event)

2.5.3 Event Format

The send event command results in the following fields being returned by the relay:

- Cell reference
- Timestamp
- Cell text
- Cell value

The menu database, P14x/EN MD, contains a table of the events created by the relay and indicates how the contents of the above fields are interpreted. Fault records and maintenance records will return a Courier Type 3 event, which contains the above fields together with two additional fields:

- Event extraction column
- Event number

These events contain additional information that is extracted from the relay using the referenced extraction column. Row 01 of the extraction column contains a setting that allows the fault/maintenance record to be selected. This setting should be set to the event number value returned within the record; the extended data can be extracted from the relay by uploading the text and data from the column.

2.5.4 Manual Event Record Extraction

Column 01 of the database can be used for manual viewing of event, fault, and maintenance records. The contents of this column will depend on the nature of the record selected. It is possible to select events by event number and to directly select a fault record or maintenance record by number.

Event Record Selection (Row 01) - This cell can be set to a value between 0 to 249 to select which of the 512 stored events is selected, 0 will select the most recent record; 249 the oldest stored record. For simple event records, (Type 0) cells 0102 to 0105 contain the event details. A single cell is used to represent each of the event fields. If the event selected is a fault or maintenance record (Type 3) then the remainder of the column will contain the additional information.

Fault Record Selection (Row 05) – This cell can be used to directly select a fault record using a value between 0 and 4 to select one of up to five stored fault records. (0 will be the most recent fault and 4 will be the oldest). The column will then contain the details of the fault record selected.

Maintenance Record Selection (Row F0) – This cell can be used to select a maintenance record using a value between 0 and 4 and operates in a similar way to the fault record selection.

It should be noted that if this column is used to extract event information from the relay the number associated with a particular record will change when a new event or fault occurs.

2.6 Disturbance Record Extraction

Select Record Number (Row 01) - This cell can be used to select the record to be extracted. Record 0 will be the oldest unextracted record, already extracted older records will be assigned positive values, and negative values will be used for more recent records. To facilitate automatic extraction via the rear port the disturbance bit of the status byte is set by the relay whenever there are unextracted disturbance records.

Once a record has been selected, using the above cell, the time and date of the record can be read from cell 02. The disturbance record itself can be extracted using the block transfer mechanism from cell B00B.

As has been stated, the rear Courier port can be used to automatically extract disturbance records as they occur. This operates using the standard Courier mechanism defined in Chapter 8 of the Courier User Guide. The front Courier port does not support automatic extraction although disturbance record data can be extracted manually from this port.

2.7 Programmable Scheme Logic (PSL) Settings

The Programmable Scheme Logic (PSL) settings can be uploaded from and downloaded to the relay using the block transfer mechanism defined in Chapter 12 of the Courier User Guide.

The following cells are used to perform the extraction:

- B204 Domain/: Used to select either PSL settings (Upload or download) or PSL configuration data (Upload only)
- B208 Sub-Domain: Used to select the Protection Setting Group to be uploaded/downloaded.
- B20C Version: Used on a download to check the compatibility of the file to be downloaded with the relay.
- B21C Transfer Mode: Used to set-up the transfer process.
- B120 Data Transfer Cell: Used to perform upload/download.

The programmable scheme logic settings can be uploaded and downloaded to and from the relay using this mechanism. If it is necessary to edit the settings MiCOM S1 Studio must be used as the data format is compressed. MiCOM S1 Studio also performs checks on the validity of the settings before they are downloaded to the relay.

3 MODBUS INTERFACE

The MODBUS interface is a master/slave protocol and it is defined by MODBUS.org: See

www.modbus.org

MODBUS Serial Protocol Reference Guide: PI-MBUS-300 Rev. E

3.1 Communication Link

This interface also uses the rear EIA(RS)485 port (or converted fiber optic port) for communication using '**RTU**' mode communication rather than '**ASCII**' mode as this provides more efficient use of the communication bandwidth. This mode of communication is defined by the MODBUS standard.

In summary, the character framing is 1 start bit, 8 bit data, either 1 parity bit and 1 stop bit, or two stop bits. This gives 11 bits per character.

The following parameters can be configured for this port using either the front panel interface or the front Courier port:

- Baud rate
- Device address
- Parity
- Inactivity time

3.2 MODBUS Functions

The following MODBUS function codes are supported by the relay:

Function	Description
01	Read Coil Status
02	Read Input Status
03	Read Holding Registers
04	Read Input Registers
06	Preset Single Register
08	Diagnostics
11	Fetch Communication Event Counter
12	Fetch Communication Event Log
16	Preset Multiple Registers 127 max

Table 1 - MODBUS function codes

These are interpreted by the MiCOM relay in the following way:

Function	Description	Addresses
01	Read status of output contacts	(0xxxx addresses)
02	Read status of opto inputs	(1xxxx addresses)
03	Read setting values	(4xxxx addresses)
04	Read measured values	(3xxxx addresses
06	Write single setting value	(4xxxx addresses)

Function	Description	Addresses
16	Write multiple setting values	(4xxxx addresses)

Table 2 - MODBUS functions, descriptions and addresses

3.3 Response Codes

Code	MODBUS Description	MiCOM Interpretation
01	Illegal Function Code	The function code transmitted is not supported by the slave.
02	Illegal Data Address	The start data address in the request is not an allowable value. If any of the addresses in the range cannot be accessed due to password protection then all changes within the request are discarded and this error response will be returned. Note: If the start address is correct but the range includes non–implemented addresses this response is not produced.
03	Illegal Value	A value referenced in the data field transmitted by the master is not within range. Other values transmitted within the same packet will be executed if inside range.
06	Slave Device Busy	The write command cannot be implemented due to the database being locked by another interface. This response is also produced if the relay software is busy executing a previous request.

Table 3 - MODBUS Response Codes

3.4 Register Mapping

The relay supports the following memory page references:

Memory Page	Interpretation
0xxxx	Read and write access of the output relays
1xxxx	Read only access of the opto inputs
3xxxx	Read only access of data
4xxxx	Read and write access of settings

Where xxxx represents the addresses available in the page (0 to 9999).

Note	*The "**extended memory file**" (6xxxx) is not supported.*

A complete map of the MODBUS addresses supported by the relay is contained in menu database, P14x/EN MD, of this service manual.

Note	*MODBUS convention is to document register addresses as ordinal values whereas the actual protocol addresses are literal values. The MiCOM relays begin their register addresses at zero. Thus, the first register in a memory page is register address zero. The second register is register address 1 and so on.*
Note	*The page number notation is not part of the address.*

3.5 Event Extraction

The relay supports two methods of event extraction providing either automatic or manual extraction of the stored event, fault, and maintenance records.

3.5.1 Manual Selection

There are three registers available to manually select stored records, there are also three read only registers allowing the number of stored records to be determined.

- 40100 - Select Event, 0 to 249
- 40101 - Select Fault, 0 to 4
- 40102 - Select Maintenance Record, 0 to 4

For each of the above registers a value of 0 represents the most recent stored record. The following registers can be read to indicate the numbers of the various types of record stored.

- 30100 - Number of stored records
- 30101 - Number of stored fault records
- 30102 - Number of stored maintenance records

Each fault or maintenance record logged causes an event record to be created by the relay. If this event record is selected the additional registers allowing the fault or maintenance record details will also become populated.

3.5.2 Automatic Extraction

The automatic extraction facilities allow all types of record to be extracted as they occur. Event records are extracted in sequential order including any fault or maintenance data that may be associated with the event.

The MODBUS master can determine whether the relay has any events stored that have not yet been extracted. This is performed by reading the relay status register 30001 (G26 data type). If the event bit of this register is set then the relay has unextracted events available. To select the next event for sequential extraction the master station writes a value of 1 to the record selection register 40400 (G18 data type). The event data together with any fault/maintenance data can be read from the registers specified below. Once the data has been read the event record can be marked as having been read by writing a value of 2 to register 40400.

3.5.3 Record Data

The location and format of the registers used to access the record data is the same whether they have been selected using either of the two mechanisms detailed above.

Event Description	MODBUS Address	Length	Comments
Time and Date	30103	4	See G12 data type description in section 3.8.
Event Type	30107	1	See G13 data type. Indicates type of event.
Event Value	30108	2	Nature of value depends on event type. This will contain the status as a binary flag for contact, opto, alarm, and protection events.

Event Description	MODBUS Address	Length	Comments
MODBUS Address	30110	1	This indicates the MODBUS register address where the change occurred. Alarm 30011 Relays 30723 Optos 30725 Protection events – like the relay and opto addresses this will map onto the MODBUS address of the appropriate DDB status register depending on which bit of the DDB the change occurred. These will range from 30727 to 30785. For platform events, fault events and maintenance events the default is 0.
Event Index	30111	1	This register will contain the DDB ordinal for protection events or the bit number for alarm events. The direction of the change will be indicated by the most significant bit; 1 for 0 – 1 change and 0 for 1 – 0 change.
Additional Data Present	30112	1	0 means that there is no additional data. 1 means fault record data can be read from 30113 to 30199 (number of registers depends on the product). 2 means maintenance record data can be read from 30036 to 30039.

Table 4 - MODBUS Record Data

If a fault record or maintenance record is directly selected using the manual mechanism then the data can be read from the register ranges specified above. The event record data in registers 30103 to 30111 will not be available.

It is possible using register 40401(G6 data type) to clear independently the stored relay event/fault and maintenance records. This register also provides an option to reset the relay indications, which has the same effect on the relay as pressing the clear key within the alarm viewer using the front panel menu.

3.6 Disturbance Record Extraction

The relay provides facilities for both manual and automatic extraction of disturbance records. The extraction mechanisms are explained below:

3.6.1 Extraction Mechanism

Records extracted over MODBUS from Px40 platform relays will be presented in COMTRADE format. This involves extracting an ASCII text configuration file and then extracting a binary data file.

Each file is extracted by reading a series of data pages from the relay. The data page is made up of 127 registers, giving a maximum transfer of 254 bytes per page.

3.6.1.1 Interface Registers

The following set of registers is presented to the master station to support the extraction of uncompressed disturbance records:

MODBUS Register	Name	Description
3x00001	Status register	Provides the status of the relay as bit flags: b0 Out of service b1 Minor self test failure b2 Event b3 Time synchronization b4 Disturbance b5 Fault b6 Trip b7 Alarm b8 to b15 Unused A '1' on b4 indicates the presence of a disturbance.
3x00800	N^{o} of stored disturbances	Indicates the total number of disturbance records currently stored in the relay, both extracted and unextracted.
3x00801	Unique identifier of the oldest disturbance record	Indicates the unique identifier value for the oldest disturbance record stored in the relay. This is an integer value used in conjunction with the 'No of stored disturbances' value to calculate a value for manually selecting records.
4x00250	Manual disturbance record selection register	This register is used to manually select disturbance records. The values written to this cell are an offset of the unique identifier value for the oldest record. The offset value, which ranges from 0 to the N^{o} of stored disturbances - 1, is added to the identifier of the oldest record to generate the identifier of the required record.
4x00400	Record selection command register	This register is used during the extraction process and has a number of commands. These are: b0 Select next event b1 Accept event b2 Select next disturbance record b3 Accept disturbance record b4 Select next page of disturbance data b5 Select data file
3x00930 - 3x00933	Record time stamp	These registers return the timestamp of the disturbance record.
3x00802	N^{o} of registers in data page	This register informs the master station of the number of registers in the data page that are populated.
3x00803 - 3x00929	Data page registers	These 127 registers are used to transfer data from the relay to the master station. They are 16-bit unsigned integers.
3x00934	Disturbance record status register	The disturbance record status register is used during the extraction process to indicate to the master station when data is ready for extraction. See next table.
4x00251	Data file format selection	This is used to select the required data file format. This is reserved for future use.

Note *Register addresses are provided in reference code + address format. E.g. 4x00001 is reference code 4x, address 1 (which is specified as function code 03, address 0x0000 in the MODBUS specification).*

Table 5 - Interface registers

The disturbance record status register will report one of the following values:

State	Description
Idle	This will be the state reported when no record is selected; such as after power on or after a record has been marked as extracted.
Busy	The relay is currently processing data.
Page ready	The data page has been populated and the master station can now safely read the data.
Configuration complete	All of the configuration data has been read without error.
Record complete	All of the disturbance data has been extracted.
Disturbance overwritten	An error occurred during the extraction process where the disturbance being extracted was overwritten by a new record.
No unextracted disturbances	An attempt was made by the master station to automatically select the next oldest unextracted disturbance when all records have been extracted.
Not a valid disturbance	An attempt was made by the master station to manually select a record that did not exist in the relay.
Command out of sequence	The master station issued a command to the relay that was not expected during the extraction process.

Table 6 - Register values

3.6.2 Extraction Procedure

The following procedure will be used to extract disturbances from the relay. The procedure is split into four sections:

1. Selection of a disturbance – either manually or automatically
2. Extraction of the configuration file
3. Extraction of the data file
4. Accepting the extracted record (automatic extraction only)

3.6.2.1 Manual Extraction Procedure

The procedure used to extract a disturbance manually is shown in Figure 6 below. The manual method of extraction does not allow for the acceptance of disturbance records.

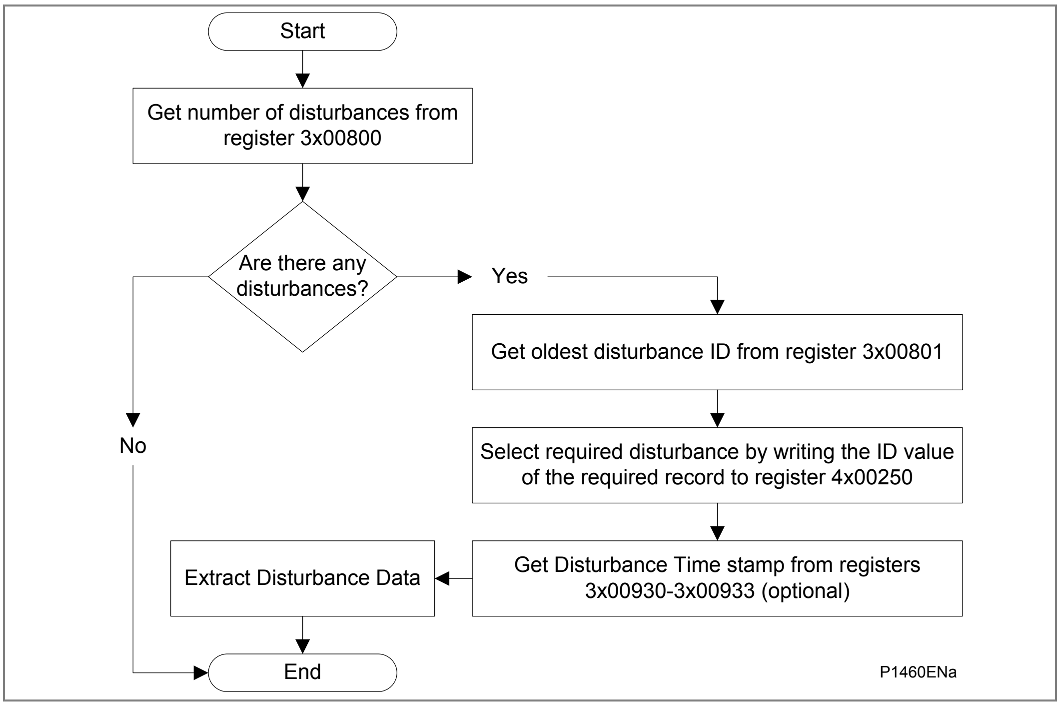


Figure 6 - Manual selection of a disturbance record

3.6.2.2 Automatic Extraction Procedure

There are two methods that can be used for automatically extracting disturbances. Option 1 is simpler and is better at extracting single disturbance records, i.e. when the disturbance recorder is polled regularly. Option 2, however, is more complex to implement but is more efficient at extracting large quantities of disturbance records. This may be useful when the disturbance recorder is polled only occasionally and hence may have many stored records.

3.6.2.3 Automatic Extraction Procedure – Option 1

The procedure for the first method is shown in Figure 7 below. This also shows the acceptance of the disturbance record once the extraction is complete.

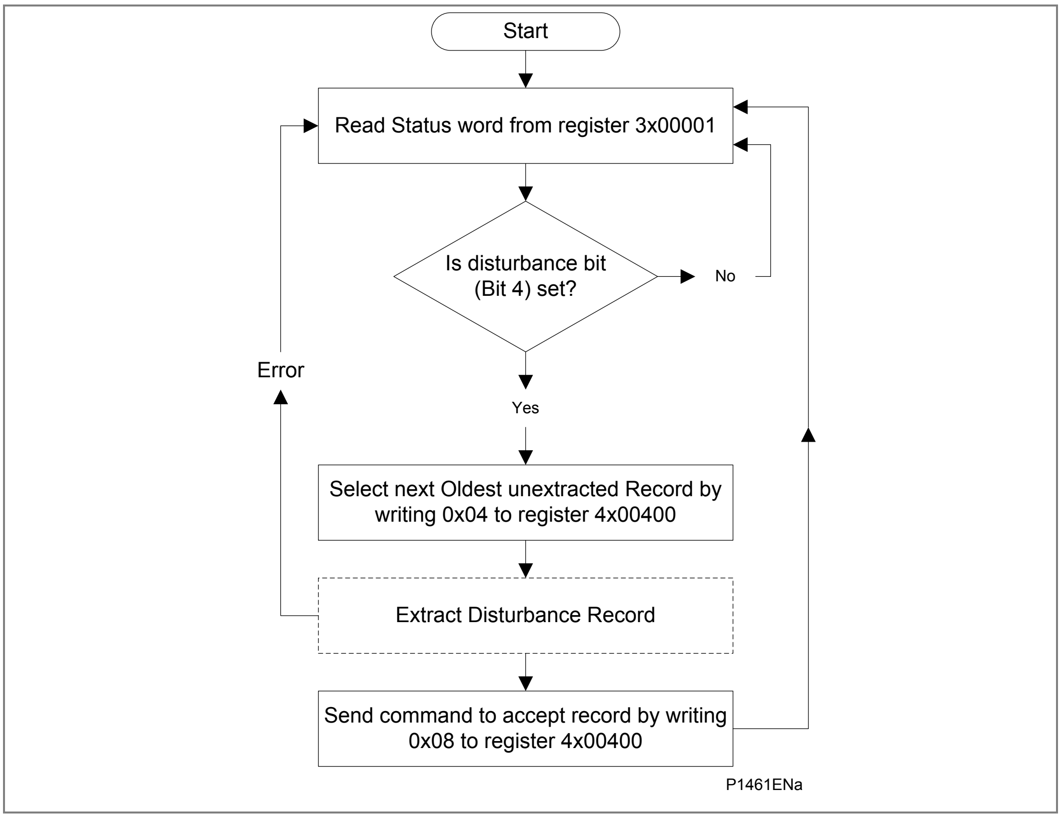


Figure 7 - Automatic selection of a disturbance – option 1

3.6.2.4 Automatic Extraction Procedure – Option 2

The second method that can be used for automatic extraction is shown in Figure 8 below. This also shows the acceptance of the disturbance record once the extraction is complete:

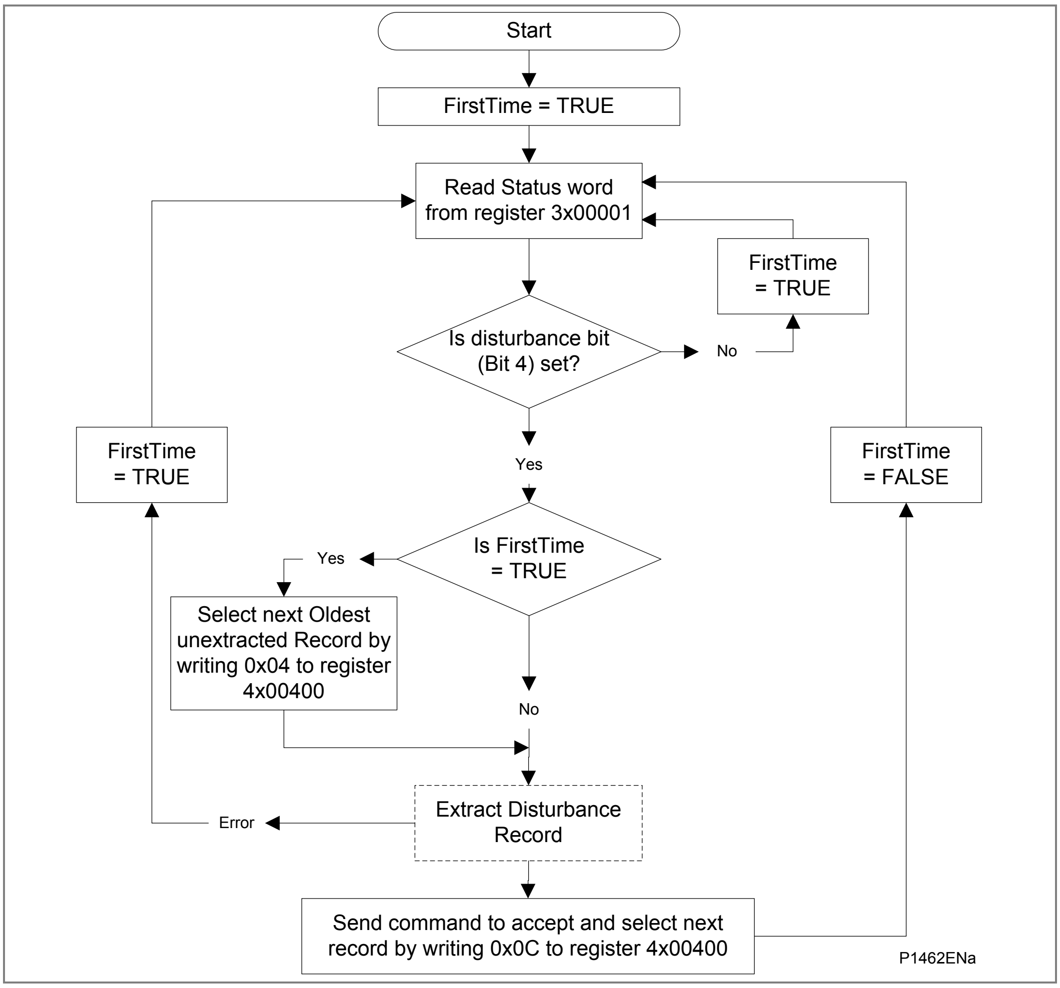


Figure 8 - Automatic selection of a disturbance – option 2

3.6.3 Extracting the Disturbance Data

The extraction of the disturbance record, as shown in the three figures above, is a two-stage process that involves extracting the configuration file first and then the data file.

The following Figure 9 shows how the configuration file is extracted from the relay:

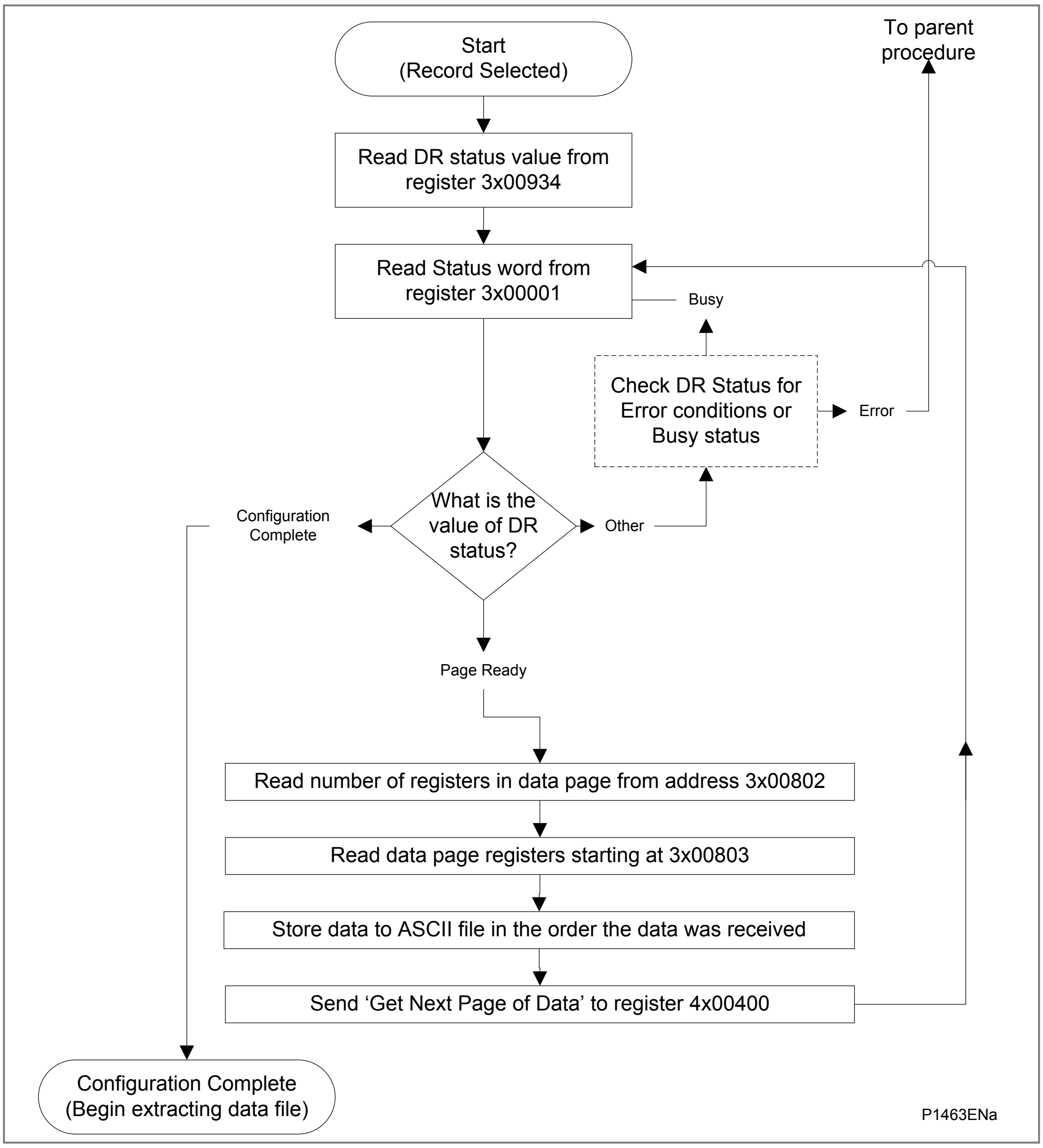


Figure 9 - Extracting the COMTRADE configuration file

The following Figure 10 shows how the data file is extracted:

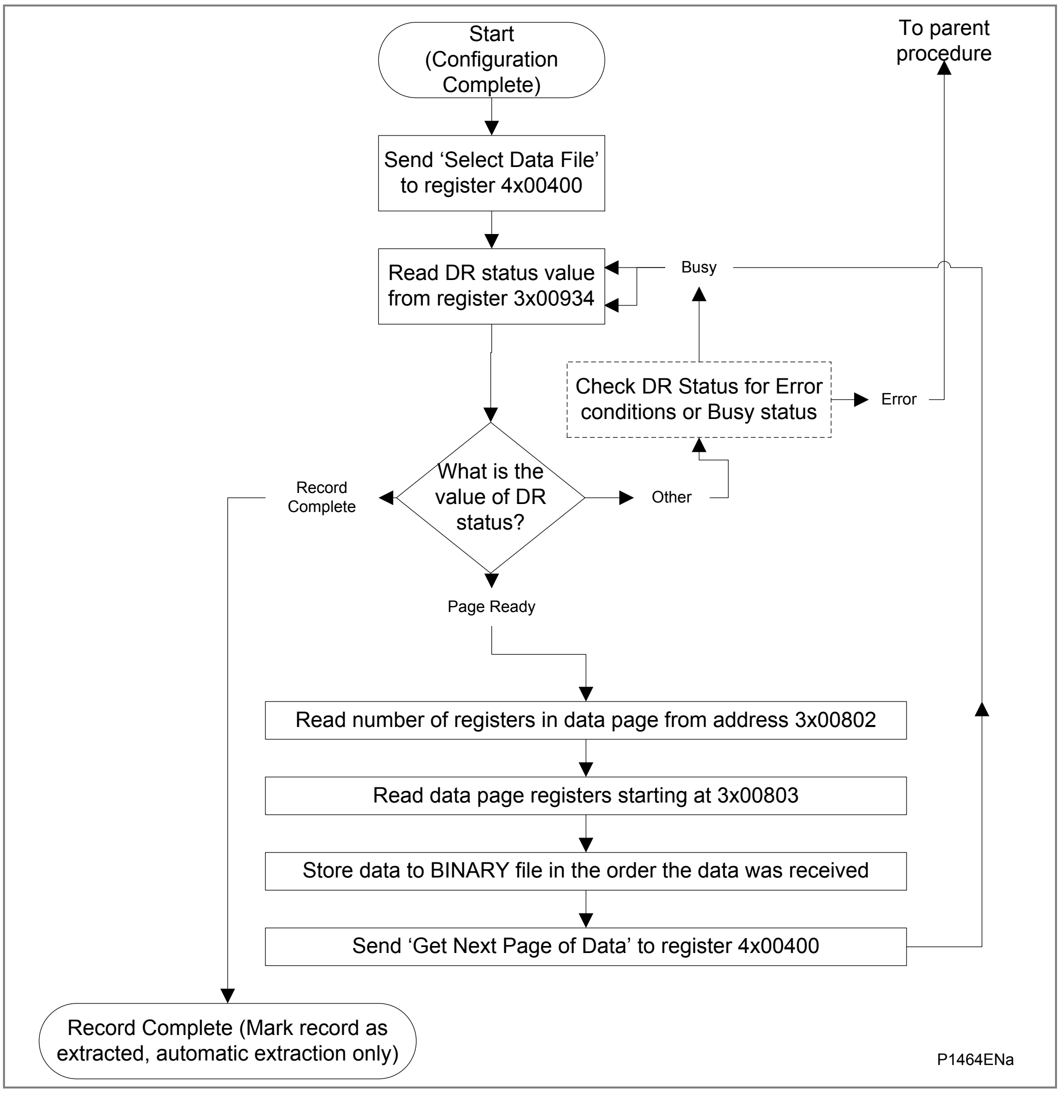


Figure 10 - Extracting the COMTRADE binary data file

During the extraction of the COMTRADE files, an error may occur that will be reported on the DR Status register 3x00934. This can be caused by the relay overwriting the record being extracted or due to the master station issuing a command that is not within the bounds of the extraction procedure.

3.7 Setting Changes

The relay settings can be split into two categories:

- Control and support settings
- Disturbance record settings and protection setting groups

Changes to settings within the control and support area are executed immediately. Changes to the protection setting groups or the disturbance recorder settings are stored in a temporary '**scratchpad**' area and must be confirmed before they are implemented. All the relay settings are 4xxxx page addresses. The following points should be noted when changing settings:

- Settings implemented using multiple registers must be written to using a multi-register write operation.

- The first address for a multi-register write must be a valid address, if there are unmapped addresses within the range being written to then the data associated with these addresses will be discarded.
- If a write operation is performed with values that are out of range then the illegal data response will be produced. Valid setting values within the same write operation will be executed.
- If a write operation is performed attempting to change registers that require a higher level of password access than is currently enabled then all setting changes in the write operation will be discarded.

3.7.1 Password Protection

As described in the introduction to this service manual, the relay settings can be subject to password protection. The level of password protection required to change a setting is indicated in the relay setting database (P14x/EN MD). Level 2 is the highest level of password access, level 0 indicates that no password is required.

The following registers are available to control password protection:

40001 & 40002	Password entry
40022	Default password level
40023 & 40024	Setting to change password level 1
40025 & 40026	Setting to change password level 2
30010	Can be read to indicate current access level

3.7.2 Control and Support Settings

Control and support settings are executed immediately on the write operation.

3.7.3 Protection and Disturbance Recorder Settings

Setting changes to either of these areas are stored in a scratchpad area and will not be used by the relay unless a confirm or an abort operation is performed. Register 40405 can be used either to confirm or abort the setting changes within the scratchpad area. It should be noted that the relay supports four groups of protection settings. The MODBUS addresses for each of the four groups are repeated within the following address ranges:

Group 1	41000 - 42999
Group 2	43000 - 44999
Group 3	45000 - 46999
Group 4	47000 - 48999

In addition to the basic editing of the protection setting groups, the following functions are provided:

Default values can be restored to a setting group or to all of the relay settings by writing to register 40402.

It is possible to copy the contents of one setting group to another by writing the source group to register 40406 and the target group to 40407.

It should be noted that the setting changes performed by either of the two operations defined above are made to the scratchpad area. These changes must be confirmed by writing to register 40405.

The active protection setting groups can be selected by writing to register 40404. An illegal data response will be returned if an attempt is made to set the active group to one that has been disabled.

3.8 Date and Time Format (Data Type G12)

The date-time data type G12 allows *real* date and time information to be conveyed down to a resolution of 1ms. The structure of the data type is shown in Table 7 and is compliant with the IEC60870-5-4 "**Binary Time 2a**" format.

The seven bytes of the structure are packed into four 16-bit registers, such that byte 1 is transmitted first, followed by byte 2 through to byte 7, followed by a null (zero) byte to make eight bytes in total. Since register data is usually transmitted in big-endian format (high order byte followed by low order byte), byte 1 will be in the high-order byte position followed by byte 2 in the low-order position for the first register. The last register will contain just byte 7 in the high order position and the low order byte will have a value of zero.

Byte	Bit Position							
	7	6	5	4	3	2	1	0
1	m^7	m^6	m^5	m^4	m^3	m^2	m^1	m^0
2	m^{15}	m^{14}	m^{13}	m^{12}	m^{11}	m^{10}	m^9	m^8
3	IV	R	I^5	I^4	I^3	I^2	I^1	I^0
4	SU	R	R	H^4	H^3	H^2	H^1	H^0
5	W^2	W^1	W^0	D^4	D^3	D^2	D^1	D^0
6	R	R	R	R	M^3	M^2	M^1	M^0
7	R	Y^6	Y^5	Y^4	Y^3	Y^2	Y^1	Y^0

Where:
m = 0…59,999ms
I = 0…59 minutes
H = 0…23 Hours
W = 1…7 Day of week; Monday to Sunday, 0 for not calculated
D = 1…31 Day of Month
M = 1…12 Month of year; January to December
Y = 0…99 Years (year of century)
R = Reserved bit = 0
SU = summertime: 0 = standard time, 1 = summer time
IV = invalid value: 0 = valid, 1 = invalid
range = 0ms…99 years

Table 7 - G12 date & time data type structure

Since the range of the data type is only 100 years, the century must be deduced. The century is calculated as the one that will produce the nearest time value to the current date. For example: 30-12-99 is 30-12-1999 when received in 1999 & 2000, but is 30-12-2099 when received in 2050. This technique allows 2 digit years to be accurately converted to 4 digits in a ±50 year window around the current datum.

The invalid bit has two applications:

- It can indicate that the date-time information is considered inaccurate, but is the best information available.
- Date-time information is not available.

The summertime bit is used to indicate that summertime (day light saving) is being used and, more importantly, to resolve the alias and time discontinuity which occurs when summertime starts and ends. This is important for the correct time correlation of time stamped records.

The day of the week field is optional and if not calculated will be set to zero.

The concept of time zone is not catered for by this data type and hence by the relay. It is up to the end user to determine the time zone utilized by the relay. Normal practice is to use UTC (universal co-ordinated time), which avoids the complications with day light saving time-stamp correlation's.

3.9 Power and Energy Measurement Data Formats (G29 & G125)

The power and energy measurements are available in two data formats; G29 integer format and G125 IEEE754 floating point format. For historical reasons the registers listed in the main part of the "**Measurements 2**" column of the menu database (see P14x/EN MD) are of the G29 format. The floating point, G125, versions appear at the end of the column.

3.9.1 Data Type G29

Data type G29 consists of three registers. The first register is the per unit power or energy measurement and is of type G28, which is a signed 16 bit quantity. The second and third registers contain a multiplier to convert the per unit value to a real value. The multiplier is of type G27, which is an unsigned 32-bit quantity. Thus, the overall value conveyed by the G29 data type must be calculated as G29 = G28×G27.

The relay calculates the G28 per unit power or energy value as G28 = ((measured secondary quantity)/(CT secondary) × (110V/(VT secondary)). Since data type G28 is a signed 16-bit integer, its dynamic range is constrained to ±32768. This limitation should be borne in mind for the energy measurements, as the G29 value will saturate a long time before the equivalent G125 does.

The associated G27 multiplier is calculated as G27 = (CT primary) × (VT primary/110V) when primary value measurements are selected, and as G27 = (CT secondary) × (VT secondary/110V) when secondary value measurements are selected.

Due to the required truncations from floating point values to integer values in the calculations of the G29 component parts and its limited dynamic range, the use of the G29 values is only recommended when the MODBUS master cannot deal with the G125 IEEE754 floating point equivalents.

Note	*The G29 values must be read in whole multiples of three registers. It is not possible to read the G28 and G27 parts with separate read commands.*

3.9.1.1 Example

For A-Phase Power (Watts) (registers 30300 - 30302) for a 110V relay, In = 1A, VT ratio = 110V:110V and CT ratio = 1A:1A.

Applying A-phase 1A @ 63.51V

A-phase Watts = ((63.51V × 1A)/In = 1A) × (110/Vn = 110V) = 63.51 Watts

The G28 part of the value is the truncated per unit quantity, which will be equal to 64 (40h).

The multiplier is derived from the VT and CT ratios set in the relay, with the equation ((CT Primary) × (VT Primary)/110V). Thus, the G27 part of the value will equal 1. Hence the overall value of the G29 register set is 64×1 = 64W

The registers would contain:

- 30300 - 0040h
- 30301 - 0000h
- 30302 - 0001h

Using the previous example with a VT ratio = 110,000V; 110V and CT ratio = 10,000A:1A the G27 multiplier would be 10,000A × 110,000V/110 = 10,000,000. The overall value of the G29 register set is 64 × 10,000,000 = 640MW.

Note	*There is an actual error of 49MW in this calculation due to loss of resolution.)*

The registers would contain:

- 30300 - 0040h
- 30301 - 0098h
- 30302 - 9680h

3.9.2 Data Type G125

Data type G125 is a short float IEEE754 floating point format, which occupies 32 bits in two consecutive registers. The high order byte of the format is in the first (low order) register and the low order byte in the second register.

The value of the G125 measurement is as accurate as the relay's ability to resolve the measurement after it has applied the secondary or primary scaling factors as require. It does not suffer from the truncation errors or dynamic range limitations associated with the G29 data format.

4 IEC60870-5-103 INTERFACE

The IEC60870-5-103 interface is a master/slave interface with the relay as the slave device. The relay conforms to compatibility level 2; compatibility level 3 is not supported.

The following IEC60870-5-103 facilities are supported by this interface:

- Initialization (reset)
- Time synchronization
- Event record extraction
- General interrogation
- Cyclic measurements
- General commands
- Disturbance record extraction
- Private codes

4.1 Physical Connection and Link Layer

Two connection options are available for IEC60870-5-103, either the rear EIA(RS)485 port or an optional rear fiber optic port. Should the fiber optic port be fitted the selection of the active port can be made via the front panel menu or the front Courier port, however the selection will only be effective following the next relay power up.

For either of the two modes of connection it is possible to select both the relay address and baud rate using the front panel menu/front Courier. Following a change to either of these two settings a reset command is required to re-establish communications, see reset command description below.

4.2 Initialization

Whenever the relay has been powered up, or if the communication parameters have been changed a reset command is required to initialize the communications. The relay will respond to either of the two reset commands (Reset CU or Reset FCB), the difference being that the Reset CU will clear any unsent messages in the relay's transmit buffer.

The relay will respond to the reset command with an identification message ASDU 5, the Cause Of Transmission COT of this response will be either Reset CU or Reset FCB depending on the nature of the reset command. The content of ASDU 5 is described in the IEC60870-5-103 section of the menu database, P14x/EN MD.

In addition to the above identification message, if the relay has been powered up it will also produce a power up event.

4.3 Time Synchronization

The relay time and date can be set using the time synchronization feature of the IEC60870-5-103 protocol. The relay will correct for the transmission delay as specified in IEC60870-5-103. If the time synchronization message is sent as a send/confirm message then the relay will respond with a confirm. Whether the time-synchronization message is sent as a send confirm or a broadcast (send/no reply) message, a time synchronization Class 1 event will be generated/produced.

If the relay clock is being synchronized using the IRIG-B input then it will not be possible to set the relay time using the IEC60870-5-103 interface. An attempt to set the time via the interface will cause the relay to create an event with the current date and time taken from the IRIG-B synchronized internal clock.

4.4 Spontaneous Events

Events are categorized using the following information:

- Function type
- Information number

The IEC60870-5-103 profile in the menu database, P14x/EN MD, contains a complete listing of all events produced by the relay.

4.5 General Interrogation

The GI request can be used to read the status of the relay, the function numbers, and information numbers that will be returned during the GI cycle are indicated in the IEC60870-5-103 profile in the menu database, P14x/EN MD.

4.6 Cyclic Measurements

The relay will produce measured values using ASDU 9 on a cyclical basis, this can be read from the relay using a Class 2 poll (note ADSU 3 is not used). The rate at which the relay produces new measured values can be controlled using the measurement period setting. This setting can be edited from the front panel menu/front Courier port and is active immediately following a change.

It should be noted that the measurands transmitted by the relay are sent as a proportion of 2.4 times the rated value of the analog value.

4.7 Commands

A list of the supported commands is contained in the menu database, P14x/EN MD. The relay will respond to other commands with an ASDU 1, with a Cause Of Transmission (COT) indicating ‘**negative acknowledgement**’.

4.8 Test Mode

It is possible using either the front panel menu or the front Courier port to disable the relay output contacts to allow secondary injection testing to be performed. This is interpreted as ‘**test mode**’ by the IEC60870-5-103 standard. An event will be produced to indicate both entry to and exit from test mode. Spontaneous events and cyclic measured data transmitted whilst the relay is in test mode will have a COT of ‘**test mode**’.

4.9 Disturbance Records

The disturbance records are stored in uncompressed format and can be extracted using the standard mechanisms described in IEC60870-5-103.

Note	*IEC60870-5-103 only supports up to 8 records.*

4.10 Blocking of Monitor Direction

The relay supports a facility to block messages in the monitor direction and also in the command direction. Messages can be blocked in the monitor and command directions using the menu commands, Communications – CS103 Blocking – Disabled/Monitor Blocking/Command Blocking or DDB signals Monitor Blocked and Command Blocked.

4.11 Setting Changes through IEC103 Protocol

The IEC 870-5-103 Standard suggests using the generic services for read/write operations on the proprietary data of different manufacture protection equipments, the directory structure specified by the standard for accessing the generic data is the same as the Px40 setting structure. With the generic services selected in the Platform Software full access to the relay's database is possible over the first rear communications port using the IEC608070-5-103 protocol with Level 3 compatibility.

Each cell in the database has an attribute that defines whether it is included in the list of cells that are subject to a General Interrogation of Generic data. The following Group 1,2,3 and 4 settings will be included in the GGI:

- OVERCURRENT, NEG SEQ O/C, BROKEN CONDUCTOR, EARTH FAULT 1 and 2,
- SEF/REF PROT'N, RESIDUAL O/V NVD, THERMAL OVERLOAD, NEG SEQUENCE O/V,
- COLD LOAD PICKUP, SELECTIVE LOGIC, ADMIT PROTECTION, POWER PROTECTION,
- VOLT PROTECTION, FREQ PROTECTION, CB FAIL & I<, SUPERVISION,
- FAULT LOCATOR, SYSTEM CHECKS, AUTORECLOSE, ADV.FREQUENCY.

5 DNP3.0 INTERFACE

5.1 DNP3.0 Protocol

The descriptions given here are intended to accompany the device profile document that is included in the menu database, P14x/EN MD. The DNP3.0 protocol is not described here, please refer to the documentation available from the user group. The device profile document specifies the full details of the DNP3.0 implementation for the relay. This is the standard format DNP3.0 document that specifies which objects, variations and qualifiers are supported. The device profile document also specifies what data is available from the relay via DNP3.0. The relay operates as a DNP3.0 slave and supports subset level 2 of the protocol, plus some of the features from level 3.

DNP3.0 communication uses the EIA(RS)485 or fiber optic communication port at the rear of the relay. The data format is 1 start bit, 8 data bits, an optional parity bit and 1 stop bit. Parity is configurable (see menu settings below).

5.2 DNP3.0 Menu Setting

The settings shown below are available in the menu for DNP3.0 in the '**Communications**' column.

Setting	Range	Description
Remote Address	0 - 65534	DNP3.0 address of relay (decimal)
Baud Rate	1200, 2400, 4800, 9600, 19200, 38400	Selectable baud rate for DNP3.0 communication
Parity	None, Odd, Even	Parity setting
RP1 Physical link	Copper or Fiber Optic	This cell defines whether an electrical EIA(RS) 485 or fiber optic connection is being used for communication between the master station and relay. If 'Fiber Optic' is selected, the optional fiber optic communications board will be required
Time Sync.	Enabled, Disabled	Enables or disables the relay requesting time sync. from the master via IIN bit 4 word 1
Meas scaling	Primary, Secondary or Normalized	Setting to report analog values in terms of primary, secondary or normalized (with respect to the CT/VT ratio setting) values
Message gap	0 - 50 msec	Setting to allow the master station to have an interframe gap
DNP Need Time	1 - 30 mins	The duration of time waited, before requesting another time sync from the master
DNP App Fragment	100 - 2048 bytes	The maximum message length (application fragment size) transmitted by the relay
DNP App Timeout	1 -120s	Duration of time waited, after sending a message fragment and awaiting a confirmation from the master
DNP SBO Timeout	1 - 10s	Duration of time waited, after receiving a select command and awaiting an operate confirmation from the master
DNP Link Timeout	0 - 120s	Duration of time that the relay will wait for a Data Link Confirm from the master. A value of 0 means data link support disabled and 1 to 120 seconds is the timeout setting

Table 8 - DNP3.0 Menu Settings

In addition, if the DNP3.0 over Ethernet option has been chosen, further settings as shown in the following table, are presented.

Setting	Range	Description
DNP Time Sync.	Disabled or Enabled	If set to 'Enabled' the DNP3.0 master station can be used to synchronize the time on the relay. If set to 'Disabled' either the internal free running clock, or IRIG-B input are used
Meas. Scaling	Primary, Secondary or Normalized	Setting to report analog values in terms of primary, secondary or normalized (with respect to the CT/VT ratio setting) values
NIC Tunl Timeout	1 - 30 mins	Duration of time waited before an inactive tunnel to a master station is reset
NIC Link Report	Alarm, Event or None	Configures how a failed/unfitted network link (copper or fiber) is reported: Alarm - an alarm is raised for a failed link Event - an event is raised for a failed link None - nothing reported for a failed link
NIC Link Timeout	0.1 - 60s	Duration of time waited, after failed network link is detected, before communication by the alternative media interface is attempted

Table 9 - DNP3.0 Menu Settings with Ethernet option

5.3 Object 1 Binary Inputs

Object 1, binary inputs, contains information describing the state of signals within the relay which mostly form part of the Digital Data Bus (DDB). In general these include the state of the output contacts and input optos, alarm signals and protection start and trip signals. The '**DDB number**' column in the device profile document provides the DDB numbers for the DNP3.0 point data. These can be used to cross-reference to the DDB definition list that is also found in the menu database, P14x/EN MD. The binary input points can also be read as change events via object 2 and object 60 for class 1-3 event data.

5.4 Object 10 Binary Outputs

Object 10, binary outputs, contains commands that can be operated via DNP3.0. As such the points accept commands of type pulse on [null, trip, close] and latch on/off as detailed in the device profile in the menu database, P14x/EN MD and execute the command once for either command. The other fields are ignored (queue, clear, trip/close, in time and off time).

There is an additional image of the control inputs. Described as alias control inputs, they reflect the state of the control input, but with a dynamic nature.

The diagram below illustrates the behavior when the Control Input is set to Pulsed or Latched.

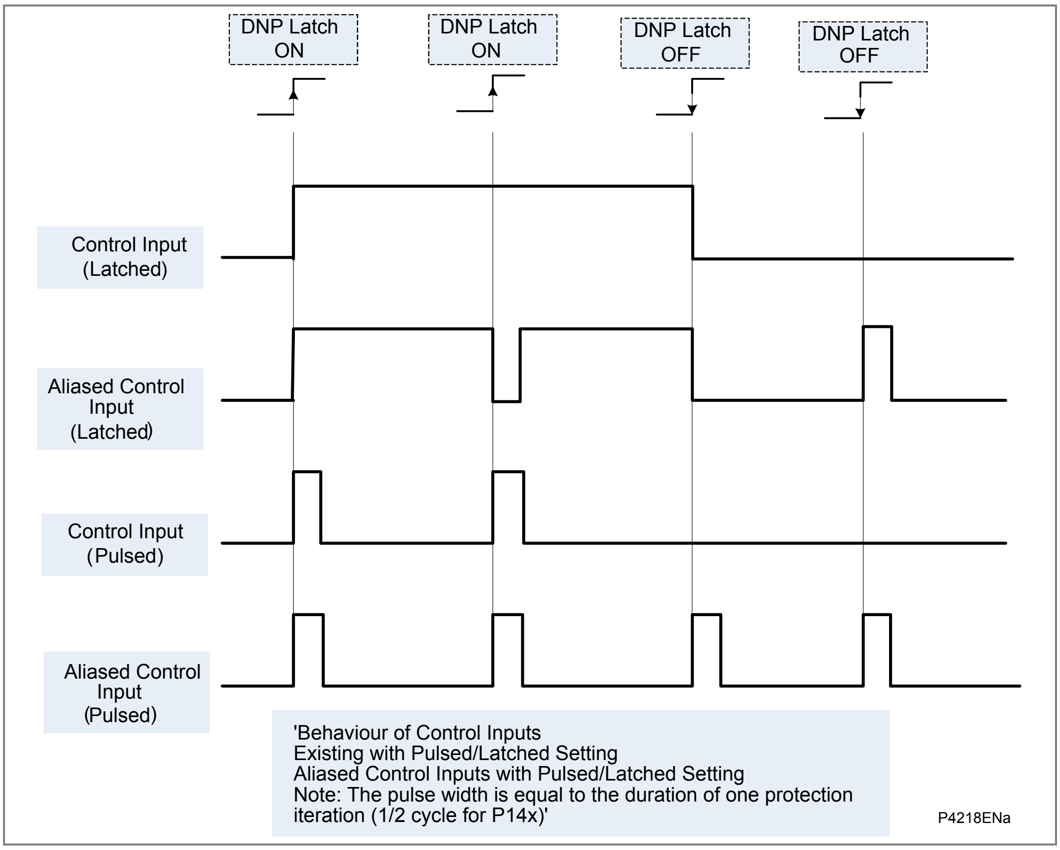


Figure 11 - Behavior of control inputs

Due to that fact that many of the relay's functions are configurable, it may be the case that some of the object 10 commands described below are not available for operation. In the case of a read from object 10 this will result in the point being reported as off-line and an operate command to object 12 will generate an error response.

Examples of object 10 points that maybe reported as off-line are:

- Activate setting groups Ensure setting groups are enabled
- CB trip/close - Ensure remote CB control is enabled
- Reset NPS thermal Ensure NPS thermal protection is enabled
- Reset thermal O/L Ensure thermal overload protection is enabled
- Reset RTD flags Ensure RTD Inputs is enabled
- Control Inputs Ensure control inputs are enabled

5.5 Object 20 Binary Counters

Object 20, binary counters, contains cumulative counters and measurements. The binary counters can be read as their present '**running**' value from object 20, or as a '**frozen**' value from object 21. The running counters of object 20 accept the read, freeze and clear functions. The freeze function takes the current value of the object 20 running counter and stores it in the corresponding object 21 frozen counter. The freeze and clear function resets the object 20 running counter to zero after freezing its value. Binary counter and frozen counter change event values are available for reporting from object 22 and object 23 respectively. Counter change events (object 22) only report the most recent change, so the maximum number of events supported is the same as the total number of counters. Frozen counter change events (object 23) are generated when ever a freeze operation is performed and a change has occurred since the previous freeze command. The frozen counter event queues will store the points for up to two freeze operations.

5.6 Object 30 Analog Input

Object 30, analog inputs, contains information from the relay's measurements columns in the menu. All object 30 points can be reported as 16 or 32 bit integer values with flag, 16 or 32 bit integer without flag as well as short floating-point values. Analogue values can be reported to the master station as primary, secondary or normalized values (which takes into account the relay's CT and VT ratios) and this is settable in the DNP3.0 Communications Column on the relay. Corresponding deadband settings can be displayed in terms of a primary, secondary or normalized value. Deadband point values can be reported and written too using Object 34 variations. The deadband is the setting used to determine whether a change event should be generated for each point. The change events can be read via object 32 or object 60 and will be generated for any point whose value has changed by more than the deadband setting since the last time the data value was reported.

Any analog measurement that is unavailable at the time it is read will be reported as offline, e.g. the frequency when the current and voltage frequency is outside the tracking range of the relay or the thermal state when the thermal protection is disabled in the configuration column.

The following fault data can be mapped in DNP3.0 protocol in serial and Ethernet connections:

- Fault voltages
- Fault currents
- Fault location
- Operating time of relay
- Operating time of breaker
- Fault time
- Fault date

The latest fault records only will be retrieved over DNP3.0.

5.7 Object 40 Analog Output

The conversion to fixed-point format requires the use of a scaling factor, which is configurable for the various types of data within the relay e.g. current, voltage, phase angle etc. All Object 40 points report the integer scaling values and Object 41 is available to configure integer scaling quantities.

5.8 DNP3.0 Configuration using MiCOM S1 Studio

A PC support package for DNP3.0 is available as part of the settings and records module of MiCOM S1 Studio. The S1 module allows configuration of the relay's DNP3.0 response. The PC is connected to the relay via a serial cable to the 9-pin front part of the relay – see Introduction (P14x/EN IT). The configuration data is uploaded from the relay to the PC in a block of compressed format data and downloaded to the relay in a similar manner after modification. The new DNP3.0 configuration takes effect in the relay after the download is complete. The default configuration can be restored at any time by choosing '**All Settings**' from the '**Restore Defaults**' cell in the menu '**Configuration**' column. In S1, the DNP3.0 data is displayed on a three main tabbed screens, one screen each for the point configuration, integer scaling and default variation (data format). The point configuration also includes tabs for binary inputs, binary outputs, counters and analogue input configuration.

Please refer to the DNP3.0 Configurator Tool User guide (S1V2DNP/EN HI/A11) for details regarding the configuration of binary points, analogues and reporting format.

6 IEC61850 ETHERNET INTERFACE

6.1 Introduction

IEC 61850 is the international standard for Ethernet-based communication in substations. It enables integration of all protection, control, measurement and monitoring functions within a substation, and additionally provides the means for interlocking and inter-tripping. It combines the convenience of Ethernet with the security which is essential in substations today.

The MiCOM protection relays can integrate with the PACiS substation control systems, to complete our offer of a full IEC 61850 solution for the substation. The majority of MiCOM Px3x and Px4x relay types can be supplied with Ethernet, in addition to traditional serial protocols. Relays which have already been delivered with UCA2.0 on Ethernet can be easily upgraded to IEC 61850.

6.2 What is IEC 61850?

IEC 61850 is an international standard, comprising 14 parts, which defines a communication architecture for substations.

The standard defines and offers much more than just a protocol. It provides:

- Standardized models for IEDs and other equipment within the substation
- Standardized communication services (the methods used to access and exchange data)
- Standardized formats for configuration files
- Peer-to-peer (e.g. relay to relay) communication

The standard includes mapping of data onto Ethernet. Using Ethernet in the substation offers many advantages, most significantly including:

- High-speed data rates (currently 100 Mbits/s, rather than 10's of kbits/s or less used by most serial protocols)
- Multiple masters (called "**clients**")
- Ethernet is an open standard in every-day use

Schneider Electric has been involved in the Working Groups which formed the standard, building on experience gained with UCA2.0, the predecessor of IEC 61850.

6.2.1 Interoperability

A major benefit of IEC 61850 is interoperability. IEC 61850 standardizes the data model of substation IEDs. This responds to the utilities' desire of having easier integration for different vendors' products, i.e. interoperability. It means that data is accessed in the same manner in different IEDs from either the same or different IED vendors, even though, for example, the protection algorithms of different vendors' relay types remain different.

When a device is described as IEC 61850-compliant, this does not mean that it is interchangeable, but does mean that it is interoperable. You cannot simply replace one product with another, however the terminology is pre-defined and anyone with prior knowledge of IEC 61850 should be able very quickly integrate a new device without the need for mapping of all of the new data. IEC 61850 will inevitably bring improved substation communications and interoperability, at a lower cost to the end user.

6.2.2 Data Model

To ease understanding, the data model of any IEC 61850 IED can be viewed as a hierarchy of information. The categories and naming of this information is standardized in the IEC 61850 specification.

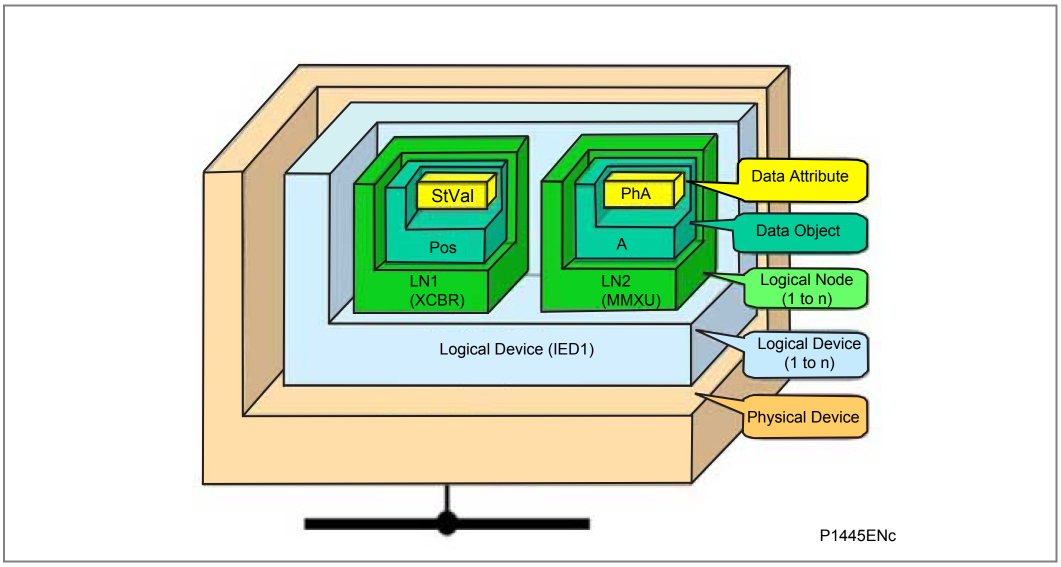


Figure 12 - Data model layers in IEC 61850

The levels of this hierarchy can be described as follows:

Physical Device	Identifies the actual IED within a system. Typically the device's name or IP address can be used (for example **Feeder_1** or **10.0.0.2**).
Logical Device	Identifies groups of related Logical Nodes within the Physical Device. For the MiCOM relays, 5 Logical Devices exist: **Control, Measurements, Protection, Records, System**.
Wrapper/Logical Node Instance	Identifies the major functional areas within the IEC 61850 data model. Either 3 or 6 characters are used as a prefix to define the functional group (wrapper) while the actual functionality is identified by a 4 character Logical Node name suffixed by an instance number. For example, XCBR1 (circuit breaker), MMXU1 (measurements), FrqPTOF2 (overfrequency protection, stage 2).
Data Object	This next layer is used to identify the type of data you will be presented with. For example, **Pos** (position) of Logical Node type **XCBR**.
Data Attribute	This is the actual data (measurement value, status, description, etc.). For example, **stVal** (status value) indicating actual position of circuit breaker for Data Object type **Pos** of Logical Node type **XCBR**.

6.3 IEC 61850 in MiCOM Relays

IEC 61850 is implemented in MiCOM relays by use of a separate Ethernet card. This card manages the majority of the IEC 61850 implementation and data transfer to avoid any impact on the performance of the protection.

In order to communicate with an IEC 61850 IED on Ethernet, it is necessary only to know its IP address. This can then be configured into either:

- An IEC 61850 "**client**" (or master), for example a PACiS computer (MiCOM C264) or HMI, or
- An "**MMS browser**", with which the full data model can be retrieved from the IED, without any prior knowledge

6.3.1 Capability

The IEC 61850 interface provides the following capabilities:

1. Read access to measurements

   All measurands are presented using the measurement Logical Nodes, in the '**Measurements**' Logical Device. Reported measurement values are refreshed by the relay once per second, in line with the relay user interface.

2. Generation of unbuffered reports on change of status/measurement

   Unbuffered reports, when enabled, report any change of state in statuses and/or measurements (according to deadband settings).

3. Support for time synchronization over an Ethernet link

   Time synchronization is supported using SNTP (Simple Network Time Protocol); this protocol is used to synchronize the internal real time clock of the relays.

4. GOOSE peer-to-peer communication

   GOOSE communications of statuses are included as part of the IEC 61850 implementation. Please see section 6.6 for more details.

5. Disturbance record extraction

   Extraction of disturbance records, by file transfer, is supported by the MiCOM relays. The record is extracted as an ASCII format COMTRADE file.

6. Controls

   The following control services are available:

   Direct Control

   Direct Control with enhanced security

   Select Before Operate (SBO) with enhanced security

   Controls shall be applied to open and close circuit breakers via XCBR.Pos and DDB signals '**Control Trip**' and '**Control Clo**se'.

   System/LLN0. LLN0.LEDRs shall be used to reset any trip LED indications.

6. Reports

   Reports only include data objects that have changed and not the complete dataset. The exceptions to this are a General Interrogation request and integrity reports.

   Buffered Reports

      Eight Buffered Report Control Blocks, (BRCB), are provided in SYSTEM/LLN0 in Logical Device '**System**'

      Buffered reports are configurable to use any configurable dataset located in the same Logical device as the BRCB (i.e. SYSTEM/LLN0)

   Unbuffered Reports

      Sixteen Unbuffered Report Control Blocks, (URCB) are provided in SYSTEM/LLN0 in Logical Device '**System**'

   Unbuffered reports are configurable to use any configurable dataset located in the same Logical device as the URCB (i.e. SYSTEM/LLN0)

7. Configurable data sets

   It is possible to create and configure datasets in any Logical Node using the IED Configurator. The maximum number of datasets will be specified in an IED's ICD file. An IED is capable of handling 100 datasets.

8. Published GOOSE message

   Eight GOCBs are provided in SYSTEM/LLN0.

9. Uniqueness of control

   Uniqueness of control mechanism is implemented in the P14x to have consistency with the PACiS mechanism. This requires the relay to subscribe to the OrdRun signal from all devices in the system and be able to publish such a signal in a GOOSE message.

10. Select active setting group

    Functional protection groups can be enabled/disabled via private mod/beh attributes in Protection/LLN0.OcpMod object. Setting groups are selectable using the Setting Group Control Block class, (SGCB). The Active Setting Group can be selected using the System/LLN0.SP.SGCB.ActSG data attribute in Logical Device '**System**'.

11. Quality for GOOSE

    It is possible to process the quality attributes of any Data Object in an incoming GOOSE message. Devices that do not support IEC 61850 quality flags shall send quality attributes as all zeros.

12. Address List

    An Address List document (to be titled ADL) is produced for each IED which shows the mapping between the IEC 61850 data model and the internal data model of the IED. It includes a mapping in the reverse direction, which may be more useful. This document is separate from the PICS/MICS document.

13. Originator of control

    Originator of control mechanism is implemented for operate response message and in the data model on the ST of the related control object, consistent with the PACiS mechanism.

14. Metering

    MMTR (metering) logical node is implemented in P14x. All metered values in the MMTR logical node are of type BCR. The actVal attribute of the BCR class is of type INT128, but this type is not supported by the SISCO MMSLite library. Instead, an INT64 value will be encoded for transmission.

    A SPC data object named MTTRs has been included in the MMTR logical node. This control will reset the demand measurements. A SPC data object named MTTRs is also included in the PTTR logical node. This control will reset the thermal measurements.

15. Scaled measurements

    The Unit definition, as per IEC specifies an SI unit and an optional multiplier for each measurement. This allows a magnitude of measurement to be specified e.g. mA, A, kA, MA.

    The multiplier will always be included in the Unit definition and will be configurable in SCL, but not settable at runtime. It will apply to the magnitude, rangeC.min & rangeC.max attributes. rangeC.min & rangeC.max will not be settable at runtime to be more consistent with Px30 and to reduce configuration problems regarding deadbands.

    Setting changes (e.g. of protection settings) are not supported in the current IEC 61850 implementation. In order to keep this process as simple as possible, such setting changes are done using MiCOM S1 Studio Settings & Records program. This can be done as previously using the front port serial connection of the relay, or now optionally over the Ethernet link if preferred (this is known as "**tunneling**").

6.3.2 IEC 61850 Configuration

One of the main objectives of IEC 61850 is to allow IEDs to be directly configured from a configuration file generated at system configuration time. At the system configuration level, the capabilities of the IED are determined from an IED Capability Description file (ICD) which is provided with the product. Using a collection of these ICD files from varying products, the entire protection of a substation can be designed, configured and tested (using simulation tools) before the product is even installed into the substation.

To aid in this process, the MiCOM S1 Studio Support Software provides an IED Configurator tool which allows the pre-configured IEC 61850 configuration file (an SCD file or CID file) to be imported and transferred to the IED. Alongside this, the requirements of manual configuration are satisfied by allowing the manual creation of configuration files for MiCOM relays based on their original IED Capability Description (ICD file).

Other features include the extraction of configuration data for viewing and editing, and a sophisticated error checking sequence which ensures that the configuration data is valid for sending to the IED and that the IED will function within the context of the substation.

To aid the user, some configuration data is available in the ‘**IED CONFIGURATOR**’ column of the relay user interface, allowing read-only access to basic configuration data.

6.3.2.1 Configuration Banks

To promote version management and minimize down-time during system upgrades and maintenance, the MiCOM relays have incorporated a mechanism consisting of multiple configuration banks. These configuration banks are categorized as:

- Active Configuration Bank
- Inactive Configuration Bank

Any new configuration sent to the relay is automatically stored into the inactive configuration bank, therefore not immediately affecting the current configuration. Both active and inactive configuration banks can be extracted at anytime.

When the upgrade or maintenance stage is complete, the IED Configurator tool can be used to transmit a command (to a single IED) authorizing the activation of the new configuration contained in the inactive configuration bank, by switching the active and inactive configuration banks. This technique ensures that the system down-time is minimized to the start-up time of the new configuration. The capability to switch the configuration banks is also available via the ‘**IED CONFIGURATOR**’ column.

For version management, data is available in the ‘**IED CONFIGURATOR**’ column in the relay user interface, displaying the SCL Name and Revision attributes of both configuration banks.

6.3.2.2 Network Connectivity

Note	*This section presumes a prior knowledge of IP addressing and related topics. Further details on this topic may be found on the Internet (search for IP Configuration) and in numerous relevant books.*

Configuration of the relay IP parameters (IP Address, Subnet Mask, Gateway) and SNTP time synchronization parameters (SNTP Server 1, SNTP Server 2) is performed by the IED Configurator tool, so if these parameters are not available via an SCL file, they must be configured manually.

If the assigned IP address is duplicated elsewhere on the same network, the remote communications will operate in an indeterminate way. However, the relay will check for a conflict on every IP configuration change and at power up. An alarm will be raised if an

IP conflict is detected. The relay can be configured to accept data from networks other than the local network by using the '**Gateway**' setting.

6.4 Data Model of MiCOM Relays

The data model naming adopted in the Px30 and Px40 relays has been standardized for consistency. Hence the Logical Nodes are allocated to one of the five Logical Devices, as appropriate, and the wrapper names used to instantiate Logical Nodes are consistent between Px30 and Px40 relays.

The data model is described in the Model Implementation Conformance Statement (MICS) document, which is available separately. The MICS document provides lists of Logical Device definitions, Logical Node definitions, Common Data Class and Attribute definitions, Enumeration definitions, and MMS data type conversions. It generally follows the format used in Parts 7-3 and 7-4 of the IEC 61850 standard.

6.5 Communication Services of MiCOM Relays

The IEC 61850 communication services which are implemented in the Px30 and Px40 relays are described in the Protocol Implementation Conformance Statement (PICS) document, which is available separately. The PICS document provides the Abstract Communication Service Interface (ACSI) conformance statements as defined in Annex A of Part 7-2 of the IEC 61850 standard.

6.6 Peer-to-Peer (GSE) Communications

The implementation of IEC 61850 Generic Substation Event (GSE) sets the way for cheaper and faster inter-relay communications. The generic substation event model provides the possibility for a fast and reliable system-wide distribution of input and output data values. The generic substation event model is based on the concept of an autonomous decentralization, providing an efficient method allowing the simultaneous delivery of the same generic substation event information to more than one physical device through the use of multicast services.

The use of multicast messaging means that IEC 61850 GOOSE uses a publisher-subscriber system to transfer information around the network*. When a device detects a change in one of its monitored status points it publishes (i.e. sends) a new message. Any device that is interested in the information subscribes (i.e. listens) to the data it contains.

*Note**	*Multicast messages cannot be routed across networks without specialized equipment.*

Each new message is re-transmitted at user-configurable intervals until the maximum interval is reached, in order to overcome possible corruption due to interference, and collisions. In practice, the parameters which control the message transmission cannot be calculated. Time must be allocated to the testing of GSE schemes before or during commissioning, in just the same way a hardwired scheme must be tested.

Each new message is re-transmitted at user-configurable intervals until the maximum interval is reached, in order to overcome possible corruption due to interference, and collisions. In practice, the parameters which control the message transmission cannot be calculated. Time must be allocated to the testing of GSE schemes before or during commissioning, in just the same way a hardwired scheme must be tested.

6.6.1 Scope

A maximum of 128 virtual inputs are available within the PSL which can be mapped directly to a published dataset in a GOOSE message (Configurable dataset is supported).

Each GOOSE signal contained in a subscribed GOOSE message can be mapped to any of the 128 virtual inputs within the PSL. The virtual inputs allow the mapping to internal logic functions for protection control, directly to output contacts or LEDs for monitoring.

The MiCOM relay can subscribe to all GOOSE messages but only the following data types can be decoded and mapped to a virtual input:

- BOOLEAN
- BSTR2
- INT16
- INT32
- INT8
- UINT16
- UINT32
- UINT8

6.6.2 IEC 61850 GOOSE Configuration

All GOOSE configuration is performed via the IED Configurator tool available within the MiCOM S1 Studio Support Software.

All GOOSE publishing configuration can be found under the '**GOOSE Publishing**' tab in the configuration editor window. All GOOSE subscription configuration can be found under the '**GOOSE SUBSCRIBE**' tab in the configuration editor window. Care should be taken to ensure that the configuration is correct, to ensure efficient GOOSE scheme operation.

Settings to enable GOOSE signalling and to apply Test Mode are available via the relay user interface.

6.7 Ethernet Functionality

Settings relating to a failed Ethernet link are available in the '**COMMUNICATIONS**' column of the relay user interface.

6.7.1 Ethernet Disconnection

IEC 61850 '**associations**' are unique and made to the relay between the client (master) and server (IEC 61850 device). In the event that the Ethernet is disconnected, such associations are lost, and will need to be re-established by the client. The TCP_KEEPALIVE function is implemented in the relay to monitor each association, and terminate any which are no longer active.

6.7.2 Loss of Power

The relay allows the re-establishment of associations by the client without a negative impact on the relay's operation after having its power removed. As the relay acts as a server in this process, the client must request the association. Uncommitted settings are cancelled when power is lost, and reports requested by connected clients are reset and must be re-enabled by the client when it next creates the new association to the relay.

7 SK5 PORT CONNECTION

The lower 9-way D-type connector (SK5) is the InterMiCOM port, which is based on the EIA232 standard.

INSTALLATION

CHAPTER 17

Date (month/year):	07/2014			
Products covered by this chapter:	P14x (P141, P142, P143 & P145), P24x (P241, P242 & P243), P34x (P342, P343, P344, P345), P44x (P441, P442 & P444), P44y (P443 & P446), P445, P54x (P543, P544, P545 & P546), P547, P64x (P642, P643, P645), P74x (P741, P742 & P743), P746, P841 & P849			
Hardware suffix:	J & K & L & M			
	P14x	J	P445	J / L
	P241	J	P54x	K / M
	P242	K	P547	K
	P243	K	P642	J / L
	P342	J	P643	K / M
	P343	K	P645	K / M
	P344	K	P74x	J / K
	P345	K	P746	K
	P44x	J / K	P841	K
	P44y	K / M	P849	K
Software version:	All			
Connection diagrams:	10P141xx (xx = 01 to 07) 10P142xx (xx = 01 to 07) 10P143xx (xx = 01 to 07) 10P145xx (xx = 01 to 07) 10P241xx (xx = 01 to 02) 10P242xx (xx = 01) 10P243xx (xx = 01) 10P342xx (xx = 01 to 17) 10P343xx (xx = 01 to 19) 10P344xx (xx = 01 to 12) 10P345xx (xx = 01 to 07) 10P391xx (xx = 01 to 02) 10P44303 (SH 01 and 03) 10P44304 (SH 01 and 03) 10P44305 (SH 01 and 03) 10P44306 (SH 01 and 03) 10P445xx (xx = 01 to 04) 10P44600 10P44601 (SH 01 and 03) 10P44602 (SH 01 and 03) 10P44603 (SH 01 and 03) 10P54302 (SH 01 to 02) 10P54303 (SH 01 to 02)		10P54400 10P54404 (SH 01 to 02) 10P54405 (SH 01 to 02) 10P54502 (SH 01 to 02) 10P54503 (SH 01 to 02) 10P54600 10P54604 (SH 01 to 02) 10P54605 (SH 01 to 02) 10P54606 (SH 01 to 02) 10P54702xx (Sh 1 to 2) 10P54703xx (Sh 1 to 2) 10P54704xx (Sh 1 to 2) 10P54705xx (Sh 1 to 2) 10P642xx (xx = 01 to 10) 10P643xx (xx = 01 to 06) 10P645xx (xx = 01 to 09) 10P740xx (xx = 01 to 07) 10P746xx (xx = 01 to 07) 10P84100 10P84101 (Sh 1 to 2) 10P84102 (Sh 1 to 2) 10P84103 (Sh 1 to 2) 10P84104 (Sh 1 to 2) 10P84105 (Sh 1 to 2) 10P849xx (xx = 01 to 06)	

CONTENTS

TABLES

FIGURES

1 INTRODUCTION TO MICOM RANGE

About MiCOM Range

MiCOM is a comprehensive solution capable of meeting all electricity supply requirements. It comprises a range of components, systems and services from Schneider Electric.

Central to the MiCOM concept is flexibility. MiCOM provides the ability to define an application solution and, through extensive communication capabilities, integrate it with your power supply control system.

The components within MiCOM are:

- P range protection relays;
- C range control products;
- M range measurement products for accurate metering and monitoring;
- S range versatile PC support and substation control packages.

MiCOM products include extensive facilities for recording information on the state and behaviour of the power system using disturbance and fault records. They can also provide measurements of the system at regular intervals to a control centre enabling remote monitoring and control to take place.

For up-to-date information, please see: www.schneider-electric.com

MiCOM Px4x Products

The MiCOM Px4x series of protection devices provide a wide range of protection and control functions and meet the requirements of a wide market segment.

Different parts of the Px4x range provide different functions. These include:

- **P14x** **Feeder Management** relay suitable for MV and HV systems
- **P24x** **Motors** and rotating machine management relay for use on a wide range of synchronous and induction machines
- **P34x** **Generator Protection** for small to sophisticated generator systems and interconnection protection
- **P44x** Full scheme **Distance Protection** relays for MV, HV and EHV systems
- **P54x** **Line Differential** protection relays for HV/EHV systems with multiple communication options and phase comparison protection for use with PLC
- **P74x** **Numerical Busbar Protection** for use on MV, HV and EHV busbars
- **P84x** **Breaker Failure** protection relays

Note	*During 2011, the International Electrotechnical Commission classified the voltages into different levels (IEC 60038). The IEC defined LV, MV, HV and EHV as follows: LV is up to 1000V. MV is from 1000V up to 35 kV. HV is from 110 kV or 230 kV. EHV is above 230 KV.* *There is still ambiguity about where each band starts and ends. A voltage level defined as LV in one country or sector, may be described as MV in a different country or sector. Accordingly, LV, MV, HV and EHV suggests a possible range, rather than a fixed band. Please refer to your local Schneider Electric office for more guidance.*

2 RECEIPT, HANDLING, STORAGE AND UNPACKING RELAYS

2.1 Receipt of Relays

Protective relays, although generally of robust construction, require careful treatment prior to installation on site.

Upon receipt, relays should be examined immediately to ensure no external damage has been sustained in transit. If damage has been sustained, a claim should be made to the transport contractor and Schneider Electric should be promptly notified.

Relays that are supplied unmounted and not intended for immediate installation should be returned to their protective polythene bags and delivery carton. Section 2.3 gives more information about the storage of relays.

2.2 Handling of Electronic Equipment

Warning **Before carrying out any work on the equipment, you should be familiar with the contents of the Safety Information chapter/safety guide SFTY/4LM/C11 or later issue, the Technical Data chapter and the ratings on the equipment rating label.**

A person's normal movements can easily generate electrostatic potentials of several thousand volts. Discharge of these voltages into semiconductor devices when handling electronic circuits can cause serious damage which, although not always immediately apparent, will reduce the reliability of the circuit. This is particularly important to consider where the circuits use Complementary Metal Oxide Semiconductors (CMOS), as is the case with these relays.

The relay's electronic circuits are protected from electrostatic discharge when housed in the case. Do not expose them to risk by removing the front panel or Printed Circuit Boards (PCBs) unnecessarily.

Each PCB incorporates the highest practicable protection for its semiconductor devices. However, if it becomes necessary to remove a PCB, the following precautions should be taken to preserve the high reliability and long life for which the relay has been designed and manufactured.

- Before removing a PCB, ensure that you are at the same electrostatic potential as the equipment by touching the case.
- Handle analogue input modules by the front panel, frame or edges of the circuit boards. PCBs should only be handled by their edges. Avoid touching the electronic components, printed circuit tracks or connectors.
- Do not pass the module to another person without first ensuring you are both at the same electrostatic potential. Shaking hands achieves equipotential.
- Place the module on an anti-static surface, or on a conducting surface which is at the same potential as yourself.
- If it is necessary to store or transport printed circuit boards removed from the case, place them individually in electrically conducting anti-static bags.

In the unlikely event that you are making measurements on the internal electronic circuitry of a relay in service, it is preferable that you are earthed to the case with a conductive wrist strap. Wrist straps should have a resistance to ground between 500kΩ to 10MΩ. If a wrist strap is not available you should maintain regular contact with the case to prevent a build-up of electrostatic potential. Instrumentation which may be used for making measurements should also be earthed to the case whenever possible.

More information on safe working procedures for all electronic equipment can be found in IEC 61340-5-1. It is strongly recommended that detailed investigations on electronic circuitry or modification work should be carried out in a special handling area such as described in the aforementioned Standard document.

2.3 Storage

If relays are not to be installed immediately upon receipt, they should be stored in a place free from dust and moisture in their original cartons. Where de-humidifier bags have been included in the packing they should be retained. The action of the de-humidifier crystals will be impaired if the bag is exposed to ambient conditions and may be restored by gently heating the bag for about an hour prior to replacing it in the carton.

To prevent battery drain during transportation and storage a battery isolation strip is fitted during manufacture. With the lower access cover open, presence of the battery isolation strip can be checked by a red tab protruding from the positive side.

Care should be taken on subsequent unpacking that any dust which has collected on the carton does not fall inside. In locations of high humidity the carton and packing may become impregnated with moisture and the de-humidifier crystals will lose their efficiency.

Prior to installation, relays should be stored at a temperature of between -40°C to +70°C (-13°F to +158°F).

2.4 Unpacking

Care must be taken when unpacking and installing the relays so that none of the parts are damaged and additional components are not accidentally left in the packing or lost. Make sure that any user’s CDROM or technical documentation is NOT discarded, and accompanies the relay to its destination substation.

Note	*With the lower access cover open, the red tab of the battery isolation strip will be seen protruding from the positive side of the battery compartment. Do not remove this strip because it prevents battery drain during transportation and storage and will be removed as part of the commissioning tests.*

Relays must only be handled by skilled persons.

The site should be well lit to facilitate inspection, clean, dry and reasonably free from dust and excessive vibration. This particularly applies to installations which are being carried out at the same time as construction work.

3 RELAY MOUNTING

MiCOM relays are dispatched either individually or as part of a panel/rack assembly.

Individual relays are normally supplied with an outline diagram showing the dimensions for panel cut-outs and hole centres. This information can also be found in the product publication.

Secondary front covers can also be supplied as an option item to prevent unauthorised changing of settings and alarm status. They are available in sizes 40TE and 60TE. The 60TE cover also fits the 80TE case size of the relay.

Product	Size	Part No
P14x	40TE 60TE / 80TE	GN0037 001 GN0038 001
P24xxxxxxxxxxxA P24xxxxxxxxxxxC	40TE 60TE / 80TE	GN0037 001 GN0038 001
P24xxxxxxxxxxxJ P24xxxxxxxxxxxK	40TE 60TE / 80TE	GN0242 001 GN0243 001
P34xxxxxxxxxxxA P34xxxxxxxxxxxC	40TE 60TE / 80TE	GN0037 001 GN0038 001
P34xxxxxxxxxxxJ P34xxxxxxxxxxxK	40TE 60TE / 80TE	GN0242 001 GN0243 001
P44x	40TE 60TE / 80TE	GN0037 001 GN0038 001
P44y	60TE / 80TE	GN0038 001
P445	40TE 60TE / 80TE	GN0037001 GN0038 001
P54x	60TE / 80TE	GN0038 001
P547	60TE / 80TE	GN0038 001
P64xxxxxxxxxxxA/B/C	40TE 60TE / 80TE	GN0037 001 GN0038 001
P64xxxxxxxxxxxJ/K	40TE 60TE / 80TE	GN0242 001 GN0243 001
P74x P74x	40TE 60TE	GN0037 001 GN0038 001
P746	40TE 60TE	GN0037 001 GN0038 001
P841	60TE / 80TE	GN0038 001
P849	40TE 60TE / 80TE	GN0037 001 GN0038 001

Note *The Part Numbers suitable for rack-mounting have an “N” as the 10th digit.*
The Part Numbers suitable for panel-mounting have an “M” as the 10th digit.

Table 1 – Products, sizes and part numbers

The design of the relay is such that the fixing holes in the mounting flanges are only accessible when the access covers are open and hidden from sight when the covers are closed.

If a P991 or MMLG test block is to be included with the relays, we recommend that you position the test block on the right-hand side of the associated relays (when viewed from the front). This minimises the wiring between the relay and test block, and allows the correct test block to be easily identified during commissioning and maintenance tests.

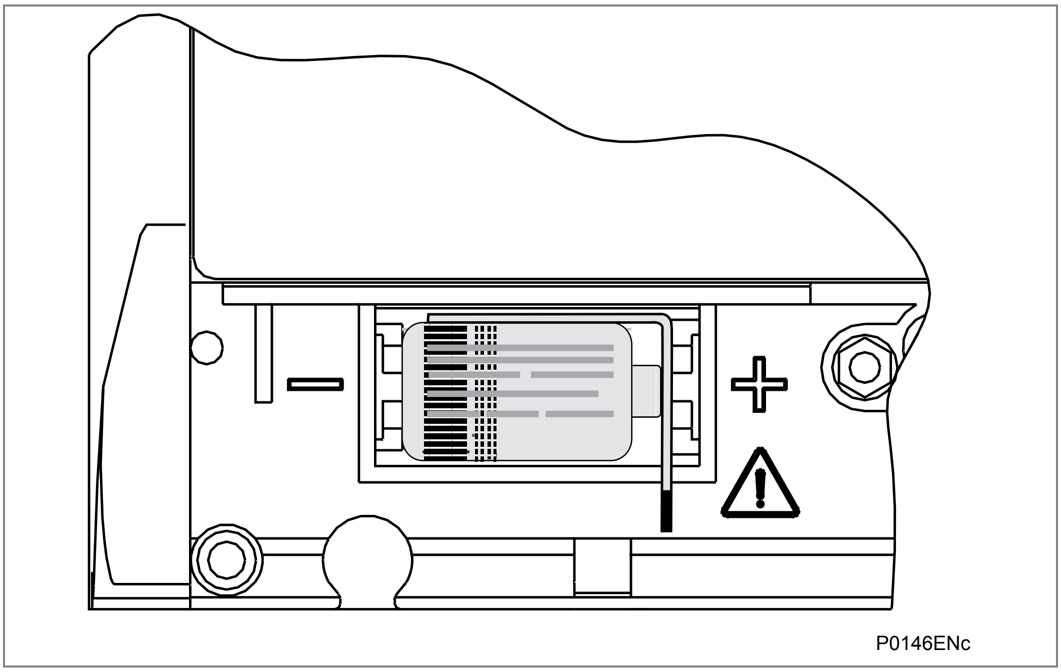


Figure 1 - Location of battery isolation strip

If you need to test correct relay operation during the installation, the battery isolation strip can be removed but should be replaced if commissioning of the scheme is not imminent. This will prevent unnecessary battery drain during transportation to site and installation. The red tab of the isolation strip can be seen protruding from the positive side of the battery compartment when the lower access cover is open. To remove the isolation strip, pull the red tab whilst lightly pressing the battery to prevent it falling out of the compartment. When replacing the battery isolation strip, ensure that the strip is refitted as shown in Figure 1, i.e. with the strip behind the battery with the red tab protruding.

3.1 Rack Mounting

Virtually all MiCOM relays (apart from P445) can be rack mounted using single tier rack frames (part number FX0021 101), see Figure 2. These frames have dimensions in accordance with IEC 60297 and are supplied pre-assembled ready to use. On a standard 483 mm rack this enables combinations of case widths up to a total equivalent of size 80TE to be mounted side-by-side.

The two horizontal rails of the rack frame have holes drilled at approximately 26 mm intervals and the relays are attached via their mounting flanges using M4 Taptite self-tapping screws with captive 3 mm thick washers (also known as a SEMS unit). These fastenings are available in packs of 5 (part number ZA0005 104).

Note	*Conventional self-tapping screws, including those supplied for mounting MiDOS relays, have marginally larger heads which can damage the front cover molding if used.*

Warning	**Risk of damage to the front cover moulding. Do not use conventional self-tapping screws, including those supplied for mounting MiDOS relays because they have slightly larger heads.**

Once the tier is complete, the frames are fastened into the racks using mounting angles at each end of the tier.

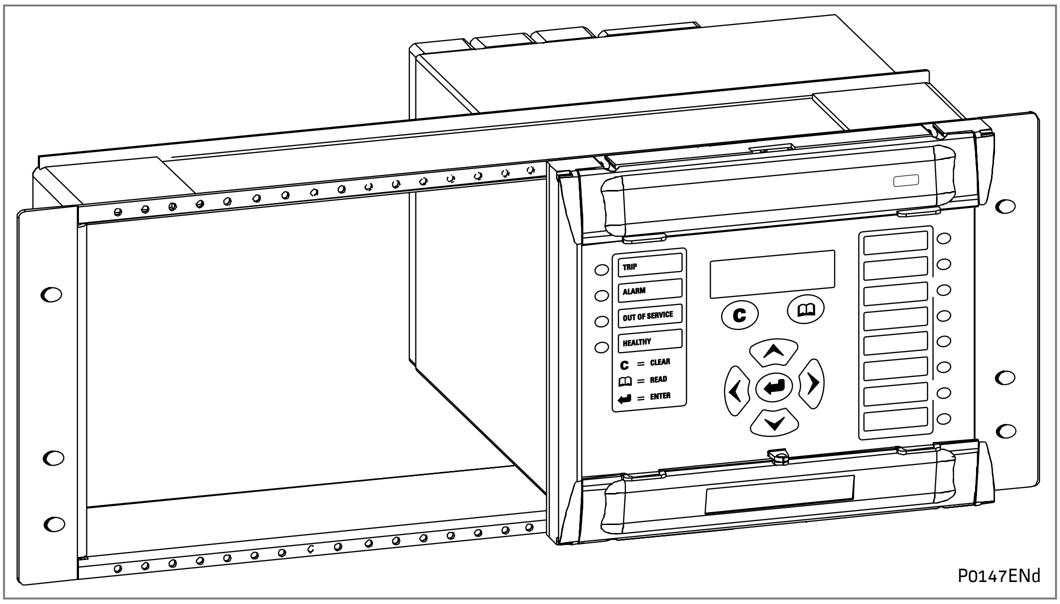


Figure 2 - Rack mounting of relays

Relays can be mechanically grouped into single tier (4U) or multi-tier arrangements by the rack frame. This enables schemes using products from the MiCOM and MiDOS product ranges to be pre-wired together prior to mounting.

Use blanking plates if there are empty spaces. The spaces may be for future installation of relays or because the total size is less than 80TE on any tier. Blanking plates can also be used to mount ancillary components. Table 2 shows the sizes that can be ordered.

Note	*Blanking plates are only available in black.*

Further details on mounting MiDOS relays can be found in publication R7012, “MiDOS Parts Catalogue and Assembly Instructions”.

Case size summation	Blanking plate part number
5TE	GJ2028 101
10TE	GJ2028 102
15TE	GJ2028 103
20TE	GJ2028 104
25TE	GJ2028 105
30TE	GJ2028 106
35TE	GJ2028 107
40TE	GJ2028 108

Table 2 - Blanking plates

3.2 Panel Mounting

The relays can be flush mounted into panels using M4 SEMS Taptite self-tapping screws with captive 3 mm thick washers (also known as a SEMS unit). These fastenings are available in packs of 5 (part number ZA0005 104).

Note	*Conventional self-tapping screws, including those supplied for mounting MiDOS relays, have marginally larger heads which can damage the front cover molding if used.*

Warning	**Risk of damage to the front cover molding. Do not use conventional self-tapping screws, including those supplied for mounting MiDOS relays because they have slightly larger heads.**

Alternatively tapped holes can be used if the panel has a minimum thickness of 2.5 mm.

For applications where relays need to be semi-projection or projection mounted, a range of collars are available from the Schneider Electric Contracts Department.

If several relays are mounted in a single cut-out in the panel, mechanically group them together horizontally or vertically to form rigid assemblies prior to mounting in the panel.

Note	*Fastening MiCOM relays with pop rivets is not advised because this does not allow easy removal if repair is necessary.*

Rack-mounting panel-mounted versions: it is possible to rack-mount some relay versions which have been designed to be panel-mounted. The relay is mounted on a single-tier rack frame, which occupies the full width of the rack. To make sure a panel-mounted relay assembly complies with BS EN60529 IP52, fit a metallic sealing strip between adjoining relays (Part No GN2044 001) and a sealing ring from Table 3 around the complete assembly.

Width	Single tier	Double tier
10TE	GJ9018 002	GJ9018 018
15TE	GJ9018 003	GJ9018 019
20TE	GJ9018 004	GJ9018 020
25TE	GJ9018 005	GJ9018 021
30TE	GJ9018 006	GJ9018 022
35TE	GJ9018 007	GJ9018 023
40TE	GJ9018 008	GJ9018 024
45TE	GJ9018 009	GJ9018 025
50TE	GJ9018 010	GJ9018 026
55TE	GJ9018 011	GJ9018 027
60TE	GJ9018 012	GJ9018 028
65TE	GJ9018 013	GJ9018 029
70TE	GJ9018 014	GJ9018 030
75TE	GJ9018 015	GJ9018 031
80TE	GJ9018 016	GJ9018 032

Table 3 - IP52 sealing rings

For further details on mounting MiDOS relays, see publication R7012, “MiDOS Parts Catalogue and Assembly Instructions”.

4 RELAY WIRING

This section serves as a guide to selecting the appropriate cable and connector type for each terminal on the MiCOM relay.

Warning **Before carrying out any work on the equipment, you should be familiar with the contents of the Safety Information chapter/safety guide SFTY/4LM/C11 or later issue, the Technical Data chapter and the ratings on the equipment rating label.**

4.1 Medium and Heavy Duty Terminal Block Connections

Key:
Heavy duty terminal block: CT and VT circuits, terminals with “D” prefix
Medium duty: All other terminal blocks (grey color)

Loose relays are supplied with sufficient M4 screws for making connections to the rear mounted terminal blocks using ring terminals, with a recommended maximum of two ring terminals per relay terminal.

If required, Schneider Electric can supply M4 90° crimp ring terminals in three different sizes depending on wire size (see Table 4). Each type is available in bags of 100.

Part number	Wire size	Insulation colour
ZB9124 901	0.25 – 1.65mm^2 (22 – 16AWG)	Red
ZB9124 900	1.04 – 2.63mm^2 (16 – 14AWG)	Blue
ZB9124 904	2.53 – 6.64mm^2 (12 – 10AWG)	Uninsulated*

Note ** To maintain the terminal block insulation requirements for safety, fit an insulating sleeve over the ring terminal after crimping.*

Table 4 - M4 90° crimp ring terminals

The following minimum wire sizes are recommended:

- Current Transformers 2.5mm^2
- Auxiliary Supply Vx 1.5mm^2
- RS485 Port See separate section
- Rotor winding to P391 1.0mm^2
- Other circuits 1.0mm^2

Due to the limitations of the ring terminal, the maximum wire size that can be used for any of the medium or heavy duty terminals is 6.0mm^2 using ring terminals that are not pre-insulated. Where it required to only use pre-insulated ring terminals, the maximum wire size that can be used is reduced to 2.63mm^2 per ring terminal. If a larger wire size is required, two wires should be used in parallel, each terminated in a separate ring terminal at the relay.

The wire used for all connections to the medium and heavy duty terminal blocks, except the RS485 port, should have a minimum voltage rating of 300Vrms.

It is recommended that the auxiliary supply wiring should be protected by a 16A High Rupture Capacity (HRC) fuse of type NIT or TIA. For safety reasons, current transformer circuits must never be fused. Other circuits should be appropriately fused to protect the wire used.

Note	*The high-break contacts optional fitted to P44y (P443/P446) and P54x relays are polarity sensitive. External wiring must respect the polarity requirements which are shown on the external connection diagram to ensure correct operation.*

Each opto input has selectable filtering. This allows use of a pre-set filter of ½ cycle which renders the input immune to induced noise on the wiring: although this method is secure it can be slow, particularly for intertripping. This can be improved by switching off the ½ cycle filter in which case one of the following methods to reduce ac noise should be considered. The first method is to use double pole switching on the input, the second is to use screened twisted cable on the input circuit. The recognition time of the opto inputs without the filtering is <2 ms and with the filtering is <12 ms.

4.2 EIA(RS)485 Port

Connections to the first rear EIA(RS)485 port use ring terminals. 2-core screened cable is recommended with a maximum total length of 1000m or 200nF total cable capacitance.

A typical cable specification would be:

Each core:	16/0.2mm copper conductors. PVC insulated
Nominal conductor area:	0.5mm^2 per core
Screen:	Overall braid, PVC sheathed

See the SCADA Communications chapter for details of setting up an EIA(RS)485 bus.

4.3 Current Loop Input Output (CLIO) Connections (if applicable)

Where current loop inputs and outputs are available on a MiCOM relay, the connections are made using screw clamp connectors, as per the RTD inputs, on the rear of the relay which can accept wire sizes between 0.1 mm^2 and 1.5 mm^2. It is recommended that connections between the relay and the current loop inputs and outputs are made using a screened cable. The wire should have a minimum voltage rating of 300 Vrms.

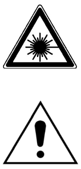
4.4 IRIG-B Connections (if applicable)

The IRIG-B input and BNC connector have a characteristic impedance of 50Ω. It is recommended that connections between the IRIG-B equipment and the relay are made using coaxial cable of type RG59LSF with a halogen free, fire retardant sheath.

4.5 EIA(RS)232 Port

Short term connections to the RS232 port, located behind the bottom access cover, can be made using a screened multi-core communication cable up to 15m long, or a total capacitance of 2500pF. The cable should be terminated at the relay end with a 9-way, metal shelled, D-type male plug. The Getting Started chapter of this manual details the pin allocations.

4.6 Optical Fiber Connectors (when applicable)



Warning	**LASER LIGHT RAYS: Where fibre optic communication devices are fitted, never look into the end of a fiber optic due to the risk of causing serious damage to the eye. Optical power meters should be used to determine the operation or signal level of the device. Non-observance of this rule could possibly result in personal injury.**

If electrical to optical converters are used, they must have management of character idle state capability (for when the fibre optic cable interface is "Light off").

Specific care should be taken with the bend radius of the fibres, and the use of optical shunts is not recommended as these can degrade the transmission path over time.

The relay uses 1310nm multi mode 100BaseFx and BFOC 2.5 - (ST/LC according to the MiCOM model) connectors (one Tx – optical emitter, one Rx – optical receiver).

4.7 Ethernet Port for IEC 61850 and/or DNP3.0 (where applicable)

4.7.1 Fiber Optic (FO) Port

The relays can have 100 Mbps Ethernet port. Fibre Optic (FO) connection is recommended for use in permanent connections in a substation environment. The 100 Mbit port uses a type ST/LC connector (according to the MiCOM model), compatible with fiber multimode 50/125 µm or 62.5/125 µm to 1310 nm.

Note	*The new LC fiber optical connector can be used with the Px40 Enhanced Ethernet Board.*

4.7.2 RJ-45 Metallic Port

The user can connect to either a 10Base-T or a 100Base-TX Ethernet hub; the port will automatically sense which type of hub is connected. Due to possibility of noise and interference on this part, it is recommended that this connection type be used for short-term connections and over short distance. Ideally, where the relays and hubs are located in the same cubicle.

The connector for the Ethernet port is a shielded RJ-45. Table 5 shows the signals and pins on the connector.

Pin	Signal name	Signal definition
1	TXP	Transmit (positive)
2	TXN	Transmit (negative)
3	RXP	Receive (positive)
4	-	Not used
5	-	Not used
6	RXN	Receive (negative)
7	-	Not used
8	-	Not used

Table 5 - Signals on the Ethernet connector

4.8 RTD Connections (if applicable)

Where RTD inputs are available on a MiCOM relay, the connections are made using screw clamp connectors on the rear of the relay that can accept wire sizes between 0.1 mm^2 and 1.5 mm^2. The connections between the relay and the RTDs must be made using a screened 3-core cable with a total resistance less than 10 Ω. The cable should have a minimum voltage rating of 300 Vrms.

A 3-core cable should be used even for 2-wire RTD applications, as it allows for the cable’s resistance to be removed from the overall resistance measurement. In such cases the third wire is connected to the second wire at the point the cable is joined to the RTD.

The screen of each cable must only be earthed at one end, preferably at the relay end and must be continuous. Multiple earthing of the screen can cause circulating current to flow along the screen, which induces noise and is unsafe.

It is recommended to minimize noise pick-up in the RTD cables by keeping them close to earthed metal casings and avoiding areas of high electromagnetic and radio interference. The RTD cables should not be run adjacent to or in the same conduit as other high voltage or current cables.

A typical cable specification would be:

Each core:	7/0.2 mm copper conductors heat resistant PVC insulated
Nominal conductor area:	0.22 mm^2 per core
Screen:	Nickel-plated copper wire braid heat resistant PVC sheathed

The extract below may be useful in defining cable recommendations for the RTDs:

Noise pick up by cables can be categorized in to three types:

- Resistive
- Capacitive
- Inductive

Resistive coupling	requires there to be an electrical connection to the noise source. So assuming that the wire and cable insulation is sound and that the junctions are clean then this can be dismissed.
Capacitive coupling	requires there to be sufficient capacitance for the impedance path to the noise source to be small enough to allow for significant coupling. This is a function of the dielectric strength between the signal cable on the noise source and the potential (i.e. power) of the noise source.
Inductive coupling	occurs when the signal cable is adjacent to a cable/wire carrying the noise or it is exposed to a radiated EMF.

Standard screened cable is normally used to protect against capacitively coupled noise, but in order for it to be effective the screen must only be bonded to the system ground at one point, otherwise a current could flow and the noise would be coupled in to the signal wires of the cable. There are different types of screening available, but basically there are two types: aluminum foil wrap and tin-copper braid.

Foil screens are good for low to medium frequencies and braid is good for high frequencies. High-fidelity screen cables provide both types.

Protection against magnetic inductive coupling requires very careful cable routing and magnetic shielding. The latter can be achieved with steel-armored cable and the use of steel cable trays. It is important that the armor of the cable is grounded at both ends so that the EMF of the induced current cancels the field of the noise source and hence shields the cables conductors from it. (However, the design of the system ground must be considered and care taken to not bridge two isolated ground systems since this could be hazardous and defeat the objectives of the original ground design). The cable should be laid in the cable trays as close as possible to the metal of the tray and under no circumstance should any power cable be in or near to the tray. (Power cables should only cross the signal cables at 90 degrees and never be adjacent to them).

Both the capacitive and inductive screens must be contiguous from the RTD probes to the relay terminals.

The best types of cable are those provided by the RTD manufactures. These tend to be three conductors (a so call "triad") which are screened with foil. Such triad cables are available in armored forms as well as multi-triad armored forms.

4.9 Download/Monitor Port

Short term connections to the download/monitor port, located behind the bottom access cover, can be made using a screened 25-core communication cable up to 4m long. The cable should be terminated at the relay end with a 25-way, metal shelled, D-type male plug.

The Getting Started and Commissioning chapters this manual details the pin allocations.

4.10 Second EIA(RS)232/485 Port

Relays with Courier, MODBUS, IEC 60870-5-103 or DNP3 protocol on the first rear communications port have the option of a second rear port, running Courier language.

The second rear communications port can be used over one of three physical links:

- twisted pair K-Bus (non-polarity sensitive),
- twisted pair EIA(RS)485 (connection polarity sensitive) or
- EIA(RS)232. This EIA(RS)232 port is actually compliant to EIA(RS)574; the 9-pin version of EIA(RS)232, see www.tiaonline.org.

4.10.1 Connection to the Second Rear Port

The second rear Courier port connects via a 9-way female D-type connector (SK4) in the middle of the card end plate (in between IRIG-B connector and lower D-type). The connection is compliant to EIA(RS)574.

4.10.1.1 For IEC 60870-5-2 over EIA(RS)232/574

Pin	Connection
1	No Connection
2	RxD
3	TxD
4	DTR#
5	Ground
6	No Connection
7	RTS#
8	CTS#
9	No Connection
# - These pins are control lines for use with a modem.	

Table 6 - Description needed

Connections to the second rear port configured for EIA(RS)232 operation can be made using a screened multi-core communication cable up to 15 m long, or a total capacitance of 2500 pF. The cable should be terminated at the relay end with a 9-way, metal shelled, D-type male plug. The table above details the pin allocations.

4.10.1.2 For K-bus or IEC 60870-5-2 over EIA(RS)485

Pin*	Connection
4	EIA(RS)485 - 1 (+ ve)
7	EIA(RS)485 - 2 (- ve)
* - All other pins unconnected.	

Note	*Connector pins 4 and 7 are used by both the EIA(RS)232/574 and EIA(RS)485 physical layers, but for different purposes. Therefore, the cables should be removed during configuration switches.* *For the EIA(RS)485 protocol an EIA(RS)485 to EIA(RS)232/574 converter will be required to connect a modem or PC running MiCOM S1 Studio, to the relay. A Schneider Electric CK222 is recommended.* *EIA(RS)485 is polarity sensitive, with pin 4 positive (+) and pin 7 negative (-).* *The K-Bus protocol can be connected to a PC via a KITZ101 or 102.* *It is recommended that a 2-core screened cable be used. To avoid exceeding the second communications port flash clearances it is recommended that the length of cable between the port and the communications equipment should be less than 300 m. This length can be increased to 1000 m or 200nF total cable capacitance if the communications cable is not laid in close proximity to high current carrying conductors. The cable screen should be earthed at one end only.*

Table 7 - Description needed

A typical cable specification would be:

Each core:	16/0.2 mm copper conductors PVC insulated
Nominal conductor area:	0.5 mm^2 per core
Screen:	Overall braid, PVC sheathed

4.11 Earth Connection (Protective Conductor)

Every relay must be connected to the local earth bar using the M4 earth studs in the bottom left hand corner of the relay case. The minimum recommended wire size is 2.5mm^2 and should have a ring terminal at the relay end.

Due to the limitations of the ring terminal, the maximum wire size that can be used for any of the medium or heavy duty terminals is 6.0mm^2 per wire. If a greater cross-sectional area is required, two parallel connected wires, each terminated in a separate ring terminal at the relay, or a metal earth bar could be used.

Note	*To prevent any possibility of electrolytic action between brass or copper earth conductors and the rear panel of the relay, precautions should be taken to isolate them from one another. This could be achieved in a number of ways, including placing a nickel-plated or insulating washer between the conductor and the relay case, or using tinned ring terminals.*

Warning **Before carrying out any work on the equipment, you should be familiar with the contents of the Safety Information chapter/safety guide SFTY/4LM/C11 or later issue, the Technical Data chapter and the ratings on the equipment rating label.**

4.12 P391 Rotor Earth Fault Unit (REFU) Mounting

Under rotor earth fault conditions, DC currents of up to 29mA can appear in the earth circuit. Accordingly, the P391 must be permanently connected to the local earth via the protective conductor terminal provided.

This section serves as a guide to selecting the appropriate cable and connector type for each terminal on the P391 unit.

Caution **You must be familiar with all safety statements listed in the Commissioning chapter and the Safety Information section SFTY/4LM/G11 (or later issue) before undertaking any work on the P391.**

Caution **Under no circumstances should the high voltage DC rotor winding supply be connected via MMLG or P990 test blocks. Both MMLG and P990 test blocks are not rated for continuous working voltages greater than 300 Vrms. These test blocks are not designed to withstand the inductive EMF voltages which will be experienced on disconnection or de-energization of the DC rotor winding supply.**

4.12.1 Medium Duty Terminal Block Connections

Information about the medium duty terminal block connections is described in section 4.1.

Caution **Wiring between the DC rotor winding and the P391 shall be suitably rated to withstand at least twice the rotor winding supply voltage to earth. This is to ensure that the wiring insulation can withstand the inductive Electro Motive Force (EMF) voltage which will be experienced on disconnection or de-energization of the DC rotor winding supply.**

Due to the limitations of the ring terminal, the maximum wire size that can be used for any of the medium terminals is 6.0 mm^2 using ring terminals that are not pre-insulated (protective conductor terminal (PCT) only). All P391 terminals, except PCT shall be pre-insulated ring terminals, the maximum wire size that can be used is reduced to 2.63 mm^2 per ring terminal.

Wiring between the DC rotor winding and the P391 shall be suitably rated to withstand at least twice the rotor winding supply voltage to earth. The wire used for other P391 connections to the medium duty terminal blocks should have a minimum voltage rating of 300 Vrms.

The dielectric withstand of P391 injection resistor connections (A16, B16, A8, B8) to earth is 5.8 kV rms, 1 minute.

It is recommended that the auxiliary supply wiring should be protected by a High Rupture Capacity (HRC) fuse of type NIT or TIA, rated between 2 A and 16 A. Other circuits should be appropriately fused to protect the wire used.

5 CASE DIMENSIONS

The MiCOM range of products are available in a series of different case sizes.

The case sizes available for each product are shown in the following table:

Product	Case Size		
	40TE	60TE	80TE
P141	Yes		
P142	Yes		
P143		Yes	Yes
P145		Yes	
P241	Yes		
P242		Yes	
P243			Yes
P341	Yes	Yes	
P342	Yes	Yes	
P343		Yes	Yes
P344			Yes
P345			Yes
P441	Yes		
P442		Yes	
P443			Yes
P444			Yes
P445	Yes	Yes	
P446			Yes
P541	Yes		
P542		Yes	
P543		Yes	
P544		Yes	
P545			Yes
P546			Yes
P547			Yes
P642	Yes		
P643		Yes	
P645		Yes	Yes
P741			Yes
P742	Yes		
P743		Yes	
P746			Yes
P841		Yes	Yes
P849			Yes

Table 8 – Products and case sizes

5.1 40TE Case Dimensions

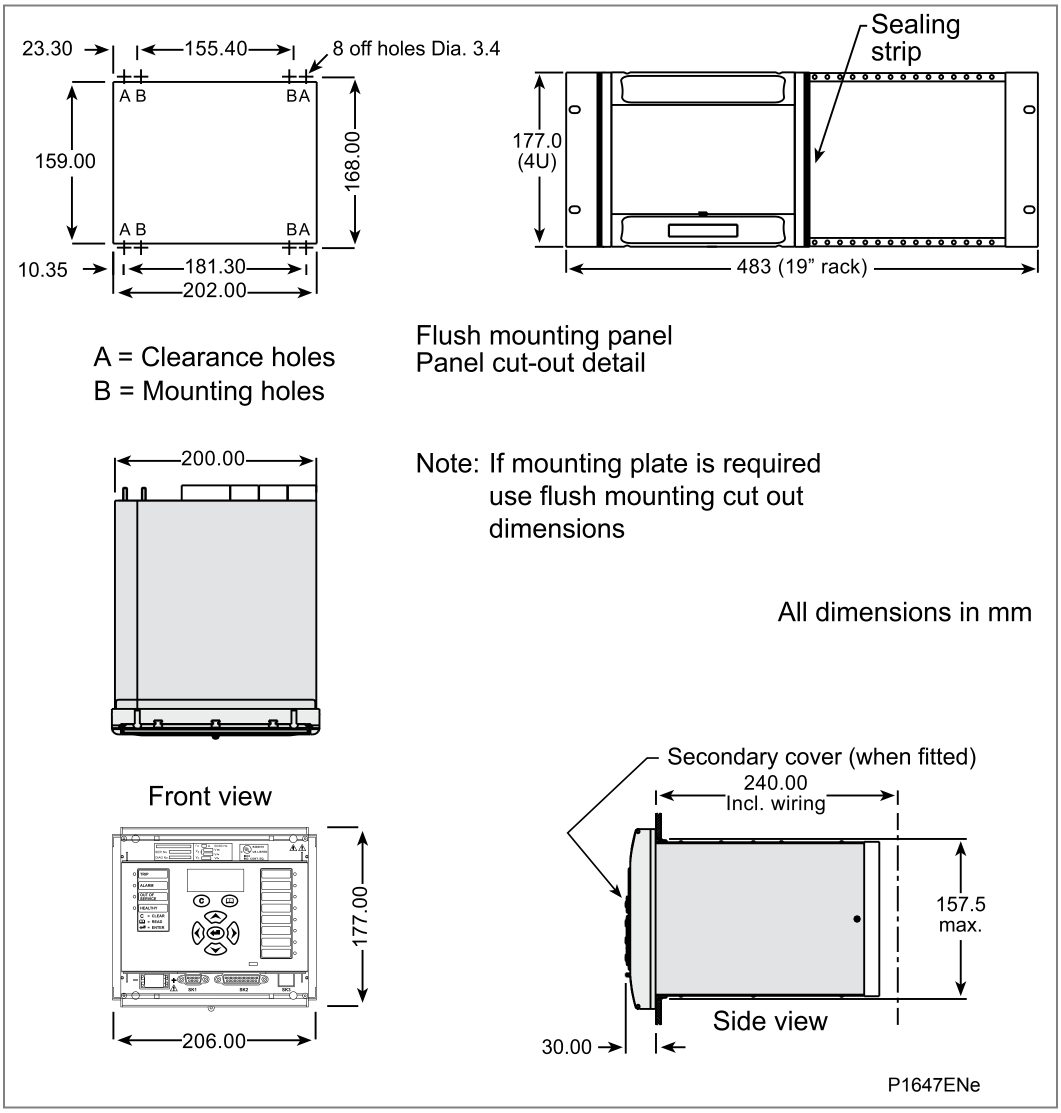


Figure 3 - 40TE Case Dimensions

5.2 60TE Case Dimensions

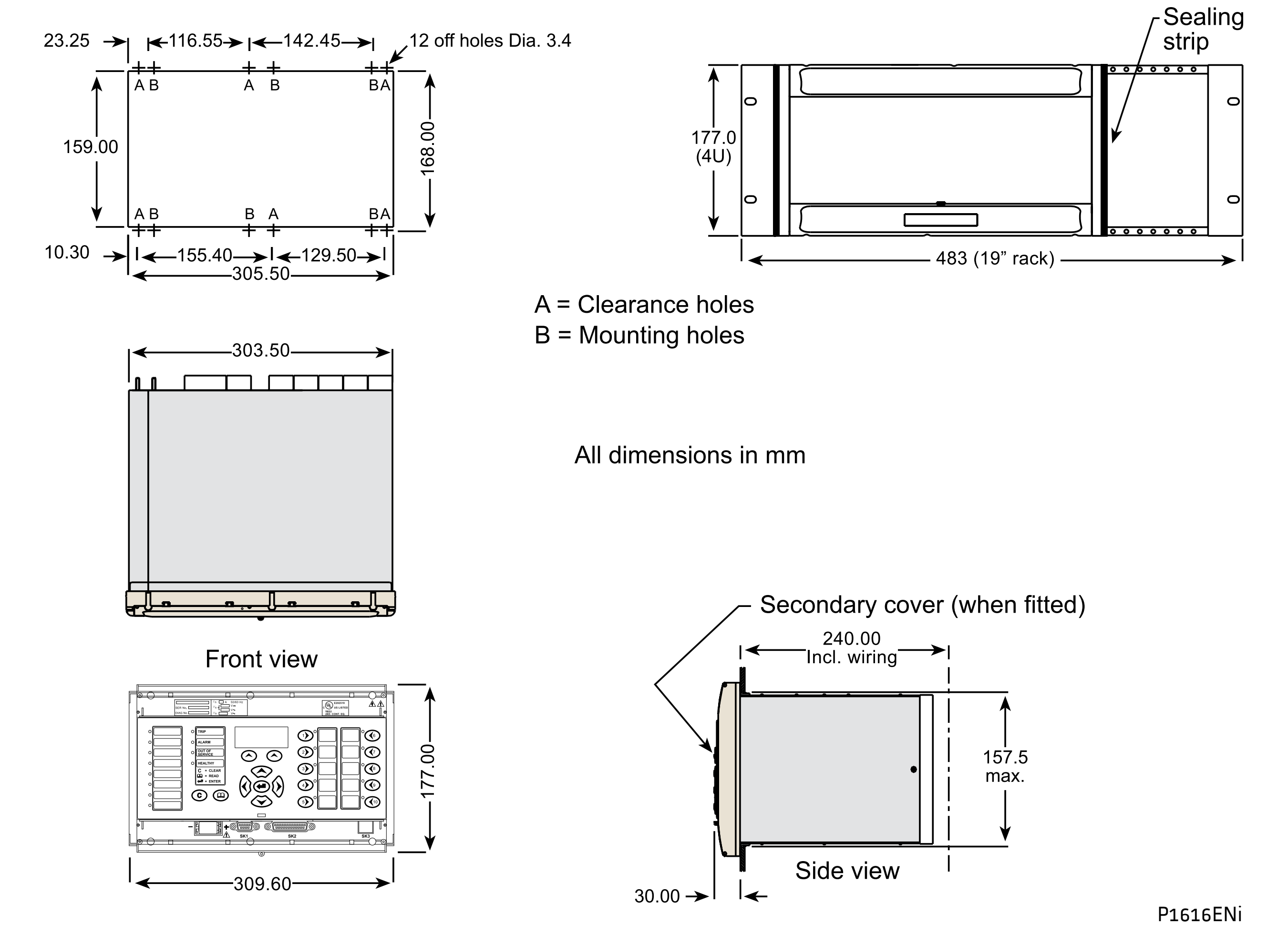


Figure 4 - 60TE Case Dimensions

5.3 80TE Case Dimensions

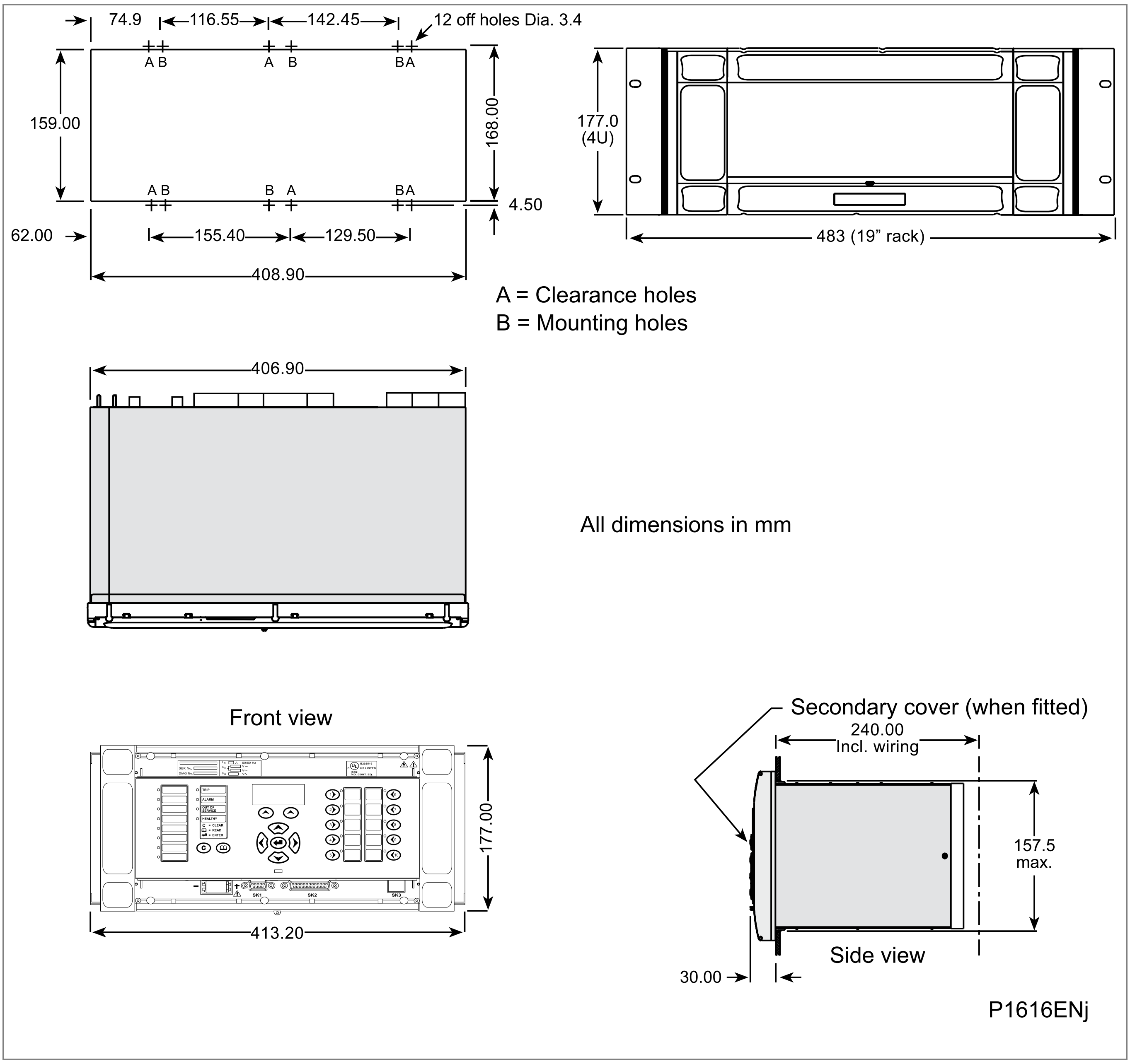


Figure 5 - 80TE Case Dimensions

Notes:

CONNECTION DIAGRAMS

CHAPTER NO 18

Date:	10/2014
Products covered by this chapter:	This chapter covers the specific versions of the MiCOM products listed below. This includes ***only*** the following combinations of Software Version and Hardware Suffix. C01152ENa
Hardware Suffix:	L (P141, P142 & P143) & M (P145)
Software Version:	A0 - P14x (P141, P142, P143 & P145)
Connection Diagrams:	10P141xx (xx = 01 to 07) 10P142xx (xx = 01 to 07) 10P143xx (xx = 01 to 07) 10P145xx (xx = 01 to 07) C01707ENa

CONTENTS

FIGURES

1 INTRODUCTION TO THE CONNECTION DIAGRAMS

The Installation chapter contains general information about the MiCOM unit. The Installation chapter covers many MiCOM P40 products. It includes items such as:

- Receiving, Handling, Storing and Unpacking the Relays
- Mounting the Relay
- Wiring the Relay
- Case Dimensions

This Connection Diagrams chapter is specific to this particular relay, and includes the detailed wiring diagrams which relate only to this particular relay.

Important	**You must be familiar with the contents of the Installation chapter, before using the information in this Connection Diagrams chapter.**

C00151ENa

2 SECOND REAR COMMUNICATION BOARD CONNECTIONS

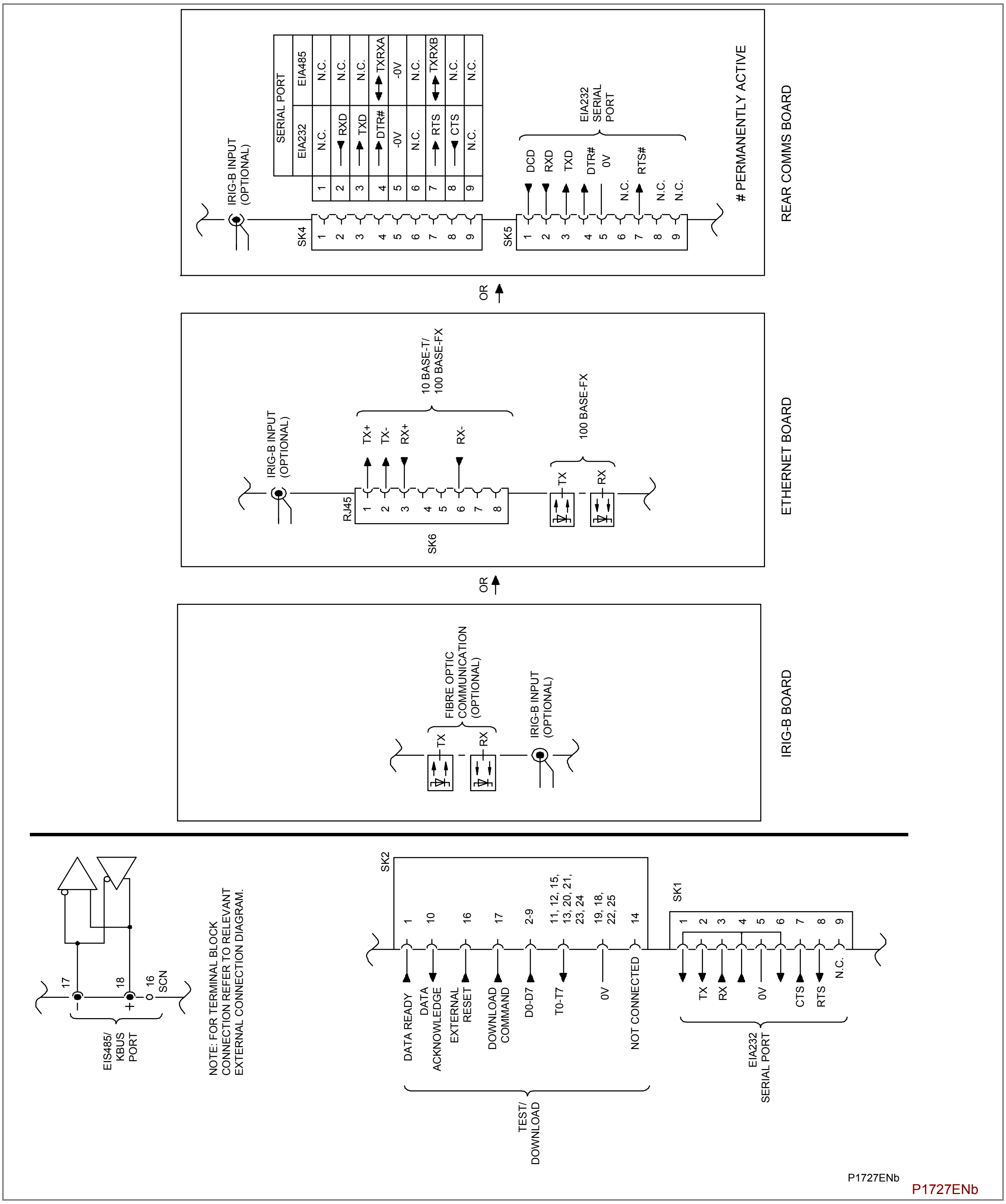


Figure 1 - P14x second rear port connection

3 EXTERNAL CONNECTION DIAGRAMS

In this section, the figure captions use these abbreviations:

- D/P = Directional Phase
- O/C = Overcurrent
- EF = Earth Fault
- SEF = Sensitive Earth Fault
- AR = Auto-reclose
- CS = Check Synchronizing
- RVI = Residual Voltage Input

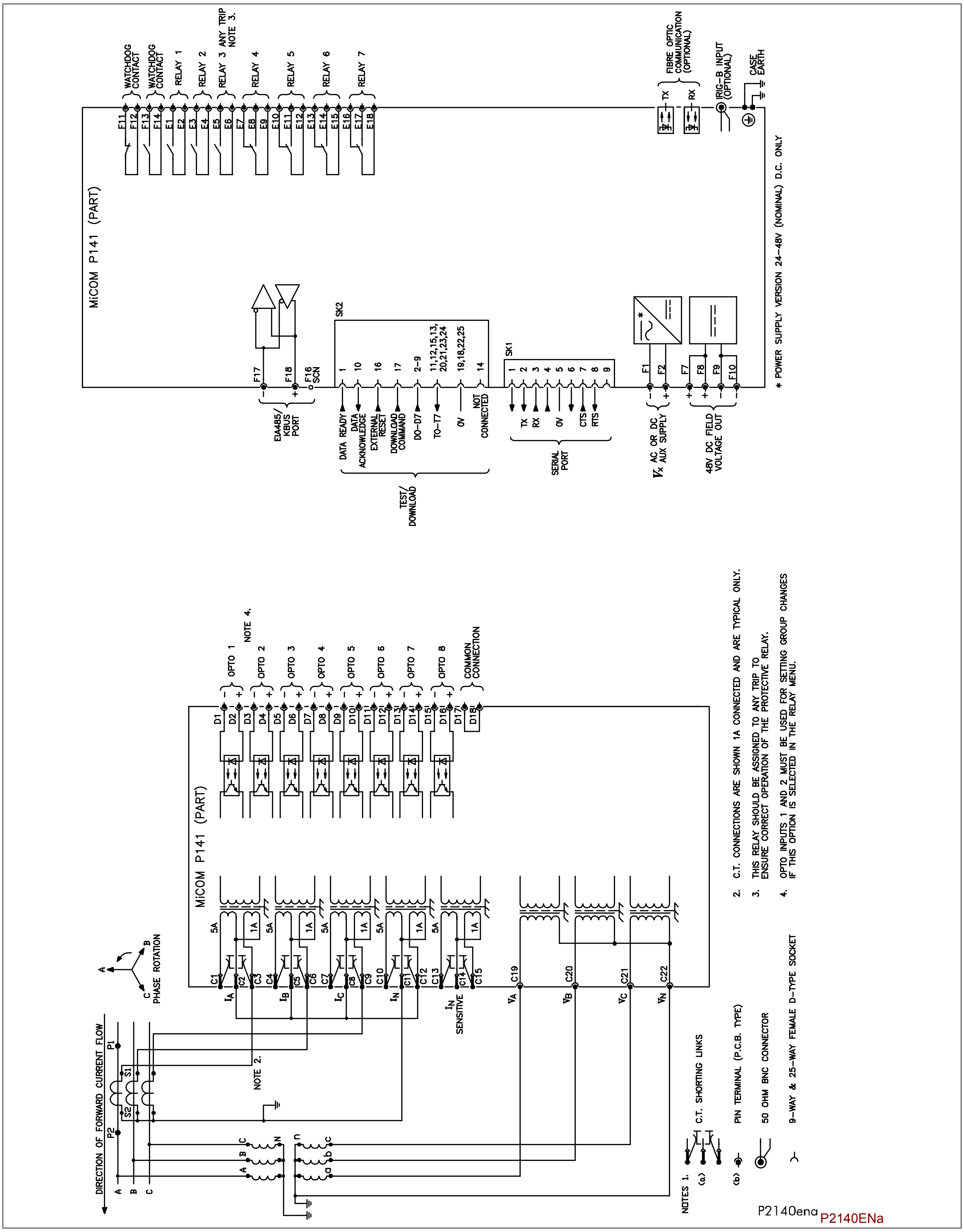


Figure 2 - P141 - D/P O/C and EF (8 I/P & 7 O/P)

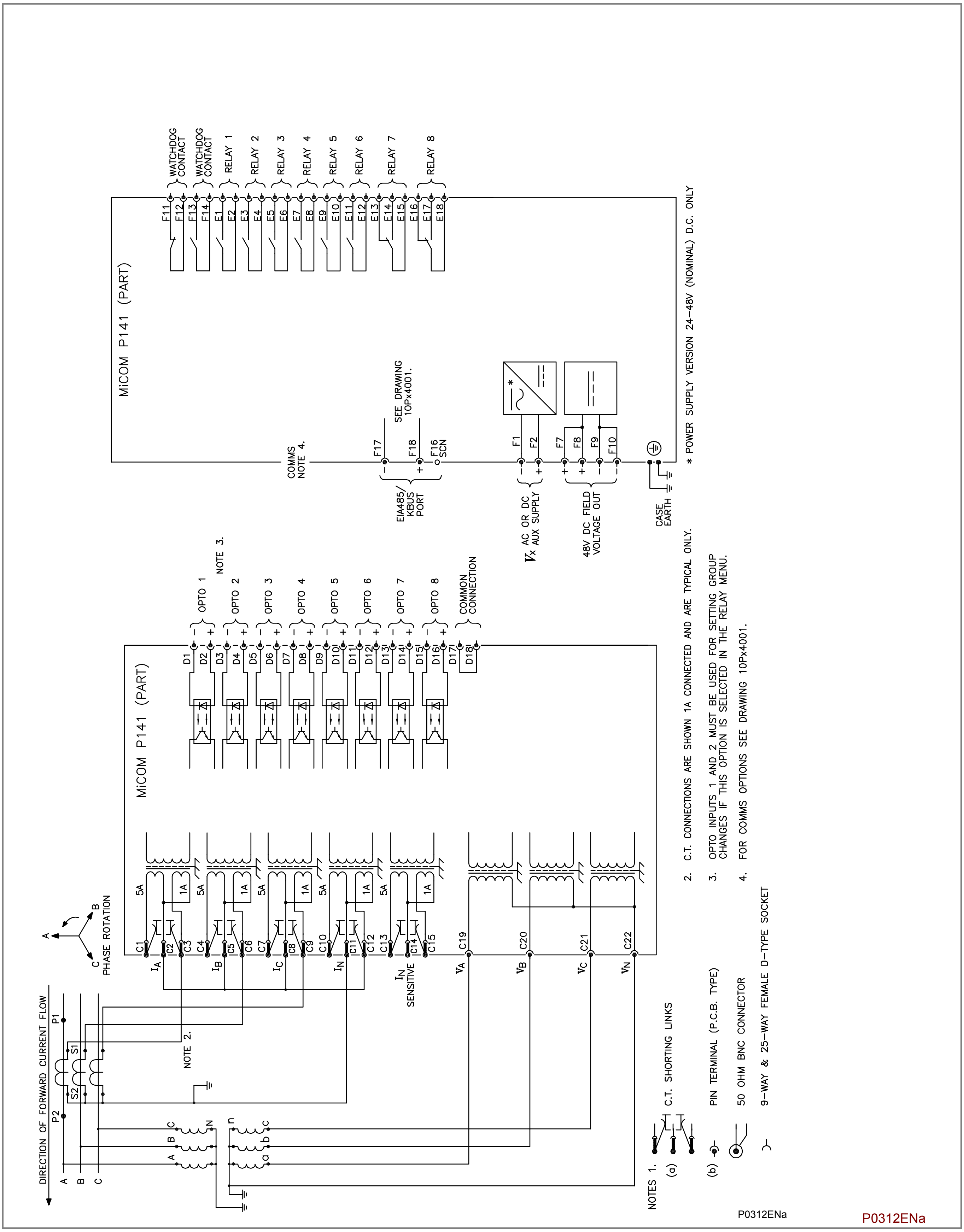


Figure 3 - P141 - D/P O/C and EF (8 I/P & 8 O/P)

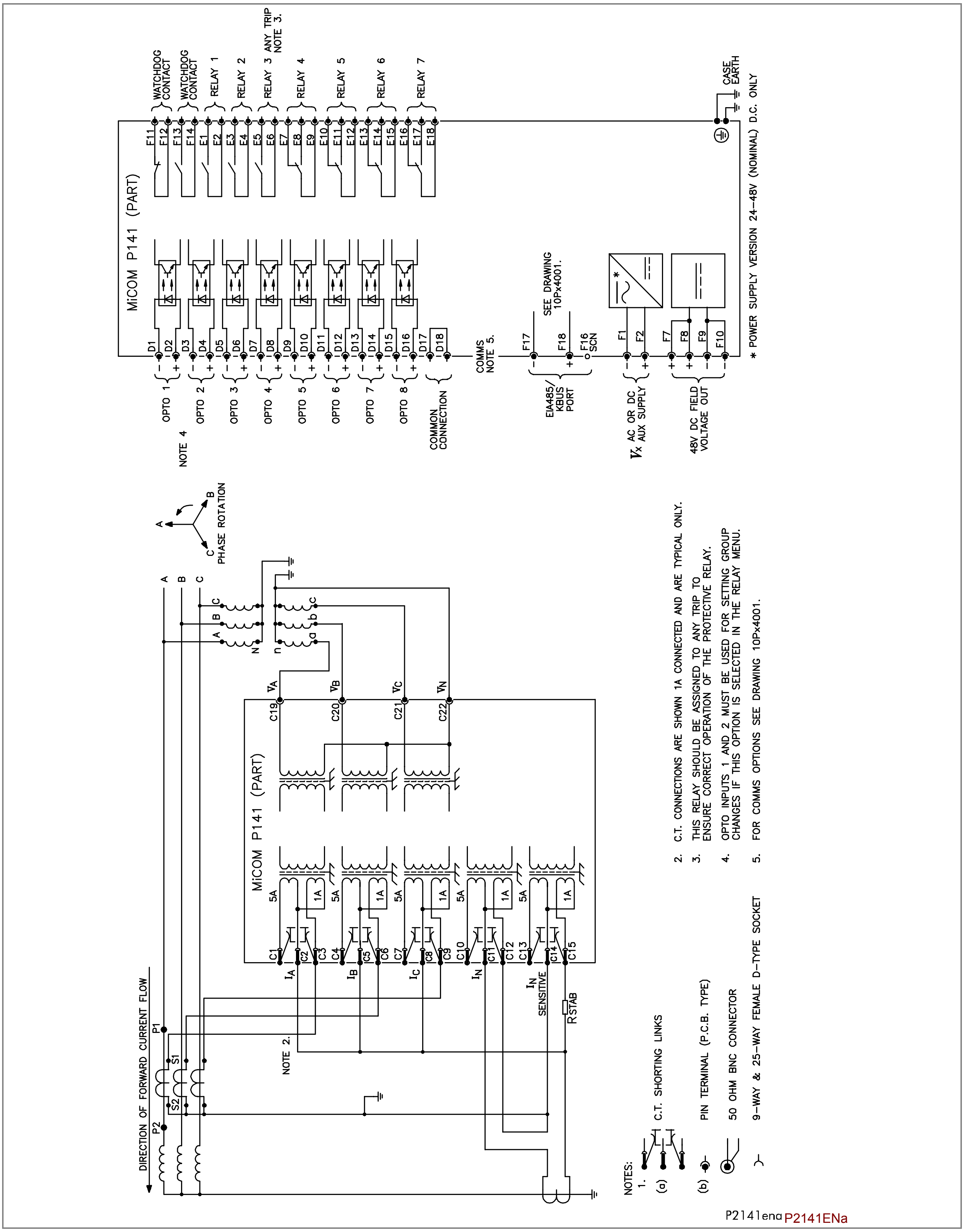


Figure 4 - P141 - D/P O/C and EF with High Impedance REF (8 I/P & 7 O/P)

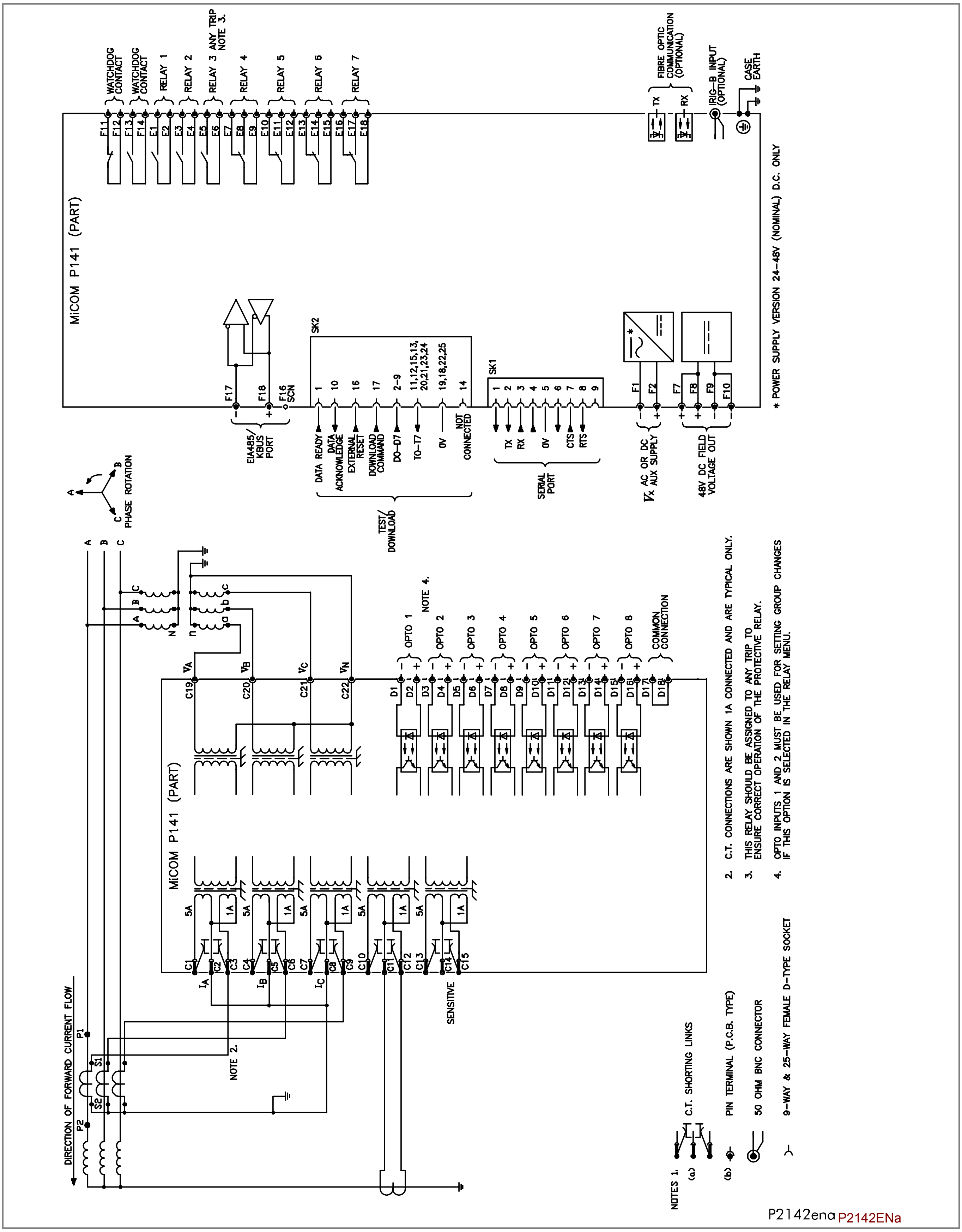


Figure 5 - P141 - D/P O/C and EF with Low Impedance REF (8 I/P & 7 O/P)

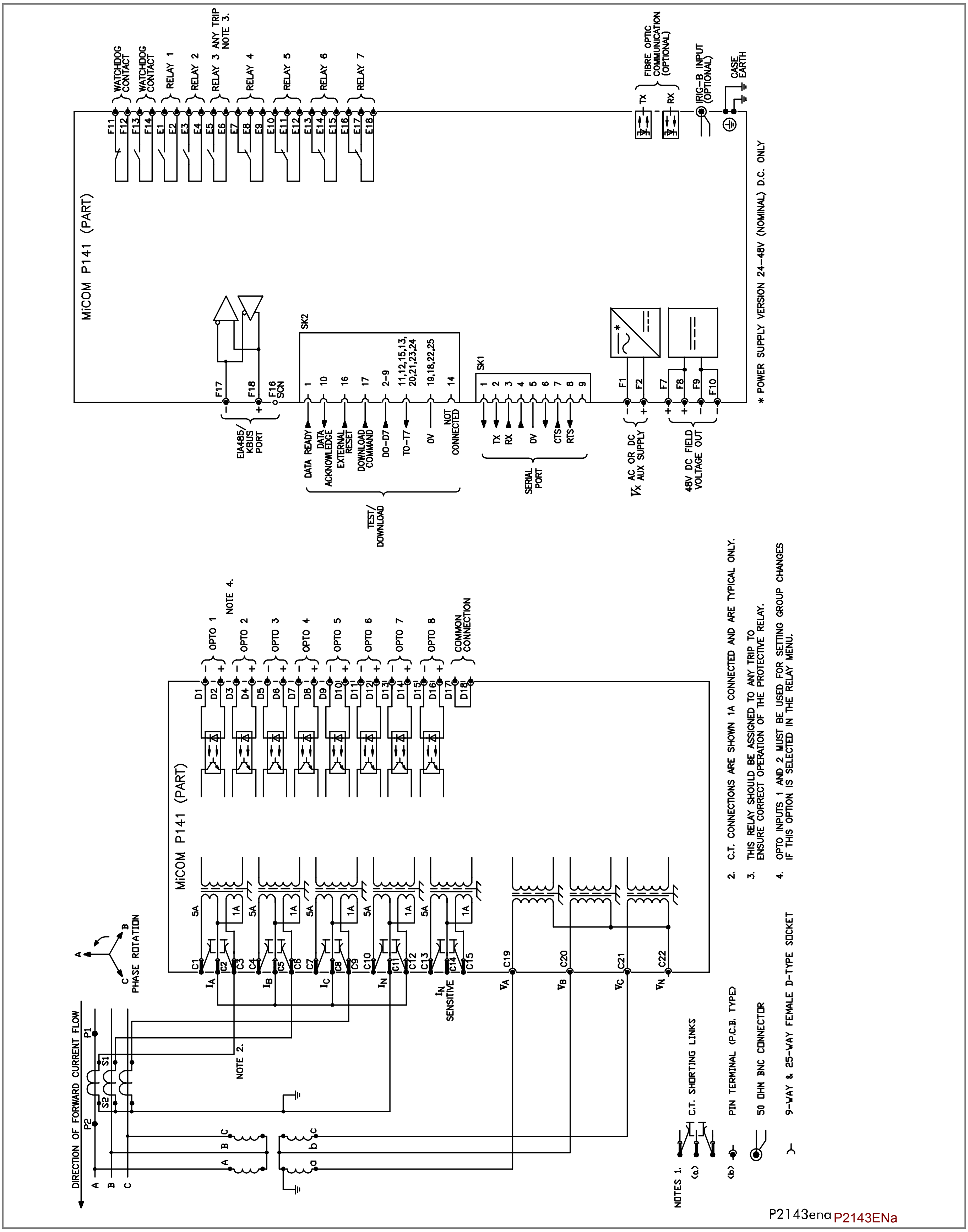


Figure 6 - P141 - Directional and Directional EF with VEE Connected VT (8 I/P & 7 O/P)

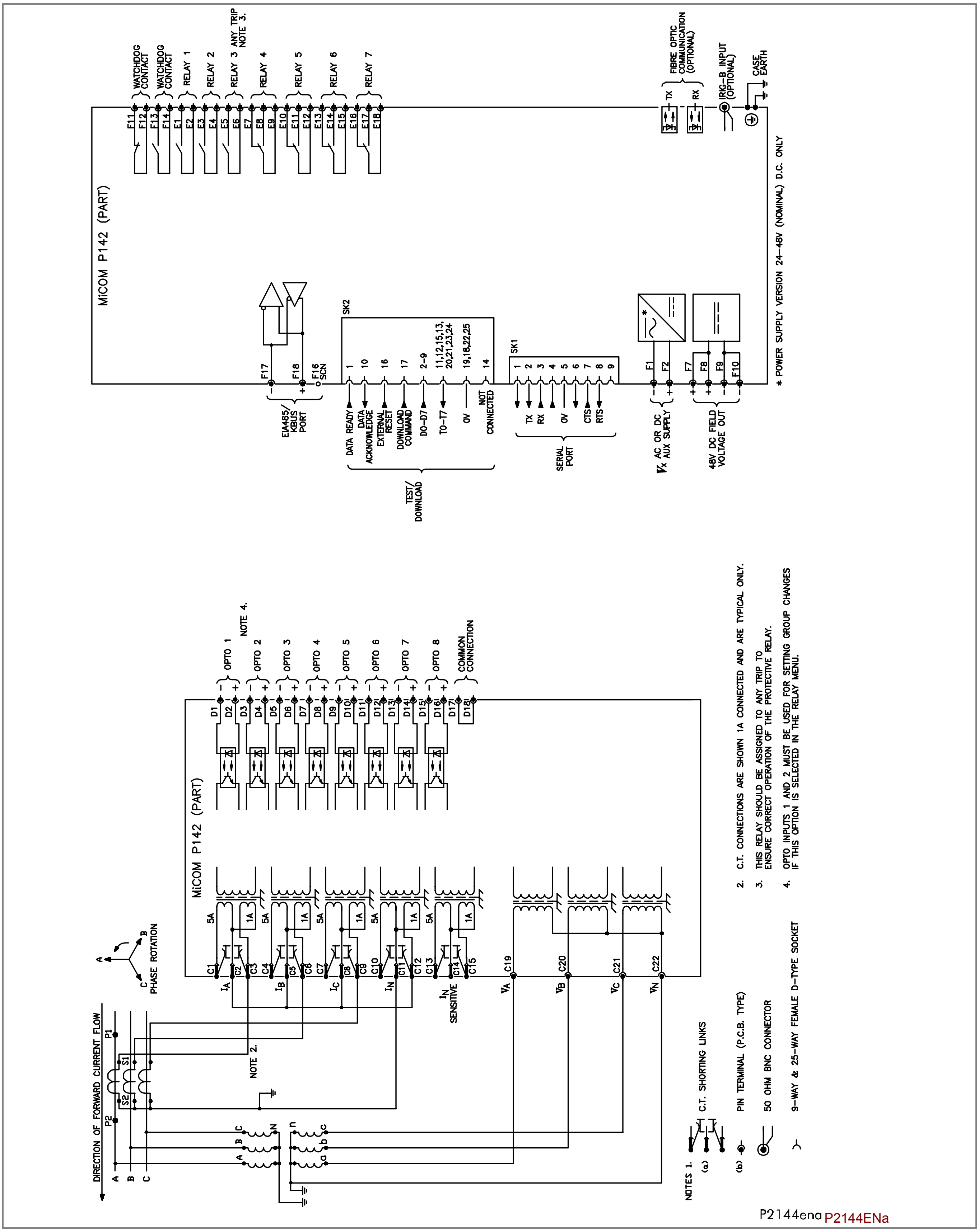
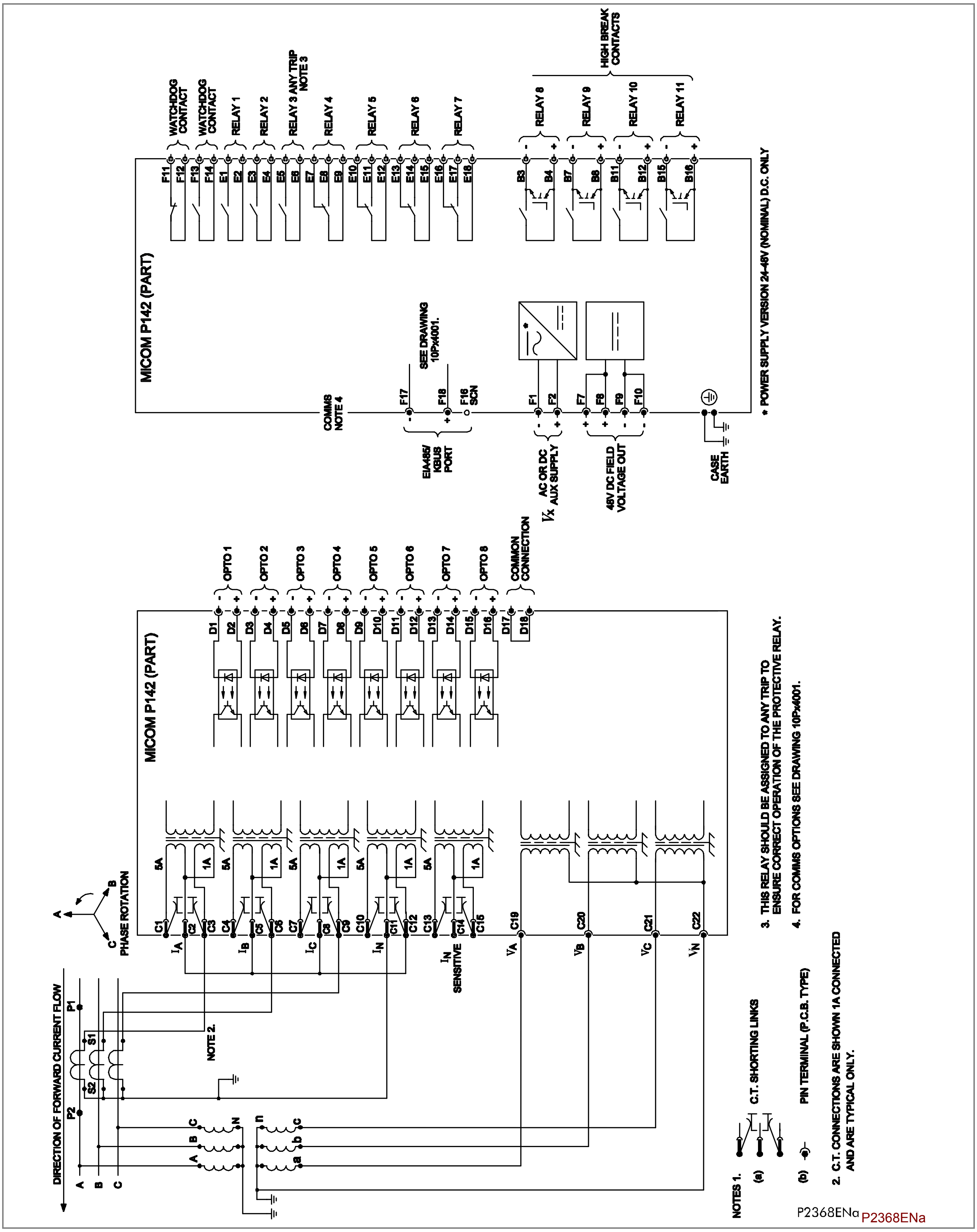


Figure 7 - P142 - D/P O/C and EF with AR (8 I/P & 7 O/P)



P2368ENa

Figure 8 - P142 - D/P O/C and EF with AR (8 I/P & 11 O/P with 4 High Break Contacts)

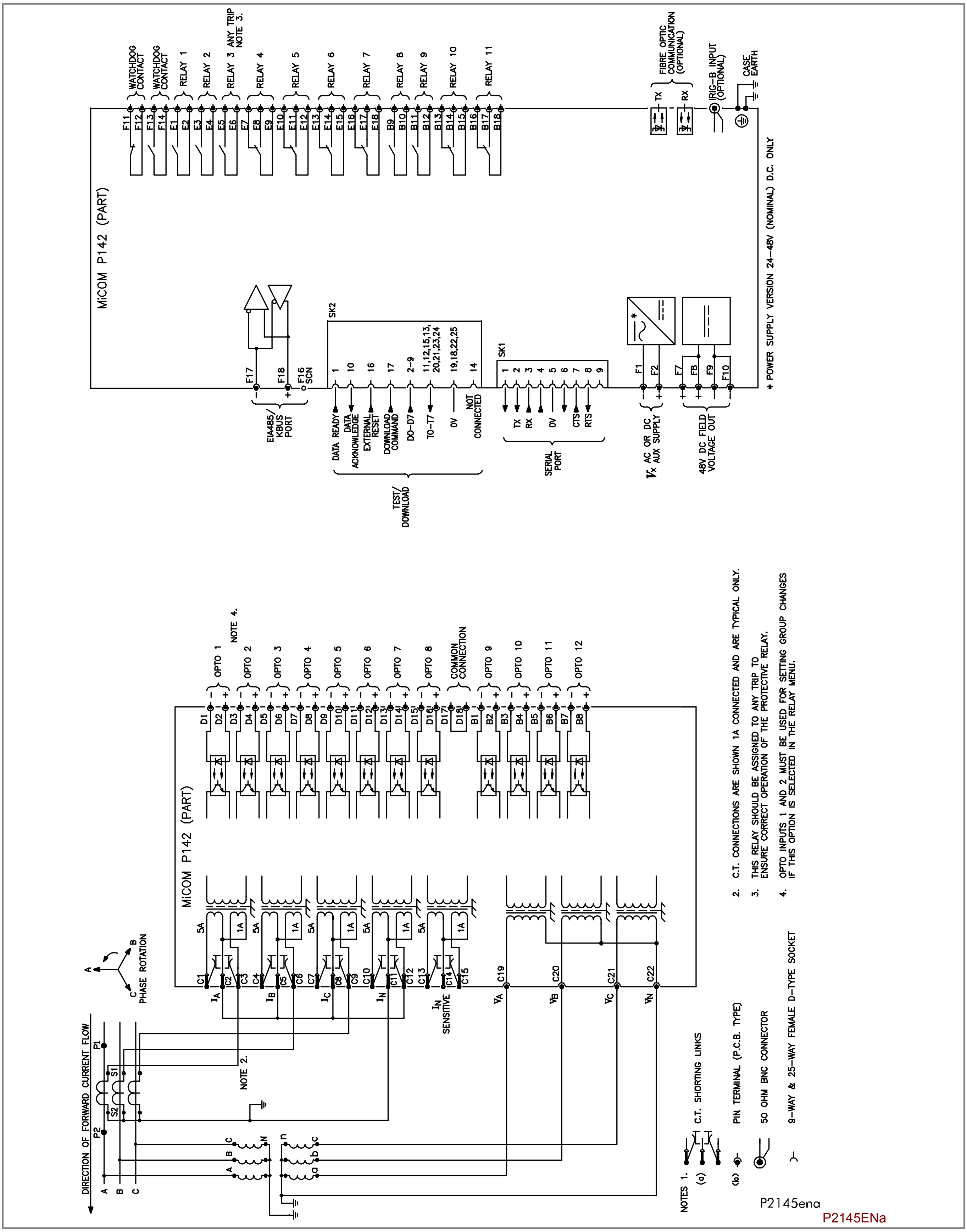
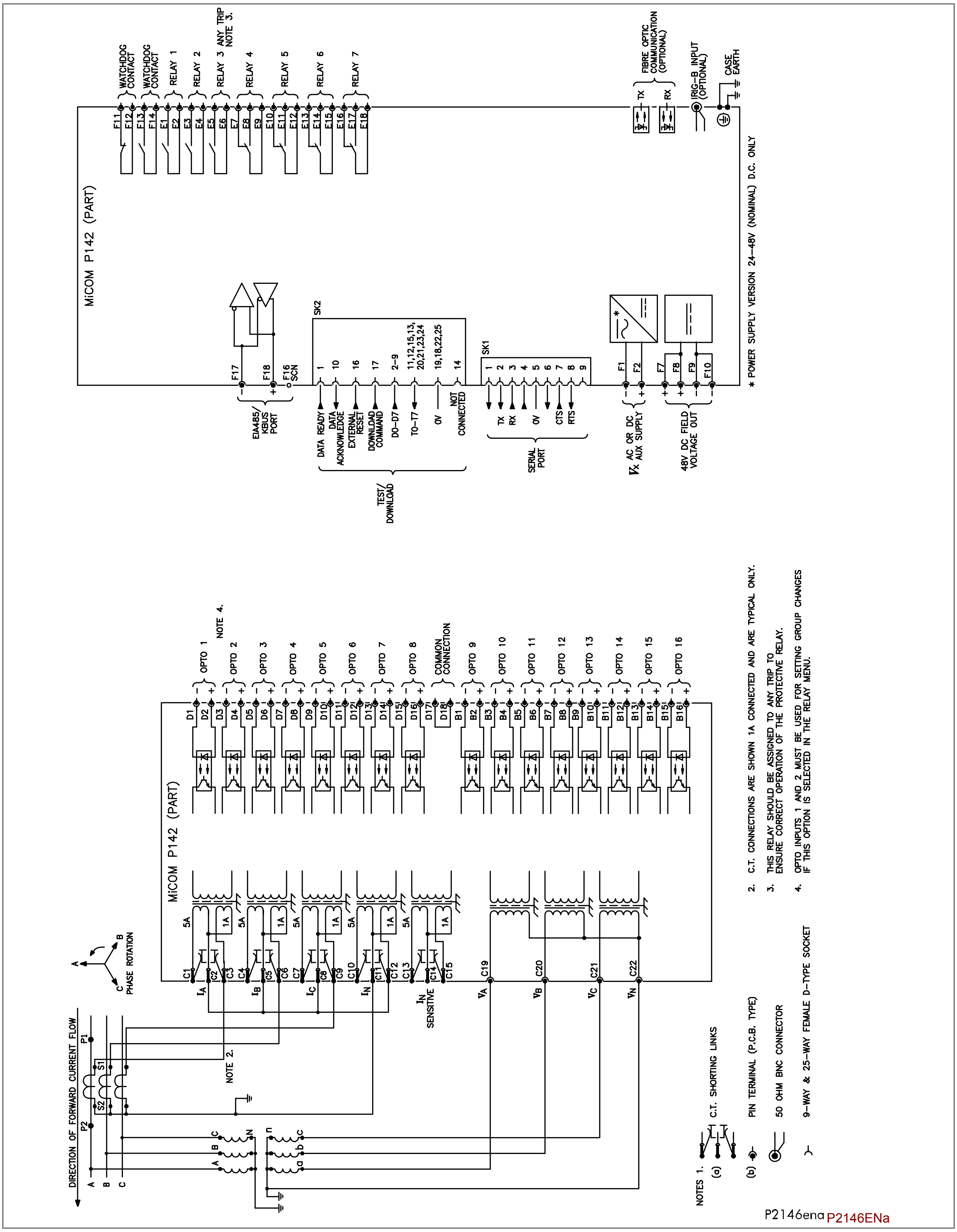


Figure 9 - P142 - D/P O/C and EF with AR (12 I/P & 11 O/P)



P2146ENa

Figure 10 - P142 - D/P O/C and EF with AR (16 I/P & 7 O/P)

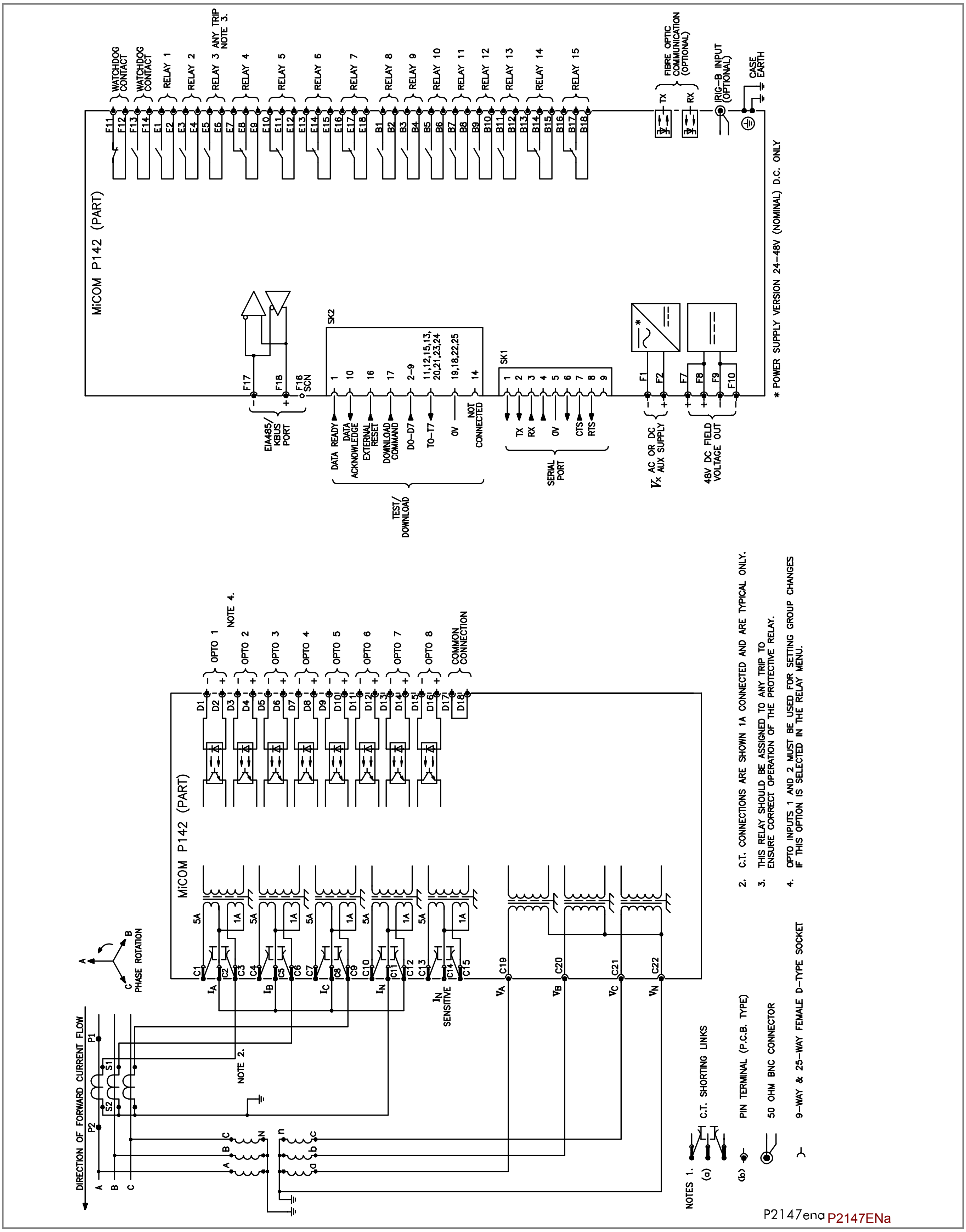


Figure 11 - P142 - D/P O/C and EF with AR (8 I/P & 15 O/P)

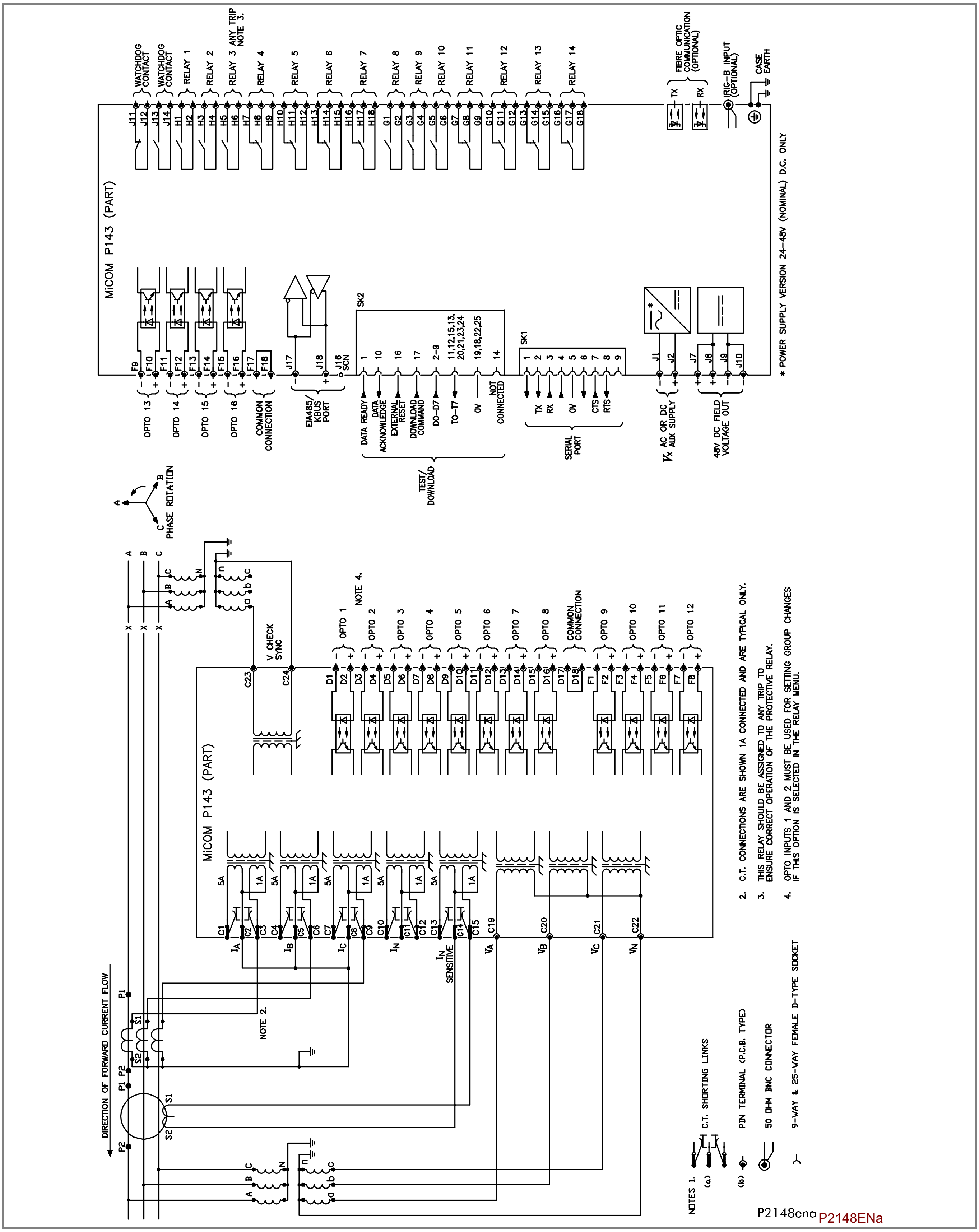
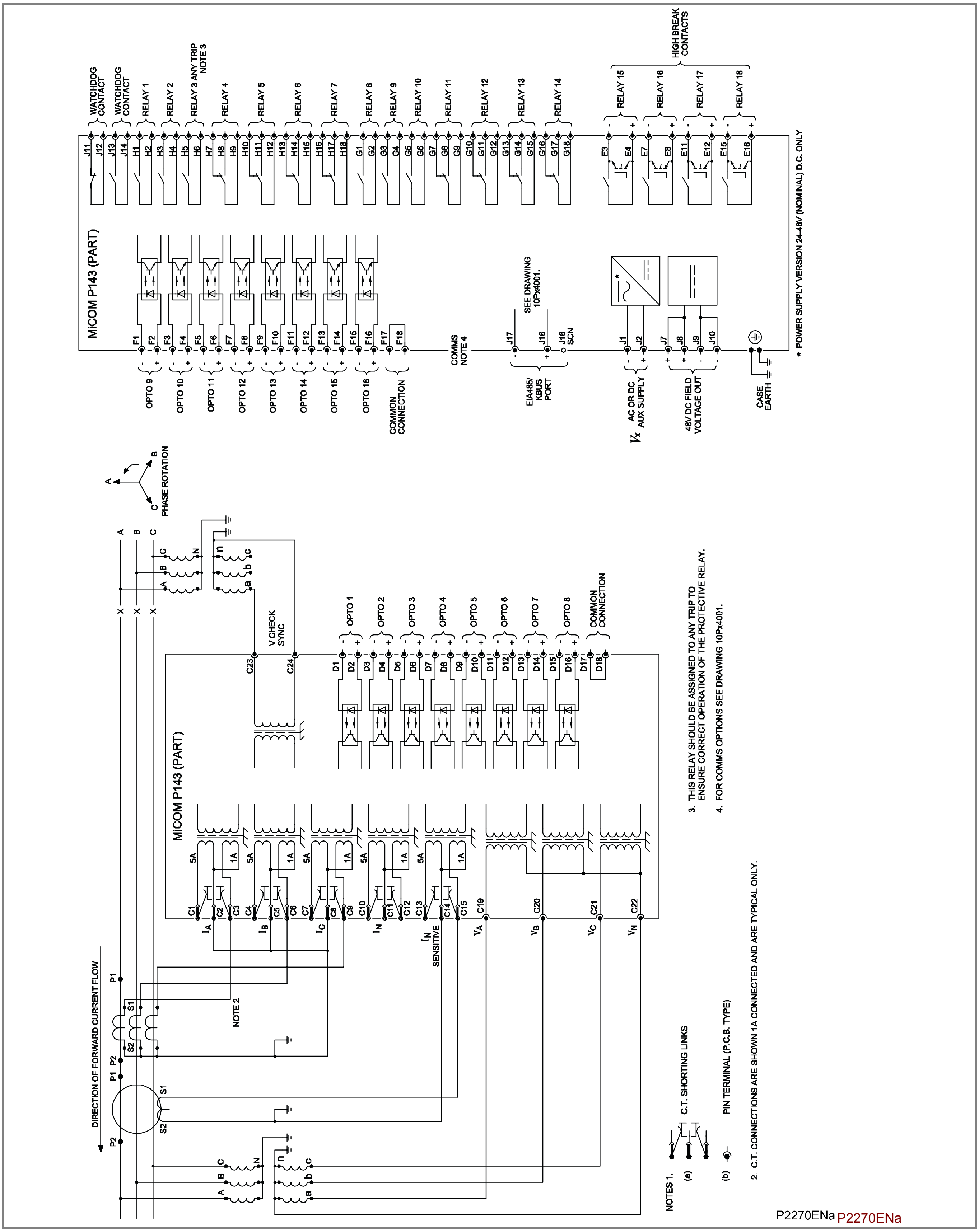
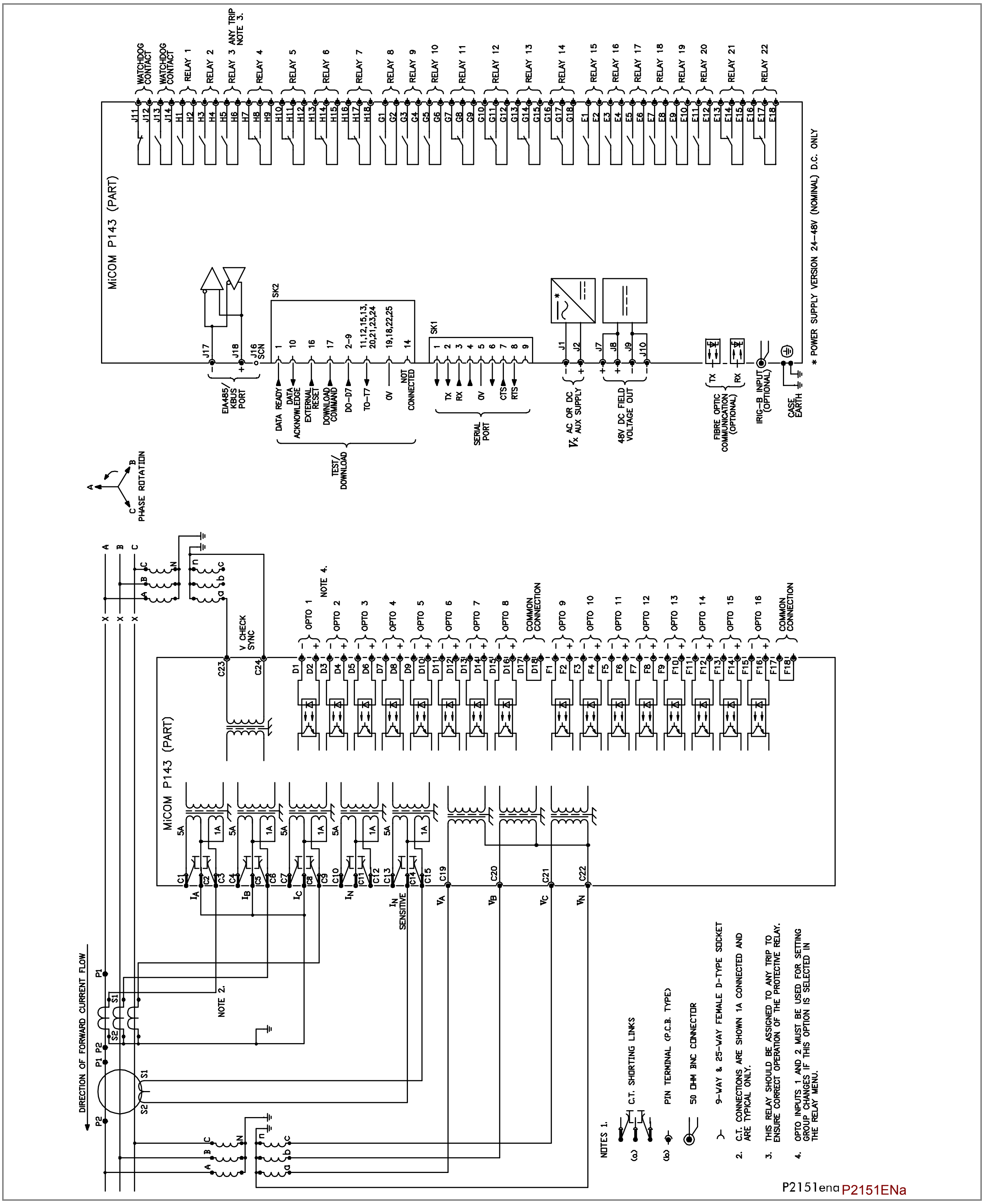


Figure 12 - P143 - D/P O/C and SEF with AR and CS (16 I/P & 14 O/P)



P2270ENa

Figure 13 - P143 - D/P O/C and SEF with AR and CS (16 I/P & 18 O/P with 4 High Break Outputs)



P2151ENa

Figure 14 - P143 - D/P O/C and SEF with AR and CS (16 I/P & 22 O/P)

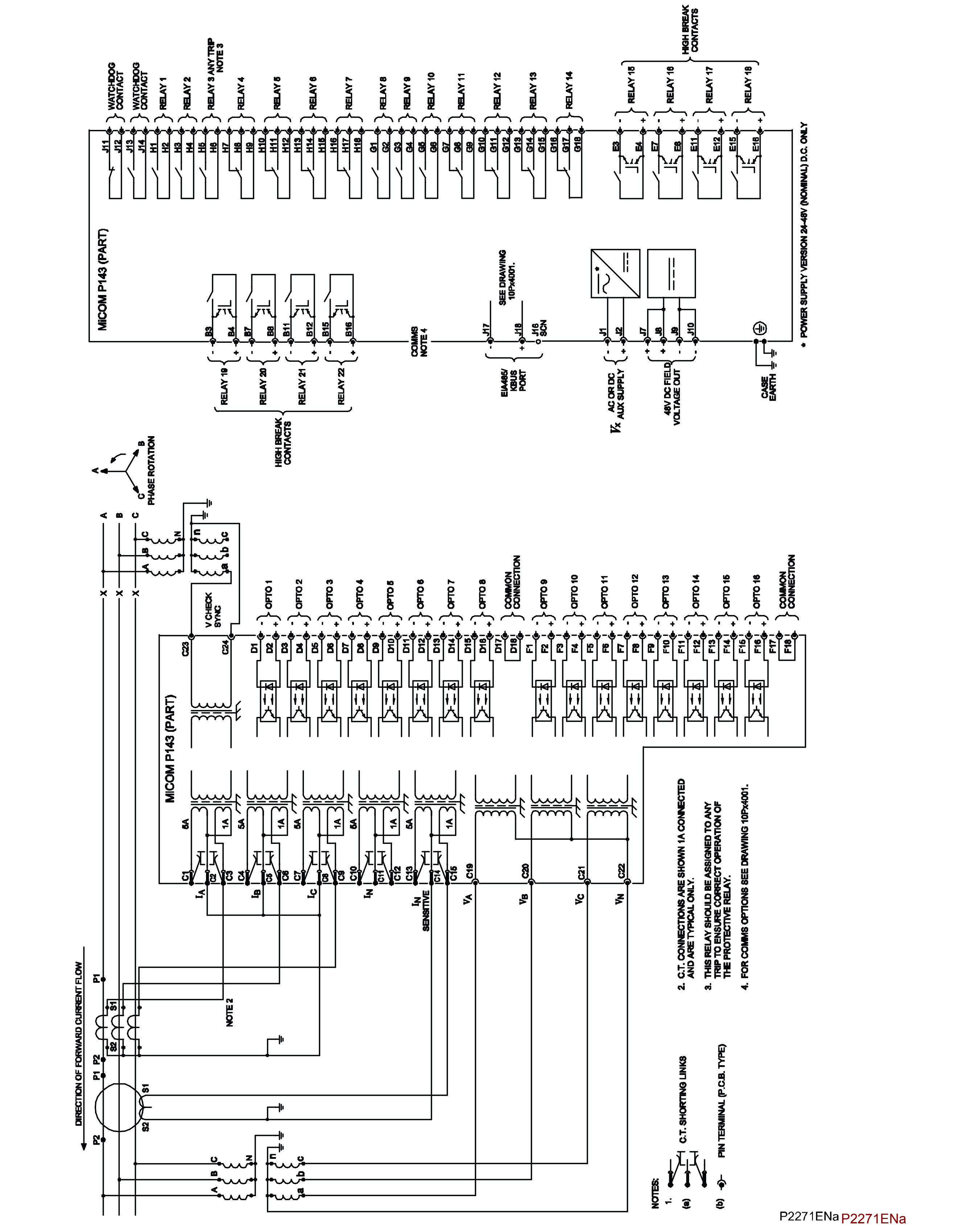
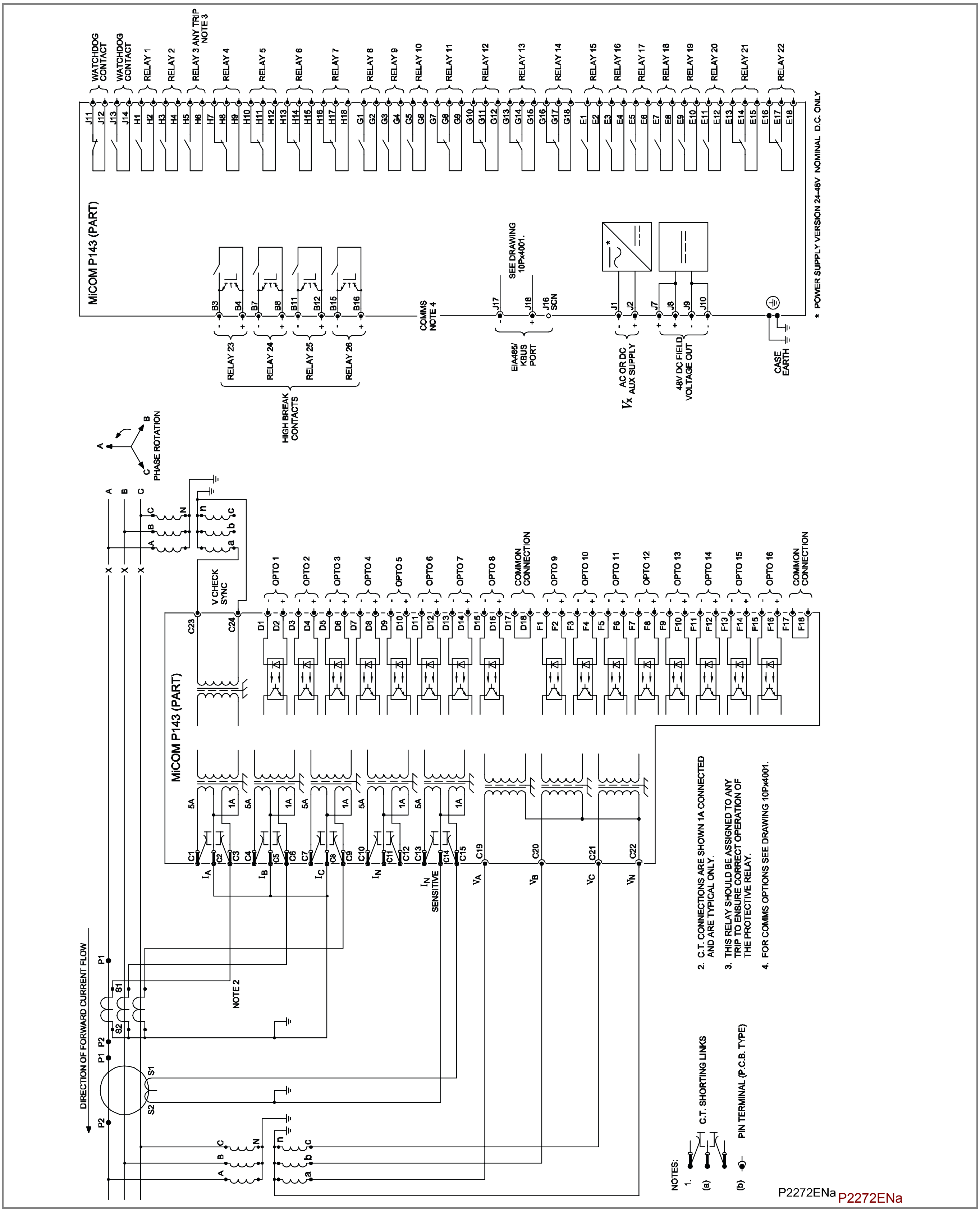


Figure 15 - P143 - D/P O/C and SEF with AR and CS (16 I/P & 22 O/P with 8 High Break Contacts)



P2272ENa

Figure 16 - P143 - D/P O/C and SEF with AR and CS (16 I/P & 26 O/P with 4 High Break Contacts)

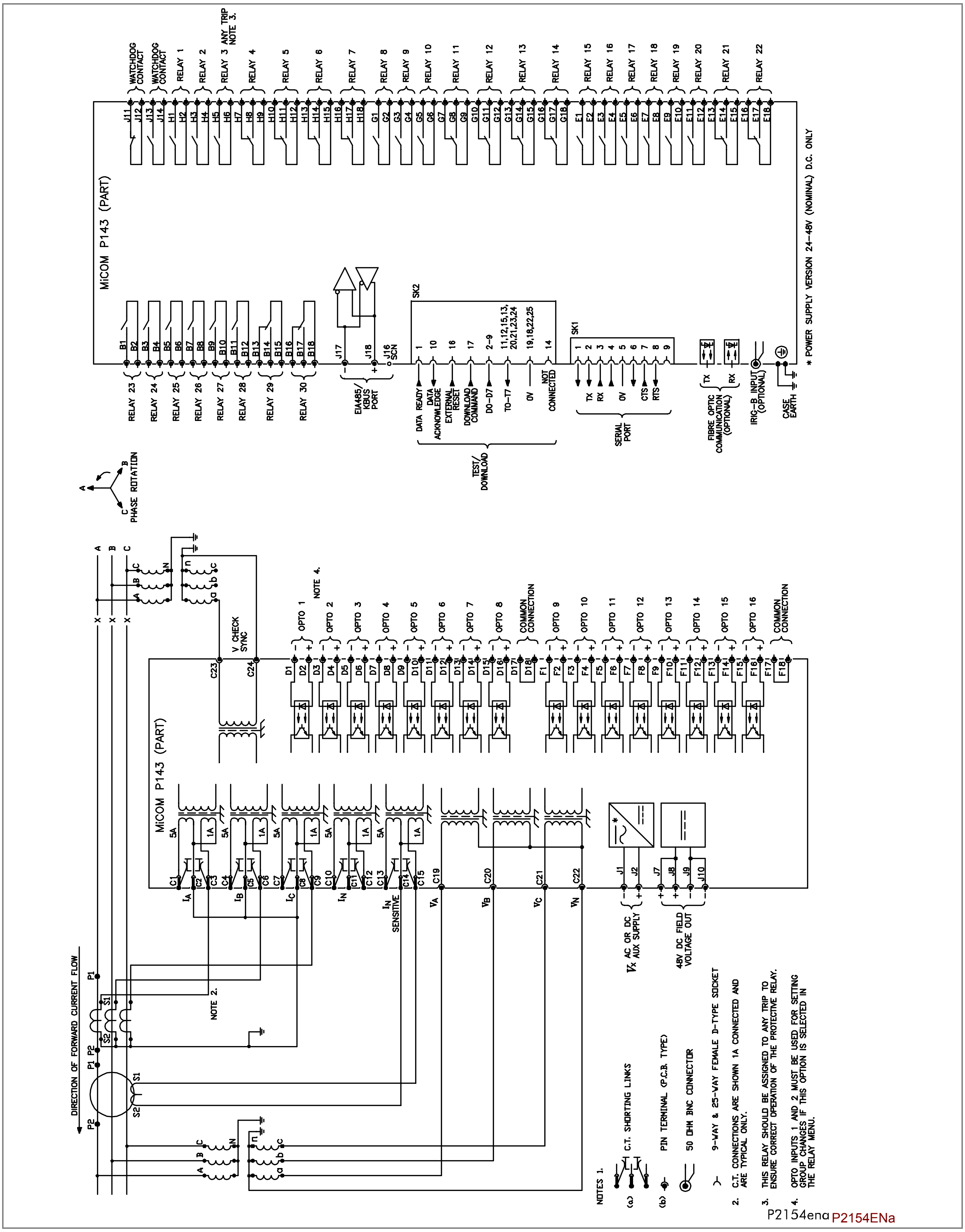


Figure 17 - P143 - D/P O/C and SEF with AR and CS (16 I/P & 30 O/P)

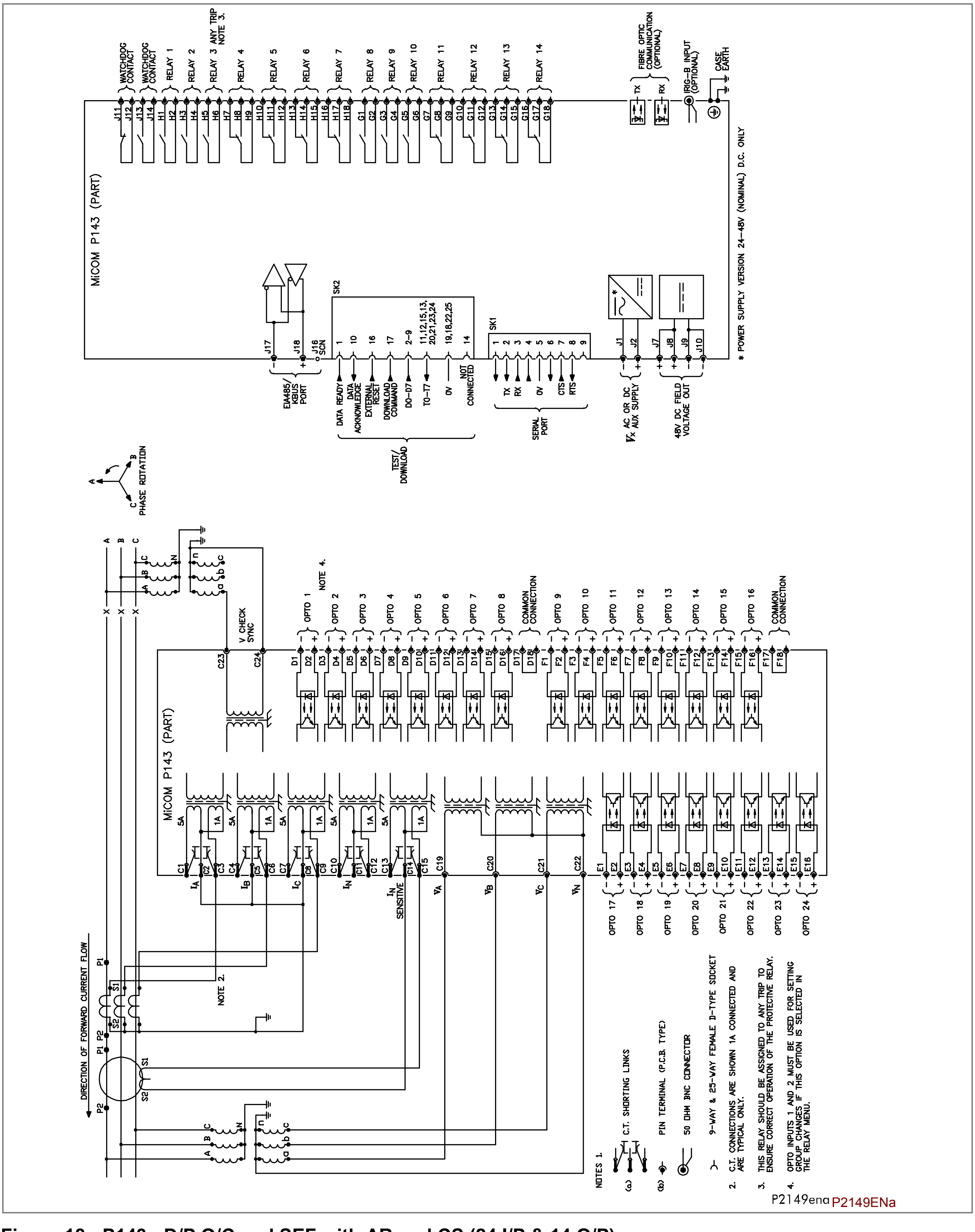


Figure 18 - P143 - D/P O/C and SEF with AR and CS (24 I/P & 14 O/P)

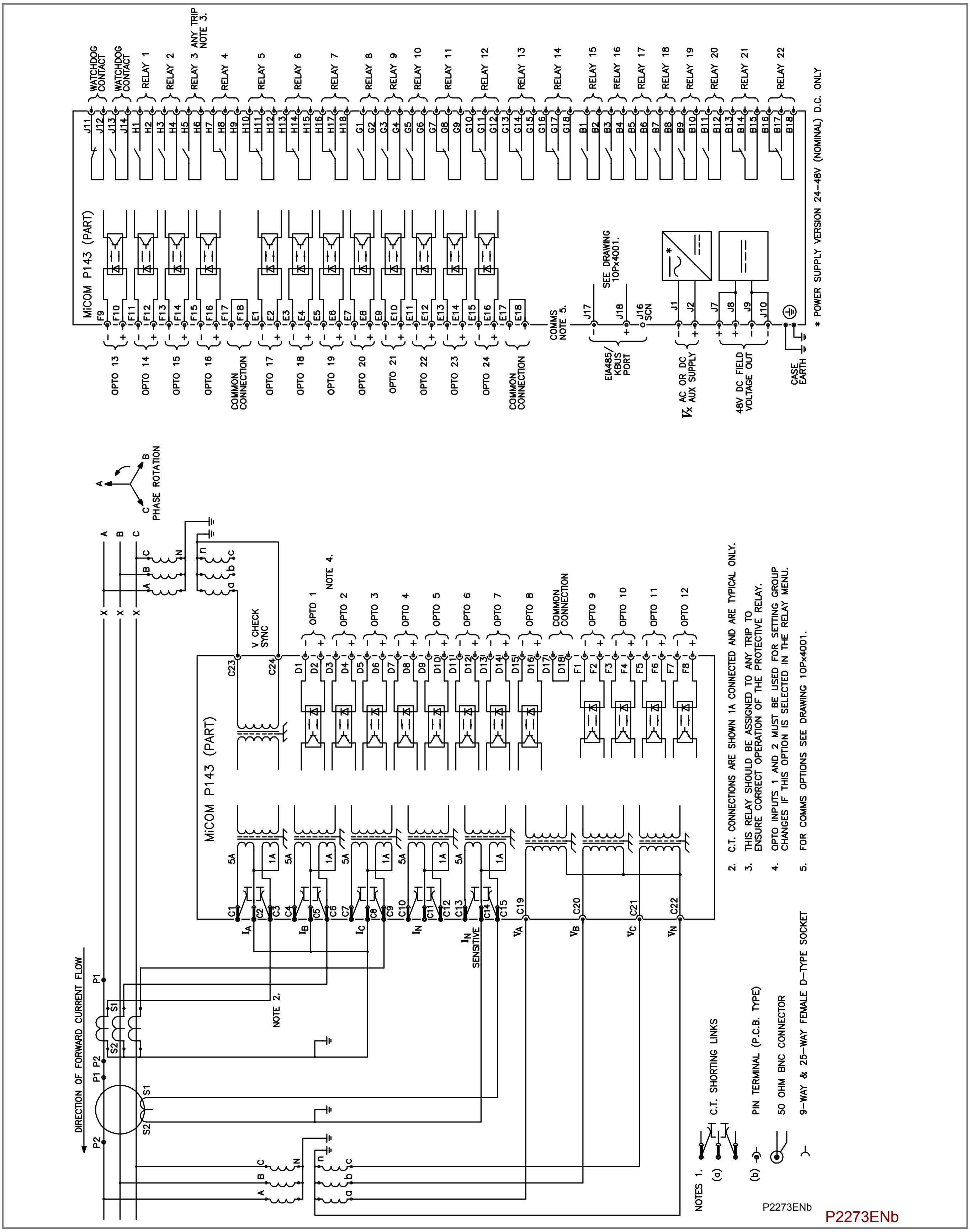


Figure 19 - P143 - D/P O/C and SEF with AR and CS (24 I/P & 22 O/P)

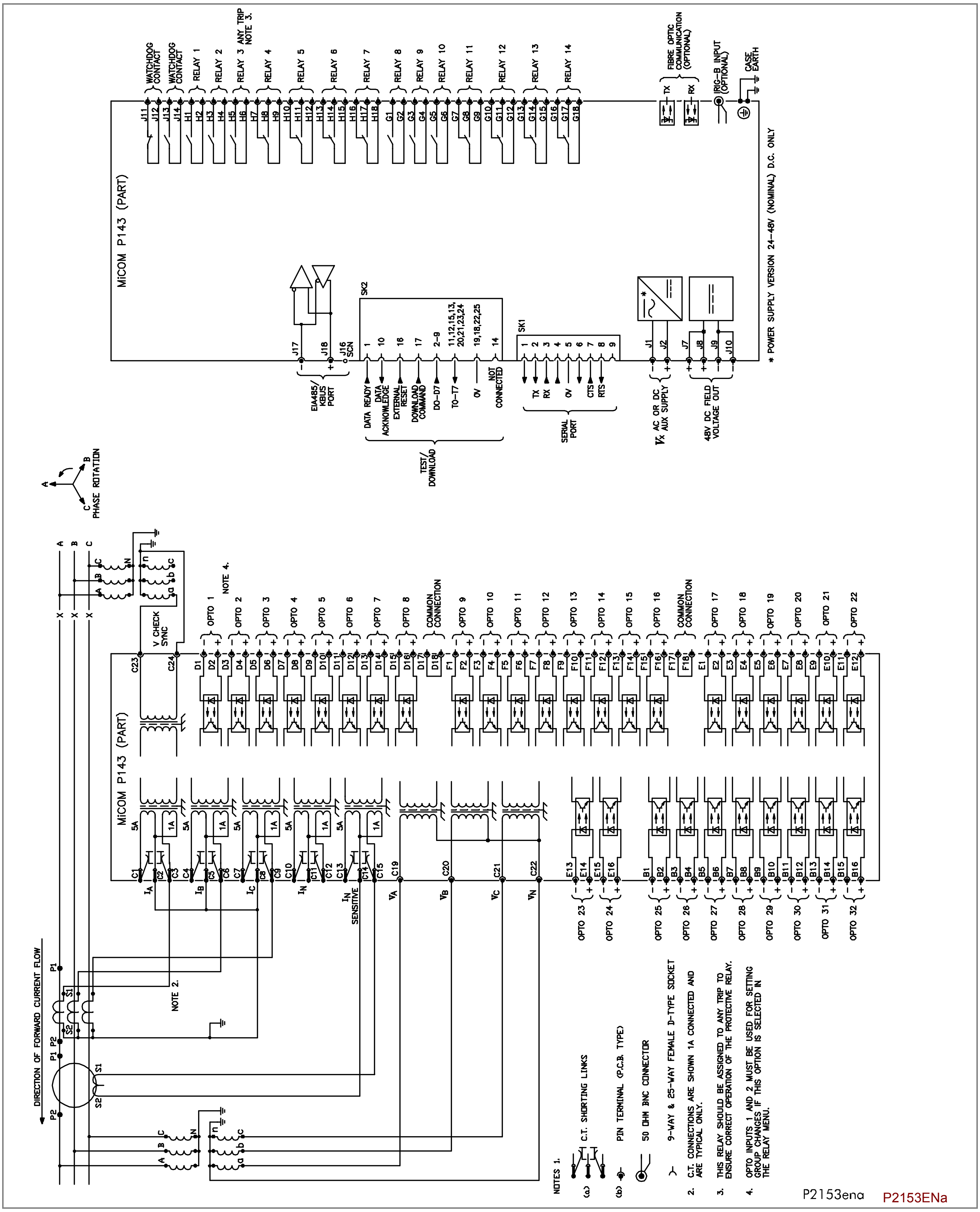
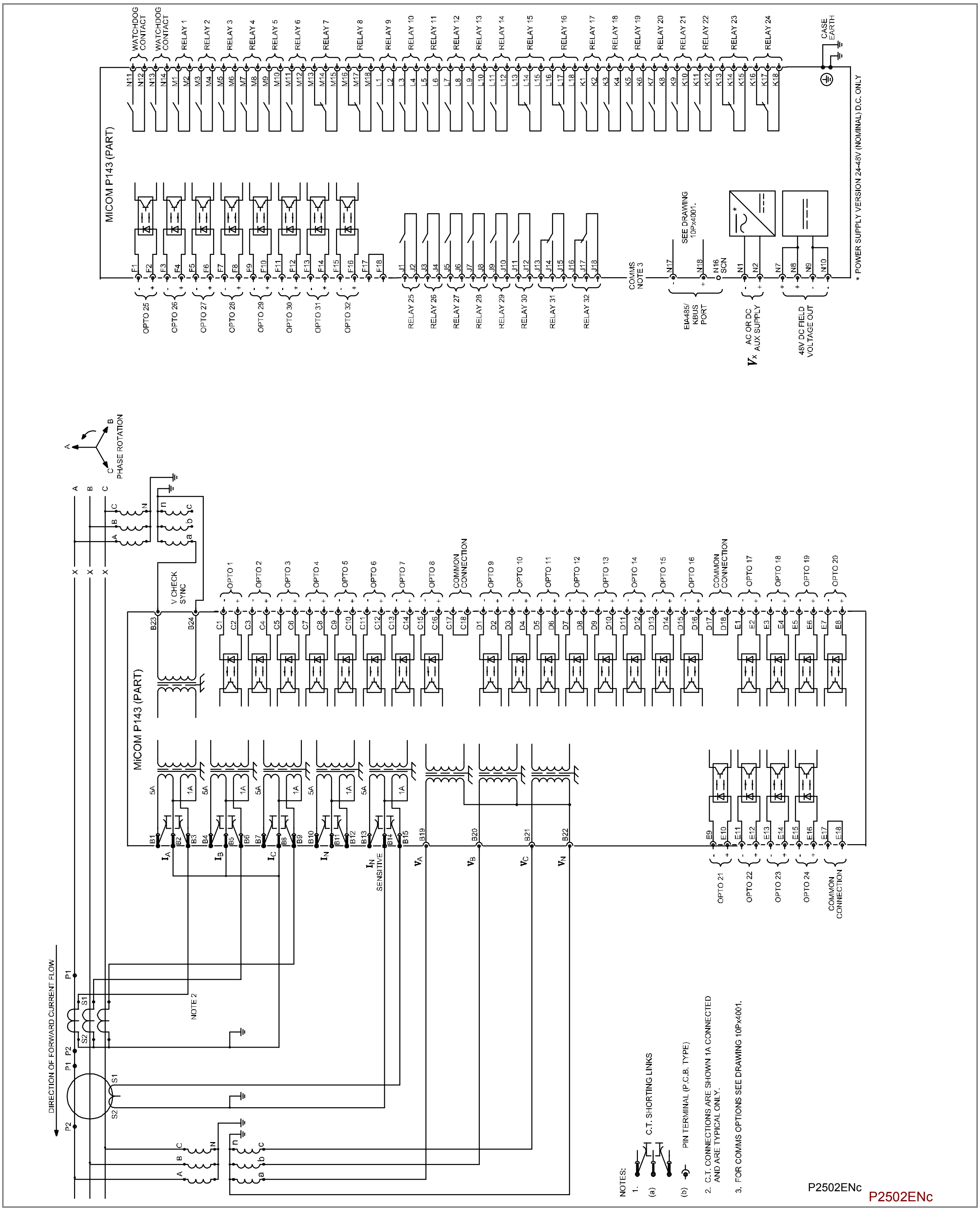
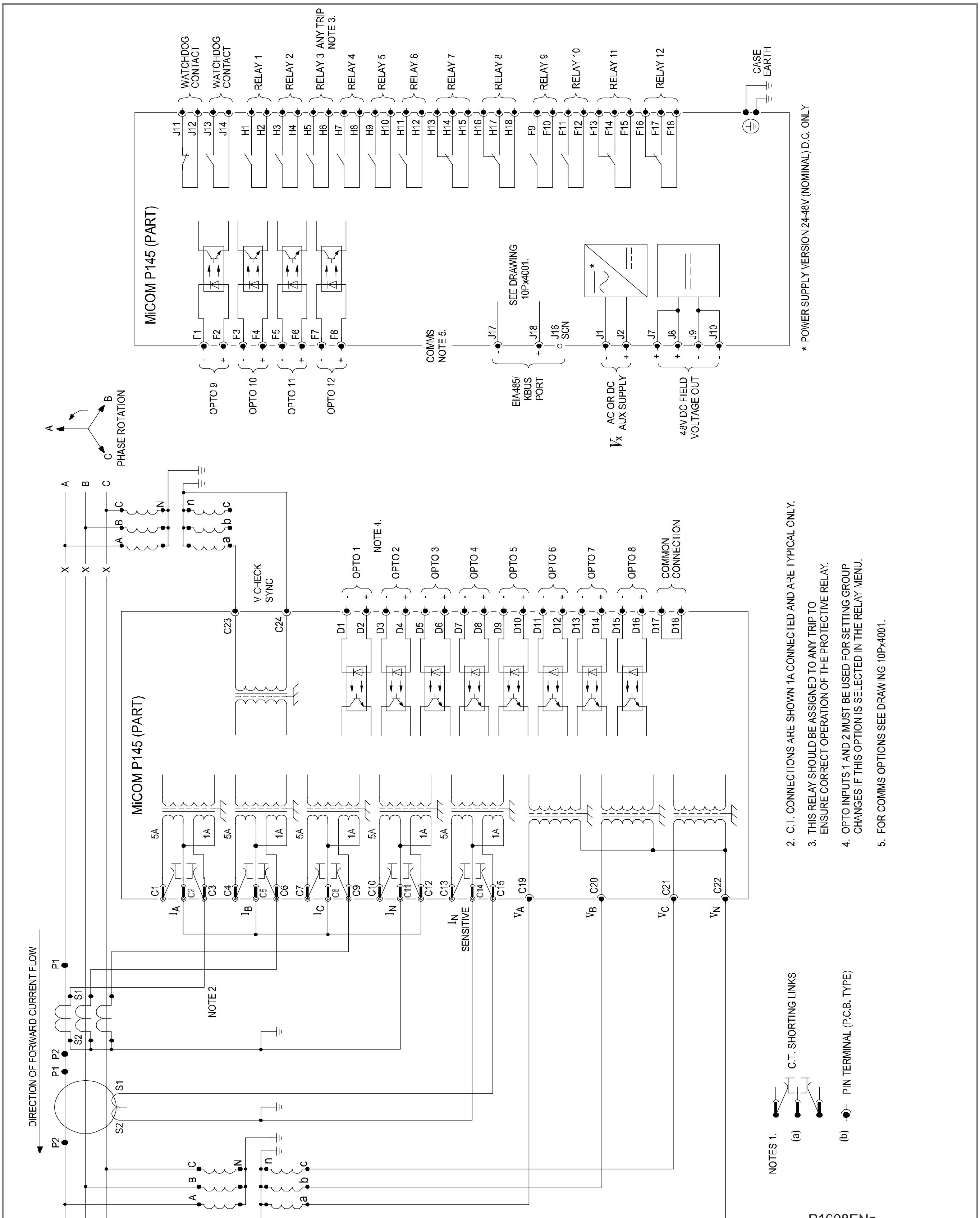


Figure 20 - P143 - D/P O/C and SEF with AR and CS (32 I/P & 14 O/P)



P2502ENc

Figure 21 - P143 - D/P O/C and SEF with AR and CS (32 I/P & 32 O/P)



P1608ENa

Figure 22 - P145 - D/P O/C and SEF with AR and CS (12 I/P & 12 O/P)

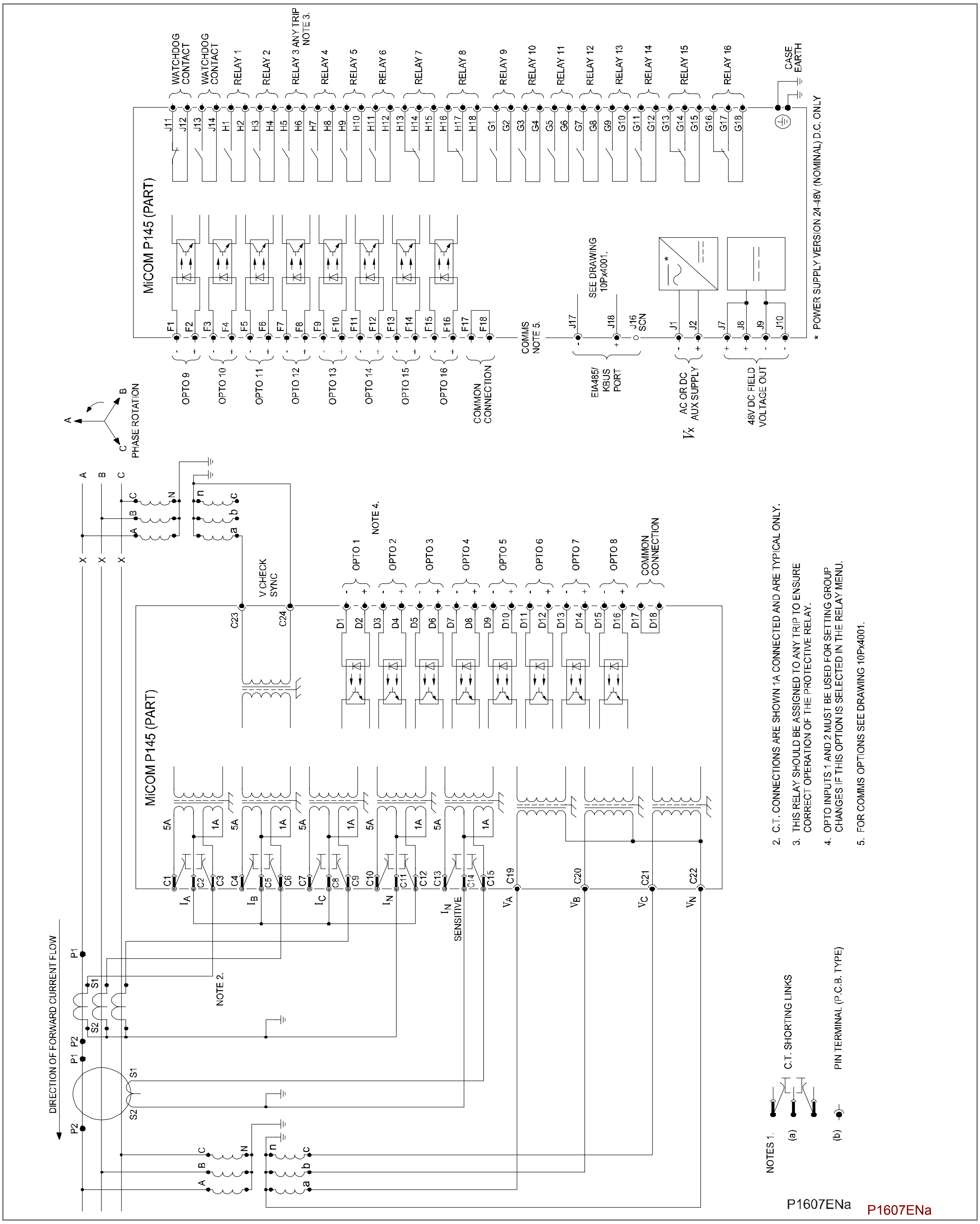


Figure 23 - P145 - D/P O/C and SEF with AR and CS (16 I/P & 16 O/P)

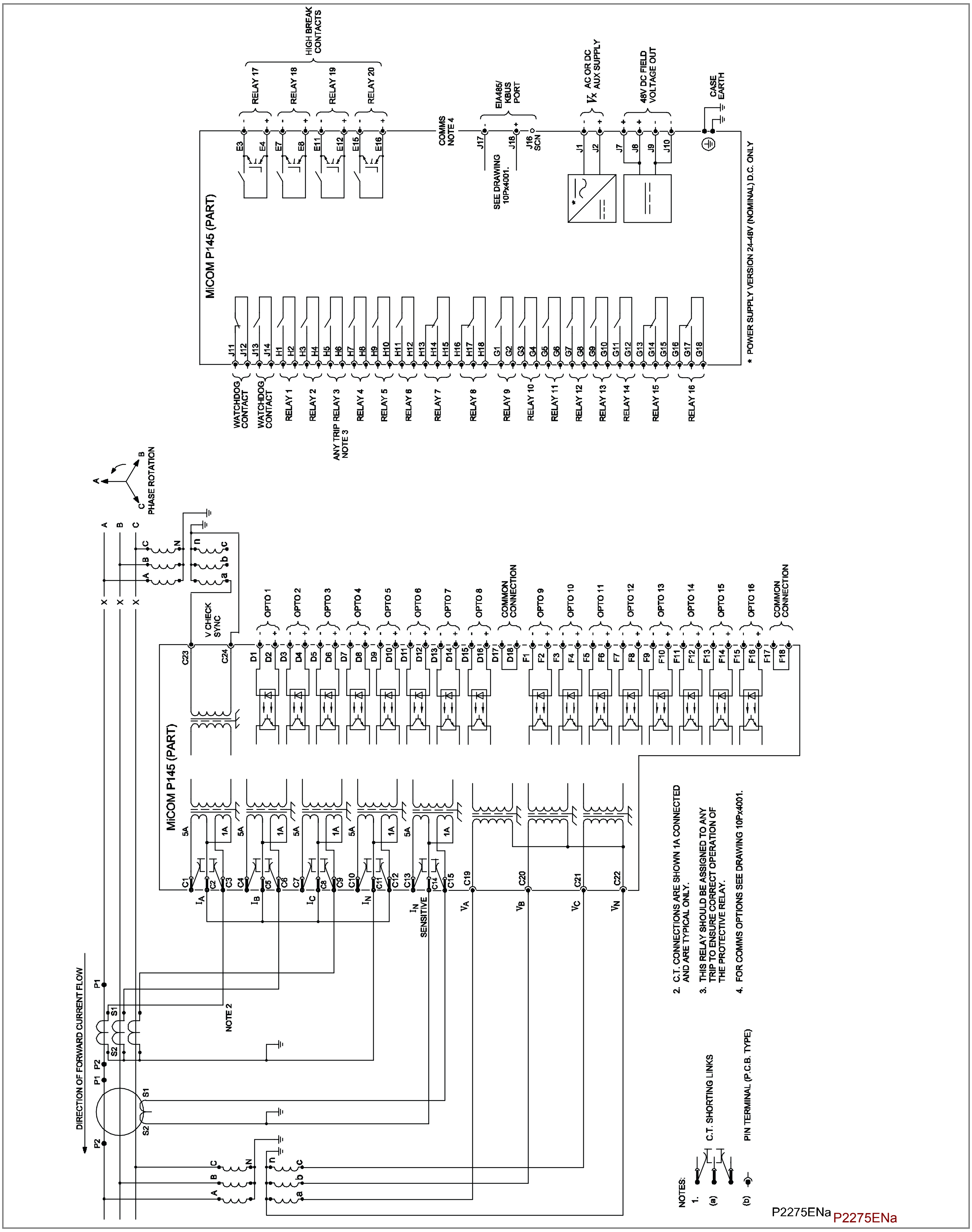
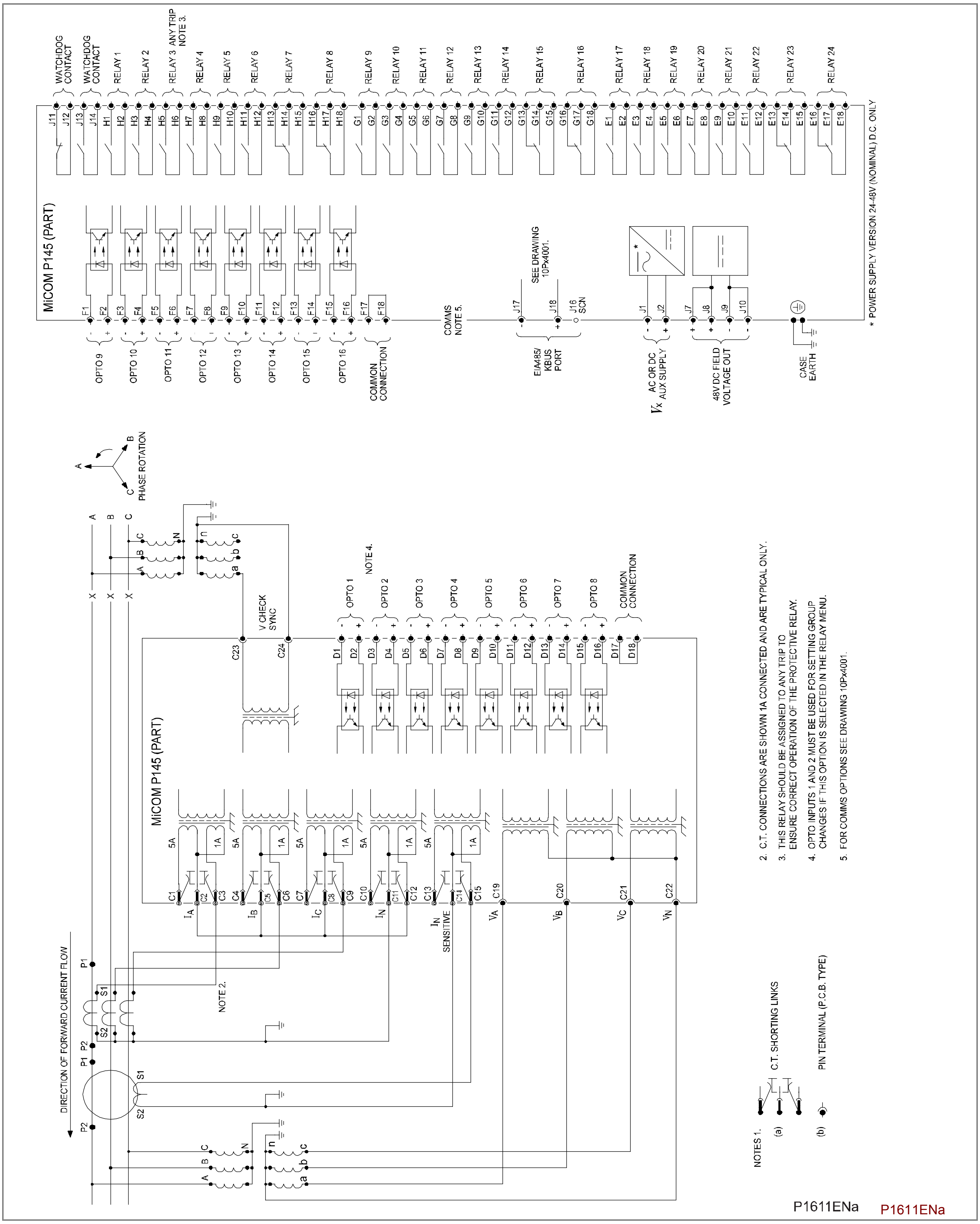


Figure 24 - P145 - D/P O/C and SEF with AR and CS (16 I/P & 20 O/P with 4 High Break Contacts)



P1611ENa

Figure 25 - P145 - D/P O/C and SEF with AR and CS (16 I/P & 24 O/P)

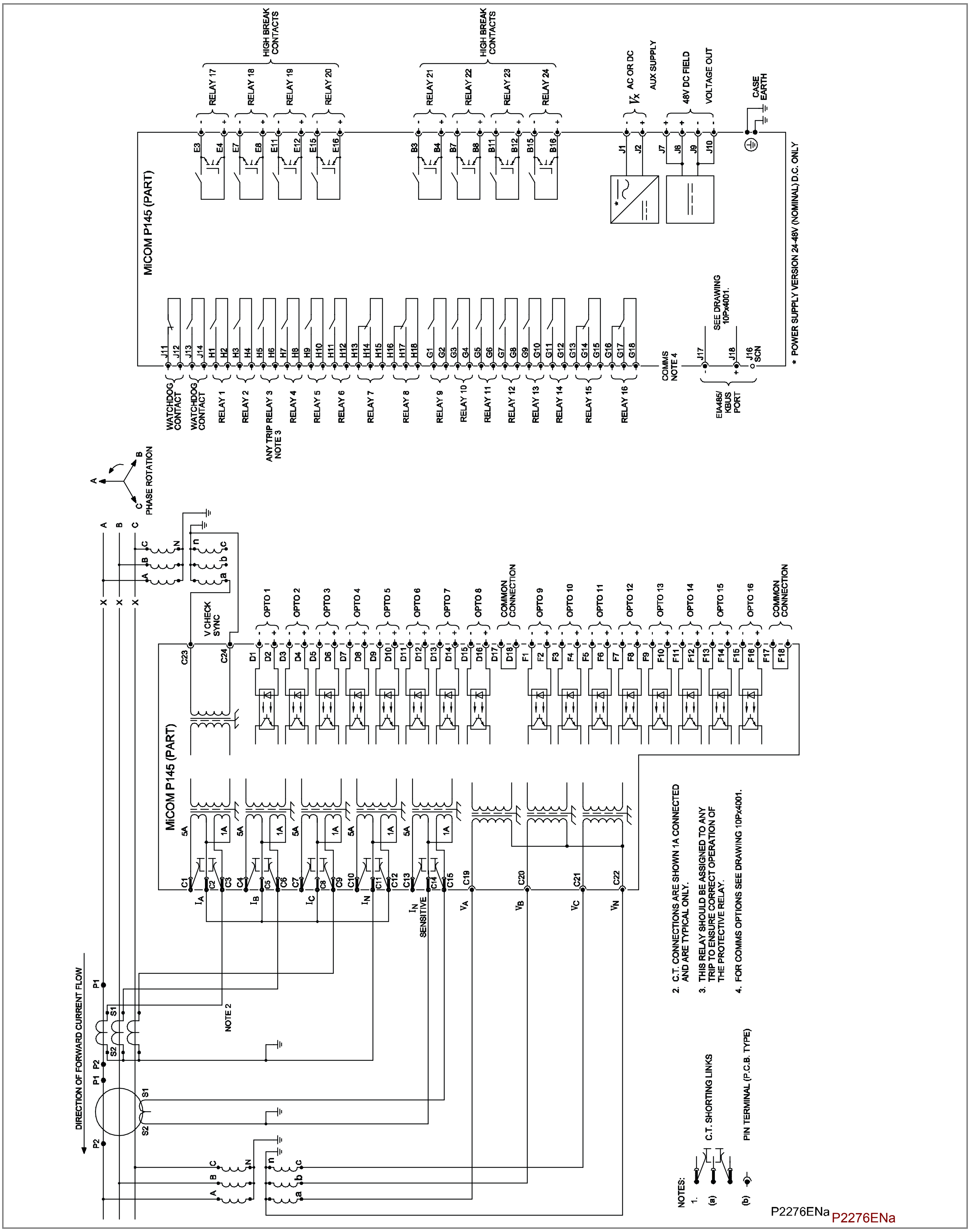
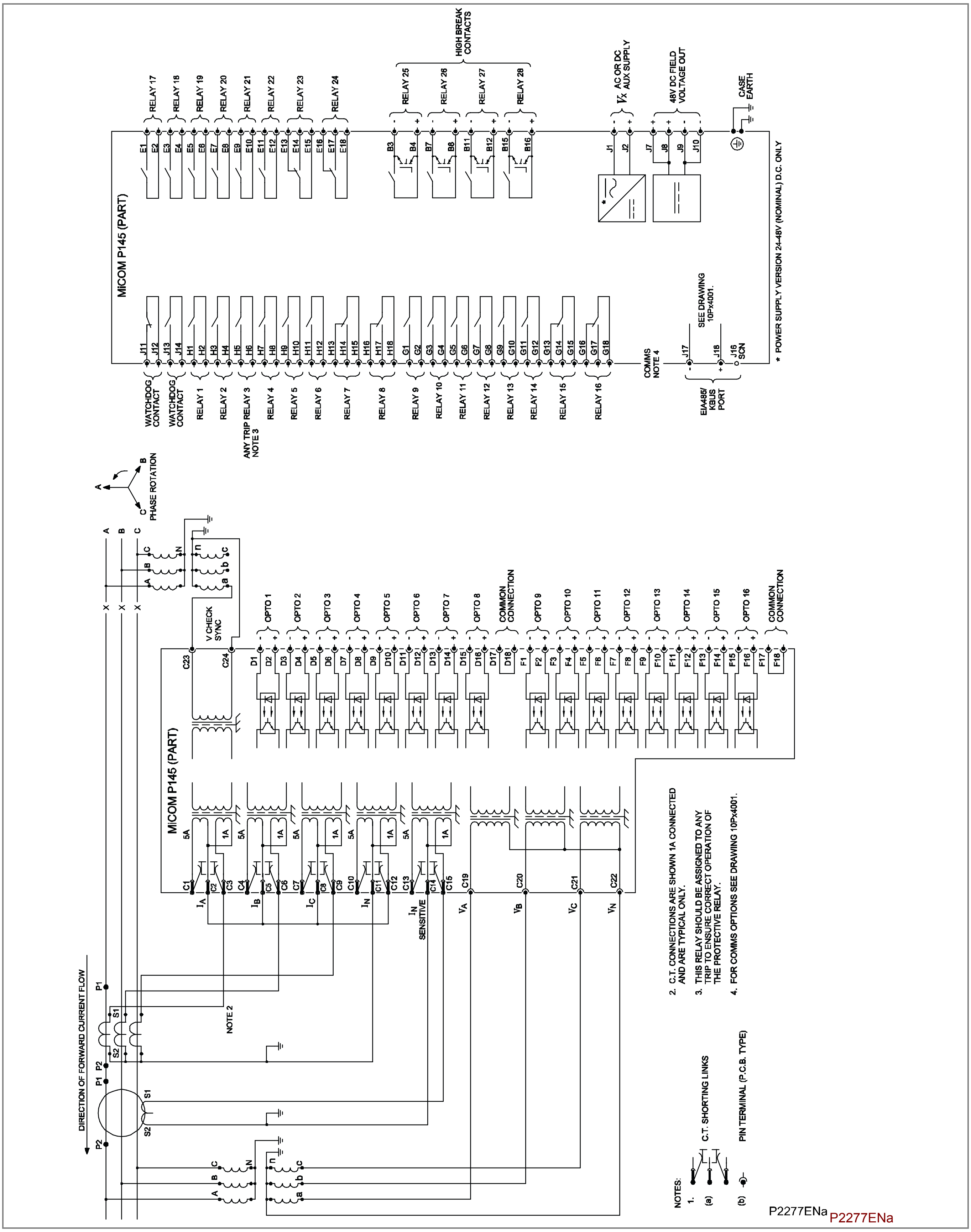


Figure 26 - P145 - D/P O/C and SEF with AR and CS (16 I/P & 24 O/P with 8 High Break Contacts)



P2277ENa

Figure 27 - P145 - D/P O/C and SEF with AR and CS (16 I/P & 28 O/P with 4 High Break Contacts)

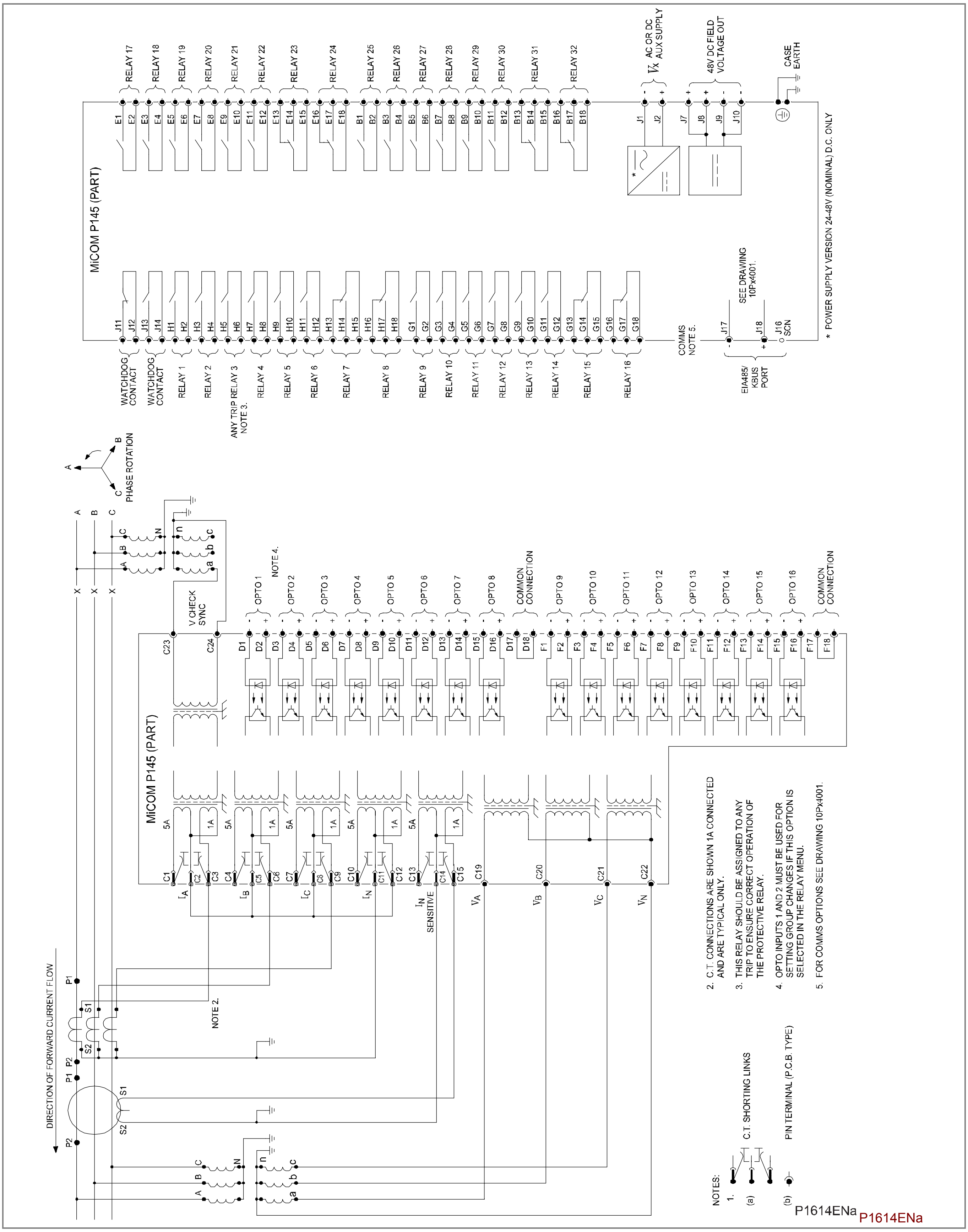


Figure 28 - P145 - D/P O/C and SEF with AR and CS (16 I/P & 32 O/P)

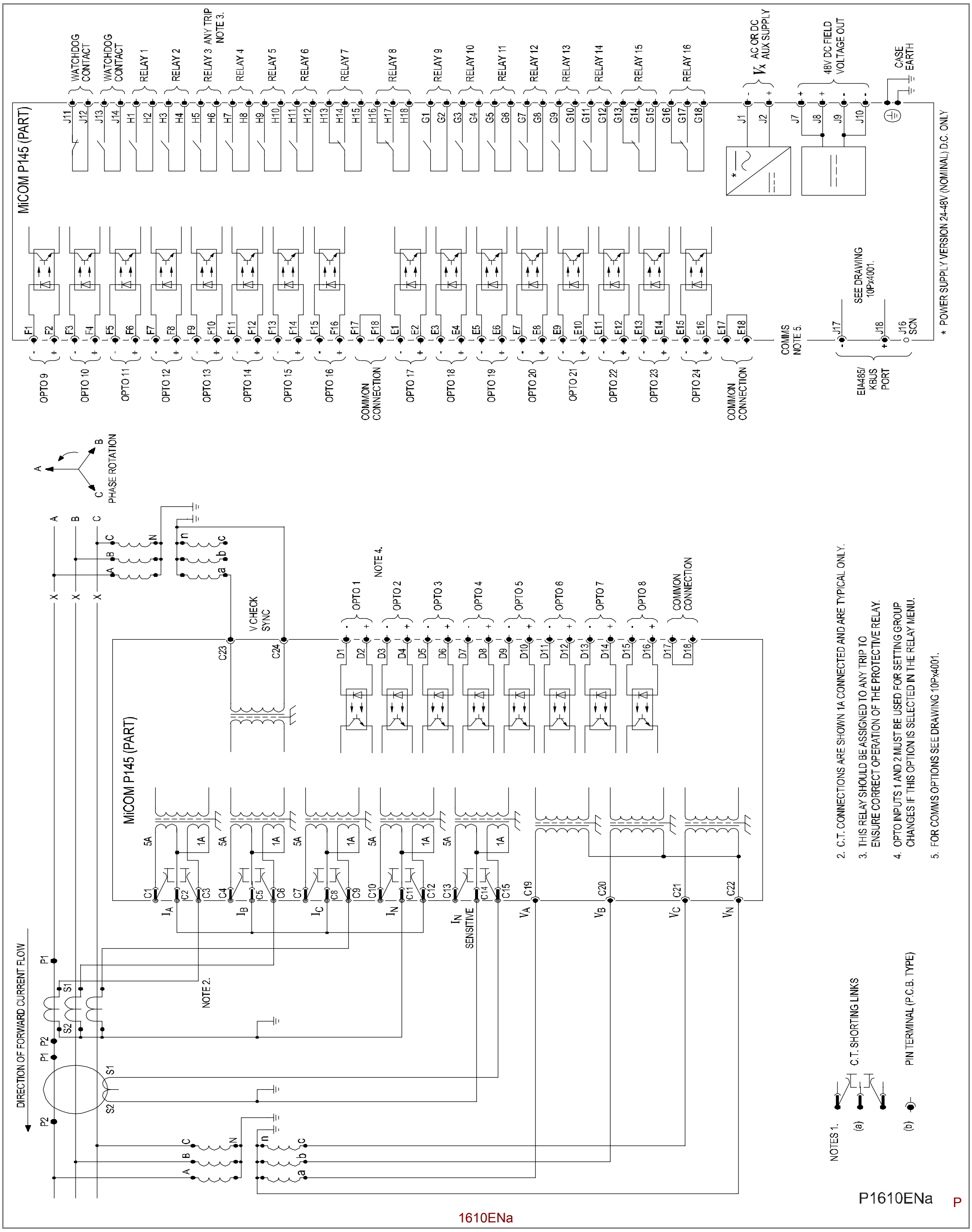


Figure 29 - P145 - D/P O/C and SEF with AR and CS (24 I/P & 16 O/P)

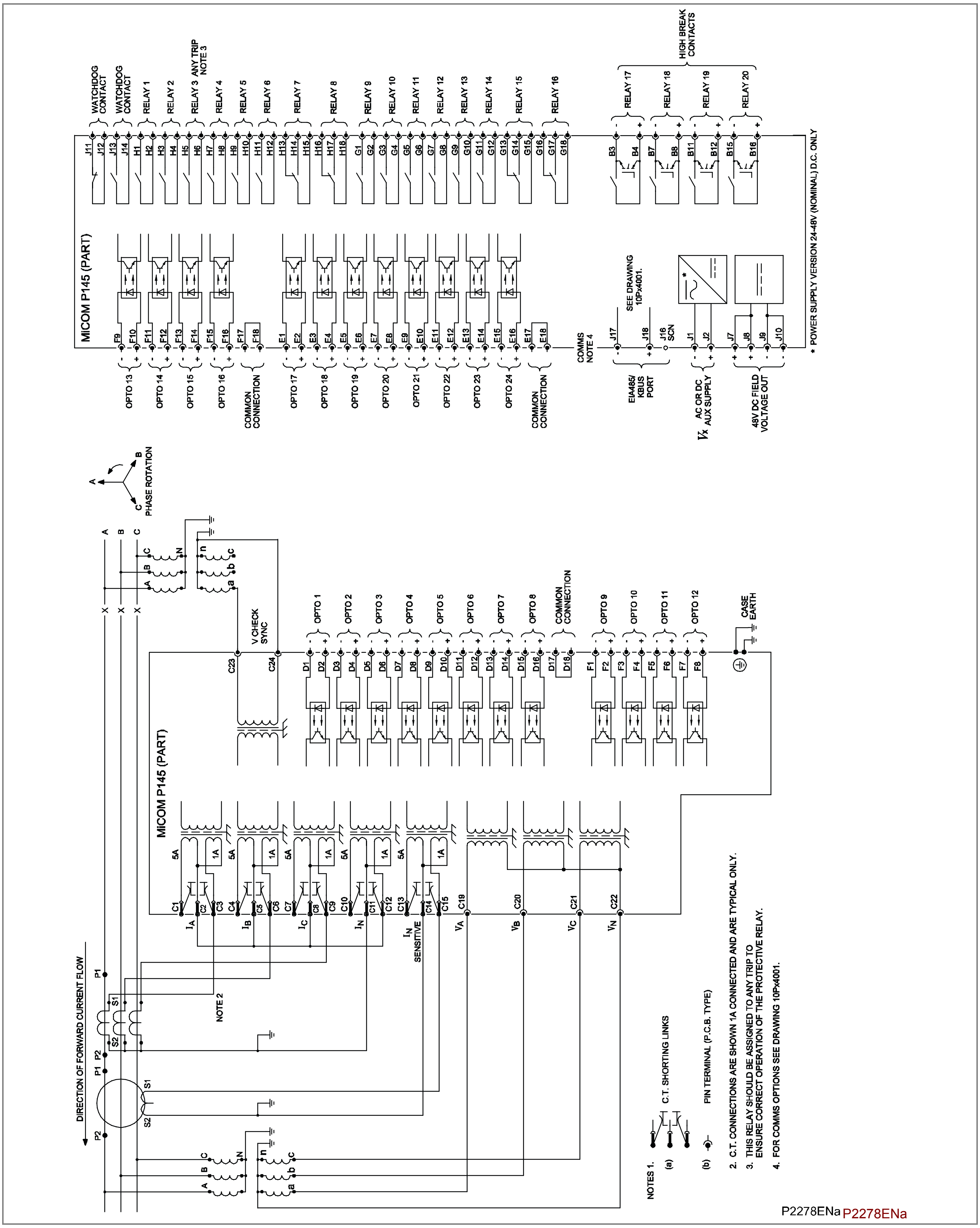


Figure 30 - P145 - D/P O/C and SEF with AR and CS (24 I/P & 20 O/P with 4 High Break Contacts)

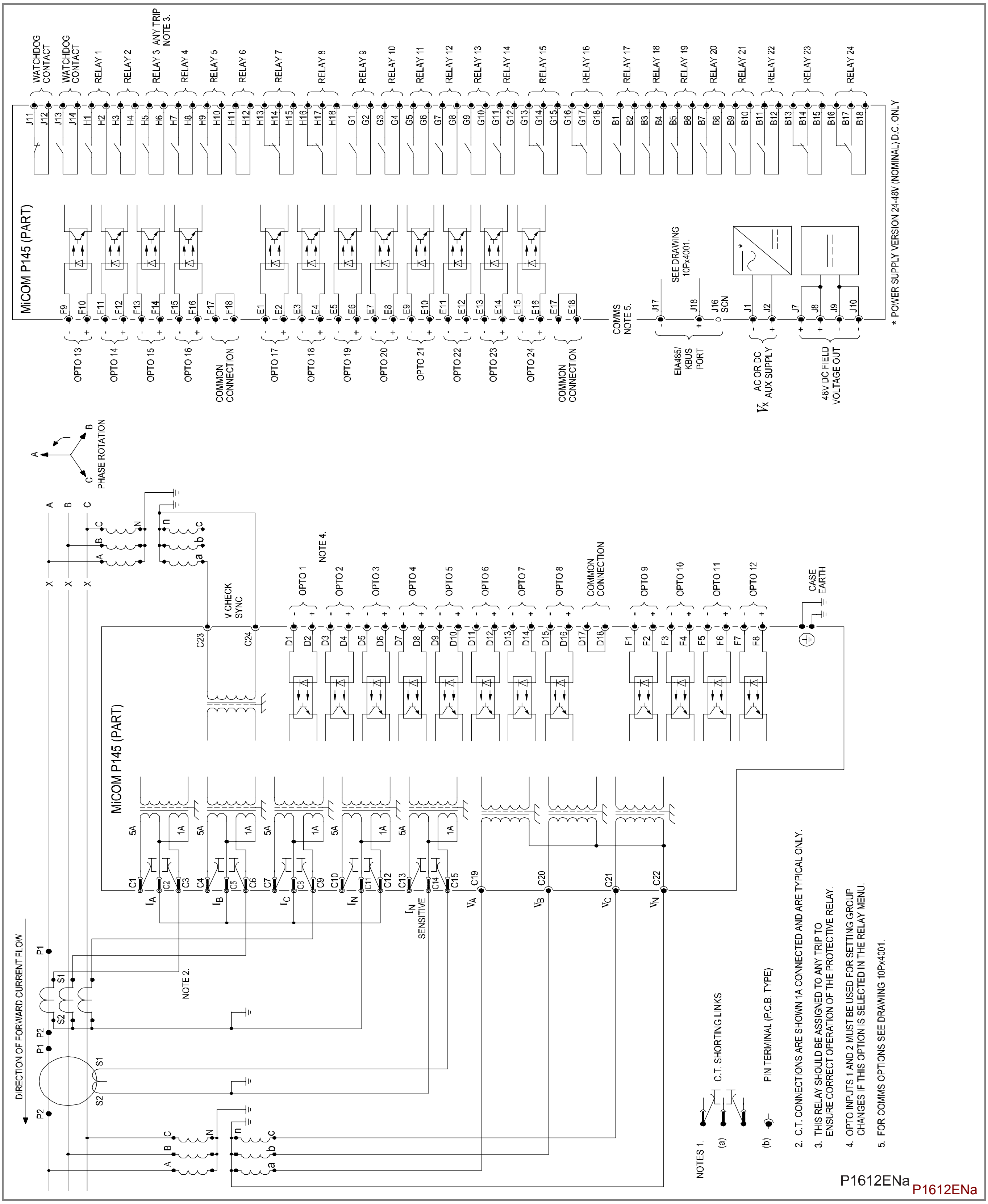


Figure 31 - P145 - D/P O/C and SEF with AR and CS (24 I/P & 24 O/P)

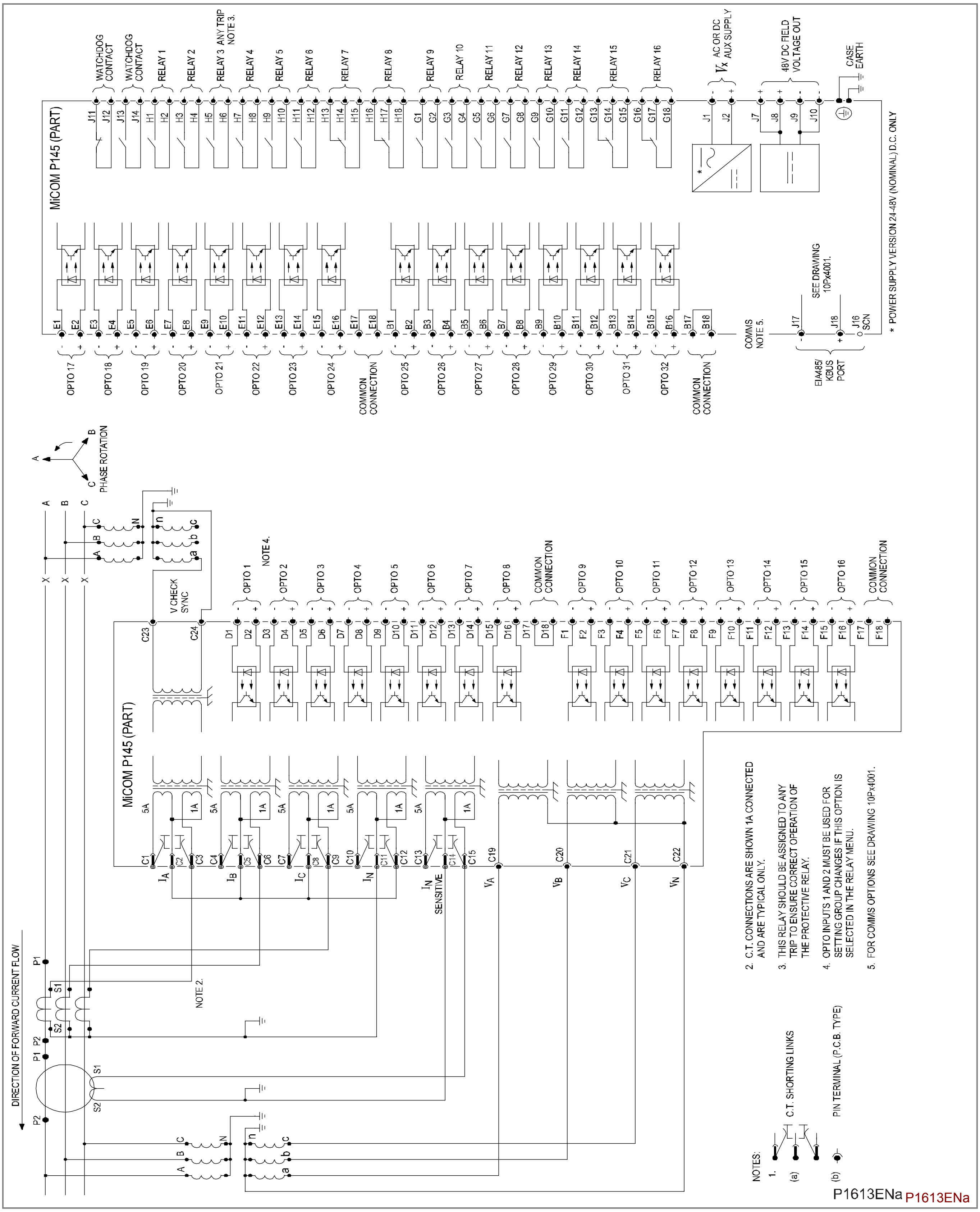


Figure 32 - P145 - D/P O/C and SEF with AR and CS (32 I/P & 16 O/P)

VERSION HISTORY

CHAPTER NO 19

Date:	10/2014
Products covered by this chapter:	This chapter covers the specific versions of the MiCOM products listed below. This includes ***only*** the following combinations of Software Version and Hardware Suffix.
Hardware Suffix:	L (P141, P142 & P143) & M (P145)
Software Version:	A0 - P14x (P141, P142, P143 & P145)
Connection Diagrams:	10P141xx (xx = 01 to 07) 10P142xx (xx = 01 to 07) 10P143xx (xx = 01 to 07) 10P145xx (xx = 01 to 07)

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TABLES

Notes:

1 VERSION HISTORY

Note	*The sixth column of the following table shows the earliest version number of the MiCOM S1 Studio software which allows you to use that feature. Unless otherwise stated in the MiCOM S1 Studio software, the latest version of MiCOM S1 Studio allows you to use all the features of previous versions.*

Software Version		Hard-ware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Document-ation
Major	Minor					
00	A	A	Oct 1998	Original Issue	V2.08	TG8612C
00	B	A	Nov 1998	Correction to make output relay test pattern settable through Courier Modification to make output relay test pattern function correctly Corrected frequency measurement cell visibility Rectified AR mode selection problems Corrected system frequency measurement in fault records	V2.08	TG8612C
00	C	A	Nov 1998	Corrected extraction of binary flags in event log Modification to AR deadtime logic Additional 100ms dwell timer added CB fail output in default PSL Modification to default undervoltage settings Correction to logic input label text	V2.08	TG8612C
00	D	A	Feb 1999	Correction to IEC870 events	V2.08	TG8612C
00	E	A	March 1999	Modification to residual overvoltage protection Modification to negative sequence overcurrent and overvoltage protection Minor bug fixes	V2.08	TG8612C
00	F	A	March 1999	Thresholds applied to measurements to prevent jitter Modification to low impedance REF settings Modification to battery failure alarms Minor bug fixes	V2.08	TG8612C
00	G	A	June 1999	Modification to minimum current setting for SEF protection Check sync signal made visible in PSL Minor bug fixes	V2.08	TG8612C
00	H	A	July 1999	Disturbance recorder modified to include correct substation name MODBUS frequency measurement corrected Fault locator miles setting now indicates miles not metres Frequency measurement indicates "Not available" instead being invisible when no current or voltage is applied. PSL downloads are now logged as events	V2.08	TG8612C
00	I	A	July 1999	IREF>Is1 setting correctly scaled by CT ratio	V2.08	TG8612C
00	J	A	Aug 1999	Modification to fault recorder prevents undervoltage starts being logged as undervoltage trips Corrected spelling mistake in French language text Modification to make "ISEF Direction" setting invisible when "Lo Z REF" is selected	V2.08	TG8612C
01	A	A	Sept 1999	Corrected spelling mistakes in French language text Modification to disturbance recorder to ensure that logic state changes are displayed at the correct times Correction to VTS logic to enable scaling of the current threshold with CT ratio Correction to VCO logic to enable scaling of the V< threshold with VT ratio Modification to prevent VT ratios returning to default when the auxiliary supply is interrupted	V2.08	TG8612C
01	B	A	Oct 1999	Modification to prevent an error code being generated when the opto inputs are switched on and off between 200 and 10,000 times per second	V2.08	TG8612C
02	A	A	Nov 1999	Frequency protection added Minor changes to Courier implementation	V2.08	TG8612C
02	B	A	Nov 1999	Modification to transient overreach algorithm to improve sensitivity for faults just above threshold	V2.08	TG8612C
02	C	A	Dec 1999	Correction to prevent error code being generated when reading thermal state via a MODBUS master station	V2.08	TG8612C
02	D	A	Feb 1999	Modification to correct system frequency, fault duration and relay trip time measurements when extracting fault records via MODBUS master station	V2.08	TG8612C
02	E	A	May 2002	Resolved possible reboot caused by invalid MODBUS requests Modification to improve compatibility between Px20 and Px40 relays on MODBUS communications networks	V2.08	TG8612C

Software Version		Hard-ware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Document-ation
Major	Minor					
03	A	A	April 2000	Admittance protection added External initiation of auto-reclose added Cos phi and Sin phi features added to SEF protection Maximum Vn polarizing voltage setting increased from 22V to 80V (increased to 320V for 440V relays) Maximum NVD setting increased from 50V to 80V (increased to 320V for 440V relays) Minimum "Fault Frequency Counter" setting increased from 0 to 1	V2.08	TG8612C
03	B	A	May 2002	Resolved possible reboot caused by invalid MODBUS requests Modification to improve compatibility between Px20 and Px40 relays on MODBUS communications networks	V2.08	TG8612C
04	A	A	July 2000	Not released to production DNP3.0 protocol added Courier and MODBUS enhancement to improve compatibility with other protection Correction to scaling of REF setting with CT ratio Corrected spelling mistakes in French, German and Spanish language text Cos phi and Sin phi features added to SEF protection	V2.08	TG8612C
04	B	A	Aug 2000	Not released to production Correction to ensure that all analogue events are generated correctly Modification to ensure the relay uses the correct deadband settings for analogue events	V2.08	TG8612C
04	C	A	Aug 2000	Not released to production Modification to IN1> and IN2> directional elements to prevent stages 2, 3 and 4 being blocked when stage 1 is set none directional	V2.08	TG8612C
04	D	A	Sept 2000	Modification to improve compatibility between Px20 and Px40 relays on MODBUS communications networks	V2.08	TG8612C
04	E	A	Oct 2000	Not released to production Modification to CB fail and CB condition monitoring logic Correction to ensure that address changes can be made using DNP3.0 remote address change feature New data type (D15) added to DNP3.0 protocol	V2.08	TG8612C
05	A	A	Nov 2000	Event filtering added	V2.08	TG8612C
05	B	A	Dec 2000	Improvements made to event filtering and energy measurements	V2.08	TG8612C
05	C	A	July 2001	Not released to production Support for MODBUS code 7 added	V2.08	TG8612C
05	D	A	Dec 2001	Modification to allow CB fail initiation by the under and over frequency elements Fault locator enhanced to allow "MILES" setting to modified via MiCOM S1	V2.08	TG8612C
05	E	A	Jan 2002	Resolved possible reboot caused by Disturbance Recorder	V2.08	TG8612C
05	F	A	Jan 2002	Resolved possible reboot caused by invalid MODBUS requests	V2.08	TG8612C
05	G	A	July 2002	Not released to production Corrected MODBUS trip and close with "0" command	V2.08	TG8612C
05	H	A	Nov 2002	Modification to allow extracted IEC60870-5-103 to be correctly sequenced Enhanced DNP3.0 Object 10 support for CB Close pulse Modification to reduce switching time between setting groups Fault locator line length setting corrected in groups 2, 3 & 4 DNP3.0 Object 10 included in Class 0 poll DNP3.0 support for season in time information	V2.08	TG8612C
05	I	A	Nov 2002	Modification to improve compatibility between Px30 and Px40 relays IEC60870 communications networks	V2.08	TG8612C
05	J	A	July 2003	Disturbance recorder triggering no longer causes loss of disturbance recorder data, temporary freezing of the user interface or loss of rear port comms	V2.08	TG8612C
05	K	A	Jan 2004	Correction to prevent loss of communications via the front courier port, noticed particularly with rear port MODBUS relays DNP3.0 Analogue scan rate reduced from 5s to 1s DNP3.0 Digital scan rate reduced from 5s to 0.5s Improvements to DNP3.0 deadband settings for data types D1 to D7 Modification to event filtering to resolve problem with undercurrent elements causing a buffer overflow Reboot of relay if clear key is pressed following a remote reset of indications	V2.08	TG8612C

Software Version		Hard-ware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Document-ation
Major	Minor					
05	L	A	May 2004	Auto-reclose trip test now produces a fault record on the user interface Overvoltage fault record page on the user interface is now correct for VCN faults Overvoltage fault record page on the user interface is now correct for VCN faults Even/odd parity setting is now correctly recognized for DNP3.0 and MODBUS at power up The analogue check channels are monitored all of the time MODBUS has improved frame reception and does not lock up when spurious messages are injected on to the RS485 network The relay will lock out if it detects an SRAM failure at power up	V2.08	TG8612C
05	M	A	July 2004	MODBUS device driver can incorrectly interpret frame length and return invalid data for valid message Remote commands can occasionally result in a reboot	V2.08	TG8612C
05	N	A	June 2005	MODBUS device driver updated to improve performance on 60 Hz Power measurements display at non-zero current inputs corrected Phase under/over voltage protection hysteresis changed to 2% CB maintenance alarm now set for each new trip AR behavior in User Set Mode improved	V2.08	TG8612C
05	P	A	Jan 2010	Update platform to B3.11 DTS PCS3198: Incorrect resetting of change of direction drop-off count strategy for evolving fault	V2.08	TG8612C
09	Special Release for Taiwan - based on Version 10 with duplicate CB Trip/Close cells in new menu column					
09	A	B	April 2002	CB trip and close functionality available via the default display	V2.08	Based upon P14x/EN T/A22
09	B	B	Dec 2002	Control inputs modified to produce protection events Control inputs enhanced to be none volatile IDG curve stage 2 improvements Modified AR mode to be none volatile Fault locator line length setting corrected in groups 2, 3 & 4 DNP3.0 Object 10 included in Class 0 poll DNP3.0 support for season in time information "Reset Relays/LED" DDB signal corrected to reset LEDs Slip frequency measurement corrected via MODBUS Modification to reduce switching time between setting groups ISEF> IDG time setting modified to include units (seconds)	V2.08	Based upon P14x/EN T/A22
09	C	B	Nov 2003	Modification to improve compatibility between Px30 and Px40 relays on IEC60870 communications networks Check synch time settings - step size reduced from 100ms to 10ms Disturbance recorder triggering no longer causes loss of disturbance recorder data, temporary freezing of the user interface or loss of rear port comms Modification to improve compatibility between Px30 and Px40 relays IEC60870 communications networks	V2.09 + Patch	Based upon P14x/EN T/A22
09	D	B	June 2005	MODBUS device driver updated to improve performance on 60 Hz Power measurements display at non-zero current inputs corrected Phase under/over voltage protection hysteresis changed to 2% CB maintenance alarm now set for each new trip AR behavior in User Set Mode improved IEC60870-5-103. Status of summer bit corrected Commissioning test pattern for output relays improved to take account of fitted relays Commissioning test DDB status cell 1022-992 now shows 31 bits (instead of 32)	V2.11	Based upon P14x/EN T/A22
10	A	B	Oct 2001	Not released to production Support for 8 input, 8 output and 4+4 cards Universal opto input added + "Opto input config" column Output contacts uprated from 5A to 10A Modification to allow CB fail initiation by the under and over frequency elements PSL reference I/D cell added Increased ddb signals from 512 to 1023	V2.08	P14x/EN T/A22
10	B	B	Nov 2001	Increased user alarms from 9 to 36 US/IEEE curves modified to TD/7 with TD IDG, Rectifier and RI characteristics added Auto-reclose and checksync enhancements Phase angles added to sequence quantities Thermal overload modified to RMS based Range of SEF high sets increased from 0.8In to 2In SEF Inhibit & AR trip test can be operated via opto input	V2.08	P14x/EN T/A22

Software Version		Hard-ware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Document-ation
Major	Minor					
10	C	B	Nov 2001	Not released to production Correction to P142 and P143 default PSL to re-map input L7 and V>2 trip signals	V2.08	P14x/EN T/A22
10	D	B	Feb 2002	Resolved possible reboot caused by Disturbance Recorder Resolved possible reboot caused by invalid MODBUS requests	V2.08	P14x/EN T/A22
10	E	B	Dec 2002	Control inputs modified to produce protection events Control inputs enhanced to be none volatile IDG curve stage 2 improvements Modified AR mode to be none volatile Fault locator line length setting corrected in groups 2, 3 & 4 DNP3.0 Object 10 included in Class 0 poll DNP3.0 support for season in time information Reset Relays/LED" DDB signal corrected to reset LEDs Slip frequency measurement corrected via MODBUS Modification to reduce switching time between setting groups ISEF> IDG Time setting modified to include units (seconds) Enhanced DNP3.0 Object 10 support for CB Close pulse	V2.08	P14x/EN T/A22
10	F	B	Sept 2003	Disturbance recorder triggering no longer causes loss of disturbance recorder data, temporary freezing of the user interface or loss of rear port comms Modification to improve compatibility between Px30 and Px40 relays IEC60870 communications networks	V2.08	P14x/EN T/A22
13	Special release for LADWP (Los Angeles)					
13	A	B	April 2002	Beta release SEF power measurement added 4 DDB signals added indicating directional starts	V2.08	
13	B	B	May 2002	Pre-validation release		
13	C	C	May 2002	Power supply modified to limit peak inrush to less than 10A Support for second rear communication port	V2.08	
13	D	C	June 2002	SEF start count strategy changed		
13	E	C	Jan 2003	ISEF> IDG Time setting modified to include units (seconds) Fault locator line length setting corrected in groups 2, 3 & 4 DNP3.0 Object 10 included in Class 0 poll DNP3.0 support for season in time information Slip frequency measurement corrected via MODBUS Modification to reduce switching time between setting groups Modified AR mode to be none volatile Control inputs modified to produce protection events Improved AR performance for short duration faults "Reset Relays/LED" DDB signal corrected to reset LEDs Corrected MODBUS trip and close with "0" command Support for trip and close pulse in DNP3.0 Object 10 IDG curve stage 2 improvements	V2.08	
15	A	C	Sept 2002	Not released to production Support for second rear communication port Power supply modified to limit peak inrush to less than 10A Support for VDEW with private codes Support for VDEW uncompressed disturbance recorder Modification so that internal clock failure is correctly reported	V2.08	P14x/EN T/A33
15	B	C	Sept 2002	Default PSL identifier corrected for P144 REF options removed for P144		P14x/EN T/A33
15	C	C	Feb 2003	IEC 103 DR no longer generates a false disturbance record when two triggers occur in close succession Some menu text changed in French and Spanish languages Modification so that manual reset user alarms are logged correctly in event records Control inputs enhanced to be none volatile Fault locator line length setting corrected in groups 2, 3 & 4 DNP3.0 Object 10 included in Class 0 poll DNP3.0 support for season in time information ISEF> IDG Time setting modified to include units (seconds) Slip frequency measurement corrected via MODBUS	V2.08	P14x/EN T/A33

Software Version		Hard-ware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Document-ation
Major	Minor					
15	D	C	Jan 2004	Disturbance recorder triggering no longer causes loss of disturbance recorder data, temporary freezing of the user interface or loss of rear port comms DNP3.0 Analogue scan rate reduced from 5s to 1s DNP3.0 Digital scan rate reduced from 5s to 0.5s Improvements to DNP3.0 deadband settings for data types D1 to D7 Modification to event filtering to resolve problem with undercurrent elements causing a buffer overflow	V2.08	P14x/EN T/A33
15	E	C	May 2004	MODBUS IEC time stamp format may be expressed in forward or reverse format by means of a setting Reset LED/latches DDB signal has same functionality as reset indications menu cell in user interface SEF power measurements include a minimum threshold Overvoltage fault record page on the user interface is now correct for VCN faults Check Synch. Reset of under/over voltage blocking is independent for bus and line Even/odd parity setting is now correctly recognized for DNP3.0 and MODBUS at power up IEC60870. The FAN now correctly increments for new fault conditions The analogue check channels are monitored all of the time	V2.08	P14x/EN T/A33
15	E	C	May 2004	MODBUS has improved frame reception and does not lock up when spurious messages are injected on to the RS485 network The relay will lock out if it detects an SRAM failure at power up	V2.08	P14x/EN T/A33
15	F	C	Aug 2004	MODBUS device driver can incorrectly interpret frame length and return invalid data for valid message Time synch resolution accuracy improved for all comms protocols DNP3.0 Enhancements: Object 20: Broken currents IAx, Ibx, ICx added to points list Object 30: Fault location in % line length added to points list.	V2.08	P14x/EN T/A33
15	G	C	April 2005	MODBUS device driver updated to improve performance on 60 Hz Correction to IDG IDMT characteristic configuration Phase under/over voltage protection hysteresis changed to 2% CB maintenance alarm now set for each new trip AR behavior in User Set Mode improved IEC60870-5-103. Status of summer bit corrected Commissioning test pattern for output relays improved to take account of fitted relays Commissioning test DDB status cell 1022-992 now shows 31 bits (instead of 32) Correction to Thermal state measurement display for remote Courier access Power measurements display at non-zero current inputs corrected	V2.08	P14x/EN T/B43
15	H	C	April 2006	MODBUS device transmit driver updated to use DMA during transmission - to reduce CPU overhead DDB ‘Frequency Not Found’ on power up correction DNP3.0 setting changes correction CS103 repeated request message correction CS103 AR Lockout Alarm between GI and spontaneous event correction	V2.08	P14x/EN T/B43
15	J	C	Nov 2007	AR Protection Lockout for SOTF for inst. protection Auto-reclose. The Hold Reclaim Logic signal does not comply with the diagram IEEE/US IDMT reset characteristics fixed DNP3 comms improvement for event avalanche Limit Power Factor measurements to +/-1	V2.08	P14x/EN T/B43
15	K	C	July 2008	CS103: Incorrect management of ACD flag for indicating class 1 data is available during a General Interrogation	V2.08	P14x/EN T/B43
15	U	C	Feb 2011	Rebranded to Schneider Electric	V2.08	P14x/EN T/B43
16	Special release for Australian market (based upon 15B software)					
16	A	C	Feb 2003	Option for pulsed/latched control inputs added IEC 103 DR no longer generates a false disturbance record when two triggers occur in close succession Some menu text changed in French and Spanish languages Modification so that manual reset user alarms are logged correctly in event records Control inputs enhanced to be none volatile Fault locator line length setting corrected in groups 2, 3 & 4 DNP3.0 Object 10 included in Class 0 poll DNP3.0 support for season in time information ISEF> IDG Time setting modified to include units (seconds) Slip frequency measurement corrected via MODBUS	V2.10	P14x/EN T/A33 (with addendum)
17	Special release for LADWP (based upon 16 software)					

Software Version		Hard-ware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Document-ation
Major	Minor					
17	A	C	Nov 2003	Not released to production Option for pulsed/latched control inputs added DNP3.0 Analogue scan rate reduced from 5s to 1s DNP3.0 Digital scan rate reduced from 5s to 0.5s Modification to event filtering to resolve problem with undercurrent elements causing a buffer overflow Missing CT Option "None" setting (P144 only) for 3 CT applications Improvements to DNP3.0 deadband settings for data types D1 to D7 Support for primary measurements over DNP3.0 using scaling factors, which may be viewed/changed both locally and remotely Disturbance recorder triggering no longer causes loss of disturbance recorder data, temporary freezing of the user interface or loss of rear port comms	V2.10	
17	B	C	Dec 2003	DNP3.0 manual reset user alarm points are now non-volatile DNP3.0 time synch command no longer causes a reboot when IRIG-B is enabled	V2.10	P14x/EN T/A33 (with addendum)
17	C	C	March 2010	DTS PCS3199 The analogue check channels are monitored all of the time.	V2.10	P14x/EN T/A33 (with addendum)
20	A	G	June 2003	Not released to production New CPU card and front display. Display is a 16 x 3 character dot matrix type with direct access keys (hotkeys) Enhanced check synch functionality including predictive close feature Support for UCA2 protocol and associated features (GOOSE etc.) Configurable opto input filtering added Time synchronization via opto inputs added Missing CT Option "None" setting (P144 only) for 3 CT applications Time synchronization via opto inputs added Enhancement to rear courier port to give K-bus and EIA(RS)485 compatibility Support for 512 events Automatic disturbance recorder extraction support for Courier, VDEW and UCA2	V2.09	P14x/EN T/A44
20	B	G	Nov 2003	Not released to production Support for Russian Language text added Automatic disturbance recorder extraction support for MODBUS	V2.09	P14x/EN T/A44
20	C	G	Dec 2003	Not released to production Improvement to ensure the restoration of Ethernet communications following a long term loss of Ethernet hub Correction to prevent relay reboot if any Ethernet settings are Modified without Ethernet card being present	V2.09	P14x/EN T/A44
20	D	G	Feb 2004	Not released to production Resolution of EMC problems with rear K-Bus port	V2.09	P14x/EN T/A44
20	E	G	Feb 2004	Improvement to increase the maximum pending UCA2 requests Number of simultaneous UCA2 clients increased from 4 to 10 Modification to prevent blank page from being displayed in the fault records when a record is generated without a genuine fault (i.e. via opto input). The blank page only occurs if fault record in generated whilst an alarm is already present	V2.09	P14x/EN T/A44
20	F	G	June 2004	Modification to prevent reboot when disturbance records are extracted over UCA2 MODBUS. IEC time stamp format may be expressed in forward or reverse format by means of a setting Overvoltage fault record page on the user interface is now correct for VCN faults Check Synch. Reset of under/over voltage blocking is independent for bus and line. Hysteresis reduced to 2% IEC60870. The FAN now correctly increments for new fault conditions	V2.09	P14x/EN T/B54
20	G	G	May 2005	MODBUS device driver updated to improve performance on 60 Hz Power measurements display at non-zero current inputs corrected Phase under/over voltage protection hysteresis changed to 2% CB maintenance alarm now set for each new trip AR behavior in User Set Mode improved IEC60870-5-103. Status of summer bit corrected Commissioning test pattern for output relays improved to take account of fitted relays Commissioning test DDB status cell 1022-992 now shows 31 bits (instead of 32) Second rear Courier communications port improved Px40 UCA2 communications improvement	V2.09	P14x/EN T/B54

Software Version		Hard-ware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Document-ation
Major	Minor					
20	H	G	June 2006	Resolution of IEC61850 VxWorks problem - association lost after 49 days IRIG-B Status reported incorrectly DNP3 interframe gap reinstated in Phase 2 CPU. Spurious indication of Voltage Controlled Overcurrent if feature is enabled and Phase Overcurrent is disabled. Spurious protection lockout events when autoreclose not enabled. US IDMT reset characteristic behaviour incorrect Autoreclose. The Hold Reclaim Logic signal does not comply with the diagram.	V2.09	P14x/EN T/B54
21	A	G	May 2004	4 stage time delayed rate of change of frequency protection. Initiation of CB Fail from external single pole or earth fault protection. Check synch indication of blocking on Stage 1. LCD contrast change confirmation. UCA2 - Ethernet card MAC address display. UCA2 - Local GOOSE IED name. MODBUS - IEC time stamp format may be expressed in forward or reverse format by means of a setting. Overvoltage fault record page on the user interface is now correct for VCN faults Check Synch - Reset of under/over voltage blocking is independent for bus and line IEC60870 - The FAN now correctly increments for new fault conditions	V2.10	P14x/EN T/B54
21	B	G	Dec 2004	Second rear Courier communications port failure Phase under/over voltage protection - 2% hysteresis CB maintenance alarm set for each new trip AR State Machine can lock in User Set Mode	V2.10	P14x/EN T/B54
21	C	G	Dec 2008	Reduced minimum setting of df/dt Averaging cycles to 2Hz/s	V2.10	P14x/EN T/B54
30	A	J	Dec 2004	4 stage definite time directional negative sequence overcurrent. Dual opto input operate/reset characteristics. Fiber optic support for Courier/MODBUS/DNP3.0 protocols. Check synch stage 2 blocking indications. Triggering of disturbance recorder from Control Inputs, GOOSE Inputs and GOOSE Outputs. Fault record information over IEC60870-5-103 protocol. Fault location and broken current information over DNP3.0 protocol. Menu text change from ALSTOM to AREVA. Grey case. Default text for relay and opto labels rationalized. Phase under/over voltage protection - 2% hysteresis. CB maintenance alarm set for each new trip. AR behavior in User Set Mode improved.	V2.11	P14x/EN T/B54
30	B	J	Feb 2006	DNP3.0 interframe gap reinstated in Phase 2 CPU IRIG-B status reporting and spurious events correction Correction to IDG IDMT characteristic configuration	V2.11	P14x/EN T/B54
30	D	J	Dec 2008	Reduced minimum setting of df/dt Averaging cycles to 2Hz/s	V2.11/2.12	P14x/EN T/B54
31	P145 only: Original Issue					
31	A	J	Feb 2005	P145 Evolution with extended User Interface (10 Function Keys and 18 tricolour LEDs) Control Input status stored in FLASH memory 10 Maintenance Records instead of 5 Programmable opto initiation of setting group change by DDB signals (rather than fixed L1 and L2) Blocking of remote CB Trip/Close by DDB signals Inhibit of Earth Fault 1&2 by DDB signals Skip first shot of AR sequence by DDB signal	V2.12	P145/EN M/A11
32	P141/P142/P143/P144 Release Only For North African EDF Market					

Software Version		Hard-ware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Document-ation
Major	Minor					
32	A	J	Oct 2005	P141/P142/P143/P144 only New DDB signals for PSL initiation of setting group selection New DDB signal for Blocking of remote CB Trip/Close commands New DDB signal to inhibit Earth Fault 1&2 Skip first shot of AR sequence by ddb signal Zero reference ddb signal Maintenance Records increased Phase Rotation in all 4 setting groups EPATR_B characteristic in SEF stages 1 and 2 Auto-reclose modifications to include: 4 Reclaim timers - one per AR shot AR Skip Shot 1 setting DDB Signals for Inhibit Reclaim, Reclaim In Progress and Reclaim Time Complete Df/dt configuration cell moved	V2.12	P14x/EN T/B64
32	B	J	May 2006	DNP3.0 interframe gap reinstated in Phase 2 CPU IRIG-B status reporting and spurious events correction	V2.12	P14x/EN AD/B64
34	P141/P142/P143 release only for Chinese market					
34	A	J	June 2006	P141/P142/P143 only - based on 32A functionality HMI has Chinese, English and French language options using a two line display (rather than 3 line) Front and rear ports support English and French only	V2.13	P145/EN T/B54+ B64 Translated into Chinese by PCW
35	P141/P142/P143/P144/P145 release for World market					
35	A	J	Oct 2006	IEC61850 Communications protocol DNP3.0 Serial evolution High break contacts - P142/3/4/5 Negative Sequence Overcurrent with IDMT characteristics Chinese HMI (taken from 34A) Definite Time Adder for POC/EF/SEF/NPSOC IDMT characteristics	V2.13	P14x/EN M/C74
35	B	J	Nov 2006	Resolution of IEC61850 reboot problem when ethernet is not connected and ddb signals change at a fast rate	V2.13	P14x/EN M/C74
35	C	J	Feb 2007	Resolution of IEC61850 VxWorks problem - association lost after 49 days. IEC60870-5-103 - Additional Measurements via Generic Services (as Courier [02xx], [03xx], [04xx])	V2.13	P14x/EN M/C74
35	D	J	March 2007	Improvements to IEC61850 data model following KEMA tests. Fix to P145 Function Keys over packed DDB.	V2.13	P14x/EN M/C74
35	U	J	March 2011	Rebranded to Schneider Electric	V2.13	P14x/EN M/C74
36	P141/P142/P143/P144/P145 release for World market					
36	A	J	April 2007	Based on 35D functionality. 16 non volatile latches with SRQ available as ddb signals. Support for local time zone.	V2.14	P14x/EN AD/C84
36	B	J	Oct 2007	AR Protection Lockout for SOTF for inst. Protection. Initialisation of non volatile latches. Year not set if IRIG-B has signal healthy.	V2.14	P14x/EN AD/C84
36	C	J	Dec 2009	Platform updated to J2.14 (PCS3153 'NIC no response'). PCS3135 Control inputs set to pulse latch outputs cause a pulse on power-cycle. PCS3198 Incorrect resetting of change of direction drop-off count strategy for evolving fault. PCS3117 Directionality of the IN>3 and IN>4 are ignored when Selective logic is enabled. PCS3217 The Fault Location in Ohms has no multipliers in the fault record in UI and in Rear Courier. PCS2995 Latched LED can not be reset using READ/CLEAR keys. PCS2971 Fault record for some earth faults produce a CB operating Time of 4.295Ms. PCS2963 CB condition monitoring alarm doesn’t always operate. PCS3129 Reclaim Timers do not reset properly. PCS2927 Incorrect reset of CB excessive Op Time alarms. PCS3047 Circuit Breaker close delay should not be applied to remote operations.	V2.14	P14x/EN AD/C84
39	P141/P142 Modbus only Release For SMEPC China only					
39	B	J	July 2009	Based on 43B functionality. Due to Modbus register misalignment, introduced in version 40 (extended DDB), Modbus registers set to version 30. Four stages of Advanced Frequency df/dt copied to df/dt coumn..	Studio/2.14	P14x/EN M/Cc4

Software Version		Hard-ware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Document-ation
Major	Minor					
40	P141/P142/P143/P144/P145 Release For World Market					
40	A	J	March 2008	Based on 36B functionality. Broken Conductor Start. Any Trip independent of Relay 3. PSL positional data - number of ddbs increased to 1280. 64 SR Latches added - configured by PSL Editor. IEC61850 over ethernet + CS103 over RS485. DNP3 over ethernet + Courier over Kbus/RS485. InterMiCOM.	Studio/2.14	P14x/EN M/C74 (with addendum) P14x/EN AD/C94
41	P141/P142/P143/P144/P145 Release For World Market					
41	A	J	June 2008	Based on 40A functionality. DNP3 Aliased Control Inputs for SSE. 2nd harmonic blocking of I>,IN1>,IN2>,ISEF>,I2>	Studio/2.14	P14x/EN M/Ca4
41	B	J	Nov 2009	Based on 41A platform release K3.10. PCS3135 Control inputs set to pulse latch outputs cause a pulse on power-cycle. PCS3115 DNP3 protocol build reboots the relay when Freeze and Clear command issued by ASE. PCS3198 Incorrect resetting of change of direction drop-off count strategy for evolving fault. PCS3117 Directionality of the IN>3 and IN>4 are ignored when Selective logic is enabled. PCS2995 Latched LED can not be reset using READ/CLEAR keys. PCS2971 Fault record for some earth faults produce a CB operating Time of 4.295Ms. PCS2963 CB condition monitoring alarm doesn’t always operate. PCS3129 Reclaim Timers do not reset properly. PCS2927 Incorrect reset of CB excessive Op Time alarms. PCS3047 Circuit Breaker close delay should not be applied to remote operations.	Studio/2.14	P14x/EN M/Ca4
42	P141/P142/P143/P144/P145 Release For World Market					
42	B	J	Nov 2008	IEC61850 phase II enhancements. Read Only Mode. Improvement to time tagging of opto-inputs.	Studio/2.14	P14x/EN M/Ca4
42	C	J	March 2009	New platform software release required for Kema conformance issues. The CB Manual Close delay is removed from any remote CB operations.	Studio/2.14	P14x/EN M/Ca4
42	D	J	Sep 2009	New platform software release required to resolve PCS3153 'NIC no response' alarm logged periodically during 24 hour heat soak production test. DTS PCS3138: IEC61850 phase 2 measurements are normalised twice for Primary measurements only. DTS PCS3143: IEC61850: It is possible for an MCL configuration to be downloaded but not implemented in the IED. DTS PCS3151: IEC61850: Enabling a RCB with non-zero IntgPd can result in values which haven't changed not being reported. DTS PCS3153: 'NIC no response' alarm logged periodically during 24 hour heat soak production test. DTS PCL1414: Double select request causes IEC61850 connection to be lost. DTS PCL1424: P740: 'LocalTime Enable' settings of the peripheral units is ignored when extracting the events via the central unit P741. DTS PCS3164: DNP3 relay fails to respond to a class 1/2/3 poll following a confirm to an other relay. DTS PCS3112: IEC61850: It is possible for an MCL configuration to be downloaded but not implemented in the IED. DTS PCS3113: Processing of messages on the ECI FIFO suspends for certain data model configurations. DTS PCS3135: Control inputs set to pulse latch outputs cause a pulse on power-cycle. DTS PCS3168/PCL1415: DDB signal status is not available to 61850 model when events are configured to be filtered out. DTS PCS3105: Executing an Assign Class, function code 22, via ASE host causes Bad DNP Error after a power cycle of the relay. DTS PCS3115: P340 relay with DNP3 protocol build reboots the relay when Freeze and Clear command issued by ASE. DTS PCS3129: Reclaim Timers do not reset properly. DTS PCS3117: Directionality of the IN>3 and IN>4 are ignored when Selective logic is enabled.	Studio/2.14	P14x/EN M/Ca4
43	P141/P142/P143/P144/P145 Release for World Market					

Software Version		Hard-ware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Document-ation
Major	Minor					
43	A	J	May 2009	IEC61850 phase III enhancements P940 porting Power Protection P143 32 I/O Check Synchronization Enhancements	Studio/2.14	P14x/EN M/Ca4
43	B	J	May 2009	PCS3148 The "Stg f+t Freq" Advanced Frequency Protection setting in Hz for all 9 stages, is incorrectly dependant on the Main VT ratios settings.	Studio/2.14	P14x/EN M/Ca4
43	C	J	Oct 2009	PCS3168/PCL1415: DDB signal status is not available to 61850 model when events are configured to be filtered out. PCS3115: P340 relay with DNP3 protocol build reboots the relay when Freeze and Clear command issued by ASE. PCS3161: The displayed text for SR User Alarm 9 to 18 is incorrect. DTS PCS3178: DR Show 1:1 ratio after reboot. DTS PCS3189: The Fun 162 Inf 167 is repeated for U/V block and User Alarm 1. DTS PCS3198: Incorrect resetting of change of direction drop-off count strategy for evolving fault. Platform release L2.5 PCS3143: The latched states of relay and LED don't get reset when the properties of the relay and LED are no longer set to 'latch'. PCS3151: IEC61850: Enabling a RCB with non-zero IntgPd can result in values which haven't changed not being reported. PCS3153: 'NIC no response' alarm logged periodically during 24 hour heat soak production test. PCS3164: DNP3 relay fails to respond to a class 1/2/3 poll following a confirm to an other relay. PCL1414: Double select request causes IEC61850 connection to be lost. PCL1424: P740: 'LocalTime Enable' settings of the peripheral units is ignored when extracting the events via the central unit P741. C1052: IEC61850 Time Quality Bits. C1053: Update the method support functions of CS103 Generic Services that support the remote read only mode.	Studio/2.14	P14x/EN M/Ca4
44	P141/P142/P143/P144/P145 Release for World Market					
44	A	J	Feb 2010	Virtual inputs increased to 128. Retrieval of fault records in DNP 3.0. dv / dt protection. Increase number of Overcurrent Stages. Increase CB close pulse to 50 seconds. 199V Phase – Phase VT Requirement. Increase of SR gates from 64 to 128. Increase P141 hardware configuration to 8 I/O. IEC61850 Metering Quantities.pulsQty set to 1000. PCS3215 Setting the Disturbance Record Digital Inputs to Unused doesn't make the Input Trigger cell invisible. PCS3212 High levels of In, above 16In, cause the disturbance record to saturate. PCS3198 Incorrect resetting of change of direction drop-off count strategy for evolving fault. PCS3161 The displayed text for SR User Alarm 9 to 18 is incorrect. PCS3217 The Fault Location in Ohms has no multipliers in the fault record in UI and in Rear Courier. PCS3178 DR show 1:1 ratio after reboot. PCS3173 The AR can lockout due to having "Man Close Fail Alarm" even if the "CB Control By" is disabled (the external AR trip DDB is used for AR initiation) and CB has closed.	Studio/2.14	P14x/EN M/De6+ P14x/EN AD/Ee7

Software Version		Hard-ware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Document-ation
Major	Minor					
44	B	J	May 2010	PCS3273: Applying XCBR1.CO.Pos Open/Close via IEDScout can cause the relay to reply with Invalid Position even though the Open/Close operation is successful. PCS3268: The SNTP poll task on the ethernet card occasionally showed a stack overflow and was corrected in Phase 1. This correction has not been implemented in Phase 2. PCS3241: The release notes for the GOOSE Enhancements section of platform L4.0 references bulk transfer mode for the ECI fifo. These updates can cause any changes to DDB signals NOT to be passed to the Ethernet board. PCS3224: Occasional increased delay between Virtual Output and GOOSE message transmitted with new state when relay under current & voltage load (IEC 61850 Phase 2 only). PCS3211: Occasionally an opto-input change of state is not registered in System\OptGGIO1.ST. PCL1505: On P442 phase 1 product when a corrupt group message is displayed on LCD, the protection functions are stopped but no watch dog is raised (Healthy LED is green). PCL1492: The bit field parameters defined in the L&F are badly converted in the IEC61850 model. PCS3256: In version 44A software issuing a change to a Control Input from a CS103 Master station is not actioned on the relay	Studio/2.14	P14x/EN M/De6 + P14x/EN AD/Ee7 P14x/EN AD/Gf7
44	C	J	July 2010	PCS3291: Reading the Logical Nodes in order to map all IEC61850 points, the master station always stops at AlmGGIO1 logical node. Platform Release L4.3: PCS3290: Slow extraction of SCL configuration data. PCW161: When one Analogue Input is no longer valid, the Flags for this Analogue Input is still remained as "Online, Local Forced". PCW162: When the beginning character of a menu text is '%', this menu text will be wrongly displayed in Courier Device Browser and MiCOM S1 Studio.	Studio/2.14	P14x/EN M/De6 + P14x/EN AD/Ee7 P14x/EN AD/Gf7
44	D	J	Sep 2010	Not released to production. DTS CTC44: The reset char of SEF stage 2 was configured to the setting value of stage 1 reset char wrongly. Platform Release L4.4: PCS3333: IEC61850 communications terminate after operating a control with control status in RCB.	Studio/2.14	P14x/EN M/De6 + P14x/EN AD/Ee7 P14x/EN AD/Gf7
44	E	J	Oct 2010	MMSLITE_V5.1001C: PCS3335: IEC61850 Heavy use of BRCB causes loss of communications	Studio/2.14	P14x/EN M/De6 + P14x/EN AD/Ee7 P14x/EN AD/Gf7
44	F	J	Dec 2010	PCS3316: “IEC61850 Data Attribute CBOpCap.stVal (CB Operate Capacity - Status value) in all XCBR Logical NodeS returns an incorrect Enumeration type.” DTS PCS3329: “Fault location reported over dnp3 is incorrect”. DTS PCS3339 “Overcurrent additional stage (5&6) don’t appear properly in the fault record.” DTS PCS3357: “Duplicate registers used; also errors in 'Look and Feel' spec register list". DTS PCS3369: Reading Trip Elements 3 and Trip Elements 4 the relay responds with "Exception:[02]-Illegal data address". Platform Release L4.5: DTS PCS3337: IEC61850 - A quickly toggled state may cause the interim state change to be not reported. DTS PCL1552: A mix of not latched and latched LED lead to an incorrect behaviour of the latched LED. Platform Release L4.6: DTS PCS3362: Px4x stops receiving (processing) GOOSE messages when managed Ethernet switch parameterised for VLAN. Px40 Platform library release MMSLITE_V5.1001D	Studio/2.14	P14x/EN M/De6 + P14x/EN AD/Ee7 P14x/EN AD/Gf7
44	U	J	Feb 2011	Rebranded to Schneider Electric	Studio/2.14	P14x/EN M/De6 + P14x/EN AD/Ee7 P14x/EN AD/Gf7
44	V	J	Feb 2012	The P140v44V Schneider maintenance software release has been made available based on the P140v44U Schneider software release with an update to resolve DTS PCS3415 "Directional negative sequence overcurrent will only reset from the tripped state by loss of current and not incorrect direction" and DTS PCS3427 "Status report over IEC61850 not in line with DDB signals".	Studio/2.14 and later versions	P14x/EN M/De6 + P14x/EN AD/Ee7 P14x/EN AD/Gf7
44	W	J	N/A	Non-Commercial Release	N/A	N/A
44	X	J	N/A	Non-Commercial Release	N/A	N/A
44	Y	J	N/A	Hold / Stopped Release	N/A	N/A

Software Version		Hard-ware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Document-ation
Major	Minor					
44	Z	J	July 2014	The P140v44Z software release is required in order to incorporate platform DTS fixes of changes to the latest L platform (L4.14) and also upgrading IEC61850 files by using a new IEC61850 modelling tool V2.251. PCS3427: Status report over IEC61850 not in line with DDB signals. 50322.C0010: The configuration of datasets to the Buffered Report control blocks appears to significantly slow down the publishing of GOOSE messages. CTCSE10079: IEC61850 Data Attribute CBOpCap.stVal(CB Operate Capacity - Status value) in XCBR1 logical node returns an incorrect enumeration type CTCSE10027: Split from Alstom, Schneider use letter for software release version. Major version is not compatible with letters of cs103 protocol, both IED code and tools. CTCSE10058: Virtual input will change from T to F several times regardless only one stable status(T) via GOOSE publishing by other devices. CTCSE10059: Logical Note of OptGGIO1.ST don't represent the correct status of Opto changes CTCSE10062: Disturbance record can not be extracted correctly via IEC61850. CTCSE10104: In some cases, after the MCL file is downloaded to the Relay, use IEDScout to modify some of the deadband settings, and then download the MCL file again, then those deadbands are not correct as set in the MCL file. CTCSE10105: The units of differential/bias current and frequency in disturbance record file extracted via IEC61850 from P64x relay are missing. CTCSE10178: When dataset include the data which data source is function type data and the status changed, report send twice even the status don't change in the second time. CTCSE10190: The IEC61850 buffered report of a Px40 device can not work when the physical connection broken. CTCSE10213: All SPS/origin in System/PloGGIO1$ST should not be writeable. CTCSE10257: In IEC61850 commnication, if the dataset has only DAs, GOOSE may sent a wrong status of "FALSE" after IED reboot even the related DDB is set to TRUE after while rebooting. CTCSE10258: The INT128 datatype seems impractical to implement on almost any computer, but especially on IEDs. There is no standard way to store INT128 values on any modern computer. And the maximum value of an INT128 is larger than anyone is likely to need. CTCSE10289: IED Subscribe GOOSE with inconformity AppID which should be discard. CTCSE10336: Control the CB(via IEC61850) to its opposite position, the position of the CB changed succeed, but the client will receive error report AddCause "Invalid-position". Control the CB(via IEC61850) to its current position, but the client will receive error report. PCL1568: Wrong german translations in menu map. CTCSE10162: The DTS is same as PCS3429 in V1.13 DTS system and re-submit in Schneider System because of discarding by Alstom. Language text for 'IED CONFIGURATOR' menu column header is English for all languages PCS3363: Discrepancy in the DR analogue signals magnitudes if the CT and VT ratios (primary/secondary) are not integers. SME10047: The front Courier Port Unlock task "FcUnlock" has been allocated an incorrect stacksize value which corresponds to the front Courier task "Fcourier" stacksize.	Studio/2.14 and later versions	P14x/EN M/De6 + P14x/EN AD/Ee7 P14x/EN AD/Gf7
46	A	J	May 2011	Load encroachment (Blinder) Voltage restrained over current protection Programmable curves Monitor bits in PSL Setting changes through IEC103 protocol Improvements in CB fail algorithm		P14x/EN M/De6 + P14x/EN AD/Ee7 P14x/EN AD/Gf7
46	U	J	May 2011	Load encroachment (Blinder) Voltage restrained over current protection Programmable curves Monitor bits in PSL Setting changes through IEC103 protocol Improvements in CB fail algorithm		P14x/EN M/De6 + P14x/EN AD/Ee7 P14x/EN AD/Gf7

Software Version		Hard-ware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Document-ation
Major	Minor					
46	V	J	Jan 2013	The P140v46V Schneider maintenance software release has been made available based on the P140v46U Schneider software release with an update to a **PRP Parallel Redundancy Protocol. with that two more hardware options will be added to reflect the modulated and de-modulated status. P14X??N???????? for modulated BOM: 2072082 A09, Issue: A & P14X??P???????? for de-modulated BOM: 2072082 A10, Issue: A **Stable solution of Goose Improvement. **Goose optimization. **Adding extra cell of VDIFF CheckSync Bus_Line Voltage **Autoreclose enhancement.	Studio/2.14 and later versions	P14x/EN M/De6 + P14x/EN AD/Ee7 P14x/EN AD/Gf7
46	W	J	N/A	Non-Commercial Release	N/A	N/A
46	X	J	Dec 2013	The P140v46X software release is required in order to incorporate enhancement to P140V46W and also to add PRP enhancement, goose optimization, goose enhancement, voltage magnitude differential measurement and autoreclose enhancement of P14x46V to the existing CBF enhancement and MEA project enhancement. Added to that 46X provides new platform with DTS CTCSE10248: Communication Interrupt of IEC61850 CTCSE10261: Impact component, DNP3 OE TCP. DNP3 OE TCP slave will lose all the events during a client disconnect period. CTCSE10200: The MMS server returns an error when users write [111111] to TrgOps field of a RCB, thus and writing operation is failed CTCSE10185: In the P141 French language. The IEEE very inverse curve is used twice; the 2nd one should be IEEE Extremely inverse. CTCSE10213: All SPS/origin in System/PloGGIO1$ST should not be writeable. CTCSE10246: Cannot PASS IEC61850 conformance certificate test, test case Srv6 is failed. CTCSE10257: In IEC61850 communication, if the dataset has only DAs, GOOSE may sent a wrong status of "FALSE" after IED reboot even the related DDB is set to TRUE after while rebooting. CTCSE10258: The INT128 data type seems impractical to implement on almost any computer, but especially on IEDs. There is no standard way to store INT128 values on any modern computer. And the maximum value of an INT128 is larger than anyone is likely to need.	Studio/2.14 and later versions	P14x/EN M/De6 + P14x/EN AD/Ee7 P14x/EN AD/Gf7
46	Y	J	July 2014	The P140v46Y software release is required in order to incorporate the DTS fixes of CTCSE10321: df/dt+T protection will be unexpected trip when df/dt value recorded in disturbance record below threshold CTCSE10306: df/dt+T protection will be unexpected trip when df/dt value recorded in disturbance record changed duration below time threshold of df/dt+T SME10079: Autoreclose failure when initiated by external protection PCL10139: The high traffic of unicast frames leads to blocking of the GOOSE subscription by the Px40 relays. Goose publishing and MMS services remains working correctly. and having using new modelling tool.	Studio/2.14 and later versions	P14x/EN M/De6 + P14x/EN AD/Ee7 P14x/EN AD/Gf7

Software Version		Hard-ware Suffix	Original Date of Issue	Description of Changes	S1 Compat-ibility	Technical Document-ation
Major	Minor					
46	Z	J		46Z provides new platform development with plus new release of MMS Stack to resolve few DTSs PCL10139: The high traffic of unicast frames leads to blocking of the GOOSE subscription by the Px40 relays. Goose publishing and MMS services remains working correctly. CTCSE10162: The DTS is same as PCS3429. Language text for 'IED Configurator' menu column header is English for all Languages CTCSE10191: The MMS communication of IEC61850 of device may get lost after perform control operations (Control\XCBR1\Pos) for several times CTCSE10202: During the software testing by customer of MEA project in Thailand, it is found that the XCBR.POS.stVal will be reported with unexpected status. CTCSE10218: Evertime downloading a MCL file to a relay, the modified deadbands of the configurable Das will take effect no matter wheather the "Restore MCL" command is executed or not. CTCSE10261: Impact component, DNP3 OE TCP. DNP3 OE slave will lose all the events during a client disconnect period. CTCSE10270: Some digital channels were lost in disturbance recorder which extracted via CS103 protocol. CTCSE10289: IED Subscribe GOOSE with inconformity AppID which should be discard. CTCSE10306: df/dt+T protection will be unexpected trip when df/dt value recorded in disturbance record changed duration below time threshold of df/dt+T CTCSE10321: df/dt+T protection will be unexpected trip when df/dt value recorded in disturbance record below threshold CTCSE10336: Control the CV (via IEC61850) to its opposite position, the position of the CB changed succeed, but the client will receive error report AddCause "Invalid-position". Control the CV(via IEC61850) to its current position, but the client will receive error report. CTCSE10360: P645 can only subscribe 32 Goose when Gosse AppID is set to more than 32 different values. SME10074: IEC61850 attribute orginaror identification (orIdent) on NULL string assigns arbitrarily values between Select and Operate which causes a conflict and then an error SME10079: Autoreclose failure when initiated by external protection.	Studio/2.14 and later versions	P14x/EN M/De6 + P14x/EN AD/Ee7 P14x/EN AD/Gf7
A0	A	L (P141, P142 & P143) M (P145)	Oct 2014	User Alarms Labels Column Virtual Input Labels Column Virtual Output Labels Column New protocol IEC61850-DNP3 (NO. 9) Increase DR digital channel to 128 External Reset DDB for CB Fail IRIG-B status DDB Special customizable inputs functionality and entries.	Studio/2.14 and later versions	P14x/EN M/De6 + P14x/EN AD/Ee7 P14x/EN AD/Gf7

Table 1 - Version history

The MiCOM S1 Studio product is updated periodically. These updates provide support for new features (such as allowing you to manage new MiCOM products, as well as using new software releases and hardware suffixes). The updates may also include fixes. **Accordingly, we strongly advise customers to use the latest Schneider Electric version of MiCOM S1 Studio.**

2 RELAY AND SETTING FILE SOFTWARE VERSION

Setting File Software Version	Relay Software Version																										
	00	01	02	03	04	05	09	10	13	15	16	17	20	21	30	31	32	34	35	36	40	41	42	43	44	45	46	A0
00	✓	✓	✓	✓	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
01	×	✓	✓	✓	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
02	×	×	✓	✓	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
03	×	×	×	✓	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
04	×	×	×	×	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
05	×	×	×	×	×	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
09	×	×	×	×	×	×	✓	✓	✓	✓	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
10	×	×	×	×	×	×	×	✓	✓	✓	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
13	×	×	×	×	×	×	×	×	✓	✓	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
15	×	×	×	×	×	×	×	×	×	✓	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
16	×	×	×	×	×	×	×	×	×	×	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
17	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
20	×	×	×	×	×	×	×	×	×	×	×	×	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×
21	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×
30	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×	×	×
31	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×	×
32	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×
34	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×
35	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×
36	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×
40	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×
41	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×
42	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
43	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
44	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
45	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×
46	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×
A0	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓

Table 2 - Relay and Setting File Software Version

3 RELAY AND PSL FILE SOFTWARE VERSION

PSL File Software Version	Relay Software Version																										
	00	01	02	03	04	05	09	10	13	15	16	17	20	21	30	31	32	34	35	36	40	41	42	43	44	45	46	A0
00	✓	✓	✓	✓	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
01	×	✓	✓	✓	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
02	×	×	✓	✓	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
03	×	×	×	✓	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
04	×	×	×	×	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
05	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
09	×	×	×	×	×	×	✓	✓	✓	✓	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
10	×	×	×	×	×	×	×	✓	✓	✓	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
13	×	×	×	×	×	×	×	×	✓	✓	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
15	×	×	×	×	×	×	×	×	×	✓	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
16	×	×	×	×	×	×	×	×	×	×	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
17	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
20	×	×	×	×	×	×	×	×	×	×	×	×	✓	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×
21	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×
30	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×	×	×
31	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×	×
32	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×
34	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×
35	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×
36	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×
40	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×
41	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×
42	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
43	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
44	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×
45	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×
46	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×
A0	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓

Table 3 - Relay and PSL File Software Version

4 RELAY AND MENU TEXT FILE SOFTWARE VERSION

Menu Text File Software Version	Relay Software Version																											
	00	01	02	03	04	05	09	10	13	15 B	15 C	16	17	20	21	30	31	32	34	35	36	40	41	42	43	44	45	46	A0
00	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
01	×	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
02	×	×	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
03	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
04	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
05	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
09	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
10	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
13	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
15 B	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
15 C	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
16	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
17	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
20	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
21	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×	×	×	×
30	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×	×	×
31	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×	×
32	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×	×
34	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×	×
35	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×	×
36	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×	×
40	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×	×
41	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×	×
42	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×	×	×
43	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
44	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×	×
45	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×	×
46	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓	×
A0	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	✓

Table 4 - Relay and Menu Text File Software Version

Notes:

SYMBOLS AND GLOSSARY

CHAPTER SG

Date	07/2014
Products covered by this chapter:	All MiCOM Px4x products
Hardware Suffix	All
Software Version	All

CONTENTS

TABLES

FIGURES

Notes:

1 ACRONYMS AND ABBREVIATIONS

Term	Description
<	Less than: Used to indicate an “under” threshold, such as undercurrent (current dropout).
>	Greater than: Used to indicate an “over” threshold, such as overcurrent (current overload)
A	Ampere
AA	Application Association
AC / ac	Alternating Current
ACSI	Abstract Communication Service Interface
ACSR	Aluminum Conductor Steel Reinforced
ALF	Accuracy Limit Factor
AM	Amplitude Modulation
ANSI	American National Standards Institute
AR	Auto-Reclose
ARIP	Auto-Reclose In Progress
ASCII	American Standard Code for Information Interchange
ATEX	ATEX is the Potentially Explosive Atmospheres directive 94/9/EC
AUX / Aux	Auxiliary
AV	Anti virus
AWG	American Wire Gauge
BAR	Block Auto-Reclose signal
BCD	Binary Coded Decimal
BCR	Binary Counter Reading
BDEW	Bundesverband der Energie- und Wasserwirtschaft | Startseite (i.e. German Association of Energy and Water Industries)
BMP	BitMaP – a file format for a computer graphic
BN>	Neutral over susceptance protection element: Reactive component of admittance calculation from neutral current and residual voltage.
BOP	Blocking Overreach Protection - a blocking aided-channel scheme.
BPDU	Bridge Protocol Data Unit
BRCB	Buffered Report Control Block
BRP	Beacon Redundancy Protocol
BU	Backup: Typically a back-up protection element
Business Service Layer	This layer coordinates the application, processes commands, make logical decision and calculation according to the business rules
C264	MiCOM C264 is the latest generation of modular substation computers. In addition to the traditional Input/Output (I/O) management, MiCOM C264 acts as a powerful communication gateway, an advanced measurement center and a fast automation processor. As a remote terminal unit, bay controller or protocol converter, MiCOM C264 is the compact solution to countless applications installed in demanding electromagnetic conditions. Also used to refer to a PACiS calculator.
CA	Certification Authority
CAT	Computer (C264) Administration Tool , for replacing CMT
C/O	A ChangeOver contact having normally-closed and normally-open connections: Often called a “form C” contact.
CB	Circuit Breaker
CB Aux.	Circuit Breaker auxiliary contacts: Indication of the breaker open/closed status.
CBF	Circuit Breaker Failure protection

Term	Description
CDC	Common Data Class
CET	Sepam Configurator
CF	Control Function
Ch	Channel: usually a communications or signaling channel
Check Synch	Check Synchronizing function
CIFS	Common Internet File System. Microsoft protocol use to share resources on a network.
CIP Standards	Critical Infrastructure Protection standards. NERC CIP standards have been given the force of law by the Federal Energy Regulatory Commission (FERC)
CLIO	Current Loop Input Output: 0-1 mA/0-10 mA/0-20 mA/4-20 mA transducer inputs and outputs CLI = current loop input - 0-1 mA/0-10 mA/0-20 mA/4-20 mA transducer input CLO = current loop output - 0-1 mA/0-10 mA/0-20 mA/4-20 mA transducer output
CID	Configured IED Description
CIP	Critical Infrastructure Protection standards
CLK / Clk	Clock
Cls	Close - generally used in the context of close functions in circuit breaker control.
CMC	Certificates Management over CMS. An IETF RFC for distribution and registration of public keys and certificates
CMP	Certificates Management Protocol. An IETF RFC for distribution and registration of public keys and certificates (RFC 4210)
CMV	Complex Measured Value
CNV	Current No Volts
COMFEDE	Common Format for Event Data Exchange
CPNI	Centre for the Protection of National Infrastructure
CRC	Cyclic Redundancy Check
CRL	Certificates Revocation List. A list of revoked certificates. Theoretically still valid, but forbidden by the Security Administrator or the Security Server
CRP	Cross-network Redundancy Protocol
CRV	Curve (file format for curve information)
CRx	Channel Receive: Typically used to indicate a teleprotection signal received.
Crypto Device	A small device embedding cryptographic capabilities and storage memory. It could be a smartcard, USB stick, serial dongle, etc, etc…
CS	Cyber Security or Check Synchronism.
CSMS	Cyber Security Management System
CSV	Comma Separated Values (a file format for database information)
CT	Current Transformer
CTRL	Control - as used for the Control Inputs function
CTS	Current Transformer Supervision: To detect CT input failure.
CTx	Channel Transmit: Typically used to indicate a teleprotection signal send.
CUL	Canadian Underwriters Laboratory
CVT	Capacitor-coupled Voltage Transformer - equivalent to terminology CCVT.
CZ	Abbreviation of “Check Zone”: Zone taking into account only the feeders.
DA	Data Attribute
DAN	Dual Attached Node
DANH	Double or Dual Attached Node with HSR protocol
DANP	Double or Dual Attached Node implementing PRP

Term	Description
Data Layer	Consists of the domain-related objects and their relationships that are manipulated by the user during the interaction with the software
DAU	Data Acquisition Unit
DC	Data Concentrator
DC / dc	Direct Current
DCC	An Omicron compatible format
DCE	Data Communication Equipment
DCS	Distributed Control System
DDB	Digital Data Bus within the programmable scheme logic: A logic point that has a zero or 1 status. DDB signals are mapped in logic to customize the relay’s operation.
DDR	Dynamic Disturbance Recorder
DEF	Directional Earth Fault protection: A directionalized ground fault aided scheme.
df/dt	Rate of Change of Frequency
df/dt>1	First stage of df/dt protection
DFT	Discrete Fourier Transform
DG	Distributed Generation
DHCP	Dynamic Host Configuration Protocol
DHM	Dual Homing Manager
DHP	Dual Homing Protocol
DHS	Dual Homing Star. Ethernet protocol allowing bumpless redundancy. Used with Redundant Ethernet board with dual homing protocol
Diff	Differential protection.
DIN	Deutsches Institut für Normung (German standards body)
Dist	Distance protection.
DITA	Darwinian Information Typing Architecture
DLDB	Dead-Line Dead-Bus : In system synchronism check, indication that both the line and bus are de-energised.
DLLB	Dead-Line Live-Bus : In system synchronism check, indication that the line is de-energised whilst the bus is energised.
DLR	Dynamic Line Rating
DLY / Dly	Time Delay
DMT	Definite Minimum Time
DNP	Distributed Network Protocol
DO	Data Object
DPWS	Device Profile for Web Services
DR	Disturbance Record
DREB	Dual Redundant Ethernet Board
DSP	Digital Signal Processor
DST	Daylight Saving Time
DT	Definite Time: in the context of protection elements: An element which always responds with the same constant time delay on operation. Abbreviation of “Dead Time” in the context of auto-reclose:
DTD	Document Type Definition
DTOC	Definite Time Overcurrent
DTS	Date and Time Stamp
DVC	Direct Variable Cost
DZ	Dead Zone. Area between a CT and an open breaker or an open isolator.

Term	Description
EF or E/F	Earth Fault (directly equivalent to Ground Fault)
EIA	Electronic Industries Alliance
ELR	Environmental Lapse Rate
EMC	ElectroMagnetic Compatibility
ENA	Energy Networks Association
ER	Engineering Recommendation
ESD	ElectroStatic Discharge
ESP	Electronic Security Perimeter
ESS	Embedded Security Server
ETS	Element To Secure. An ETS is an entity that represents a tool, utility or application function block that can be protected within the tool suite. It gathers a list of corresponding permissions with their set of values. This list is pre-defined and cannot be edited by any business user. A same ETS can be associated to many roles with different set of authorizations.
FAA	Ageing Acceleration Factor: Used by Loss of Life (LOL) element
FCS	Frame Check Sequence
FFail	A field failure (loss of excitation) element: Could be labeled 40 in ANSI terminology.
FFT	Fast Fourier Transform
FIR	Finite Impulse Response
FLC	Full load current: The nominal rated current for the circuit.
FLT / Flt	Fault - typically used to indicate faulted phase selection.
Fn or FN	Function
FPGA	Field Programmable Gate Array
FPS	Frames Per Second
FTP	File Transfer Protocol or Foil Twisted Pair
FTPS	FTP over TLS protocol. The classic file transfer protocol (FTP) secured using TLS tunneling.
Fusion	Project name for merge of previous 'MIRROR' and 'New SEPAM' projects
FWD, Fwd or Fwd.	Indicates an element responding to a flow in the "Forward" direction
GAT	Gateway Administration Tool (not yet developed)
Gen Diff	A generator differential element: Could be labeled 87G in ANSI terminology.
Gen-Xformer Diff	A generator-transformer differential element: Could be labeled 87GT in ANSI terminology.
GI	General Interrogation
GIF	Graphic Interchange Format – a file format for a computer graphic
GN>	Neutral over conductance protection element: Real component of admittance calculation from neutral current and residual voltage.
GND / Gnd	Ground: used in distance settings to identify settings that relate to ground (earth) faults.
GoCB	GOOSE Control Block
GOOSE	Generic Object Oriented Substation Event
GPS	Global Positioning System
GRP / Grp	Group. Typically an alternative setting group.
GSE	General Substation Event
GSSE	Generic Substation Status Event
GUESS	Generator Unintentional Energization at StandStill.

Term	Description
GUI	Graphical User Interface
HIPS	Host intrusion Prevention System based on “white list” of accepted executables.
HMI	Human Machine Interface
HSR	High-Availability Seamless Ring or High Availability Seamless Redundancy
HTML	Hypertext Markup Language
I	Current
I/O	Input/Output
I/P	Input
IANA	Internet Assigned Numbers Authority
ICAO	International Civil Aviation Organization
ICD	IED Capability Description
ID	Identifier or Identification. Often a label used to track a software version installed.
IDMT	Inverse Definite Minimum Time. A characteristic whose trip time depends on the measured input (e.g. current) according to an inverse-time curve.
IEC	International Electro-technical Commission
IED	Intelligent Electronic Device - a term used to describe microprocessor-based controllers of power system equipment. Common types of IEDs include protective relaying devices, load tap changer controllers, circuit breaker controllers, capacitor bank switches, recloser controllers, voltage regulators, etc.
IEEE	Institute of Electrical and Electronics Engineers
IET	IED Engineering ToolSuite for FUSION project. Similar to SET but dedicated to IED. or IED Engineering Tool.
IETF	Internet Engineering Task Force
IID	Instantiated/Individual IED Description
IIR	Infinite Impulse Response
Inh	An Inhibit signal
Inst	An element with Instantaneous operation: i.e. having no deliberate time delay.
IP	Internet Protocol
IRIG	InterRange Instrumentation Group
ISA	International Standard Atmosphere
ISA	Instrumentation Systems and Automation Society
ISO	International Standards Organization
JPEF	Joint Photographic Experts Group – a file format for a computer graphic
L	Live
LAN	Local Area Network
LCB	Log Control Block
LCD	Liquid Crystal Display: The front-panel text display on the relay.
LD	Level Detector: An element responding to a current or voltage below its set threshold. Or Logical Device
LDAP	Lightweight Directory Access Protocol
LDOV	Level Detector for OverVoltage
LDUV	Level Detector for UnderVoltage
LED	Light Emitting Diode: Red or green indicator on the front-panel.
LLDB	Live-Line Dead-Bus : In system synchronism check, indication that the line is energized whilst the bus is de-energized.
Ln	Natural logarithm
LN	Logical Node

Term	Description
LOGS	All the operations related to the security (connection, configuration…) are automatically caught in events that are logged in order to provide a good visibility of the previous actions to the security administrators.
LoL	A Loss of Load scheme, providing a fast distance trip without needing a signaling channel.
LPDU	Link Protocol Data Unit
LPHD	Logical Physical Device
LRE	Link Redundancy Entity
MAC	Media Access Control or Mandatory Access Control.
MC	MultiCast
MCB	Miniature Circuit Breaker
MIB	Management Information Base
MICS	Model Implementation Conformance Statement
MIDOS	Modular Integrated DrawOut System
MMF	Magneto-Motive Force
MMS	Manufacturing Message Specification
MRP	Media Redundancy Protocol
MU	Merging Unit
MV	Measured Value
N	Neutral
N/A	Not Applicable
N/C	A Normally Closed or “break” contact: Often called a “form B” contact.
N/O	A Normally Open or “make” contact: Often called a “form A” contact.
NERC	North American Reliability Corporation
NERO	NERC Electric Reliability Organization (ERO) certified by the Federal Energy Regulatory Commission to establish and enforce reliability standards for the bulk-power system.
NIC	Network Interface Card: i.e. the Ethernet card of the IED
NIST	National Institute of Standards and Technology
NPS	Negative Phase Sequence
NTP	The Network Time Protocol (NTP) is a protocol for synchronizing the clocks of computer systems.
NVD	Neutral Voltage Displacement: Equivalent to residual overvoltage protection.
NXT	Abbreviation of “Next”: In connection with hotkey menu navigation.
o	A small circle on the input or output of a logic gate: Indicates a NOT (invert) function.
O/C	Overcurrent
O/P	Output
OCB	Oil Circuit Breaker
OCSP	Online Certificate Status Protocol. An IETF RFC for online verification of certificates by servers (RFC 2560).
OID	Object IDentifier
Opto	An Optically coupled logic input. Alternative terminology: binary input.
OSI	Open Systems Interconnection
PAP	Policy Administration Point. Software entity that manage the security Policy
PCB	Printed Circuit Board
PCT	Protective Conductor Terminal (Ground)
PDC	Phasor Data Concentrator
PDP	Policy Decision Point. Software entity that evaluates the applicable policy and takes an authorization decision

Term	Description
PEP	Policy Enforcement Point. Software entity that performs access control and enforces authorization decision.
Ph	Phase - used in distance settings to identify settings that relate to phase-phase faults.
PICS	Protocol Implementation Conformance Statement
PIP	Policy Information Point. Software entity acting as an information source for the PDP.
PKI	Public Key infrastructure
PMU	Phasor Measurement Unit
PNG	Portable Network Graphics – a file format for a computer graphic
Pol	Polarize - typically the polarizing voltage used in making directional decisions.
POR	A Permissive OverReaching transfer trip scheme (alternative terminology: POTT).
POTT	A Permissive OverReaching Transfer Trip scheme (alternative terminology: POR).
PRP	Parallel Redundancy Protocol
PSB	Power Swing Blocking, to detect power swing/out of step functions (ANSI 78).
PSL	Programmable Scheme Logic: The part of the relay's logic configuration that can be modified by the user, using the graphical editor within MiCOM S1 Studio software.
PSlip	A Pole slip (out-of-step - OOS) element: could be labeled 78 in ANSI terminology.
PSP	Physical Security Perimeter
PSTN	Public Switched Telephone Network (RTC in French)
PT	Power Transformer
PTP	Precision Time Protocol
PUR	A Permissive UnderReaching transfer trip scheme (alternative terminology: PUTT).
Q	Quantity defined as per unit value
Qx	Isolator number x (from 1 to 6).
R	Resistance
RA	Registration Authority
R&TTE	Radio and Telecommunications Terminal Equipment
RBAC	Role Based Access Control. Authentication and authorization mechanism based on roles granted to a user. Roles are made of rights, themselves being actions that can be applied on objects. Each user's action is authorized or not based on his roles
RBN	Lead burden for the neutral.
RBPh	Lead burden for the phases.
RCA	Relay Characteristic Angle - The center of the directional characteristic.
RCB	Report Control Block
RCT	Redundancy Control Trailer or Redundancy Check Tag
REB	Redundant Ethernet Board
RedBox	Redundancy Box
REF	Restricted Earth Fault
Rev.	Indicates an element responding to a flow in the "reverse" direction
RMS / rms	Root mean square. The equivalent a.c. current: Taking into account the fundamental, plus the equivalent heating effect of any harmonics.
Roles	A role is a logical representation of a person activity. This activity authorizes or forbids operations within the tool suite thanks to permissions that are associated to the role. A role needs to be attached to a user account to have a real purpose.
RP	Rear Port: The communication ports on the rear of the IED
RS232	A common serial communications standard defined by the EIA
RS485	A common serial communications standard defined by the EIA (multi-drop)

Term	Description
RST or Rst	Reset generally used in the context of reset functions in circuit breaker control.
RSTP	Rapid Spanning Tree Protocol. Ethernet protocol allowing bumpless redundancy. Used with Redundant Ethernet board.
RTCS	Real Time Certificate Status. Facility. An IETF draft for online certificates validation.
RTD	Resistance Temperature Device
RTU	Remote Terminal Unit
Rx	Receive: Typically used to indicate a communication transmit line/pin.
SAM	Security Administration Module. Device in charge of security management on an IP-over-Ethernet network.
SAN	Singly or Single Attached Node
SAS	Substation Automation Solutions / System
SAT	Security Administration Tool TSF based application used to define and create security configuration
SAU	Security Administration Utility
SBS	Straight Binary Second
SC	Synch-Check or system Synchronism Check.
SCADA	Supervisory Control and Data Acquisition
SCD	Substation Configuration Description
SCEP	Simple Certificate Enrollment Protocol. An IETF draft for distribution and registration of public keys and certificates
SCL	Substation Configuration Language. In IEC 61850, the definition of the configuration files.
Scopes	The nodes of the hierarchy are viewed as scopes and can be secured independently. Each node could include some roles and user accounts defined in the tool suite and create a specific security policy.
SCSM	Specific Communication Service Mappings: In IEC 61850, the SCSMs define the actual information exchange mechanisms currently used (e.g. MMS).
SCU	Substation Control Unit
SCVP	Server-based Certificate Validation Protocol. An IETF RFC for online certificates validation.
SDEF	Sensitive Differential Earth Fault Protection
Secured IED	Devices embedding security mechanisms defined in the security architecture document
Security Administrator	A user of the system granted to manage its security
SEF	Sensitive Earth Fault Protection
Sen	Sensitive
SET	System Engineering Tools. New Tools in place of SCE and SMT, to deal with complete life cycle for Systems (design, realization, testing, commissioning, maintenance).
SFTP	A Secured File Transfer Protocol based on SSH.
SGCB	Setting Group Control Block
SHM	Self-Healing Manager
SHP	Self Healing Protocol
SHR	Self Healing Ring: Ethernet protocol allowing bumpless redundancy. Used with Redundant Ethernet board with self-healing protocol.
SIR	Source Impedance Ratio
SLA	Service Level Agreement
SMB	Server Message Block. Microsoft protocol for network resources sharing. Called CIFS on NT
SMT	Substation Management Tool (previously used on PACIS project)
SMTP	Simple Mail Transfer Protocol (SMTP) is an Internet standard for electronic mail (e-mail) transmission across Internet Protocol (IP) networks.
SMV	Sampled Measured Values

Term	Description
SNMP	Simple Network Management Protocol (SNMP) is an "Internet-standard protocol for managing devices on IP networks
SNTP	Simple Network Time Protocol
SOA	Service Oriented Architecture
SOAP	Simple Object Access Protocol
SOC	Second of Century
SOTF	Switch on to Fault protection. Modified protection on manual closure of the circuit breaker.
SP	Single pole.
SPAR	Single pole auto-reclose.
SPC	Single Point Controllable
SPDT	Single Pole Dead Time. The dead time used in single pole auto-reclose cycles.
SPS	Single Point Status
SQRT	Square Root
SSD	Solid State Device
SSH	Secured Shell. A secured encrypted network protocol for remote administration of computers
SSL	Secured Socket Layer or Source Impedance Ratio or See TLS (TLS is based on SSLv3).
SSO	Single Sign On
STP	Shielded Twisted Pair or Spanning Tree Protocol
SUI	Substation User Interface
SV	Sampled Values
SVC	Sampled Value Model
SVM	Sampled Value Model
TAF	Turbine Abnormal Frequency
TAT	Transfer Administration Tool
TBD	To Be Defined
TCP	Transmission Control Protocol
TCS	Second of Century
TCS	Trip Circuit Supervision
TD	Time Dial. The time dial multiplier setting: Applied to inverse-time curves (ANSI/IEEE).
TE	Unit for case measurements: One inch = 5TE units
THD	Total Harmonic Distortion
TICS	Technical Issues Conformance Statement
TIFF	Tagged Image File Format – a file format for a computer graphic
TLS	Transport Layer Security network protocol successor to SSL. Or Transport Layer Security. Creates encrypted tunnel for TCP connections. Can guarantee authentication when used in a PKI.
TMS	Time Multiplier Setting: Applied to inverse-time curves (IEC)
TOC	Trip On Close (“line check”) protection. Offers SOTF and TOR functionality.
TOR	Trip On Reclose protection. Modified protection on autoreclosure of the circuit breaker.
TP	Two-Part
TSF	Tool Suite Foundation. Common framework for SET and IET. Mainly 3 parts Core, Workbench (for standardized HMI), Utilities (applicative components like trace viewer, installer)
TUC	Timed UnderCurrent
TVE	Total Vector Error

Term	Description
Tx	Transmit
UA	User Account. A user account is a logical representation of a person with some configurable parameters. It includes information about the user identity and gives him a login to be recognized within the tool suite. A user account is principally interesting when it is associated to some roles that will grant him authorizations.
UDP	User Datagram Protocol
UL	Underwriters Laboratory
Unsecured IED	Relay/IEDs with no security mechanisms.
UPCT	User Programmable Curve Tool
UTC	Universal Time Coordinated
V	Voltage
VA	Phase A voltage: Sometimes L1, or red phase
VB	Phase B voltage: Sometimes L2, or yellow phase
VC	Phase C voltage: Sometimes L3, or blue phase
VCO	Voltage Controlled Overcurrent element
VDAN	Virtual Dual or Doubly Attached Node
VDEP OC>	A voltage dependent overcurrent element: could be a voltage controlled or voltage restrained overcurrent element and could be labeled 51V in ANSI terminology.
VDR	Voltage Dependent Resistor
VDS	Virtual Device Solution
V/Hz	An overfluxing element, flux is proportional to voltage/frequency: could be labeled 24 in ANSI terminology.
Vk	IEC knee point voltage of a current transformer.
VPN	Virtual Private Network (a secure private connection established on a public network or other unsecured environment).
VT	Voltage Transformer
VTS	Voltage Transformer Supervision: To detect VT input failure.
WAN	Wide Area Network
XACML	eXtensible Access Control Markup Language. An OASIS standard defining an XML access control policy implementation.
Xformer	Transformer
XKMS	XML Keys Management Specifications. A 3C standard, XML based, for distribution and registration of public keys and certificates
XML	Extensible Markup Language
XSD	XML Schema Definition

Table 1 - Acronyms and abbreviations

2 COMPANY PROPRIETARY TERMS

Symbol	Description
Courier	Schneider Electric's proprietary SCADA communications protocol
Metrosil	Brand of non-linear resistor produced by M&I Materials Ltd.
MiCOM	Schneider Electric's brand of protection relays

Table 2 - Company-proprietary terms

3 ANSI TERMS

ANSI no.	Description
3PAR	Three pole auto-reclose.
3PDT	Three pole dead time. The dead time used in three pole auto-reclose cycles.
52a	A circuit breaker closed auxiliary contact: The contact is in the same state as the breaker primary contacts
52b	A circuit breaker open auxiliary contact: The contact is in the opposite state to the breaker primary contacts
64R	Rotor earth fault protection
64S	100% stator earth (ground) fault protection using a low frequency injection method.
89a	An Isolator closed auxiliary contact: The contact is in the same state as the breaker primary contacts.
89b	An Isolator open auxiliary contact: The contact is in the opposite state to the breaker primary contacts.

Table 3 - ANSI abbreviations

ANSI no.	Function	Description
Current Protection Functions		
50/51	Phase overcurrent	Three-phase protection against overloads and phase-to-phase short-circuits.
50N/51N	Earth fault	Earth fault protection based on measured or calculated residual current values: • 50N/51N: residual current calculated or measured by 3 phase current sensors
50G/51G	Sensitive earth fault	Sensitive earth fault protection based on measured residual current values: • 50G/51G: residual current measured directly by a specific sensor such as a core balance CT
50BF	Breaker failure	If a breaker fails to be triggered by a tripping order, as detected by the non-extinction of the fault current, this backup protection sends a tripping order to the upstream or adjacent breakers.
46	Negative sequence / unbalance	Protection against phase unbalance, detected by the measurement of negative sequence current: • sensitive protection to detect 2-phase faults at the ends of long lines • protection of equipment against temperature build-up, caused by an unbalanced power supply, phase inversion or loss of phase, and against phase current unbalance
46BC	Broken conductor protection	Protection against phase imbalance, detected by measurement of I2/I1.
49RMS	Thermal overload	Protection against thermal damage caused by overloads on machines (transformers, motors or generators). The thermal capacity used is calculated according to a mathematical model which takes into account: • current RMS values • ambient temperature • negative sequence current, a cause of motor rotor temperature rise
Re-Closer		
79	Recloser	Automation device used to limit down time after tripping due to transient or semipermanent faults on overhead lines. The recloser orders automatic reclosing of the breaking device after the time delay required to restore the insulation has elapsed. Recloser operation is easy to adapt for different operating modes by parameter setting.
Directional Current Protection		
67N/67NC type 1 and 67	Directional phase overcurrent	Phase-to-phase short-circuit protection, with selective tripping according to fault current direction. It comprises a phase overcurrent function associated with direction detection, and picks up if the phase overcurrent function in the chosen direction (line or busbar) is activated for at least one of the three phases.

ANSI no.	Function	Description
67N/67NC	Directional earth fault	Earth fault protection, with selective tripping according to fault current direction. Three types of operation: • Type 1: the protection function uses the projection of the I0 vector • Type 2: the protection function uses the I0 vector magnitude with half-plane tripping zone • Type 3: the protection function uses the I0 vector magnitude with angular sector tripping zone
67N/67NC type 1	Directional current protection	Directional earth fault protection for impedant, isolated or compensated neutral systems, based on the projection of measured residual current.
67N/67NC type 2	Directional current protection	Directional overcurrent protection for impedance and solidly earthed systems, based on measured or calculated residual current. It comprises an earth fault function associated with direction detection, and picks up if the earth fault function in the chosen direction (line or busbar) is activated.
67N/67NC type 3	Directional current protection	Directional overcurrent protection for distribution networks in which the neutral earthing system varies according to the operating mode, based on measured residual current. It comprises an earth fault function associated with direction detection (angular sector tripping zone defined by 2 adjustable angles), and picks up if the earth fault function in the chosen direction (line or busbar) is activated.
Directional Power Protection Functions		

32P	Directional active overpower	Two-way protection based on calculated active power, for the following applications:
		• active overpower protection to detect overloads and allow load shedding
		• reverse active power protection:
		  • against generators running like motors when the generators consume active power
		  • against motors running like generators when the motors supply active power

32Q/40	Directional reactive overpower	Two-way protection based on calculated reactive power to detect field loss on synchronous machines: • reactive overpower protection for motors which consume more reactive power with field loss • reverse reactive overpower protection for generators which consume reactive power with field loss.
Machine Protection Functions		
37	Phase undercurrent	Protection of pumps against the consequences of a loss of priming by the detection of motor no-load operation. It is sensitive to a minimum of current in phase 1, remains stable during breaker tripping and may be inhibited by a logic input.

48/51LR/14	Locked rotor / excessive starting time	Protection of motors against overheating caused by:
		• excessive motor starting time due to overloads (e.g. conveyor) or insufficient supply voltage.
		The reacceleration of a motor that is not shut down, indicated by a logic input, may be considered as starting.
		• locked rotor due to motor load (e.g. crusher):
		  • in normal operation, after a normal start
		  • directly upon starting, before the detection of excessive starting time, with detection of locked rotor by a zero speed detector connected to a logic input, or by the underspeed function.

66	Starts per hour	Protection against motor overheating caused by:
		• too frequent starts: motor energizing is inhibited when the maximum allowable number of starts is reached, after counting of:
		  • starts per hour (or adjustable period)
		  • consecutive motor hot or cold starts (reacceleration of a motor that is not shut down, indicated by a logic input, may be counted as a start)
		• starts too close together in time: motor re-energizing after a shutdown is only allowed after an adjustable waiting time.

ANSI no.	Function	Description
50V/51V	Voltage-restrained overcurrent	Phase-to-phase short-circuit protection, for generators. The current tripping set point is voltage-adjusted in order to be sensitive to faults close to the generator which cause voltage drops and lowers the short-circuit current.
26/63	Thermostat/Buchholz	Protection of transformers against temperature rise and internal faults via logic inputs linked to devices integrated in the transformer.
38/49T	Temperature monitoring	Protection that detects abnormal temperature build-up by measuring the temperature inside equipment fitted with sensors: • transformer: protection of primary and secondary windings • motor and generator: protection of stator windings and bearings.
Voltage Protection Functions		
27D	Positive sequence undervoltage	Protection of motors against faulty operation due to insufficient or unbalanced network voltage, and detection of reverse rotation direction.
27R	Remanent undervoltage	Protection used to check that remanent voltage sustained by rotating machines has been cleared before allowing the busbar supplying the machines to be re-energized, to avoid electrical and mechanical transients.
27	Undervoltage	Protection of motors against voltage sags or detection of abnormally low network voltage to trigger automatic load shedding or source transfer. Works with phase-to-phase voltage.
59	Overvoltage	Detection of abnormally high network voltage or checking for sufficient voltage to enable source transfer. Works with phase-to-phase or phase-to-neutral voltage, each voltage being monitored separately.
59N	Neutral voltage displacement	Detection of insulation faults by measuring residual voltage in isolated neutral systems.
47	Negative sequence overvoltage	Protection against phase unbalance resulting from phase inversion, unbalanced supply or distant fault, detected by the measurement of negative sequence voltage.
Frequency Protection Functions		
81O	Overfrequency	Detection of abnormally high frequency compared to the rated frequency, to monitor power supply quality. Other organizations may use 81H instead of 81O.
81U	Underfrequency	Detection of abnormally low frequency compared to the rated frequency, to monitor power supply quality. The protection may be used for overall tripping or load shedding. Protection stability is ensured in the event of the loss of the main source and presence of remanent voltage by a restraint in the event of a continuous decrease of the frequency, which is activated by parameter setting. Other organizations may use 81L instead of 81U.
81R	Rate of change of frequency	Protection function used for fast disconnection of a generator or load shedding control. Based on the calculation of the frequency variation, it is insensitive to transient voltage disturbances and therefore more stable than a phase-shift protection function. **Disconnection** In installations with autonomous production means connected to a utility, the “rate of change of frequency” protection function is used to detect loss of the main system in view of opening the incoming circuit breaker to: • protect the generators from a reconnection without checking synchronization • avoid supplying loads outside the installation. **Load shedding** The “rate of change of frequency” protection function is used for load shedding in combination with the underfrequency protection to: • either accelerate shedding in the event of a large overload • or inhibit shedding following a sudden drop in frequency due to a problem that should not be solved by shedding.
Dynamic Line Rating (DLR) Protection Functions		

ANSI no.	Function	Description
49DLR	Dynamic line rating (DLR)	Protection of overhead lines based on calculation of rating or ampacity to dynamically take into account the effect of prevailing weather conditions as monitored by external sensors for: • Ambient Temperature • Wind Velocity • Wind Direction • Solar Radiation

Table 4 - ANSI descriptions

4 CONCATENATED TERMS

Term
Undercurrent
Overcurrent
Overfrequency
Underfrequency
Undervoltage
Overvoltage

Table 5 - Concatenated terms

5 UNITS FOR DIGITAL COMMUNICATIONS

Unit	Description
b	bit
B	Byte
kb	Kilobit(s)
kbps	Kilobits per second
kB	Kilobyte(s)
Mb	Megabit(s)
Mbps	Megabits per second
MB	Megabyte(s)
Gb	Gigabit(s)
Gbps	Gigabits per second
GB	Gigabyte(s)
Tb	Terabit(s)
Tbps	Terabits per second
TB	Terabyte(s)

Table 6 - Units for digital communications

6 AMERICAN VS BRITISH ENGLISH TERMINOLOGY

British English	American English
…ae…	…e…
…ence	…ense
…ise	…ize
…oe…	…e…
…ogue	…og
…our	…or
…ourite	…orite
…que	…ck
…re	…er
…yse	…yze
Aluminium	Aluminum
Centre	Center
Earth	Ground
Fibre	Fiber
Ground	Earth
Speciality	Specialty

Table 7 - American vs British English terminology

7 LOGIC SYMBOLS AND TERMS

Symbol	Description	Units
&	Logical “AND”: Used in logic diagrams to show an AND-gate function.	
Σ	“Sigma”: Used to indicate a summation, such as cumulative current interrupted.	
τ	“Tau”: Used to indicate a time constant, often associated with thermal characteristics.	
ω	System angular frequency	rad
<	Less than: Used to indicate an “under” threshold, such as undercurrent (current dropout).	
>	Greater than: Used to indicate an “over” threshold, such as overcurrent (current overload)	
o	A small circle on the input or output of a logic gate: Indicates a NOT (invert) function.	
1	Logical “OR”: Used in logic diagrams to show an OR-gate function.	
ABC	Clockwise phase rotation.	
ACB	Anti-Clockwise phase rotation.	
C	Capacitance	A
df/dt	Rate of Change of Frequency protection	Hz/s
df/dt>1	First stage of df/dt protection	Hz/s
F<	Underfrequency protection: Could be labeled 81-U in ANSI terminology.	Hz
F>	Overfrequency protection: Could be labeled 81-O in ANSI terminology.	Hz
F<1	First stage of under frequency protection: Could be labeled 81-U in ANSI terminology.	Hz
F>1	First stage of over frequency protection: Could be labeled 81-O in ANSI terminology.	Hz
f_{max}	Maximum required operating frequency	Hz
f_{min}	Minimum required operating frequency	Hz
f_n	Nominal operating frequency	Hz
I	Current	A
I^	Current raised to a power: Such as when breaker statistics monitor the square of ruptured current squared ($\wedge$ power = 2).	An
I’f	Maximum internal secondary fault current (may also be expressed as a multiple of In)	A
I<	An undercurrent element: Responds to current dropout.	A
I>>	Current setting of short circuit element	In
I>	A phase overcurrent protection: Could be labeled 50/51 in ANSI terminology.	A
I>1	First stage of phase overcurrent protection: Could be labeled 51-1 in ANSI terminology.	A
I>2	Second stage of phase overcurrent protection: Could be labeled 51-2 in ANSI terminology.	A
I>3	Third stage of phase overcurrent protection: Could be labeled 51-3 in ANSI terminology.	A
I>4	Fourth stage of phase overcurrent protection: Could be labeled 51-4 in ANSI terminology.	A
I>BB	Minimum pick-up phase threshold for the local trip order confirmation.	A
I>DZ	Minimum pick-up phase threshold for the Dead Zone protection.	A
I_0	Earth fault current setting Zero sequence current: Equals one third of the measured neutral/residual current.	A
I_1	Positive sequence current.	A
I_2	Negative sequence current.	A
I2>	Negative sequence overcurrent protection (NPS element).	A
I2pol	Negative sequence polarizing current.	A
I2therm>	A negative sequence thermal element: Could be labeled 46T in ANSI terminology.	
IA	Phase A current: Might be phase L1, red phase.. or other, in customer terminology.	A
IB	Phase B current: Might be phase L2, yellow phase.. or other, in customer terminology.	A
IbiasPh> Cur.	SDEF blocking bias current threshold.	

Symbol	Description	Units
IC	Phase C current: Might be phase L3, blue phase.. or other, in customer terminology.	A
ID>1	Minimum pick-up phase circuitry fault threshold.	
ID>2	Minimum pick-up differential phase element for all the zones.	
IDCZ>2	Minimum pick-up differential phase element for the Check Zone.	
Idiff	Current setting of biased differential element	A
IDN>1	Minimum pick-up neutral circuitry fault threshold.	
IDN>2	Minimum pick-up differential neutral element for all the zones.	
IDNCZ>2	Minimum pick-up differential neutral element for the Check Zone.	
IDZ	Minimum pick-up differential neutral element for the Check Zone.	
If	Maximum secondary through-fault current	A
If max	Maximum secondary fault current (same for all feeders)	A
If max int	Maximum secondary contribution from a feeder to an internal fault	A
If Z1	Maximum secondary phase fault current at Zone 1 reach point	A
Ife	Maximum secondary through fault earth current	A
IfeZ1	Maximum secondary earth fault current at Zone 1 reach point	A
Ifn	Maximum prospective secondary earth fault current or 31 x I> setting (whichever is lowest)	A
Ifp	Maximum prospective secondary phase fault current or 31 x I> setting (whichever is lowest)	A
I_m	Mutual current	A
IM64	InterMiCOM64.	
IMx	InterMiCOM64 bit (x=1 to 16)	
I_n	Current transformer nominal secondary current. The rated nominal current of the relay: Software selectable as 1 amp or 5 amp to match the line CT input.	A
IN	Neutral current, or residual current: This results from an internal summation of the three measured phase currents.	A
IN>	A neutral (residual) overcurrent element: Detects earth/ground faults.	A
IN>1	First stage of ground overcurrent protection: Could be labeled 51N-1 in ANSI terminology.	A
IN>2	Second stage of ground overcurrent protection: Could be labeled 51N-2 in ANSI terminology.	A
IN>BB	Minimum pick-up neutral threshold for the local trip order confirmation.	
IN>DZ	Minimum pick-up neutral threshold for the Dead Zone protection.	
Inst	An element with “instantaneous” operation: i.e. having no deliberate time delay.	
I/O	Inputs and Outputs - used in connection with the number of optocoupled inputs and output contacts within the relay.	
I/P	Input	
Iref	Reference current of P63x calculated from the reference power and nominal voltage	A
IREF>	A Restricted Earth Fault overcurrent element: Detects earth (ground) faults. Could be labeled 64 in ANSI terminology.	A
IRm2	Second knee-point bias current threshold setting of P63x biased differential element	A
Is	Value of stabilizing current	A
IS1	Differential current pick-up setting of biased differential element	A
IS2	Bias current threshold setting of biased differential element	A
I_{SEF}>	Sensitive Earth Fault overcurrent element.	A
Isn	Rated secondary current (I secondary nominal)	A
Isp	Stage 2 and 3 setting	A
Ist	Motor start up current referred to CT secondary side	A
K	Dimensioning factor	

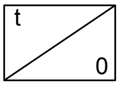
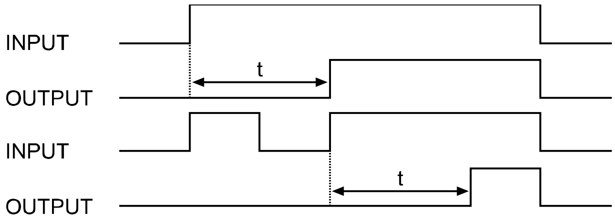
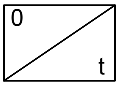
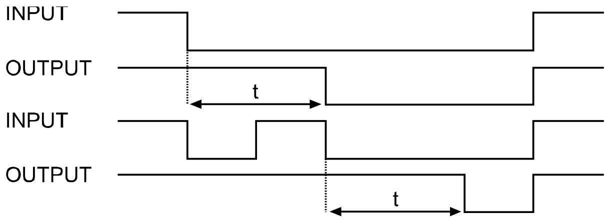
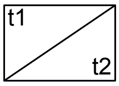
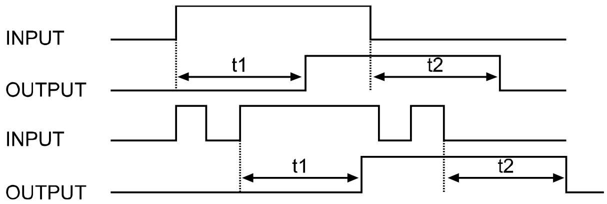
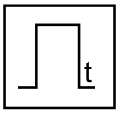
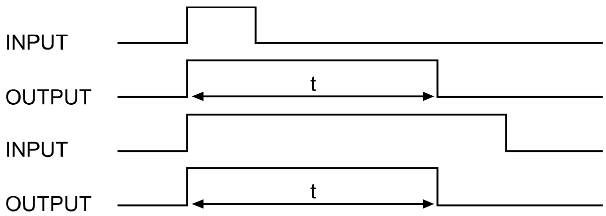
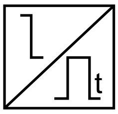
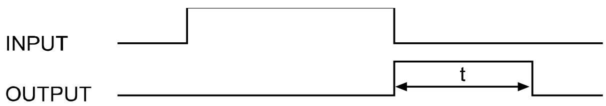
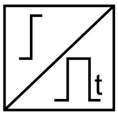
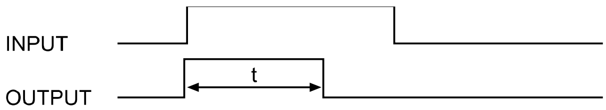
Symbol	Description	Units
K_1	Lower bias slope setting of biased differential element	%
K_2	Higher bias slope setting of biased differential element	%
KCZ	Slope of the differential phase element for the Check Zone.	
K_e	Dimensioning factor for earth fault	
km	Distance in kilometers	
K_{max}	Maximum dimensioning factor	
KNCZ	Slope of the differential neutral element for the Check Zone.	
K_{rpa}	Dimensioning factor for reach point accuracy	
K_s	Dimensioning factor dependent upon through fault current	
K_{ssc}	Short circuit current coefficient or ALF	
K_t	Dimensioning factor dependent upon operating time	
kZm	The mutual compensation factor (mutual compensation of distance elements and fault locator for parallel line coupling effects).	
kZN	The residual compensation factor: Ensuring correct reach for ground distance elements.	
L	Inductance	A
m1	Lower bias slope setting of P63x biased differential element	None
m2	Higher bias slope setting of P63x biased differential element	None
mi	Distance in miles.	
N	Indication of “Neutral” involvement in a fault: i.e. a ground (earth) fault.	
-P>	A reverse power (W) element: could be labeled 32R in ANSI terminology.	
P>	An overpower (W) element: could be labeled 32O in ANSI terminology.	
P<	A low forward power (W) element: could be labeled 32L in ANSI terminology.	
P1	Used in IEC terminology to identify the primary CT terminal polarity: Replace by a dot when using ANSI standards.	
P2	Used in IEC terminology to identify the primary CT terminal polarity: The non-dot terminal.	
P_n	Rotating plant rated single phase power	W
PN>	Wattmetric earth fault protection: Calculated using residual voltage and current quantities.	
Q<	A reactive under power (VAr) element	
R	Resistance (Ω)	Ω
R< or 64S R<	A 100% stator earth (ground) fault via low frequency injection under resistance element: could be labeled 64S in ANSI terminology.	
R Gnd.	A distance zone resistive reach setting: Used for ground (earth) faults.	
R Ph	A distance zone resistive reach setting used for Phase-Phase faults.	
Rct	Secondary winding resistance	Ω
RCT	Current transformer secondary resistance	Ω
Rl	Resistance of single lead from relay to current transformer	Ω
Rr	Resistance of any other protective relays sharing the current transformer	Ω
Rrn	Resistance of relay neutral current input	Ω
Rrp	Resistance of relay phase current input	Ω
Rs	Value of stabilizing resistor	Ω
Rx	Receive: typically used to indicate a communication receive line/pin.	
S<	An apparent under power (VA) element	
S1	Used in IEC terminology to identify the secondary CT terminal polarity: Replace by a dot when using ANSI standards.	

Symbol	Description	Units
S2	Used in IEC terminology to identify the secondary CT terminal polarity: The non-dot terminal. Also used to signify negative sequence apparent power, S2 = V2 x I2.	
S2>	A negative sequence apparent power element, S2 = V2 x I2.	
t	A time delay.	
t’	Duration of first current flow during auto-reclose cycle	s
T1	Primary system time constant	s
TF	Through Fault monitoring	
tfr	Auto-reclose dead time	s
Thermal I>	A stator thermal overload element: could be labeled 49 in ANSI terminology.	
Thru/TF	Through Fault monitoring	
tIdiff	Current differential operating time	s
Ts	Secondary system time constant	s
Tx	Transmit: typically used to indicate a communication transmit line/pin.	
V	Voltage.	V
V<	An undervoltage element: could be labeled 27 in ANSI terminology	V
V<1	First stage of undervoltage protection: Could be labeled 27-1 in ANSI terminology.	V
V<2	Second stage of undervoltage protection: Could be labeled 27-2 in ANSI terminology.	V
V>	An overvoltage element: could be labeled 59 in ANSI terminology	V
V>1	First stage of overvoltage protection: Could be labeled 59-1 in ANSI terminology.	V
V>2	Second stage of overvoltage protection: Could be labeled 59-2 in ANSI terminology.	V
V0	Zero sequence voltage: Equals one third of the measured neutral/residual voltage.	V
V1	Positive sequence voltage.	V
V2	Negative sequence voltage.	V
V2>	A negative phase sequence (NPS) overvoltage element: could be labeled 47 in ANSI terminology.	
$V2_{pol}$	Negative sequence polarizing voltage.	V
V_A	Phase A voltage: Might be phase L1, red phase.. or other, in customer terminology.	V
V_B	Phase B voltage: Might be phase L2, yellow phase.. or other, in customer terminology.	V
V_C	Phase C voltage: Might be phase L3, blue phase.. or other, in customer terminology.	V
Vf	Theoretical maximum voltage produced if CT saturation did not occur	V
Vin	Input voltage e.g. to an opto-input	V
V_k	Required CT knee-point voltage. IEC knee point voltage of a current transformer.	V
VN	Neutral voltage displacement, or residual voltage.	V
VN>	A residual (neutral) overvoltage element: could be labeled 59N in ANSI terminology.	V
V_n	Nominal voltage	V
Vn	The rated nominal voltage of the relay: To match the line VT input.	V
VN>1	First stage of residual (neutral) overvoltage protection.	V
VN>2	Second stage of residual (neutral) overvoltage protection.	V
VN3H>	A 100% stator earth (ground) fault 3rd harmonic residual (neutral) overvoltage element: could be labeled 59TN in ANSI terminology.	
VN3H<	A 100% stator earth (ground) fault 3rd harmonic residual (neutral) undervoltage element: could be labeled 27TN in ANSI terminology.	
Vres.	Neutral voltage displacement, or residual voltage.	V
Vs	Value of stabilizing voltage	V
V_x	An auxiliary supply voltage: Typically the substation battery voltage used to power the relay.	V

Symbol	Description	Units
WI	Weak Infeed logic used in teleprotection schemes.	
X	Reactance	None
X/R	Primary system reactance/resistance ratio	None
Xe/Re	Primary system reactance/resistance ratio for earth loop	None
Xt	Transformer reactance (per unit)	p.u.
Y	Admittance	p.u.
YN>	Neutral overadmittance protection element: Non-directional neutral admittance protection calculated from neutral current and residual voltage.	
Z	Impedance	p.u.
Z<	An under impedance element: could be labeled 21 in ANSI terminology.	
Z0	Zero sequence impedance.	
Z1	Positive sequence impedance.	
Z1	Zone 1 distance protection.	
Z1X	Reach-stepped Zone 1X, for zone extension schemes used with auto-reclosure.	
Z2	Negative sequence impedance.	
Z2	Zone 2 distance protection.	
ZP	Programmable distance zone that can be set forward or reverse looking.	
Zs	Used to signify the source impedance behind the relay location.	
Φal	Accuracy limit flux	Wb
Ψr	Remanent flux	Wb
Ψs	Saturation flux	Wb

Table 8 - Logic Symbols and Terms

8 LOGIC TIMERS

Logic symbols	Explanation	Time chart
	Delay on pick-up timer, t	
	Delay on drop-off timer, t	
	Delay on pick-up/drop-off timer	
	Pulse timer	
	Pulse pick-up falling edge	
	Pulse pick-up raising edge	

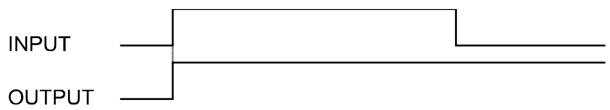
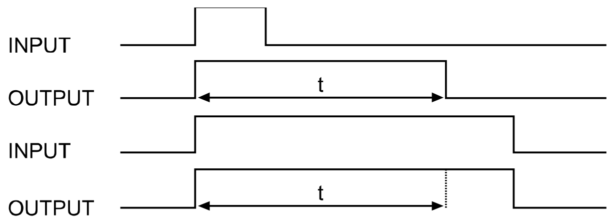
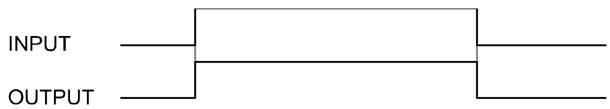
Logic symbols	Explanation	Time chart
Latching	Latch	
Dwell Timer	Dwell timer	
Straight	Straight (non latching): Hold value until input reset signal	

Table 9 - Logic Timers

9 LOGIC GATES

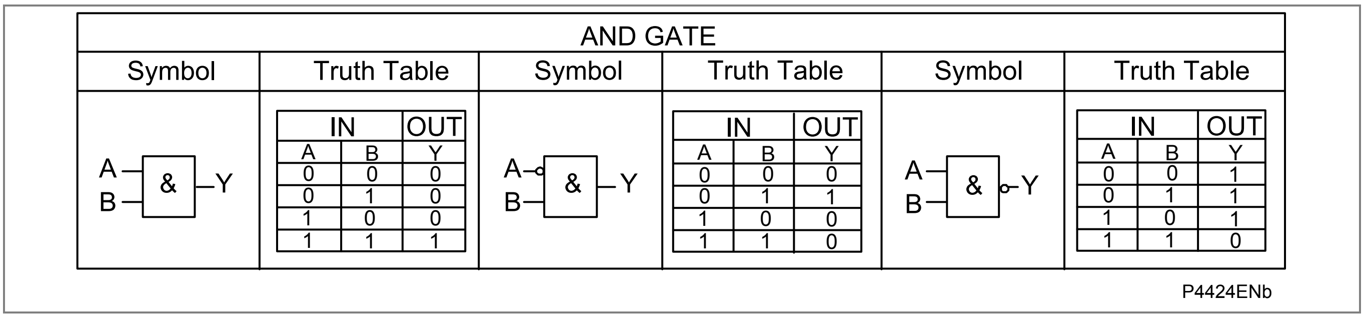


Figure 1 - Logic Gates - AND Gate

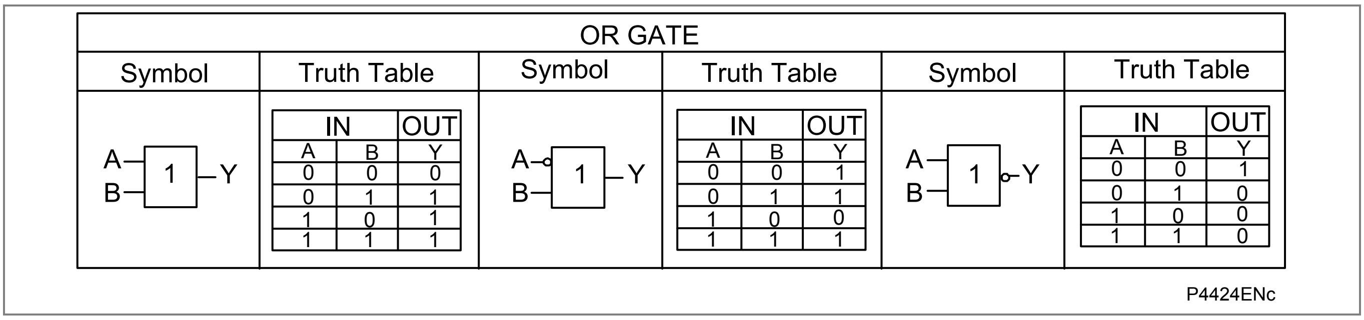


Figure 2 - Logic Gates - OR Gate

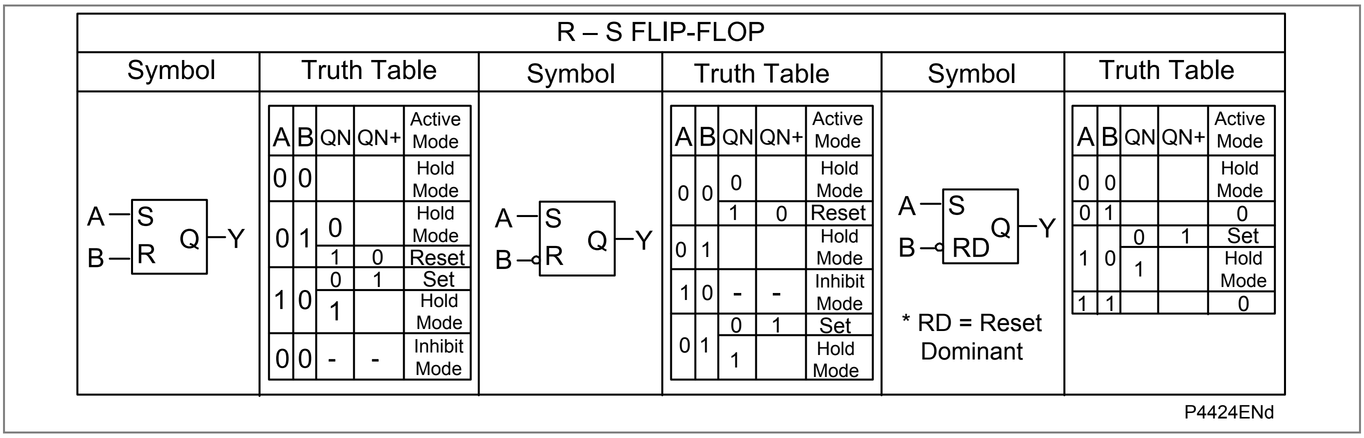


Figure 3 - Logic Gates - R-S Flip-Flop Gate

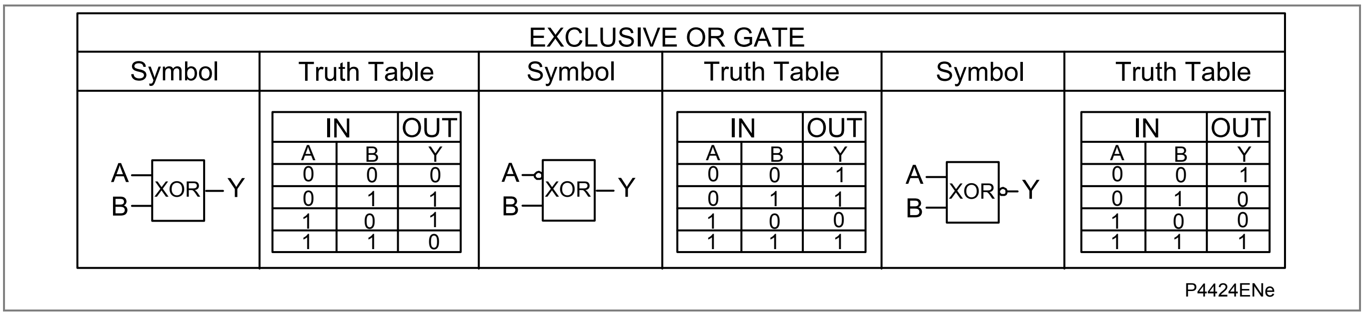
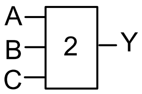


Figure 4 - Logic Gates - Exclusive OR Gate

PROGRAMMABLE GATE

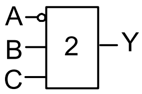
Symbol



Truth Table

IN			OUT
A	B	C	Y
0	0	0	0
0	0	1	0
0	1	0	0
0	1	1	1
1	0	0	0
1	0	1	1
1	1	0	1
1	1	1	1

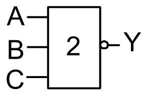
Symbol



Truth Table

IN			OUT
A	B	C	Y
0	0	0	0
0	0	1	1
0	1	0	1
0	1	1	1
1	0	0	0
1	0	1	0
1	1	0	0
1	1	1	1

Symbol



Truth Table

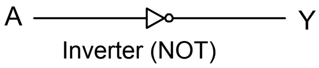
IN			OUT
A	B	C	Y
0	0	0	1
0	0	1	1
0	1	0	1
0	1	1	0
1	0	0	1
1	0	1	0
1	1	0	0
1	1	1	0

P4424ENf

Figure 5 - Logic Gates - Programmable Gate

NOT GATE

Symbol



Truth Table

IN	OUT
A	Y
0	1
1	0

P4424ENg

Figure 6 - Logic Gates - NOT Gate

Notes:

Customer Care Centre

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